Stefan Orszulik *Editor*

Environmental Technology in the Oil Industry

Third Edition

Springer

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Grove, Wantage, UK

ISBN 978-3-319-24332-0 ISBN 978-3-319-24334-4 (eBook)
DOI 10.1007/978-3-319-24334-4

Library of Congress Control Number: 2015959156

Springer Cham Heidelberg New York Dordrecht London

Printed on acid-free paper

Springer International Publishing AG Switzerland is part of Springer Science+Business Media (www.springer.com)

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Chapter 1
General Introduction

A. Ahnell and Peter Evans

1 Environmental Technology

Perhaps the place to start this book is with definitions of the two key words [1]:

- **Technology** – the scientific study and practical application of the industrial arts, applied sciences, etc., or the method for handling a specific technical problem.
- **Environmental** – all the conditions, circumstances and influences surrounding and affecting the development of an organism or group of organisms.

Environmental technology is the scientific study or the application of methods to understand and handle problems which influence our surroundings and, in the case of this book, the surroundings around oil industry facilities and where oil products are used. Traditionally the phrase has meant the application of additional treatment processes added on to industrial processes to treat air, water and waste before discharge to the environment. Increasingly the phrase has a new meaning where the concept is to create cleaner process technology and move towards sustainability.

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_1

2 The Beginning

As we begin our discussion of environmental technology, it is important to take a few moments to remember how we became so involved with this substance, oil. For the purpose of this book, the general term oil is used to capture a wide range of naturally occurring hydrocarbons ranging from small molecules such as natural gas (methane) through to heavy molecules such as tars (asphaltics). They are all formed over millions of years through geologic processes and in their crude state comprise complex mixtures of many thousands of different compositions. They can be processed (refined) into an even greater array of products including fuels, plastics and fertilizers.

Regardless of our opinions about its use, oil was the key energy resource in the twentieth century. From humble beginnings as a medicine and a lamp oil, oil has become the energy of choice for transport and many other applications and is the feedstock for a major class of the material used today, plastic. Projections of energy demand for the twenty-first century continue this trend with oil and gas continuing to provide around half of all of the worlds' primary energy production through to 2035 and beyond in a global economy where demand for energy is set to increase by over 40 % [2].

It is in some ways ironic that oil, initially the cheap fuel for lighting that improved many peoples' lives, next the enabler of affordable motorized personal transport and later the solution to the air pollution problems caused by coal, has become one of the chief environmental concerns of the early twenty-first century. Often the fuel of choice because of price and convenience, oil was once also the 'environmentally friendly' choice. Long before the 1950s, London suffered from 'pea souper' fogs caused by stagnant air patterns and emissions from open coal fires which resulted in serious respiratory problems. These fogs caused hospitals to fill with sufferers of respiratory ailments. As a result, 'smokeless zones' were enacted and coal gas and then oil became the heating fuels of choice.

It can truly now be said we exist in a Hydrocarbon Society [3], the paradox being that we want the mobility and convenient energy that oil provides, but we also want a clean environment. In recognizing the need for oil, we also need to ensure that the environment is respected.

At this stage it is also worth introducing two further terms. The production of hydrocarbons can be divided into two quite distinct operational phases:

Upstream – which comprises the exploration, drilling, pumping, separation and initial transport of the oil

Downstream – the refining (processing) of crude oil into directly useable products such as fuels (gasoline, diesel etc.) and the manufacture of basic building blocks such as PTA (purified terephthalic acid – the precursor for polyethylene) that act as the feedstock for a host of other uses.

In addition, the term mid-stream is occasionally used to define logistical operations such as pipelines and shipping. Whilst some companies cover the entire production cycle, the so-called IOCs – Integrated Oil Companies such as BP, Exxon Mobil and Shell, others specialize in one or more aspect of the product cycle.

3 The Environmental Effects of the Oil Industry

What kind of impact does the oil industry have? One way to begin to assess this aspect is to look at the emissions, in terms of both their effect and the quantity. Although emissions data for industry worldwide are not available, the drive for greater transparency and regulated disclosures has resulted in many oil companies adopting shared standards of reporting that sit alongside annual statements of financial results and from which general long term trends can be inferred [4]. In a global marketplace where companies invest and divest major assets, such compilations offer a more stable benchmark than reviewing any one company in isolation. Here, we derive values from the 2012 Environmental Performance indicators as compiled by the International Association of Oil and Gas Producers – IOGP. Together these equate to over 40 companies and 16.6 Billion BOE (barrels of oil equivalent) or approximately a third of global production. However, it should be noted that this compilation is not evenly spread across the world and whilst it contains almost all production from Europe the data from Russia, for example, equates to only 8 % of oil produced in that country.

A global benchmark for downstream processes is harder to establish and there are a number of reasons for this. To begin with the number of companies involved is far greater, and materials may pass through multiple organizations as they are converted from crude oil to finished product. Defining the end-point is also far harder – should we stop measuring where PTA has been made or where it has been converted into polyethylene. Although not as extensive as the OGP upstream data, the United Kingdom Petroleum Industry Association (UKPIA) compiled similar 2010 data for the refining sector in the UK. These data represent activities of nine companies at seven refineries with approximately 1.7 million barrels per day crude production capacity. These refineries typically use 5 and 6 % of throughput to provide the energy needed to refine the crude into products [5].

Regardless of what part of the value-chain we examine, one fact always holds true. The industry comprises of large, complex and very expensive equipment which is years in the designing and may operate for decades before it become redundant or replaced. Change is therefore always incremental as there will be a legacy of environmental hardware and practices.

3.1 Air Emissions

The production and processing of oil releases gases to the atmosphere. Like any large-scale industrial process, there are gaseous emissions linked to energy usage that have to be accounted for. In addition, the process of bringing hydrocarbons to the surface from deep geological reservoirs, where they are held under pressure, will also result in a range of gases escaping. These include gases such as carbon dioxide and sulphur dioxide which are known to be harmful to the environment and therefore their effects have to be assessed and quantified.

3.1.1 Carbon Dioxide

Carbon Dioxide (CO_2) is a trace gas in the atmosphere, around 0.04 % or 400 ppm (parts per million). It is the waste product of aerobic respiration and from combustion of organic material and may also be released from the manufacture of materials such as cement. It is essential for photosynthesis and therefore an integral building block for all life on earth. However, rising levels of carbon dioxide in the atmosphere since the industrial revolution of the eighteenth century have been implicated as the principal mechanism behind global warming and climate change. Carbon Dioxide affects the reflectance of energy away from the Earth's surface (hence why it is frequently referred to as a greenhouse gas) and whilst atmospheric concentrations are known to have varied considerably over geological time, the human influence on carbon dioxide concentrations in the atmosphere and climate system is clear, and recent anthropogenic emissions of greenhouse gases are the highest in history. Recent climate changes have had widespread impacts on human and natural systems. Warming of the climate system is unequivocal, and since the 1950s, many of the observed changes are unprecedented over decades to millennia. The atmosphere and ocean have warmed, the amounts of snow and ice have diminished, and sea level has risen [6]. Projections of greenhouse gas emissions into the next century vary over a wide range, depending on both socio-economic development and climate policy but the role of carbon dioxide in this process is now accepted by all major governments and most industries.

From the IOGP data, carbon dioxide dominates gaseous emissions from the oil industry – contributing more than 99 % of all releases to the atmosphere. Around 132 tonnes of carbon dioxide are released per thousand tonnes of oil and gas produced. Of this, around 60 % is associated with the energy demands of oil and gas production – operating energy intensive equipment such as pumping. The remainder is dominated by flaring – the combustion of natural gas associated with oil production which cannot be economically captured, processed and used on-site or sold. Only a small fraction, around 6 %, is associated with venting of carbon dioxide dissolved within the oil and released as pressure drops.

In recent years there has been notable reductions in the amount of carbon dioxide emitted per unit volume of oil produced, dropping by almost 10 % since 2006. This can be attributed to improvements in production processes including greater re-injection of unused gases into mature oil reservoirs to maintain pressure and boost production. However, within this global trend there underlies significant variation depending upon both the source of hydrocarbons and their production process. For example, high volume liquid oil production in Europe and the Middle East yield less than a third of carbon dioxide compared to production in Africa and North America. The reasons for this are many, but include less developed infrastructure and markets for gas resulting in increased flaring through to the growth of the so-called unconventional hydrocarbon reserves such as shale gas (methane tightly bound to shale rocks and released by hydraulic fracturing ‘fracking’) and oil sands – (bituminous hydrocarbons that require heating to liquefy and extract the oil fraction) which are more energy intensive.

Downstream data from UKPIA, carbon dioxide emissions for the UK refineries was slightly over 16 million tonnes, or 220 tonnes of carbon dioxide per thousand tonnes of oil processed as compared to the 132 tonnes for the upstream. For further context, these emissions are about 3 % of the UK’s CO_2 emissions. UK refinery CO_2 emissions declined year on year in 2010 by a little more than 0.6 %

3.1.2 Methane

Methane is the simplest hydrocarbon. Its main impact is as a greenhouse gas, with 21 times greater global warming potential than carbon dioxide. Methane is emitted from process vents and gas driven pneumatic devices along with fugitive emissions from process components such as valves. Incomplete combustion of natural gas in turbines and in flares can also release methane to the atmosphere. Before a well is complete gases from the reservoir will also be lost to the atmosphere and this effect is particularly relevant to methane as it is the principal hydrocarbon released from unconventional ‘tight’ deposits such as shale and coals.

Methane emissions per unit of production are rising steadily, from 1.00 tonne per thousand tonnes of hydrocarbon production in 2006 to 1.33 tonnes in 2012. However, as in the case carbon dioxide, the amount of methane emitted varies across the world, with a 17-fold difference between the lowest emitter (Middle East) and the highest (Asia) reflecting differences in production techniques as well as underlying geological conditions. The greatest change in recent years is in North America where an increase over 1 tonne per thousand tonnes of oil produced can be most readily linked to increasingly complex hydrocarbon production processes including hydraulic fracturing where many more wells will be drilled and completed to yield the same volume of production as a conventional reservoir. With unconventional reserves set to play an increasing role in world energy production in future decades, the trend for increasing methane emissions is one that is liable to continue.

Downstream data specific to methane are not available but the category of Volatile Organic Compounds (VOC) will be covered after the non-methane upstream data presented next. Since methane is removed from the crude before refining, downstream methane emissions are expected to be negligible.

3.1.3 Non-methane Hydrocarbon Emissions

Many of petroleum industry products are volatile. When exposed to air, some components of crude oil, gasoline, other fuels and many chemicals can evaporate. In addition, gas can be released from operations through controlled process vents for safety protection. Further safety devices, such as flares, are used to burn excess hydrocarbons in the industry, but can allow a small proportion of hydrocarbon into the atmosphere without being burnt. Industry contains and controls these emissions wherever possible to minimize any loss of hydrocarbon.

Hydrocarbon vapours, often described as non methane volatile organic compounds or NMVOCs, are potentially harmful air pollutants, which can result in local health impacts as well as local or regional contributions to the formation of low level ozone; which in turn, may also impact human health.

In contrast to methane, there has been a marked decrease in overall release of NMVOCs in oil and gas production falling from 0.7 tonnes per thousand tonnes of oil produced in 2006 to 0.48 in 2012. This can be directly linked to improvements in technology such as vapour recovery equipment that captures the volatile component of the oil during processing and returning in to the storage tanks.

Recall that VOC emissions would be similar to the upstream non-methane designation in the upstream data since methane would not be present at a refinery. VOCs are produced from evaporation from refining and storage of oil products. From the UKPIA data we can see that about 0.7 tonne of VOC was emitted per thousand tonnes of crude refined and then distributed and 0.3 tonnes per thousand tonnes of crude refined. Since 1990 refinery and storage emissions have fallen by 70 % due to leak detection and repair programmes.

3.1.4 Sulphur Dioxide

Sulphur is a component of most crude oils and many gases and a significant percentage of emissions. Crude oil containing more than 0.5 % sulphur is termed ‘sour’ a phrase derived from early prospectors who would taste the crude to determine it quality – low sulphur crude tasting ‘sweet’ and whilst the practise has long since died out the terms persist to this day. Sweet crude is easier to refine and safer to extract and transport than sour crude. Because sulphur is corrosive, light crude also causes less damage to refineries and thus results in lower maintenance costs over time. Due to all these factors, sweet crude commands a premium per barrel over sour. Major locations where sweet crude is found include the Appalachian Basin in Eastern North America, Western Texas, the Bakken Formation of North Dakota and Saskatchewan, the North Sea of Europe, North Africa, Australia, and the Far East including Indonesia.

Irrespective of whether it is sweet or sour, the majority of the sulphur is bound as sulphur containing hydrocarbons. Combustion leads to the emission of sulphur dioxide either in energy production or in flaring. Sour crudes may also contain appreciable levels of hydrogen sulphide, with its characteristic rotten egg smell, which is poisonous and pose a significant health and safety hazard to afflicted production facilities. At moderate concentrations, hydrogen sulphide can cause respiratory and nerve damage. At high concentrations, it is instantly fatal. Hydrogen sulphide is so much of a risk that sour crude has to be stabilized via removal of hydrogen sulphide before it can be transported by oil tankers.

The recent global trend has been for a small, but measurable, decline in SO_2 emissions per unit of production, falling from 0.2 tonnes per thousand barrels in 2006 to 0.17 in 2012. Flaring is the dominant source of emissions accounting for almost two thirds of that released. Again, there is considerable variation in the amount of sulphur dioxides emitted by region, reflecting both local differences in whether the crude is sweet or sour and differences in flaring. Accordingly, Europe with low levels of flaring and predominately sweet crudes produces the least sulphur dioxide.

In the downstream as with the upstream, the major source of SO_2 emissions is combustion of the sulphur naturally present in crude. Refinery SO_2 emissions from the UK refineries was around 56 thousand tonnes or 0.75 tonnes per thousand tonnes of crude refined as compared to the 0.2 tonnes reported for the upstream. For the UK refineries SO_2 emissions have decreased 72 % since 1970 due to increased sulphur recovery and less sulphur in the crudes refined. Crude sulphur content has increased recently in the UK and further reductions are planned.

3.1.5 Nitrogen Oxides

Nitrogen oxides are produced whenever fossil fuels are burned with energy production accounting for the majority of nitrous oxides generated in oil and gas production. Increases in NOx are therefore closely correlated with energy intensive operations such as drilling. Emissions are a function of the peak temperature at which the fuel is burnt. When emitted, they result in nitrogen dioxide pollution.

Nitrous oxides can have both local health and vegetation impacts, as well as contributing to regional acid rain impacts and low-level ozone formation. Unlike other emissions nitrogen oxides are frequently estimated from other operating data and differences in the calculations used can have significant impacts upon reported figures. Nitrogen oxides can be reduced through the installation of modern low NOx burners. Globally, nitrous oxide emissions remain stable – around 0.4 tonnes per thousand tonnes of oil produced, with higher emissions in where oil production is more energy intensive.

As with upstream the downstream source of NOx is energy production, in this case at refineries. The UK 2010 refinery data show 0.33 tonnes of NOx emitted per thousand tonnes of crude refined with refinery NOx having fallen by over a third since 1990.

3.1.6 Gas Flaring from Exploration and Production Operations

As discussed previously, flaring is the controlled burning of hydrocarbons that cannot be economically used or exported is part of oil and gas production. This is often referred to as ‘stranded’ gas. It is a significant source of air emissions and so trends in its use are worthy of separate mention. It is estimated by the World Bank that over 400 million tonnes of greenhouse gases are generated by flaring annually, a figure equivalent to approximately half of all CO_2 emissions from aviation. Finding more effective uses of flared gas is therefore both economically and socially attractive [7]. In recent years improvements in production facility design, reuse of gas to maintain reservoir pressure and improved markets have all contributed to a marked decline in flaring – falling from 23.9 tonnes per thousand tonnes of hydrocarbons produced in 2006 to 13.9 in 2012. Further reductions will need to focus on the developing world, and in particular Africa, where flaring is an order of magnitude higher than in the developed economies of Europe and North America.

3.2 Water Management

3.2.1 Key Concepts

It may be surprising but in many cases the petroleum industry manages a great deal of water and in some locations handles more water than oil. The extent to which water should be considered within the context of environmental technology is heavily dependent upon the situation- the type of oil reservoir being exploited and geographic location. The water itself may be the material of interest, but more often it is industry related contaminants in the water that drive environmental risks. But before we explore those in more detail, it is important to define some key terms with regards to water management:

Water withdrawal – refers to freshwater that is taken either from the surface or from aquifers and exploited as part of the oil production cycle. Water withdrawal alone poses no net loss to the hydrological cycle provided that it can be cleaned and returned successfully. Vast quantities of seawater are also withdrawn for a number of oil and gas related purposes, but under normal operational circumstances this resource can be considered effectively infinite.

Water consumption – refers to water that has been withdrawn from the hydrological cycle and cannot be returned. This may be because it is contaminated and must be disposed of by pumping it into geological formations where it remains isolated from the water cycle or where is actually broken down – such as in some petrochemical processes.

Discharge refers to the release of water to the surface, or near surface. Where that water has previously been contaminated by oil or other materials used in the production of oil, it will require cleaning. The standard to which water has to be cleaned in heavily dependent upon both the nature of the environment in which the oil in being produced or refined and the local legislation in which the company operates.

Produced water – this is the largest, by volume, liquid discharge generated during the production of oil and gas. It comprises formation water, that was naturally present in the reservoir, floodwater – water that has been artificially injected into the reservoir to maintain or increase productivity and in some cases condensed water. Produced water has to be separated from the oil and then cleaned for discharge or re-injected. As we shall see, increasingly stringent demands on the amount of impurities (such as dissolved and dispersed oil) that remain in the produced water after clean-up are driving innovation in to new and higher performing water treatment facilities.

As the demand for water varies considerably between the production type, location and stage of oil and gas operations these shall separately be reviewed here.

3.2.2 Conventional Oil

Most conventional oil reserves come with associated water – water that coexists with the oil within the reservoir and which will come to surface during production. During primary production, where reservoir pressure is sufficient for fluids to flow without stimulation this will be the only water that requires handling and this phase may last for years, possibly decades. The water is separated from the oil at the point of production as it otherwise increases the volume of material being handled and accelerates the degradation of equipment and pipelines through corrosion. The water requires filtering and cleaning to a standard sufficient either for discharge – such as release into surface waters or reinjection – either into the reservoir itself or via a disposal well. As the reservoir enters the phase of secondary production so the pressure has to be maintained and this is achieved by injecting water, and in some case gases, which substantially increases the volumes of water that have to be handled. In the offshore environment this is routinely achieved using the plentiful supply of seawater. Onshore, resources may be scarcer. In mature fields there is increasing use of tertiary production – often referred to as enhanced oil recovery whereby water, gases such as CO_2 and chemical additives are injected in to the reservoir to increase overall production. The industry is becoming increasingly stringent about the quality of water used in secondary and tertiary phases and so along with societal demands to improve the quality of discharged water, this is placing new demands on the technology applied in water management.

3.2.3 Conventional Gas

Like conventional oil, conventional gas fields include water. However, here water injection is not necessary and so water consumed in drilling may be the dominant factor in water use. Natural gas arriving at the surface will contain water vapour, which will condense as the temperature of the gas falls, taking with it soluble hydrocarbons including benzene and toluene. These require separation from the gas and disposal or capture for use.

3.2.4 Heavy Oil

Oil with a high density will not flow at ambient temperatures – these are often referred to as heavy oils and are found in large deposits including Canada, Kazakhstan and Russia. As conventional reserves fall so the importance of these deposits as a global source of hydrocarbons is increasing. Heavy oil is frequently found as oil sands – mixtures of bitumen, sand water and clay in which the hydrocarbon content can be as high as 18 % by weight. A number of processes have been developed to mobilise the oil and these predominately involve the use of water. As the majority of oil sands are located onshore, often hundreds of miles from the coast, this technology places a new and considerable demand of freshwater supplies. Taking the Alberta oil sands of Canada as an example, 3.1 barrels of water is consumed for 1 barrel of oil produced [8]. The simplest technology involves surface or 'strip' mining of the oil sands but the high environmental costs associated with this method have driven improved in-situ methods that are less damaging. An example of in this is steam assisted gravity drainage (SAGD) whereby two parallel wells are drilled horizontally. The upper well carries superheated water, warming the surrounding oil sands, which then oil to drain into the lower well from where it can be pumped to the surface. In situ techniques typically require less consumption of water. In Alberta this is in the region of 0.4 barrels per barrel of oil produced.

3.2.5 Unconventional Gas and Tight Oil

Arguably the most reported and contested oil technology of the early twenty-first century is hydraulic fracturing – or fracking for short. Actually, this is not a new technology at all, but the combination of two well established oil production techniques – horizontal drilling and fracturing of reservoir rocks using high-pressure water. Combined, they have unlocked hitherto inaccessible reserves of gas, and in some instances oil that is trapped in impermeable rocks such as shale. Hydraulic fracturing can be truly said to be a game-changing event in world energy markets – turning countries such as the USA from net importers of hydrocarbons to exporters.

However, alongside the unquestionable economic benefits hydraulic fracturing has provided it has also lead to a new generation of environmental issues, most notably the large volumes of water that are required to stimulate the reservoir. Calculating the total volume of water required per well is subject to a wide range of uncertainties, not least that the water is used during the start of operations whereas the gas will be produced for years after albeit at a declining rate. Each well can require in excess of 35,000 m^3 of water. The flow-back water will be contaminated with hydrocarbons alongside production chemicals used to maintain the fractures. The returning water must either be cleaned for recycling, generating a waste stream, or consumed via disposal via specially drilled wells.

3.2.6 Trends in Produced Water Discharge

In 2012, for every tonne of hydrocarbons produced 0.5 tonnes of produced water was discharged to the surface and 0.9 tonnes re-injected. The average oil content of water discharged was 13.5 mg/l a figure that is falling progressively with time as new cleaning technologies and more stringent discharge limits both come into effect. The quantity of oil discharged per unit of production is falling over time too, from an average of over 9 tonnes per million tonnes of hydrocarbons produced in 2006 to less than 7 tonnes in 2012. As for air emissions, this general trend masks considerable differences between both onshore and offshore production and between countries. Offshore, an average of 9.99 tonnes per million tonnes of oil produced is discharged, with the highest levels recorded in Asia. Onshore, the figure is much lower with 1.94 tonnes discharged but where figures for Africa (5.95 tonnes) are many times that seen in North America (1.42 tonnes) and Europe (0.73 tonnes) reflecting differences in both operating practise and legislative regimes.

3.2.7 Refining

Water is integral to the refining of hydrocarbons. There are two distinct ways in which water is involved

No direct Contact with the oil – Here, the water is used as a coolant. Consumption, by evaporation, is around 40 %

Process water – Where water molecules are essential to the refining technology. Examples include desalting – the removal of residual salt found in the crude (which otherwise accelerate corrosion) to hydro-treatments – the use of hydrogen to react with nitrogen and sulphur impurities in the oil. Steam reforming is also an integral part of emergent refining techniques such as GTL – gas-to-liquid that upgrade the relatively low value natural gas to synth-diesel and other products.

The European oil industry environmental technical group, CONCAWE, released a report on refining wastewater in Europe in 2012 [9]. Their data provides some comparable data on water. In 2010 and based on data from 100 refineries, the amount of process water discharged 550 tonnes per thousand tonnes of oil throughput. When all flows are considered (process, cooling and other) then the water discharge is 2200 tonnes per thousand tonnes of oil throughput. The ‘All Flows’ water discharge amount has decreased by more than half since the 1980s.

The amount of oil discharged with these water discharges was 1.3 kg/thousand tonnes of oil throughput. A figure well below the OSPAR recommendation 89/5 of 3 g/tonne of oil throughput set in 1997. Additionally the amount of oil discharged has decreased by a factor of more than 10 since the 1980s.

3.2.8 Business Operations

Alongside management of water as an integral part of the oil and gas production cycle it is also important to note that water plays an integral role in the wider management of almost every aspect of daily life within the industry. From supplying clean freshwater to its rigs, platforms, refineries and offices to water for cleaning or sanitation. As most oil and gas operations exist away from municipal supplies of water so the oil companies must also provide water for these uses.

3.3 Waste Management

The extraction of raw materials and the many manufacturing uses to which they are put all generate waste. The careful use and conservation of these materials, and the products they result in, is one of the most effective ways to address the waste issue. However carefully we use raw materials and the products derived from them, some waste is inevitable at present. Waste is generally disposed of either by burying in a landfill, or by incineration. Landfill sites can affect groundwater should hazardous materials seep out. Decomposing landfill waste can also produce methane, which we have seen is a greenhouse gas. There is now also a growing shortage of suitable landfill sites.

3.3.1 The Waste Disposal Hierarchy

Government and industry employ many different waste disposal strategies, but there is broad agreement that the following options, listed in order of acceptability, constitute the waste disposal hierarchy:

– reduce waste at source through improved design – less packaging, for instance
– re-use materials wherever possible
– recycle materials wherever possible
– incinerate with energy recovery
– incinerate without energy recovery
– landfill

Businesses along with other organisations, and individuals can all make an impact on waste. Long-term solutions depend on policies that promote and support the conservation and recovery of materials. Creative strategies for resource efficiency in homes and businesses also have a part to play.

Unlike water and especially air emissions, waste is a local issue: it presents different risks and potential consequences depending on where it is generated. Typical significance is assessed locally, and local waste management plans are developed to reduce impacts.

Concerns about the heavy metals and dioxins that incineration can produce make this a controversial process in many countries. Such emissions can be reduced or eliminated with special filters, and the heat produced by alternatively incinerating waste may be recovered for direct use, or employed to generate electricity.

3.3.2 Non-hazardous Waste

Waste is generated by many different industry operations: apart from hydrocarbon and petrochemical raw materials associated with our products it can include wood, metal, glass, process chemicals, catalysts and drilling cuttings, plastics, packaging and food. Like all industrial processes, this waste constitutes the bulk of material generated and must be disposed of appropriately.

3.3.3 Hazardous Waste

Beyond hydrocarbons, a main concern is liquid or solid wastes classified as hazardous (under local or national regulations) and requiring special treatment. Where solid waste is produced on offshore facilities, there's the added pressure of limited storage space and the need to transport it back to land for treatment and disposal. Minimizing waste production is thus particularly critical.

Hazardous waste can come in many forms. One of the better-known risks comes from heavy metals such as mercury. Mercury occurs in natural low concentrations in oil. During the oil production and processing cycle it can become concentrated into waste streams such as sludges and in some cases heavier oil fractions. Alongside being toxic, mercury poses a risk to business as it can 'poison' (degrade) the platinum series based catalysts that lie at the heart of modern refining technology. Disposal increasingly relies upon incineration followed by landfill of the ash – but this will be heavily reliant upon what is available within its country or origin. Under the Basel convention – an international treaty for waste management, hazardous wastes such as mercury contaminated material cannot be transported internationally for disposal (to avoid waste being dumped in developing countries) [10].

As we look forward into the twenty-first century there is also growing awareness that for many metals it is not simply the concentration in which it is found that defines the risk but also the molecular form in which it occurs. This is known as metal speciation and can have stark impacts upon the overall risk that is encountered. Consider again mercury – in its inorganic state as elemental mercury it is significantly less toxic that when encountered as methyl mercury in which it is combined with a CH_3 group. Inorganic mercury will become methylated to methylmercury in aquatic environments through microbial activity. Speciation may also be of the ionic kind, where different charge states affect toxicity. There is growing and legislated concern in the downstream environment over releases of chromium – and more specifically chromium VI (6+). Chromium III (Cr 3+) is the most stable form of chromium and is actually found in our bodies in small amounts to process sugars and fats. Chromium VI (also known as hexavalent chromium, Cr VI, Cr 6+) is toxic metal, which affects us if we inhale, ingest, or get it on our skin. Hexavalent chromium is categorized as a carcinogen and causes lung cancer; it is also extremely irritating to the nose, throat, lungs, and skin. Hexavalent chromium exposure occurs during hot work on chromium containing metals, such as stainless steel, which is commonly encountered in large quantities in refineries.

As a large number of oil production and refining facilities reach the end of their natural life, so there is a growing need to manage large volumes of hazardous materials arising from decommissioning. Alongside the vast tonnages of non hazardous materials such as steel which are destined for recycling, there is also the need to manage materials such as asbestos and flame retardants built into the fabric of the facilities in an age where their risks were less well understood and modern alternatives yet to be developed.

One particular source of hazardous waste worthy of mention is NORM – Naturally Occurring Radioactive Material as it is a good illustration of the challenges that oil companies face with hazardous waste. The rocks that form oil reservoirs contain very low levels of naturally occurring radioactive elements such as Thorium and Uranium. Whilst both of these elements are largely insoluble, their radioactive daughters such as Radium and Radon can be transported alongside the oil, gas and produced water and become concentrated in the scales and sludges that build up in pipes, tanks and other oilfield equipment. The levels of radioactivity never reach activity levels where they pose an immediate or acute health risk but long-term exposure can lead to chronic health effects such as cancers. The problem of NORM was not widely known until the 1990s since when precautionary steps have been taken to screen for contaminated equipment and provide appropriate clean-up and disposal options. This has, however, left a legacy of contaminated operations sites that pre-date these controls. Whilst the health risks are well understood and relatively simple to manage, NORM discharged into the environment poses a significant and currently poorly understood problem. NORM is not unique to the oil industry and can be found in other industrial sectors such as pigment manufacture and metal refining but the wide scale of oil production means that it is of growing attention. For example, the oil industry accounts for around 7 Terebequerel (TBq) of alpha particles discharged into the North Sea each year – approximately 40-times that released by the nuclear energy sector. Servicing of oil field equipment leads to stockpiles of NORM contaminated waste. Disposal options include landfilling, land spreading and discharge to sea – but many countries lack the infrastructure to manage NORM waste appropriately leading to large and growing stockpiles around the world that are awaiting long term disposal options to be implemented.

3.3.4 Oil Spill

When we think about the environmental impacts of oil production it is inevitable that we also think about the uncontrolled releases of oil that occur when a well, ship or pipeline is breached. Major events such as the sinking of the Torrey Canyon

(1967), Exxon Valdez (1989) and the Deepwater Horizon spill (2010) are thankfully rare when compared to the vast quantities of oil produced and shipped globally, but the images of oiled wildlife and oil slicks washing ashore are nonthe-less evocative.

Looking at the upstream environment, in 2012 those companies reporting to the OGP recorded some 7826 oil spills, of which the vast majority (79 %) were of less than one barrel in volume amounting to 89 tonnes of oil. Larger spills amounted to 9483 tonnes, a figure that has remained stable in recent years. Overall, less than 1.5 barrels of oil is spilled for every million barrels of oil produced.

3.4 Global Trends and Emergent Issues

Looking ahead, what are the major trends in the oil and gas industry that will affect environmental technology demands? We have already mentioned hydraulic fracturing and whilst development of these fields is in full-swing in the United States there is considerable formations considered economically viable elsewhere in the world including Europe and China. Other unconventional sources will also grow in importance as established fields such as the North Sea in Europe begin to reach their end of life. We are also seeing exploration in increasingly difficult environments such as into deep water, such as offshore Brazil where water depths can exceed 3000 m, and the Arctic where sea ice and other challenges of working in very low temperatures abound. In a resource-constrained world the industry will also be affected by other sustainability issues – such as the availability of key resources such as precious metals that form the building blocks of key components such as platinum catalysts in refining.

The range of environmental risks that need to be assessed and managed is also growing. One good example of this is risks associated with sound. Alongside the obvious noise-pollution issues that may arise from living alongside a major refinery or other such onshore facility, there is growing interest in the sounds that are generated by offshore activities such as shipping and most significantly geophysical surveys. The use of geophysical acoustics to probe the deep rock layers that hold oil reservoirs is the dominant technique of oil exploration. Early methods such as the use of explosives to generate an acoustic wave have long since been supplanted by more precise and manageable sound source such as airguns. But all sources generate sound waves that fall within the audible range of sea-life including ‘iconic’ species such as whales, dolphins and turtles. Whilst there is little or no direct evidence of oil operations having resulted in direct physical harm to an animal (let alone overall population decline) concern remains over behavioural effects such as stranding. Considerable efforts already go into mitigating these risks by creating cordon zones around geophysical survey boats and operations will be suspended if a marine mammal is encountered. Further research is underway to understand the immediate and long-term effects of sound on marine life and the contribution that the oil industry makes alongside other commercial sound sources such as shipping and naval activity.

Alongside these trends we are also seeing increased consumer interest in both the direct impact of oil production – such as the risks associated with routine discharges and non-routine events such as major oil spills and the indirect consequences of hydrocarbon combustion including climate change. This will manifest itself it increasingly stringent environmental legislation, monitoring and risk assessment that the industry must rise to.

4 Technology Used in the Oil Industry

We began this chapter with a brief definition of technology as the 'practical application of the industrial arts' and then went on to describe the range of environmental challenges that the oil industry faces. There are, of course, a myriad of different industrial responses to these challenges ranging from the very simple to the highly complex. Obviously in this introduction it is only possible to skim the surface of these solutions and subsequent chapters will go into much greater detail, but there are some general trends that we can discuss here.

The first major trend is that where historically environmental management was predominantly 'end-of-pipe' pollution control (fixing the problem); over the last 10 years the focus has been shifting towards pollution prevention which requires a fuller understanding of the risks posed by various forms of pollution and the different management strategies that can be applied in response. All pollution control techniques are very dependent on plant and process specifics, but we can divide them into six classes of activity and based upon the challenges discussed previously give some examples of their application (Fig. 1.1).

4.1 Understand Your Environment

The first step in developing an appropriate technology plan is to understand the source and effects of the pollution. The issues discussed previously are not always obvious on the ground and their effects are often felt a long way from their origin. One of the best examples of this is the effects of carbon dioxide, methane and other 'greenhouse' gases on climate change. As we have seen, the oil industry is major emitter of these gases as an unavoidable part of oil production and yet their effects will not be immediately obvious 'at the well'. Over the past 20 years, as the evidence for anthropogenic climate change has grown so every major oil company has developed a policy position on climate change and in many cases invested heavily to understand its effects. As a business there is, of course, concern over 'stranded carbon' whereby global policy over the use of carbon-based fuels stops the exploitation of oil and gas reserves. Locally, major new projects that may have

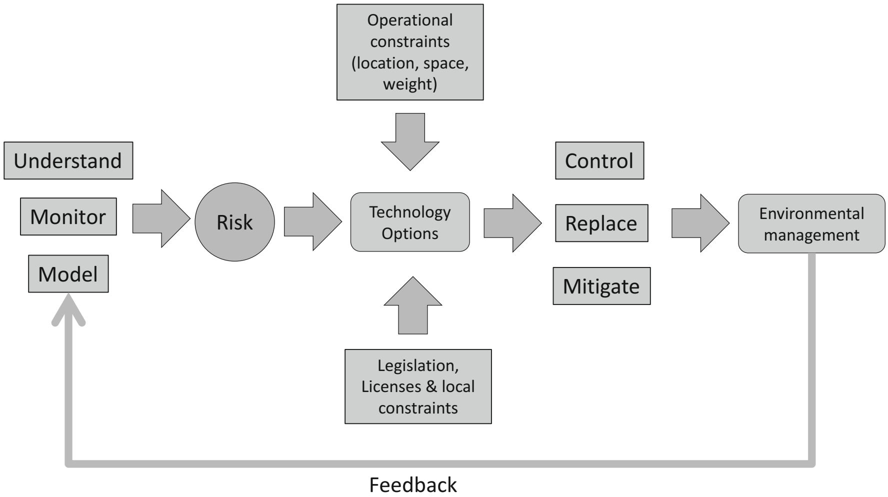

Fig. 1.1 Building an appropriate environmental technology management plan

to operate for decades in order to pay back their initial investment may also need to plan for the likely effects of climate change such as changes to the availability of water resources, changing weather patterns or formation of sea ice.

Whilst climate change is a global phenomenon, understanding the environment can also be very local. A good example of this is in the discharge of oil and oil-field chemicals. As we have seen, produced water is frequently cleaned and discharge to the surface environment but even with the best available technology there will always be a small oil content that remains. Crude oil contains a large number of organic molecules, some of which are known to persist for long periods in the environment where they can accumulate within the food-chain and become hazardous to life. The observed effects will therefore be a combination of the chemical properties and how it behaves in different climates, temperatures, salinity of water etc. it will also depend upon the organisms which encounter it. Different species, even those that fulfill similar ecological niches, may respond very differently to the same concentrations of a specific pollutant.

4.2 Monitor

Having built up a profile of those sources of pollution that are of concern, technology is required to monitor their quantities and effects. Technology can be very simple – such as overfill protection control circuits that are designed to limit the amount of oil and chemicals being pumped into a storage vessel to avoid their accidental releases. Conversely, technology can be highly complex working at the frontiers of science and engineering. A good example is the growing use of satellite based remote sensing systems for earth observation. Here, radar can be used to detect oil on water or highly sensitive hyper-spectral sensors used to measure changes in the plant cover arising from re-vegetation following trenching for pipelines. Modern satellites have remarkable levels of resolution – with pixel sizes of 50 cm or less allowing very subtle changes to be monitored. The trend is towards improvements in resolution, specificity and accessibility; so that high quality satellite data is no longer a technology only open to major governments but within reach of corporations, environmental groups and other stakeholders.

For many of the sources of pollution described earlier there are legal requirements to monitor and record the amounts released with strict financial penalties and in some cases, such as greenhouse gases, taxes linked to the amounts emitted. It is therefore vital that the monitors are not only capable of detecting the presence of a pollutant but that can be quantified and the figures reported independently verified. Monitoring methods can be very simple, such as oil-in-water analysis which uses classic 'wet chemistry' techniques to extract the oil and measure its abundance by fluorometry or may use high performance spectrometry techniques such as field-based FT-IRS (Fourier Transform infra-red spectrometry) to detect fugitive gas releases based upon the emission spectra of the gases of interest.

Monitoring often begins before oil operations are truly underway – setting baseline conditions against which the effects of industrialization can be measured. As oil companies explore into new and poorly understood environments such as the deep ocean floor and the arctic these baseline surveys are operating at the boundaries of scientific research, identifying new species and ecosystems. One recent example of this is from offshore Angola, where natural tar mounds – seafloor structures built up from vast quantities of heavy hydrocarbons naturally seeping up from the oil reservoirs beneath are host to unique assemblages or deep water organisms.

Having recognized the importance of local ecosystems there is then the growing need to monitor changes that arise from oil production. Offshore, the oil industry is leading the way in the design and installation of long term monitoring stations such as Delos – a subsea monitoring platform in Angola designed for a 25 year deployment capturing information on sound, sedimentation and macro-fauna. Periodic surveys have also been helped by the use of other oilfield equipment such as ROVs (remotely operated vehicles) that were designed to service subsea equipment but have gave provided alternative and cost effective means of exploring the ocean floor.

4.3 Modelling

Monitoring alone only goes some way to managing environmental risks. The oil industry also relies heavily upon environmental models to predict effects before they happen. This is particularly prevalent in planning for uncontrolled releases of oil when a platform, pipe or vessel is breached. Several systems exist, but all work in essentially the same way – combining the physical characteristics of the oil (weight, density, chemistry) with information on currents, water depth and chemistry to predict where the oil will travel, how it will behave and its eventual fate including stranding on to shorelines, entrainment into sediments or degradation by micro-organisms. Increasingly, these models are being augmented by local information on ecosystems and commercially sensitive parameters such as fisheries.

4.4 Technology Options

Understanding likely sources of pollution, monitoring their amounts and their effects and being able to predict their impact all combine to form a detailed risk profile that is specific to every oil company asset. Translating this into a suitable environmental management plan must then consider two further influences. Firstly there is the political and social climate in which the asset is based. Simply because a technology is viable for a given location does not mean that it is acceptable. Consider the management of drill cuttings generated offshore. In some countries it is considered acceptable to clean drill cuttings and discharge them overboard where they settle on the seabed, eventually becoming integrated in to the natural sediments. Other countries ban this practice and require cuttings to be brought ashore, cleaned and landfilled. Both options come with an environmental cost and neither can be considered universally 'better' but the license within which an oil company operates will mandate which technologies can be used. The OSPAR convention in Europe takes this one step further. The OSPAR Convention is the current legal instrument guiding international cooperation on the protection of the marine environment of the North-East Atlantic. Work under the Convention is managed by the OSPAR Commission, made up of representatives of the Governments of 15 Contracting Parties and the European Commission, representing the European Union. Together standards are set for the a wide range of oil related issues, controlling both which chemicals and materials can be used offshore and tracking the amounts of oilfield chemicals that are discharged.

Secondly, in conjunction with socio-political constraints there are also the practical limitations of what can be achieved. It is often said that oil platforms are the most expensive real-estate on earth, where each square meter of the platform costs many millions to design, install and maintain. Whilst onshore production sites and downstream refineries may be less constrained, it is equally true that all environmental controls are a 'cost of business' and developing a fit-for-purpose environmental management plan will have to consider the size, weight, capital and operating costs of potential technologies to identify those that are practical to implement. In an era where oil prices were high and environmental requirements relatively small this had little bearing upon whether a specific new project would be economically viable, but increasingly the costs of environmental management are seen as a major influence over which oil reserves can be exploited.

4.5 Replacement

Of course, the simplest solution to a known source of pollution is to replace it with a preferable alternative and 'design out' the risk. Today, drilling muds used to lubricate and manage fluid flows during the drilling of an oil well are mostly water based. These have come to replace the oil-based muds that were commonplace until the 1990s. However, this still leaves a legacy of oil-contaminated drill cuttings that have built-up around the feet of offshore oil platforms and which can become re-mobilized during decommissioning.

Another good illustration of designing out the risk comes in waste management. Traditionally, gasoline retail sites have become contaminated with the multiple of small drips and leaks on to the forecourt during trading. These build up over time to leave a significant amount of contaminated soil that has to be disposed of before a site can be used for other purposes. In continental Europe service stations now are built to improve groundwater protection. Designs in Germany and other countries now use technology such a suction pumps at the dispenser, double skinned containment with pressurized and monitored interstitial space, and leak proof forecourt pavement. All being done to ensure fuel never reaches the ground or groundwater.

4.6 Control Strategies

Where replacement is not viable – such as emissions of water and gases during oil production, control strategies must be developed to minimize the known risk. We can illustrate this with some of the challenges discussed previously.

4.6.1 Air

As we have seen, CO_2 is the dominant emission to air, but CO_2 can also be seen as a resource. CO_2 separated from the oil can be returned to the oil-field and re-injected into the reservoir to maintain reservoir pressure and increase overall yield. Such techniques are referred to as enhanced oil recovery – or EOR and use a variety of fluids and gases. As a number of major oil fields enter the tertiary stage of development so EOR is set to become a major part of oil production in future years.

Upstream, significant advances have been made in recent years to reduce emissions from flaring. These have taken many forms, but include improved use of gas within the oil operations itself (such as the use of micro-turbines that use the gas to generate electricity), improved design of flare stacks so that hydrocarbons are burnt more efficiently and the stimulation of local markets so that more of the gas has an economic outlet. A good example of this is in Angola where multiple oil companies have come together to install a new onshore gas management plant. Alongside much needed energy generation the provision of cheap gas should stimulate other energy intensive industries such as brick and cement manufacture which in turn will help develop and diversify the economy.

In shipping, some of the main sources of VOCs come from tanker loading and unloading; the major control technologies are closed-loop systems and vapour recovery units, liquid absorption (usually kerosene), liquefaction by refrigerated cooling and membrane systems.

In refining, CO_2 is an inevitable by-product of the large amounts of energy required to drive the various processing technologies. Controlling CO_2 emissions are therefore primarily an issue of efficiency – optimizing plant design to maintain the often high temperatures required across the plant, and not simply considering each process in isolation. This of course also has direct bearing upon the operating costs of the plant and its economic viability. Emission of volatile components such as the non-condensable fraction that is ejected from vacuum distillation units are controlled through incineration or through coupling of the waste stream to the fuel gas system and so contributing to the heating of the plant. Sulphur emissions as (SO_x) are controlled through the installation of water or caustic scrubbers. Where site location permits, suplhur oxides can be reacted with seawater to neutralize the acid gas whilst the use of solid reactors using calcium hydroxides as a feedstock (produced from limestone) generate hydrated calcium sulphate (gypsum) as an end-product which has market value as a construction material. Elsewhere, hydrogen sulphide can be captured in sulphur recovery plants to yield the safer and more easily disposed elemental sulphur.

4.6.2 Water

Water management technologies offer a wide and often bewildering array of choices for the oil operator – drawing upon technologies intended specifically for the oil sector, such as hydro-cyclones that separate oil from water, along with technologies that are used extensively in other sectors – such as the use of anaerobic digestion. Anaerobic digestion is a mainstay of municipal water treatment, but is now becoming increasingly common on onshore oil operations such as refineries for sludge treatment.

Significant amounts of water can also be re-injected – returned to the reservoir or other deep rock formations with adequate porosity and far away from aquifers used for other purposes. Many fields include specifically drilled disposal wells for this purpose also providing an effective route for the disposal of drill cuttings that can also be incorporated in to the wastewater. The provision of disposal wells, or cost effective alternatives for treatment of water on-site has become a major issue in the exploitation of unconventional gas fields. As we have seen, this technology uses far more water than conventional production methods and has brought with it unprecedented demands for water disposal. Driven by the lack of adequate disposal resources, emergent technology for water re-use is now becoming available.

In water scarce areas the oil industry is drawing upon expertise again from the municipal sector, using methods such as reverse osmosis to convert brackish waters in to water suitable for use in both oil production and refining and within support camps and infrastructure. Here, the challenge often lies not in the underlying membrane technology itself but in engineering it into a hardware option that can be easily transported or cope with the harsh conditions in which it has to operate reliably.

Process water from refining needs to be cleaned before it can be discharged. This is routinely achieved by collection and transfer of water to a centralized water treatment works where a range of technology solutions are deployed. These include primary treatment such as neutralizers, oil-water separators, settling chambers, coagulators followed by secondary treatment such as biological activated sludge with further clarification whereby microbial degradation of residual hydrocarbons is achieved. Some of the organic component can be lost to the atmosphere, making water treatment units a significant contributor to refineries overall air emissions budget unless emissions are controlled. Refineries are also sometimes using tertiary treatment methods as well such as activated carbon, or advanced filtration methods to decrease organics or metals in discharges to receiving waters.

4.6.3 Oil Spills

Technology for the management of oil spills falls into two distinct categories. Firstly, these are recovery techniques. Offshore these include skimmers, booms and other devices that return the oil to a vessel. Onshore soil contaminated with oil is frequently dug up. In either case, the oil and entrained material then becomes a hazardous waste that has to be disposed of appropriately – such as incineration. The alternative is to treat the oil in situ. Offshore this includes the use of chemical dispersants that transform the oil into smaller droplets where the natural action of waves and microbes break down the oil. Similar biodegradation techniques are also widely used onshore, especially in the remediation of contaminated land where the alternative is to dig-up and often landfill large quantities of soil. As always, there are environmental consequences in the use of chemicals to treat oil spills and these have to be weighed-up relative to the risk that the oil itself poses.

4.7 Mitigation

Finally, once all other technology options have been considered the alternative approach to managing environmental consequences is to mitigate against the environmental harm that has been incurred. At a trans-national level we see this with carbon credits and trading – taxation that encourages low CO_2 technologies to help address climate change. This is one of the drivers behind the increased use of natural gas in Europe in recent years which is seen as a ‘clean’ alternative to coal for electricity generation. Locally, offsets come in the form of investment, protection and improvement of ecosystems away from the oil assets so that the net impact of the industry is closer to zero. This requires accurate assessment of the value of different land taking into consideration a host of environmental, social and economic considerations. This has led to the development of techniques such as 'ecosystem services assessment' to standardize such calculations. At its core, there is a need to assess the negative impacts of the industry, which brings us back to understanding the baseline conditions before the oil industry began work.

5 Summary

Oil is integral to our society and is likely to continue to be so. The oil industry does produce emissions to the environment but these emissions are continually being minimized by the application of improved 'end-of-pipe' technology and improved design of facilities. Further chapters in this book will deal with all these issues in much more detail.

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Chapter 2
Environmental Control Technology for Oilfield Processes

A.K. Wojtanowicz

1 Introduction

For over 100 years, oilfield science and technology have been continually improving. The oil industry has evolved from one that was interested mainly in inventing tools and equipment to one that is not only economically, but also environmentally, conscious. In the 1980s, low oil prices forced oilfield technology to focus on economic efficiency and productivity. Simultaneously, environmental regulatory pressure added a new factor to petroleum engineering economics: the cost of working within the constraints of an environmental issue. In the 1990s, the industry has absorbed this cost and made a considerable progress in pollution control. The progress has been demonstrated by various indicators as follows [1–3]:

Since 1970, emissions of six principal pollutants (nitrogen dioxide, ozone, sulfur dioxide, particulates, carbon monoxide, and lead) decreased by 25 %. At the same time, U.S. Gross Domestic Product (GDP) increased 161 %, energy consumption grew 42 %, and vehicle miles traveled rose 149 %.

- Since the early 1990s, emissions of air toxics decreased by almost 24 %.
- The rate of annual wetland losses decreased from almost 500,000 acres per year three decades ago to less than 100,000 acres per year, on average, since 1986.
- Between 1991 and 1997, volumes of the 17 most toxic chemicals in hazardous waste fell 44 %.
- In the North Sea, total discharges have declined by 3000 tons annually since 1996; despite the fact that produced-water discharges have increased by 15 %.
- Industry spending on environmental activities averaged $9 billion per year in the last decade, more than it spent on exploration, and more than EPA's entire budget.

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_2

Behind these and other general indicators of environmental performance lies the technology progress – various modifications and improvements of the oilfield process.

Some of the new technologies have directly addressed pollution control. Most of the technological progress, however, has been made primarily for productivity enhancement, but – indirectly – it also improved environmental performance. The technological progress made in the 1990s increased sevenfold the average new discovery of oil and gas reserves comparing to that in the late 1980s [4]. Moreover, the exploration drilling success rates have increased from 27 % in the 1980s to over 42 % in the 2000–2003.

These technological advances have indirectly produced environmental benefits by [4, 5]:

- Due directional drilling, fewer well sites add the same reserves; by the early 2000, the U.S. industry would add two to four times as much oil and gas to the domestic reserve base per well site than in the 1980s.
- Generating lower drilling waste volumes; today, the same level of reserve additions is achieved with 35 % of the generated waste.
- Leaving smaller footprints; the average well site footprint today is 30 % of the size it was in 1970, and through the use of extended reach drilling, an average well can now contact over 60 times more subsurface area.

The above observations show that environmental performance can be interrelated with productivity improvements and the overall technological progress so it does not have to be considered a separate and expensive undertaking with no economic returns on investments. Hence, it is feasible to develop technologies that increase productivity while protecting environment.

Traditionally, industry activities focused on environmental protection, was felt not to contribute to corporate profitability. Increasingly, however, environmental performance is being considered as a potentially important contributor to the bottom line. Consequently, the oil and gas industry is responding to a market increasingly driven, at least in part, by desires for simultaneously improved environmental performance and growth and profitability. More and more companies are reporting progress on environmental performance with a comparable level of rigor and sophistication as that exhibited in their financial reports.

Environmental performance is also being considered an important factor impacting corporate image. Petroleum industry is particularly vulnerable to public image because, on one hand it must seek public approval for accessing geographical areas and developing natural reserves, while – on the other hand – its image can be easily damaged by highly visible accidents of oil spills or well blowouts. For example, in March 2001, Petrobras's P-36 platform in the Roncador field in the Campos Basin off the coast of Brazil sank after three explosions left 11 workers dead. The world's largest semisubmersible at the time had been producing 84,000 barrels per day of oil and 1.3 million cubic meters per day of natural gas. The operator's report concluded that a gas leak had escaped into the sea where the blasts took place [6]. Another example is the highly publicized oil spill from the Prestige tanker that sank off the coast of Spain in November 2002 [7–9]. The tanker was carrying 20 million gallons of fuel oil – nearly twice the amount of oil as the *Exxon Valdez*. Although much of the fuel remained in the tanker after it sank, substantial volumes of spilled fuel washed up on beaches over a large area of Northern Spain and Southern France, damaging prime fishing areas.

The petroleum industry involved in these and other visible accidents learned that public perception might often play a larger role in influencing a course of action than facts. They learned that compliance with existing laws and regulations is not sufficient to convince the public but there must be evidence of improvement of technology to receive approval for continuing operation. Moreover, a company's environmental performance is becoming an important factor in corporate assessments by the investment community, not just as a factor considered as part of the 'watchdog' function of environmental organizations. In fact, a company's environmental performance is increasingly becoming a factor in investor evaluations of future potential [10].

Petroleum industry is expected to perform concurrently in three areas, productivity, environmental and social. This 'triple bottom line' concept operates on the principle that better performance of one of the three pillars – representing economic, environmental and social considerations – cannot be considered substitutable for underperformance in another [11]. Therefore, a successful technological progress must address a technology that combines productivity advantage with environmental protection and – as such – make the operator accountable to the public.

2 Environmental Control Technology

Environmental control technology (ECT) is a process-integrated pollution prevention technology. Within the broader scope of environmental technology that includes assessment of environmental impact, remediation and prevention, ECT relates mostly to prevention and risk assessment. Historically, developments in preventive techniques came after analytical and remediation measures, which have been found to be inadequately reactive and progressively expensive.

Reactive techniques focus on impacts and risk. With reactive pollution control, the positive action is entirely linked to the environmental objective. History provides ample evidence that reactive strategies do little more than transfer waste and pollution from one medium to another. *Preventive* action seeks root causes of pollution generation. It often requires modification of technology that has no apparent linkage to an environmental objective and is intrinsically more comprehensive than reactive strategies [12].

In principle, ECT is a process-engineering approach to the prevention of environmental damage resulting from industrial (oilfield) operations. The approach draws on the modern theory of 'clean production', a term coined by the United Nations Environmental Program's Industry and Environmental Office (UNEP/IEO) in 1989 [13].

The clean production theory, in its broadest sense, delineates an approach to industrial development that is no longer in conflict with the health and stability of the environment, a kind of development that is sustainable. In the narrowest sense of the theory, clean production signifies a preventive approach to design and management of 'environmentally controlled' industrial processes. The approach seeks to reduce 'downstream' or end-of-pipe solutions to environmental problems by looking 'upstream' for reformulation and redesign of the processes or products. It also involves a broader, integrated, systematic approach to waste management.

Within the parameters of clean production, then, oilfield environmental control technology allows an examination of drilling, well completion and production as environmentally constrained processes containing inherent mechanisms of environmental impact. These mechanisms include the generation of waste, induction of toxicity or creation of pathways for pollutant migration. Identification and practical evaluation of these mechanisms constitute two parts of the ECT scope. A third part involves the development (at minimum cost) of new methods and techniques to meet environmental compliance requirements without hindering productivity.

Naturally, ECT tackles a large spectrum of oilfield technologies, such as closed-loop drilling systems, subsurface injection, borehole integrity, toxicity control in petroleum fluids, downhole reduction of produced water and use of land for on-site storage and disposal of oilfield waste. In this chapter, basic concepts of the ECT approach are presented first. Then, the ECT approach is used to analyze oilfield processes of drilling and production and to describe developments of environmental control components in these technologies.

3 Evolution of Environmentally Controlled Oilfield Processes

Conceptually, the perception of environmental problems and solutions is an evolutionary process of shifting paradigms of waste management as depicted in Fig. 2.1. Over time, concepts regarding what is the best strategy for waste management have changed from 'disposing at will' (followed by remediation), to dilution/dispersion of waste below the assimilative capacity of the environment, to controlling the rate or concentration of pollutants at the waste discharge ('end-of-pipe' treatment), to developing truly preventive technologies.

In the petroleum industry this shift of paradigms is described as a transition from a PCD (produce–consume–dispose) approach to a WMT (waste management technology) approach and, finally, to a preventive ECT approach [14]. The large quantities of waste fluids and slurries (drilling muds and produced waters), and their associated wastes that are created during everyday oilfield activities have been conventionally perceived as unavoidable. This perception is typical of the PCD approach. Not only does this approach assume a proportional relationship between the production stream rate (oil/gas) and the volume of waste, but it also assumes

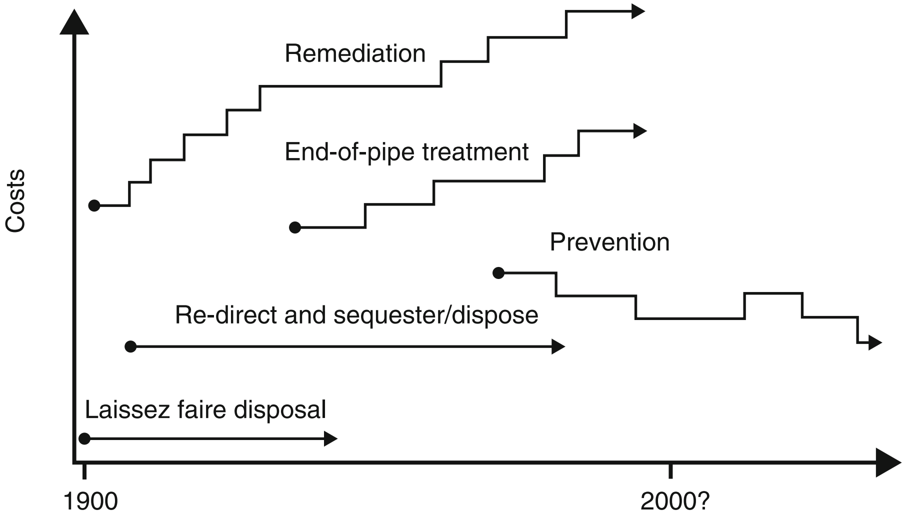

Fig. 2.1 Waste management strategy paradigm shift [12]

that the flow of materials is open so that the waste must be discharged from the process into the environment. Such an attitude has prevailed for most of the modern history of petroleum engineering.

In the early 1980s, evidence of health and environmental hazards in the oilfield was accumulated and made public, which triggered serious public concerns and resulted in regulatory pressures [15–19]. Public opinion has been documented in several surveys. Growing public pressures (and private lawsuits) prompted regulatory activities. Since the late-1980s and early 1990s in the USA, for example, oilfield waste has been identified, its volume and toxicity evaluated and its disposal methods scrutinized [20–22]. This scrutiny, together with the industry's PCD-dominated environmental paradigm, resulted in the rapid development of waste management programs (the WMT approach). Indeed, at the time, clean-ups were prioritized over preventive measures in an effort to employ the existing waste disposal industry rather than to rethink the whole oilfield process again and identify environmental control techniques.

This seemingly logical paradigm was founded on three fundamental arguments: (1) waste must be managed because there is no other way to protect the environment; (2) waste has no value so its management is the most efficient solution; and (3) waste is external to the oilfield process. In fact, all these arguments lack substance:

(1) The environment can be efficiently protected by reducing waste volume and/or its toxicity (source reduction and source separation); for example, downhole oil/water separation (DOWS) could revolutionize the industry by dramatically reducing the amount of water brought up the wellbore [23]. These technologies can minimize the possibility of groundwater contamination from tubing and

casing leaks, and can help minimize s pillage of produced water onto the soil because less water is handled at the surface. Produced-water lifting, treatment, and disposal costs are large components of operating costs; reducing the amount of water brought to the surface can help to substantially reduce these costs.

(2) Oilfield waste does sometimes have value; for example, in California, production sludge is processed to recover crude, and in Alaska the drilled cuttings gravel is used for road construction [24]. A study by Shell examined alternatives for recycling spent drill cuttings. From an initial list of over 100 options, the most viable alternatives for application in the U.K. were determined to be used in cement manufacture, road pavement, bitumen and asphalt; as low-grade fuel, and for cement blocks and ready mix concrete [25].

(3) Waste becomes external only if it is released from the process; for instance, the annular injection of spent drilling mud leaves no drilling waste. Another example is taking carbon dioxide emitted from the coal gasification in south-eastern Saskatchewan and injecting it in the Weyburn field to enhance recovery [26].

Within the petroleum industry, a change in the environmental paradigm from the PCD syndrome to the preventive approach of environmental control has recently emerged as a result of high disposal costs. The cost of waste management has grown steadily in response to increasing volumes of oilfield waste. Interestingly, the amount of regulated waste has grown much faster than oil and gas production because regulated waste volume has been driven mainly by regulations rather than by production rates.

In principle, the environmental control paradigm in petroleum engineering involves three concepts: (1) the fundamental purpose of petroleum engineering is not to protect the environment but to maximize production while preventing environmental impact; (2) compliance problems can be eliminated when environmental constraints are introduced into the production procedures; and (3) any stream of material is off-limits to regulatory scrutiny and can be controlled by oilfield personnel as long as it remains within the oilfield process. In practice, this attitude requires an understanding of environmental impact mechanisms and the willingness to redesign the process.

The environmental control paradigm presented above is a philosophical concept which needs a practical methodology. Such a methodology would give a designer some guidelines regarding how to analyze an industrial process and where to put efforts to make the process 'cleaner' (or 'greener', as some put it).

3.1 Scope and Characteristics of Oilfield ECT

This overview of ECT methodology includes a definition, objectives and characteristic features, general ECT methods and a description of basic steps needed to develop a specific technology. ECT is defined as a technical component of an industrial process that is functionally related to the interaction between the process and environment. Such interaction involves pollution and other adverse effects (impacts) on environmental quality. The objective ECT is to prevent this interaction by controlling the impact mechanisms. The three important features of ECT are integration with the process, specific design and association with productivity.

These three features make ECT different from the technologies of waste management. The difference requires further discussion in relation to oilfield applications. First, however, we must recognize the difference between waste and the process material stream. This difference draws on two facts: (1) where the material is with respect to the process; and (2) what the material's market value is. This concept assumes that no waste exists inside the process – just material streams. On leaving the process (i.e. crossing the process boundary) a stream of material becomes either a product (including by-products) or waste. The difference stems from the market value of the material. Having a positive market value, the material becomes a product. Material with zero value becomes waste. When the value is negative, the material becomes regulated waste (regulated waste requires expenditures for proper disposal).

In view of the above, WMT becomes extraneous to the process because it operates outside the process boundaries and within the environment. WMT involves processing and disposing of the waste as it is discharged from a well site or production plant. Expertise in waste management technologies lies mostly outside the petroleum engineering field. Over the last 10 years, the oil industry has been offered several waste management technologies, providing considerable understanding of the available services. Examples of alternative WMT for production operations are land farming, incineration, road spreading, commercial waste injection facilities and brine demineralization plants. The WMT for drilling operations, other than those for production, include offshore hauling of drilling fluids and cuttings for onshore disposal. These techniques abate pollution without interfering with oilfield procedures; therefore, they provide no incentive for process improvement. Also, the implementation of WMT requires no expertise in petroleum engineering and does nothing to prevent waste generation.

In contrast to WMT, ECT is an integral part of petroleum engineering. It addresses all of the mechanism and control techniques that relate to adverse environmental effects, such as generation of the waste volume and its toxicity, subsurface migration of toxicants and damage to the land surface. The objective of ECT is to minimize, through process improvements, interactions between oilfield processes and the environment. Therefore, the ECT concepts draw exclusively from petroleum engineering expertise. However, development of specific techniques may require expertise outside of petroleum engineering, such as solid–liquid and liquid–liquid separation, environmental science and environmental law, risk analysis and economics.

The use of outside expertise to develop ECT for petroleum engineering includes, of course, some waste management techniques. Indeed, both technologies are bound to draw from the same pool of science. This may sometimes create an impression that ECT is merely a part of WMT. There is, however, a distinct difference between the two. For example, dewatering of abandoned oilfield waste pit slurries, highly diluted with rainfall/run-off water, is a WMT and does not require any oilfield expertise. However, the inclusion of the dewatering component within the closed-loop mud system is an ECT. In this application, dewatering becomes intrinsic to the drilling process; it requires an in-depth knowledge of mud engineering. It also poses a research challenge since drilling fluids, unlike waste water, contain high concentrations of surface active solids.

ECT overlaps with WMT in the area of subsurface injection, which has long been perceived as a waste disposal option in various industries. In this case, however, the petroleum engineering expertise in borehole technology has merely been extended to other applications. Further, when subsurface injection is used in the oilfield for recycling produced water or annular injection of drilling fluids, the method is (1) intrinsic to the oilfield process and (2) requires oilfield expertise to perform, thus making it an ECT.

There is a strong affiliation between ECT and process-control measures. Similar to process-control projects, ECT requires a considerable knowledge of oilfield processes in order to identify the chain reactions that lead to the environmental impact. As an example, let us consider the cause-and-effect relationship between the seemingly unrelated phenomena of drilling mud inhibition and the environmental discharge of drilling waste from the well site. In fact, there is a strong functional relationship between the degree of drilled cuttings dispersion in mud and the waste mud volume. There is also a close analogy between ECT and process-control methods when solving design problems. In process-control design one must prioritize objective function and consider constraints imposed on the design. Similarly, any practical design of ECT must consider the environmental regulations as constraints, while also prioritizing productivity measures (such as daily production or cost per foot).

In this chapter, the term ‘environmental control’ is preferred over ‘pollution prevention’ because it implies broader objectives and suggests the process-control-related means to accomplish these objectives. Oilfield operations create the potential for ecological damage that can hardly be viewed as ‘pollution’, though this damage may set the scene for pollution. Examples of such ecological impact include land subsidence or damage to subsurface zonal isolation resulting from a poor annular seal or from fracturing a confining zone. Characteristically, the destruction of interzonal isolation will not result in pollution if there is no sufficient pressure differential across confining zones.

In summary, any WMT may become ECT if it becomes integrated with the oilfield process. Such integration requires (1) containing the process within clearly defined environmental boundaries and (2) placing the WMT within these boundaries.

3.2 Methodology of ECT Design

A conceptual schematic diagram of an environmentally controlled industrial process is shown in Fig. 2.2. Any process including oilfield operations can be visualized as such an entity having both market and environmental boundaries. Of course, manufacturing processes are best fitted to this schematic because their boundaries are visible and clearly defined. Nevertheless, petroleum drilling and production can also be visualized using the material flowpath in Fig. 2.2. In contrast to manufacturing, oilfield processes do not have readily perceived environmental boundaries, particularly in the subsurface environment. However, they may generate subsurface pollution, which implies a flow of pollutants across a subsurface environmental boundary. The presence of such a boundary is implicit in the issues of borehole integrity and migration across confining (sealing) zones into underground sources of drinking water. Oilfield technologies related to these issues are discussed later.

Although ECT must be specifically designed for each industrial process, its methodology includes general techniques such as source reduction, source separation, recycling, confinement, beneficial use (reuse), environment risk analysis and life-cycle assessment. Figure 2.1 depicts the concepts that underlie these methods.

Source reduction involves restricting the influx of pollutants into the process or inhibiting reactions that produce toxicants within the process (examples: slimhole drilling; subsurface water 'shut-off'; low-toxicity substitution).

Source separation means the removal of pollutants from the process material stream before the stream leaves the process across the environmental boundary and becomes a waste (examples: surface or downhole separators of petroleum and water; segregated production of oil and water; reserve-pit dewatering).

Internal recycling involves closing the loop of a material stream within the process (examples: drill solids-control systems; annular injection of cuttings; downhole separation and disposal of produced brines).

Internal reuse involves employing potential waste within the process (examples: mud-to-cement technology; reservoir pressure maintenance through produced-water reinjection; water flooding with produced brines).

Containment means prevention of an uncontrolled transfer across the environmental boundary caused by leaking, leaching, breaching or cratering (examples: mechanical integrity tests; shallow well shut-in procedures; anti-gas migration cements; annular pressure monitoring during subsurface injection).

Environmental risk analysis (ERA) consists of analytical methods for predicting localized environmental impact (endpoint) for a given variant of process design (emission point). Generally, these are mathematical models (and software) of flow, transport, mixing and dispersion. ERA for oilfield operations involves simulation models of flow across leaking confining zones, channeling outside unsealed boreholes and disposal fracture propagation.

Life-cycle assessment (LCA) is another analysis method for economic production strategies that considers concurrently the productivity and pollution aspects of the production process. In petroleum production the LCA approach qualifies for

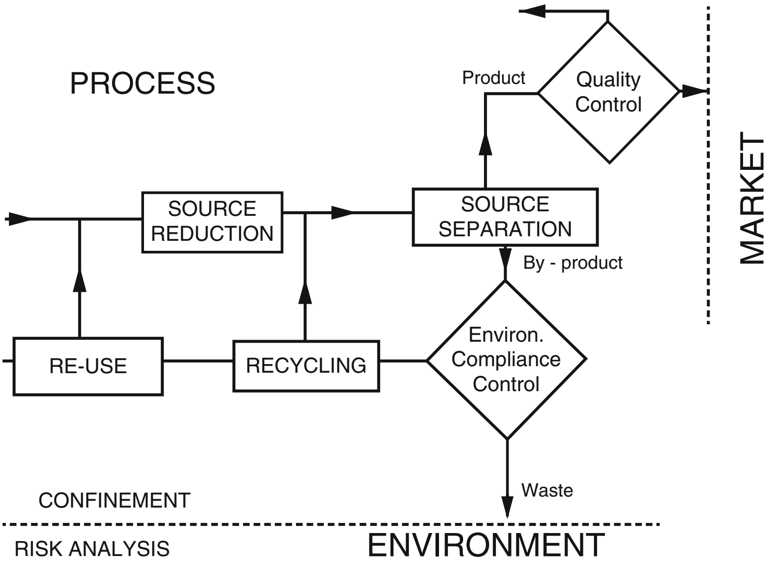

Fig. 2.2 Conceptual flowpath of environmentally controlled process

macro-analysis of petroleum development projects in environmentally sensitive areas, economic impact analysis of environmental regulations or, on a smaller scale, for designing environmental management of a single drilling well or production site [27].

Conceptually, process modification through additions of the environmental control components requires a systematic approach that can be summarized in the following steps:

- define environmental boundary of the process;
- identify inherent mechanisms of environmental impact;
- consider ECT methods and create options for process modification;
- evaluate technical performance (upstream and downstream) of each ECT option;
- calculate net ECT cost;
- decide on process modification.

The difficulty in defining subsurface environmental boundaries for oilfield drilling and production has been discussed above. The surface boundary is somewhat easier to define, but the decision is still based upon subjective judgement rather than scientific definition. In drilling operations, for example, reserve pits were initially included in the drilling fluid circulation systems (hence the name 'reserve') and considered part of the drilling process. Later, the pits were often used as a waste dump that belonged to the environment. After well completion, reserve pits were either abandoned [15] or opened and spread on the surrounding land. Today, on modern rigsites, reserve pits during drilling are carefully isolated from the surrounding environment and are closed promptly after well completion using various environmental techniques described in Chap. 5. In this modern approach, reserve pits are considered part of the drilling process rather than as part of the environment; they reside within the environmental boundary that surrounds the whole rigsite and underlays the bottoms of the pits.

Being an integral part of the process, each ECT component not only improves environmental compliance (downstream performance), but also affects the process productivity (upstream performance). Thus, evaluation of ECT performance should include both the upstream and downstream effects. The most typical example here is the screening of various oilfield chemicals in search of those chemicals that give a combination of the highest performances both upstream and downstream. In one such study [28], five different biocides used to prevent microbically induced corrosion, souring (generation of hydrogen sulphide) or fouling (plugging) of petroleum production installations were evaluated. The evaluation method involved assessment of upstream performance, i.e. the effectiveness of these chemicals in reducing production of H_2S or soluble sulfides (by-product of bacterial growth). Downstream performance was evaluated by modelling transport and the fate of these chemicals for five scenarios of their possible emissions from the production process to the environment.

The net cost of an ECT component is the sum of the ECT cost, value of lost (or gained) production due to ECT and savings in compliance costs due to ECT. Typically, the use of ECT would result in some productivity losses. In drilling, for example, the use of water-based, low-toxicity mud substitute for an oil-based mud would result in a slower rate of drilling. However, some ECT components show potential for improvement of both productivity and environmental compliance. One example here is the new production technique of *in situ* water drainage, described later. Potentially, this method may increase petroleum production while reducing both the amount and contamination level of produced water.

4 ECT Analysis of Drilling Process

A fundamental notion in the ECT approach is that petroleum production, being a process of extraction of minerals from the environment, comprises inherent mechanisms of environmental impact that result from disruption of the ecological balance. The objective of this chapter is to identify these mechanisms and discuss the present level of understanding.

The disruption of the ecological balance (environmental impact) through drilling operations (excluding the well site preparation work) occurs in two ways: (1) surface discharge of pollutants from an active mud system; and (2) subsurface rupture of confining zones (that hydrodynamically isolate other permeable strata) to provide a potential conduit for vertical transport of pollutants.

The regulatory definition of pollutant (in contrast to the popular perception based on health hazards) includes seemingly non-toxic elements such as total suspended solids (TSS), biological oxygen demand (BOD), pH and oil and grease (O&G) (the list of conventional pollutants in the USA includes TSS, BOD, pH, fecal coliform and O&G).

4.1 Mechanisms of Drilling Waste Discharge

Volume and toxicity are two environmental risk criteria for evaluating drilling waste discharge. The flowpath of the drilling process and its environmental discharge mechanisms is shown in Fig. 2.3. The process material stream comprises two recycling loops, the solids-control (drilling mud) loop and the volume-control (water) loop. Conventional drilling operations employ only the solids-control loop. Theoretically, the solids-control loop could be ‘closed’ so that all drill cuttings may be removed in their native state, and the mud may be recycled in the system. In reality, however, some cuttings are retained in the mud system and some drilling fluid is lost across the separators so that the loop is always open, thus contributing to surface discharge. The excessive build-up of drilling mud from loop 1 passes over to the second stage process depicted as the water loop 2 in Fig. 2.3 [29]. The objective of the water loop process is to reduce the volume and recover the water phase of drilling mud. The process has been developed from the principles of industrial sludge dewatering and it employs two mechanisms of mud dewaterability: soil destabilization and cake expression. Dewatering is discussed in more detail later.

The largest volume of drilling-related wastes is spent drilling fluids or muds. The composition of modern drilling fluids or muds can be complex and vary widely, not only from one geographical area to another, but also from one depth to another in a particular well as it is drilled. Muds fall into two general categories: water-based muds, which can be made with fresh or saline water and are used for most types of drilling, and oil-based muds, which can be used when water-sensitive formations are drilled, when high temperatures are encountered, when pipe sticking occurs or when it is necessary to protect against severe drill string corrosion. Recently, there has been a rapid development of a third category of drilling fluids, synthetic muds. These muds are formulated with synthetic organic compounds instead of mineral or diesel oil and are less toxic than oil-based muds.

Drilling muds contain four essential parts: (1) liquids, either water or oil or both; (2) active solids, the viscosity/filtration building part of the system, typically bentonite clays; (3) inert solids, the density-building part of the system, such as barite; and (4) additives to control the chemical, physical and biological properties of the mud.

Drill cuttings consist of inert rock fragments and other solids materials produced from geological formations encountered during the drilling process and must be managed as part of the content of the waste drilling mud. Other materials, such as sodium chloride, are soluble in freshwater and must be taken into account during disposal of drilling muds and cuttings.

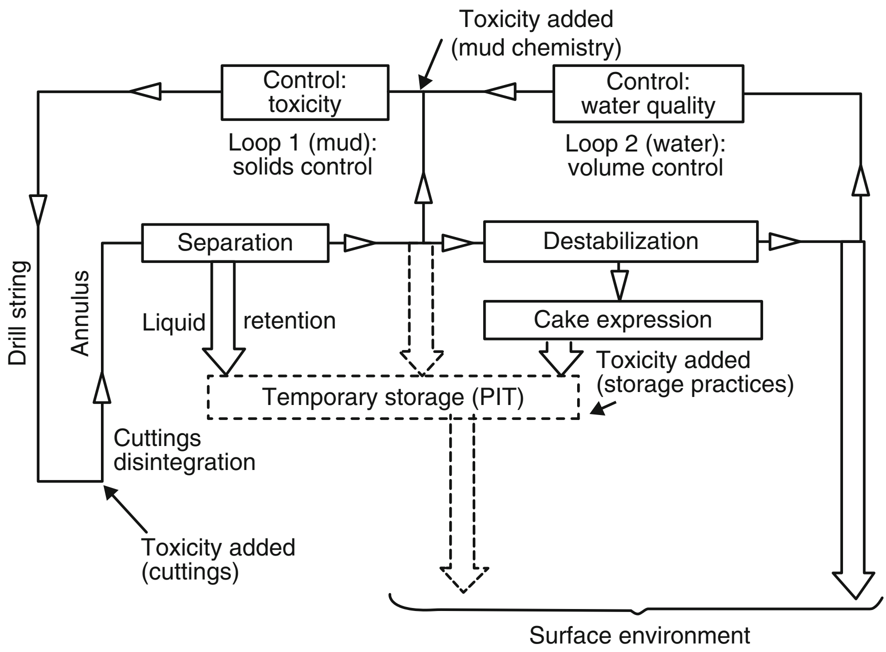

Fig. 2.3 Flowpath of drilling process in relation to environmental discharge

The most general classification of drilling waste includes primary waste and an associated waste. The classification considers the origin and volume of generated waste. Drilling wastes with low toxicity constitute primary waste. The category of primary drilling waste comprises drilling muds and drill cuttings. Associated drilling waste may include rigwash, service company wastes such as empty drums, drum rancid, spilled chemicals, workover, swabbing, unloading, completion fluids and spent acids.

Large volumes of primary drilling waste are generated during the drilling process as a result of volumetric increase in the mud system. The volumetric increase of the active drilling fluid (loop 1 in Fig. 2.3) is inherent in the drilling process. The volume build-up mechanism is a chain reaction shown in Fig. 2.4 [29]. The chain reaction begins with the dispersion of reactive cuttings into the drilling fluid environment. The dispersion results in the decrease of cuttings size from their initial size to the few-microns size range. Most currently used separators do not work efficiently with small solids, i.e. they remove only a small fraction (or none) of these solids. The resulting build-up of fine solids affects the ability of the drilling fluid to perform its functions, which, in turn, hinders drilling process performance (low drilling rate, hole problems).

The minimum acceptable drilling performance relates to a certain maximum concentration of solids or solids tolerance. Solids tolerance varies for different mud systems and densities. Low-solids/polymer systems display the lowest level of

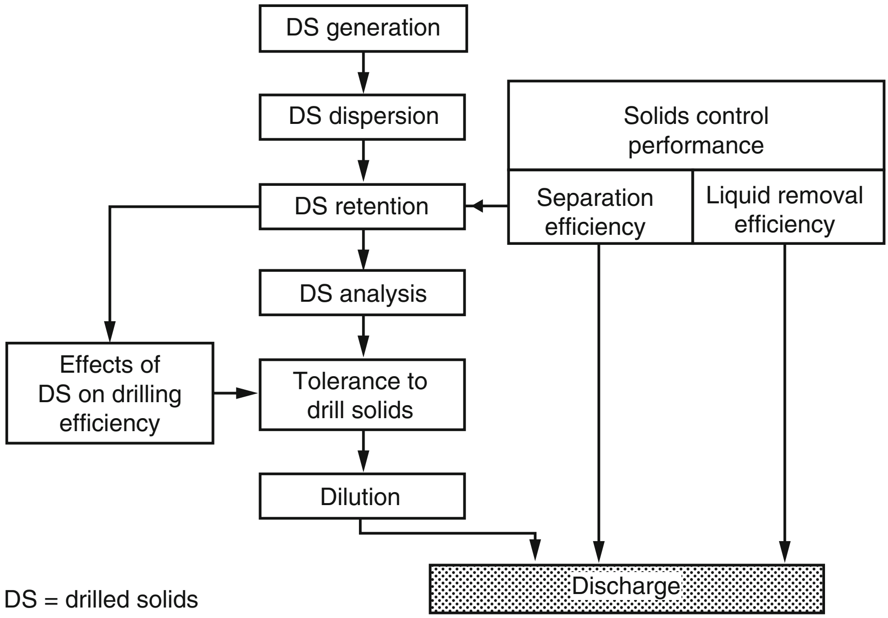

Fig. 2.4 Chain of causality in generation of primary drilling waste [29]

solids tolerance (4 %), whereas the dispersed systems display the highest (15 %). Also, the increase in mud density reduces its tolerance to solids. (Specific values of solids tolerance for various muds have been compiled in various empirical nomograms.) Dilution with fresh mud (or water) is used to keep the solids concentration below the solids tolerance level. The dilution results in a steady build-up in the mud system volume and a subsequent overflow of loop 1 in Fig. 2.4. In conventional drilling operations, the overflow of loop 1 becomes a waste discharge stream. Its volume may exceed by several-fold the actual borehole volume. Table 2.1 shows the estimated discharge volumes of waste mud per barrel of the drilled hole [30]. It is evident that the volume build-up mechanism is most active for dispersed lignosulfonate systems. Characteristically, these systems are the most tolerant to solids.

Disintegration of drilled solids takes place during annular transport from the drilling bit to the flowline. As a result, cuttings become smaller. This size reduction of cuttings is the first factor contributing to cuttings retention in the mud system. The size of cuttings depends upon (1) the initial size resulting from the bit action, (2) bottomhole cleaning efficiency, and (3) the mechanical strength of cuttings in the mud environment. Besides a qualitative understanding of the effects of bit type and pressure differential across the rock face, very little is known about the initial size of cuttings. An example of the actual initial size of cuttings generated by various types of cone bits is shown in Table 2.2 [31]. Data support the common knowledge that the harder is the bit type, the smaller are the cuttings. However, there is no predictive model based on drilling mechanics that would relate initial cuttings size to bit geometry and rock strength. A preliminary study in this area

Table 2.1 Mud used per hole drilled[a]

Mud type	Mud/hole (v/v)
Lignosulfonate	6–12
Polymer	4–8
Potassium (KOH)/lime	3–6
Oil-base	2–4

[a]After Ref. [30]

Table 2.2 Effect of roller cone insert bit type on initial size of cuttings[a]

Bit type	Chip volume (mm^3)	Height[b] (mm)	Diameter[c] (mm)	R/R_2[d]	T/T_{2e}
Very soft	825	5	26	2.5	2
Soft[f]	504	4	22	1	1
Soft[g]	495	3	26	2	2

[a]After Ref. [31]
[b]Minimum measured
[c]Calculated for cylindrical chip
[d]Relative drilling rate, related to bit No. 2
[e]Relative bit life, related to bit No. 2
[f]Slim, wedge-shaped inserts
[g]Thick, short, scoop-shaped chisels

determined the relationship between the specific energy of rock destruction, total mechanical energy of a bit and cuttings size [32].

The effect of bottomhole cleaning on the initial size of cuttings can be inferred from the experimentally verified response of the drilling rate to the bottomhole hydraulic energy generated by bit nozzles. It is generally assumed that in soft rock drilling, the bit flounder point represents an offset of poor cuttings removal from under the bit [33]. The remaining cuttings undergo additional grinding, which results in size reduction. The flounder point can be determined experimentally using the drill-off test. Further cuttings destruction can be prevented by adjustment of the mechanical energy to the hydraulic energy at the bottom of the hole.

Size reduction of cuttings is caused by loss of cohesion due to hydration of their rock matrix. Cuttings originating from non-swelling rocks (sand, limestone) are unlikely to lose their initial cohesion on their way up the borehole annulus. It has been proved, however, that even these inert solids undergo disintegration under conditions of shear, as shown in Table 2.3 [34].

The major mechanism controlling cuttings disintegration stems from the hydration energy of their source rock, usually shale. The disintegration has been correlated with several variables measured in various tests of cuttings hydration rate, such as (1) the swelling test (measured: linear expansion); (2) capillary suction time test, CST (measured: time of water sorption); (3) cation exchange capacity test, CEC (measured: dye adsorption); (4) activity test (measured: electrical resistance of water vapor); and (5) rolling test (measured: weight loss of drill cuttings of a certain size) [35–38]. The drawback of these tests is that they do not provide a direct measurement of drill cuttings properties (strength, size). However, they do determine other variables that correlate with these properties.

Table 2.3 Shear disintegration of inert solids in mud[a]

Shear treatment	Particles smaller than 2 μm (volume fraction)						
	Barite A (green)	Barite B (orange)	Barite C (orange)	Barite D (buff)	Barite E (orange)	Itabarite	Ilmenite
None	6.6	8.0	5.3	8.8	12.6	4.3	0.3
Ultrasound (1 min)	13.3	13.2	12.1	16.9	12.8	15.7	0.6

[a]After Ref. [34]

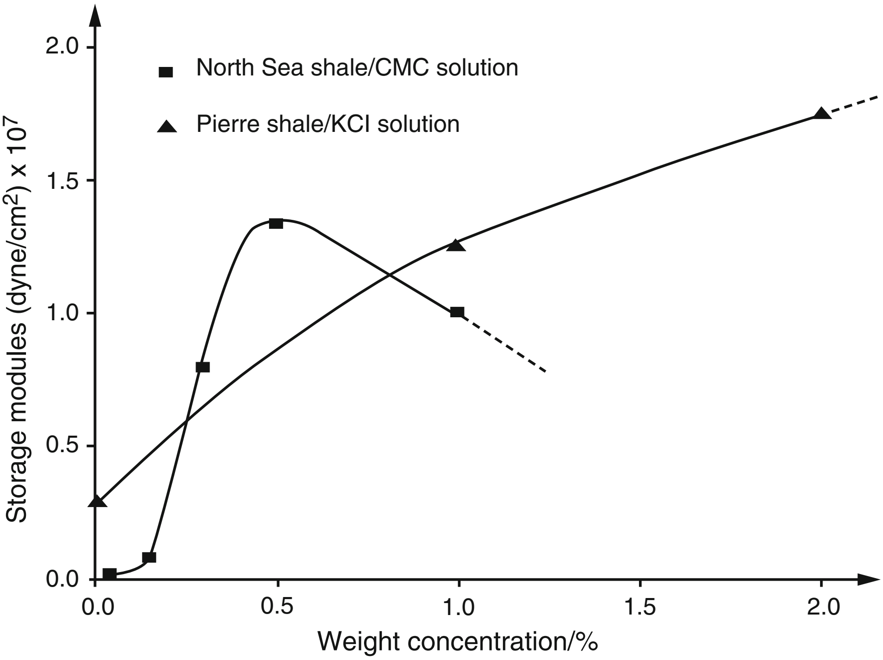

Fig. 2.5 Strength of shale cutting in various mud environments (1 dyne = 10^{-5} N) [39]

The proposed single property of shale cuttings representing their strength is the storage modulus of viscoelasticity [39]. The storage modulus is a measure of the energy stored and recovered under conditions of oscillating stresses. It can be measured using an oscillatory viscometer and a compacted ‘drill cutting’ platelet after various exposure times of a cutting to drilling mud. Figure 2.5 shows the strength of a shale cutting after 18 h of exposure to various concentrations of salts (KCl) and polymer in the drilling fluid.

The initial strength of cuttings and their tendency to become hydrated can be inferred from the mineralogy of shales with respect to depth. The disintegration rate of shale cuttings results from the mineralogical composition of the shale and can be directly related to geological structures in the drilling area. For example, Fig. 2.6 shows the drilled-depth correlations of the illite concentration (low-reactivity clay) and shale water content for the offshore Louisiana Gulf Coast [40].

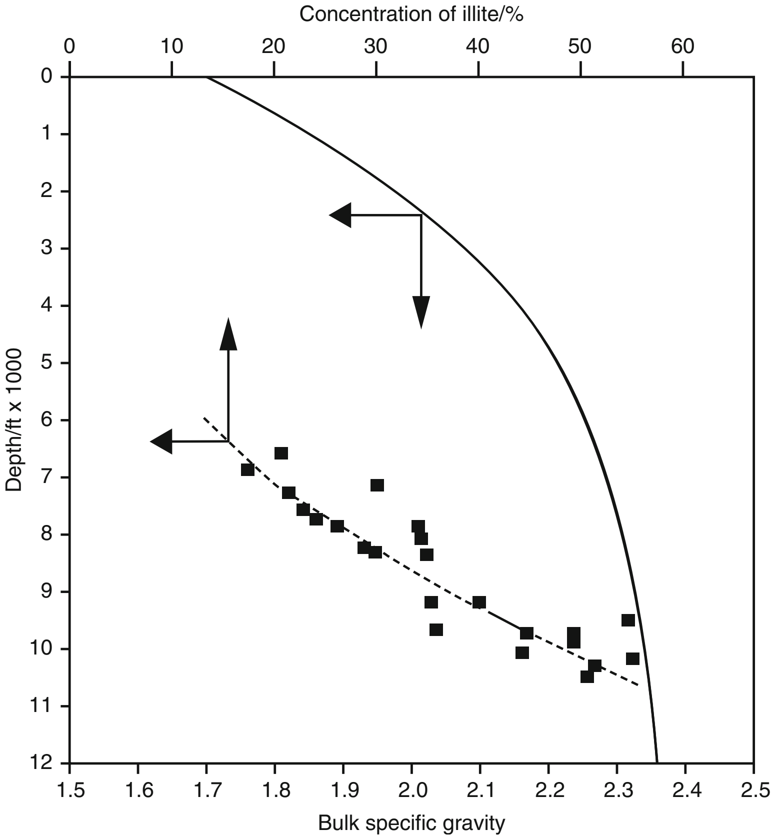

Fig. 2.6 Shale reactivity indicators versus depth for Louisiana Gulf Coast [35]

The depth-related reactivity of shales can also be observed in the size of cuttings coming from the well. An analysis of the size distribution of solids at the flowline versus drilling depth shows different rates of cuttings disintegration during their annular transport, as evidenced by Fig. 2.7 [41]. Also shown in Fig. 2.7 is a correlation between size of mud solids at the flowline and at the pump suction (i.e. upstream and downstream of solidscontrol system). Such correlations are more useful than measurements of the rock hydration rate because they not only identify well sections with water-sensitive rocks but also provide data that can be used to evaluate solids-control systems.

The separation efficiency of a solids-control system is limited by the size of the solids in the drilling mud entering the separators. This limitation is the next factor contributing to solids retention in the mud system. The plots in Fig. 2.7 show a comparison of solids size in drilling mud samples taken from the flowline and the suction tank. In the three sections of the well (2300–2800, 5000–5600 and 6150–7215 ft; 1 ft = 0.3048 m), the efficiency of cuttings removal was evidently

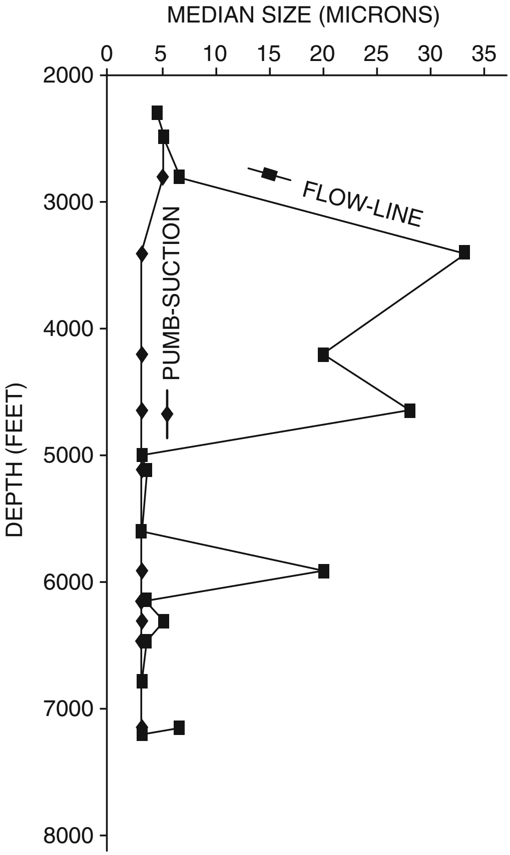

Fig. 2.7 Depth-related size of cuttings upstream (flowline) and downstream (pump suction) from solids-control separators [34]

almost zero. The most likely reason is that the size of the solids was below the removal range of the surface separators. Thus, the drilling fluid loop in these sections was 'wide open' because the only way to control mud solids was to dilute the mud system and generate an excessive volume.

There is an important misconception about the performance of solidscontrol separators. The widely recognized concept of the subsequent size exclusion of solids holds that the shale shaker removes cuttings >120 μm, desander 50 μm, desilter 15 μm and a centrifuge 3 μm. However, the actual performance is not only lower than the theoretical one, but it is also affected by the feed mud rheology and operational parameters of a separator. As an example, Fig. 2.8 shows the theoretical and actual grade separation curves for a 4 in (10 cm) hydrocyclone [34, 41, 42]. Both the laboratory and the field data indicated poor performance of hydrocyclones with weighted mud systems; this raised some questions regarding the applicability of mud cleaners. Reportedly, the 50 % cut made by the 100-mesh screen was smaller than the cut for the 4 in hydrocyclone [42]. Note however, that when comparing separators, the grade efficiency should be considered together with

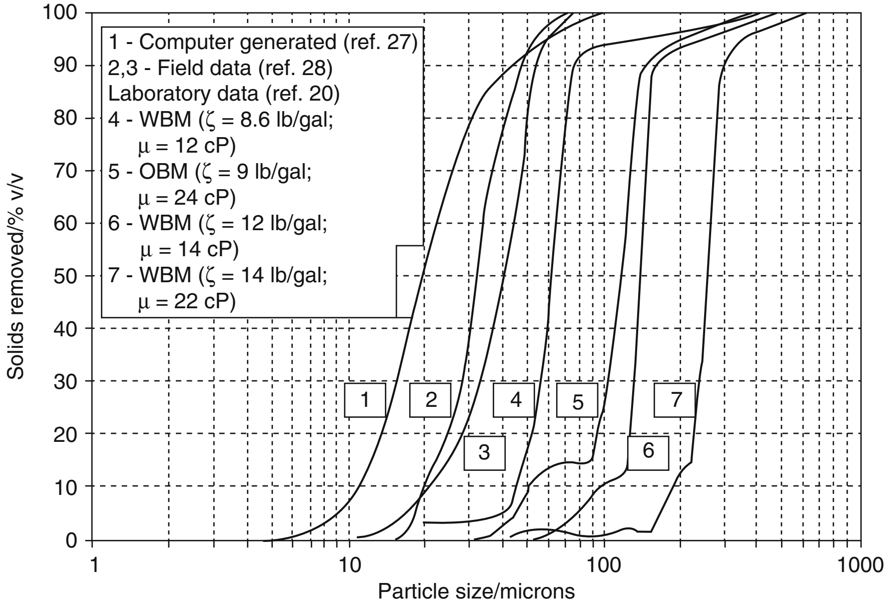

Fig. 2.8 Theoretical and actual performances of 4 in hydrocyclones: effects of mud and type and rheology (1 lb = 0.454 kg; 1 gal = 3.785 dm^3; 1 cP = 10^{-3} N s/m^2)

the load capacity. The liquid conductance of vibrating screens has been proved to decrease rapidly with increasing mesh size and mud viscosity [43]. In contrast, the operator can increase the volume processed by the hydrocyclones simply by adding more cones.

The separation efficiency of centrifuges is highly dependent upon the type of separated solids. The theoretical values of 50 % cut, 3–4 μm, claimed by manufacturers are relevant only for the barite-recovery application of centrifuges. Much poorer separation is obtained for low-gravity (reactive) solids, as shown in Fig. 2.9 [44]. The inability of the decanting centrifuge to control fine solids in the mud system during the double-stage centrifuging was observed in both field [42] and full-scale laboratory tests [44].

4.2 *Sources of Drilling Waste Toxicity*

There are three contributing factors of toxicity in drilling waste: the chemistry of the mud formulation, inefficient separation of toxic and non-toxic components and the drilled rock. Typically, the first mechanism is known best because it includes products deliberately added to the system to build and maintain the rheology and stability of drilling fluids. The technology of mud mixing and treatment is recognized as a source of pollutants such as barium (from barite), mercury and cadmium

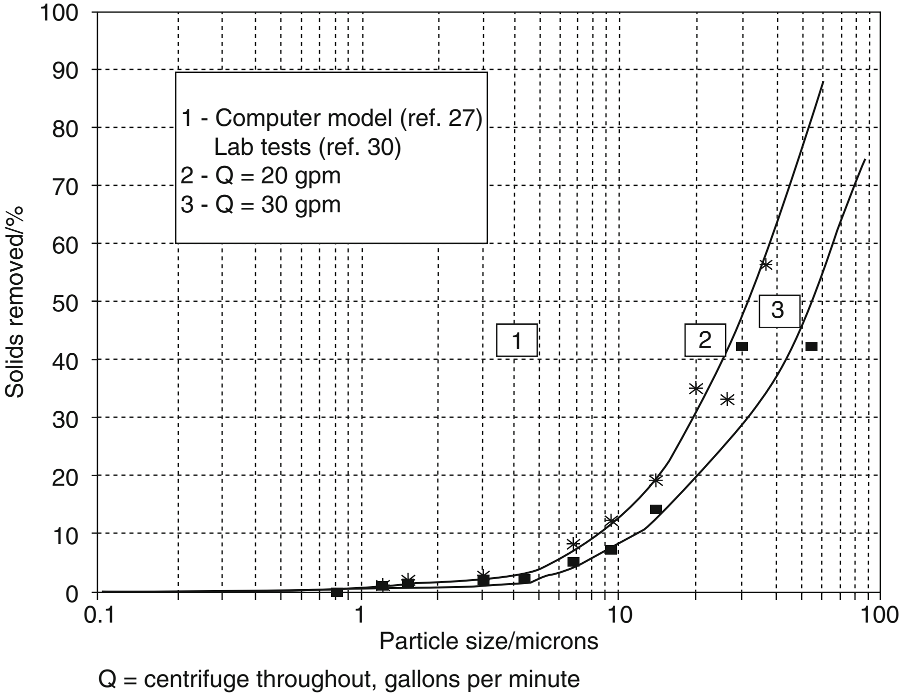

Fig. 2.9 Theoretical (inert solids) and actual (active solids) performance of decanting centrifuge

(from barite impurities), lead (from pipe dope), chromium (from viscosity reducers and corrosion inhibitors), diesel [from lubricants, spotting fluids, and oil-based mud (OBM) cuttings] and arsenic and formaldehyde (from biocides).

Inefficient separation of toxic components from the drilling waste discharge stream becomes another source of toxicity through retention of the liquid phase on OBM cuttings, use of spotting pills or indiscriminate practices of on-site storage. Removal of the liquid phase from cuttings separated by the solids-control equipment becomes particularly important while using diesel-based drilling fluids (DOBM). Field data show that the total oil-based mud discharge rate jointly for the mud cleaner and centrifuge is 10 bbl/h [28]. Also, the OBM removal performance is different for various separators as shown in Table 2.4 (the highest for mud cleaners, and lowest for centrifuges) [42, 45, 46].

Research revealed that the OBM retention on cuttings is smaller for the mineral oil-based than for diesel-based OBMs, as evidenced by field data in Table 2.5 [47, 50]. The hypothetical mechanisms of oil retention on solids have been attributed to adhesive forces, capillary forces and oil adsorption and were identified as the amount of oil removed from OBM cuttings using centrifugal filtration, *n*-pentane extraction and thermal vaporization, respectively. The conclusion has been forwarded that 50 % of the oil–solids bond could be attributed to adhesive/

Table 2.4 Liquid discharge and oil retention on cuttings from oil-based muds (OBM) for various separators

	Oil content (% w/w)/OBM discharge rate (gal/min)[a]		
Reported data	Shale shaker	Mud cleaner	Centrifuge
Ref. [32]	12.3/NR	14.1/NR	8.4/NR
Ref. [28]	NR/NR	NR/4.2	NR/0.7
Ref. [31]	11.1–16.5/NR	NR/NR	3–10.2/NR

[a]NR = not reported

Table 2.5 Oil retention on OBM cuttings[a] vs type of oil[b]

	Well			
Drilling fluid	1	2	3	4
Diesel OBM	20.0	13–16	9.8	10.8
Mineral OBM	7.9	10.3	NR	NR

[a]Percent by dry weight of discharge from shale shaker
[b]Compiled from Refs. [47–50]

capillary forces, 29 % to weak adsorption and 20 % to strong adsorption, i.e. 20 % of oil on cuttings could not have been removed with *n*-pentane extraction. The adhesive mechanism was also explained using the wettability preference of drilled rock. The preference was evaluated by measuring the adhesion tension of thin-cut plates of quartz and shales immersed in OBM. The results showed that the rocks immersed in diesel OBM became strongly oil-wet, whereas for the mineral OBM, the initially oil-wet surfaces tended to reverse their wettability and became water-wet.

Indiscriminate storage/disposal practices using drilling mud reserve pits can contribute toxicity to the spent drilling fluid, as shown in Table 2.6. The data in Table 2.6 are from the U.S. EPA survey of the most important toxicants in spent drilling fluids. In the survey, sample taken from active drilling mud in the circulating system were compared with samples of spent drilling mud in the reserve pit [20]. The data show that the storage/disposal practices were a source of the benzene, lead, arsenic and fluoride toxicities in the reserve pits because these components had not been detected in the active mud systems.

The third source of toxicity in the drilling process discharges is the type of drilled rocks. A recent study of 36 core samples collected from three areas (Gulf of Mexico, California and Oklahoma) at drilling depths ranging from 3000 to 18,000 ft revealed that the total concentration of cadmium in drilled rocks was more than five times greater than the cadmium concentration in commercial barites [51]. With a theoretical well discharge volume in a 10,000 ft well model, 74.9 % of all cadmium in drilling waste was estimated to be contributed by cuttings, whereas only 25.1 % originate from the barite and the pipe dope.

Table 2.6 Toxicity difference between active and waste drilling fluids[a]

Toxicant	Active mud	Detection rate (%)	Reserve pit	Detection rate (%)
Benzene	No	–	Yes	39
Lead	No	–	Yes	100
Barium	Yes	100	Yes	100
Arsenic	No	–	Yes	52
Fluoride	No	–	Yes	100

[a]Based on Ref. [20]

4.3 Waste Generation Mechanisms in Petroleum Production

Petroleum production involves the extraction of hazardous substances, crude oil and natural gas, from the subsurface environment. Therefore, by its very nature, production technology involves pumping and processing pollutants. Any material used in conjunction with the production process and exposed to petroleum becomes contaminated. In essence, there are two mechanisms of pollution in the production process: generation of contaminated waste and leakage of material streams from the process to the environment. All non-petroleum materials entering the production process are either naturally occurring subsurface substances, such as formation waters and produced sand, or deliberately added chemicals facilitating production operations.

Inside the process, these materials are mixed into the stream of petroleum, then separated into three final streams at the process output: marketable oil or gas products, produced water and associated waste. This simplified analysis is depicted in Fig. 2.10 and discussed below.

The mechanisms of waste generation are related to production operations. *Downhole production operations* include primary, secondary and tertiary recovery methods, well workovers and well stimulations. Primary recovery refers to the initial production of oil or gas from a reservoir using only natural pressure to bring the product out of the formation and to the surface. Most reservoirs are capable of producing oil and gas by primary recovery methods alone, but this ability declines over the life of the well.

Eventually, virtually all wells must employ some form of secondary recovery. This phase of recovery is at least partially dependent on artificial lift methods, such as surface and subsurface pumps and gas lift, but typically also involves injection of gas or liquid into the reservoir to maintain pressure within the producing formation. Water flooding is the most frequently employed secondary recovery method. It involves injecting treated freshwater, seawater or produced water into the formation through a separate well or wells.

Tertiary recovery refers to the recovery of the last portion of the oil that can be economically produced. Chemical, physical and thermal methods are available and may be used in combination. Chemical methods involve injection of fluids containing substances such as surfactants and polymers. Miscible oil recovery

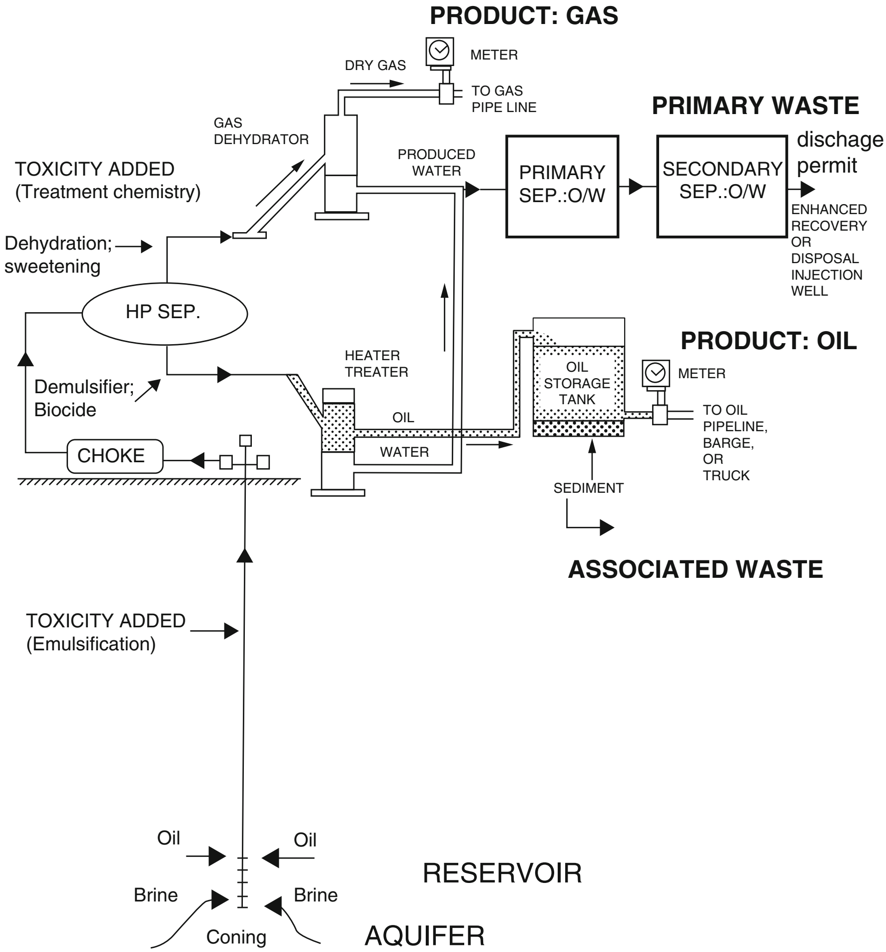

Fig. 2.10 Waste generation mechanisms in petroleum production process

involves injection of gases, such as carbon dioxide and natural gas, which combine with the oil.

When oil eventually reaches a production well, injected fluids from secondary and tertiary recovery operations may be dissolved in formation oil or water or simply mixed with them. The removal of these fluids is discussed below in conjunction with surface production operations.

Workovers and stimulations are another aspect of downhole production operations. Workovers are designed to restore or increase production from wells whose flows are inhibited by downhole mechanical failures or blockages, such as those caused by sand or paraffin deposits. Fluids circulated into the well for this purpose must be compatible with the formation and not adversely affect permeability. Stimulations are designed to enhance the wells productivity through fracturing or acidizing. Fluids injected during these operations may be very toxic (hydrochloric acid, for example) and may be produced partially back to the surface after petroleum production is resumed. Other chemicals may be periodically or continuously pumped down a production well to inhibit corrosion, reduce friction or simply keep the well flowing. For example, methanol may be pumped down a gas well to keep it from becoming plugged with ice.

Surface production operations generally include gathering the produced fluids (oil, gas, gas liquids and water) from a well or group of wells and separating and treating the fluids.

During production operations, pressure differentials tend to cause water from adjoining formations to flow into the producing formation (water breakthrough or water coning). The result is that, in time, production water/oil ratios may increase steeply. New wells may produce little, if any, water; mature wells may produce more than 100 barrels of water for every barrel of oil. Virtually all of this water must be removed before the product can be transferred to a pipeline (the maximum water content permitted is generally less than 1 %). The oil may also contain completion or workover fluids, stimulation fluids or other chemicals (biocides, fungicides) used as an adjunct to production. These, too, must be removed. Some oil–water mixtures may be easy to separate, but others may exist as fine emulsions that do not separate by gravity settling. Conventionally, gravity settling has been performed in a series of large or small tanks (free water knock-outs, gun barrels, skim tanks), the large tanks affording longer residence time to increase separation efficiency (API separators). When emulsions are difficult to break, heat is usually applied in so-called ‘heater treaters’. Whichever method is used, crude oil flows from the final separator to stock tanks. The solids and liquids that settle out of the oil at the tank bottoms (‘produced’ sand) must be collected and discarded along with the separated water.

Natural gas requires different techniques to separate out crude oil, gas liquids, entrained solids and other impurities. These separation processes can occur in the field, in a gas processing plant, or both. Crude oil, gas liquids, some free water and entrained solids can be removed in simple separation vessels. Low-temperature separators remove additional gas liquids. More water may be removed by any of several dehydration processes, frequently through the use of glycol, a liquid desiccant or various solid desiccants. Although these separation media can generally be regenerated and used again, they eventually lose their effectiveness and must be discarded.

Both crude oil and natural gas can contain the highly toxic gas hydrogen sulfide (200 ppm in air is lethal to humans). At plants where hydrogen sulfide is removed from natural gas, sulfur dioxide (SO_2) release may result. Sulfur is often recovered from the SO_2 as a commercial by-product. Hydrogen sulfide (H_2S) dissolved in crude oil does not pose any danger, but, when it is produced at the wellhead in gaseous form, it poses serious occupational risks through possible leaks or blowouts. These risks are also present later in the production process when the H_2S is separated out in various ‘sweetening’ processes. The amine, iron sponge and selexol processes are three examples of commercial processes for removing acid gases from natural gas. Each H_2S removal process results in spent iron sponge or separation media that must be disposed of.

Production waste is broadly classified as either primary or associated waste. Most of the materials used and discarded from production operations fall into the associated waste category. A listing of associated waste is shown in Table 2.7. This waste is characterized as having low volume and high toxicity.

Produced water is a primary production waste having a very large volume and relatively low toxicity compared with associated waste. In 1989, the daily average discharge of produced water from all North Sea production operations was 355,000 m^3/day, with oil and gas production rates of 535,000 m^3/day and 267×10^6 m^3/day, respectively [52]. During 1990, Gulf of Mexico oilfield operations produced 866.5 million barrels of water [53], while the total U.S. production of water from oil and gas operations was 14 billion barrels [54]. Because of these large volumes, produced water is the major production waste stream with potential for environmental impact.

Excessive water production has been a continuing problem for operators since the beginning of petroleum industry [55]. To date, 98 % of US E&P waste volume is produced water [56]. Based on the survey of American Petroleum Institute [57] about 17.9 billion barrels (bbl) of produced water was generated by the onshore E&P operations in the US in 1995; similarly, there was also a large amount of produced water generated by offshore production operations. Khatib and Verbeek estimated that, an average of 210 million bbl of water was produced each day worldwide in 1999, which means about 77 billion bbl of produced water for the whole year [58]. Usually, the produced water volume increases over the life of a conventional petroleum well and the water/oil ratio rises with production. According to the report by Schlumberger, 75 % of the total production from petroleum reservoirs is only water, equivalent to 249.3 million bbl of water per day worldwide in 2005 [59, 60]. It has been also reported that oil wells produce – on average – more than 7 bbl of water for each barrel of oil [61]. When the wells mature, water may amount to as much as 98 % of the fluids brought to the surface.

The system analysis of the production process in Fig. 2.10 clearly shows that formation water enters the process downhole through the petroleum producing perforations, where it begins to mix with hydrocarbons. The water may flow into the hydrocarbon formation through processes of coning or fingering. The process kinetics of mixing oil and water under conditions of variable temperature and pressure during the two-phase flow in the well have not yet been investigated. In this process, formation water becomes contaminated by dispersed oil and soluble organics. The time required to reach an equilibrium concentration of fatty acids and other polar, water-soluble components of crude oil in produced brine is expected to be significantly shorter than the time of the two-phase flow [62]. Thus, a maximum level of contamination is reached before the brine is separated from oil. In addition to hydrocarbons, all treating chemicals used in surface operations are mixed into the water, thus adding to the final toxicity of produced-water discharge. Characteristically, most of the recent research regarding composition and toxicity of produced water has focused solely on the endpoint product of the above mixing mechanism

Table 2.7 Associated production waste

Oily wastes: tank bottoms, separator sludges, pig trap solids
Used lubrication or hydraulic oils
Oily debris, filter media and contaminated soils
Untreatable emulsions
Produced sand
Spent iron sponge
Dehydration and sweetening wastes (including glycol amine wastes)
Workover, swabbing, unloading, completion fluids and spent acids
Used solvents and cleaners, including caustics
Filter backwash and water softener regeneration brines

while disregarding subsequent stages of water contamination on its way from the aquifer to the environmental discharge point.

4.4 Sources of Toxicity in Produced Water

As discussed above and depicted in Fig. 2.10, toxicity of produced water results from two factors: properties of formation water in its natural state and toxicity contributed by the very process of production. Sources of produced-water toxicity that has been added to the water during the production process include hydrocarbons and treating chemicals. Water toxicity has been shown to increase along its flowpath across the production process [20]. Table 2.8 compares toxic components in a typical oilfield production waste stream at the midpoint and at the endpoint of the production process. As can be seen, the hazard of benzene and pH toxicity increases along the process flowpath. Also, three additional toxicants, phenanthrene, barium and arsenic, are detectable at the endpoint but are absent in the midpoint samples.

Prior to production, formation waters may display some level of toxicity which is usually unknown. Unlike toxicity of produced water, the *in situ* toxicity of oilfield brines has not been investigated. The most likely sources of toxicity in formation water prior to production are salt and radionuclides.

The lack of hydrocarbon contamination of the formation water column underlying the oil column was recently evidenced in a pilot study in which water was produced separately from, and concurrently with, oil using a dually completed well [63, 64]. No polyaromatic hydrocarbons (PAHs) or oil and grease were detected in that water. Therefore, conventional concurrent production of petroleum and water was concluded to be the sole source of hydrocarbon contamination of produced water, at least in water-drive reservoirs where the oil column is separated from the water column. The contamination may take two forms: dispersed oil and soluble oil (mostly non-hydrocarbon organic material).

Table 2.8 Toxicity increase of produced water across production process[a]

Pollutant	Midpoint	Detection rate (%)	Endpoint	Detection rate (%)
pH	6.4, 6.6, 8.0	–	2.7, 7.6, 8.1	–
Benzene	Yes[b]	60	Yes[b]	76
Phenanthrene	No	–	Yes[b]	24
Barium	No	–	Yes	87
Arsenic	No	–	Yes	37

[a]Based on Ref. [20]
[b]Detected concentration was 1000 times greater than that hazardous to humans

Dispersed oil consists of small droplets of oil suspended in the water. As a droplet moves through chokes, valves, pumps or other constrictions in the flowpath, the droplet can be torn into smaller droplets by the pressure differential across the devices. This is especially true of flow viscosity oils and condensates. Precipitation of oil from solution results in a water fraction with smaller droplets. These small droplets can be stabilized in the water by low interfacial tension between the oil and the produced water. Small droplets can also be formed by the improper use of production chemicals. Thus, the addition of excess production chemicals (such as surfactants) can further reduce the interfacial tension so that coalescence and separation of small droplets becomes extremely difficult.

Oilfield deoiling technology, discussed later in this chapter, is designed to remove dispersed oil. Failure to remove small oil droplets results in the presence of dispersed oil in produced-water discharges. (The total maximum concentration of oil and grease, O&G, in these discharges varies in different areas. In the USA, for example, the daily maximum O&G concentration is 42 mg/l, while under the Paris Convention the maximum dispersed oil concentration is 40 mg/l.)

Soluble oil includes organic materials such as aliphatic hydrocarbons, phenols, carboxylic acids and low molecular weight aromatic compounds. The concentration of dissolved oil in produced water depends upon the type of oil. However, it is also related to technological factors, such as the type of artificial lift techniques (mixing energy of petroleum in water) and stage of production (encroachment of formation water into petroleum-saturated zone).

The concentration of dissolved organics may in some cases reach the maximum regulatory limit for offshore discharge (O&G 29 mg/l monthly average), as shown in Fig. 2.11 [65]. Most of the contribution to these concentrations comes from phenols and volatile aromatics, as shown in Table 2.9 [66].

At least one study has shown that the toxicity of soluble oil is not significant. The soluble oil fractions of two different produced waters were tested for toxicity and found to have acute toxicities of 15.8 and 4.8 % [66, 67]. One of the reported characteristics of these components is that they are easily biodegraded. Therefore, low levels of dissolved organic materials are easily assimilated by the receiving ambient water. In addition to locally increasing BOD, the components of soluble oil each have a different fate in the environment [67].

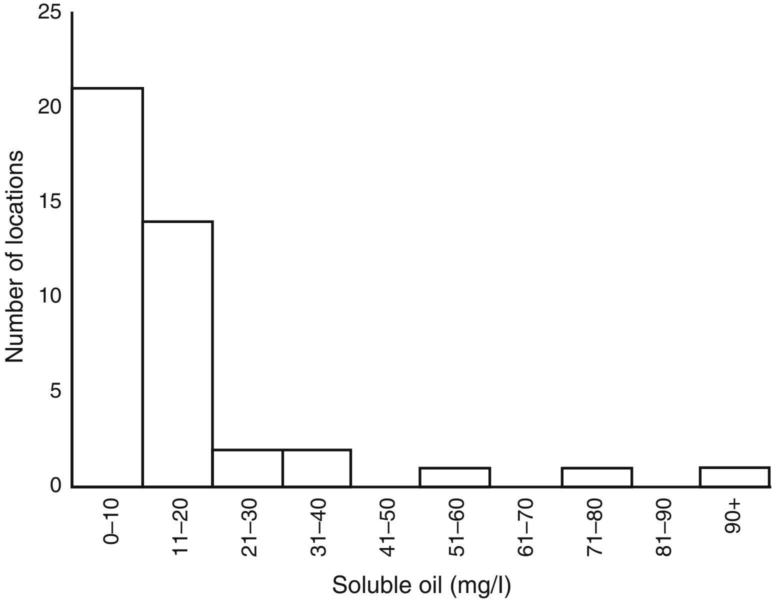

Fig. 2.11 Concentration of soluble oil in produced water [65]

Table 2.9 Phenols and volatile aromatics in produced water[a]

Production	Concentration (μg/l)	Toxicant			
		Phenols	Benzene	Toluene	C_2–Benzene
Gas	Average	4743	5771	5190	700
	Standard deviation	5986	4694	4850	1133
	Maximum	21,522	12,150	19,800	3700
	Minimum	150	683	1010	51
Oil	Average	1049	1318	1065	221
	Standard deviation	889	1468	896	754
	Maximum	3660	8722	4902	6010
	Minimum	0	2	60	6

[a]From Ref. [66]

Heavy metals in produced waters may be either present in formation water or added through the production process. Metals that may contribute to toxicity include barium, cadmium, chromium, copper, lead, mercury, nickel, silver and zinc. Typically, their concentrations in produced water may be in the range of thousands of μg/l while their concentration in seawater varies from trace to tens of μg/l. Heavy metals have been reported to pose little harm in the marine environment [67, 68]. They may settle out in marine sediments, thus increasing the sediment metal concentrations. However, they are tightly adsorbed to other solids and have much lower bioavailability to marine animals than do the metal ions in solution.

Radionuclides found in produced waters are often referred to as naturally occurring radioactive material (NORM). The source of the radioactivity in scale deposits from produced water comes from the radioactive ions, primarily radium, that coprecipitate from produced water along with other types of scale. The most common scale for this coprecipitation is barium sulfate, although radium has also been found in calcium sulfate and calcium carbonate scales.

Studies of soluble radionuclides in produced water have been summarized recently [58]. Early studies of wells in Oklahoma, the Texas panhandle and the Gulf of Mexico coastal area showed ^{226}Ra levels ranging from 0.1 to 1620 pCi/l (1 Ci $= 3.7 \times 10^{10}$ Bq) and ^{228}Ra levels ranging from 8.3 to 1507 pCi/l. Recent studies conducted by the State of Louisiana, Offshore Operators Committee and the U.S. Environmental Protection Agency showed ^{226}Ra level ranges of 0–930, 4–584 and 4–218 pCi/l, respectively, and ^{228}Ra level ranges of 0–928, 18–586 and 0–68 pCi/l, respectively. These levels are considerably lower than those from early findings. Also, reported research provides no evidence of the impact of radionuclides on fish or human cancers exceeding that resulting from a background concentration of radium.

Treating chemicals used in production operations can be classified according to types of production operations and the purpose of the treatment, as production liquid treating chemicals, gas processing chemicals and stimulation or workover chemicals. The production liquid treating chemicals are those routinely added to the produced oil and water (including waters used for water flooding). Chemically, these compounds are complex mixtures manufactured from impure raw materials. However, when looked upon as a source of toxicity in produced water these chemicals can be broadly analyzed according to their function, initial toxicity, solubility in water and treatment concentration. Obviously, all the above factors will control individual contribution of these chemicals to the final toxicity of produced-water discharge. For the purpose of reference, Table 2.10 shows the general grading of toxicity using lethal concentration values representing the 50 % mortality rate (LC_{50}) [68]. The following analysis summarizes findings regarding production chemical use and toxicity [69].

Biocides control bacterial growth, particularly sulfate-reducing bacteria that cause corrosion or fouling. Aldehydes, quaternary ammonium salts and amine acetate salts are the most commonly used biocides. All the biocides are highly water soluble. Intermittent slug treatments at 50–200 ppm of formulation are used to obtain good control with a minimum total biocide usage. The LC_{50} values for biocides may vary from less than 1 to above 1000 ppm.

Scale inhibitors control deposition of common oilfield scales of calcium carbonate, calcium sulfate, strontium sulfate and barium sulfate. Three generic chemical types – phosphonates, phosphate esters and acrylic-type polymers – comprise 95 % or more of the chemical being used. All formulations are highly water soluble. A minimum concentration, typically 3–10 ppm, must be present at all times to prevent scale deposition. After squeeze treatments (relatively uncommon) the concentration of compound in the produced water may be as high as 5000 ppm

Table 2.10 Classification of toxicity grades[a]

Classification	LC_{50} value (ppm)
Practically non-toxic	>10,000
Slightly toxic	1000–10,000
Moderately toxic	100–1000
Toxic	1–10
Very toxic	<1

[a]From Ref. [68].

for a few days. The LC_{50} values for scale inhibitors fall within the range 1000–11,000 ppm.

Corrosion inhibitors include compounds of the amide/imidazoline, amine or amine salt, quaternary amine and heterocyclic amine types. Oil-soluble inhibitors generally are preferred for oil production because of their great effectiveness. Continuous treatment with 10–20 ppm may be used in oil wells or pipelines. The initial LC_{50} values for corrosion inhibitors may be below 1 ppm. Most typical values, however, are from 1.2 to less than 10 ppm.

Emulsion breakers improve the separation of oil from water. The most common compounds are oxyalkylated alkylphenol–formaldehyde resins, polyglycol esters and alkylaryl sulfonates. Almost all formulations contain more than one of these generic types, as well as a surfactant. Virtually all components of these formulations are very insoluble in water and distribute into the oil phase. Typical use concentrations are about 25–100 ppm based on oil, with perhaps only 0.4–4 ppm distributing into the produced water. Initial LC_{50} values for emulsion breakers range from 3.8 to 80 ppm.

Reverse breakers are used to help remove droplets of oil from the produced water before discharge into the ocean. The two most common generic types are low molecular weight (2000–5000) polyamines and polyamine quaternary ammonium compounds. Both types are highly water soluble. Some formulations also include moderately high concentrations of aluminium, iron or zinc chlorides. Dosages of 5–25 ppm may be required, with perhaps half distributing into the discharged water. Minimum initial values of LC_{50} for reverse breakers can be below 1 ppm. Coagulants and flocculants are used to enhance the oil–water separation process. They are polymers similar to reverse breakers, but have a wider range of molecular weights, from 0.5 to 20 million. They are water soluble and used in concentrations from 5 to 10 ppm. Their LC_{50} values in the salt water environment are from 2 to 14,800 ppm.

They are, however, more toxic to freshwater organisms.

Surfactants are used for cleaning equipment, tanks and decks. The two most common types are the alkylaryl sulfonates and the ethoxylated alkylphenols, both of which are widely used in other industrial and household applications. Oil-soluble versions are available for maintenance of tank and vessel internals. The LC_{50} values for surfactants may be as low as 0.5 ppm.

Paraffin inhibitors prevent solid hydrocarbons from forming or sticking to the walls of the system, thereby controlling accumulations of solid hydrocarbons in the system. Vinyl polymers, sulfonate salts and mixtures of alkyl polyethers and aryl polyethers are the most common compounds. Paraffin solvents are used to remove accumulations of deposits. The solvents are usually refinery cuts and may be primarily aliphatic or aromatic, depending on the nature of the deposits. Inhibitors are usually added in the 50–300 ppm range, while the solvents may range from a few percent in a stream to near 100 % in cleaning out a vessel. All these materials are far more soluble in the oil than in the produced water. The LC_{50} values range from 1.5 to 42 ppm.

Gas treating chemicals include hydrate inhibitors and dehydration agents. A typical hydrate inhibitor is methanol, which has LC_{50} values from 8000 to 28,000 ppm. Also, glycol dehydration is a closed-loop process that may produce leaks. However, glycol toxicity is low, with LC_{50} values from 5000 to 50,000 ppm.

Stimulation and workover chemicals include hydrochloric acid (HCl) and workover brines. If properly used, these fluids should not contaminate produced water. Acids should be caught separately and neutralized, while toxic brines (e.g. zinc bromide) should be collected and reconditioned for reuse.

The potential effect of treating chemicals on produced-water toxicity is summarized in Table 2.11 [69]. The 'discharge concentration' is an estimated concentration range in the discharge pipe. The top four chemicals are all water soluble and expected to be primarily in the water phase. The biocides are the only type in which

Table 2.11 Toxicity of treatment chemicals and their potential concentration in produced water[a]

Function type	Use concentration (ppm)	Discharge concentration (ppm)	LC_{50} concentration (ppm)
Scale inhibitor	3–10 normal	3–10	1200–>12,000, 90 % >3000
	5000 squeeze[b]	50–500	
Biocides	10–50 normal	10–50	0.2–>1000, 90 % >5
	100–200 slug	100–200	
Reverse breakers	1–25 normal	0.5–12	0.2–15,000, 90 % >5
Surfactant cleaners	Not measured	Not measured	0.5–429, 90 % >5
Corrosion inhibitor	10–20 water[b]	5–15	0.2–5, 90 % >1
	10–20 oil[b]	2–5	2–1000, 90 % >5
	5000 squeeze[b]	25–100	
Emulsion breakers	50 oil	0.4–4	4–40, 90 % >5
Paraffin inhibitor	50–300	0.5–3	1.5–44, 90 % >3

[a]After Ref. [69]

[b]Water indicates solution of a water-soluble inhibitor; oil means that the inhibitor is mostly oil soluble; squeeze is the maximum concentration of inhibitor in returns from the well after squeeze or batch treatment

the discharge concentration is likely to be above the LC_{50} values, and then only for periodic, short durations. The corrosion inhibitors are the most complex type, as compounds and formulations are made to be water soluble, oil soluble or mixed soluble/dispersible. The water-soluble compounds are most likely to resemble biocides chemically but are most commonly added to injection water or gas pipelines and are not discharged to the ocean continuously. The oil-soluble corrosion inhibitors are at or below the LC_{50} value, except possibly for short periods after squeeze or batch treatments.

The *salinity* of produced water can vary from very low to saturation, depending on geology and the production process. It is believed that the impact of discharging fresh or brackish produced water into the ocean would be the same as for rain [66]. This view is supported by observations from platforms that discharge produced water with very high salt contents show that there is a lively aquatic life community present. Also, dilution of a 200,000 mg/l salt water solution, such as produced water, in a 35,000 mg/l ocean occurs very quickly. Therefore, the concentration of salt in produced water discharged offshore has little potential to cause a harmful impact on aquatic life.

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Chapter 3
Environmental Control of Well Integrity

A.K. Wojtanowicz

1 Introduction

Productivity performance requires petroleum wells to provide a sealed high-pressure conduit for reservoir fluids production to the surface. The installation typically includes well completion, production casing, packer and tubing string. Absence of possible leaks in the installation is often referred to as "internal integrity" of the wells.

Environmental performance requires petroleum wells to maintain "external integrity" to prevent pollution. Figure 3.1 shows the pollution mechanism due to the loss of external integrity of injection or production wells resulting in upwards migration of fluids outside cemented wellbores. Pollution of air, surface waters or groundwater aquifers may result from the migration of produced petroleum hydrocarbons, injected brines or other toxic waste fluids. The migration takes place in the annular space between the well casing string and borehole walls. This phenomenon has long been known in petroleum terminology as "flow behind cement", "gas migration", "flow after cementing" or "annular migration", or – more recently, "sustained casinghead pressure". Most of these terms refer to the failure of well cements.

2 Mechanism of Cement Seal Failures

In theory, well construction requires that the subsurface isolation of aquifers and other strata be restored with annular seals (cement, grout, resin mixtures). Failure of these seals would provide conduits for vertical transport of pollutants. The

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_3

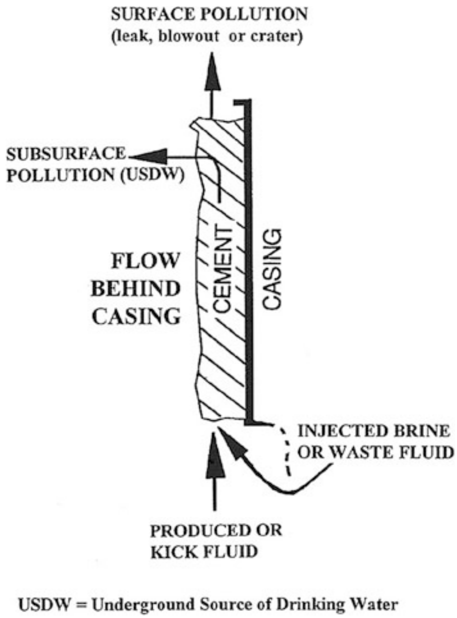

Fig. 3.1 Pollution caused by lack of well integrity

pollutants may originate from either wellbore fluids (drilling mud or injected wastewater) or formation fluids (oil, gas, or brine).

Typically, cement design specifications are based on the compressive strength of set cement; its tensile strength is assumed to be about 12 times smaller than the compressive strength. These properties have little effect on the quality of the annular seal. The failure of annular seals has been shown to be caused by poor bonding of cement or by the development of channeling during the cement setting process. The ability of set cement to isolate subsurface zones has been conventionally attributed to bonding of hardened cement to the pipe and borehole wall. Two magnitudes have been used to measure the quality of cement bond to the pipe (bond strength): shear bonding and hydraulic bonding. Shear bonding represents the force required to move pipe in a cement sheath [1]; hydraulic bonding represents the pressure required to initialize a leak between cement and pipe for liquid or gas [2]. Bond strength testing has been performed in laboratories for various pipe surfaces (rusty, sandblasted, resin–sand coated). This testing gave some basis for the actual design of cementing operations. The understanding of the cement-formation bond mechanism has been limited to the qualitative observations regarding the role of a mud cake and formation permeability [3] and the effect of mud displacement practices [4].

Channeling or development of secondary permeabilities in the cemented well annulus can be caused by either the annular gas migration during the cement thickening process [5, 6] or the sagging phenomenon (i.e. formation of water channels in inclined wellbores caused by solids–water separation) [7].

Two causes of annular gas migration are the loss of hydrostatic pressure in the cement column and volumetric changes in the annulus. Annular pressure loss occurs during the transition of the cement slurry from the fluid state to the solid state due to fluid loss and development of static gel strength [8]. Simultaneously with the hydrostatic pressure, the pore pressure is reduced. The pore pressure loss mechanism results from the development of a matrix stress in the thickening cement so that the water pore pressure responds to the volumetric shrinkage, caused by dehydration of the matrix. The hydrostatic and pore pressure changes in cement are shown in Fig. 3.2.

Volumetric changes in the cemented well annulus may result from either a pressure drop inside the casing or volumetric shrinkage of the cement sheath. The casing pressure drop may create a microannulus between the casing and cement while cement shrinkage may cause the development of a microannulus between the formation and cement. Though the casing–cement microannulus is, by itself, too small to allow substantial flow, it is believed to be capable of initializing development of a flow channel and therefore must be prevented [11].

Shrinkage of cement, which is believed to be 3–4 % by volume, is related to the concentration of calcium silicate crystals (which form during hardening) and the amount of available water during hardening [10]. An observation has also been made that 95 % of volume shrinkage (up by 7 % by volume) takes place after cement is in the solid state; therefore, the development of gas channeling through the bulk cement sheath when it is in a plastic state (transition state) is very unlikely [10, 12].

Sagging of cement slurries is an important mechanism of channeling in deviated wells. Settling of cement solids along the lower portion of the inclined well has been documented in well tests [9]. Also, the formation of a water channel along the upper portion of an inclined well, together with the resulting loss of the effective density, was observed in pilot-scale laboratory tests, as shown in Fig. 3.3 [13].

3 Improved Cementing for Annular Integrity

Annular seal integrity has been achieved through improvements in well cementing technology in three main areas: (1) steel–cement bonding techniques; (2) mud displacement practices; and (3) cement slurry design to prevent fluids from migrating after placement. The control of the steel–cement bond and mud displacement practices have long been incorporated into cementing technology [3, 4]. The most recent techniques have been developed to prevent the formation of channels due to gas migration in annuli after cementing [5, 11, 13–15].

Understanding the role of static gel strength in the mechanism of hydrostatic pressure loss has led to the development of delayed gel strength technology for oilwell cements. The technology was successfully demonstrated in the field when an addition of 0.4 % of the delayed gel strength additive effectively stopped annular flow problems that had been traditionally experienced in the area [13].

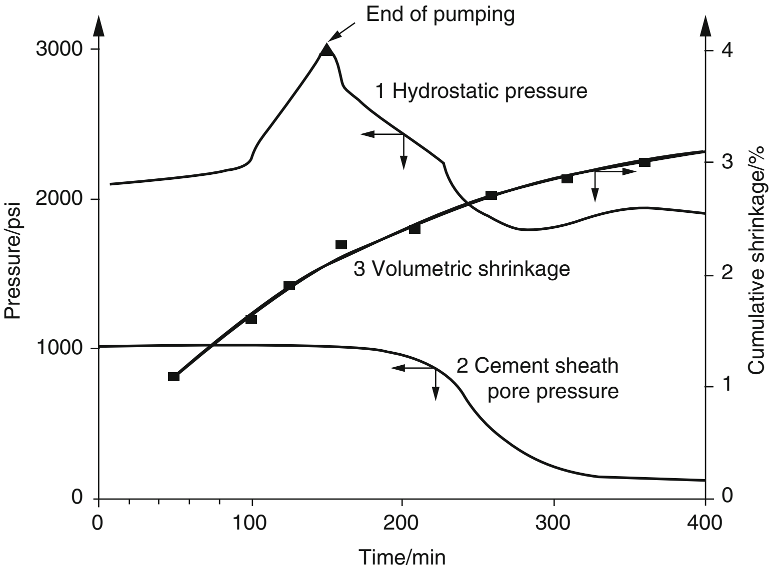

Fig. 3.2 Loss of bottomhole pressure and shrinkage of cement slurry after cementing. (*1*) Field data at 4034 ft. (After Ref. [9]) (*2*) Laboratory gas flow simulator (pressure = 1000 psi). (After Ref. [6]) (*3*) Laboratory shrinkage cell at 250 °F (121 °C) (After Ref. [10])

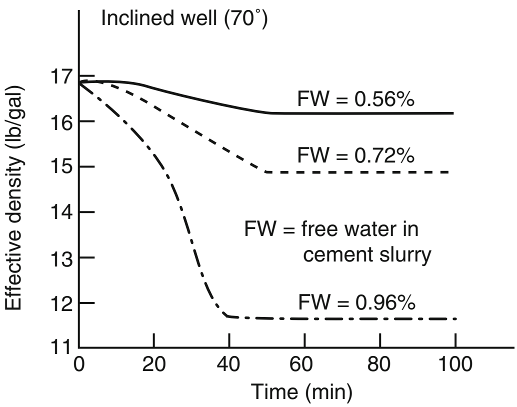

Fig. 3.3 Loss of equivalent density in cement slurry column after cementing (After Ref. [7])

Another control measure, foam cementing technology, was derived from observation of the pore pressure drop in the annular cement column caused by shrinkage of the solids matrix and low compressibility of the matrix–water system. In typical applications of foam cements, gas is either added to the slurry at the surface or is generated by chemical reaction downhole. A recent improvement in this technology is to use foaming surfactants in cement slurry [5]. This new system employs a formation gas (invading the cement) to generate the foam.

A new laboratory procedure has been proposed to find an optimal composition of cement slurry for particular wellbore conditions. In this procedure, a sample of cement slurry is exposed to the expected gas invasion pressure in the gas flow cell simulating the downhole environment of the wellbore [14].

A more fundamental approach has been used in the slurry response number (SRN) method [161]. In principle, SRN is a ratio of static gel strength development rate to the fluid loss rate at a critical time. This critical time corresponds to the onset of a rapid increase in static gel strength. Fluid loss represents volumetric reduction of the slurry. The rate of fluid loss declines over time. At the critical time, the rate of fluid loss should be very small (high values of SRN). Otherwise, pressure at the bottom of the cement slurry could rapidly decline, causing gas migration.

SRN can be evaluated graphically from laboratory measurements of static gel strength and fluid loss versus time for a given cementing system. The optimal cement slurry selected is the one with the largest value of SRN. Recently, the SRN method was correlated with a conventional measure of gas migration tendency, i.e. gas flow potential (GFP) [15]. The analytical correlations, SRN versus GFP, in the form of two equations, constitute the first quantitative model of the annular seal integrity for a well.

4 Cement Pulsation After Placement

In 1982, a landmark field experiment performed by Exxon revealed hydrostatic pressure loss in the annuli after primary cementing in wells [16]. Since then, hydrostatic pressure loss after cement placement has been considered a primary reason for loss of well's external integrity due gas migration in the un-set cement. As the annular cement – still in liquid state – loses hydrostatic pressure, the well becomes under-balanced and formation gas invades the slurry and finds its way upwards resulting in the loss of well's integrity.

Cement slurry vibration using a low-frequency cyclic pulsation is used by the construction industry for improving quality of cement in terms of better compaction, compressive strength, and fill-up. (Cement gelation or transmission of hydrostatic pressure is not a concern in these applications.)

In the oil industry, the idea of keeping cement slurry in motion after placement has been postulated a promising method for prolonging slurry fluidity in order to sustain hydrostatic pressure and prevent entry of gas into the well's annulus. The idea was based upon experimental observations that cement slurries in continuous motion remained liquid for a prolonged period of time [17, 18].

Manipulating the casing string would move the cement slurry. Thus, early concepts considered keeping cement slurry in motion through casing rotation or reciprocation [19–21]. The motion should improve displacement of drilling mud and placement of cement slurry in the annulus.

The concept of using forced casing vibrations for gas flow prevention prompted several inventions in the 1970s, 1980s and 1990s [22–27]. For example, "enhanced filling of annulus with cement slurry without rotating or reciprocating the casing" was considered the main advantage of the first casing vibration method with mechanical vibrator placed at the bottom of the casing string [22]. All these methods have been already experimentally studied and patented. However, none of them have been used commercially because of difficulty involved in manipulating the entire casing string. Apparently, heavy equipment and installation needed to vibrate a long and heavy string of casing makes these methods not feasible, even onshore.

In 1995, Texaco patented a technique based on pulsation of the cement top [28, 29]. In this method, low frequency and small-amplitude pressure pulses are applied at the top of the cement by cyclic pumping of water or air to the wellhead. The treatment continues for sufficiently long time to keep cement in liquid state, reduce transition time, and maintain hydrostatic pressure overbalance.

Texaco field-tested a number of shallow (up to 4700 ft) wells in the Concho (Queen) field of the Permian basin, Texas. The tests demonstrated that pulses could be transmitted through the slurry in the lab and that the bond logs of pulsed wells were superior to those that were not pulsed.

In 2001–2002, the Coiled Tubing Engineering Services, and the Louisiana State University jointly further developed the cement pulsation technology in a project sponsored by the Gas Technology Institute [30]. Field testing of instrumented wells (with downhole pressure gauges) demonstrated that annular pulses could be transmitted to a significant depth in excess of 9000 ft and that hydrostatic pressure in the annulus was maintained by pulsing the slurry [31, 32]. Full-scale laboratory pulsation experiments with thixotropic slurry in an LSU well showed how small pressure pulses would progressively break gel structure and deliver pressure to the well's bottom [33, 34]. They also revealed that pulsation should have an additional advantage versus application of a constant pressure [34]. Another laboratory study showed that pulsation did not reduce final compressive strength or shear bond of cement [35].

The process of top cement pulsation works as follows. After cement placement, the well annulus is intermittently pressurized–depressurized by cyclically pumping water from the cement pulsation unit to the wellhead. A portable cement pulsation unit consists of an air compressor, water tank, hoses to connect to the well, instrumentation, and a recording system. Pulses are applied to the annulus by water that is pressurized by the air compressor. After charging the well, the water is bled back to the tank. The system schematic is shown in Fig. 3.4.

The air compressor continuously pressurizes an air tank. To pressurize the annulus, the control system opens a valve between the air tank and a water tank. The air pressure forces the water into and pressurizes the casing annulus. To release the pressure, the control system closes the pressurization valve and opens the exhaust valve. As the pressure is released, water returns from the casing annulus to the water tank. Once the pressure is fully released, water is added to the water tank if needed, to keep the water tank full.

The volume of water displaced to the well for each pulse is determined by measuring the water level in the tank. From this measurement a "compressible

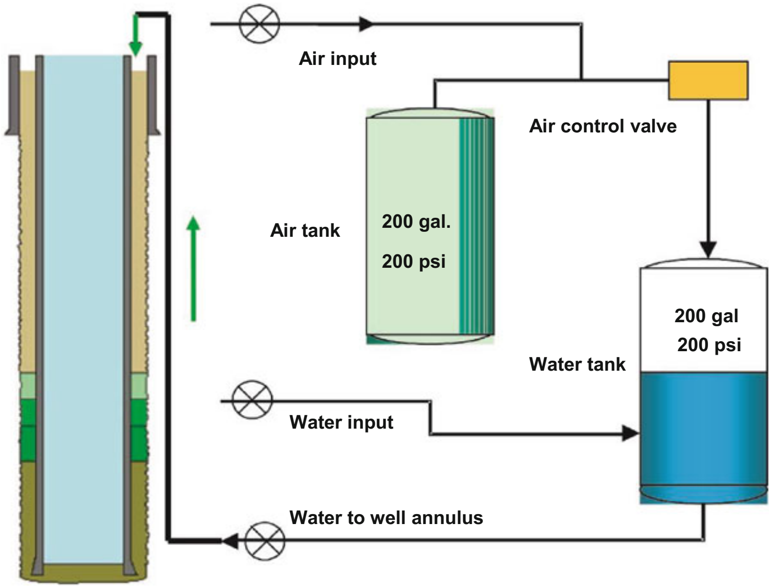

Fig. 3.4 Principle of top cement pulsation method (After Ref. [30]) (See *Color* Plates)

volume" is derived using a data-smoothing algorithm with corrections for water loss in the well and compressibility of surface installation [36]. As the cement slurry thickens, the compressible volume of the casing annulus decreases. When the cement sets, the compressible volume becomes constant and pulsation is stopped.

Frequency of pressure pulses is quite low, with built-in delays. Each pressure pulse is applied and held for up to 10–25 s (design parameter). After pressure is released, there is a dormant period of up to 10–25 s (design parameter). Thus, the pulsation frequency is of the order of 1–2 cycle/min (design parameter).

Development and commercialization of the technology required a method for designing the treatment. Mathematical modeling, performed at LSU, provided theoretical basis for the treatment design and diagnostic analysis methods and software [18, 33, 37–39]. Industrial use of the technology has been carried out by two companies in three oilfields of Eastern Alberta, Canada [40, 41]. As depicted in Fig. 3.5 the top pulsation method showed a 91 % success rate in preventing gas flow after cementing [30, 40, 41].

5 Integrity of Injection Wells

The problem of hydraulic integrity of well annular seals has been addressed through both regulatory and technological measures. The two areas of regulatory initiatives to control annular integrity are drilling permit regulations and injection permit

Field	Probability of Gas Flow P (GF), %	Wells Treated with Cement Pulsation			
		CP Jobs #	Wells w/o GF, #	Wells with GF, #	CP Performance, %
Tanglefl ags	10.5	24	24	0.0	100.0
Wildmere	25.0	20	18	10.0	60.0
Abbey	80.0	8	6	25.0	69.0
Other	75.0	28	28	0.0	100.0
All	44.0	80	76	4.0	91.0

$$\text{Performance} = \frac{\text{P(GF)-P(GF)cp}}{\text{P(GF)}}$$

P(GF) = probability of gas flow after cementing w/a pulsation
P(GF)cp = probability of gas flow after cementing with pulsation

Fig. 3.5 Performance of top cement pulsation method

regulations. Drilling regulations focus mostly on the integrity of the surface casing. Typically, drilling permits require the surface pipe to be entirely cemented to protect freshwater sands from oil and gas zones. In addition, typical drilling regulations may specify minimum footage for surface pipe, minimum waiting-on-cement (WOC) time, minimum volume of cement slurry to be used, minimum length of cement sheath above the top producing zone and at the salt–fresh groundwater interfaces and the minimum testing requirements after completion [pressure test or cement-bond log tests (CBL)]. At present, no quantitative requirements exist to verify a potential annular flow between well casing and formations. For production casing, drilling permits are not very specific about the verification of annular integrity even though this integrity is most important in effectively isolating upper zones from produced hydrocarbons and brines.

Subsurface injection permits require an operator to provide evidence of the hydrodynamic integrity of the well's annular seal. However, no direct standardized tests for such integrity exist [13]. Usually, permit decisions are based upon indirect evidence of the well's integrity, such as CBL, electric logs, the driller's log and geological crossplots, which indicate to the regulatory agency that no unusual environmental risk is involved [42]. Typical generic criteria for wells injecting oilfield brines address the following issues: (1) the length of casing; (2) the mechanical integrity (pressure) test procedure (wellhead pressure, test duration, maximum pressure drop) and its frequency (usually before the operation, then every 5 years); and (3) the minimum distance to any abandoned well (usually 0.4–0.8 km). A permit is also required for the annular injection of solid drilling waste, the common method of on-site disposal during drilling operations (as discussed in the previous section).

In the area of subsurface brine injection, the permitting issue revolves around reliable techniques to prevent the stream of brine from migrating freely into the environment. The three main criteria are the "internal" mechanical integrity of the borehole installation (IMI), the "external" integrity of annular seals (EMI) and the integrity of the confining layer. The IMI practices of pressure testing casing as well as monitoring the annular pressure during injection are the most typical field technologies. However, since there are no standard procedures for IMI test analyses, the results of these tests are often left to the judgment of the permitting agency [43]. In addition, several factors may affect the result of pressure tests, such as the length and type of gas blanket, gas solubility in the annular liquid, temperature, and the tubing–annulus pressure changes [44]. These effects should be included in quantitative interpretations of the tests.

A simple system to control continuously the internal integrity of an injection well has been developed by the chemical industry [45]. As shown in Fig. 3.6, the system does not use a packer at the bottom of the injection tubing or a surface pressurization system. Instead, it relies upon the laws of hydrostatics to separate the annular fluid from the injected fluid. A continuously recorded pressure differential between the injection and annular pressure is considered to be a sensitive indicator of tubing splits or casing leaks. Unlike the conventional "packed" annular configuration, this system is believed to be insensitive to injection pressure variations and is unaffected by the packer leaks. Also, it has the unique ability to locate a point at which the mechanical integrity of a well is lost. Recently, the static fluid seal design was criticized for lack of precision, which is caused both by slow mixing at the interface between the annular and the injected fluids and by the sensitivity of the design to injection fluid density/flow rate variations [46]. Therefore, unless the interface-mixing problem is solved (by placing a viscoelastic spacer, for example), conventional completions with packers will probably remain the accepted field practice.

Verification of the external (annular) mechanical integrity (EMI) of injection wells includes two groups of techniques: EMI tests and continuous monitoring systems. The most promising methods of EMI testing are radioactive tracer surveys [47], helium leak tests [48] and oxygen activation logging [also known as behind-casing water flow (BCWF)] or neutron activation technique (NAT) [48–51]. None of the techniques, however, has been yet adopted as a single tool to demonstrate well integrity [52]. For hazardous waste injection wells, EMI is performed in a two-stage procedure using a combination of EMI tests. The first stage involves a demonstration of the absence of interzonal flow using noise, temperature or oxygen activation logs. In the second stage, the path of injected fluid as it exists in the wellbore is monitored, using the radioactive tracer survey to determine whether it is confined to the permitted injection zone. However, in the USA, for example, the use of the above procedure is not a required EMI test for oilfield brine injection but is considered the best achievable practice for oilfield injection wells [52]. In fact, the actually practiced requirements for EMI involve only reviews of cementing records; radioactive tracer surveys or temperature surveys are required infrequently [53–55].

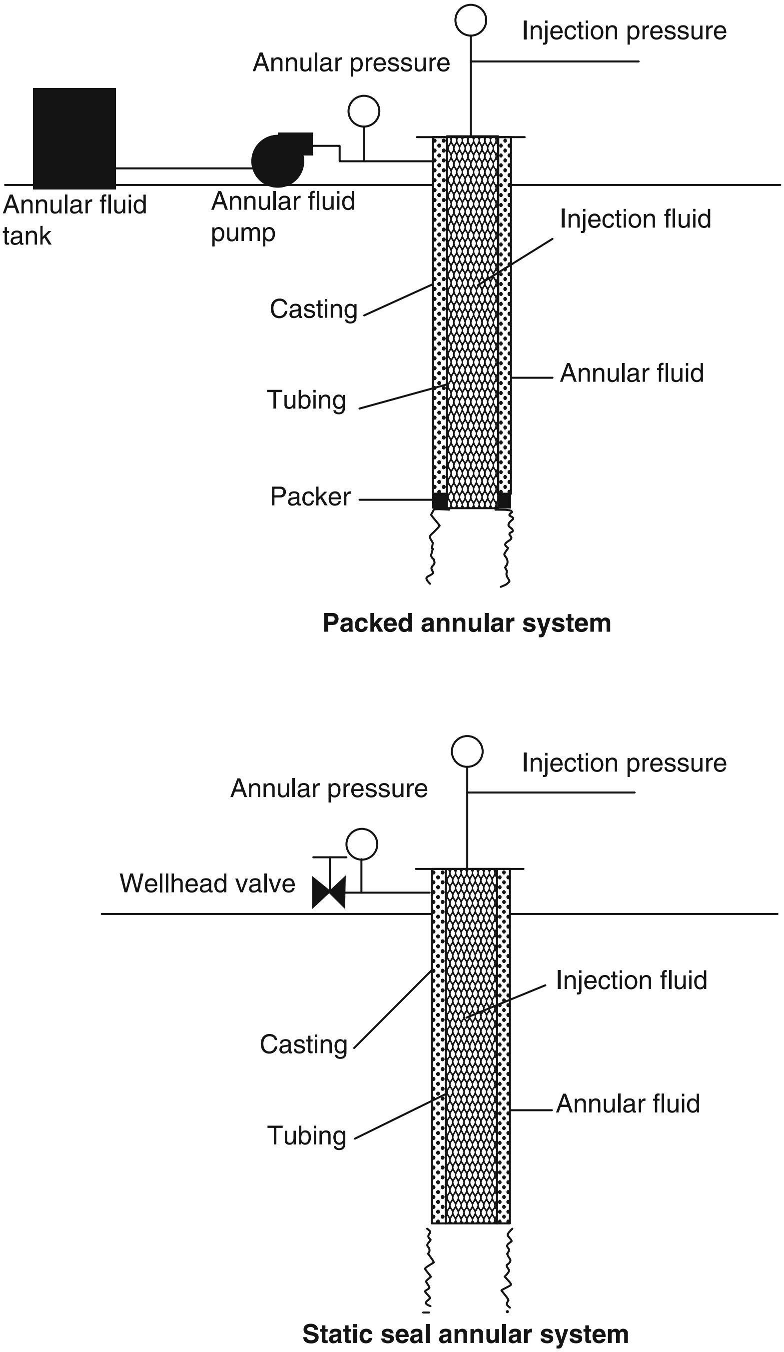

Fig. 3.6 Two methods for continuous control of well integrity during subsurface injection (After Ref. [45])

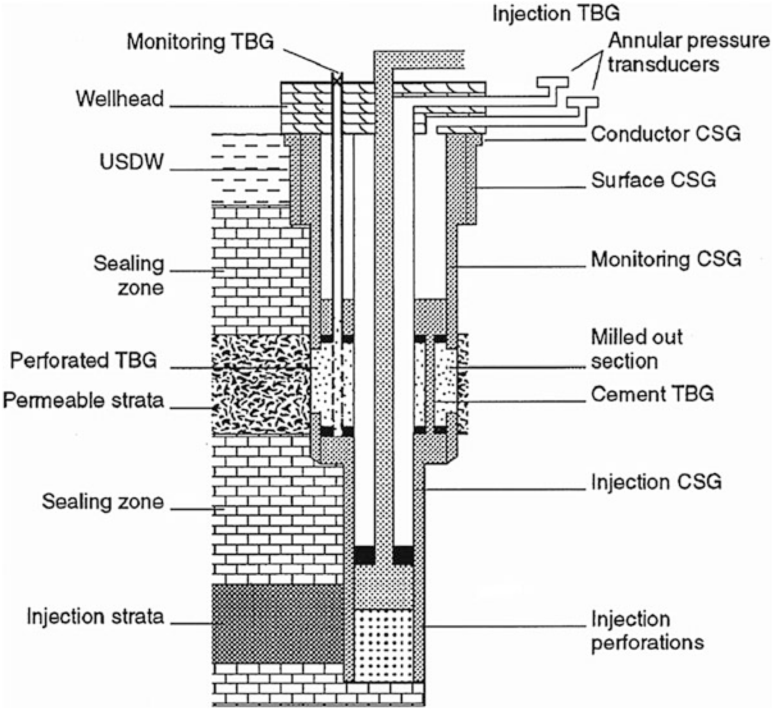

Fig. 3.7 Dual completion for continuous monitoring of injection wells (After Ref. [56])

NAT seems to be a particularly promising tool to detect flow in channels within annular seals. The wireline tool consists of a generator of neutrons and two gamma-ray detectors that are installed above and below the generator for detecting the upward and downward flow, respectively. The flowing water in the channel is irradiated with neutrons emitted by the generator. These neutrons interact with oxygen nuclei in the water to produce ^{16}N, which decays with a half-life of 7.13 s, emitting gamma radiation. Radiation energy and intensity is recorded by detectors and is used for computation of flow.

A concept of an on-line monitoring system installed in a single injection well is shown in Fig. 3.7. The suggested completion procedure would involve the following steps: (1) set a monitoring casing in the confining layer that overlays the injection zone and cement the monitoring casing inside the surface casing; (2) drill the well to the injection zone; (3) set a cement bridge plug and mill a short window in the monitoring casing opposite the permeable formation that is above the confining layer; (4) run the casing with a sophisticated packer (cement retainer) equipped with two (upper and lower) packing elements connected with two short tubing sections, one of which has been perforated; (5) install monitoring tubing in the annulus of the injection casing and land the monitoring tubing in the perforated section of the cement retainer; (6) cement the injection casing below and above the cement retainer; and (7) complete the well with injection tubing and a packer inside the injection casing [56].

During the injection operation, any change in pressure in the monitoring tubing becomes a sensitive indicator of fluid migration across the confining layer. Although theoretically sound, the system requires a complex well completion procedure, and its practical implementation still remains to be seen.

6 Measurements of Well Integrity

In the early 1980s, a systematic study was conducted in the USA to determine the state-of-the-art in EMI testing [57]. The first phase of the study was a survey of methods available for determining the mechanical integrity of oilfield brine injection wells. The second and third phases of the project involved experimental work using three research wells. The first two wells were used to evaluate the performance of CBL tools to detect channels in the cement sheaths behind the steel and fiberglass casings. The purpose of the third well was to evaluate the capability of various downhole tools to detect fluid movement behind the casing. The tested tools included an acoustic CBL tool, a noise logging tool and a neutron activation technique (NAT). In addition to the research well experiments, a “real world” test was conducted in an abandoned 10,600 ft gas well using the NAT method. A known 100 ft long channel in the annular cement sheath of the well had been identified using a radioactive tracer survey.

The results of this study showed that most present commercial techniques do not provide sufficient information to determine the mechanical integrity of a well. With the acoustic CBL technique, the flow in channels behind the casing could only be detected when cement was not present. The noise logging tool proved to be very sensitive to extraneous sources of sound that resulted in poor quality of the noise log. Moreover, when the logging tool was placed either in the casing or within the tubing, only the NAT method showed good detection of flow in the annular channel. In conclusion, there seems to be a trend in the permit regulations to verify external integrity by a test rather than the review of cementing records. NAT has great potential for testing EMI. Particularly, NAT seems to be an excellent method for detecting flow in a channeled annular seal. Also, since the cost of periodic EMI tests may be excessive, it seems possible that the oil industry might develop a new well completion system for injection wells that would allow a continuous monitoring of pressures across confining zones.

7 Sustained Casinghead Pressure

One of the most typical problems caused by the lack of well integrity is “sustained casinghead pressure”. Sustained casing (or casinghead) pressure (SCP) originates from late gas migration in one of the well’s annuli and manifests itself at the wellhead as irreducible casing pressure. In the United States, the federal statistics have shown that the problem in the Gulf of Mexico (GOM) is massive, as 11,498 casing strings in 8122 wells exhibit SCP [58]. In the offshore operations, sustained casing pressure represents a potential loss of hydrocarbon reserves, risk of harm to or loss of human lives and physical facilities, possible damage to the marine and coastal environments, and air pollution. Although 90 % of sustained casing pressures are small and could be contained by casing strength, it is still potentially risky to produce or more importantly, to abandon such wells without elimination of the pressure.

Risks associated with SCP depend upon the type of affected casing annulus and the source of migrating gas. Most serious problems have resulted from tubing leaks. A tubing leak would exhibit SCP at the production casing. A failure of the production casing may result in an underground blowout that, in turn, can cause damage to the offshore platform, loss of production and/or widespread pollution. Catastrophic outcomes of SCP on production casing have been documented in several case histories [59].

Consequences of SCP on casings other than the production casing are less dramatic but equally serious. SCP on these casings usually represents gas migration originating from an unknown gas formation. As the gas migration continues, casing pressure may increase to the point when either the casing or casing shoe fails so the migrating gas will leak into the annulus of the next (and weaker) casing string. As a result, the gas would not be contained by any of the well's casings and would come to the surface outside the well. Eventually, the process could potentially result in destabilization of the seafloor around the well and pollution of the water column, or failure of the casing head and emissions to the atmosphere. Environmental risk of SCP is addressed in the following sections.

Remediation of wells with SCP are inherently difficult because of the lack of provisions to access the affected annuli. Since there is no rig at the typical producing well, the costs and logistics involved in removal of SCP are frequently equivalent to a conventional workover. Moreover, there may be multiple casing strings between the accessible wellbore and the affected annulus. Methods for SCP removal are of two categories: the rig methods and rig-less methods-discussed in the following sections.

In the US, most of regulatory attention has been focused on the SCP problem in the Gulf of Mexico. However, the "surface casing vent leakage" problem with gas wells in Alberta has essentially the same downhole causes. It has received substantial attention via regulation by the Alberta Energy and Utilities Board and prevention and remediation efforts by the industry [60, 61]. Serious problems resulting from unintended pressure on casing–casing annuli have also been reported in the San Juan Basin of New Mexico, in South Louisiana, in India, and in Tunisia. Hydrocarbon intrusion into drinking water aquifers has occurred in the San Juan Basin and in Alberta, and its potential for occurrence should be a major concern in any onshore producing areas.

In the US, the Federal agency, Mineral Management Service – presently, Bureau of Safety and Environmental Enforcement (BSEE), promulgated regulations to address sustained casing pressure in oil and gas wells [62]. They developed rules for managing SCP and established criteria to monitor and recommendations for pressure test these wells.

The US regulations for the Gulf of Mexico require that an operator may continue production (i.e. be self approved) if:

- casing pressure remains at less than 20 % of internal yield rating of casing; and
- casing pressure bleeds to zero during diagnostic tests.

If casing pressures are greater than 20 % of internal yield, a departure from the regulations may be applied for. The granting of a departure allows the well to continue *producing without elimination of SCP*.

Normally, departures are granted for producing wells with casing pressures that bleed to zero and demonstrate a relatively slow subsequent 24-h build-up rate. However, for wells that are temporarily or permanently abandoned, the casing pressures must remain at zero which means *elimination of SCP is mandatory*.

Furthermore, recent regulations further reduce operator eligibility for being granted a departure. They allow only a 1-year, fixed-term, departures for some producing wells, eliminate departures for non-producing wells, and require operators to remove SCP on temporarily abandoned wells. Also, the proposed regulation requires operators to document their plans for SCP removal thus making operators actively responsible and prepared for future removal of SCP in all wells. In conclusion, there is an undeniable trend in the regulatory strategy to require remedial treatments of SCP rather than tolerate the SCP problem.

The Bureau of Safety and Environmental Enforcement (BSEE) regulations also require pressure bleed-down/buildup (B/B) testing of wells with annular Sustained Casing Pressure (SCP) if the casing head pressure is greater than 100 psig. The test involves bleeding the pressure with a needle valve followed with up to 24-h monitoring pressure return after the valve is closed. As the test description is limited to its principle, the way it is actually performed varies considerably among operators leading to different results.

The petroleum industry, through American Petroleum Institute (API), and Offshore Operators Committee (OOC) has developed Recommended Practice on SCP [63]. This new API RP describes the monitoring, diagnostics, and remedial actions that should be taken when SCP occurs. Thus, the RP is to summarize and standardize all the industry knows about dealing with SCP problem in a set of performance-based procedures.

The API standards describe a protocol for pressure bleed-down/buildup (B/B) testing of wells with Sustained Casing Pressure The B/B test is performed by bleeding down the wellhead pressure through a one-half inch needle valve, followed by a 24 h shut-in period. According to the API standard, diagnostic testing is done to determine if the pressure can be bled to zero psig and if the pressure builds back up and the rate at which it builds. The procedure of conducting B-B tests needs to be determined by the operator. All pressures should either be reported continuously or recorded at a set time interval. The amount of fluids recovered during bleed down should be recorded. A typical plots of these tests are shown in

Fig. 3.8. Rapid pressure bleed down followed with high buildup rate occurs when the pressure reaches its stabilized maximum value within 24 h time period. Slow buildup patterns are most likely in annuli with small leak rate as more than 24 h is needed for the pressure to stabilize.

Per API RP-90, cement leak size can be qualitatively rated using the pattern shown in Fig. 3.9 as follows: In case the pressure bleeds to zero psig through a ½ in. needle valve at a low differential pressure and builds back up to original pressure or to a lower pressure within 24 consecutive hours, then the annulus in question has a small leak. The leak rate is considered acceptable and the barriers for pressure containment are considered adequate. If the pressure does not bleed to zero psig, then the barrier to pressure containment may have partially failed and, in some cases, the leak rate is unacceptable. Therefore, according to API RP-90, the two parameters which are considered in leak size evaluations are minimum bleed down pressure and the rate of pressure buildup.

Quantitative analysis of B/B test has not been, yet, standardized, and at present, could be based only on a few modeling.

Analysis of B/B tests described in the API standards is merely qualitative and limited to the finding if pressure could be bled to zero and if it would re-build to its initial value before the test. Needless to say, the two findings might depend upon the way needle valve has been operated and also they do not provide any quantitative information about gas migration in the leaking cement. Quantitative analyses methods and models have been already proposed, but – as discussed in the following sections – they either produce ambiguous results or they have oversimplifying assumptions that lead to widely-spread estimations of the cement leak size by orders of magnitude.

Remedial treatments of wells with SCP are inherently difficult because of the lack of provisions to access the affected annuli. Since there is no rig at the typical producing well, the costs and logistics involved in removal of SCP are frequently equivalent to a conventional workover. Moreover, there may be multiple casing strings between the accessible wellbore and the affected annulus. Methods for SCP removal can be divided into two categories: rig and rig-less methods.

7.1 Quantitative Analysis of SCP Well Test

Quantitative analysis of B/B test has not been, yet, standardized, and at present, could be based only on a few modeling studies. In 2001, first mathematical model was developed for testing SCP build up [64]. The model describes gas flow in leaking cement and migration through Newtonian fluid. The gas accumulates in the gas chamber above free fluid level. The model considers having a gas free mud having constant compressibility, and ignores the time of gas migration in the mud column. At each time step, the pressure change in the gas chamber is calculated using a closed form formula. The model was used to study the effect of well parameters (casing gas chamber, mud compressibility, cement permeability, and

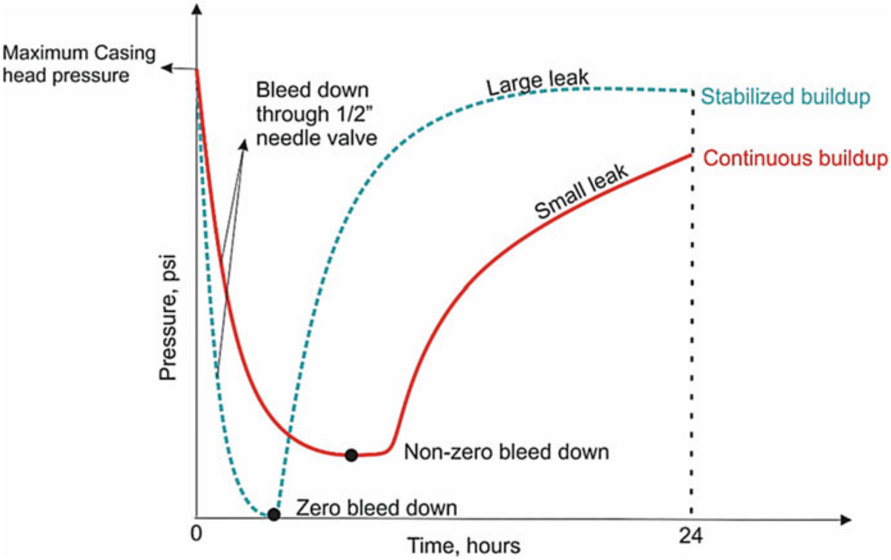

Fig. 3.8 Depending on the annulus leak size, stabilized buildup or continuous buildup may be followed after the bleed down

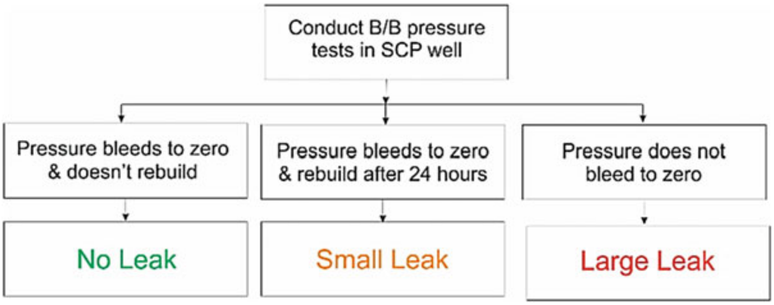

Fig. 3.9 API qualitative analysis of leak size in wells with SCP

formation pressure) on SCP build up. The model disregards gas migration in the mud column and oversimplifies the process.

In 2002, the model was improved by coupling equations for transient gas flow in the leaking cement with two-phase flow gas migration in mud column of non-Newtonian power law fluid [65]. In the new model, the pressure bleed-down and buildup are treated separately so the test can be analyzed by trial and error for each stage. Once the match is obtained separately for bleed down and build up, the unknown parameters of the system are determined (permeability of cement, gas source pressure and depth, mud compressibility and the size of gas chamber – a gas cap above free liquid level). The improved model was also used to study typical patterns of the B-B test pressure data from SCP field testing [66]. Unfortunately, the analysis is ambiguous as it converges on several solutions.

In 2009, Huerta et al. applied the 2001 model of casing pressure buildup, above, to study CO_2 leakage rate along wellbore [67]. He used the model to determine the leakage depth, cement permeability and gas source pressure in two real field wells. The gas source pressure was determined hydrostatically from known values of stabilized casing pressure and the column length of Newtonian fluid in annulus. The calculations involved guessing the gas source depth. Then, the pressure buildup data was fitted by iterating the cement permeability until a match was obtained. Repeated guessing would give the best match. The match would determine both the cement permeability and depth of the gas source. The effect of gas cut mud was ignored as no gas entrapment was assumed. (The assumption of gas-free mud disregards mud compressibility effect that may significantly change the pressure buildup analysis result.) Also, the gas chamber volume is assumed to be zero initially. At each time step, the volume of gas released from cement/mud column interface is assumed to move to the casing head and therefore, the gas chamber forms by compressing the mud column. The assumption of zero gas chamber volume at the start of buildup stage may not be an accurate assumption since the free fluid level in annulus is not known.

In 2010, Tao et al. also used the 2001 SCP buildup model to find the effective permeability of leaking cement and depth of the gas source [68]. Similar to Huerta study, the source pressure was calculated from the hydrostatic balance of known mud column and stabilized casing pressure, so that pressure buildup is entirely controlled by mud compressibility. The compressibility is computed from empirical correlation with mud density. The compressibility is therefore minimized, particularly, that the annular mud is assumed free of entrained gas. Their model does not provide a method to determine the value of mud column length, representing the gas chamber volume. The primary unknowns of the system were considered to be the permeability of cement and the depth of gas source formation. Thus, the model's input requires data on cement top depth, mud density and the pressure buildup record. The model output gives the cement leak permeability and the length of cement leak, i.e. depth of the gas source. Upper and lower limits for the gas formation depth were set arbitrarily and the field buildup curves were matched using Monte-Carlo simulation to determine cement permeability for each assumed depth. The best fit would give the values of cement effective permeability and gas source depth. In computations, the authors used a long-term field record of the casing pressure buildup over 400 days, instead of B-B test pressure buildup. Therefore, the estimated values of cement permeability were very small and varied by several orders of magnitude.

In 2011, Zhu et al. used the 2002 Xu model and verified the model for one SCP field diagnostic test [69]. They did not modify the fitting method nor changed the number of unknown parameters to be fitted. They also did not mention any ambiguity problem in the test analysis.

In 2012, Kinik developed a model to determine the maximum emission gas rate from an open annulus in a well with SCP [70]. The objective of his study was to compute maximum air emission rates (MER) for failed casing head due excessive SCP. His model considers linear gas flow through cement and two-phase gas flow through a stagnant column of water based Newtonian fluid with constant atmospheric pressure above the fluid. The Caetano's mechanistic model was also employed to determine the flow regime transitions and to calculate pressure gradient [71]. The Kinik's model also considers mud unloading due to expansion of gas bubbles in the upper section of mud column by considering the total volume of gas and mud at each time step and comparing with total annulus volume. The computation assumes that the gas source formation pressure, cement permeability, and initial volume of gas chamber are known from SCP test analysis. Effect of gas trapping is ignored. This model can only be used for a top-open annulus resulting from casing head failure so it does not contribute to the study of gas migration during B-B tests.

Recently, Rocha-Valdez simplified the 2002 Xu model and developed an analytical method for analysis of pressure buildup data recorded in SCP wells [72]. In their model, gas migration in the liquid column is ignored so that the gas exiting the leaking cement is instantly injected to the gas cap above the free liquid level. The simplification enables coupling the steady state linear gas flow formula (flow in cement) with the gas law describing pressure change in the gas cap resulting from the gas injection. (The gas pressure drop from the cement top to the gas cap equals hydrostatic head of the liquid column.) The resulting analytical model relates casing head pressure to time for constant values of several parameters of the annular system: cement leak permeability (or "seepage" factor), gas source pressure, length of cement, length of liquid column and the gas cap length. By assuming that all other parameters are known (with reasonable confidence) the recorded pressure vs. time data can be matched statistically to find the value of cement seepage factor. The method was verified using casing pressure buildup data from few wells used in other studies [65, 67, 68] with the seepage factor closely matching the values from the studies [67, 68] that also ignored gas migration in the liquid column and severely overestimating the values from the study that considered the gas migration in liquid column [65]. Apparently, gas migration in the liquid column significantly affects pressure buildup trend resulting in smaller amount of gas entering the gas cap and, therefore, smaller value of the cement leak permeability or seepage factor.

In the recently-published work [73], the 2002 B-B test model was improved by considering yield-power-law fluid (Herschel-Bulkley) instead of the power-law fluid, and re-writing the software to make the model a predictive tool, i.e. solving direct problem rather than inverse problem. The improved model was used to analyse SCP well system parameters and operational parameters affecting the B/B test. Parametric sensitivity analysis of the pressure bleed down, constant flow, and pressure build-up stages of B/B test was performed to learn if a stage-by-stage rather than entire test analysis would be possible. Also, the study qualified significance of the system parameters controlling each of the three stages of the test to further verify merit of the stage-by stage analysis. In addition, three operational parameters of the B-B test (pressure bleeding rate and duration, and pressure recording time step) were evaluated to see how they affect test results in view of possible improvements in the testing procedure.

The conceptual plot in Fig. 3.10 illustrates three stage of B-B test (bleed down, stabilized flow, and buildup) and lists the parameters that could be determined from analysis of each stage (size of the gas chamber above the top of liquid column, Vgti, length and permeability of leaking cement column, Lc and k, and density if the gas-cut mud column, ρl.) That means a stage-by-stage analysis of the SCP diagnostic test, comprising three stages, could either give value of a system parameter directly (Vgti from the bleed-down stage), or reduce ambiguity in finding values to unequivocal solution of coupled numerical models of the stabilized flow and pressure buildup stages. It also follows that a simple unambiguous estimation of the four SCP well system parameters is attainable particularly, when the source pressure, pf, could be determined from another test. The observation provides an opportunity for a stage-by-stage analysis of the test instead of trying to find all system parameters by matching the whole test.

The study also qualified significance and effect of operational parameters on each of the three stages of the B-B test in view of possible improvements in analysis of test results and the testing procedure. (The testing procedure must specify the opening size of the bleed-down valve, the valve shut-in time and frequency of pressure recording.) It was demonstrated that operational parameters have significant effect on the B/B test response and may cause misinterpretation of the test results. Specifically,

- Needle valve opening size controls the gas bleed-down rate and valve shut-in time. The valve opening should be restricted to allow precision in monitoring casing pressure drop pattern and prevent loss of annular liquid.
- The valve should stay open until stabilized flow is reached in order to see the true value of minimum bleed-down pressure. In some cases, an initial pressure stabilization (including its zero value) may not indicate the steady state gas flow in the leaking cement. The true leak rate may be much higher. Closing the needle valve before the steady-state flow onset provides no information about the tested system; it also complicates determination of the minimum bleed-down pressure and gives pressure build-up that misrepresents cement leak size because the build-up is caused mostly by gas movement in the liquid column – not the gas flow in the cement.
- The maximum 24-h value of buildup pressure in some cases can be much lower than the SCP value before the test. The "valve closing time dilemma" in Fig. 3.11 demonstrates that early valve closure does not show the minimum bleed down pressure but reveals the maximum build up pressure. Conversely, late closing of the valve displays the minimum bleed down pressure but does not show the maximum build up pressure. It seems that without wider valve opening or extended test duration the two parameters cannot be determined.

The "valve closing time dilemma" should not be resolved by early valve closure to monitor the entire pressure buildup. Early pressure buildup brings more information on the cement leak size than the late buildup. It seems that without wider valve

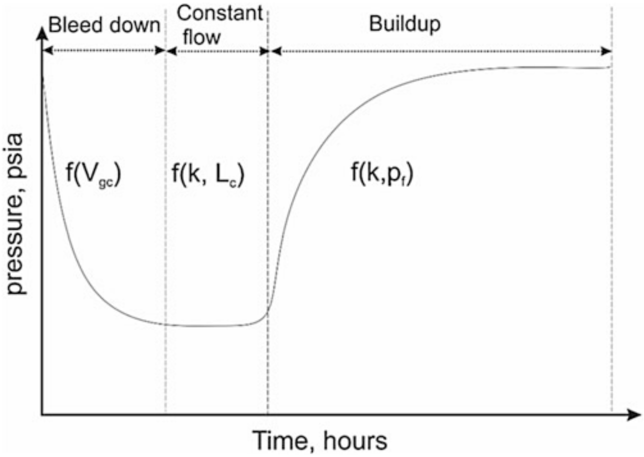

Fig. 3.10 Three stages of B-B test with well system parameters controlling each stage

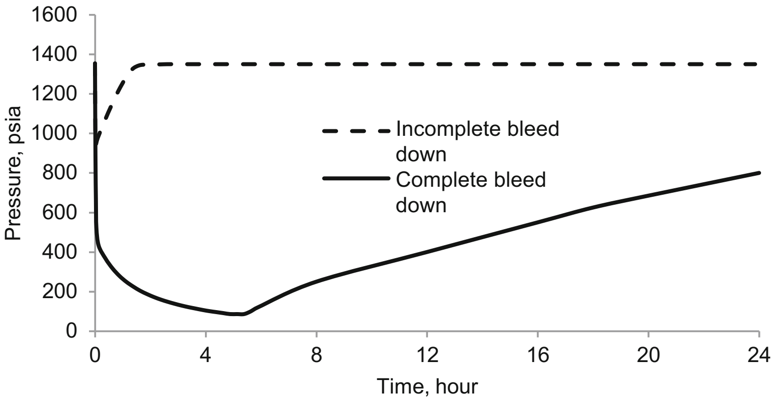

Fig. 3.11 Minimum bleed down and maximum build up pressures cannot be found in a single 24-h test

opening or extended test duration the two parameters cannot be determined; If the maximum buildup pressure is needed, the valve should be closed earlier so that the pressure could stabilized in 24 h. However, if the minimum bleed-down pressure is desired, the valve should be left open until no change in the pressure is observed. In such a situation it would be more important to assure flow stabilization and continue the test beyond the 24-h limit. Alternatively, the test should be re-designed and repeated.

7.2 *Environmental Risk of SCP*

In the USA, the BSEE regulations do not specifically define risk of SCP but indirectly relate the risk to the value of casing pressure higher than 100 psi that requires conducting the bleed-down/build-up (B-B) test. In Canada, Energy and Utilities Board (EUB) regulates SCP using the flowing bleed-down pressure and the increase of casing pressure during the shut-in period of the B-B test [74] If flowing pressure is greater than $14 \cdot 10^5$ Pa, or increases more than 42 psig ($2.9 \cdot 10^5$ Pa) during test shut in period, the SCP is considered to constitute high risk. In Norway, NORSOK Standard D-010 Well Integrity in Drilling and Well Operations [75] regulates SCP using an arbitrary sub-surface failure criterion. If casing pressure is greater than $70 \cdot 10^5$ Pa for any intermediate casing, SCP is considered high risk.

The API Recommended Practice 90 identifies risk of SCP based on the magnitude of casing pressure and its comparison with the maximum allowable well-head operating pressure (MAWOP) [63]. MAWOP is calculated considering the collapse of the inner tubular and bursting the outer tubular [1]. It equals either 50 % of MIYP of the pipe body for the casing being evaluated, or 80 % of MIYP of the pipe body of the next outer casing, or 75 % of collapse rating of the inner tubular pipe body, whichever is smaller. For the outermost casing, MAWOP is the lesser value of 30 % of MIYP of the pipe body for the casing or production riser being evaluated or 75 % of inner tubular pipe body collapse rating.

For casing pressure exceeding 100 psig ($6.9 \cdot 105$ Pa) or the casing's minimum internal yield pressure (MIYP), a B-B test must be performed and the risk rating is defined using logic summarized in Fig. 3.12 [76].

As discussed above, present regulations consider the environmental risk of SCP based on the surface failure scenario. However, the well-head may not necessarily be the weakest barrier of the well's integrity system. A subsurface barrier may be the first to fail in response to the pressure build up due gas migration. Typically, the formation below a casing shoe is the weakest point in the annulus and its pressure limitation is termed here as casing shoe strength (CSS). If the well-head pressure increases high enough to create a downhole pressure exceeding the CSS, the formation below the casing shoe would fail. In this case, the gas would breach the casing shoe and flow into the outer annulus or rock causing an underground blowout [78]. Environmental consequences of an underground blowout may be catastrophic as the migrating gas may charge the shallower formations causing unexpected abnormal pressures or polluting the fresh water aquifers.

Critical conditions for the surface and subsurface failure has been compared for two wells – offshore and onshore [76]. The results for offshore well are shown in Table 3.1. In the GOM well's annuli C and D, casing pressure for surface failure is smaller than that for subsurface failure. Thus, wellhead failure criterion is more restrictive than the subsurface failure. However, for annulus B, the subsurface failure criterion (3569 psi) is more restrictive than surface failure (4168 psig) so a continuous buildup of casing pressure in annulus B would cause the casing shoe breaching, first.

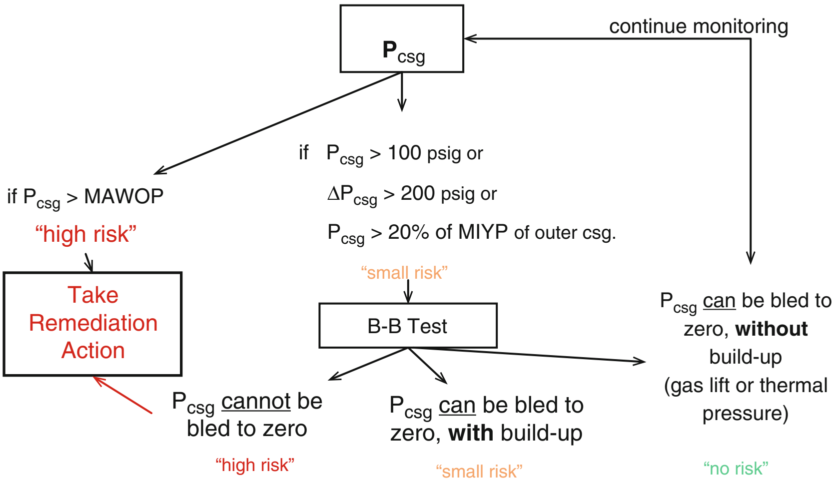

Fig. 3.12 Summary of SCP risk assessment [76, 77]

Table 3.1 Surface vs. Subsurface integrity failure for GOM well

Annulus		MIYP, psi	Collapse, psi	Well head failure MAWOP, psi	Casing shoe failure, psi
A	9 5/8″, 53.5#, Q-125	12,390	8440	N/A	N/A[a]
B	13 5/8″, 88.2#, Q-125	10,030	4800	4168	3569
C	18 5/8″, 136#, N-80	5210	2480	1276	1424
D	24″, 256#, Gr.B	1595	742	478	558

[a]Pressure in A annulus is not considered SCP

Comparison of the critical casing pressures for the surface and subsurface failure in an onshore well in Table 3.2 considers a 9895 ft vertical well located in KhorMor field in Kirkuk, Iraq. Reference [76] shows schematics and drilling data from this well. The well's sections – surface, upper and lower intermediate and production – were drilled with 9, 10.5, 14 and 17.6 ppg water base muds, respectively. All annuli were cemented to the surface, except the 7″ production liner that was hanged at 6778 ft with 195 ft cement overlap with the 9-5/8″ casing. Therefore, the B annulus constituted the first pressure containment barrier protecting the tubing at the surface. As shown in Table 3.1, the well-head constitutes a weaker pressure containment barrier, i.e. with increasing casing pressure due gas migration, the well would fail at the surface. This result is mainly due the practice of cementing the annuli to the surface. This action noticeably reduces the risk of subsurface failure but it also limits the SCP remediation options over the life time of the well [79].

Table 3.2 Surface vs. Subsurface integrity failure for onshore well

Annulus		MIYP, psi	Collapse, psi	Well head failure MAWOP, psi	Casing shoe failure, psi
A	7″, 29#, L-80	8160	7020	N/A	N/A
B	9-5/8″, 53.5#, P-110	10,900	7930	N/A	N/A[a]
C	13-3/8″, 68#, K-55	3450	1950	1725	3206
D	20″, 133#, K-55	3060	1500	918	1344

[a]7″ liner is hanged inside the 9 5/8″ casing at 6680 ft

Safety margins implicit in the calculation of MAWOP has been defined arbitrarily based on industry experience. However, the critical condition for the casing shoe failure is set with no safety margin making the comparison somewhat biased towards the surface-failure scenario. Moreover, an actual environmental risk of the casing head failure depends on the flow potential of the leaking annulus and amount of gas emissions to the atmosphere.

A mathematical model and software has been developed to calculate the maximum gas emissions rate (MER) from a SCP well with failed casing head [70, 76]. The approach is similar to the widely-accepted "nodal" analysis method used for assessing productivity of petroleum wells. In the model, performance of the annular flow system is expressed as two nodes coupled at the cement top. The bottom node represents gas flow from the source formation through the leaking cement sheath and the upper node is the gas migration in fluid column from the top of cement to the failed casing head and to atmosphere. Modeling of gas migration in liquid column was based on the models developed for analysis of B-B tests [64, 80].

The Maximum Emission Rate (MER) software allows computation of the SCP Well System performance plotted in Fig. 3.13. The plot can be used to find the MER value graphically. It could also be used to analyze options for SCP control and to study effects of the system parameters.

Top cement inflow performance (CTIP) and cement top outflow performance (CTOP) plots are shown in Fig. 3.13. The Cement Top Inflow Performance represents gas flow in the cement sheath and gas source formation. It depends solely on cement leak size and the reservoir pressure of gas bearing formation. Linear gas flow theory provides mathematical description of flow from the constant-pressure formation to the top of cement. The Cement Top Outflow Performance represents gas migration upwards from the cement top through the liquid-filled annulus with free level of liquid opened to atmosphere. When liquid unloading occurs, at high gas rates, hydrostatic pressure at the cement top gets reduced that further increases the emission rate. At low gas rates, however, liquid remains in the annulus and the gas rate remains low. Mathematically, the maximum steady-state gas flow rate (MER) is the common solution to the two nodes at the cement top. Graphically, the solution is the intercept of the CTIP and CTOP curves.

The Maximum Emission Rate (MER) model supporting the software has been derived with the following assumptions:

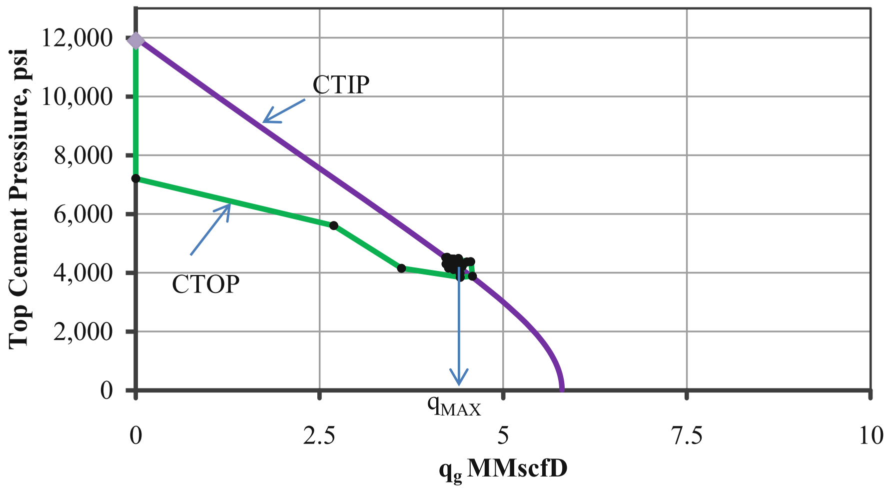

Fig. 3.13 Computation of gas emission rate from SCP well

- Pressure of gas source formation is not affected by emission rate;
- Flowing hydrocarbon is in dry gas phase;
- Gas flow is steady state;
- Top of cement is above the shoe of outer casing;
- Well is vertical;
- Annular fluid properties are known and constant;
- Heat transfer due to flowing gas from the reservoir is neglected;
- Temperature profile in annulus follows the geothermal gradient;
- There is no leak in inner/outer casings;
- Gas migration flowpath is contained by the casing-casing annulus;

Sensitivity of gas emission rate to parameters of SCP well – cement leak size, initial liquid column density and length, and mud rheology (plastic viscosity) has been studied using field data from an actual 18,000 ft (5864.4 m) with all other properties constant [64].

Figure 3.14 shows the annular system flow performance of this well. Initially, the top of cement pressure (PTOC) is equal to the reservoir pressure of 8000 psi (The gas column's hydrostatic inside the cement sheath is neglected in the model).

As the casing head fails, the well-head pressure of 3355 psi is removed, causing PTOC to reduce from 8000 psi to 4665 psi. (The dashed line is CTOP for frictionless gas migration in the mud column with no liquid unloading.) In such a case, the intercept point of CTOP (dashed) and CTIP curves indicates MER of 0.065 MMscfD. Interestingly, the actual value of MER considering flow friction and unloading is only slightly greater, 0.067 MMscfD as the friction effect is very small and unloading nonexistent. The bottom plot in Fig. 3.14 represents the "absolute open flow" (AOF) performance of the well with no liquid column and top cement open to the atmosphere. In such case, MER would be twice greater, 0.13 MMscfD. The analysis shows that with thin low-density mud the unloading is

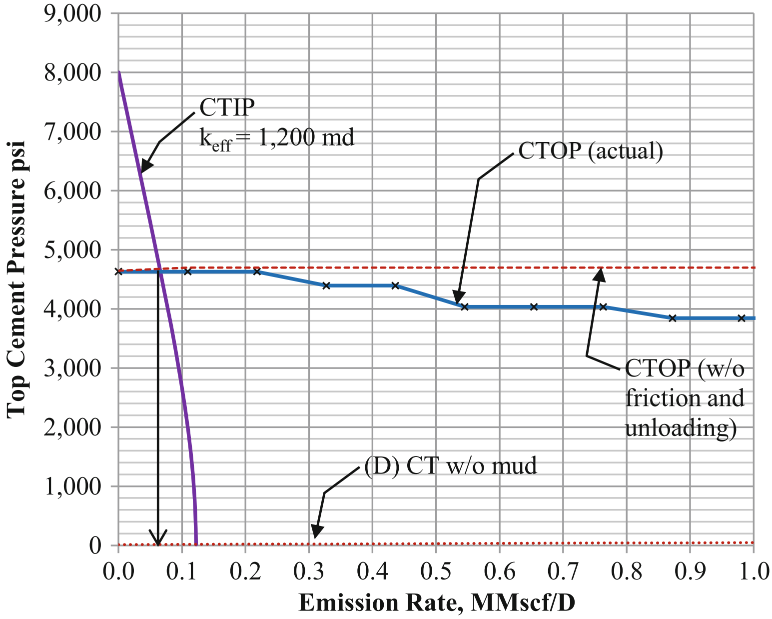

Fig. 3.14 Gas emission rate from SCP well with low density-low viscosity liquid column – no liquid unloading

minimal and hydrostatic pressure of the mud column acts as a pressure containment barrier and prevents AOF.

Shown in Fig. 3.15 is the effect of cement leak conductivity (k_{eff}, mD) density of the liquid above the cement top. It is demonstrated that small leaks with heavy mud drastically reduce emission rate. Moreover, fluid density effect alone is negligible comparing to the effect of cement leak size. Also the liquid unloading effect seems not dependent on mud density-the reduction of pressure due unloading is the same for the same increase of emission rate.

There are some irregularities in the flow performance plots resulting from discontinuities due transition from the slug to annular flow regime in the annular column. Moreover, as the transition criteria for slug/churn and churn/annular flows are not widely accepted in the literature, the churn flow is not considered in the model [81].

Figure 3.16 demonstrates sensitivity of SCP well gas emissions to the initial length of liquid column in the annulus (L_m). As shown, for short liquid column ($L_m = 1000$ ft) and large cement leak ($k_{eff} = 12{,}000$ mD), a complete unloading of the annulus may occur, and MER would be maximum and equal to AOF. Again, the leak size dominates the process – for small leak ($k_{eff} = 1200$ md), regardless of liquid column length, MER does not exceed 0.13 MMscf/D.

Figure 3.16 also reveals that liquid unloading effect strongly depends on the length of liquid column. For short liquid column, the CTOP plots remain relatively flat with increasing emission rates. However, when the annulus is full of liquid

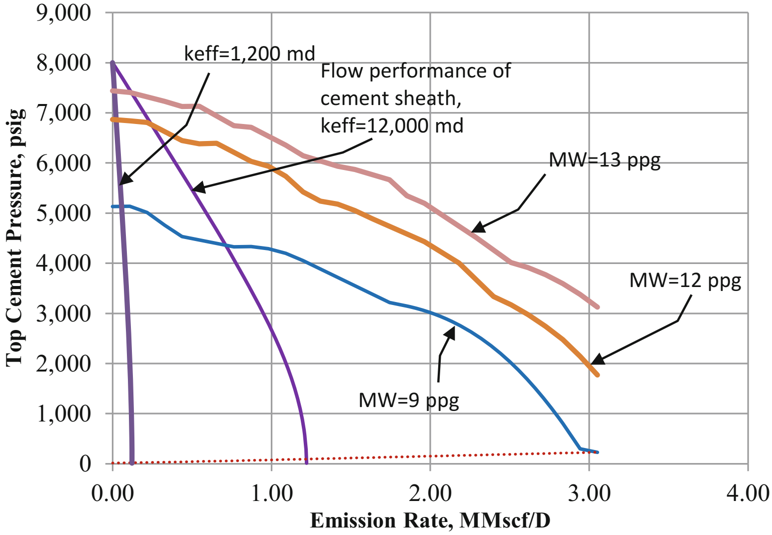

Fig. 3.15 Effect of liquid density and leak size on gas emission [70]

($L_m = 10{,}000$ ft), CTOP line rapidly reduces with increasing emission rate indicating loss of liquid from the annulus due rapid unloading.

In all, the maximum gas emission rate is mostly controlled by the leak size, i.e. hydraulic conductivity of the cement sheath that had lost integrity. The smallest rate may result from high hydrostatic pressure of the mud column that results from both the mud density and the amount of liquid in the annulus. Moreover, when the SCP well annulus is only partially filled with heavy mud, gas emission rate to atmosphere can be estimated from a simple formula describing only flow in cement with hydrostatic pressure of the liquid at the cement top. However, for the liquid-filled annulus, the simplified approach would give under-estimation of gas rate and the model proposed in [70] should be used.

As discussed above, environmental risk of SCP well's integrity loss involves atmospheric emissions due casing head failure and subsurface release of gas outside the well due to breaching of the casing shoe. (The well's casing shoe may be weaker pressure containment barrier compared to the casing head.) SCP at the surface is transmitted to the casing shoe through the liquid column in the annulus and through the cement leak resulting in elevated pressure at the casing shoe downhole (SCP_d). If SCP_d exceeds the casing shoe strength (CSS) – maximum pressure that the casing shoe could withstand, a subsurface failure occurs. Thus, the risk of critical condition of subsurface failure is,

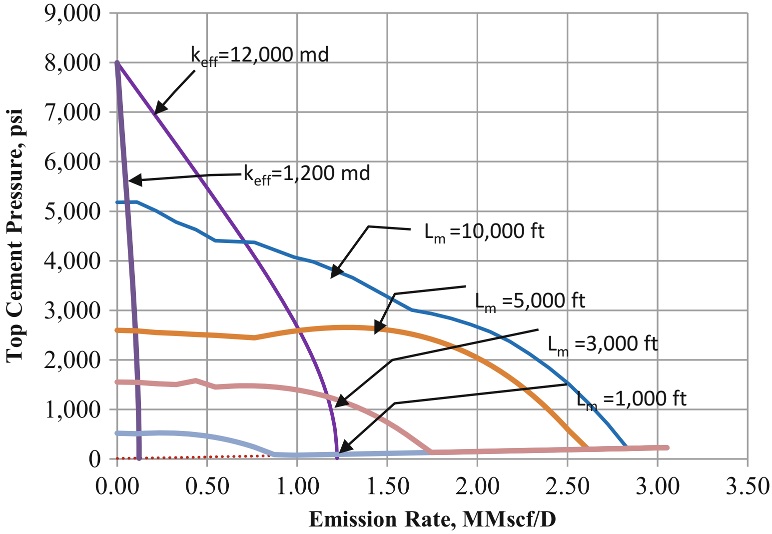

Fig. 3.16 Effect of mud column length and cement leak size on SCP well gas emission [70]

$$P[SCP_d - (CSS/SF)] > 0 \tag{3.1}$$

where, P is probability function, and SF is safety factor, SF < 1.0

The critical condition, above, considers two magnitudes – SCP_d,and CSS, that are not measured directly, but are merely estimated with some level of uncertainty. Uncertainty of casing shoe strength (CSS) results from the way it is determined from various types of formation strength tests (FST) performed to verify the strength of the cement bond and rock, such as formation integrity test (FIT), leak off test (LOT), or extended leak off test (XLOT). Conventional analysis of these tests is inaccurate as it ignores effects of several factors: drilling mud gelation, variable mud density vs. depth and temperature change during a non-circulation time – between stopping mud circulation and conducting the test. Oort et al. [82] demonstrated the discrepancy between the calculated downhole pressures during a leak off test and measured by MWD (measurement while drilling) tools.

Probabilistic analysis of CSS uncertainty was performed using quantitative risk assessment method (QRA) used also to analyze wellbore stability loss problems [83]. In the QRA terminology, uncertain variables are stochastic, while certain variables (with zero confidence interval) are deterministic. Statistical model relates dependent variables to independent variables. The analysis involves a single run of the model based on a simulation cycle considering large number of experiments with the model parameters selected randomly from the 'pool' of their values. The result gives frequency and probability density function (PDF) of the dependent variable.

Using QRA, a statistical study was performed to investigate the effect of non-circulating time, mud type and drilling mud properties on CSS uncertainty using the probabilistic CSS model [70]. The probabilistic study identified two parameters that mostly control dispersion of CSS values, Young's modulus and non-circulating time. Young modulus is a geological property widely varying for rocks due their heterogeneity. The non-circulating time is an operational parameter that could be controlled but is not reported. Casing shoe at the bottom of four sections of a GOM were considered in the study together with drilling data from the well. In this study, all input parameters were kept constant, except for the parameter being investigated. An example PDF for CSS at the bottom of intermediate casing (14,830 ft) is shown in Fig. 3.17 [70]. The CSS is log-normally distributed with mean value 16,476 psi, the 90 % confidence interval between 15,367 and 19,490 psi, and standard deviation 1382 psi. The CSS value calculated with conventional method is 14,806 psi. Thus, the mean CSS at 14,830′ is 1670 psig (11.2 %) greater than the conventional CSS and there is considerable uncertainty of the CSS value.

Similar to CSS, there is a significant level of uncertainty of estimated downhole pressure, SCP_d, in mature wells with SCP resulting either from incomplete well drilling records and long term changes in the annular mud properties. Variation of the estimated SCPd values can be very significant with 90 % confidence interval being 128 % fraction of the average value and standard error of estimate from 24 to 38 % depending upon the mud type and knowledge of the mud column length [70]. For the known surface casing pressure (SCP) and the size of mud column, the SCPd uncertainty would result from time-dependent reduction of density (thermal degradation of water-based polymer mud, and "fragile" gels) and thixotropy (progressive gels). Since both effects reduce bottom-hole pressure, the resulting SCPd distribution would be positively skewed.

Conventional (deterministic) prediction of SCPd values using annular fluid properties similar to the reported drilling mud properties was compared to probabilistic estimation of SCP_d [70]. The difference of the predicted values would mostly depend upon the type of the annular fluid. Conventional calculation of SCP_d neglects development of mud gelation over time in static conditions and mud density variation due mud aging. It may overestimate the SCP_d value for a short column of low density mud with progressive gels or underestimate SCP_d for a long column of high density mud with fragile gels.

Thermal stability of the annular fluid due mud aging plays critical role in the magnitude of SCP_d. If the mud maintains its thermal stability, gelation partially prevents the transmission of surface pressure to the casing shoe. If the thermal stability is lost, solids tend to sag reducing the mud density significantly. Thus, the mud aging would reduce SCP_d. Moreover, accurate knowledge of the annular fluid column size is critical as it removes almost half of the downhole pressure uncertainty. An unknown mud column size would negatively skew SCP_d distribution.

Environmental risk of subsurface loss of well integrity due SCP can be estimated by probabilistic analysis of Eq. (3.1). Similar approach has been used by Liang, et al. [84] to predict pore pressure and fracture gradients to determine the safe mud

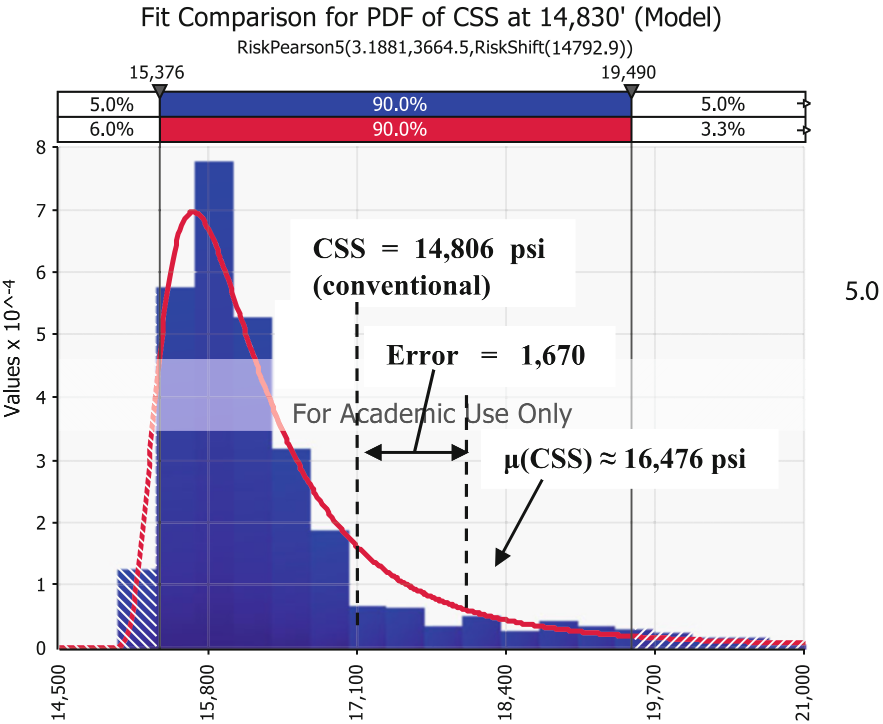

Fig. 3.17 Probabilistic analysis of casing shoe strength CSS at 14,830 ft [70]

density window. The authors defined risk similar to Eq. (3.1) and used QRA to describe the uncertainties of the pore and fracture pressure values as continuous probability densities to calculate the lower limit and upper limits for the mud density during drilling. Their study can be considered as a typical example of QRA application to determine risk of wellbore integrity loss.

As defined by Eq. (3.1), calculation of risk of casing shoe failure considers the SCP_d and CSS as two populations with known, but different means and standard deviations. As the two magnitudes (SCP_d and CSS) represent totally different operational set up (i.e. the leak off test for CSS, and well-head pressure transmission during entire life of the well) the two populations are considered independent. The QRA involved very large number statistical experiments (Monte Carlo simulations), thus the central limit theorem suggests that the probabilistic CSS and SCP_d models represent their actual populations. This means that the sample variances approximate the population variance, allowing Z test statistics. Under these assumptions, the risk of CSS failure is calculated by one-tailed testing of two hypotheses on two population means,

$$\begin{aligned} &\mathrm{HO} : \mu(\mathrm{SCPd}) = \mu(\mathrm{CSS}) \\ &\mathrm{HA} : \mu(\mathrm{SCPd}) > \mu(\mathrm{CSS}) \end{aligned} \tag{3.2}$$

Assuming safety factor, SF = 1, risk of casing shoe breaching becomes the probability value of the Z statistic of the difference between the means of two independent populations, as,

$$R_F = P\left[\left(\overline{SCP}_d - \overline{CSS}\right) > 0\right] \cong P[(\mu(SCP_d) - \mu(CSS)) > 0] \tag{3.3}$$

Shown in Fig. 3.18, is an example statistical estimates of the SCPd and CSS values at the $13^5/_8''$ casing shoe in the $9^5/_8'' \times 13^5/_8''$ annulus of the intermediate well section at 14,830 ft filled with oil-based liquid above the cement top at 10,385 ft. [70]. As the annular fluid has high thermal stability and non-progressive gels it maintains hydrostatic head and does not obstruct downhole transmission of SCP pressure of 4168 psi from surface to the casing shoe. In the result, the population's mean value of SCP_d is 303 psi greater than that of CSS that, deterministically, indicates casing shoe failure. However, the QRA application suggests that there is a significant probability, 20.6 %, that the casing shoe would not fail at SCP = 4168 psi (Fig. 3.19).

7.3 *Rig Methods for SCP Isolation*

The rig methods involve moving in a drilling rig, workover rig or, in some cases, a coiled tubing unit and performing either routine well repair, such as replacing the tubing and/or packer, some kind of plug back to isolate the productive zone, or perforate/cut-and-squeeze operations in the well. The rig methods are inherently expensive due to the moving and daily rig costs [58]. When SCP affects the production casing string, the tubing repair or plug back operations are generally successful. When the SCP affects outer casing strings, the rig method usually involves squeezing cement. These procedures involve perforating or cutting the affected, inner casing string and injection of cement to plug the channel or microannulus in the cement outside the inner string. Both block and circulation squeezes have been attempted. The success rate of this type of operations is low (less than 50 %) due to the difficulty in establishing injection from the wellbore to the annular space of the casing with SCP and getting complete circumferential coverage by the cement. In the 1990s, the SCP workover programs concentrated on squeezing cement into the affected casing annuli of wells. Initially, deep cement squeezes were attempted where logs indicated poor bond. Annular pressures were not successfully reduced until large cement volumes were squeezed at intermediate shoes. The early workover programs succeeded in reducing annular pressures but did not bring them to zero.

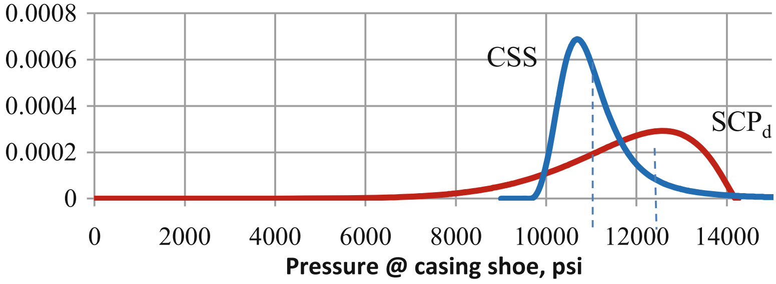

Fig. 3.18 Probability densities of SCPd and CSS at 14,830 ft

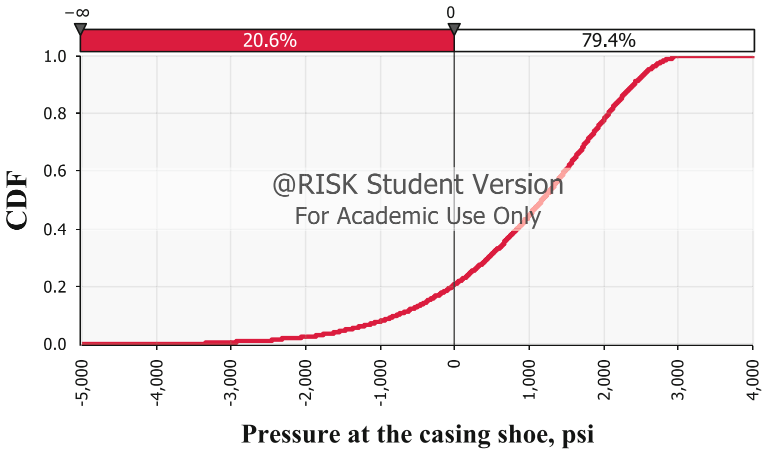

Fig. 3.19 Risk (CDF) of casing shoe failure P [SCP_d – CSS] at 14,830

Recently, the rig methods have been significantly improved by adding more drastic techniques for pressure isolation [85]. Two main approaches to accessing and alleviating sustained casing pressure have been adopted: casing termination and window milling. The first method involves terminating the affected casing string as deeply as possible inside the outer casing without extending below the casing shoe. By terminating the casing as deeply as possible, it maximizes the room available for possible future intervention as well as gaining the hydrostatic advantage of the longer fluid column.

Shown in Fig. 3.20 is an example of a typical "cut and pull" operation of the 7″; casing inside the 10¾″; casing. "Upon gaining access to the wellbore, the mud was circulated out with the kill heavy brine. A trip in the hole with the workstring and a mechanical cutter was made to cut the 7″ casing in an attempt to circulate kill weight fluid down the casing and into the annulus if possible. The pumps were rigged up and tested to circulate in the 11.6-ppg brine into the 7″ casing. Upon making both the deep cut and the cut immediately below the hanger, the well was

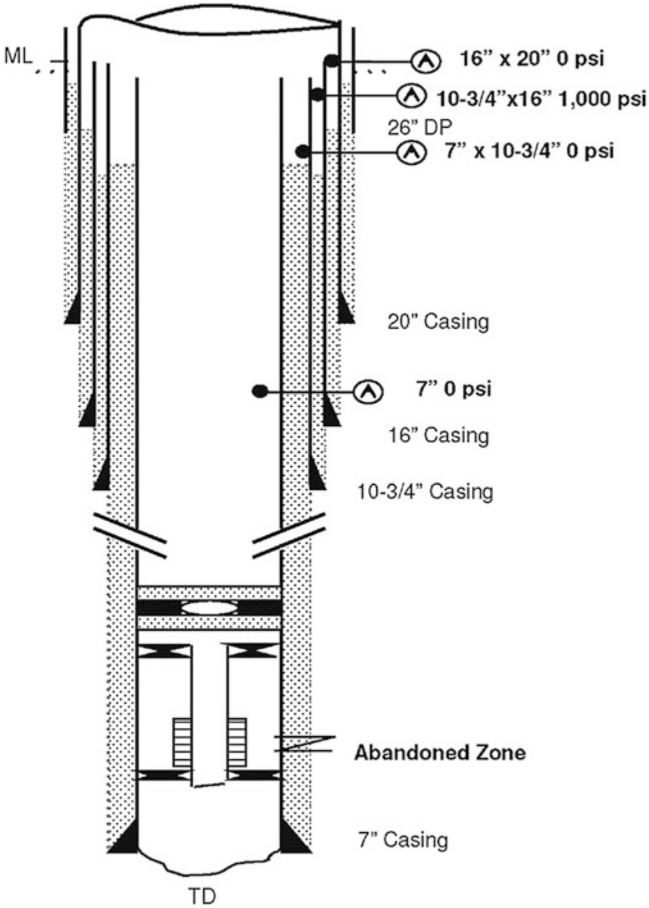

Fig. 3.20 Cut-and pull-casing method for SCP removal. (After Ref. [85])

verified to be dead before continuing rigging down the pumps and pulling out of the hole with the workstring.

A spear and grapple set to catch the 7″ casing was then picked up on 4½″ workstring and tripped into the hole to spear into the 7″ casing. An attempt to establish circulation was not made until there was casing movement in order to avoid packing mud or sediment in the annulus. Once the pipe was moving, it was reciprocated while circulating mud in the hole. The casing was picked up and pulled out of the hole to recover the casing to the deeper cut" [85].

The second method involves milling a long window and isolating both the lower stub and upper stub with cement plugs. This method is used in cases where the inner casing string could not be economically or feasibly removed to a necessary minimum depth to isolate annular pressure. For instance, if drilling reports indicates the inner casing was cemented in place with cement to surface or if a cement bond log indicates too shallow depth of the cement's top, a window milling procedure is applicable.

7.4 Rig-Less Technology for SCP Isolation

The rig-less technology involves external treatment of the casing annulus usually involving a combination of bleeding-off pressure and injecting a sealing/killing fluid either at the wellhead (bleed-and-lube method) or at depth through flexible tubing inserted into the annulus (Casing Annulus Remediation System, CARS).

The concept of the lube-and-bleed method is to replace the gas and liquids produced during the pressure bleed-off process with high-density brine such as zinc bromide. It is, then, expected that the hydrostatic pressure in the annulus can gradually be increased using this technique. The procedure – shown in Fig. 3.21 – involves lubricating (injecting) zinc bromide brine into the wells' annulus, holding the pressure to allow settling of the brine to the bottom, and bleeding small amounts of lightweight gas and fluid from the annulus over several treatment cycles.

Limited number of case histories reported the lube-and-bleed method as partially successful. In one of these cases, SCP in the 13-3/8″ casing was reduced from 4500 to 3000 psi. The operation took over a year with numerous cyclic injections during which 118 bbls of 19.2 ppg Zinc Bromide brine replaced 152 bbls of the annular fluid (a gas-cut water-based mud having density of 7.4–9.5 ppg) [86]. Other operators also observed incomplete reduction in surface casing pressures from this method. A study of the lube-and-bleed method demonstrated dramatic effect of the interaction between the lubricated and annular fluids on the method's performance [87]. The study showed that injection of Zinc Bromide into the annulus filled with conventional water-based mud is ineffective because of flocculation-plugging effect. Compatibility of the two interacting fluids entirely controlled the method's performance. Others also observed in the field that pressures can increase while applying this method [58]. They also hypothesized that this occurs when a new "gas bubble" migrates to the surface. In all, after trying the lube-and-bleed method for several years in several wells, the field results have not been as promising as first indicated.

In 1997, Shell Oil and ABB Vetco Gray designed a system called CARS (Casing Annulus Remediation System) [88, 89]. This system is similar to the "lube-and-bleed" process in that it is designed to place heavy fluids into the casing annulus without the use of workover rig or perforating. This is done by running a thin flexible hose into the casing annulus through the casing valve. After placing the hose at certain depth, heavy fluids can be circulated through the hose, as opposed to the "lube-and-bleed" process in which fluids are squeezed into the closed annulus system from the top of the annulus.

The CARS equipment has been designed and successfully tested in the lab at maximum surface pressures of approximately 200 psi. The system has been also upgraded for surface pressures up to 1000 psi. Shown in Fig. 3.22 is the CARS

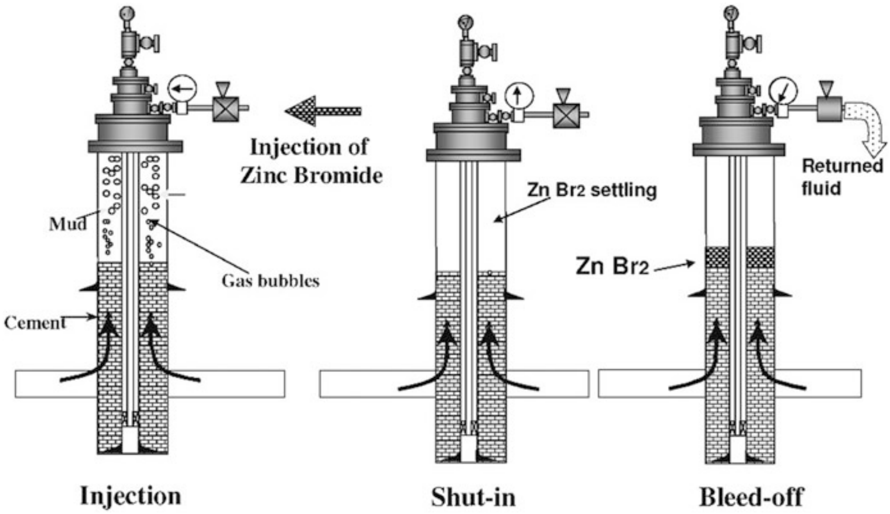

Fig. 3.21 Principle of the lube-and-bleed method for SCP removal

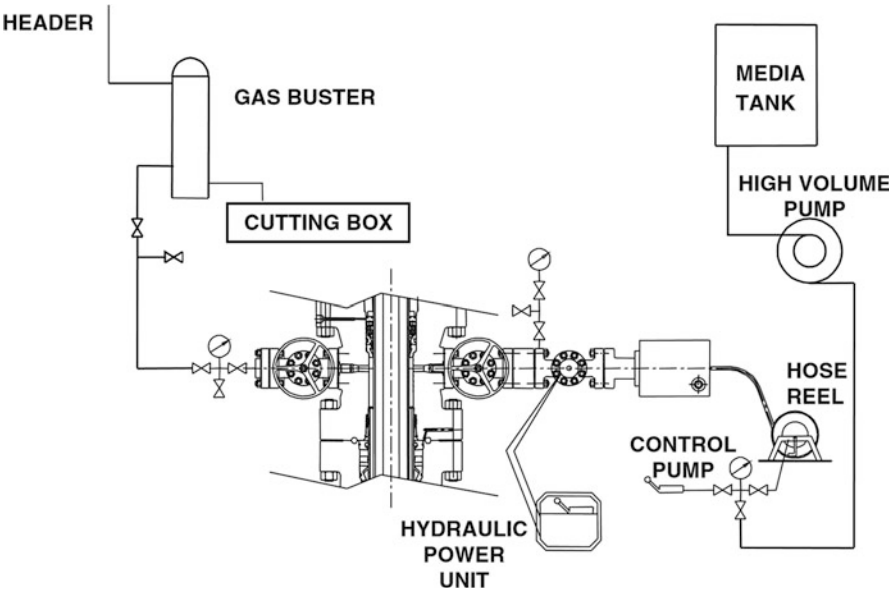

Fig. 3.22 Schematics of CARS installation. (After Ref. [88])

system schematics [88]. There are several options for CARS equipment arrangement, depending on the casing pressure conditions. The arrangement shown in Fig. 3.22 is for casing pressure that would not bleed to zero, i.e. the CARS hose must be run under pressure. The system comprises the following items counting from the wellhead to the right:

1. Shear valve flanged directly onto the wellhead. The valve is used in cases when it becomes necessary to cut the hose
2. A 5000-psi BOP, for containment of pressure on outside of the hose during hose cutting or crimping operations
3. Injector head used to "grip" the hose and force into the well
4. CARS hose reel
5. A pump connected to the tank filled with displacing fluid

On the opposite (left) side of the wellhead there is a discharge manifold, gas buster, and a cutting box. This installation's function is bleeding off the casing, monitoring casing pressure, and taking fluid samples. In cases when the casing pressure bleeds to zero, the 5000-psi BOP may be removed. Depending on the severity of the casing pressure and its bleed-down/build-up characteristics, the shear valve and/or the injector head may be removed and replaced with a casing valve and a pack-off. In principle, the procedure of CARS operation is as follows [88]:

- Connect one annulus outlet to test facilities and bleed down
- Install VR plug in opposite annulus and install shearing valve
- Rig up CARS packoff, driver, and pumping system
- Run in hole until desired depth is achieved
- Displace annular volume with selected fluid
- Bleed off all lines and verify pressure is reduced to zero
- Disconnect CARS system and install terminal fitting
- Rig down and secure well

The major problem encountered with CARS, to date, has been the inability to get the hose to a depth that would allow circulation of a significant volume of Zinc Bromide. Because the hose depths are so shallow, the Zinc Bromide brine must be pumped in stages, the volumes of which are equal to the annular displacement to the depth of the hose. In some cases, these volumes were as small as one barrel. Thus, the fluid must be pumped over several one-barrel cycles separated by shut-in periods when the brine would gravitate down the annulus.

Recently, a new technique for isolation of SCP has been patented and tested experimentally [90, 91]. The method involves placing palletized alloy–metal into the well's annulus, heating the alloy–metal above its melting point, and then allowing the alloy–metal to cool. When the alloy–metal cools, it expands slightly and seals the annulus. The method was tested on large-scale models of the 5½″ by 8½″ pipe-open hole annulus and the 10¾″ by 13⅜″ casing–casing annulus by applying 100 psi pressure. The testing proved the concept that the alloy metal pellet could be placed in an annulus through a static column if drilling mud but the seal quality needs improvements.

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Chapter 4
Environmental Control of Drilling Fluids and Produced Water

A.K. Wojtanowicz

1 Control of Drilling Fluid Volume

This section presents technology for environmental control of waste generation from the drilling process. Spent drilling fluid is the primary waste stream from the process. Thus, by the preventive nature of ECT, discussed in Chap. 2, new waste reduction components have been built into the mud engineering technology.

A steady increase of the mud system volume, as shown in Chap. 2, is inherent in the drilling process and results from both disintegration of cuttings during their transport to the surface and limited efficiency of cuttings removal by the solids-control separators. For water-based muds, this mechanism can be controlled by adding a second (dewatering) loop to the mud processing system so that the mud's water phase can be recycled and the volume of drilling waste minimized. Ultimately, disposal of this waste depends upon the toxicity of mud systems used to drill the well. Therefore, the properties of mud systems that are directly related to pollution are dispersibility, dewaterability, and toxicity. In a 'clean' drilling process these properties must be controlled. Also, such a process requires improvements in mud solidsremoval efficiency.

1.1 Control of Mud Dispersibility

In mud engineering, several conventional methods can be used to inhibit swelling of shales. These methods have been developed primarily to combat the borehole instability problems. In addition, these methods usually prevent disintegration of

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_4

Table 4.1 Drilling mud dispersibility vs toxicity [1]

Mud type	Mysid shrimp LC_{50} (ppm)
PHPA (9.6 lb/gal)	>1,000,000
PHPA (14.3 lb/gal)	>1,000,000
PHPA/salt water (20 % NaCl, 14.5 lb/gal)	140,000
PHPA/sea water (13.5 lb/gal)	>1,000,000
Sea-water lignosulfonate (generic no. 2)[a]	621,000
Freshwater lignosulfonate (generic no. 8)[a]	300,000
Lime base (generic no. 3)[a]	203,000
KCl/polymer (generic no. 1)[a]	33,000
Cationic mud system	>1,000,000
Freshwater CLS – chromium lignosulfonate (2 % diesel)	5970
Freshwater CLS (2 % mineral oil, 15 % aromatics)	4740
Freshwater CLS (2 % mineral oil, 0 % aromatics)	22,500
Mineral oil-based mud (MOBM)[b]	1,80,000

[a]Generic muds [2, 3]
[b]After Ref. [4]

cuttings, thus providing a basis for development of dispersibility control systems. Most of known inhibitive muds, however, are too toxic to be environmentally acceptable. Table 4.1 lists the inhibitive drilling fluids together with values of their toxicities, as reported by various sources. The data indicate a general trend, suggesting that the stronger the inhibitive properties are, the more toxic the mud becomes.

Potassium/polymer muds have traditionally been the best water-based system with the lowest dispersibility. Unfortunately, in the USA, the toxicity limitation of a minimum LC_{50} value of 30,000 ppm essentially eliminated potassium from use in the Gulf of Mexico and other offshore areas of the outer continental shelf [3, 5]. High-salt (NaCl) polymer muds, instead of the more effective potassium systems, are now being used in the Gulf of Mexico. However, potassium muds are being used in the North Sea and elsewhere where regulations are not biased against addition of potassium to sea water. To reduce the dispersibility characteristics of potassium muds in the North Sea, a variety of additives based on glycol and glycerol chemistry have been developed and are being used successfully [6–8].

One feature of polymer mud systems is that they typically operate at low pH levels relative to lignosulfonate muds that are highly dispersive. Lignosulfonate requires an alkaline additive for activation, such as sodium hydroxide (caustic soda), and the pH ranges from 9 to 11.5. The lower pH of polymer muds appears to be an important feature that helps reduce cuttings disintegration when cuttings are circulated to the surface. However, a number of high-pH lime muds are being used to take advantage of low dispersibility arising from the presence of insoluble lime [$Ca(OH)_2$] [9–11].

An example of non-dispersive polymer mud concept is the 'cationic' system [12–14]. The cationic mud is designed to have low dispersibility and toxicity. These mud systems were usually formulated using non-reactive sepiolite or attapulgite clay, cationic polymeric extender, and cationic inhibitors so that the solids in suspension are positively charged. Negatively charged reactive cuttings are encapsulated by adsorption of the cationic inhibitor on their surfaces, thus preventing their disintegration. Another formulation of the cationic mud system employs a solids-free combination of pregelatinized starch and hydroxyethylcellulose (HEC) for viscosity and fluid loss with cationic polymer and 10 % KCl for dispersibility control. Because the system is solids free, it has been developed exclusively for slim-hole drilling with high rotating speeds and annular transport velocities.

A non-toxic claim has been made on the inhibitive mud system known as the *mixed metal-layered hydroxide compound* MMLHC (or MMH) fluid [15–17]. In fact, the system formulation clearly implies lack of toxicity. It is built using low concentration of bentonite clay (10 lb/bbl) and an inorganic MMLHC (<1 lb/bbl). Microscopically, the MMLHC compound contains discrete layers of metal ions surrounded by hydroxide ions. The layers are positively charged and are smaller than clay platelets. The clay inhibition is based on an ion-exchange mechanism (similar to that of KCl systems) with the MMLHC exchange capacity being more than three times greater than that of sodium bentonite. However, not only are the particles of bentonite inhibited from swelling through the exchange of sodium ions for the metal ion hydroxide platelets, but they are also aggregated around MMLHC particles owing to their excess of positive charge. The practical result of this interparticle association is the development of gel structure and excellent solid suspension ability. Field applications confirmed the non-dispersive behavior of MMH drilling fluids through the following observations: (1) no washouts; (2) no viscosity increase; (3) clean borehole; (4) small volume of clean shaker cuttings; and (5) low MBT values. Also, the retention of simulated cuttings on a 6-mesh screen was over 80 % by weight.

The most promising group of the water-based muds that has been successfully developed, field tested and commercialized has been based on synthetic organic compounds. The concept gave rise to the new type of mud – Synthetic Base Muds, discussed in the following sections. One of such early systems was based on highly concentrated solutions of methyl glucoside (30–70 % by weight). Laboratory studies indicated that this fluid may indeed have possessed the low dispersibility property achievable by oil muds [18].

1.2 Improved Solids-Control–Closed-Loop Systems

The overall efficiency of cuttings removal by the solids-control system, E_s, can be expressed as

$$E_s = E_1 f_1 + (1 - E_1)E_2 f_2 + (1 - E_2)E_3 f_3 + (1 - E_3)E_4 f_4 \qquad (4.1)$$

where E_1–E_4 are solids-removal efficiencies (by volume) of the shale shaker, desander, desilter, and centrifuge, respectively, and f_1–f_4 are volume fractions of mud processed by these separators. The equation has little practical use because the efficiencies E_1–E_4 are dependent upon separators' inputs, which in turn depend on the variable content of the flowline mud. However, Eq. (4.1) is useful for the design of a new system configuration, and also for the evaluation of solids-control separators at work. In the latter case, the efficiency of each separator should be determined using API procedures [19]; then the overall efficiency should be calculated from Eq. (4.1).

There are a few direct methods available at the well site to determine the overall efficiency of cuttings removal. The methods are based either on density measurements or water dilution records. Calculation of the overall separation efficiency using mud density measurements at the suction pit usually takes a long time (a day) and requires several cycles of mud circulation. The other method, measurement of the density difference between flowline mud and suction pit mud, does not give enough accuracy with the use of a mud balance. Alternatively, determination of reactive cuttings in the mud using the retort and the Methylene Blue tests does not have the precision required to detect the increase of clay concentration before it affects the mud rheology. An interesting method has been presented to determine a solids-control index (SCI) from the monitored water dilutions required to control drilled solids [19, 20]. (SCI can be converted to the separation efficiency through the equation $E_s = 1 - \mathrm{SCI}$.) Although very practical, the method requires monitored water usage for dilutions and cannot be used for weighted mud systems.

Several attempts have been made to develop a mathematical computerized model of cuttings removal [21–25]. All of these attempts use the steady-state material balance approach with known and constant values of separation efficiencies of system components. They do not consider the relationship between the separation efficiency and particle size distribution, solids throughput and liquid-phase properties of the processed mud stream. Also, practical verification of the models is limited because no solids-control instrumentation is available on drilling rigs. More successful efforts have been made to develop experimental models of single separators: hydrocyclones [26, 27], shale shakers [28, 29], and centrifuges [30], together with the analytical and field-deployable techniques for evaluation of the separators' performances [31–33].

Emphasizing the efficiency of solids-removal may lead to the generation of excessive volumes of drilling waste. For any separator, whether shale shaker, hydrocyclone or centrifuge, a strong correlation exists between solids separation efficiency and volume removal of the associated mud liquid phase. Hydrocyclones, for example, when operated at 0.6 solids separation efficiency, may remove up to nine times more liquids than solids, as shown in Fig. 4.1 [27, 34]. Generally, any increase in E_s would result in increasing values for liquid removal, represented by the liquid removal ratio, R (the ratio of the volume of removed liquid to the volume of removed solids). The correlation between E and R is unique for solids-control equipment and drilling mud used in the well. Theoretical calculations indicate that maximizing the efficiency of solids separation may result in up to a 50 % increase of drilling waste volume [34]. Hence, there is an optimum value of E_s that gives a minimum volume of waste.

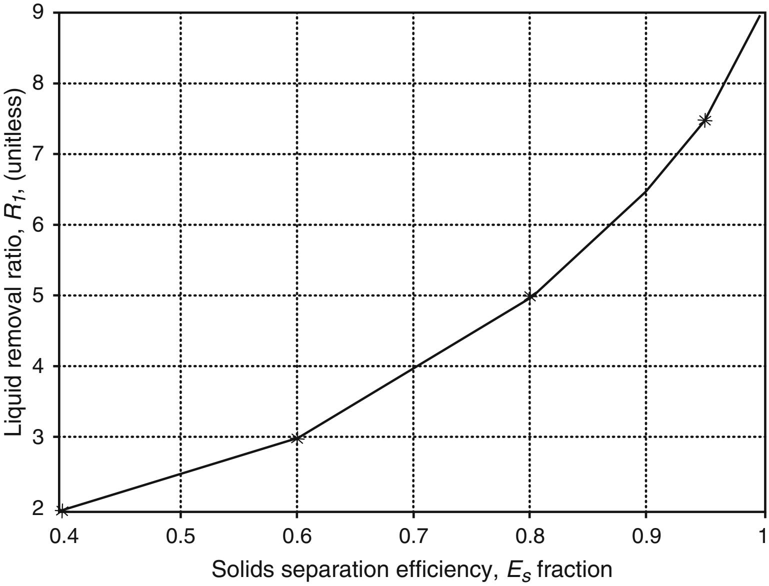


Fig. 4.1 Typical relation between efficiency of solids removal and liquid removal ratio for hydrocyclones

In the late 1980s and over the 1990s, a considerable improvement was made in solids-control separators [35, 36]. One significant improvement was in shale shakers and screens. Drilling rigs are now equipped with two or more linearmotion shale shakers. Some rigs may have as many as ten shakers, several of which are used as scalping shakers upstream of the fine-screen linear-motion shakers. The linear-motion shakers are often fitted with screens having an equivalent mesh size of 150 or more, which results in the removal of fine particles. The dramatic reduction in the size of the particles that can be screened from the drilling fluid has led to improved drilling-fluid performance and to a reduction in the volume of fluid required for drilling a well and discharged at the end of drilling the well. In addition to shale shakers and screens, the importance of the entire mechanical solids-removal system in reducing waste volumes from drilling operations has become better understood, which has resulted in the development of closed-loop drilling systems [37, 38].

The closed-loop system approach requires that the drilling waste should be disposed of at the drilling site and not taken out of the loop for offsite disposal [38]. From the standpoint of ECT methodology, closed-loop system technology integrates on-site disposal techniques with the drilling process (the environmental boundary is drawn around the drillsite, reserve pits and land treatment area). The drilling mud loop is partially closed through improved efficiency of the solids-control separators. The loop is finally closed through ultimate disposal on-site within the process boundaries. Table 4.2 shows the improvement in cuttings

Table 4.2 Development and performance of closed-loop drilling systems[a]

Performance measure	1983	1984–1985	1986	Closed-loop condition
Surface hole removal efficiency (%)	15	46	68	81
Production hole removal efficiency (%)	20	67	80	89
Surface hole mud and disposal costs ($)	10,200	7800	6300	4500
Production hole mud and disposal costs ($)	25,600	14,300	8300	4800
Total costs ($)	35,800	22,100	14,600	9300

[a]After Ref. [38]

separation (hole removal) efficiency and economics resulting from the closed-loop system approach [38]. Closed-loop technology employs high-quality solids-control separators in various configurations. Sometimes these systems are provided as skid-mounted tandems known as unitized solids-control systems. Two types of unitized systems are available: one built by the solids-control equipment vendors and the other custom designed and built by operators.

1.3 Dewatering of Drilling Fluids: 'Dry' Drilling Location

An ECT alternative to closed-loop systems is a zero-discharge, or 'dry', drilling location at which no disposal on-site is permitted. A dry drilling location requires advanced technology for mud processing to minimize the volume and cost of on-site storage and off-site disposal [34]. One such technology is mud dewatering [39]. The dewatering component incorporates technology for separating water from water-based muds for reuse in the mud system. It also significantly reduces the volume of liquid waste that is destined for ultimate disposal.

A schematic diagram of the mud processing system with the dewatering component is shown in Fig. 4.2. After flowing out of the well, drilling mud is initially processed by solids-control separators (classification) and recycled back to the well. Since cuttings removal is not complete, a continuous increase of mud contamination by solids occurs. The contamination is controlled through additions of freshly mixed mud so that the mud system is steadily replaced with the new one. The rate of mud replacement is directly proportional to the rate of contamination of the system with fine cuttings. As a result, the rheological and filtration properties of drilling fluids are constant. Also unchanged is the mud system chemistry, which is closely maintained to its original formulation. In order to maintain a constant volume of the surface mud, the rate of mud replacement must be balanced with the mud discharge rate. Therefore, part of the mud stream, after being processed by the solids-control system, is diverted and treated by the dewatering component. First, the weighting material (barite) is removed and recycled back to the mud system. Second, the diverted mud is diluted with water to improve the chemical treatment which follows. Third, the diluted mud is treated with chemicals. The treatment transforms

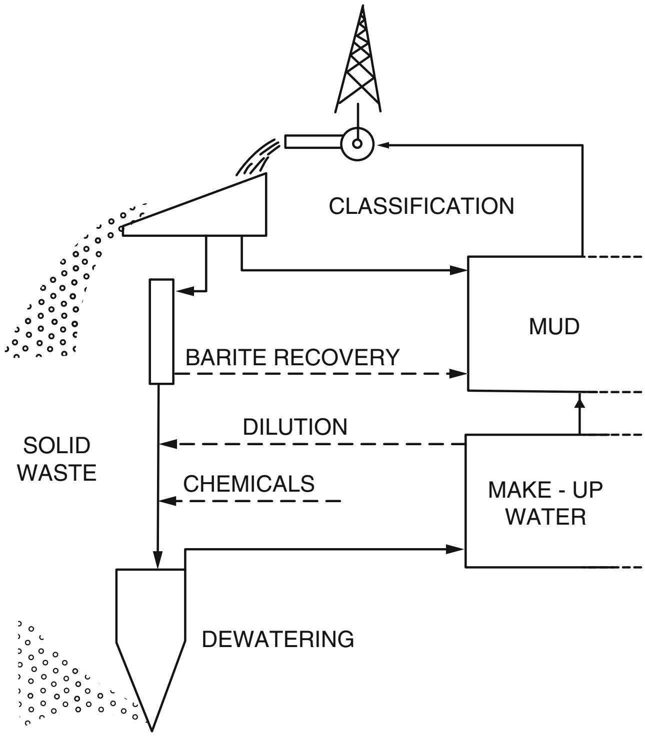


Fig. 4.2 Principles of drilling mud dewatering

the mud from a stable suspension into a mixture of water-soaked flocculates and free water. The flocculates readily release water under a squeeze. The last stage of dewatering involves centrifugation of flocculates, resulting in a dense, solid cake (underflow) and solids-free water (overflow). The volume of underflow is significantly smaller than the feed mud volume. Also, returning the overflow water to the mud dilutions reduces water consumption and saves on chemicals dissolved in the mud–water phase.

Dewaterability involves the ability of drilling fluid suspensions to destabilize and release their water phase. The treatment consists of two stages: (1) chemical destabilization, in which a uniform liquid suspension is converted to two phases, free water and wet structure of solids (flocculates); and (2) mechanical expression, in which additional water is released by squeezing the solid structure. Like other properties of drilling fluid (e.g. water loss, viscosity, and gel strength) dewaterability embodies complex physical mechanisms. However, it can be determined simply by measuring relative volume reduction due mechanical expression [40, 41].

Table 4.3 Dewaterability of drilling fluids[a]

Mud system	Density (lb/gal)	Water removal (% v/v)	Cake solids (% v/v)	Volume Reduction (% v/v)
Spud	9.2	65	43	72
Salt/polymer	13.5	65	66	28
Lime	9.6	63	47	62
CLS/unweighted	9.1	59	49	79
KCl/polymer	11.6	48	53	30

[a]After Ref. [42]

Dewaterability values for various drilling fluids are presented in Table 4.3 [42]. The data indicate that, theoretically, the volume of waste drilling mud can be reduced by 1.4–4.8-fold. On the other hand, the data show that the presence of inert solids (barite) may distort the dewatering performance. For example, high solids content in the dewatered salt/polymer mud may create the illusion of high performance and 'dry cake'. However, the actual performance is low, a mere 1.34-fold volume reduction. Therefore, in field applications, barite should be separated from drilling fluid prior to dewatering.

The inverse effect of reactive solids on dewaterability was observed in laboratory tests [43] and documented in field tests as shown in Fig. 4.3 [45]. Evidence shows that mud solids with a high cation-exchange capacity (CEC) produce moist cakes. However, the data do not show the simultaneous effects of mud inhibition and cuttings CEC on the cake's moisture. Moreover, the high moisture level in dewatering cakes has been often misinterpreted for low dewatering efficiency. In fact, the volume reduction ratio R_{vr} for unweighted mud is a function of both the cake moisture M and the fraction of water phase in the dewatering mud, f_w, as

$$\mathrm{R_{vt}} = \frac{1 - M}{1 + M(SGm - 1) - f_w} \tag{4.2}$$

where SG_m is the specific gravity of the mud. Equation (4.2) indicates that a significant volume reduction can be obtained even with wet cakes (large M) for the low-solids mud systems (large f_w). For example, if the dewatering of a mud with 4 % cuttings (and 10 lb/bbl commercial solids) produces a solid cake having only 30 % solids by weight (14 % solids by volume), the volume reduction is still a significant 2.5-fold.

Selection of the best chemical treatment for a drilling mud has been repeatedly reported as a difficult design problem. Typically, the only selection method is the tedious trial-and-error approach. A solution to this problem has been developed using the theory of multiple factorial experiments [40]. In this method, the number of experiments required to find the best treatment (dilution, coagulant, flocculent,

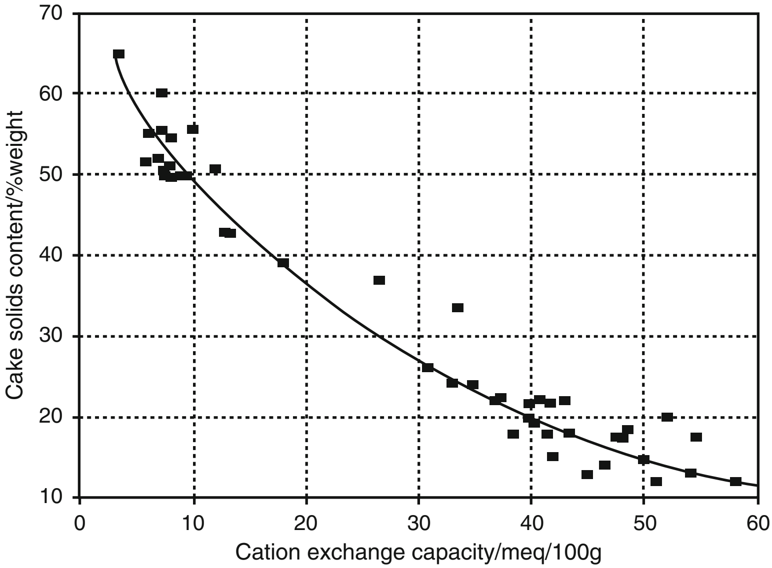


Fig. 4.3 Effect of drilling mud solids reactivity on dewatering cake dryness [44]

error) is reduced to nine points (nine-point test). In principle, the nine-point test is a simultaneous optimization of three variables of chemical treatment.

The second stage of the dewatering process, cake expression, is critical for reducing the volume of waste mud because it generates almost all of the water recovered in the process. Characteristically, for drilling fluids, the content of water in the flocculated structure of solids is greater than that in untreated drilling mud.

The cost of mud dewatering has been considered a key factor of the process design and control in all reported applications [39, 45–47]. The decision regarding whether or not to use the mud dewatering process should be based upon calculations of economics because (1) the dewatering process may be non-economical for a well, when traditional solids-control system is efficient enough, or when savings due to volume reduction with the dewatering process cannot offset its cost and (2) at certain stages of well drilling, the dewatering component should be disconnected because its cost breaks even with the off-site disposal cost.

2 Control of Drilling Fluid Toxicity

A remarkable progress was made during the 1980s and early 1990s in the development of technical measures to control the toxicity of environmental discharges from drilling operations. The methodology of toxicity control includes testing methods, low-toxicity substitutes and source separation techniques.

2.1 Drilling Fluid Toxicity Testing

Toxicity testing of drilling fluids is currently required in the USA, North Sea and other offshore drilling areas. Various tests have been adopted from conventional bioassays, measurements involving living organisms, for marine, freshwater or sediment toxicities. Organisms used in marine toxicity testing are oysters, shrimp (white, brown, grass, or Mysid), crabs, fish, and clams. Freshwater assays involve fish such as sheepshead minnows, bluegill, rainbow trout, and daphnia. Typically, bioassays are conducted in licensed laboratories under controlled environmental conditions (light–dark cycles, temperature, salinity, pH, etc.), over time periods from a day to a week, and use organism populations carefully grown to meet sensitivity standards. Because of these reasons, the laboratory tests, rather than field-based toxicity tests, have been incorporated into environmental discharge regulations.

For example, the 96 h Mysid shrimp bioassay for drilling fluids was adapted from the US Army Corps of Engineers procedure for measuring the toxicity of dredged materials in compliance with ocean dumping criteria [2]. The test has been included in general permits for offshore dumping of drilling waste to the waters of the US Outer Continental Shelf (OCS) since the early 1980s. The Mysid shrimp LC_{50} value of 30,000 ppm has been set as the limiting toxicity to maintain the general permit for drilling mud discharge offshore, together with ‘no sheen’ and ‘no free oil’ requirements, and concentration limits for mercury (1.0 mg/l) and cadmium (3.0 mg/l) in barite. Companies that discharge mud with LC_{50} value smaller than 30,000 ppm are subject to penalty because acute toxicity increases as the LC_{50} decreases.

The Mysid shrimp bioassay has been criticized for its imprecision and inconvenience in practical applications [1, 5, 48, 49]. The test’s turnaround time may be as long as 2–3 weeks, which is comparable with the well’s drilling time. Major problems for operators in using the 96 h LC_{50} test is just how to comply because results are not known for days or weeks following a mud or cuttings discharge. Operators currently comply with the regulations by setting an internal margin of safety based on LC_{50} tests run previously on the mud type they are using. This safety level may be set 60,000 ppm higher than the regulatory limit of 30,000 ppm or even higher, reflecting the fact that LC_{50} test results are highly variable and that some cushion is needed for unexpected events [50].

A considerable effort has been made to develop a new field-deployable test of toxicity, a rapid bioassay [51–55]. The three basic requirements for such test are a short (few hours) completion time, feasibility for use at well sites and correlation with the Mysid shrimp bioassay. The Microtox toxicity test is a promising alternative for rapid bioassay. One concept was to use the test as a statistical tool to predict on the offshore drilling platform whether the mud’s Mysid shrimp toxicity would exceed (or not) its limiting value of 30,000 ppm (with a probability level of 98–100 %) [53]. Drilling mud passing such a test can be discharged overboard.

The method could probably be further refined by introducing an element of calculated environmental (and economic) risks.

Another rapid toxicity test, cumulative bioluminescence, showed promise for further developments [55]. The test measures the total cumulative flux of light generated by a stirred suspension of algae plants in a controlled solution of drilling mud. The preliminary research results showed sensitivity of the test to progressive changes of mud toxicity. Also observed was a drastic improvement in the correlation with the Mysid test for higher mud toxicities (below the Mysid LC_{50} value of 300,000 ppm). However, neither of the rapid toxicity tests have been approved by the regulators and adopted for commercial use.

To avoid long waiting time for the test results, several useful methods are currently used for quickly checking a mud for compliance before discharge. A computer program is also available for estimating the LC_{50} based on mud composition [56]. However, from the compliance viewpoint, quick checks and computer estimates cannot be substituted for a full 96 h LC_{50} test.

2.2 Low-Toxicity Substitutes

Low-toxicity substitutes include either completely new mud systems, or replacement of individual mud treatment chemicals with low-toxicity alternatives. The low-toxicity substitutions have been used to solve the metal toxicity problem in drilling muds. Chromium lignosulfonate contains 2–4 % by weight of trivalent chromium. Because it is considered a heavy metal, chromium presents an environmental problem. Even though toxicity tests have usually not indicated an adverse effect caused by the presence of chromium in lignosulfonate, considerable effort has been made to reduce the chromium content or replace the chromium with another cation. Chromium lignosulfonates have been replaced with modified sulfonates of the less toxic metals, such as iron, manganese, calcium, potassium, titanium, and zirconium. Most of these substitutes have shown certain deficiencies in performance when compared with chromium-based thinners, particularly in the thermal gelation after hot oven rolling. One of these new products, based on titanium lignosulfonate, has been reported as not showing any increase in gel strength, yield point and plastic viscosity when the weighted freshwater muds are heat-aged [57]. Also, the reported field applications indicated that the viscosity control performance with this new thinner (measured by the treatment dosage, lb/bbl, required to maintain a low value of yield point) was equivalent to the conventional chromium lignosulfonate performance.

Spotting fluids used for freeing stuck drillstrings have been traditionally based on diesel or mineral oil and are notorious for adding toxicity to the mud systems. Starting in the late 1980s, suppliers and chemical companies began to develop spotting fluids formulated without diesel or mineral oil [58]. Effective low-toxicity, water-based spotting fluids are now available that, after freeing a pipe, can be incorporated into the water-based mud system without causing a significant change in the toxicity so that overboard discharges of mud and cuttings can be continued [59]. Other low-toxicity substitutes for miscellaneous drilling chemicals, such as biocides, lubricants, defoamers, and corrosion inhibitors, have also been developed recently.

A dramatic progress has been made in developing low-toxicity substitution for oil-base muds. The idea of replacing diesel OBM with mineral oil-based mud (MOBM) was initially derived from toxicity measurements made in the UK. These measurements showed that the toxicity of mineral oil is five times lower than that of diesel oil [4]. Other comparisons of mineral and diesel oil toxicities in sea-water emulsions showed mineral oil to be at least 14 times lower in toxicity [60]. The difference has been attributed to reduced content and different types of aromatic hydrocarbons in mineral oils. Aromatics are particularly toxic because of their rapid bioaccumulation rates. Toxic effects of monocyclic and polynuclear aromatics are dependent upon their water solubility [61]. Mononuclear and dinuclear aromatics are the most toxic. Other polynuclear aromatics (with higher molecular weight) contribute little to toxicity because their solubility in water is low. Because mineral oils do not contain volatile monocyclic aromatics, their main toxic component is dinuclear aromatics.

Currently available mineral oils with no aromatics may be almost non-toxic with the Mysid shrimp LC_{50} value over one million ppm. However, some presence of aromatics is necessary for stability of invert emulsions. Therefore, a toxicity trade-off is needed for the MOBM formulations. The reported toxicities of MOBM are different, as shown in Table 4.1. The LC_{50} value of 180,000 ppm does not compare well with the values of 22,500 and 4740 ppm reported for two freshwater muds having 2 % mineral oil with 0 % and 15 % aromatics, respectively. One explanation might be a different concentration of aromatics in the base mineral oils. Also, higher toxicities of MOBMs than their base mineral oils may result from the toxic nature of primary and secondary emulsifiers used in these muds.

2.3 Synthetic Base Drilling Fluids

A whole new class of non-toxic drilling fluids has been developed in the last two decades. These muds are formulated with a variety of synthetic organic base fluids. The resulting so-called synthetic-based mud possess most of the performance properties of oil-based muds but avoid most of the environmental problems of diesel and mineral oil muds [62–64]. (An environmentally-acceptable substitute for the mineral oil drilling fluids was first noticed with the use of a mud made from an ester in the Norwegian sector of the North Sea in 1990).

The chemistry of the synthetic-based fluids that are currently commercially available includes an ester derived from palm kernel oil, a diether, a foodgrade paraffin, and a Poly-Alpha-Olefin (PAO) [65]. The ether-based SBM was used offshore Norway in 1990. The first PAO mud was used in 1991. Other synthetic base fluids were introduced to the industry in the following order: Linear

Alkybenzene (LAB), acetal, Linear Alpha Olefins (LAO), Internal Olefins (IO), and linear Paraffins (LP) [66]. The chemistry of the components of the synthetic-based muds, other than the base fluid, is usually different from those in mineral-oil muds. These compounds may be found in petroleum and other sources, but they should not be called synthetic base fluids unless they are synthesized or manufactured. The use of feedstocks and strict control of the manufacturing process assure that SBM will not contain trace amounts of priority pollutants as even the purest highly refined and processed liquids do [67]. As synthetic fluids used for SBM are synthesized by the reaction of purified compounds, they are typically free of polycyclic aromatic hydrocarbons (PAHs).

The general definition of synthetic material requires production process be chemical synthesis. The compounds used SBM formulations must meet two ECT criteria for drilling fluids delineating the environmental and productivity performance. To be environmentally acceptable, they must meet local standards and regulations for the discharge of drill cuttings into the sea. (If the cuttings have to be collected and transported to land, then there is no advantage in using SBM rather than oil-base mud other than health and safety.) From the productivity standpoint, the synthetic material must be the base fluid for a stable mud systems with inhibitive properties of an invert emulsion oil-base mud.

Synthetic-based muds proved little or no toxic. Initially, as they passed the LC-50 Mysid toxicity test required for offshore discharges, cuttings from SBM systems were discharged on the interim basis within the context of water-base mud discharge limitations. Problems have been reported, however, in passing the US-based sheen test for these muds as they had been viewed by the regulators as another family of oil-based muds. At the time when SBM were introduced, regulations were developed only for water and oil-based muds and the testing and regulatory structure in place for these fluids did not fit with synthetics. To allow industry to continue discharging SBM cuttings, a new toxicity testing methods – specific to SBM – had to be developed.

Presently, the SBM cuttings discharge to sea is controlled by limiting concentration of synthetic fluid on cuttings to about 7 % (dependent upon the type of base fluid) by using advanced solids-control equipment with cuttings dryers (centrifuges) that could reduce the concentration to 3 % by weight. Regulators believe that reducing fluid content on cuttings also controls the amount of SBM discharged to ocean, enhances the biodegradation rate, and controls development of cuttings beds that damage the seafloor. In the US, in 2001, Environmental Protection Agency published final regulations that established technology-based effluent limitation guidelines and standards for controlled discharge of SBM cuttings anywhere offshore beyond 3 miles. The agency also revised general permit under the National Pollutant Discharge Elimination System allowing operators in the western Gulf of Mexico to discharge SBM cuttings under the new regulation specific for SBM. The permit requires toxicity testing and best management practices [68].

Biodegradation test discriminates the base fluids so they can be ranked for the use in SBM. The base fluid is the primary organic constituent that dominates biodegradation of mud system. The test has been adopted from an anaerobic test developed in the UK for sewage sludge [69]. The test runs for 275 days and costs about $2000. The regulatory stock limitations for SBM cuttings discharge specify that the base fluid's biodegradation ratio must be less than or equal to one. The ratio is computed by dividing the percent degradation of $C_{16-}C_{18}$ internal olefin reference fluid by the percent degradation of the stock fluid used in SBM.

The LC_{50} toxicity of SBM is different to the LC_{50} Mysid test for water-based muds performed on suspended particulate phase (SPP). It is a 10-day bentitic toxicity test using organisms from the specie of amphipods (Leptocheirus plumulosus) that lives in the sediments at the sea floor. (As SBM are water insoluble they bond to solids and settle quickly at the bottom of water column. Consequently, there is little of suspended particulate phase.) It has taken over 7 years for the industry to develop the test. The regulatory stock limitations for SBM cuttings specify that the base fluid's toxicity rate ratio must be less than or equal to unity. Again, the ratio is computed by dividing the value of the 10-day LC_{50} for the $C_{16-}C_{18}$ internal olefin reference fluid by the LC_{50} value of the stock fluid used in SBM [70].

The disadvantage of the synthetic-based muds is their high cost, typically several hundred dollars per barrel. However, this high cost is offset by cost reductions arising from the use of a high-performance, high-penetrationrate fluid and the ability to handle cuttings disposal on-site without special equipment. The main technical uncertainty associated with these fluids is the threat of lost circulation. Losses can be extremely expensive because lost fluid cannot be returned to the service company at the end of the well for credit, reconditioning and reuse [5].

2.4 Source Separation – Drill Cuttings Deoiling

The ECT method of pollution source separation – discussed in Chap. 3 – has been used to reduce oil-related toxicities of offshore drilling discharges. The most typical applications include removal of oil from drill cuttings and separation of diesel spots from water-based muds. Table 4.4 gives a summary of the maximum oil retention values for OBM cuttings using various separation techniques. Considerable controversy exists regarding the performance of centrifuges, with the lowest and highest values of oil retention being 3 % and 10.25 %, respectively (the typical reported values fall within the range 5–8 %). The best-performing separation technique, vacuum distillation, has been commercially applied in the oilfield. Three vacuum distillation plants for OBM cuttings have been reported as working efficiently in the North Sea [77].

Characteristically, most of the research and development work regarding OBM cuttings cleaning methods has been done in Europe for North Sea applications [72, 74, 78, 79]. In the past, European regulations specified the maximum oil content on OBM cuttings with different values for different types of oils: 3 % and 10 % in Norway and 5 % and 15 % in the UK for diesel oil and mineral oil, respectively. In the USA, however, the general permit regulations placed a ban on

Table 4.4 Separation techniques for oil removal from OBM cuttings[a]

Separation method		Oil retention (%w/w)
Shale shaker[b]		11.1–16.5
Mechanical cuttings washer[c]		9.4
Centrifuge[d]		3.0–10.25
Incinerator		0.0005–3
Solvent extraction		0.2
Vacuum distillation		0.01–0.05
	Diesel washed	3–5
Ultrasonic cleaning[e]	Unwashed mineral oil	8–15
	Screw type unit	1.0
Thermal desorption[f]	Hammermill	0.1
Liquefied gas extraction[g]		0.5–4.0

[a]After Ref. [71]
[b]After Ref. [61]
[c]After Ref. [72]
[d]After Ref. [73]
[e]After Ref. [74]
[f]After Ref. [75]
[g]After Ref. [76]

the overboard discharge of OBM cuttings, regardless of whether they came from diesel OBM or MOBMs, or SBM. The situation has changed with the development of SBM – once the regulators accepted these fluids as different to OBM as discussed above. Presently, in the Gulf of Mexico the discharge of cuttings with oil levels (measured as TPH) of either 6.9 % or 9.4 % by weight, depending on the synthetic oil selected, is allowed if the toxicity and biodegradation standards are met. These levels of oil on cuttings can be reached with centrifugal ‘cuttings dryers’.

As the regulations have become more stringent the technology for removal of oil from cuttings has changed. Presently in Europe and South America, the processed cuttings typically measure less than 1 % by weight of Total Petroleum Hydrocarbons (TPH) before disposal to in landfills. For offshore discharge of cuttings in the UK sector of the North Sea, an oil content of less than 1 % is also required. Generally, oil-based cuttings generated offshore in the North Sea have been taken to land for treatment and disposal because, until recently, no method for reducing the oil content to less than 1 % was available at offshore platforms. This situation has changed with development of thermal desorption technology for offshore locations.

Until recently, thermal desorption units were fixed facilities to which cuttings had to be transported. Now however, a unit has been successfully developed for use offshore [75, 76]. Use of desorption units offshore has required significant changes in the configuration and technology. Thermal process evaporates the oil and water from cuttings. The evaporation removes free oil and emulsified oil because the heat required for evaporation of the oil and water provides enough energy to remove and separate emulsified oil. However, removal of interstitial oil is more difficult as the

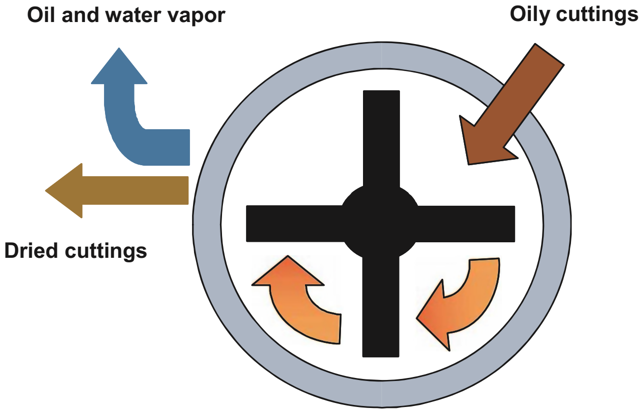


Fig. 4.4 Principles of Hammermill thermal desorption unit (See *color* plates)

oil is trapped in the rock interstices by molecular forces and surface tension. A higher level of heat is needed to overcome these forces, hence the removal of the last fraction of oil from cuttings – usually less than 1 % – requires additional energy.

Hammermill desorption units have been specifically developed for offshore work and approved by regulators for use in the North Sea [80]. Principle of its operation is shown in Fig. 4.4.

In the unit, a Hammermill grinder is used to pulverize the cuttings to a very fine powder comprising 60 % particles smaller than 50 μm. The grinding generates friction and heat in the process. Typical temperature of products produced in the unit is 460 °F (240–260 °C), but can be as high as 570 °F (300 °C). This temperature range is more than adequate to remove oil with water.

Vapors are drawn off with a slight vacuum and dust is removed in a cyclone. After the dust removal a two-stage condenser removes oil and water. The Hammermill unit is very compact and relatively light. It has been used offshore in the North Sea where the dried cuttings having TPH lesser than 0.1 %w/w are directly discharged to the sea. The low level of TPH indicates that the interstitial oil has been removed by reducing the particle size. Interstices are physically removed or destroyed as the rock particles fracture along their surfaces.

The technology of liquefied gas extraction of oil from cuttings has been developed as an alternative to thermal desorption [76]. The drawback of thermal desorption is the high energy consumption excessive frictional wear and associated cost. In addition, some base fluids for SBM may contain a high concentration of esters. The esters enhance drilling performance of SBM and impart properties of low toxicity and high biodegradation. However, they cannot be recovered thermally because their thermal stability is lower than that of other oils commonly used.

In principle, liquefied gas extraction is identical to supercritical carbon dioxide extraction. However, it employs as a solvent a hydrocarbon gas instead of carbon dioxide. Hydrocarbon gas can be liquefied at pressures much lower than carbon dioxide (40–100 psi). Presently, the technology is in the development stage; pilot scale testing showed that liquefied gas extraction can be used with SBM drilling fluids containing variety of base fluids and that low (below 1 %) retention on cuttings can be achieved. Also, high-cost synthetic oils, including the ester-base fluids not recoverable by thermal desorption, can all be recovered with very low consumption of energy.

The ECT concept of pollution source separation has been also used for handling discharges of water-base muds contaminated with toxic spotting fluids. After a stuck pipe has been freed, the spotting fluid is circulated out of the hole and – in principle – should be separated from the drilling fluid. A separation technique for diesel-based spotting fluids was pilot-tested in the USA under the 1 year diesel pill monitoring program (DPMP) [81]. The program allowed participating operators to use a diesel pill that had been separated from the remaining mud by 50 bbl buffers on each side. After the diesel spot had been used in the well, the pill and the buffers were separated from the mud and sent ashore for toxicity testing, while the remaining mud was allowed to be discharged overboard regardless of diesel content. The purpose of DPMP was to create a database to determine toxicity limitations for diesel oil.

The results of DPMP showed that only about 70 % of the spot was actually separated; the rest was incorporated into the drilling fluid. The remaining 30 % has been proven to increase the toxicity of the water-based mud to the extent that it cannot be discharged even if a mineral-oil spot has been used. DPMP generated data that disqualified this separation technique and resulted in the ban on dumping mud after using diesel-based spotting fluids. Although this separation technique may still work for mineral oil-based spots, operators frequently haul all of the mud and cuttings to the shore instead of taking the risk of non-compliance following use of mineral-based spotting fluids [3].

3 Control of Produced Water Volume

Recently, new technologies for subsurface management of produced water have been developed, as shown in Fig. 4.5. These technologies represent attempts either to eliminate surface production of formation waters through injection *in situ* (downhole water separation – water unloading, downhole water sink/injection – water drainage/injection), or to reduce the water inflow into the wellbore (water ‘shut-off’), or to eliminate hydrocarbon contamination of the water by segregating inflows of petroleum and water (downhole water sink/production – water drainage/ production).

Several of these technologies improve the deliverability of petroleum wells and have been primarily developed as productivity measures having some environmental merit. For example, horizontal well completions are used for combating water coning problems in thin petroleum strata underlaid by strong aquifers. The environmental implication of this technology is that produced water to be disposed of is reduced. This implication has never been a main reason for the development of

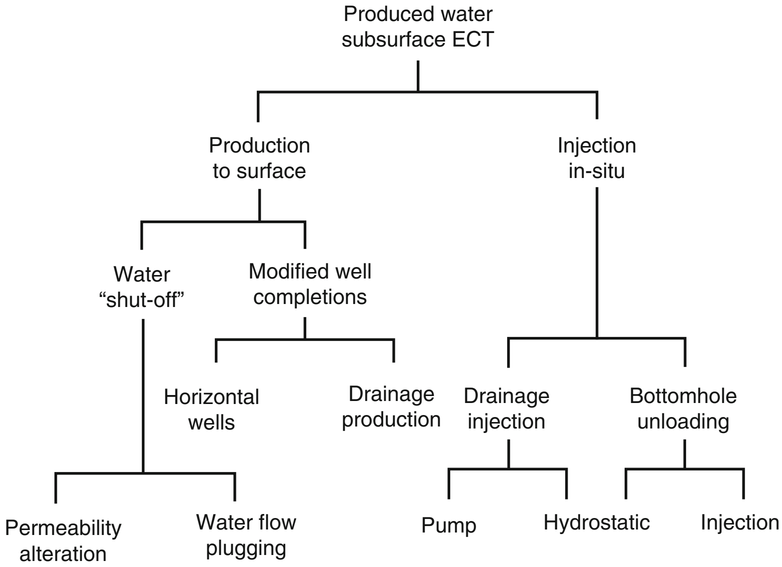


Fig. 4.5 Subsurface environment-control technologies for produced water

horizontal drilling. On the other hand, the technology of *in situ* injection of formation water has been solely developed for environmental reasons, but it also enhances well productivity by eliminating water coning (water sink). Thus, in the ECT terminology discussed in Chap. 3, each of these technologies shows both the upstream (productivity) and downstream (environmental) performances to some degree.

3.1 Source Reduction – Water Shut-Off Technology

Methods of water shut-off include techniques based on alteration of permeabilities or rock plugging. Alteration of relative permeability involves injection of a low-concentration polymer into the pay zone producing oil and water to create a selective near-well barrier with reduced permeability to water and unchanged permeability to oil. The selective effect has been evidenced in laboratory experiments with sandpacks [82] and rock cores [83, 84], as well as in field tests [85, 86]. The physical mechanism of this method is not very well known. Most researchers agree that the water permeability reduction is attributed to surface adsorption of the polymer and that the effect works only in small size pores. The effect is based on either selectively plugging the water-flowing pores [85] or, according to the other theory, altering the flow pattern in the two-phase flowing pores so that the annular flow of water is hindered while the central core flow of oil remains essentially unaffected [83].

The method of rock plugging is used to reduce brine flow when water and hydrocarbon flowpaths are clearly separated. This method requires selective placement of a reversible barrier into the water flowpath by injecting a gel slug. When the water flowpath consists of a system of high-conductivity fractures producing mostly water, the effect on oil production is small while the water flow is greatly reduced.

Three basic mechanisms of *in situ* gelation of the injected slug are polymer crosslinking, reversible gelation and sol stabilization. Crosslinking is accomplished with inorganic multivalent salts such as magnesium chloride, aluminum sulfate, aluminum nitrate, or aluminum citrate [87]. These salts attract reactive sites on anionic polymer molecules so that they become larger and more rigid. At present, polyacrylamides crosslinked with solutions of inorganic Cr^{3+} are the most widely used gels. Their advantage stems from the ability to control the gelation time by selecting process parameters such as polymer and metal ion concentrations [88]. Also, crosslinking cationic polyacrylamide with organic crosslinking agents has recently been reported [86].

The biopolymer used in the reversible gelation process has the ability to change from the solution to the gel state by reducing the pH. This process has been proven to be reversible through an increase in pH. The proposed field procedure for this method, based upon laboratory tests [89], involves placing a biopolymer slug in the water zone and then displacing it with a solution of hydrochloric acid, which would create a barrier. To remove the barrier, an injection of sodium hydroxide would reverse the process and restore the initial permeability of the barrier zone.

The most environmentally attractive mechanisms of formation plugging, sol stabilization, is based on the gelling properties of colloidal silica suspensions. These suspensions are stable in fresh water, and their stability is sensitive to changes in pH and salinity. When destabilized, the suspensions form an impermeable gel structure. The time of destabilization and gelation can be controlled by pH and salinity changes. The field procedure involves pre-flushing the treated zone with fresh water to displace the *in situ* brine, followed by controlled on-line mixing and injection of the freshwater suspension of silica gel with a controlled volume of NaCl brine. The process has been field-tested with varying success and is considered a new alternative to polymer treatments [90].

A typical field example of successful gel treatments is shown in Table 4.5. Although the method reportedly works in the field, an actual outcome of the treatment is difficult to predict in the laboratory. Recent analysis of 57 field treatments with polymers and colloidal dispersion gels in water flood projects showed that 89 % of these treatments were successful, despite laboratory predictions of a maximum 58 % success rate [91]. The laboratory assessment of crosslinked gels' ability to build structure and resist shear rates in reservoir conditions was concluded to be inadequate, primarily owing to uncertainties regarding downhole flow variables. Another treatment design problem arises because the mechanism that triggers the disproportionate reduction in water permeability compared with oil permeability is poorly understood. Recent studies of this mechanism have suggested that segregation of oil and water pathways throughout a porous medium, which results in selective plugging of water flowing pores, may be a

Table 4.5 Example field performance of water 'shut-off'[a]

		Oil production rate (bbl/day)		Water production rate (bbl/day)	
Well no.	Area	Before treatment	After treatment	Before treatment	After treatment
1	Kansas	6	23	634	183
10	Kansas	7	10	384	96
4	Louisiana	33	12	440	0
7	Offshore Louisiana	30	30	720	370

[a]After Ref. [86]

dominant effect of gel treatment [92]. The conclusion was based on observations that the water-based gel reduced water permeability more than oil permeability, whereas the oil-based gel reduced oil permeability more than water permeability.

3.2 *Source Separation–Downhole Oil/Gas/Water Separation*

As shown in Fig. 4.6, the techniques for bottomhole unloading and re-injection of water fall within the scope of technologies for *in situ* disposal of formation brines that eliminate water production to the surface. The technique is also called downhole oil/gas water separation (DHOWS or DHGWS) as it involves moving the separation equipment from the surface to the bottom of the well. Moreover, the downhole – separated brine is disposed of by injection to the bottom (tail) section of the same well. DHOWS can be accomplished either by using a gravity segregation mechanism for gas wells or by adding a liquid– liquid separator to the downhole completion installation for oil wells. Downhole brine disposal involves either hydrostatic drainage to a low-pressure disposal zone or *in situ* injection using a downhole pump and isolating packer.

Because of spontaneous and rapid separation of gas and water, these techniques were first used in producing natural gas, which requires unloading excessive water. For example, dewatering coalbed methane gas formations has been successfully applied in field operations to stimulate gas production. The Fruitland coal gas wells in the San Juan Basin in southwestern Colorado require artificial lift for dewatering. Most Fruitland wells produce 150–250 Mcf/day of gas, with flow rates improving gradually as dewatering continues. Dewatering is performed in this area using conventional plunger pumps that produce water concurrently with gas production. Similarly to the San Juan Basin, removing water from the Antrim shale gas reservoir in northern Michigan is necessary for efficient gas production in the area. Conventionally, the wells require continual dewatering to reduce the head of water. Therefore, several operators installed submersible pumps as a means of lowering the flowing pressure of the bottomhole water. In this application, water is pumped up through the tubing, and gas is produced from the annulus.

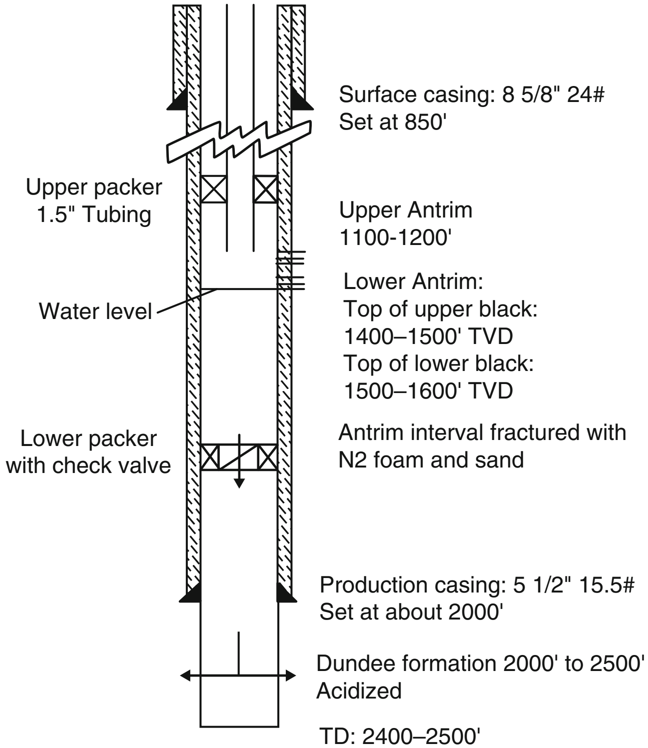


Fig. 4.6 Schematic of 'waterless' completion in Antrim shales (1″ = 2.54 cm; 1′ = 0.3048 m) [93]

Although the concurrent water removal from the San Juan Basin coal seams and Antrim shales increases gas production rates, water pumping consumes energy, and the problem of brine disposal arises. In the Antrim shale wells a recent solution to this problem has been the waterless completion technique that employs downhole dumping of produced water to the Dundee limestone located about 1000 ft below the Antrim shale formations [93]. The completion is shown in Fig. 4.6. In this technique, the same well is used as both a production and disposal well. Its upper part, at about the gas–water contact (GWC), produces gas; the bottom part provides a conduit for the Antrim water downwards to the low-pressure Dundee limestone. Since the water drainage is hydrostatic due only to the formation pressure difference between Antrim and Dundee, the water removal rate is limited and cannot be controlled. Despite this problem, the waterless completion has been successfully field tested and approved by both the US Environmental Protection Agency (EPA) and the Michigan Department of Natural Resources as a waste injection method [94, 95].

Another technique of downhole water disposal using hydrostatic drainage is to build a hydrostatic head of water inside the well to overcome the injection pressure of the disposal zone [96]. In this technique, the well is dually completed both in the gas reservoir and the deeper disposal zone. These two completions are separated by a packer. A mixed gas–water stream enters the well through the upper completion, where gravity separation takes place above the packer. The accumulated water is then picked up by a downhole pump and lifted inside the string of tubing, while the gas is produced to the surface through the tubing–casing annulus. When the hydrostatic head of water in the tubing exceeds the pressure in the disposal zone, the water flows down the tubing, bypassed the pump (through the seating nipple bypass valve) to the well section below the packer, moves to the bottom completion and then goes to the disposal zone. Because the underground injection is entirely controlled by the hydrostatic head of brine, this method can only be used in a specific geological area. Also, the disposal zone's pore pressure gradient must be substantially lower than its normal value. In addition, the permeability must be high enough to assure the minimum required injectivity index so that the water injection rate will match its inflow rate. In pilot tests conducted in southwestern Kansas and the Oklahoma panhandle, the required injection rates were from 50 to 300 bbl/day per well, with average inflow rates of 134 bbl/day of water and 105,000 scf/day of natural gas per well. One of the two reported failures of this method (out of the seven total wells tested) was attributed to the low injectivity of the disposal zone.

Development studies using mechanical downhole separators for oil and water have been reported in Canada and Norway [97, 98]. A downhole separation system developed in Canada is shown in Fig. 4.7. The system uses a dual-stream pump/hydrocyclone system to separate mechanically the produced water and oil. The bulk of the water is separated downhole (near the production zone) and re-injected into a disposal zone, while the oil-rich stream is pumped to the surface. The system includes a liquid–liquid hydrocyclone unit from Vortoil Separation Systems and standard artificial lift equipment modified to operate with the downhole separator. Systems have been tested in two separate field trials, the first with a Reda dual-stream electric submersible pump in a light crude application and the second with a progressive cavity pump in medium crude. In both cases, water production was reduced by 80–90 % with no detrimental impact on oil production.

A prototype downhole separation system (DHS) developed in Norway has not yet been field tested [98]. The system is run on production tubing and temporarily connected with a polished bore receptacle to the permanent lower section of the tubing installed inside a 7 in. liner string. The liner string goes all the way down through the oil reservoir, into the water disposal zone and is perforated in the oil zone. A packer at the top of the liner holds the lower tubing, while the second packer below the oil zone isolates the oil from the disposal zone below. A mixture of oil and water can enter the liner–tubing annulus and flow upwards, across and above the dual-bore top packer. Then, the mixture is segregated and oil is produced to the surface through the upper section of production tubing, while the separated water is pumped with the electrical submersible pump down the lower tubing and into the disposal zone. The DHS separation system consists of an integrated string with a bulk hydrocyclone, a dewatering hydrocyclone and a produced water hydrocyclone in series. This arrangement enables the oil to be dewatered down to

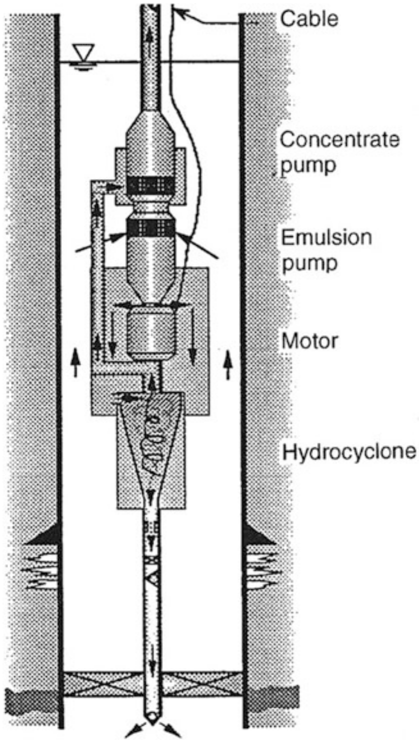


Fig. 4.7 Downhole separation– disposal system [97]

1 % bottom sediment and water (BS&W) and the produced water to be deoiled down to 40 ppm.

3.3 Source Separation with Downhole Water Sink (DWS)

The source separation technique of downhole water sink (DWS) employs a modified dual completion of an oil well such that the inflows of oil and water into the well are produced selectively *in-situ*. The oil is drained from the oil "pay zone" above the oil-water contact (OWC) while the water is drained from the aquifer below OWC. The concept draws on a hydrodynamic theory of water coning control and it employs dual well completion and segregated inflows of oil and water into the well [99–107].

Pirson and Mehta [108] discovered that selective production of water and hydrocarbons from their respective zones might reduce water cone growth. Widmyer [109] patented a well completion principle with separated production of oil and water in order to control coning. It was proposed to perforate both the top and bottom completion in the oil zone. Driscoll [110] suggested the possibility of having more than two perforated intervals and placing the bottom one below the initial water-petroleum contact. The well is then produced as a single completion with the fluids commingled in the well bore. For "non-ideal conditions," Driscoll proposed to use a packer and adjustable flow choke to adjust pressure drops and flow rates of petroleum and water. Fisher et al. [111], using a numerical simulator, concluded that dual completions could reduce the effect of coning and in some cases eliminate them entirely. Castaneda [112] checked the applicability of this idea for heavy oil reservoirs. In 1991, Wojtanowicz et al. [99] - using numerical model and field data – evaluated well performance for coning control using dual completion with "tailpipe water sink" – later dubbed: Downhole Water Sink (DWS). They concluded that the tailpipe sink would control water coning and produce more oil with less water than conventional wells.

Theoretical simulation studies of in situ water drainage revealed that, for each completion, a unique relationship exists between the oil production and water drainage rates, a performance window [104]. The window envelops the area of all possible combinations of oil and water rates that would provide stable operation of the drainage system. The window can be developed theoretically using data regarding reservoir and fluid properties in addition to well completion design. Also, the window can provide input for the economic analysis of the production project at hand.

The DWS mechanism is based upon a local hydraulic drainage generated by a controlled downhole water sink installed in the aquifer beneath the oil or gas-water contact. Figure 4.8 depicts the principle of the DWS system. In the system, a well is dual – completed in the oil and water zones and the two completions are separated by a packer set inside the well at depth of the oil-water contact. The water sink (bottom) completion comprises a submersible pump and the water drainage perforations. The submersible pump drains the formation water around the well and controls the water cone growth and it's breaking through the oil column into the oil-producing (top) completion. The fluids produced by the top completion are either free of water or have small water content – subject of the drainage rate adjustments. In the result, the well's productivity potential can be fully utilized to maximize oil production.

Quality of the produced formation water is superior to conventional produced water because of no (or very small) oil contamination. The water is lifted to the surface for disposal or beneficial use – if applicable. The system applies to the offshore oil wells operating in the "clean water" range such that the drained water is free of oil and could be readily discharged overboard.

A considerable number of R&D studies have been done to understand and evaluate DWS performance and its potential for different application. The work included mathematical models, physical experiments, numerical simulation of hypothetical and actual field reservoirs, and field projects with rigorous DWS design. The feasibility studies also addressed different well categories such as vertical oil wells, oil wells with gas lift, horizontal oil wells, and gas wells.

Productivity and environmental performance of DWS in vertical oil wells was evaluated using analytical, numerical, and physical models [44, 113, 114]. Physical and numerical models revealed that DWS could dramatically accelerate oil

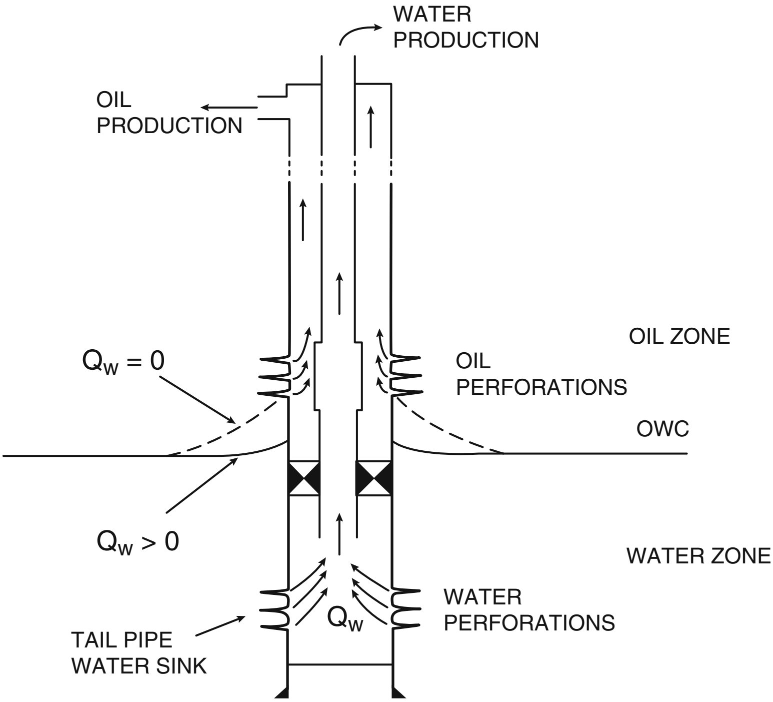


Fig. 4.8 DWS well installation

production rate and increase oil recovery [113]. In numerical simulations, a fivefold increase of the oil production rate resulted from increasing the drainage rate at the bottom completion without changing the rate at the top completion. Also, a 70-percent, and 30-percent increase of oil recovery was observed with the physical, and numerical models respectively.

Demonstrated in these studies was also the physical mechanism of oil rate enhancement with DWS by controlling water cut (WC). In conventional wells, water cut is persistent and irreversible resulting in hard-to-separate mixture of oil in water. In contrast, DWS installation provides flexibility and potential to reduce water cut in the produced fluid stream so more oil could flow in the tubing. Moreover, it was shown that although DWS could reduce or eliminate water-cut at the top completion it cannot reduce the total (top and bottom completion) water cut that includes the volume of drained water. However, most of the produced water would be free of oil contamination as had been also demonstrated in the field test [106, 107].

The field test of DWS in an oil well was conducted by Hunt Petroleum Co. in the Nebo Hemphill Field in Louisiana, USA [106, 107]. The pay zone is clean sand located at 2500 ft with permeability between 1 and 4 Darcy. The reservoir has a very strong water drive at the oil-water contact from the bottom water column making up 10–90 % of the reservoir height throughout the field.

Table 4.6 DWS well water contamination vs. conventional well [107]

Parameter	Unit	Detection limit(DL)	Drainage water[a]	System water[b]
Total dissolved solids	mg/l	1.0	63,300	69,100
Oil and grease	mg/l	2.0	<DL	484
Benzene	mg/l	1.0	<DL	<DL
Ethyl benzene	mg/l	1.0	<DL	<DL
Toluene	mg/l	1.0	<DL	<DL
Xylene	mg/l	1.0	<DL	<DL

[a]Average of two measurements
[b]Endpoint system water

Initial oil production rate of the well completed with DWS was 30 % higher than a typical well in the field. After 17 months of production, the well was making 57 B. P. comparing to 12–16 B.P. from conventional wells in this field. The top completion's water cut after 2 years of production was 0.1 % compared with 92 % for a typical well. However DWS well's bottom completion was draining 1900 B.P. so the total WC was 97 % – pretty close to the WC value in the conventionally-completed wells in the same field.

Oil contamination of the produced (drainage) water from DWS well was analysed and compared to the produced (system) water from conventional commingled completions in the same reservoir. Initially, the comparison was based on measurements of Total Dissolved solids (TDS), Oil and Grease (O&G), and BTEX concentrations. TDS was used as a marker to ensure that the produced waters are from the same aquifer, as shown in Table 4.6 (Method ASTM 160.1).

The analysis of Table 4.6 shows no detectable O&G contamination of drainage water (below 2 mg/l). From the regulatory standpoint, this water would not require any clean-up for contamination with hydrocarbons before discharge or reuse. The reason for adding BTEX measurements was that these volatile toxicants were considered most likely to be present in the water column due to their high solubility and diffusion mechanism. However, there is a lack of BTEX contamination in both the drainage and system waters. (Note that the system water undergoes gravity separation in an $8' \times 10'$ free water knockout followed by a 750 bbl. settling tank). The small concentration of volatiles may be attributed to the settling time of this heavy crude (21 API gravity), but no conclusion can be made without more analytical data for this oil. Clearly BTEX is not a component differentiating drainage water from system water in this application.

Additional analysis was made to compare concentrations of polyaromatic hydrocarbons (PAH) – the most toxic components of oil pollution in water. Shown in Table 4.7 is the result of a high performance liquid chromatographic analysis of PAH in the drainage and system waters.

The results clearly show that the drainage water is very clean relative to the conventionally produced water samples. Only 12 out of the total 55 tested PAHs were above the detection level of 0.005 parts per billion. Also, only a few of the most soluble aromatics such as naphthalene and a few of its alkylated analogues

Table 4.7 DWS well water PAH contamination vs. conventional well [107]

Component	Unit	DWS well	Conventional well	
			Mid-point[a]	End-point[b]
Naphthalene	ppb	11.32	536.61	450.38
Phenanthrene	ppb	ND	34.74	26.35
Fluorine	ppb	ND	6.66	6.11
Dibenzothiophene	ppb	ND	12.70	9.54
Anthracene	ppb	ND	0.17	ND
Pyrenees	ppb	ND	0.25	0.23
Other PAH	ppb	ND	1.48	0.33
Total PAH	ppb	11.32	592.61	492.94

[a]Effluent from free water knockout
[b]Endpoint system water

were detected and these were found at very low levels. The total portion of aromatics in the DWS well water was approximately 11 parts per billion – almost 50-fold less than the conventional well water samples.

The DWS technique has been also assessed for use in horizontal wells. These wells have been used for developing reservoirs with severe coning problems as they could maximize oil rate due their long penetration and minimize water inflow due small pressure drawdown. Several field reports, however, indicate that horizontal wells are also not free from the problem of water coning. In some reports, water breakthrough into horizontal wells could be quite dramatic and tend to erode the merit of high deliverability [115].

Evaluation of two possible DWS configurations in horizontal wells has been done using numerical simulator models [115]. The study evaluated two innovative concepts of "smart" completions for controlling water cresting in horizontal wells: "tail pipe water sink" (TWS), and "bi-lateral water sink" (BWS) – Figs. 4.9 and 4.10. TWS comprises a vertical well extension into the water zone and an upper horizontal section targeted at the top of the oil pay. BWS includes two horizontal parallel wells drilled laterally on top of each other with the upper section targeted at the top of the oil zone and the lower section targeted a few feet below the original oil-water contact.

As it is shown in Table 4.8, the BWS variant outperforms the TWS variant by increasing oil recovery [115]. It was also found out that the water sink (bottom) leg could be much shorter than the production (top) leg of the bilateral well. A horizontal section in the water zone equal to one third of the horizontal section in the oil zone was adequate to control water-cresting with BWS.

Using DWS in wells with gas lift requires a dual gas-lift installation – one for the oil and another one for water. Such an installation was studied using a two-tier nodal analysis, and a numerical simulator model [116]. The study was done using data from actual wells in Venezuela. The results indicate that it is possible to use dual gas lift combined with DWS. Performance of DWS, however, would be controlled by the gas lift design since the water-lifting rate limits the oil inflow

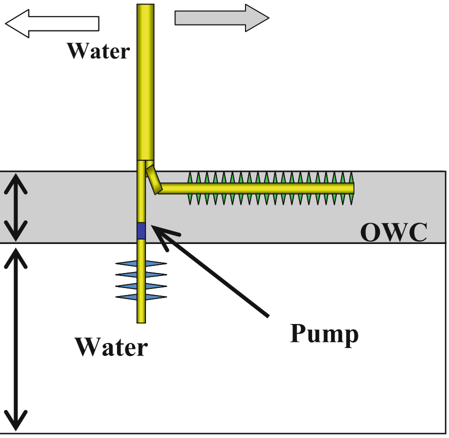


Fig. 4.9 Tail pipe water sink (TWS)

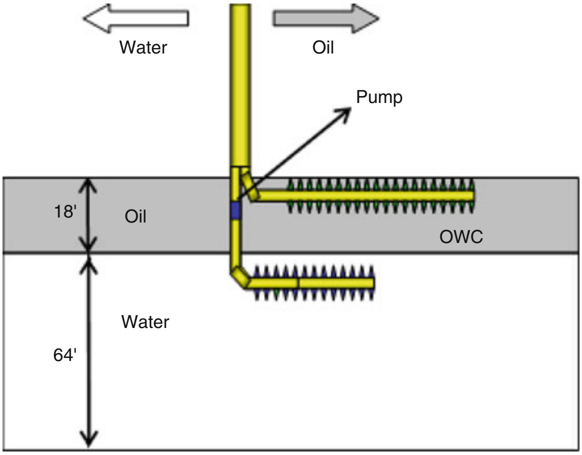


Fig. 4.10 Bi-lateral water sink (BWS)

Table 4.8 Oil recovery study in horizontal wells using TWS and BWS techniques

Well completion type	Cumulative oil production (stb)	Recovery factor (RF)	Percent increase (%)
Conventional horizontal well	2,762,463	0.799	0
Horizontal well with Tail-pipe DWS (TWS)	2,917,122	0.844	4.5
Horizontal well with bi-lateral DWS (BWS)	3,013,089	0.872	7.3

rates. Other factors controlling DWS performance included well geometry, gas injection rate, and injection gas pressure. Figure 4.11 depicts a conceptual design of DWS with dual gas lift.

A field trial using DWS with dual gas lift well was performed in a depleted oil field in the coastal region of South Louisiana, USA. The pay zone is homogeneous

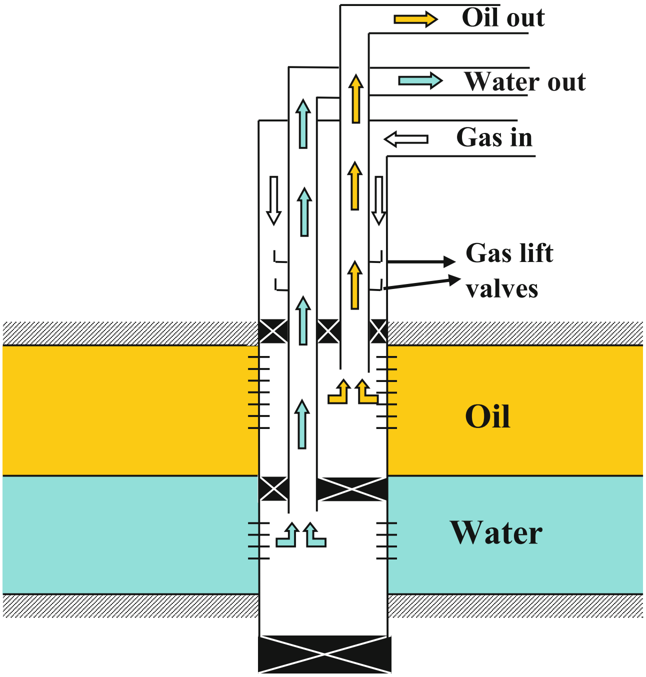


Fig. 4.11 DWS well with dual gas lift [116]

sand located at 7339 ft. The pay zone is about 18-ft thick with an underlying 88 ft of the water column. Permeability of the zone is 573 mD. Top and bottom completion are located at 7339-ft and 7357-ft, respectively. After the DWS installation, the well produced 20-percent more oil than a typical well in the field.

The DWS technology is also applicable in wells producing a gas-bearing formation with bottom aquifer. Gas wells are more sensitive to water inflow than oil wells because small inflow may cause liquid loading and kill the well [117]. Conventional techniques for water un-loading enhance water removal mechanism inside the well either by increasing tubing lifting performance (chemical injection, concentric pipes, thermal, gas lift) or by directly removing water from the well's bottom (pumps, plungers, and Downhole Gas Water Separation – DGWS). All these techniques do nothing to prevent gas-inflow reduction due to water inflow. They merely improve tubing performance relationship (TPR) without tackling inflow performance relationship (IPR). On the other hand, DWS technique increases tubing performance, while controlling water inflow to the well.

A DWS completion design suitable for gas wells is shown in Fig. 4.12. In the design, the top completion is used only for gas production, and the bottom completion for water drainage, inverse gas coning, gravity separation and water injection.

Feasibility study of DWS for gas wells was performed using reservoir simulator models [118]. The study qualified the use of DWS in gas reservoirs by comparing

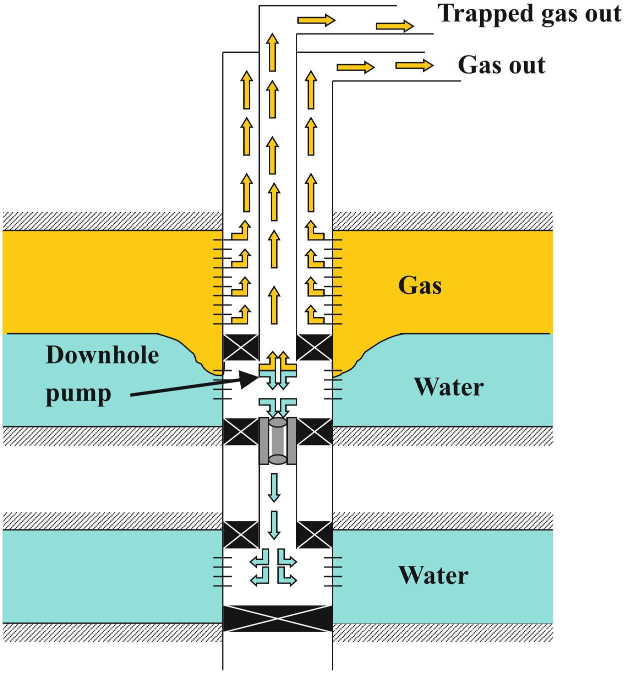


Fig. 4.12 DWS installation for gas wells [118]

simulated performance of the conventional, and DWS wells over a broad range of the initial reservoir pressure and permeability values for a gas reservoir with large associated aquifer. The results revealed a considerable advantage of DWS completion over conventional wells in the low-pressure (subnormal) and tight (1 mD) reservoirs. In such reservoirs, there was a 2.6-fold increase in gas before well loaded with water and died. However, in reservoir with normal pore pressure gradient and permeability above 10 mD the incremental recovery with DWS would reduce to 10 %.

In addition to oil reservoirs with bottom water coning problem, DWS has been also studied for application in the side-water systems with the problem of unrecovered oil under-run by water tongues [119–121]. As shown in Fig. 4.13, the water tongue commonly conforms to strike far from the well, and then forms a salient (or areal tongue) as it approaches the well; finally, a water cone may form atop the tongue reaching the well and leaving unrecovered oil behind. DWS would prevent the water cone from reaching the well and, therefore, enable recovery of the by-passed oil.

Incremental oil recovery with DWS in a side water system was assessed theoretically for a well located in a mature oil reservoir (KE-KF) in Louisiana, USA [120, 121]. Reservoir simulator model was used in this work. The dipping reservoir has been water-flooded and the well has had a long history of severe water problem resulting on well shut-in when water cut was 90-percent. The results revealed a

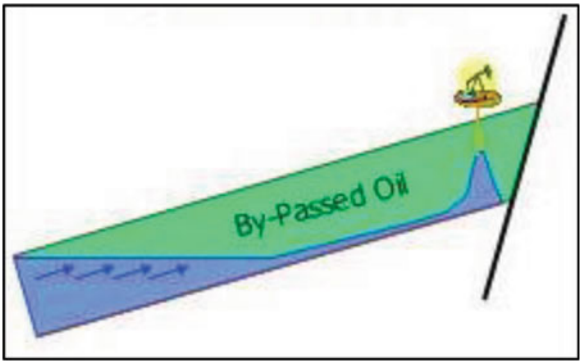


Fig. 4.13 Bypassed oil due side water under-running and coning [121]

twofold increase in oil recovery when DWS is in place comparing to the case without using DWS.

3.4 Source Reduction with DWS – Drainage Disposal

As shown in Fig. 4.14, the DWS technique of coning control can be coupled with downhole injection of the drained water in the same well into a deeper disposal zone. Ideally, the disposal zone should be isolated from the drainage zone by an impermeable stratum. Alternatively, when no outside isolating stratum exists between the disposal and drainage zones, the water will be drained from and pumped into the same aquifer, thus constituting a D*ownhole Water Loop (DWL)*. The DWS drainage-disposal technology has not yet been used in petroleum wells. In gas wells, applications of this technology are often mistaken for DHGWS techniques. However, the difference between the two is that DHGWS does not control water coning, whereas the DWS drainage-disposal technique does.

For oil wells, the feasibility and design of DWS drainage-disposal systems were theoretically investigated in the simulation studies [122–124]. Also, downhole installation for drainage injection was tested in the field [125]. In the field test, the pumping system was installed in an existing water flood well with one packer placed above the water drainage perforations and a second packer placed between these perforations and the injection perforations below (see Fig. 4.15). During the test, a sucker rod-driven, progressive cavity pump drained formation water from the upper water supply zone and pumped it into the injection perforations. The injection rate, measured with a downhole recording flow meter, was from 130 to 180 bbl/day at the differential pressure between the pump suction and discharge of 175 psi. The test proved that the drainage-disposal system was functional. Also, the study resolved engineering problems regarding packing-off the system components inside the production casing and installing pressure gauges and a flow meter downhole. However, the test provided no information on annular isolation of the

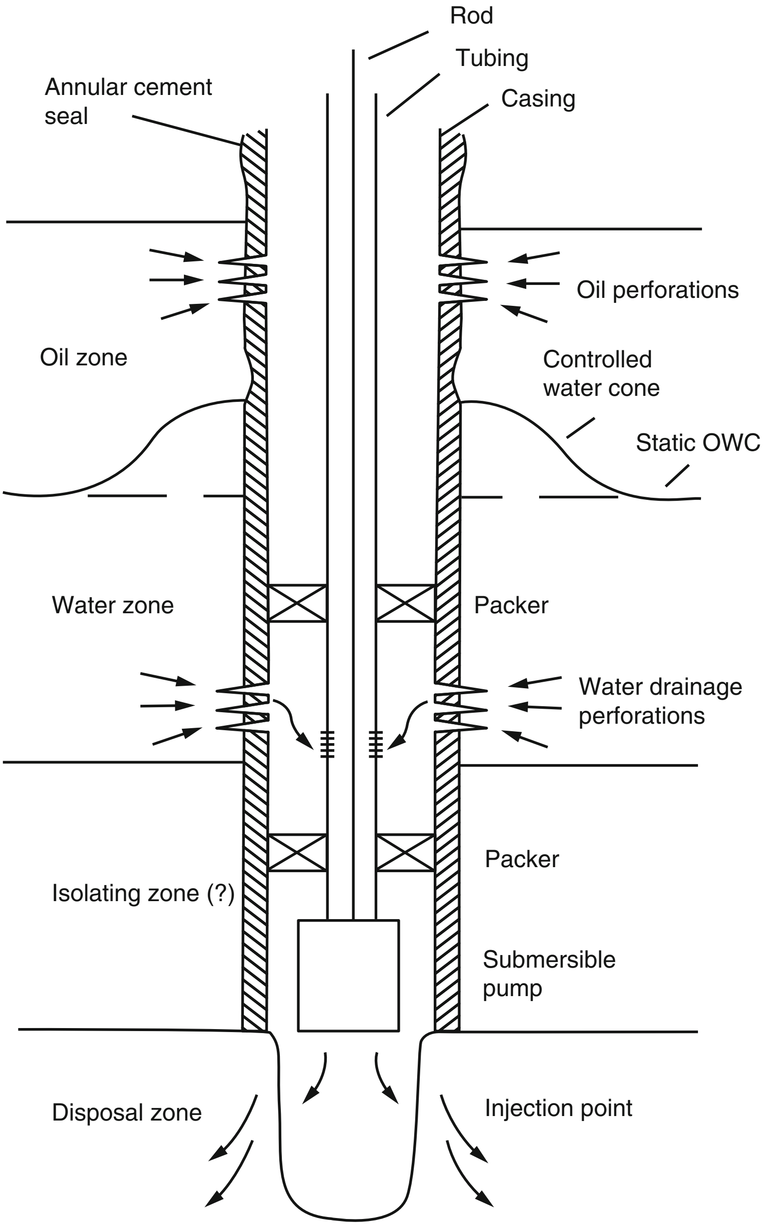


Fig. 4.14 Downhole water drainage-disposal system [122]

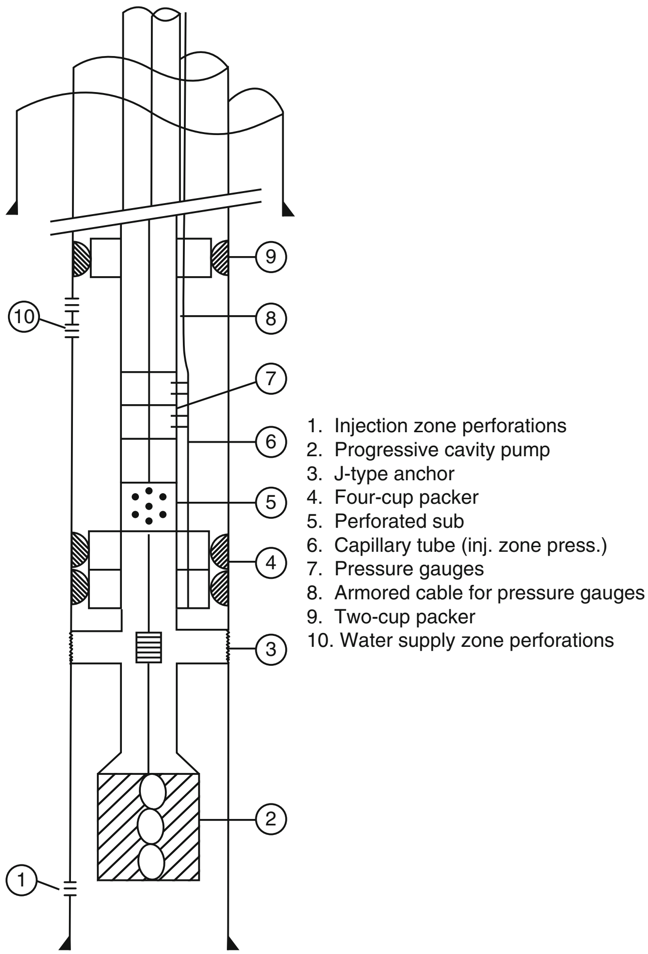


Fig. 4.15 Field-tested downhole water loop [125]

drainage and injection zones because its objectives were limited to the installation and operation of the downhole tools inside the casing.

A single potential problem in using DWS drainage-disposal systems is hydraulic isolation of the system components. This problem is likely to be commonplace in practical applications and may be caused either by geological conditions or by installation failures. For example, the configuration of geological strata below the pay zone may lack an isolating zone between the aquifer and the water disposal strata. Also, some degree of leaking across the well's annular seal may develop as a result of the well completion operations. Therefore, actual field systems are likely to operate under conditions of partial hydraulic communication between their components.

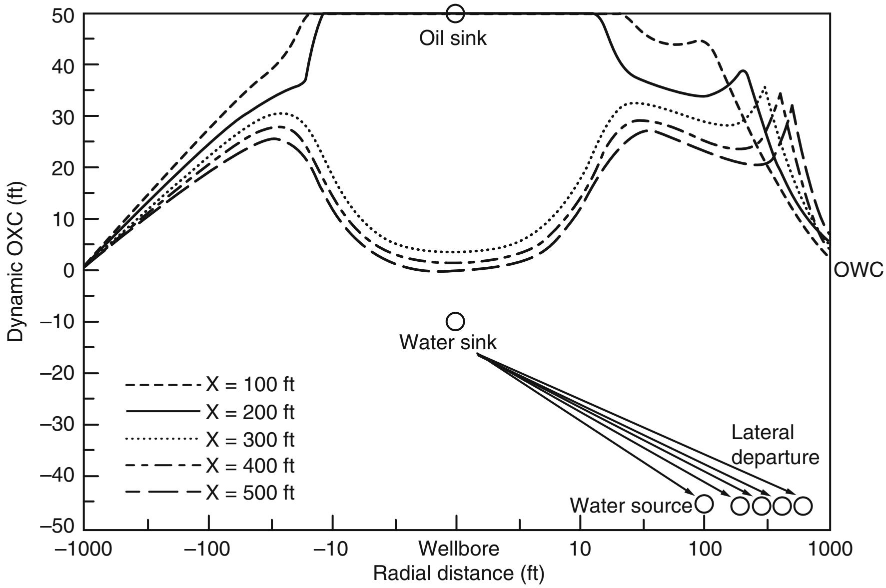


Fig. 4.16 Dynamic oil–water contact (OWC) profiles for water drainage-disposal systems with deviated rat holes [123, 124]

An analytical tool and computer program were developed and used to model dual well completions (DWS) with downhole injection in a multi-layered reservoir with crossflows and annular leaks [123, 124]. The analytical tool generates dynamic profiles of oil–water/gas–water contacts for a given geology, completions fluids and production/drainage injection rates. An example of a dynamic oil–water contact for a well with a deviated disposal section is shown in Fig. 4.16. It shows the effect of lateral departure of the disposal completions (x) on water coning reversal. It is clear that the lateral departure of 300 ft is sufficient for reversing the cone. In fact, it has also been proved that the disposal section does not have to be placed in a deviated section of the well – just in the lower section of the same vertical well [123]. For injecting the water into the same aquifer (downhole water loop), the only requirement is to drill an adequate vertical rat hole and complete disposal section deep enough so injection completion will have no effect upon the water cone.

The DWS drainage-injection systems have also been proven to be effectively operated with a leaking annulus outside the well.

When an annular leak develops around a well completed in isolated water zones, the amount of leaking water becomes proportional to the total water pumping rate. Therefore, a reduction in the system's performance caused by a leak depends only on the leak's conductivity. The reduced performance can be estimated using the predicted rate of leakage and the performance window plot. Thus, the performance window without the leak can be modified and used to predict the reduced performance with the leak.

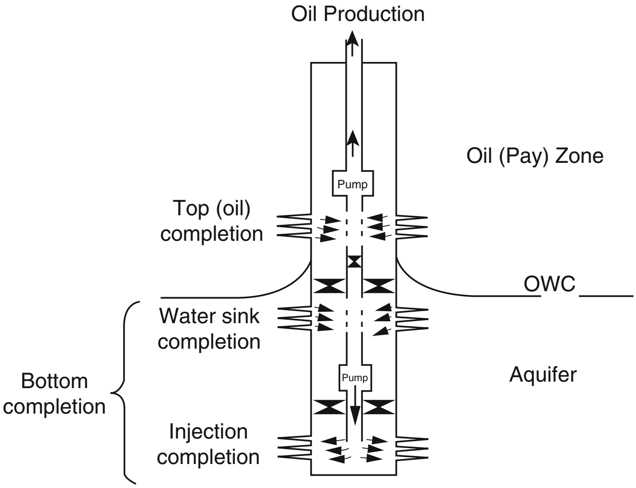


Fig. 4.17 Downhole water loop (DWL) Well completion

3.5 Source Reduction with Downhole Water Loop, DWL

The source reduction technique of DWS well completion with downhole water loop (DWL) involves re-injection if the water sink completion's drainage water back to the same aquifer. The technique solves two problems of DWS Drainage-Disposal method, discussed above: (1) depletion of weak aquifer by draining large volumes of water; and, (2) lack of suitable disposal formation below the aquifer in the same well without lifting the water to surface. DWL installation, shown in Fig. 4.17, includes three completions: the top (oil) completion, the middle completion for water drainage, and the bottom completion for water injection.

DWL well is triple – completed in the oil and water zones and the completions are separated by two packers set inside the well at the oil-water contact and inside the aquifer. The oil and water drainage completions are equipped with two submersible pumps. The upper submersible pump lifts the oil to the surface while the lower pump drains the formation water around the well to control water coning and injects the water deeper into the same aquifer.

Despite mechanical complexity of the triple well completion, there are two limitations of the DWL system: the drained-and-injected water must be free from oil and the pressure interference between the two water completions must be minimized. The second limitation requires designing the D/I spacing – vertical distance between the drainage and injection completions to eliminate their pressure interference.

The D/I design has been derived from the flow potential theory and expressions for the streamlines and iso-potential lines for a number of cases of 2D fluid flow in the DWL well system as showed in Fig. 4.18.

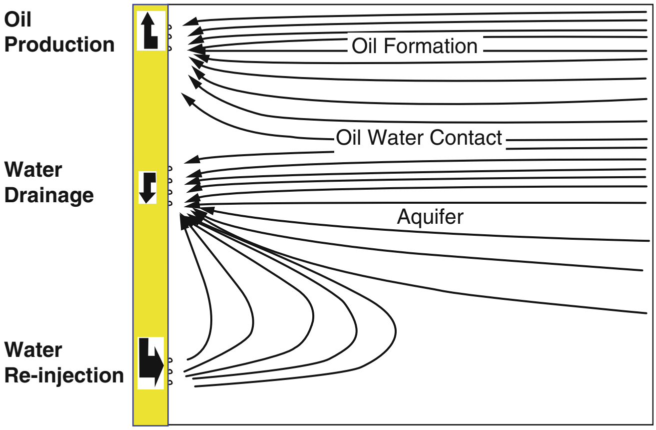


Fig. 4.18 Flow streamlines around DWL well

In principle, D/I must place the injection point at large enough distance from water drainage point where pressure gradient is small. Thus, re-injecting the drained water to the same aquifer at a vertical distance from the drainage completion would reduce hydraulic communication between the two completions while maintaining pressure (water drive energy) in the aquifer. The known benefit of water replacement for aquifer pressure maintenance has been recently related to improved recovery factor [126–130].

Re-injection of oil-free water is another very important condition for DWL. If the drainage-injection water contains some oil, not only the aquifer will be polluted, but also the injection completion will be damaged. (Even small oil content in injection water would deposit residual oil-saturated skin zone around the injection completion thus reducing permeability to water and injectivity of the completion.) So, it is critically important to avoid oil in the injection water [131, 132].

The two limitations of DWL – minimum pressure interference and oil-free drainage water are predominantly controlled by the D/I spacing. The effect has been studied mathematically using dimensional analysis [133] to develop an analytical model of DWL well [134, 135]. The model was verified with reservoir simulator and gave rise to formulation of critical conditions for DWL well design. The model assumes vertical equilibrium, stabilized production rates, and stabilized (flat) dynamic OWC between the oil and water sink completions. The OWC assumption requires mathematical balance of the flow potential and capillary pressure in upwards and downwards directions as shown in Fig. 4.18. A simple analytical relationship between the production rate, drainage/injection rate and D/I spacing was derived to determine design limitations of these parameters. Figure 4.19 shows that DWL could improve oil production rate effectively without producing any water to the surface. This is evident especially for low values of D/I which means that only a small D/I spacing is needed to make the system work. If D/I spacing is 50 ft, the well could produce oil at 30 bopd while draining water at

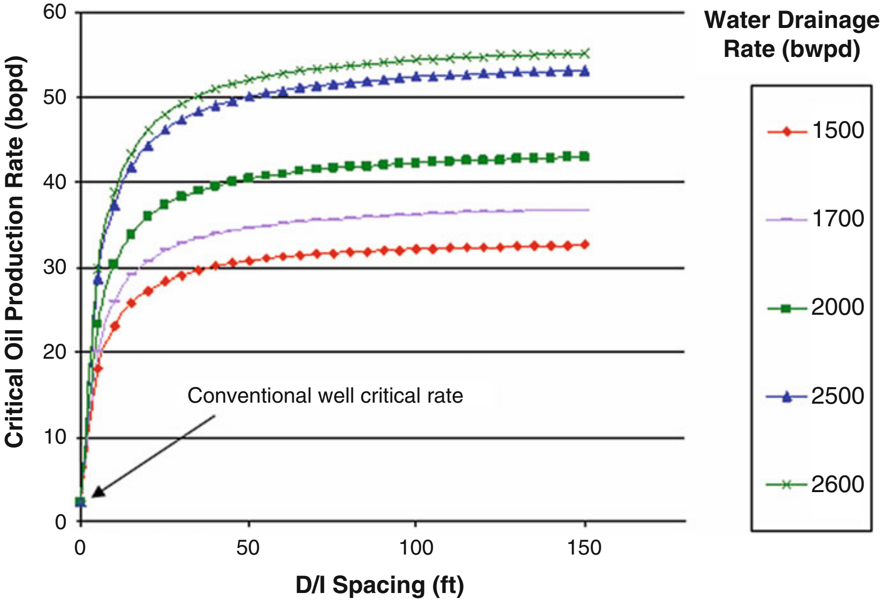


Fig. 4.19 Water-free oil rate increases with D/I spacing [135]

1500 bwpd. Also, oil would increase to about 50 bopd if water drainage/injection rate increase to 2500 bwpd.

For each oil production rate, there is required rate of water to be drained and injected and the water should be free from oil contamination. As shown in Fig. 4.20, for small D/I spacing, the required water drainage rate is very large. However, small increase in D/I spacing could eliminate the problem.

The plots in Figs. 4.19 and 4.20 indicate that there is a range of D/I spacing (for a specific reservoir) that would give fast increase of oil production rate in response to small increase of water drainage rate. Above this range there is practically no further improvement in oil production. Thus, critical oil production or water drainage rates become insensitive to D/I spacing larger than a certain "critical" value. A simple mathematical formula defines minimum required D/I spacing for a reservoir-aquifer system [135]. The model implies that if the bottom aquifer thickness exceeds the minimum D/I spacing, DWL well could be successfully installed.

The DWL design limitation of oil-free water injection is not practically attainable due to capillary pressure effect and expansion of transition zone shown in Fig. 4.21. Because of the effect, sustainable drainage of oil-free water with DWS or DWL becomes somewhat difficult as the water drainage completion may receive small inflow of oil.

To understand the transition zone effect on well performance, a study was carried out using the numerical and pie-shaped physical models [136]. The results show that, in conventional wells with water coning, the transition zone is small and

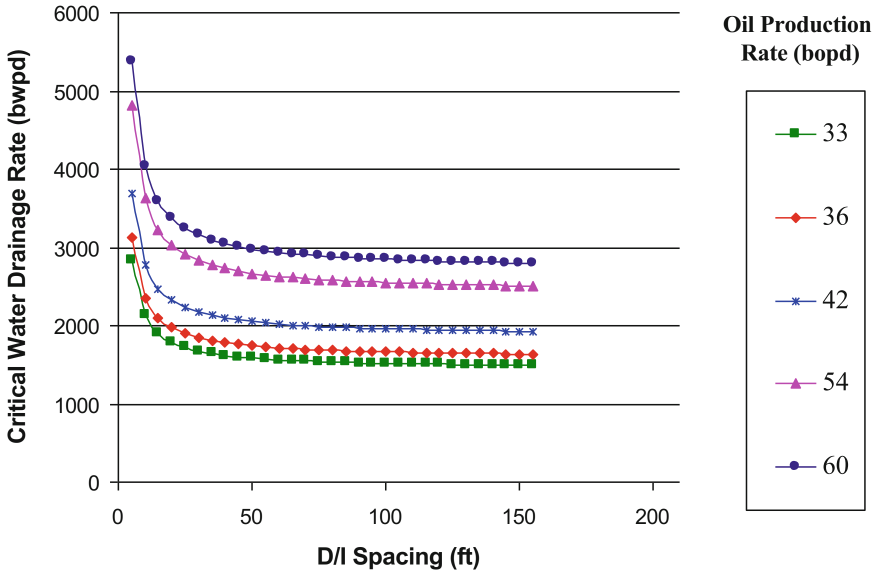


Fig. 4.20 Oil-free water drainage rate decreases with D/I spacing

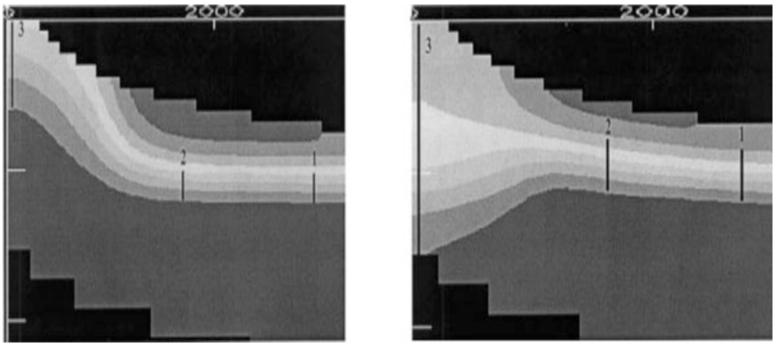


Fig. 4.21 Transition zone enlargement around conventional (*left*) and DWS (*right*) wells [136]

constant away from the well but enlarges towards the wellbore (Fig. 4.21-left). In conventional wells, transition zone grows upwards due enhanced diffusion resulting from high pressure drawdown around the well. In DWS or DWL wells, the enlargement is both upwards and downwards – towards the water sink completion (Fig. 4.21-right). The effect must be considered in DWL well design since the oil-free water drainage is a desired objective of the design. Thus, DWL should be designed assuming some small level of oil contamination in the injected water.

In DWL wells, small amount of oil may enter the water drainage completion and be re-injected to the aquifer together with water when the water drainage rate is high. However, this oil, although small, could significantly damage the injectivity of the bottom well completion [137, 138]. Thus, it is important to determine the maximum water drainage/injection rate or water velocity to prevent oil entering the injection zone.

Most of research on relative motion of oil and water concerns upwards co-current flow. In the flow, co-current separation occurs due to the slippage of oil droplets. The co-current separation has been widely studied. However, in DWL well and the water injection in-situ, the oil rises in opposite direction to water flow resulting in counter-current separation. The phenomenon has not received much attention and – instead of oil – water separation form continuous oil flow was studied [139, 140].

Recent study specifically addressed the counter-current gravity separation of oil in DWL wells by considering small (up to 3 %) concentration of oil in the downward flow of the O/W mixture [141]. The experiments employed seven different oils having wide range of density, viscosity and interfacial tension. The experiments monitored oil droplets ejected from a single perforation into the stream of water flowing downwards at various velocities. A practical finding from this study is the 0.33 ft/s (0.1 m/s) value of critical maximum water velocity that corresponds to the onset of counter-current oil separation. As shown in Fig. 4.22, the critical water flow velocity is little dependent upon the type of oil.

Mechanistic approach and the drift-flux concept were used to develop an empirical model for predicting the oil droplets raise velocity at different water flow velocities. As shown in Fig. 4.22, both models give similar results – verifiable with the experiments.

The critical water velocity computed from the models does not limit the water drainage rate. In a real DWL well, oil enters only at the top of the drainage completion where velocity of water is small while water enters the entire completion length. The critical water velocity defines a point in the perforated well section above which separation takes place. Below this point, small fraction of oil entering the well will not be separated due to the high water velocity. Since the water rate is linearly distributed along the completion, oil separation could be predicted from a given water sink completion length and drainage-injection rate.

Figure 4.23 is an example of such prediction for a DWL well with required water drainage-injection rate 1500 bwpd. The plots follow the change of water rate and oil cut along the vertical length the water drainage completion. It is clear that all the oil entering the upper three-foot section of the completion would be separated since the maximum water velocity in this section is smaller than the critical water velocity (0.11 ft/s < 0.33 ft/s). Moreover, the plot of oil cut clearly shows no oil entering the well below the upper section. Thus, no (or very little) oil contamination is expected to be injected at the bottom completion of this well.

As discussed above, assuming oil-free re-injected water is not realistic as some small amount of oil may still be carried over by water to the disposal completion resulting in progressive damage to the well's injectivity. Injectivity decline caused by oil contamination of injected water is a time-dependent process known from field practice of subsurface water disposal – wells with injectivity decline require fracturing to maintain the target injection rates [142–144]. In addition,

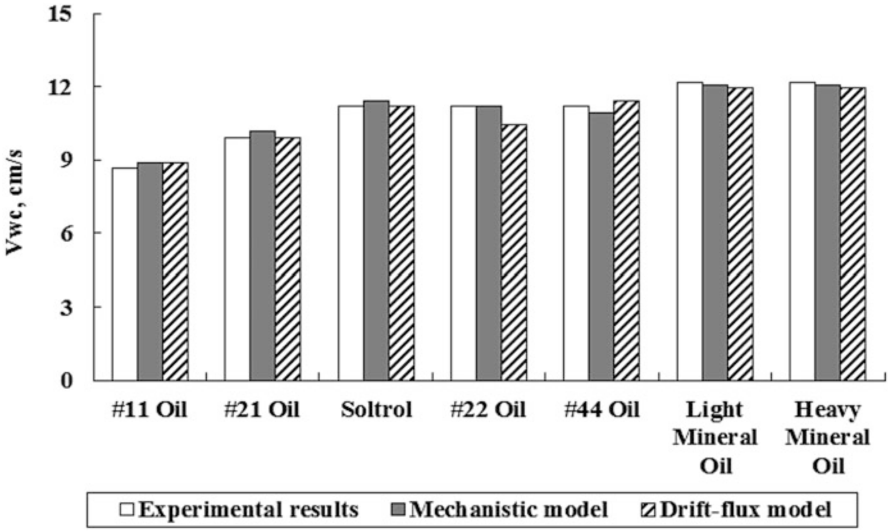
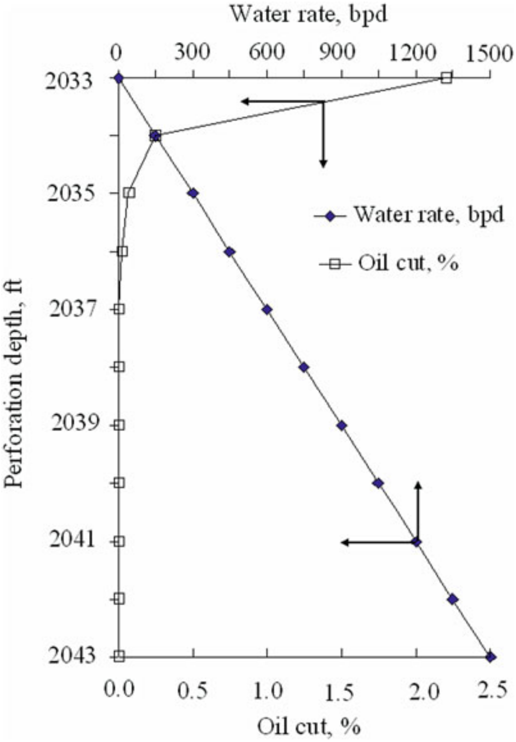


Fig. 4.22 Comparison of critical water velocity for experiments and models

Fig. 4.23 Water rate and oil cut change along drainage completion



experimental and theoretical work has shown that even small amount of dispersed oil in water can cause severe formation damage around injectors by oil droplet capture, especially when there is no oil saturation in the formation at the beginning of injection [145–154]. Complex mathematical models have been proposed for predicting this process [154–157] and were recently simplified for application in DWL wells design [158, 159].

Water injectivity decline as a function of time, as

$$I_D = \frac{I_{w\_t}}{I_{w\_0}} = \frac{K_{w\_t}}{K_{w\_0}} = \frac{K_{rw\_t}}{K_{rw\_0}} \tag{4.3}$$

Where, I_w and I_D are the dimensional and dimensionless indices of water injectivity, K_w is the effective water permeability, K_{rw} is the relative permeability to water, and subscripts "0" and "t" denote initial and instant values, respectively. The time dependent relative permeability reduction results from increasing saturation of oil captured in the rock by straining – where oil droplets clog the pore throats, and interception – with droplets captured by van der Waals colloidal forces. Injectivity decline in radial flow outside the well can be modelled using the advection-dispersion-adsorption (ADA) approach that describes two radial zones shown in Fig. 4.24: The zone next to well with maximum oil saturation, S_{oe}, the frontal zone having saturation reduced from Soe to zero, as there is no oil in the aquifer unaffected by the injection [159].

Since the frontal zone is very small, the ADA model can be simplified using Buckley-Leveret (B-L) theory that uses the fractional flow approach and considers concurrent flow of the two phases – oil and water, by describing separately the flow of each phase. Schmidt, et al. [160] found that injectivity decline caused by oil droplets invasion could be predicted using Buckley-Leverett approach based on the equilibrium oil saturation and relative permeability relationship, however, they did not provide formulas to calculate the injectivity reduction in time. Devereux modified the Buckley-Leverett theory by including a "retardation factor" to consider the capillary resistance effect [161, 162]. He proposed a mathematical model to calculate water injectivity decline caused by oil contamination, and presented a numerical solution for a linear-flow case of constant-pressure injection. The model was then verified with experimental data.

The simplified model of DWL well injectivity decline [159] follows the Buckley –Leverett (B-L) concept and considers instant capture and permanent retention of oil inside the rock out of the flowing water so the advancement of oil saturation falls behind the advancement of the water front. In the oil-invaded zone oil saturation is constant and maximum, S_{oe}, while in the water invaded zone there is no oil saturation. The concept is shown in Fig. 4.25.

The maximum (or equilibrium) oil saturation in the invaded zone is the asymptotic maximum value of oil saturation in the rock that would not increase with continuing injection of the same oily water at a constant rate. It is a function of droplet to pore throat size ratio and capillary number. The exact value of equilibrium oil saturation can only be found from the "bump-rate" tests that are uncommon

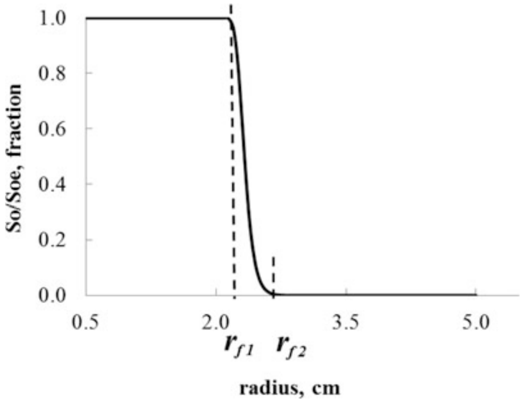


Fig. 4.24 Radial distribution of captured oil saturation outside DWL well [159]

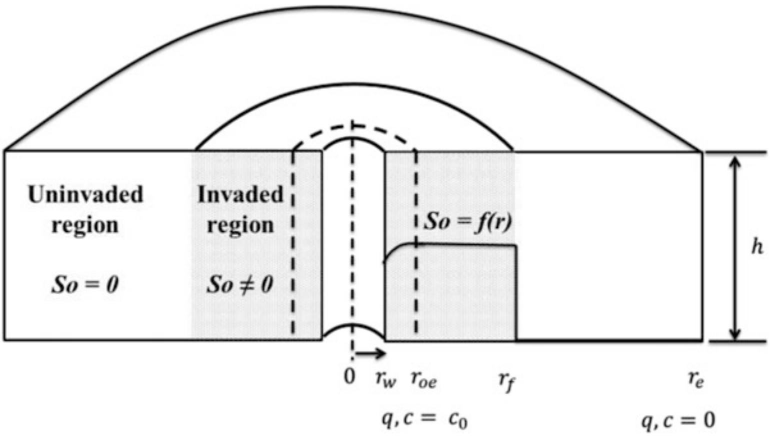


Fig. 4.25 Schematics of radial invasion of oil for oily water injection [159]

additions of routine relative permeability testing. However, as a first approximation, equilibrium oil saturation can be estimated as residual oil saturation using either laboratory test or common correlations for low values of capillary numbers [159]. Various correlations have been developed to predict the residual oil saturation based on capillary number for routine core analysis, which is known as capillary desaturation process.

The proposed model of DWL well injectivity decline in time relates injectivity index to the size of oil-invaded zone, r_f, as

$$I_D = \left[\frac{ln\frac{r_e}{r_f}}{ln\frac{r_e}{r_w}} + \frac{ln\frac{r_f}{r_w}}{\mu_w\left(\frac{K_{rw}}{\mu_w} + \frac{K_{ro}}{\mu_o}\right) ln\frac{r_e}{r_w}}\right]^{(-1)} \tag{4.4}$$

and the oil-invaded zone size to time as,

$$r_f \cong \sqrt{r_w^2 + \frac{2(\delta r_w - 1)exp(\delta r_w)}{\delta^2} + \frac{qtC_0}{\pi h_w \phi S_{oe}^*}} \tag{4.5}$$

Using parameter, δ, defined as

$$\delta = \frac{-\lambda N_{Ca}^* 2\pi h_w \phi \sigma_{ow}}{q\mu_w} \tag{4.6}$$

Where, r_e is the aquifer size, r_w is the well radius, μ_w and μ_o are viscosities of water and oil, respectively, q is the d = water drainage-injection rate, h_w is aquifer thickness, K_{rw} and K_{ro} are end-point relative permeabilities of water and oil, respectively, N_{Ca}^* is the critical capillary number that the equilibrium oil saturation begins to decrease (estimated value, $N_{Ca}^* = 10^{-4}$), λ is empirical constant determined from the bump-rate tests, and ϕ is rock porosity [159].

Figure 4.26 is a theoretical verification of the water injectivity decline using reservoir simulator and B-L models in the same rock for different oil droplet sizes. It shows that for larger oil droplets (higher value of the droplet-to-pore throat ratio, N_d) injectivity damage is more pronounced. It has been also found that water injectivity declines more rapidly in radial flow than in linear flow [159],

Practical implication of DWL well's injectivity decline is the increase of the injection pressure to maintain the same water drainage-injection rate or to control the pressure by reducing rate. Thus, keeping the pressure safely below the limiting value of fracturing pressure and the injection rate above its economic limit necessitates occasional well's workover and stimulation treatments. DWL well's performance depends on the water "looping" rate within the aquifer so the injectivity decline effect becomes a controlling factor of the system. Frequent well stimulation treatments may be required to restore the injectivity needed for maintaining the water looping rate. Thus, feasibility of DWL must be evaluated by coupling the injectivity decline with stimulation economics.

3.6 ECT Performance of DWS and DWL Techniques

DWL technology is the ECT source reduction method and features all properties of ECT discussed in Chap. 2. Firstly, by definition, the technique is inherent in the oil production process but is also functionally related to the environment as it controls discharge and processing of produced water. Secondly, by the ECT objective, the DWL technique prevents pollution and other adverse effects on environmental quality. Thirdly, by controlling the water coning, DWL helps producing more oil. Also, construction and operation of DWL well requires expertise in petroleum engineering. Lastly, by the ECT methodology, DWL employs principles of two

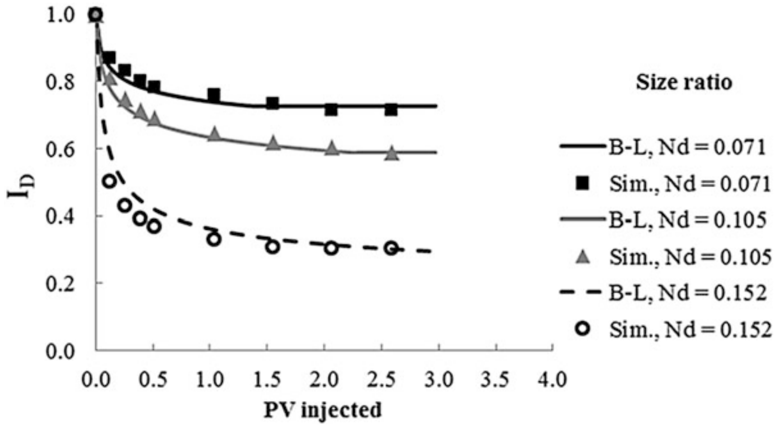


Fig. 4.26 Injectivity decline for different oil droplets size

ECT methods: the source reduction and the internal (in-situ) recycling; Returning of water back to the aquifer maintains the water-drive mechanism; By reducing the water cut in the stream of produced fluids, DWL employs the source reduction principle of ECT.

In order to determine which of the three alternative wells, conventional, DWS or DWL would be better to develop a given reservoir, an ECT cost performance analysis is needed. The cost models for conventional and DWS wells have the same components but differ by values. Conventional well produces oil together with water from the reservoir to the surface via the same tubing, as the critical oil rate is always too low to be economically feasible. A set of complex and expensive surface facilities is used to treat the oil/water mixture: oil and water are separated, first, then oil is transported to the market and water is cleaned, transported and disposed of subsurface via injection wells. In offshore operations, produced water is usually disposed through direct ocean discharge.

In DWS wells, critical oil production rate is much higher than that in conventional well so a water-free oil production is economically possible so the cost of oil water separation is significantly small than that for conventional; wells. However, DWS well always drains and lifts a lot of water to the surface that must be cleaned prior to disposal. Although the produced water from DWS well is relatively clean and needs less treatment per unit volume the cost of water treatment and disposal could be is still significant due to large water volume. For comparing the two types of wells one may consider water-free oil production from the top DWS well completion and the produced water from the water sink bottom completion lifted to the surface and treated prior to disposal.

Thus, the cost of conventional and DWS wells' operation well can be broken up into the following parts:

$$C_{Conv} = C_{cons} + C_{facl} + C_{lift} + C_{treat} \tag{4.7}$$

Where, C_{cons} is well construction cost, C_{fac} is water treatment facilities cost, C_{lift} is water lifting cost, and C_{treat} is water treatment and disposal cost.

Similar to DWS, water-free oil production is also feasible with DWL wells having adjusted rate of water drainage – injection. However, in contrast to conventional and DWS wells, DWL well doesn't lift water to the surface so no water treatment facilities are needed. However, due to complexity of the well's construction and poor quality of the water injected, DWL wells involve higher well construction and stimulation costs than those of conventional and DWS wells. Thus, the cost of DWL well's operation is,

$$C_{DWL} = C_{cons} + C_{inj} + C_{stim} \tag{4.8}$$

Where, C_{inj} is water re-injection cost, and C_{stim} is well workover and stimulation cost.

By analysing components of the three cost models, it is possible to make qualitative comparison. When related to a conventional well, DWS is more expensive in the well drilling, completion, downhole facility and bottom water lifting categories, and less expensive in the water treatment facilities and processing categories. On the other hand, DWL well vs. conventional well would cost more in the well drilling, completion, stimulation, downhole installation and water injection categories but would provide savings in water lifting, water treatment facilities, processing and disposal costs. For DWS vs. DWL, DWL costs are higher for drilling, completion, well stimulation, downhole installation and water injection, and with savings in water lifting, water treatment facilities, processing and disposal.

The use of principles of the ECT economic performance discussed in Chap. 2 involves evaluating the upstream performance – productivity improvement or impairment, and downstream performance – environmental impact reduction, or savings in compliance cost. The net cost of the ECT component is the summation of the value of lost (or gained) production (due ECT) and savings in compliance costs (due ECT). Typically, the use of ECT may result in some productivity losses. In this work, DWL increases oil production while reducing both the amount and contamination level of produced water. Following these principles, the net ECT cost of DWL (vs. conventional/DWS wells can be defined as,

$$\sum C_{upstream} + \sum C_{downstream} + C_{ECT} = Net\ \ ECT\ \ Cost \tag{4.9}$$

Where, $C_{upstream}$ is total revenue from produced oil and gas, $C_{downstream}$ is operational cost, and C_{ECT} is process modification cost.

Using the cost comparison model, described above, DWL well feasibility is evaluated over assumed 10-year production period for an oil reservoir with strong bottom water drive [163]. The economic data for the study are taken from published literature [164–166].

The study compares DWL well with conventional and DWS wells. To make the comparison levelled, oil production rates of DWS and DWL wells are set the same: 187.8 bopd, and the pressure drawdown of DWS and DWL is also constant during the production period. The conventional well is produced with the same pressure drawdown as the DWS and DWL wells and its oil and water rates are 98 bopd and 127 bwpd, respectively. The water/oil mixture is produced to the surface, separated, treated and disposed of. The DWS and DWL wells produce water-free oil from their top completions; The DWS well drains water at 2400 bwpd, which is then lifted to the surface, treated and disposed of. The DWL well recycles the water in-situ at 2800 bwpd so no water is produced to the surface.

In the DWL well, the drained water is re-injected into the same aquifer. The water is assumed to contain 15 mg/l solids and 500 ppm oil droplets [167] that results in injectivity decline and injection pressure increase so the well is periodically stimulated when its injectivity index value drops to 0.2. The periodic stimulation to restore injectivity is the main component of the total cost of DWL well. Each stimulation treatment restores only 96 % value of the previous injectivity. A worst-case stimulation schedule has been assumed for this study with 31 stimulations over the 10-year operation that gives the final injectivity equal to 30 % of its initial value. Shown in Fig. 4.27 are the initial cycles of DWL well stimulations and the resulting incremental cost of this treatment.

Qualification of the cost components in Eq. (4.9) for the conventional well considers the "upstream" cost of the fluid lifting and the "downstream" cost of separation, water treatment facilities, water processing and disposal. The cost of ECT installation, C_{ECT}, is zero. For DWS well, the upstream cost is the separated oil and water lifting, the cost of ECT installation is the well construction (water drainage part), while the downstream cost components are the same but smaller than those for the conventional well. For the DWL well, the upstream cost comprises the modified well construction (water drainage and injection completions), water recycling process, and well stimulations. There is no downstream cost for DWL well as no water is produced to the surface.

Water treatment can be quite expensive – especially for conventional wells – due to the high oil content in the mixture [168]. The cost of water treatment and disposal varies from 0.5 to 4.3 $/bbl based on the water composition and well location. In this study, the prices of water treatment and disposal for conventional and DWS wells are 3.3 $/bbl and 0.5 $/bbl, respectively.

Depicted in Fig. 4.28 is the forecast of oil production for the three wells. Also, Fig. 4.28 presents cumulative produced water by the conventional and DWS wells and the recycled water in the DWL well. (Pressure drawdown at the oil-producing completions is the same for all three wells.) The cumulative oil production in conventional well is much less than that of the DWS and DWL well as a result of water coning. On the other hand, maintaining high oil rate in the DWS and DWL wells involves pumping large volumes of water.

Figure 4.29 shows the Net ECT costs and Net Present Values (NPV) of the three wells after 10 years' of production. The Net ECT cost of DWL is $4,687,663 while

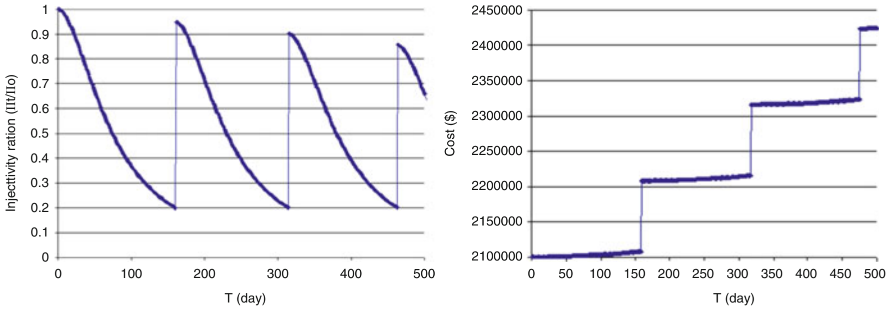


Fig. 4.27 DWL well's injectivity stimulation (*left*) and its incremental cost (*right*)

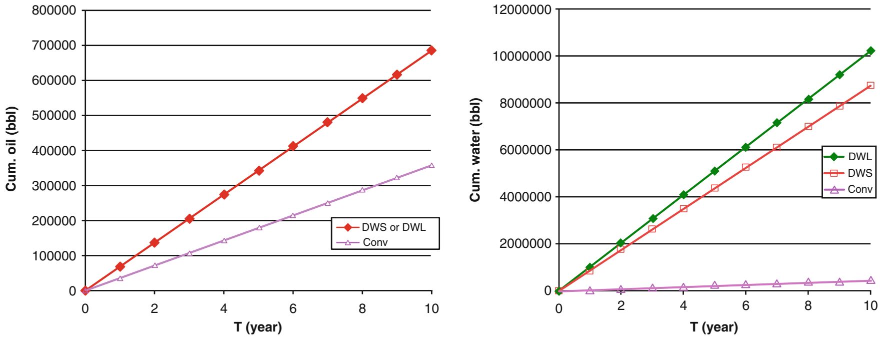
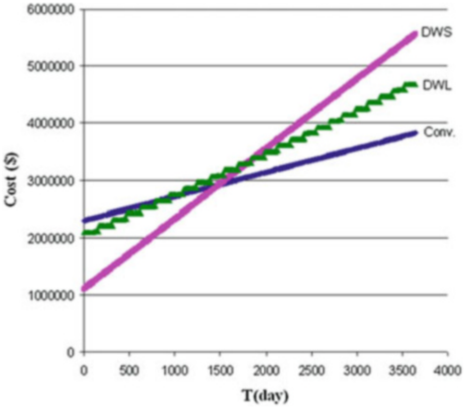


Fig. 4.28 Forecasted oil (*left*) and water (*right*) production for three wells

the DWS cost is $5,871,500. The saving with DWL is evident comparing to lifting, treating and disposing of the large volume of water with the DWS well.

Initial cost of conventional well exceeds that for the other two wells due to capital cost of the surface fluid processing facility but the later cost becomes smaller as the well produces less water. (However, it also produces less oil than the other two wells.) After 10 years of operation, the net present values are $21,207,757, $42,416,501 and $42,600,338 for conventional, DWS and DWL wells, respectively. There is clear twofold economic advantage of DWS and DWL wells over convention well. Moreover, though NPV of DWL is almost the same as DWS, the DWL technology provides additional environmental benefit of eliminating the surface-produced water.

To identify domain of DWL applications, different cases were considered by varying oil price ($50/bbl, $70/bbl, and $100/bbl), economic and reservoir conditions (electricity price, produced water treatment price, reservoir stimulation cost and frequency, permeability ratio, mobility ratio and other properties) and NPV for the three types of wells to identify conditions when DWL is the best choice [158]. The results, show a broad range of conditions where DWS and DWL are economically superior to conventional wells as they give higher oil production rates. Their economic advantage is more significant in areas with high water cost,



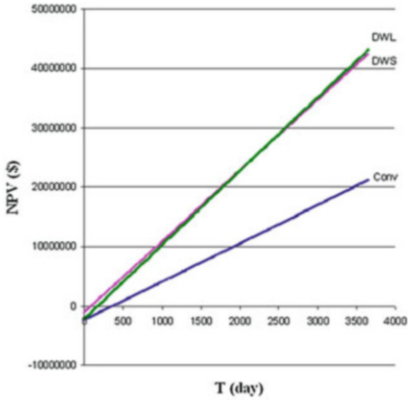


Fig. 4.29 Net ECT cost (*left*) and NPV (*right*) of three wells

good formation injectivity and unfavorable mobility ratio. Moreover, in most cases DWL wells would give the best economic performance. However, the cost of well stimulation due injectivity decline and mobility ratio appears to be the strongest cost-controlling factor.

4 Control of Produced Water Pollutants

This section presents a brief overview of the source separation technology for removing pollutants from oilfield produced waters to comply with environmental discharge limitations. The technology is categorized according to the type of pollutant as control of oil – deoiling, removal of organics and demineralization. Deoiling involves separation of free oil suspended in the continuous water phase. The objective of organic treatment is to remove dissolved oil. The demineralization process is designed for removing salinity from produced water.

Limitations regarding the discharge of produced water to surface waters vary considerably in different countries. For land production operations the most restrictive limitation is prohibition of discharge. In this case, the only two alternatives for final disposal are either subsurface injection or evaporation to dryness followed by disposal of the solid material in permitted landfills. However, in arid areas having little surface water, discharge of produced water may be allowed under limitations on salinity (within a few thousand ppm of chlorides) and O&G (below 30 mg/l). In this case, the discharged water is used for beneficial purposes, such as crop irrigation or livestock watering.

In offshore production, a simple approach to regulating overboard discharge may address only maximum O&G concentrations in the discharge with little consideration given to other pollutants. In fact, such an approach has been typical for early regulatory initiatives in many countries. In this approach, the objective was to lower the O&G concentration in produced water and was subject to the discretion of regional authorities. For example, the O&G discharge limits would vary for geographical areas within the following values: 48 mg/l for the Gulf of Mexico, 40 mg/kg for the UK/North Sea, 30 mg/l for Australia and 15 ppm for the Red Sea and the Mediterranean Sea [169–171].

Produced water discharge limitations have undergone, and are continuing to undergo, steady evolution. A conventional regulatory approach to the produced water effluent guidelines has been changed from one based solely upon the total O&G concentration to one which discriminates between the limiting constituents and specifies maximum concentrations for each constituent separately.

For example, Table 4.9 shows effluent limitations for discharging produced water to the saline inland, coastal and offshore state waters of Louisiana [172].

If this regulatory trend continues, more sophisticated (and expensive) technology for water cleaning will be needed. Some believe that the costs associated with such development may result in the technology shift from the source separation approach to subsurface injection (recycling-containment) or subsurface reduction (source reduction) of produced water. These methods are discussed later in this chapter.

4.1 Deoiling of Produced Water

In the early 1980s, the conventional systems of produced water treatment were exclusively designed for oil removal and employed a two-stage configuration. In these systems, the primary stage would incorporate either a gravity settler (skim tank, gun barrel) or a coalescer (parallel/corrugated plates, serpentine path), and the second stage would employ a flotation unit.

All gravity settlers are settling tanks designed to provide sufficiently quiescent flow conditions so that free oil rises to the water surface and coalesces into a separate oil layer to be mechanically removed. In addition, particulates coated with heavy oil may settle to the bottom and are removed as a sludge or underflow. Chemicals such as de-emulsifiers and/or coagulents may be added to improve separation.

Serpentine-path coalescers convert small oil droplets to larger ones. The process of oil coalescence can be realized by forcing the oil–water mixture to flow through a permeable pack of a granular or fibrous material. The idea is attractive, but there are a number of practical difficulties (one of which is the occurrence of both droplet coalescence and droplet fragmentation in the permeable pack). In practice, this technique is not often used for reduction of the oil concentration in produced water.

A plate coalescer consists of an assembly of parallel plates, through which the oil-in-water emulsions flow. The presence of the plates leads to a reduction in the settling distance of the oil droplets and to coalescence on the plates’ surfaces. To enhance the removal of the collected oil, the plates are inclined and corrugated. The main advantages of plate coalescers are their simplicity, low maintenance and lack

Table 4.9 Produced water discharge limitations to saline waters of Louisiana[a]

Pollutant	Discharge limitation
Benzene	0.0125 mg/l (daily maximum)
Ethylbenzene	4.380 mg/l (daily maximum)
Toluene	0.475 mg/l (daily maximum)
Oil and grease	15 mg/l (daily maximum)
Total organic carbon	50 mg/l (daily maximum)
pH	6–9 standard units
Total suspended solids	45 mg/l (daily maximum)
Chlorides	Dilution required at a ratio of 10:1 (ambient water: produced water). All other prescribed parametersmust be within acceptable limits prior to dilution
Dissolved oxygen	4.0 mg/l (daily minimum)
Toxicity (acute and chronic)	1 toxicity unit[b]
Soluble radium	60 pCi/l (2.2 Bq/l)
Visible sheen	No presence

[a]After Ref. [172]
[b]Toxicity unit is defined as the ratio of discharged effluent concentration to concentrations producing either lethality (acute toxicity) or no observable effects (chronic toxicity)

of moving parts. Their limitation is that oil droplets below a minimum size, reportedly around 8 μm, cannot be separated. However, also reported was a practically achievable minimum size of oil droplets in the range 20–30 μm [173].

The induced gas flotation process disperses fine gas bubbles into a reaction chamber to suspend particles that ultimately rise to the surface and form a froth layer. Oil droplets and oil-coated solids, which are suspended in the water, attach to these bubbles as they rise to the surface, are trapped in the resulting foam and are removed when the foam is skimmed from the surface. Flotation cells for deoiling produced water utilize two different methods to induce gas into the produced water. The most common method is mechanical and uses a rotating impeller positioned inside a stator at the base of a draft tube. The rotation of the impeller creates a vacuum which draws gas down the draft tube. The gas is then ejected from the impeller through the stator, which disperses the gas in the form of fine bubbles. The second type of gas induction uses hydraulic ejectors to aspirate gas into the produced water. This requires recirculation of a portion of the treated water for use as the motive force to aspirate the gas.

The oil removal performance of conventional water treatment systems has been evaluated in field [174–176] and laboratory studies [177, 178]. The results provided a general assessment of this technology: (1) there was no removal of dissolved organic fractions; (2) the minimum oil concentration at the output of gravity settlers was 113 mg/l; (3) the mean oil concentrations in effluents from over 50 % of the flotation units tested were above the regulatory limit of 48 mg/l; and (4) the design of a system should incorporate an actual brine and crude produced from a reservoir.

The field survey data [175] were further analyzed [179]. The objective was to determine a relationship among the system variables, such as water flow rate, the oil content in the feed water and the oil content in the effluents from primary and secondary separators. A multiple regression analysis was used to model the simultaneous changes of the recorded variables. The results indicated a lack of any statistically meaningful correlation between the variables. The oil-separation performance, measured as the effluent oil concentration, appeared insensitive to varying input rates and oil contents. Several factors explain this insensitivity. First, the system was operated at a fraction of its nominal throughput (insensitivity to the flow rate). Second, the separation efficiency was a possible maximum (insensitivity to the influent oil content). Additionally, the mean value of the effluent oil content was below the compliance level of 48 mg/l (monthly average) for only five out of ten systems, and the daily values fluctuated closely to the compliance limit of 72 mg/l (daily maximum). Further reduction of oil content at the process end-point was concluded to be accomplished only by adding an efficient separator downstream from the flotation unit.

Also, the statistical analysis provided an interesting insight into the performance of the primary separation devices. The study revealed that, during most of the test, the primary separation was redundant. As shown in Fig. 4.30, the flotation units were capable of reducing the oil content in produced water to levels of 10–60 mg/l for influents containing less than 800 mg/l oil. This performance was not significantly dependent either on the feed oil content or the flow rate. The plot in Fig. 4.30 also indicates that, for the same range of the input oil, the primary-stage separator effluents had oil content levels well above those for flotation units. Moreover, the field data used in this analysis show that system input oil contents smaller than 800 mg/l were very common (93 % of all input samples contained less than 800 mg/l oil). Therefore, the actual use of gravity settlers and coalescers was minimal.

The logical steps in the future development of deoiling systems for the oilfield production process appear to be: (1) the improved control of effluents from heater treaters using API separators to stabilize oil concentration below 500 mg/l; (2) design of the first-stage separation (e.g. flotation unit) to reduce the oil content to a range of 10–50 mg/l; and (3) addition of a new, high-quality separator to the second stage of the process.

Several new technologies show promise for the oilfield surface process application. A list of these technologies, together with their tested efficiencies of oil removal, is presented in Table 4.10 [170, 171, 180–185]. This table has been compiled using information from various sources, ranging from rigorous scientific laboratory projects [171] to commercial publications [181]. Therefore, the data in Table 4.10 should be viewed as the best estimates of the performances for each method. In addition, the oilfield applicability of the methods either has not been fully analyzed or is controversial. For example, the use of hydrocyclones requires a stable input pressure and a constant feed rate, both of which cannot be easily achieved at the output of free water knock-outs (FWKO) [187]. There is an ongoing discussion among oilfield service companies on the superiority of various modern deoiling technologies; hydrocyclones, centrifuges, membrane filters, diffusion-barrier filters, etc. [188].

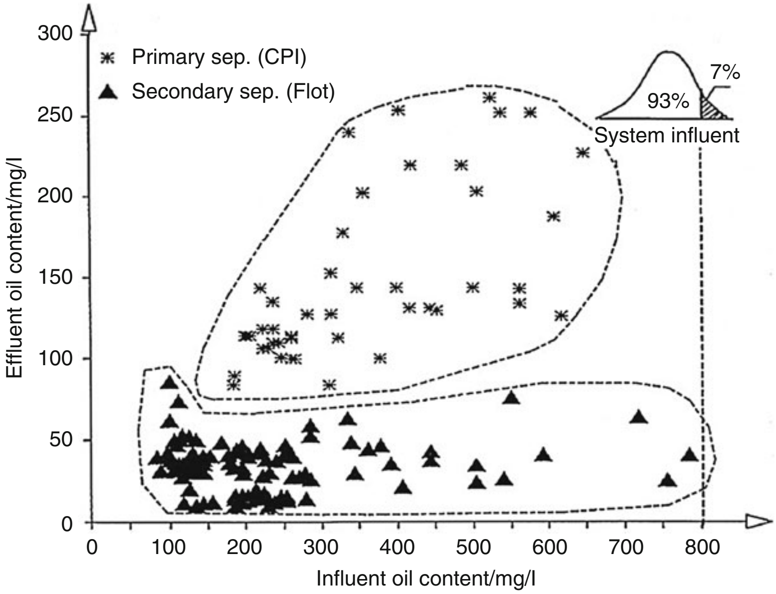


Fig. 4.30 Redundance (93 %) of primary treatment of produced water [179]

Table 4.10 Environmental performance of modern techniques for deoiling produced waters

Technology	Influent oil (mg/l)	Effluent oil (mg/l)
Vortoil hydrocyclone [170][a]: 35 mm	43	11
60 mm	408	16
Colman–Thew hydrocyclone [171][b]	100	12
	1000	100
Rotary hydrocyclone [180][c]	100	15
	1000	35
Disk-stack centrifuge [181][d]	<1000	5
Crossflow microfiltration [182, 183][e]	28–583	5
High-gradient magnetic separation [184][f]	190–240	23
Electrolytic treatment: [185][g]	1000–2000	3–11
[186][h]	500–5000	TR[i]

[a]Field tests offshore; flow rate up to 11 gpm/cone
[b]Laboratory tests; constant size of oil droplet in influent, $d_{50} = 35$ μm; flow-rate range 21.5–37.4 gpm/cone
[c]Prototype test offshore (mean value of results from two platforms); flow rate 26–36 gpm/cone; rotary speed 1900 rpm
[d]Commercial data for oily water only; flow rate 29 gpm; rotary speed 5000 rpm
[e]Offshore field test; permeate flux 850 gpd/ft^2; flow rate 3 gpm per two units in series
[f]API separators effluent tests
[g]Bench- and pilot-scale experiments; wastewater from manufacturing plant
[h]Bench-scale experiments; Nigerian light crude + sea-water emulsion
[i]TR = no residual turbidity; 100 % removal claimed

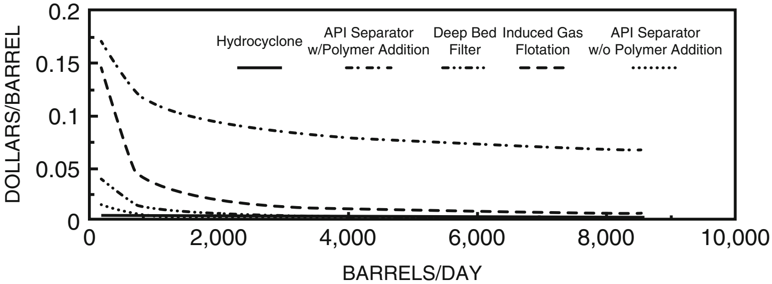


Fig. 4.31 Cost of deoiling technologies for produced water (1994 dollars; 20 year project life; 5 % discount rate) [189]

Cost performance of the deoiling technology is shown in Fig. 4.31 [189]. Unit cost curves are presented for five options of deoiling technology versus water production rate: deep bed filter; gas flotation; hydrocyclone; and API separator, with and without chemical conditioning. The unit costs presented in Fig. 4.31 have been calculated using the following assumptions regarding removal efficiency: 5 mg/l O&G concentration in effluents from induced gas flotation or API separator, 98 % removal efficiency for deep bed filtration and 80 % removal efficiency for hydrocyclones. These assumptions are not universal but represent average performances of these technologies.

From Fig. 4.31, the least-cost deoiling treatment is apparently the API separator, followed by the hydrocyclone, deep bed filter, induced gas flotation and the API separator with chemical polymer addition. The higher cost for the API separator with chemical conditioning results from the use of the chemicals. However, the selection of a deoiling technology should be based on technical performance as well as cost. Technical performance determines the lower limit of O&G concentration that each treatment technology can attain and is dependent on the removal efficiency and influent O&G concentration. Moreover, these two factors, removal efficiency and influent quality, are inter-related. Therefore, selection of the specific deoiling treatment process would require consideration of the upstream quality of the process influents and the downstream quality of the effluents. The effluent O&G concentration may be either subject to discharge permits or determined by downstream pretreatment requirements.

4.2 *Removal of Dissolved Organics from Produced Water*

Two technologies, bio-oxidation and granular carbon adsorption, have been recently selected as the most promising options for removal of organic material dissolved in produced waters. These technologies have been included in the computer-aided engineering model for calculation of the cost of different produced water treatments for the natural gas industry [190].

The bio-oxidation process for produced water has been adapted from the biological fluidized bed reactor (FBR) process for treatment of municipal wastewater. FBR for produced water is an aerobic reactor employing aerobic bacteria to biodegrade dissolved organics. The process consists of passing the produced water to be treated upwards through a bed of finegrained media, such as sand, granular activated carbon or ion-exchange resins, at a velocity sufficient to impart motion to, or 'fluidize', the media. This occurs when the drag forces caused by the liquid moving past the individual media particles are equal to the net downward force exerted by gravity (buoyant weight of the media). This is referred to as the point of incipient fluidization (defined either as the point at which fluidization occurs or the maximum bed porosity achievable prior to fluidization occurring). Greater fluid upflow velocities (flux rates) cause the bed of media to expand beyond the point of incipient fluidization.

Fluidization of fine-grained media allows the entire surface of each individual particle to be colonized by bacteria in the form of a biofilm. Surface areas of the order of 300 m^2/m^3 of bed are common in FBR systems. This results in accumulation of biomass concentrations of 5–50,000 mg of volatile suspended solids (VSS) per liter of fluidized bed, which is an order of magnitude greater than that obtained in most other biological processes. Manipulating the volume of media added to a system, the fluidization velocity and the point in the reactor at which the bed height is controlled allows the average biofilm thickness and mean cell retention time to be designed for maximum performance.

The granular activated carbon (GAC) adsorption process employs a fixedbed column that is used as a means of contacting the produced water with the carbon media. Produced water with dissolved organic compounds enters the inlet to the granular activated carbon container. Soluble organics are adsorbed on the surface of the carbon and the treated produced water exits the GAC container. The GAC must be reactivated when it can no longer absorb organics. The carbon can be reactivated in the canister or removed and reactivated off-site.

Figure 4.32 is a plot of the unit cost curves for dissolved organic treatment using bio-oxidation (GAC–FBR), GAC–FBR with a sand filter and GAC alone [189]. The GAC–FBR unit cost curve is a function of the flow rate and an influent chemical oxygen demand (COD) concentration of 34 mg/l. The GAC unit cost curve is a function of the flow rate and influent organic concentrations of 12 mg/l benzene, 1 mg/l naphthalene and 1 mg/l phenol. A sand filter would be needed to remove biosolids in certain situations, such as when total suspended solids (TSS) would be above permit limits or prior to electrodialysis, reverse osmosis or vapor compression, forced evaporation and solar evaporation. It is also shown that the addition of a sand filter does not significantly affect the unit cost of using a GAC–FBR. The cost for removing dissolved organics ranges from less than \$0.01 to \$0.25/bbl of produced water, depending on the process selected.

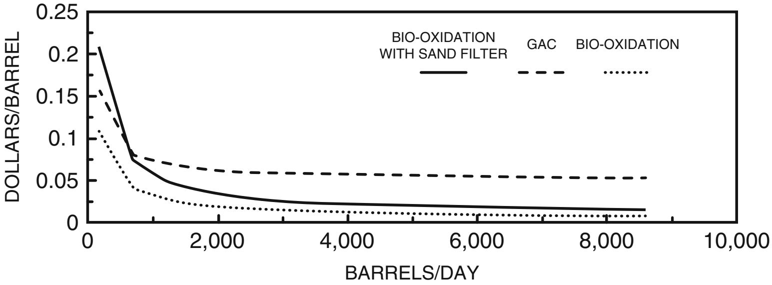


Fig. 4.32 Cost of various techniques for removal of dissolved organics from produced water (1994 dollars; 20 year project life; 5 % discount rate) [189]

4.3 *Produced Water Salinity Reduction*

Demineralization technologies are electrodialysis, reverse osmosis, vapor compression, forced evaporation, and solar evaporation. A brief description of each of these processes is given below [189].

Electrodialysis accomplishes a selective separation of ionic compounds from produced water using semi-permeable, ion-selective membranes and electricity. Application of an electric potential between two electrodes causes cations to move toward the negative electrode and anions toward the positive electrode. Alternate spacing of cationic- and anionic-permeable membranes results in the formation of diluted (product) and concentrated (reject brine) salt solutions between the alternate membranes.

Reverse osmosis is a process in which produced water is partially demineralized by being forced through a semi-permeable membrane at a pressure greater than the osmotic pressure caused by the dissolved salts in the produced water. A partially demineralized water stream and a concentrated brine solution are produced.

Vapor compression is a process in which steam is used to heat the produced water above the boiling point. The vaporized produced water is compressed and also used to heat the incoming produced water in a heat exchanger. The condensate from the heat exchanger is the treated, demineralized, produced water.

Forced evaporation uses a spray dryer into which the produced water is flashed at temperatures above boiling point, resulting in the production of steam and solid salt. The steam is then emitted to the atmosphere or recondensed.

Solar evaporation is accomplished in ponds and can be used in arid regions. Produced water evaporates from the surface of the pond, resulting in the build-up of solid salt in the pond.

Figure 4.33 is a plot of the unit cost curves for the five demineralization treatment options discussed above [189]. The cost ranges from \$0.10 to \$2.00/bbl of produced water. These unit costs are related to flow rate and have been calculated assuming an influent TDS concentration of 50,000 mg/l and an effluent TDS concentration of 500 mg/l. Electrodialysis is the least expensive technology

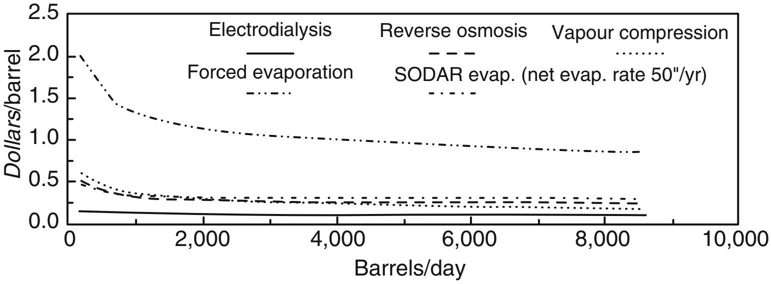


Fig. 4.33 Cost of demineralization technologies for produced water (1994 dollars; 20 year project life; 5 % discount rate) (50″ = 1.27 m) [189]

for partial demineralization of produced water and ranges from \$0.11 to \$0.16 over a produced water flow rate range of 8570–170 bbl, respectively. Disposal cost of the rejected stream has not been included in the given unit costs. Forced evaporation is the most expensive technology for managing inorganic salts in produced water. The unit cost ranges from \$0.88 to \$2.00 over a produced water flow rate range of 8570–170 bbl, respectively. These unit costs do not include solids disposal or recovery of water. The solar pond unit costs were based on a 50 in./year net evaporation rate.

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Chapter 5
Oilfield Waste Disposal Control

A.K. Wojtanowicz

1 Introduction

Environmental control of waste generation in the oilfield processes, discussed in Chaps. 2 and 4, may pro-actively reduce the waste volume and toxicity but cannot eliminate the waste altogether. Typically, in offshore operations the waste would be either disposed of on-site by discharging to the sea – as discussed in another section of this book, or reinjected to disposal wells – as discussed in this chapter, below. In the onshore operations, the waste fluids would be temporarily stored in earthen pits (on-site or off-site) before its ultimate disposal to the land or subsurface.

Land disposal of oilfield waste, known also as "pit closure by land treatment" may be performed using landspreading or landfarming. Lanspreading involves spreading the waste over the surface of the ground and tilling it into the soil. After this initial tilling, no further action is needed. In land farming, the soil is commonly processed for several seasons after the initial application of the waste. This additional processing may include adding fertilizers and tilling repeatedly to increase oxygen uptake in the soil.

There are two potential problems with waste disposal to land that may limit future applications. First, land treatment provides little control over migration of the mobile (leachable) fractions that may eventually enter the food chain of animals or humans. Second, spreading of oily wastes results in emissions of volatile organic compounds resulting in violation of some local laws and regulations controlling air pollution.

Injection to subsurface is the most widely used method for the disposal of most petroleum industry wastes. Liquids are usually injected to permeable formations through injection wells. Solids are grinded and slurrified before being injected into the petroleum well's annulus or to a designated slurry injection well. During the

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_5

injection, the disposal strata would be fractured with the slurry. Then, the solids would be filtered out at the fracture face and permanently stored inside the fracture.

2 Oilfield Waste Disposal to Land

On-site oilfield pits are surface impoundments usually excavated directly adjacent to the site of operation so that they can be used for temporary storage of waste generated from field operations prior to its final disposal. In the past, oilfield pits were typically used for both the temporary storage and final disposal. Such practices often resulted in surface damage due to excessive concentrations of buried hydrocarbons or permanent disposal of produced brines in pits. Modern technology of pit closure involves partial removal of waste from the pit, separation of liquids from solids and different treatment of these two phases prior to their final disposal on-site.

The petroleum industry has been using on-site pits in several different applications so the pits can be classified according to type of waste or function as follows [1]:

- *Drilling reserve pits* are used to accumulate, store and, to a large extent, dispose of spent drilling fluids, cuttings and associated drill site wastes generated during drilling and completion operations.
- *Workover pits* typically contain workover fluids and are open only for the duration of workover operations. Workover fluids may contain total dissolved solids (TDS) in excess of 3000 ppm (approximately 4 mmho/cm conductivity) in addition to hydrocarbons or potentially toxic additives or compounds.
- *Produced water* (*collecting*) *pits* are used for storage of produced water prior to disposal to sea at a coastal (tidal) disposal facility or for storage of produced water or other oil and gas wastes prior to disposal at a fluid injection well.
- *Basic sediment pits*, also called burn pits, are used in conjunction with a tank battery for storage of basic sediment removed from a production vessel or from the bottom of an oil storage tank.
- *Blowdown/emergency pits* are used for storage of produced water for limited periods of time. They are not used for storage or disposal. Fluids diverted to emergency pits are removed as quickly as practical. After pit closure, contaminated soil should be remediated.
- *Skimming pits* are used for skimming oil off produced water prior to disposal of the water at a tidal disposal facility, disposal well or fluid injection well.
- *Percolation pits* allow liquid contents to drain or seep through the bottom and sides of the pit into surrounding soils. Percolation pits are unlined.
- *Evaporation pits*, defined as surface impoundments that are lined with clay or synthetics, are used in areas where small volumes of wastewaters are generated. Disposal of wastewater by evaporation results in the concentration of salts and residual hydrocarbons in the pit.

2.1 Impact of Oilfield Pit Contaminants

Typical contaminants in oilfield pits are heavy metals, chloride salts and organics. Studies showed that soluble chloride salts and excess exchangeable sodium cause harmful effects on soil and plant growth [2, 3]. High levels of soluble salt lower the amount of water in the soil available to plants and reduce plant uptake of required nutrients [4, 5]. High levels of exchangeable sodium cause loss of soil structure, resulting in low water and air infiltration and excessive compaction of soil.

Heavy metals in soil can become incorporated and accumulated in the food chain or contaminate local sources of drinking water if leaching and migration occur from oilfield pits. Migration of metal ions from a pit site is usually limited by their attenuation in clay minerals and the formation of insoluble complexes in the soil. For drilling reserve pits, for example, researchers found little or no migration of metal ions from drilling muds because of clay attenuation and complexing [6, 7]. Attenuation and migration are affected by the type of soil; it is more extensive in porous soils than in clayey soils [4].

Incorporation of metals from oilfield pits into the food chain takes place through several possible pathways of exposure from soil to an individual. Research indicated that the exposure pathway may be different for each metal [8, 9]. In this research, a maximum soil concentration (MSC) (soil loading factor) was calculated using a so-called soil ingestion rate, i.e. the estimated amount of soil ingested by the individual per day. It was found out that of 14 possible exposure pathways for sewage sludge, four pathways have been identified as most likely to apply to oilfield pits. Maximum loading factors for 12 metals of concern in soils associated with oilfield pits are listed in Table 5.1. The table also shows the most likely exposure pathway for each metal and its maximum concentration detected in oilfield waste.

The presence of organics in soil, typically measured as oil and grease (O&G) concentration, may severely limit revegetation efforts after oilfield pit closure (usually, the revegetation should be accomplished in one season). It has been established that, for most soils, an O&G concentration of 1 % is an acceptable maximum [10, 11]. Surveys of oilfield pit content have indicated that 92.6 % of the pits had organics concentrations below the soil loading level [12]. The remaining 7.4 % of the pits required some dilution mixing of the waste with soil to reduce the O&G concentration to 1 % by weight.

Table 5.1 gives a comparison of soil loading factors recommended by the API guidelines with those from Louisiana State Wide Order 29-B and Canadian Interim Soil Remediation Criteria for Agriculture [13]. The Louisiana 29-B criteria were developed primarily from early work on metals in sewage sludge (before 1980) (these early studies were later superseded by the research supporting the API guidelines). The Canadian Agriculture values for maximum loading have been adopted by the Canadian Council of Ministers for the Environment (CCME) from values that were currently in use in various jurisdictions across Canada. The API guidance criteria have resulted from a quantitative risk assessment, in combination

Table 5.1 Maximum soil loading for oilfield pit metals[a, b]

Metal	Exposure pathway	API guidance	Louisiana 29-B[c]	Canadian agriculture	Maximum concentrations detected[d]
Arsenic	1	41	10	20	29/27.9/140
Barium[c]	1	180,000	20,000	750	56,200
			40,000		24,500
			100,000		10,700
Boron	3	2 mg/l	–	2 mg/l	290/73.6
Cadmium	4	26	10	3	14/1.5/3
Chromium	3	1500	500	750	368/145/54
Copper	3	750	–	150	82/124/210
Lead	1	300	500	375	446/302/970
Mercury	1	17	10	0.8	2.1/1.1/1.4
Molybdenum	2	–	–	5	16/9
Nickel	3	210	–	150	61/40.6/100
Selenium	1	–	10	2	3/0.6/1.4
Zinc	3	1400	500	600	823/413/400

[a]After Ref. [9]
[b]All concentrations in mg/kg unless otherwise specified
[c]Louisiana 29-B barium values for wetlands, uplands and commercial landfarming facilities, respectively [10]
[d]Independent evaluations by American Petroleum Institute and US Environmental Protection Agency in 1987 and 1995

with the best available data, which provided less conservative guidelines than those proposed by CCME.

2.2 *Oilfield Pit Sampling and Evaluation*

The design of pit closure depends upon the degree of pit contamination. Oilfield pit samples must fully represent the concentration of pollutants in the pit waste material. Recent publications provide methodologies for representative sampling using grid networks and composite samples [14]. For example, sampling can be performed at the 50 × 50 ft (15 × 15 m) grid basis with subsamples collected over 2 ft (60 cm) intervals and the lowermost sample taken below the waste bottom. Then, at each of the sampling points (not necessarily a grid point), the subsamples are combined into a single composite for this point. Detailed testing procedures have been developed for environmental analysis of oilfield waste [10]. Particularly important in these procedures are the measurements of true total barium [15] and hot water-soluble boron [16].

Optimization of the sampling plan is an important issue because, theoretically, the cost of taking and analyzing samples at each grid point, multiplied by the number of grid points, is prohibitive. Usually, the number of sampling points can be much smaller than the number of grid points. An analytical method for determining a minimum required number of pit samples was developed using the variability of metals in the oilfield reserve pits [17].

In addition to oilfield pit content, sampling of the background soils is necessary on locations designated for pit closure by on-site land treatment.

The land treatment area should be well drained and out of floodplains and wetlands. Background soil samples should be collected from the A soil horizon or upper 1 ft (30 cm), and composited from a number of nearby locations. Details for designing and executing a soil sampling plan can be found in the relevant literature [14, 18, 19].

2.3 Oilfield Pit Closure: Liquid Phase

Oilfield pits are closed by segregating the liquid phase from the solid phase and disposing of each phase separately. The liquid phase can be broadly defined as an aqueous layer usually containing some suspended solids and situated above settled solids. The solid phase comprises the settled solids and significant amounts of liquids remaining in the pit after pumping the liquid phase out. Usually, the pumping continues until the remaining mixture becomes non-pumpable.

Three options for on-site disposal of the liquid phase are disposal to surface waters, land spreading or subsurface injection (annular injection or injection well). Disposal to surface waters requires dewatering the oilfield pit. The dewatering process can be accomplished *in situ* by chemical flocculation and settling or by using a portable process of chemically enhanced decanting [20, 21]. The principles of dewatering have been described earlier in this chapter. After dewatering, the pit liquid phase is practically solids free and may qualify for surface water disposal if it meets permit requirements for such disposal. An example requirement for disposal of oilfield pit liquids to surface waters is shown in Table 5.2.

If the liquid phase cannot meet requirements for surface water disposal, the only two options for disposal are subsurface injection or land spreading. The decision in this case is solely based upon electrical conductivity (EC) of pit liquids [22]. For an EC greater than 4 mmho/cm (4 Si/cm), liquids should be injected underground.

The design of land spreading of pit liquids requires calculation of the minimum land area for liquid application. Typically, water infiltration rates are used to determine the minimum required land spreading area that would not cause liquid phase run-off. Alternatively, the minimum land area can be calculated using the required values of ESP = 15 % after the pit liquid phase infiltrates the soil to an assumed depth, usually 15 cm [22].

Table 5.2 Effluent limitations (MAC) for reserve pit water discharge for Gulf of Mexico coast states[a]

Analysis[b]	Texas	Louisiana	Mississippi
Ph	6–9	6–9	6–9
O&G (mg/l)	15.0	15.0	–
Chloride (mg/l)	500 (inland)	500	500
	1000 (coast)		
EC (μmho/cm)	–	–	1000
Total solids (mg/l)	–	–	–
TSS (mg/l)	50.0	50.0	100
TDS (mg/l)	3000	–	–
COD (mg/l)	200	125	250
TOC (mg/l)	–	–	–
Metals (mg/l):			
Arsenic	0.1	–	–
Barium	1.0	–	–
Cadmium	0.05	–	–
Chromium	0.5	0.5	0.5
Copper	0.5	–	–
Iron	–	–	–
Lead	0.5	–	–
Mercury	0.005	–	–
Nickel	1.0	–	–
Selenium	0.05	–	–
Zinc	1.0	5.0	5.0
Phenol (ppm)	–	–	0.1

[a]*MAC* maximum allowable concentration for effluent discharge
[b]*COD* chemical oxygen demand, *TOC* total organic carbon, *TSS* total suspended solids, *TDS* total dissolved solids

2.4 Oilfield Pit Closure: Solid Phase

The oldest and cheapest technique for pit closure is backfilling. This technique involves pushing the pit berm into the pit on top of waste, letting pit fluids spread over the adjacent well and compacting the closure surface area. A potential environmental risk of this technique stems from the fact that waste is buried inside the pit in concentrated form, so it may become subject to leaching from periodic rainfalls. Also, hydrocarbon-contaminated waste may be buried too deep for biodegradation of organics due to insufficient supply of oxygen. In Louisiana, for example, the method of backfilling would meet regulatory approval only if the concentration of contaminants was below certain levels that would make the waste harmless without dilutions [10]. Otherwise, land treatment techniques should be used for oilfield pit closure.

Land treatment is another method for rendering the waste pit material harmless through soil incorporation. The method employs dilution, chemical alteration and biodegradation mechanisms to reduce the concentrations of pollutants to acceptable levels consistent with intended land use [14]. The technique combines the treatment with final disposal of salts, petroleum hydrocarbons and metals. Land treatment of pit solids can be performed using techniques of land spreading, dilution burial (trenching or landfill) or solidification and burial. Laboratory analysis of waste composition must be made for each pit in order to evaluate levels of contamination [23]. Then, these levels are compared with their limiting values [loading factors or limiting constituents (LC)] to decide on the type of pit closure technique needed for successful land treatment design. Table 5.3 shows limiting constituents required for oilfield pit closures related to on-site disposal options in Louisiana [10].

The technique of land spreading involves addition of pit waste solids to the receiving soil, disking these solids to an appropriate depth such that the final waste–soil mixture meets the limiting constituent criteria.

The dilution burial technique involves both the mixing of soil with waste solids to reduce concentrations below LC values followed by burial of the mixture in trenches. The mixture is buried with at least 5 ft of soil cover above it and with at least 5 ft of undisturbed soil between the mixture and the highest level of groundwater table below. Management of waste in dilution burial is based on mechanisms of dilution and chemical alteration with little effect from the biodegradation mechanism due to lack of oxygen.

The technique of solidification and burial involves mixing solidifying agents, such as commercial cement, flash and lime kiln dust, with pit sediments to produce a relatively insoluble concrete matrix. Then, the solidified concrete is buried in the pit using the levee material, or in trenches using a protective liner. Solidification is a viable disposal option but is more expensive than land spreading or dilution burial. However, for highly contaminated waste or a small area of available background soil for mixing, operators may find this option more cost effective than off-site disposal. Also, the operator must demonstrate integrity and strength of the waste material, as shown in Table 5.3 (compressibility, wet–dry cycling, permeability and leachate test).

3 Subsurface Waste Disposal to Wells

Technically, the term ‘waste slurries’ includes suspensions in fluids having various concentrations of solids, from less than 1 % to over 20 % by volume. All waste liquids from oilfield pits, contaminated produced water, drilling muds and slurrified (fluidized) drill cuttings fall into the category of oilfield waste slurries. Also, subsurface injection includes injection through the annular space between two strings of oilfield casing (annular injection) and injection well technology (tubular injection).

Table 5.3 Limits for oilfield pit closure and on-site disposal

Parameter (for waste material)	Units	Land treatment: Uplands (waste- soil mixtures)	Land treatment: Freshwater wetland (waste-soil mixtures)	Burial or trenching (waste-soil mixtures)	Solidification and burial (solidified material)
pH		6–9	6–9	6–9	6–12
EC (electrical conductivity)	mmho/cm	<8 mmho/cm sol. phase[a]	<4 mmho/cm sol. phase[a]	<12 mmho/cm sol. phase[a]	
SAR (sodium adsorption ratio)	Ratio	<14 solution phase[a]	<12 solutionphase[a]	–	–
ESP (Exchangeable sodium percentage)	%	<25 % solidphase[a]	<15 % solid phase[a]	–	–
CEC (cation-exchange capacity)	millieq. v/100 g				
	Soil	–[b]	–[b]	–[b]	–[b]
O&G (oil and grease)		<1 % by weight[a]	<1 % by weight[a]	<3 % by weight[a]	<10 mg/l[c]
Metals:	%dry weight				
As (arsenic)	ppm (or mg/l)	<10 ppm[a]	<10 ppm[a]	<10 ppm[a]	<0.5 mg/l[c]
Ba (barium)					<10 mg/l[c]
Elevated wetlands			<20,000 ppm[d]	<20,000 ppm[d]	<10 mg/l[c]
Uplands		<40,000 ppm[d]		<40,000 ppm[d]	
Cd (cadmium)		<10 ppm[a]	<10 ppm[a]	<10 ppm[a]	<0.1 mg/l[c]
Cr (chromium)		<500 ppm[a]	<500 ppm[a]	<500 ppm[a]	<0.5 mg/l[c]
Pb (lead)		<500 ppm[a]	<500 ppm[a]	<500 ppm[a]	<0.5 mg/l[c]
Hg (mercury)		<10 ppm[a]	<10 ppm[a]	<10 ppm[a]	<0.2 mg/l[c]
Se (selenium)		<10 ppm[a]	<10 ppm[a]	<10 ppm[a]	<0.1 mg/l[c]
Ag (sliver)		<200 ppm[a]	<200 ppm[a]	<200 ppm[a]	<0.5 mg/l[c]
Zn (zinc)		<500 ppm[a]	<500 ppm[a]	<500 ppm[a]	<5.0 mg/l[c]

Soluble anions:					
Cl (chlorides)	ppm (or mg/l)	–	–	–	<500 mg/l[a]
Ratioisotopes:					
Coastal areas after 20 Oct. 90		–[b]	–[b]	–[b]	–[b]
Other requirements					
Moisture content	% by weight	–	–	<50 % by weight	–
Top of buried mixture	ft	–	–	<5 ft below ground level	10 < 5 ft below ground level
				w/5 ft soil on top	w/5 ft soil on top
Bottom of burial cell	ft	–	–	<5 ft above high water	<5 ft above high water
				Table	Table
Qu (unconfined compressive strength)					
	Ib/in^2 (psi)	–	–	–	<20 psi[e]
Permeability	cm/s	–	–	–	$<1 \times 10^{-6}$ cm/s[e]
Wet/dry durability	cycles to failure	–	–	–	>10 cycles to failure

[a]Analyzed using 'standard soil' testing procedures [23]
[b]Mentioned as a parameter to analyze for, but no limitations are given
[c]Analyzed using 'leachate' testing procedures [23]
[d]Analyzed using 'true total' testing procedures [23]
[e]Testing must be done according to ASTM
GL Ground level

Subsurface disposal of solid waste has evolved from downhole injection of solids-free liquids combined with the well stimulation technique of hydraulic fracturing to the new technology of subsurface injection of slurrified solids. Conventional injection of solids-free liquids such as water flooding or deep well disposal of the cleaned produced water is based upon mechanisms of flow and displacement in continuous porous media. On the other hand, injection of the waste slurry implies fracturing of the disposal zones, even for cases when these zones display very high permeabilities of the order of several darcies ($1\ \mathrm{D} = 0.9868 \times 10^{12}\ \mathrm{m}^2$), and low pore pressures. In high permeability zones, fracturing may still occur during the injection as a result of plugging off the disposal zone adjacent to the wellbore. For the purpose of this chapter, we shall call this technology high-permeability slurry injection in contrast to slurry fracture injection, the technology of slurry disposal in artificial fractures that have been created in impermeable rocks. The technology of high-permeability slurry injection has been also termed, *slurry subfracture injection* – as the injection is performed at pressure lower than formation fracturing pressure [24]. Recently, the high-permeability slurry injection technique has also been applied to dispose of municipal sanitation wastes [25]. In this application, the natural geothermal heat present in the deep subsurface would biodegrade the organic waste, converting it into carbon dioxide and methane. The carbon dioxide is preferentially dissolved and sequestered in the native formation fluids, while methane in relatively pure form collects for potential recovery as a source of renewable energy.

In the early 1980s, high-permeability annular injection of small volumes of drill cuttings became an environmentally sound alternative for on-site disposal of drilling waste, particularly in the Gulf Coast area [26–29]. Later, slurry fracture injection technology was developed for disposal of drill cuttings from oil-based muds in Alaska and the North Sea [30–32], and for NORM (Naturally Occurring Radioactive Materials) disposal [33]. In the mid-1990s, the first large commercial facility with dedicated injection wells began operation [34, 35]. This was followed by large-scale injection operations in Alaska [36] and Gulf of Mexico [37–39].

Since the early 2000s, annular injection has become available for routine use offshore, with several different service companies providing a range of operations and engineering support [40]. An example of continuing evolution of the technology was documented in a study on commingled drill cuttings and produced water injection [41]. Also, slurry fracture injection has been used for disposal of oilfield wastes other than drilling mud and cuttings such as produced sand, sediment from tank bottoms, unset cement and unused fracture sand [42–44]. However, the most common sources of waste injected are from ongoing drilling operations and from mud and cuttings stockpiled in tanks or stored in earthen pits.

Volumes of cuttings from drilling operations could be very large. In the US Gulf of Mexico, for example, over 1000 wells were drilled in 1998. Each well would generate at least 1500 barrels of cuttings or about 5000 barrels of slurry. On the North Slope of Alaska, cuttings from wells drilled in the 1970s and 1980s had been stored in reserve pits at numerous drill sites. By 1993, the volume had grown to about 5 million cubic yards of mud and cuttings, or about 15 billion pounds of solid cuttings.

There is a tremendous range in the capacity of surface processing systems used for injection. In contrast to offshore cuttings injection units having batch mixing capacity of 200 bbl, a large-scale onshore waste disposal facility in South Texas has the capacity to process 20,000 bbl of cuttings slurry and there are two other facilities within a few miles of this one. Each of these facilities has several injection wells available at any time [34, 35]. Between 1994 and 2001, these facilities injected over 7 million barrels of NORM slurry and over 10 million barrels of NOW (Non-Hazardous Oilfield Waste) slurry.

3.1 Description of Slurry Injection Process of Muds and Cuttings

Virtually, all slurry injection operations are batch processed, where drill cuttings are mixed with waste mud and water in the mixing/processing tanks, sent to a holding tank and then injected downhole. In offshore applications, the mixing is done in skid-mounted units on the platforms. Drill solids are mixed with seawater. The mixture is circulated through centrifugal pumps that grind the solids to a desired size. The slurry is then sent to a holding tank and injected downhole with a triplex pump. The offshore units are designed to keep up with the rig drilling rate and the volume of batch is typically about 200 barrels.

The two typical wellbore configurations for injection are annular injection and tubing and packer injection. Shown in Fig. 5.1 is a typical wellbore schematic of a tubing and packer completion, where the slurry is injected down the tubing and into the formation through perforations. This type of completion has been more typical for longer or permanent injection operations onshore. As tubing has lower frictional losses than the annulus, injection rates are much higher than those for the annular injection (1–6 bbl/min) and can be up to 5–25 bbl/min. In some locations, existing producing wells could be recompleted as injection wells while in other places new injection wells must be drilled for the purpose. Reportedly, dedicated injection wells are frequently in service for several years and total slurry volumes can be greater than 2 million barrels per well [40].

In the past, the annular disposal of waste fluids from drilling mud reserve pits has been practiced only in onshore drilling operations [26]. Later, annular injection became more common offshore with the cuttings injected either into the upper annulus of the same well or into an annulus of a nearby well. As shown in Fig. 5.2, annular injection is the injection of fluids between the annulus created by the space between the surface and intermediate casings or between the surface and production casings. The surface casing is cemented all the way to the surface to protect fresh waters, and its setting depth may range from approximately 300 to 2000 ft. The intermediate casing is cemented below the depth at which the surface casing is set

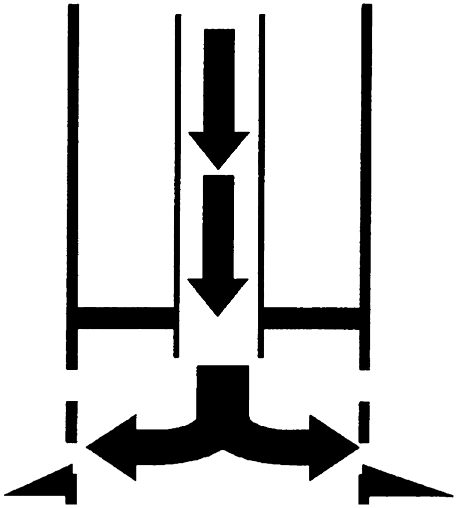

Fig. 5.1 Tubing and packer injection wellbore schematic [40]

so there is an open hole annulus below the surface casing shoe. The annular space that has an open hole exposure enables the fluids to go down between the surface casing and the intermediate casing and out into the permeable formation. In wells with no intermediate casing strings, the fluid will go down below the surface casing and above the top of the cement on the production casing and out into the zones of least resistance. Usually, these zones of least resistance are low- pressure non-productive sands.

In the mid-1980s, the typical application of annular injection followed a fairly routine procedure [26]. The pit fluid injection contractor would connect the injection pump discharge line to the valve at the wellhead that led to the annulus. Then, the waste drilling mud from the pit was pumped into the annulus to fill it up. (Some void space in the annulus, which was caused by settling of the mud, sometimes occurred.) Next, the pumping pressure was increased to 'break the formation down'. This breakdown pressure was usually higher than the average pumping pressure by 200–500 psi (~1360–3400 kPa). The process of formation breakdown is believed to have been in fact a fracturing treatment because gelled and thick mud was pushed out of the annulus and into the permeable rock.

After pumping for a few minutes, the pumping pressures were returned to normal. In most cases, the pumping was begun with water and was gradually changed from water to pit slurry, often with a corresponding increase in pressure. Most contractors injected the entire contents of the pit; therefore, at the end of injection, the pit was usually almost empty. Crowding (pushing) the pit levee with dozers ensured that most of the slurry was removed from the pit.

By the time the pumping was finished, the dozers would have covered and closed the pit, grading the surface back to its original elevation. During the reserve pit injection, the wellhead pressure typically ranged from 500 to 1000 psi in most areas. For shallow wells, such as those in the Canadian counties of McClain or

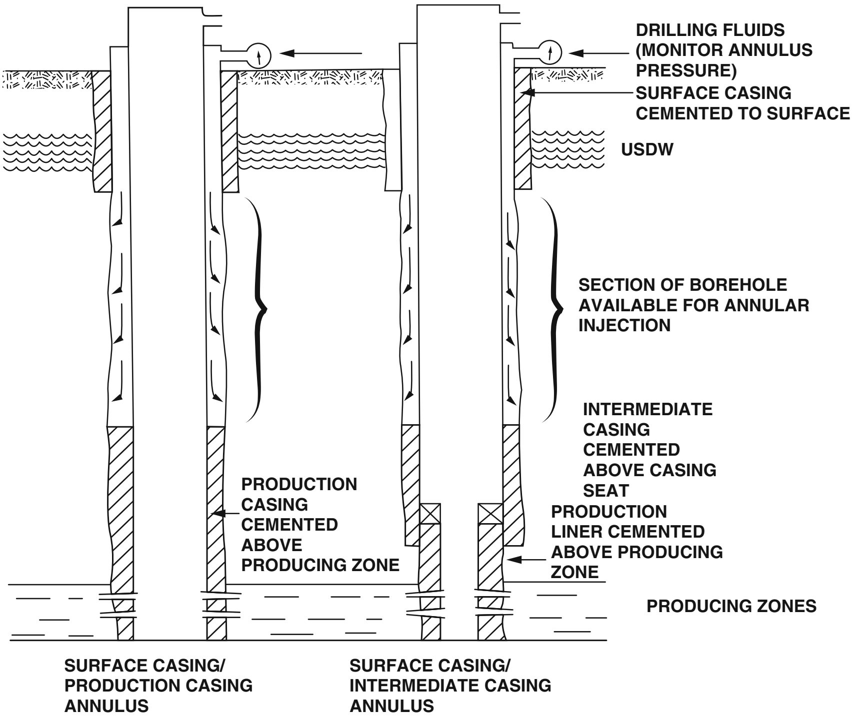

Fig. 5.2 Well configurations for annular injection. *USDW* underground source of drinking water

Kingfisher, for example, the average injection pressure ranged from 500 to 700 psi. In the Anadarko Basin, on the other hand, the deep-drilled wells usually required injection pressures ranging from 1000 to 5000 psi. The waste volume injected from a well depended upon the well's depth and pit volume and ranged from 15,000 to 60,000 barrels. The rates of injection, from two to ten barrels per minute, varied depending on the contractor's equipment. The equipment used in this technology was a type of centrifugal pump, known as a 'trash' pump, which homogenized the contents of the pit by circulating and stirring the pit and mixing the mud, cuttings and water together.

Specific for early applications of slurry injection technology was a lack of concern for hydraulic fracturing of the disposal zones. The injection zones were shallow (3600–4600 ft) unconsolidated sand strata with extremely high permeability due to the presence of shell deposits. Table 5.4 shows properties of the rock strata in the disposal zone. The high permeability of these formations allowed successful disposal of materials such as slurrified, drilled-out cement, shredded paper waste (mud sacks and cardboard boxes), shredded industrial plastic foil and ground wood with plastics (shredded wooden pallets and crates) [28]. Lack of concern for fracturing was based on the assumption that in highly permeable rocks fractures cannot be propagated far because most of the liquid phase of the

Table 5.4 Description of subsurface disposal zone: Gulf of Mexico

Depth range (ft)	Rock	Per cent	Description
3810–3960	Sand	40–90	Clear, white, translucent, loose, very fine grained, well sorted
	Shale	10–50	Light gray, soft (occasionally firm), flaky, sticky, calcareous
	Shells	10	Loose fragments, macro fossils, microfossils
3960–4080	Sand	70–90	Clear, white, moderately well consolidated, fine grained, well sorted, calcareous cement
	Shale	0–10	Gray, moderately firm, blocky, platy
	Shells	0–20	As above
4080–4280	Sand	30–70	Clear, translucent, unconsolidated, fine grained, moderately sorted, spherical
	Shale	10	Firm, blocky, platy, calcareous
	Shells	20–60	As above

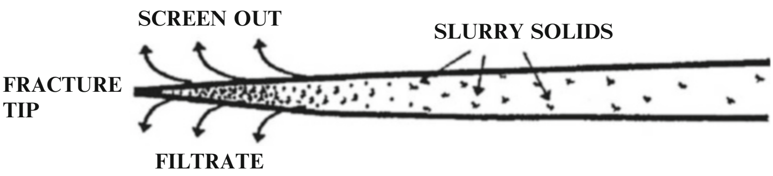

Fig. 5.3 Fracture screen-out during high-permeability injection of slurrified solid waste

injected slurry is lost from the fracture into the rock structure due to the ‘screen out’ effect.

As shown in Fig. 5.3, screen-out can occur when the fluid phase of a solid–liquid mixture is lost into the fractured formation. As the liquid phase fraction diminishes, the solids fraction can increase in the fracture tip until there is no longer enough liquid phase to continue conveying the solids. Cuttings slurries typically have a high potential for rapid screen-out across fracture walls since they tend to exhibit excessive fluid loss properties. However, data from various cuttings injection operations show that a drill cuttings’ slurry can be successfully injected into formations with high permeability [29].

Figure 5.4 is a schematic diagram of the basic surface slurrification equipment and the downhole cuttings injection process. Cuttings generated by drilling operations are removed from the drilling fluid using conventional solids control equipment and then transported to the cuttings slurrification system using conveying equipment. When the cuttings reach the system, they are transformed into pumpable slurry by mixing water with the drilled cuttings at approximately a 3:1 ratio. Once the cuttings and water are blended into a homogeneous mixture, the cuttings are reduced to an acceptable particle size distribution by shearing them with specially modified centrifugal pumps and/or by grinding them using mechanical grinding equipment. Injection pumps are modified to enhance cavitation. Also, the pump impellers are hard faced so that erosion of the blades is minimized.

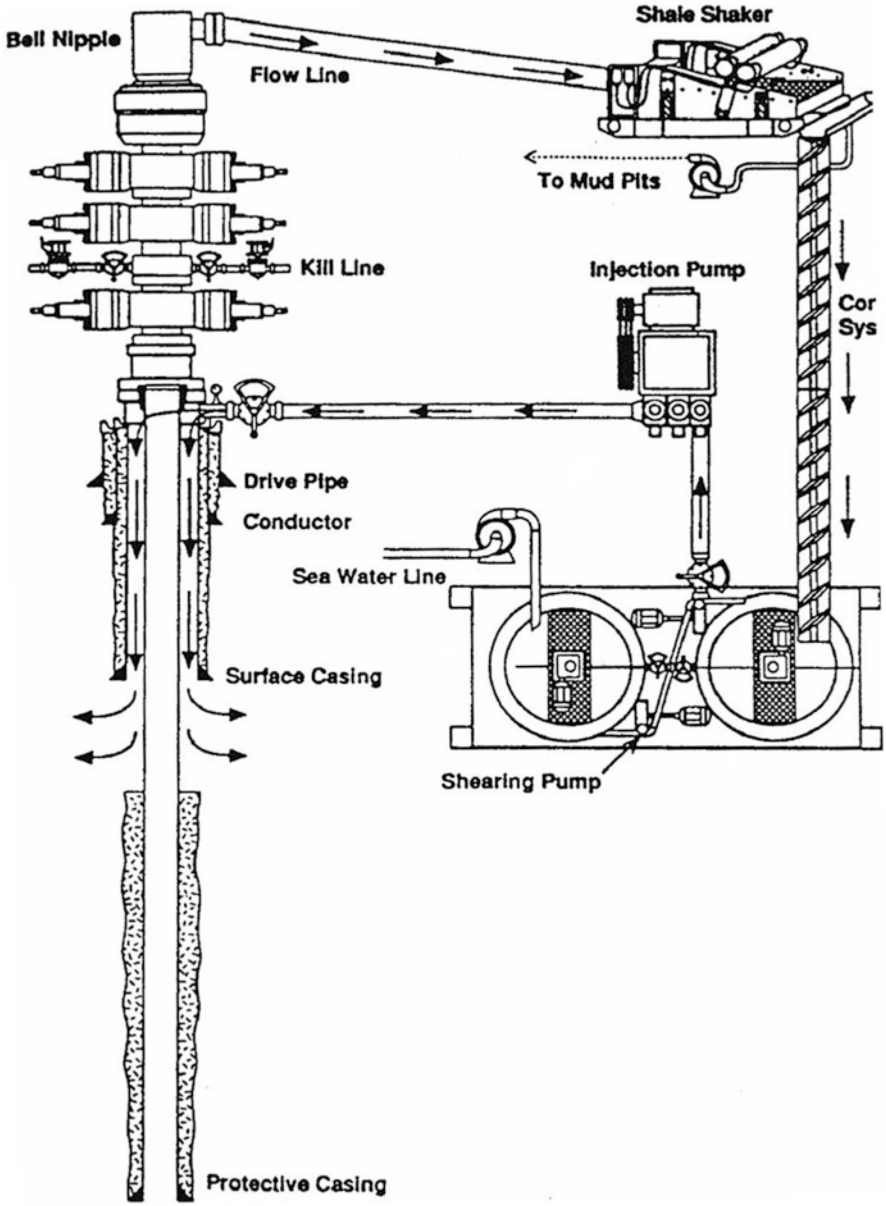

Fig. 5.4 Schematics of slurrification and annular injection process for OBM cuttings in the Gulf of Mexico [27]

Table 5.5 Properties of slurrified drill cuttings injected in Gulf of Mexico[a]

Property	Minimum	Maximum
Density (lb/gal)	9.9	12.7
Funnel viscosity (s/qt)	41	92
Retort solids (vol %)	4	25
Retort water (vol %):	64	85
Retort water (vol %)	4	24

[a]After Ref. [27]

In the Gulf of Mexico area, drilled cuttings are so soft that the dispersion of the cuttings and the preparation of the slurry generally require only one pass through the centrifugal pump. Then, a small triplex pump takes the slurry from the slurrification pods and pumps it down the well's annulus. The slurry is kept at an optimum viscosity by adding sea water, dispersant, caustic or gel and is pumped at a specified rate. Typical properties of the slurry are shown in Table 5.5. When the pressure increase resulting from the pumping operation exceeds the strength of the exposed formation, the rock fractures and the cuttings slurry flow into the created fissure.

The pumping operation continues until all slurry is injected into the formation. Table 5.6 gives the maximum injection parameters for four wells in the Gulf of Mexico. Maximum pumping pressures evidently exceeded the fracturing pressures of the disposal zones at times.

The high-permeability annular injection process has not yet been standardized. However, some basic guidelines have been developed from experience gained mostly in the Gulf of Mexico [29]. In the presence of a high permeability disposal zone overlaid by a continuous sealing shale formation, the surface casing should be set and cemented at the bottom of the sealing zone. It has been proved by radioactive tracer surveys that the injected slurry would enter the high-permeability zone immediately below the surface casing shoe. Hydraulic fractures initiated in these zones are short and wide and do not propagate very far. Also modeling studies indicate that the amount of open hole below the surface casing shoe and the top of the cement controls the direction of fracture propagation [29]. As the length of the open hole section increases, the propagating fracture will tend to grow in the downward direction.

Since fracturing is not of much concern in the high-permeability injection, the limiting factors for injection pressure and rate design are casing resistance to collapse, burst and erosion. Typically, operational practices call for the maximum injection pressure limits based on 70 % of the burst rating for surface casing and 50 % of the collapse pressure for intermediate casing string. Protection from erosion involves installation of a steel collar that deflects the stream of slurry entering the casing head and protects the intermediate casing hanger from exposure to the stream.

Table 5.6 Injection parameters for four wells in the Gulf of Mexico[a]

	Surface casing		Intermediate casing			Maximum injection parameters		
Well location	TVD[b](ft)	Size (in)	Size (in)	TOC[c] (ft)	Leak-off test equivalent mud weight (lb/gal)	Volume (bbl)	Rate (bbl/min)	Pressure (psi)
East Cameron	4724	10.750	7.625	5230	14.4	1270	0.5	1500
Matagorda Island	4490	13.375	9.625	5800	14.3	9560	4.0	1800
Galveston	3566	13.375	9.625	5200	14.1	19,579	2.0	2000
Galveston	3495	13.375	9.625	5890	14.3	9990	3.5	1200

[a]After Ref. [27]
[b]*TVD* true vertical depth
[c]*TOC* top of cement

3.2 Slurry Fracture Injection of Muds and Cuttings

The technology of disposal to artificial fractures has been developed in drilling areas that lack low-pressure/high-permeability disposal zones typical for the Gulf of Mexico or other areas with naturally fractured formations. In the North Sea, for example, permeable shallow sands having a porosity of 35 % and permeability in the range of a few darcies are underlain by massive Tertiary mudstones, as shown in Fig. 5.5. Two options for annular disposal can be considered theoretically:

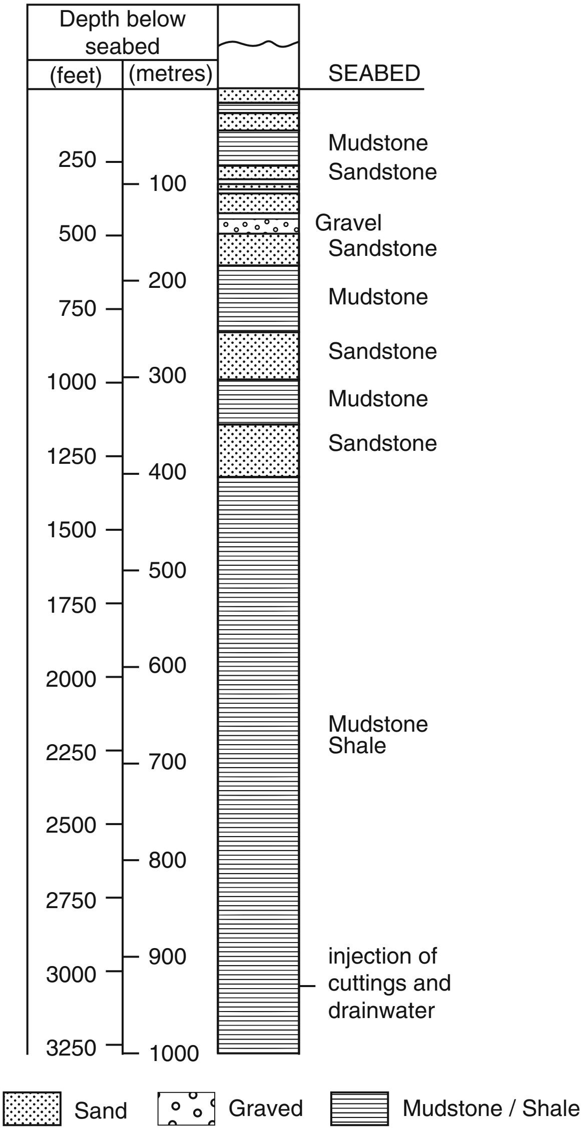

Fig. 5.5 Example of shallow subsea stratigraphy in the North Sea area

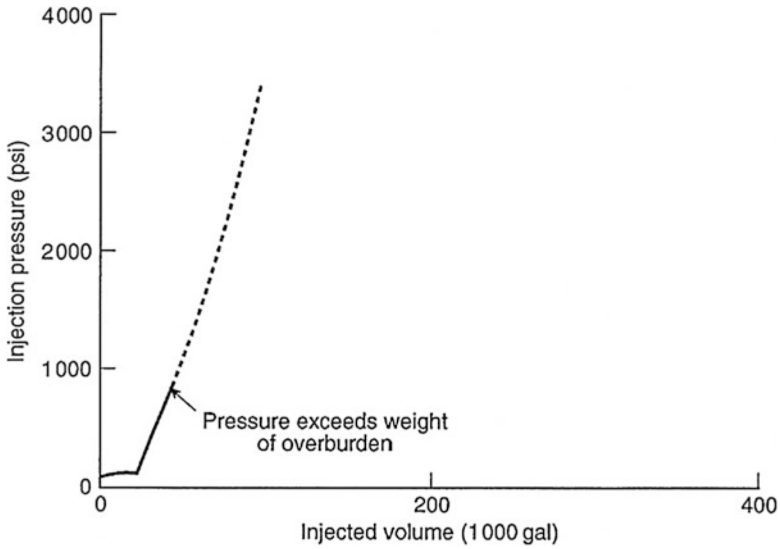

Fig. 5.6 Computer-simulated trend of injection pressure during high-permeability injection to single fracture with early slurry screen-out [32]

high-permeability injection to the lowermost sandstone formation or slurry fracture injection into the mudstone.

A numerical simulation study of high-permeabily injection showed that the disposal fracture in sandstone would be shorter owing to slurry dehydration and would tend to propagate upwards into the overlying (impermeable) shales and siltstones [32]. Also, the calculations showed a rapid increase in injection pressure due to early screen-out (dewatering) of the slurry, as shown in Fig. 5.6. High permeability injection was concluded to result in smaller disposal volumes, a rapid increase in injection pressure for any new fracture created and a tendency of the fracture to propagate upwards into the sealing zone.

The other alternative, slurry fracture injection into a massive mudstone overlaid by permeable sandstone, proved superior to the high-permeability injection in the North Sea area. The conclusion was initially based upon theoretical simulation studies of fracture initiation, propagation, fracture shape and slurry screen-out [32, 45]. Fractures made in practically impermeable rocks were concluded to have a favorable, circular shape, i.e. they will propagate uniformly in vertical and horizontal directions. This process is shown in Fig. 5.7. Initially the vertical fracture expands as a radial fracture until its top reaches the permeable sand. Then, the cuttings laden slurry would start to dehydrate, plugging the portion of the fracture that is in contact with the sand. Additional lateral fracturing would then occur (probably at a slightly higher pressure), as illustrated by fracture ‘2’, until again the fracture could grow vertically up into the permeable formation, where it would again screenout, etc. Hence this mechanism of fracture propagation could

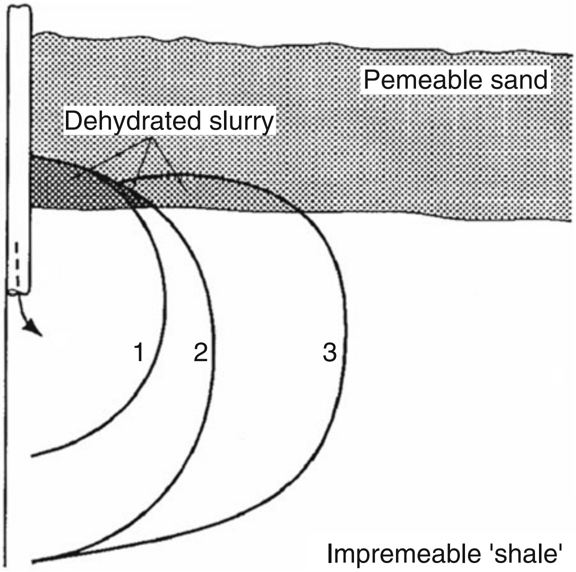

Fig. 5.7 Propagation of disposal fracture during slurry fracture injection process [32]

conceivably allow significantly larger quantities of injection than might be possible for injection directly into a permeable formation.

Cuttings injection could be used in a wide range of geologic formations. In the North Sea, injection is typically into shales, with overlying sandstones used to dissipate pressures and contain waste migration. In Alaska and California, injection is into sandstone, with shales used to contain fracture propagation. In the large waste disposal facility in South Texas injection is into a naturally fractured formation [34, 35]. All of these completion schemes have injected large quantities of waste.

As we start injecting into a formation that is not naturally fractured, the pressure will rise as the formation accepts fluid under matrix injection, as shown in Fig. 5.8. At this point, the pressure will exceed the breakdown pressure of the formation and a hydraulic fracture will initiate and begin to propagate. Fracturing is essential for solids placement because without fracturing the slurry would screen-out at the surface of the open hole and solids would fill-out the well.

The slurry fracture injection process for OBM cuttings has been fully implemented in the Gyda field [31, 46–49]. The BP Norway's Gyda was the first platform in the North Sea to dispose of all its drilling waste by downhole injection. The process is shown in Fig. 5.9 [49]. The oil-based mud is used to drill the three lower sections of 12¼, 8½ and 6 in holes.

Approximately 500, 13 and 15 tonnes of rock and 35, 20 and 2 tonnes of oil were typically discharged from each of the respective hole sizes per well. As shown in Fig. 5.9 the surface installation for slurry fracture injection was very similar to the high-permeability injection process used in the Gulf of Mexico. A simple centrifugal pump shearing system was used to grind and mix drill cuttings with sea water

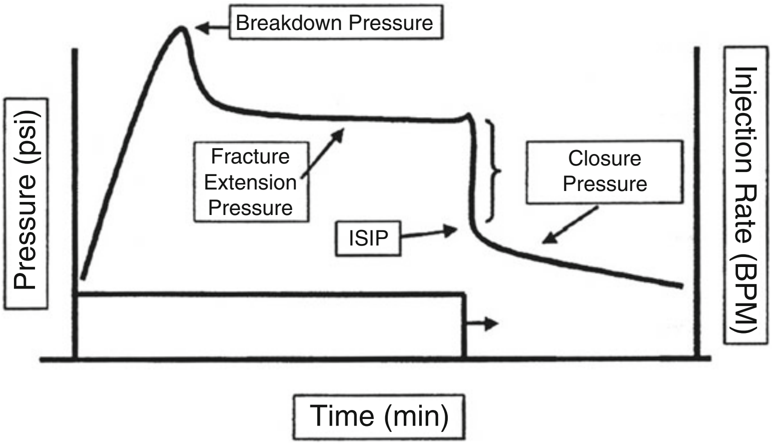

Fig. 5.8 Slurry fracture injection process [41]

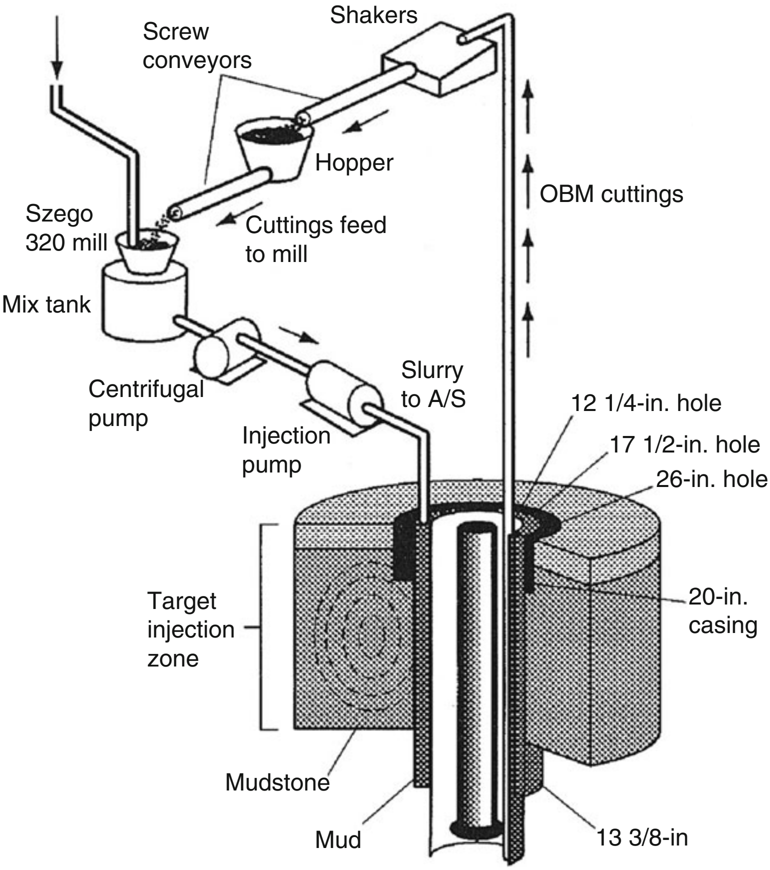

Fig. 5.9 Slurry fracture injection process [49]

Table 5.7 Parameters of slurry fracture injection at Gyda[a]

	Well numbers: injection/drilled							
Parameter	A-23/ A-09	A-09/ A-22	A-22/ A-16	A-16/ A-19	A-19/ A-27	A-27/ A-15	A-15/ A-26	A-26/A-24
Start injection	30/7/91	12/9/91	5/11/92	18/1/92	1/5/92	2/7/92	11/8/92	29/9/92
Duration (days)	42	31	47	41	42	21	30	Ongoing
Volume (bbl)	13,500	27,000	27,000	16,245	15,037	13,111	16,033	11,615
Injection rate (bbl/min)	8	3.8	7	7	7	7	9	11
Injection pressure (psi)	900	1000	1200	1100	1200	1400	1600	1450
Initial shut-in pressure (psi)	900	1100	700	NR[b]	NR	NR	NR	NR
Shut-in pressure (psi) (01/02/92)	700	150	700	NR	NR	NR	NR	NR
Shut-in presssure (psi) (10/10/92)	900	900	700	1100	1000	900	1100	950

[a]After Refs. [45] and [49]. Data as of 10 October 1992
[b]*NR* not recorded

to produce pumpable slurry. The slurry was pumped through the casing spool wing valve into the $9^5/_8 \times 13^3/_8$ in casing annulus to fracture the massive Tertiary mudstones below the $13^3/_8$ in casing shoe, which is about 900 m below the seabed (Fig. 5.5). Several sand intervals with interbedded shales between 250 and 400 m below the seabed provide excellent geological barriers against fracture propagation and fluid migration to the seabed.

At Gyda, sequential annular injection, whereby cuttings from the well being drilled are injected into the annulus of the most recently completed well, has been adopted. On average, about 15,000 bbl of slurry per well were injected, including wash water and other watery drain-off wastes, with a maximum volume of 33,000 bbl in one well.

Performance of the fracture injection process is documented in Table 5.6 for the Gyda platform [45]. Note a sequential annular injection procedure in which cuttings from the well being drilled are injected into the annulus of the most recently completed well, etc. Also note in Table 5.7 that the annular shut-in pressure has not dropped over 1 year period, which may become an environmentally significant fact regarding fracture disposal technology. This and other environmental considerations are discussed below.

The fracture injection process from Gyda platform was designed using hydraulic fracturing models to estimate maximum volume injected. In the design, they assumed zero leak-off in any of the formations above the injection zone and modeled multiple batch injections as a single batch. The analysis showed that 90,000 barrels of slurry could be injected before a fracture grew to the seabed. Then, they allowed leak-off into the various sandstone layers and noted that 52,000 barrels could be injected before the fracture grew into the deepest of these layers. The sandstone layers would contained the fracture from any additional growth uphole. Since the typical Gyda injection volume was only 15,000 barrels, there was a built-in safety factor in the analysis.

In 1993, ARCO performed a field demonstration of fracturing for solid waste disposal in an unconsolidated formation in Southeast Texas [50–52]. This project was designed to mimic a long-term large-scale solid waste disposal operation, not a small batch cuttings injection operation. A volume of 50,000 barrels of bentonite mud with 100-mesh sand was pumped in four batches over a 5 day period.

The real-time microseismic monitoring project showed the fractures were contained in the 200-ft thick injection zone and grew to roughly 1200 ft in half-length. In the first three stages, the fractures systematically grew out to about 1200-ft half-length in fairly planar growth. During the last injection cycle, the microseismic events grew out 90° off the original fracture plane. Subsequent geophysical analysis confirmed these off-planar events indicating the onset of multiple fracture evolution as a result of batch injection, even in unconsolidated formations.

In 1994, a commercial injection of cuttings began in a dedicated disposal well started in the Wilmington Field in Long Beach, California [52]. The injection well was an old producer and was scheduled for plugging and abandonment. The injection stratum consists of several shale-sand sequences, all of them below groundwater and bounding shale. The injection started in the deepest sand and has moved uphole as zones gained pressure over time. The injection permit allowed the packer to be set above all these injection zones, which allowed inexpensive through-tubing re-completions to set plugs, perforate and establish injection into a new disposal zone. In the late 2000, over 1.3 million barrels of slurry and 26,000 cubic yards of solids have been injected into this well [52].

The Prudhoe Bay Unit Grind and Inject program began in early 1995 with a surface processing capacity of 24,000 bbl/day. The injection interval is a poorly-consolidated sandstone with large aerial extent. Over 8 million barrels of slurry were injected into one well over 3 year time, but the operation was temporarily stopped in 1997 due to a surface breach suspected to be caused by the slurry breaking into not cemented annulus of another well. Three new wells were drilled in 1998 and, by 2002, over 35 million barrels of slurry has been injected in these three wells. The fact that so much fluid and solids was injected with no sustained pressure increase led to considerable debate about the downhole mechanics of solids injection and the concept of multiple fracturing – discussed later in this chapter.

3.3 Properties of Injected Slurries

Cutting slurry injection is similar to fracture stimulation technology in that both technologies inject liquids and solids into a fracture and both technologies rely on the ability to continue fracture propagation until the entire volume of materials has been injected. Still, there are differences between these two technologies, primarily because cuttings slurries exhibit fluid properties very different from those of fracture stimulation fluids.

During conventional fracture stimulation operations, a low-solids fluid with very low fluid loss properties is injected ahead of solids-laden (proppant) phase. This low fluid loss pad is essential to maximizing fracture propagation and to minimizing the chance of fracture screen-out. As shown above, screen-out can occur when the fluid phase of a solid–liquid mixture is lost into the fractured formation. As the liquid phase fraction filters out, the solids fraction can increase in the fracture tip until there is no longer enough liquid phase to continue conveying the solids.

In slurry injection technology the particle size distribution of solids in the slurry can be designed such that it controls the rate of the screen-out. If the selected injection zone is impermeable, the particle size of solids in the slurry should be increased to cause rapid fracture screen-out when the fracture propagates into a permeable formation. On the other hand, for high-permeability injection, the particle size of solids in the slurry should be reduced to minimize the rate of fracture screen-out and to maintain fracture propagation into the permeable injection zone.

The size of particles in a slurrified suspension results from the type of grinding device used. These devices include a hard-faced centrifugal pump for weak cuttings (Gulf of Mexico), a vibrating ball-mill (Alaska [30]), an autogenous wet-crushing mill or a Szego ball-mill (North Sea [29, 32]). An example of the size distribution of solids in the slurry injected in the North Sea area is $d_{10} = 3$, $d_{50} = 9$ and $d_{90} = 120$ μm [44, 45]. With 50 % of the particles smaller than 9 μm, the viscosity of the suspension is sufficient to prevent settling of larger solids in the fracture.

Rheological properties of injected slurries reported in the literature are plastic viscosity = 15 cP, yield point = 60 dyn/cm^2, flow behavior index = 0.26, consistency index = 0.148 lbf/ft^2/s$^{0.26}$, solids content ≈ 30 % by volume and specific gravity = 1.68. Also reported was the use of polymeric viscosifiers with biocides [32], as well as thinners, bentonite and caustic, to control the rheology and biodegradation of the slurries [27].

The filtration properties of injected slurries follow the theoretical mechanism of cake (or 'static') filtration, with filtrate volume directly proportional to the square root of time and with a proportionality constant equal to 0.004 ft/min$^{0.5}$ [32].

3.4 Environmental Implications of Subsurface Slurry Injection

The most important environmental concern for all injection operations is the protection of the groundwater. In the liquid or solid injection wells, groundwater protection is accomplished through both the internal mechanical integrity of the casing/tubing system and external integrity of the annulus isolation with cement – discussed in Chap. 4. For solid injection into geologic zones that are not highly naturally fractured, there is an added concern of hydraulic fracturing height growth and its safe containment below the groundwater zone.

The most important technical parameters in the fracture slurry injection are vertical propagation of the disposal fractures, loss of annular integrity of wellbore and the ultimate fate of the injected slurry. Typically, the risk of vertical propagation of fractures has been evaluated through mathematical modeling with the use of 3-D fracturing simulators. The simulator inputs include minimum *in situ* stresses, pore pressure gradients, Young's modulus and Poisson's ratio variations, slurry filtration (screen-out) and rheological properties, depth of injection and injection rate. The calculations typically show a relationship between the cumulative volume injected and the vertical height of the fracture for a given geological profile of sediments above the injection point. For example, simulation studies for the Gyda platform showed that, in the absence of any high-permeability sands above the massive mudstone (disposal zone), 90,000 bbl of slurry would be needed to propagate the fracture of the seabed [45]. This study also showed that any shallow sand strata would become a barrier for fracture propagation. Similar studies were also reported for the Clyde platform in the North Sea [31].

In Alaska, field measurements of surface deformation were used to assess the potential for vertical propagation of disposal fractures under the permafrost in Prudhoe Bay field [42]. The fractures were initiated under the permafrost at 2000 ft. Then, a total of 2 million barrels of oilfield waste fluids were injected into three wells with injection rates averaging 1–2 bbl/min. Surface deformation of the permafrost was measured with an array of tiltmeters installed 25 ft into the permafrost. Analysis of the surface deformation was combined with transient pressure testing (step-rate and fall-off tests) of the injection wells. The analysis revealed the presence of horizontal fractures without discernible vertical fracturing.

Propagation of vertical disposal fractures in the highly permeable and thick (155 ft) Frio Sand at 4500 ft was effectively stopped by a 130 ft thick layer of shale overlaying the sand. This finding was documented by a recent field study involving computer simulation combined with a new method of realtime passive seismic monitoring and analysis [46].

Loss of external annular integrity of the borehole involves channeling outside the outer casing of the injection annulus and the flow of injected waste slurry to shallow aquifers or breaching the slurry to the surface. Verification of external integrity involves periodic additions of radioactive tracers to the slurry injected to the well's annulus while drilling the lower sections of the well. Typically, different types of short half-life tracers such as antimony, iridium and scandium are injected at the beginning, during and at the end of the annular injection process (upon reaching the total drilling depth). Upon completion of all drilling operations, a multiple isotope tracer log is run to determine actual injection points and flow behind the casing [28].

A long-term environmental risk results from the ultimate fate of injected slurry. When injecting wholly into shales, fluid screen-out is minimal. Here the fate of the solid waste slurry is dependent on chemical reaction with the surrounding shale. The hypothesis has been proposed that, since shales are usually reactive with water-based fluids, over time the sea water carrying the fluid reacts with the swelling clays to form increasingly viscous, dehydrated slurry within the fracture, which will eventually seal the fracture over a long time period. The softened zone adjacent to the fracture would be relatively localized (a few feet at most, by virtue of the low permeability), thus posing little threat to subsequent well drilling, which may pass through the sealed fracture plane. In this new well the fracture will manifest itself as a localized tight-spot within the open hole without abnormally high-pressure trapped in the fracture. Moreover, even if the pressure has been trapped, the high viscosity and gel strength of the remnant of dehydrated slurry preclude taking an unexpected kick. The above theory has never been verified experimentally. To date, field data indicate the continuing presence of pressurized fractures with no observed release of pressure in time, as shown in Table 5.6.

Significant fluid migration is also believed to be impossible, even in permeable strata. When disposal fractures intersect an unconsolidated sand of considerable thickness (10 m or so is usually sufficient), a rapid leak-off of the filtrate (screen-out), resulting in dehydration of the slurry, takes place. The dehydration assures permanent disposal of the solid particles, which remain trapped at the fracture–sand contact surface. Only the smallest clay particles may enter the sand formation. Also, the dehydrated solid cake will in time reduce the intrusion of the liquid phase into the sand. As the pore volume of these laterally extensive shallow sands is large and because of their compressible nature, substantial volumes of slurry could be injected without the risk of over-pressuring either the fracture or the sand formation.

3.5 Periodic Injection to Multiple Fractures

A new concept of multiple fracturing due periodic injection has been derived from the observation that for periodic injections, there is a repetitive pattern of initial increase of injection pressure followed by pressure decrease and final stabilization [53]. Also, the stabilized pressure level at the end of each injection tends to increase with the number of injections. This behavior contradicts the propagation of a single fracture, which would require a smaller propagation pressure due to the fracture size increase. This observation led to the conclusion that periodic injections may create multiple fractures in the same region of the formation around the injection borehole (disposal domain).

The mechanism of inducing disposal domain of multiple fractures due periodic injection begins with creation of a single planar fracture after the first batch injection [40] – as shown in Fig. 5.10. After the injection stops, slurry liquid will leak-off into the rock, and the fracture will close on the solids, trapping the mud filter cake and cuttings. The trapped material will slightly increase *in situ* stress in the direction normal to the fracture face. Also, the pore pressure around the fracture will be increased by the liquid leak-off (filtration). Finally, the conductivity of the closed fracture (controlled by the very low permeability of waste solids) will be

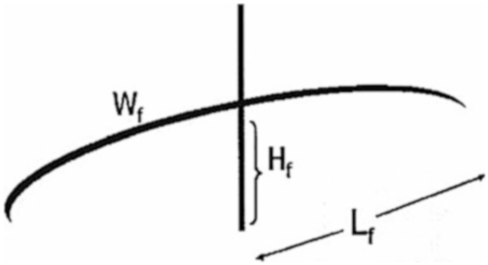

Fig. 5.10 A single two-wing planar fracture [40]

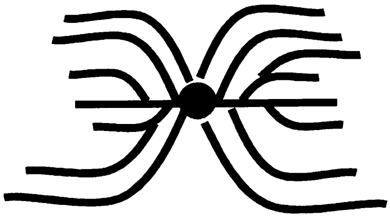

Fig. 5.11 Multi-fractured "disposal domain" [53]

very low comparing to a conventional fracture filled with breakers and proppant. In fact, the permeability will be lower than that of the formation matrix.

The next batch injections may still re-open the existing fracture and extend its height, length or width. However, as the number of batches increase, the combined effects of low fracture conductivity and increasing stresses due to growing fracture width would favor the creation of a new fracture. These new fractures will be branching off the original fracture. As we inject more batches, these multiple fractures become numerous thus creating a network of interconnected fractures – a disposal domain, as shown in Fig. 5.11.

For soft, unconsolidated rocks with low compressive strengths – typical of the Gulf of Mexico and shallow formations on the North Slope of Alaska, liquefaction (disaggregation) may also take place [54]. In addition to creation of multiple fractures, each injection may induce enough shear stress to overcome the minimal grain-to-grain cementing. This in turn would increase the *in situ* porosity and yield a tremendous storage capacity of the formation. The disaggregation concept is shown in Fig. 5.12.

The theoretical concept of multiple fractures was verified experimentally by a drilling Engineering Association consortium DEA-81 funded by the petroleum industry (Amoco, Arco BP, Chevron, Exxon, Shell, and Statoil) [52]. In the project, a series of laboratory experiment were conducted using blocks of shale, hard sandstone, soft sandstone and synthetic rocks placed under confining stresses and pore pressures. The blocks ranged in size from about one cubic foot to one cubic meter. The hard rocks were from quarries and the weak rocks were made in the lab. Each test involved multiple batch injections of slurries of mud and simulated cuttings with each injection followed by a long shut-in time to allow fractures to close.

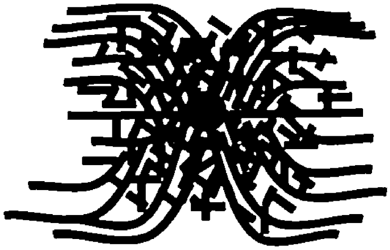

Fig. 5.12 Schematic of "disaggregation" concept [54]

The most important result from the DEA-81 project was that multiple fractures are indeed created with multiple batch slurry injections. It was found out that, in most cases, each new batch injection created a new fracture. In hard rocks, the multiple fractures tended to be parallel to one another and very closely spaced.

Multiple fracturing in soft rock samples also involved multiple parallel fractures but some of the fractures were wider than others with blunted tips and solids invasion ahead of the fracture tip. Some of the tests also showed solids invasion across the fracture face, suggesting liquefaction (disaggregation) of the rock.

One of the important parameters of periodic injection process is the incremental volume of storage resulting from large number of fractures having limited size (storage domain). The number of multiple fractures in the disposal domain has been initially modeled using analogy with fractures induced by thermo-elastic effect [55]. The solution scaled the number of fractures with the fracture height, yielding:

$$\begin{aligned} N_f &= \pi R/4H_f \\ \text{for} R &> 4H_f/\pi \end{aligned} \tag{5.1}$$

where:

N_f = number of fractures; R = radius of single fracture; H_f = fracture height.

For example, for a fracture height of 100 ft, with fracture domain radius 1000 ft, the number of fractures is rounded up to eight fractures. This simply means that the storage volume of the domain is eightfold larger than that for a single fracture.

The results of the DEA-81 project did not confirm the above concept, however. It suggested that the number of multiple fractures would scale with the fracture width rather than height. That would mean – by a very rough approximation [56], that formula (5.1) should read:

$$N_f = \pi R/4W_f \tag{5.2}$$

where:

W_f = width of fractures.

Thus, for the same radius of the domain and fracture width of 0.5 ft., the number of fractures becomes 19,625. Even for a radius of 50 ft, with a width of 0.1 ft., the number is almost 500. Notwithstanding accuracy, the examples show tremendous storage volume of this disposal method.

The periodic injection method has been also verified in field experiments. In 1998, the Mounds Drill Cuttings Injection project was funded jointly by petroleum industry and Gas Research Institute and the US Department of Energy [57–59]. The project involved drilling three wells in Mounds, Oklahoma. One well was the injection well and the other two were monitoring wells for microseismic and downhole tiltmeter measurements. Surface tiltmeters were also used. In addition, four sidetrack core runs were conducted after the injection to confirm the location of the created fractures and injected waste.

There were two target intervals for slurry injection: the Wilcox Sand at 2600–2800 ft, and Atoka Shale at 1950 ft. Both formations have large elastic modulus typical of this mid-continent US geologic setting. In the Wilcox, a total of 22 batches were injected of which 17 were slurry batches. There were 23 injections to Atoka, of which 20 were slurry batches. The batches ranged in size from 50 to 100 barrels.

The coring results integrated with the fracture diagnostics provided indisputable proof that multiple fractures can be created in the field as a result of batch slurry injection. The conclusion was later independently confirmed in the data assessment study [59].

The apparent environmental advantage of periodic fracturing is minimization of risk due to better containment of a large volume of waste in a small disposal domain comprising multiple fractures of controlled extent.

The new process has been also evaluated from the standpoint of design methodology using mathematical modeling of the disposal domain. In a project involving large-volume slurry injection, a comprehensive approach was used for injection design, operations, and data interpretation [39, 60]. The conclusion was that simulation models of hydraulic fractures did not adequately describe nonlinear fractures and dilation behavior of soft formations. The existing models could be only used for qualitative evaluation of formation response to the injection process. The findings suggest that there is a need for improved modeling capability.

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Chapter 6
Environmental Impacts of Hydraulic Fracturing

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1 Introduction

Unconventional oil and gas development has dramatically changed the ability of the US to meet current and future energy needs. Advanced drilling technology as well as hydraulic fracturing techniques have led to efficient production from shales and dramatic improvements in the productivity of oil and gas fields. This has led to rapid growth in the industry and oil and gas development in many areas where there was limited or no activity [27]. Rapid development in the industry, however, has raised public concerns associated with human health risks and environmental impacts [26]. Unconventional oil and gas development involves well drilling and completion, hydraulically fracturing, oil and gas extraction and transportation and processing of the produced oil and gas [62]. Each of these steps can lead to environmental disturbance, contamination and other impacts. Environmental concerns associated with hydraulic fracturing activities extend from proppant sand mining to chemicals and contaminants in fracturing fluids; leaks during drilling, production, and storage; natural resource use (including substantial water use); light and noise pollution, and impacts to cultural resources and aesthetics. There are also ecological risks which include (1) direct habitat destruction, erosion, and effects on biota of light and noise pollution associated with clearing, drilling, equipment and vehicles, as well as fracturing sand mining; (2) pollutant effects on biota from exposures to surface releases (routine and accidental) of wastewater; and (3) animal health impacts from contaminant exposures, such as via ingestion of high salts in

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_6

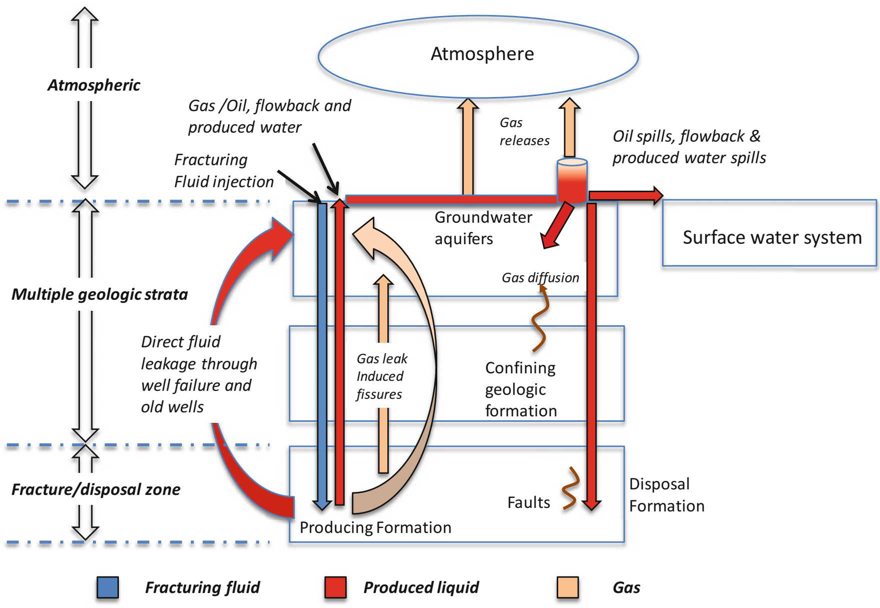

Fig. 6.1 Pathways of potential environmental impact from hydraulic fracturing

impounded brine (impacting both wildlife and pets), as well as population migration and reduced survival rate of wildlife (such as mule deer) [7].

This chapter will survey these potential environmental impacts and their significance but will focus on potential risks to water resources, air pollution and geological risks (seismicity) and human impacts. The discussion will not address the social impacts associated with rapid growth of oil and gas in areas with limited prior development nor the global environmental risks associated with fossil fuels and their link to climate change. Further the discussion will focus on environmental risks at and near the well head. Risks during transport away from the well head and downstream processing will not be considered. Key potential contamination pathways that will be the focus of the current discussion are illustrated in Fig. 6.1. These can be summarized as

- Risks to Water Resources – including migration, spills and leaks of hydrocarbons or produced waters below ground and on the surface
- Risk to Air Resources – including hydrocarbon leaks and particulate emissions
- Geologic Risks – primarily seismicity due to produced fluid disposal

Hydraulic fracturing uses a large volume of fracturing fluid, primarily water, in order to develop fractures for extracting oil and gas. Different additives and organic compounds such as friction reducers or gels, biocides and a proppant such as sand are added to the fracturing fluid in order to improve its characteristics. Although other fluids have been proposed, the primary fracturing fluid is water, often freshwater because of its relatively simple and easily modified properties. The use of freshwater is of concern because shale plays are often located in water scarce areas and some of the greatest growth in hydraulic fracturing for oil and gas production has occurred during a period of serious drought in the western United States.

The technology involves pumping water into a shale formation under high pressure and then reducing the pressure to allow the well to begin to produce hydrocarbon. In addition to hydrocarbons (oil or gas or both), substantial quantities of flowback (originating with the injected fluids) and formation water is produced. The composition of the returned water can differ from site to site based on the geological formation and kind of the additives which have been used in fracturing fluids. Much of the flowback remains in the subsurface, with typically only 10–25% of the injected fluid returning to the surface [38, 69]. Long term generation of produced water depends on the type of formation. As an example, the Marcellus shale play in the northeastern United States may produce 84–420 gallons per day per well which is equivalent to 200–1000 gallons per million cubic feet of gas production [69].

The quality of the flowback and produced water is quite variable as shown in Table 6.1 [10]. Generally, produced water has a very high salinity as indicated by high total dissolved solids (TDS) and hardness mostly caused by barium, strontium, calcium, magnesium and in some cases naturally occurring radioactive materials (NORM) notably Radium [66, 71].

There are concerns about the volume of water required for fracturing as well as the migration of the hydrocarbons and injection fluids as a result of the fracturing process. There are also concerns about the produced fluids (gaseous and liquid hydrocarbons and flowback and produced waters) leaking either directly into aquifers or released at the surface to the atmosphere (volatile constituents) or surface waters (liquids). The primary hydrocarbon of concern is methane both due to its greenhouse gas potential if released to the atmosphere and due to its potential to contaminate drinking water supplies as a result of migration from depth or as a result of leaks in near surface well casings. Potential contamination at the surface can result from spills or inappropriate processing or disposal of the wastewaters [42]. The high TDS levels in these fluids can contaminate soil and water as well as pose a direct threat to plant and animal life. In addition, disposal of these wastewaters can, under some circumstances, lead to induced seismicity. Each of these issues will be discussed in turn.

2 Risks to Water Resources

The risks to water resources, particularly drinking water, has long been the focus of the debate about environmental concerns of hydraulic fracturing. Initial concerns focused on migration of methane and/or fracturing fluid contaminants from the fractured formation as a direct result of fracturing. Over time, the primary concerns have evolved to contamination due to near surface well casing leaks or spills at the surface. These concerns are common to all oil and gas activity and the effect of

Table 6.1 Wastewater production and total dissolved solids (TDS) in different basins [10]

Geologic basin	Water production (m^3/day)	Median TDS (mg/L)
Williston	18,000	132,400
Powder River	370,000	977,300
Big Horn	360,000	4900
Wind River	54,000	5300
Green River	41,000	9400
Denver	14,000	10,200
Uinta-Piceance	42,000	13,200
Paradox	21,000	67,000
San Juan	14,000	22,700
Anadarko	34,000	132,200
Permian	250,000	89,200
San Joaquin	NA	22,700
Los Angeles	NA	30,330

hydraulic fracturing has been simply to increase oil and gas activity and as a result increase the potential for such environmental problems to occur. A water resource concern unique to hydraulic fracturing is the demand for water to stimulate the oil and gas production in the low permeability shales that are the target of the technology. An overview of the environmental concerns, both unique to hydraulic fracturing (impacts on water availability) and common to all oil and gas activity (impacts on soil and water quality) are summarized in [78]. Here we will focus on water resource issues categorized by

- Water availability
- Methane and hydrocarbon contamination
- Contamination by formation fluids due to well construction problems and spills and leaks at the surface

2.1 Water Availability

Much oil and gas activity in the US and worldwide takes place in arid or semi-arid regions where water availability is of concern. It is been reported that from 40,000 drilled wells in the United States in 2011, three quarters are in areas that exhibit water scarcity which can put significant pressure on water demand for other application [15]. The shale gas industry consumes significant quantities of water during both drilling and hydraulic fracturing although our focus here will be on fracturing. Fracturing will consume an average of between 2.3 and 3.8 million gallons of water per well although substantial variations are observed [26]. The quantity of water can vary based on the type of drilling fluid, and the depth and horizontal extension of the well [41, 77]. The average water consumption for the Marcellus shale formation is around 4.5 million gallons for fracturing each well

[8]. In the Eagle Ford shale, water use for each well is between 1.2 and 8.4 million gallons [57]. In 2007, Bené et al. estimated that in the Barnett Shale required 2.35 billion gallons of fresh water in 2005 [9]. Around 60 % of this quantity of water was provided by groundwater from the Trinity and Woodbine aquifers. About 3 % of regional groundwater use was consumed in gas well development in the Barnett shale in 2005 but this could reach up to 7 % of ground water consumption due to expansion of the field [9].

Although the amounts of water needed in an individual well are large, the total amount of water needed is small relative to other uses. Typically shale gas development only requires between 0.1 and 0.8 % of total water use of a basin [24, 41] although the fraction of the available water applied to hydraulic fracturing can be considerably more in some areas with intensive oil and gas activity but limited municipal or agricultural water use.

The quality of groundwater and surface water can also be affected by hydraulic fracturing water withdrawal. In aquifers with low permeability, the local ecological impacts of this large water withdrawal can be significant due to substantial lowering of the water table and potential reduced discharge to surface waters. Lowering the water table level can lead to increased oxidation and solubilization of minerals. Bacterial growth can be intensified by these ecological changes which leads to taste and odor issues with water. A large volume of water withdrawal can reduce pore space and cause the compaction of the aquifer which may lead to land subsidence and destroy surface structures. In coastal areas, groundwater withdrawal decreases the hydrostatic pressure potentially inducing penetration of sea water and increasing the salinity of the ground water [21, 24]. Declines in groundwater levels can reduce availability for agriculture or municipal needs and also decrease the amount of groundwater release to lakes and surface waters [70]. Decreasing groundwater levels also increase pumping costs for agricultural and residential uses due to the greater lift requirements. Direct use of surface water also reduces surface water availability and potentially its quality affecting environmental flows for ecological needs.

As a result of these concerns, there is increased interest in using alternative water sources rather than freshwater. Municipal wastewaters, brackish groundwaters and produced waters have all been proposed for use for hydraulic fracturing as an alternative to freshwater or potable waters. The volume of municipal wastewaters that might be available is often limited by the need for municipalities to return their wastewater to surface waters to meet environmental flow requirements. Brackish groundwaters, typically with total dissolved salt contents of 3000–30,000 mg/L and produced waters, with total dissolved salts in the 50,000–200,000 mg/L range, represent viable sources of hydraulic fracturing waters. Initially, there was substantial resistance to use of these waters since the effectiveness of additives for control of the fracturing fluid physical properties, for example, viscosity reducers for "slick" water fracturing efforts and cross-linking gels for "gel" fracturing is influenced by salts in the water. The development of alternative additives as well as recognition that additive performance is less sensitive to salt contents than originally thought, however, has led to increased usage of brackish and produced waters.

Brackish water supplies are normally not economically employed for potable waters, particularly in rural low population density areas. These waters are typically of higher quality (lower TDS) than produced waters and require less treatment to employ effectively as hydraulic fracturing fluids. Moreover, there are near surface brackish water supplies in many of the potential shale plays worldwide [55]. These brackish water supplies have historically not been effectively utilized due to lack of knowledge or variability in the physical and chemical characteristics of the aquifer. The transmissivity of the aquifer and the potential productivity of wells is largely unknown since these sources have been little utilized in the past. Moreover, substantial variability in water quality which may make effective management of fracturing fluid properties through additives more difficult. The potential for use of brackish waters in the arid Permian Basin area of Texas is summarized in (Uddameri and Reible [74]).

Produced water is also a viable alternative source of water for hydraulic fracturing. The quality of these waters is such that treatment for other uses such as drinking water or agricultural water is unlikely to be cost-effective. In the Marcellus shale play, limited availability of disposal wells has led to significant recycling of produced water over the past 5 years, despite the very high salt content (often in excess of 200,000 mg/L) in these waters. Limited treatment, including precipitation of problematic minerals, filtration and blending with fresh water has enhanced the ability to recycle these waters. In other shale plays, recycling of produced water has not significantly reduced freshwater demand. This is primarily due to the availability of relative inexpensive deep well disposal options that reduce or eliminate any economic advantages of recycling this water, particularly if some treatment is required before reuse. Any substantial transportation requirements to move produced water from point of production to point of use for hydraulic fracturing is a further barrier to reuse. Legal barriers may make it difficult to use produced water outside of the oil field where it is produced. In addition, water sales for oil and gas activities can be a substantial source of income to a landowner and lease agreements may require the operator to purchase that water. Produced water remains a viable source of alternative water, however, and can ultimately offset much of the needs for freshwater in hydraulic fracturing [82].

The amount of flowback and produced water available for recycling is strongly dependent upon the formation. Much of the injected water is lost into the formation as shown in Table 6.2. The quality and quantity of water produced from a formation is also widely variable. Permian Basin wells, for example, generally produce much more water over time than originally injected for fracturing while the total volume of water (flowback and produced) is much closer to the volume originally injected in Marcellus wells.

At the current time, the use of alternative water sourcing is relatively small except for the Marcellus shale play. There, the limited and relatively high cost of disposal puts a great deal of pressure on recycling produced and flowback waters for hydraulic fracturing. Blending with freshwater along with minimal treatment has made essentially complete recycling possible throughout much of the Marcellus play. In other plays the balance between produced water and fracturing water is not

Table 6.2 Fraction of flowback and produced water at various areas

Producing area	Fraction of hydraulic fracturing fluid returned as flowback	Produced water volumes
Bakken	15–40	High
Eagle Ford	<15	Low
Permian Basin	20–40	High
Marcellus	10–40	Moderate
Denver-Julesburg	15–30	Low

Source: [11]

as favorable. Increased resistance to disposal as a result of induced seismicity may ultimately encourage greater recycling in addition to public pressure to reduce the apparent impact on freshwater supplies, but neither are a major factor at this time.

2.2 *Methane Contamination*

One of the primary environmental concerns related to shale oil and gas development is methane contamination of the aquifers at an active fracturing site. Other hydrocarbons may also be of concern as a result of releases to air and water at the surface but methane will migrate much more rapidly than other hydrocarbons in the subsurface. Methane can exist in most anoxic groundwater aquifers [19, 22, 30, 40]. However, this methane can be biogenic, typically from fermentation and CO_2 reduction in the shallow subsurface as well as thermogenic, from the high temperatures and pressures existing in the deep subsurface.. One method to differentiate between these sources is to analyze the methane to ethane ratio. Thermogenic methane is normally associated with relatively high levels of ethane compared to biogenic methane, which is associated with negligible levels of ethane [37]. In addition, biogenic methane is relatively depleted of ^{13}C with $\delta^{13}C$ values typically less than $-40‰$ for methane formed by fermentation and less than $-60‰$ for methane formed by CO_2 reduction. Thermogenic methane, however, is typically less depleted of ^{13}C with values of $\delta^{13}C$ greater than $-50‰$ [80]. Note that while these properties can help differentiate between thermogenic or biogenic methane in groundwater, they do not directly indicate the source of that methane. There are instances of thermogenic methane migrating to surface aquifers through natural faults and over long times as well as instances of such contamination due to well casing failures. While the latter may be the result of oil and gas activity, there is little or no connection to the technology of hydraulic fracturing. Effectively addressing the concern depends upon adequate management or regulation of casing design and construction rather than management or regulation of hydraulic fracturing.

Effective identification of the source of any methane contamination in near-surface aquifers requires a more sophisticated analysis than simply determining thermogenic or biogenic methane. The first step is baseline monitoring of groundwater before oil and gas activity to detect the presence or absence of such methane. This can be coupled with continued monitoring during and after oil and gas activity to determine changes in the type and amount of methane in the water. Additional isotopic tracers and samples showing gradients from potential source areas can also be helpful in determining the source of any methane in the aquifers.

Gas movement through the aquifer can occur by free gas and dissolved gas migration. Drilling, weak casing and cementing can cause release of free gas into water. Annular growth of gas pressure in and around casing cements during drilling can lead to stray gas migration through the pores to the surface [37]. Moreover, hydraulic fracturing produces new fractures and enlarges existing ones above the shale geological layers that can increase the connection between these strata and shallower ones [56]. In some cases methane gas could move through these fractures and release in a higher strata [60] although this is most likely when the fractured strata and groundwater aquifers are in close proximity. In many cases, however, the fracturing is conducted at depth and such migration will not penetrate to the near surface except over geologic time or possibly through natural faults that penetrate to the near surface. Generally gas migration toward the surface will take place in areas with the lowest hydrostatic pressure such as groundwater discharge zones, springs, topographic lows or valleys [48]. At these points there is a possibility of surface water contamination by the free methane. The challenges of describing methane migration in the subsurface are discussed in (Illangasekare et al. [46]).

Dissolved gas can also migrate in the subsurface although at much reduced rates compared to free methane. Generally methane solubility is low, approximately equal to 32 mg/L at 1 atm and ambient average groundwater temperatures of 10 °C [84]. However at ambient temperature the saturation solubility of the methane in groundwater depends on the well depth. The pressure will increase by 1 atm for each 33 ft increase in well depth, initially increasing the saturated concentration of methane by approximately 32 mg/l [37].

At the surface the small solubility of methane is not considered as health hazard but other effects are important [79]. The existence of methane will increase oxygen consumption by methane oxidizing bacteria. When oxygen depletion occurs, the solubility of some minerals such as arsenic and iron will increase in water which can change the water mineral composition. Reducing conditions can also lead to sulfate reduction and increases in sulfide [79].

The increase in solubility of methane with depth can make the measurement of the methane concentration in wells difficult and inaccurate [25]. Also if a deep aquifer is saturated with methane, even a small decrease in water depth can lead to free methane release. Methane close to saturation (28 mg/L) has been identified as at high risk for free methane [25].

In a case study on the Catskill and Lockhaven aquifers overlying the Marcellus and Utica shale formations of northeastern Pennsylvania and upstate New York, methane in shallow drinking water wells which were near active gas production areas (within 1 km of a gas well) were elevated [60]. The average methane concentration in drinking water at these zones was 19 mg/l which was more than

10 times higher than the reported amount in wells outside 1 km from active gas wells. The maximum methane concentration of drinking water was measured to be 68 mg/l which is well above saturation if the pressure were reduced to 1 atmosphere. In this study the source of methane in locations near active gas production was primarily thermogenic and while in non-active areas the methane largely stemmed from biogenic processes [60]. This study was limited by the lack of data prior to active gas production and the potential for both thermogenic and biogenic methane from sources unrelated to fracturing. For example, gas storage fields, coal mines, landfills, gas pipelines and even abandoned gas wells can release methane into ground water [12, 51]. About 350,000 oil and gas wells have been drilled in Pennsylvania, and the location of 100,000 of these wells are unknown [23].

Methane contamination of near surface groundwater aquifers due to oil and gas activity appears to occur most commonly due to well casing and cementing failures in the near surface region. Well casing and cement failures have been suggested to occur in 1–2 % of wells in Pennsylvania [20]. Note that these failures most often lead to inner casing failures and do not lead to release to the surrounding environment. Some fraction of these wells, however, can fail completely leading to some nearby contamination. Hydraulic fracturing wells do not appear to increase the frequency of well casing failures suggesting that such contamination issues are reflective of any form of oil and gas activity [50]. Recent improvements in casing construction suggest that the failure rate will trend downward over time.

Other hydrocarbons may also be of interest in near surface groundwater aquifers. Due to the slow migration of these typically more hydrophobic constituents in the subsurface, however, the most likely cause of substantial groundwater contamination from other than methane is likely due to surface spills in the vicinity of the contaminated zone.

2.3 Environmental Concerns of Formation Waters

Formation waters that are returned to the surface as produced water pose substantial environmental concerns if not managed properly. As indicated previously, this water is of very poor quality, with TDS in the produced water often exceeding 100,000 mg/L. Multiple contaminants of concern include lead, arsenic, and naturally occurring radionuclides; bromide and chloride (brine); hydrocarbons and volatile organic compounds; and microorganisms, including bacterial growth (e.g., in evaporation ponds used to manage flowback/produced waters) that can lead to odors and impact taste of water as well as a health risk. Potential environmental concerns associated with the formation waters include aquifer or surface water contamination by drilling accidents or casing leaks in the completed wells or by spills or improper disposal of produced fluids at the surface.

In general a comparison between the geochemistry of groundwater used for drinking water in the Marcellus does not indicate any significant change of water quality by shale and gas industry development [80]. There have, however, been local effects due to one or more of the issues identified above.

2.3.1 Drilling Accidents or Leaks

Natural gas, brine and also toxic compounds can be released to the environment due to accidents during transport, for example of fracturing fluids, and equipment failures during the drilling or well development process. Experiencing higher than expected pressures can cause equipment failures which may result in well blowouts [1]. Surface blowouts release natural gas and volatile organic compounds (VOCs) to the air. If cementing and casing of the well is not done properly, natural gas, brine and fracturing water additives can be released to the groundwater and cause subsurface blowout and environmental pollution [1]. Gas releases can also migrate under the surface and accumulate below houses close to the drilling area and, in a worst case scenario, this can lead to fires or explosion [39].

Pressure excursions were identified as the cause of three equipment failures in a shale gas well pad in Dimock Township, Pennsylvania [1]. In another accident in Pennsylvania, natural gas and fracturing fluids were released for over 16 h, leading to air emissions and contamination of the surrounding grounds [1]. The Department of Environmental Protection also reported another blowout at Marcellus Shale in Ward Township, Tioga County, Pennsylvania [81].

Drilling fluid muds are water-based, oil-based, or synthetic oil-based substance applied to control subsurface pressures, lubricate the drill bit, stabilize the wellbore, and carry cuttings to the surface [3, 4]. Oil-based drilling fluids which have in the past been preferred in horizontal drilling, contain diesel, mineral oil, or synthetic alternatives and their application can cause local environmental pollution.

Drill cuttings are a byproduct of drilling which operators manage them either by burying them on site, sending them to a commercial disposal facility, or removing drill mud and selling the cuttings for road spreading, as fill material, to cover landfills, or as an aggregate or filler in concrete, brick, or block manufacturing [3, 4]. In the case of improper handling of these wastes, heavy metals and other components of drill mud and cuttings can leach into groundwater or have adverse impacts on soil. In an accident in Clearfield County, Pennsylvania, drilling muds stored in an unlined pit leaked into groundwater leading to elevated barium levels in a nearby spring [54].

Drilling may also lead to other impacts on groundwater quality. Vibration and pulses caused by drilling may change the physical properties of groundwater such as turbidity, color and odor [21] due to the suspension and oxidation of subsurface solids.

2.4 *Surface Spills and Improper Disposal of Flowback or Produced Water*

Hydraulic fracturing requires water, chemical and proppant storage, mixing and injection facilities as well as collection and processing equipment. Failures of this equipment may lead to spills of fracturing fluid, produced water or oil. These failures could lead to soil contamination, or contamination of shallow groundwater or surface water. Spills or improper disposal of these very poor quality wastewaters are often the driving risk concern for oil and gas activities including hydraulic fracturing [67, 68].

There are a variety of individual incidents that illustrate potential environmental issues. In 2005, flowback fluids were sprayed into the air as a result of a valve failure which caused contamination leaks onto nearby pastureland [72]. In another accident in 2012, mud and natural gas leaked for several days from a well in Niobrara shale gas formation, requiring the evacuation of 70 people within a 5 mile radius of the well [6]. In New Mexico, New Mexico Oil Conservation Division (OCD) reported 700 examples of groundwater contamination caused by leaks and spills of oilfield waste [72]. It has been reported that 20,000 gallons of wastewater from oil and gas activity was spilled in January 2012 in Canton Township, Pennsylvania. This was identified as the result of "criminal mischief" [17]. A similar example is the intentional release of produced water committed by a transportation company in March 2012 in Pennsylvania [61]. Unintentional transport accidents can also result in release of wastewater from hydraulic fracturing, as illustrated by a December 2011 truck accident in Mifflin Township, Pennsylvania [64]. A Pennsylvania report showed 155 industrial waste discharges, 162 violations of wastewater impoundment construction regulations, and 212 faulty pollution prevention practices in the state [63].

The path of spills to groundwater, surface water and air depends mainly on site properties, type of chemical and fluid properties. Site factors are characterized based on the location of the spill with respect to ground and surface water resources, the weather condition at the time and the type of surface. Chemical specific factors include physical and chemical properties of the component such as vapor pressure, density, solubility, diffusion, and partitioning coefficients. The primary concerns from produced water is dissolved salts, which can contaminate soil and water, endanger plant and animal life, and can easily be transported offsite with water. Hydrocarbons are also of concern, particularly volatile organic compounds that may evaporate from open processing facilities or after spills or leaks. These are discussed in more detail in the next section.

3 Risks to Atmospheric Resources

Air issues include releases of methane, VOCs and particulate matter (PM), including fugitive dust and fracturing sand and the diesel PM associated with extensive transport operations. Some of the associated health concerns include asthma, lung disease, and other respiratory effects. Methane emissions, e.g., from condensate and oil tanks at well sites, are not typically a health risk issue; rather the key concern is the contribution of this highly potent GHG to climate change [5].

Activities of the shale and gas industry are known to produce a variety of air pollutants. Of particular concern are volatile organics including benzene, toluene, ethylbenzene and xylenes (BTEX), hazardous air pollutants (HAPs) and greenhouse gases (primarily methane) [29]. One study in Northeastern Colorado determined that about 55 % of an elevated VOC concentration in air in that region was directly generated by shale gas activities [34]. In another study, high concentrations of BTEX compounds were linked to different shale gas activities [83]. Exposure to these chemicals can increase the risk of eye irritation, headaches, asthma symptoms, and, at high levels have been linked to acute childhood leukemia, acute myelogenous leukemia, and multiple myeloma [13, 35, 49, 65]. In addition, conventional air pollutants such as nitrogen oxides (NO_x), carbon monoxide (CO), diesel particulate matter (DPM), and VOCs can be released by the operation of internal combustion engines from compressors, generators, and other equipment, as well as truck and other vehicle transport which can pose a substantial concern in areas with concentrated shale gas activities [59].

Secondary air pollutants, such as ozone, can be formed by the reaction between VOCs and NO_x both of which can be found at locations of oil and gas activity. Long term exposure to ozone can have significant health hazards [18, 47] and levels in areas of concentrated oil and gas activity can be similar to that observed in large urban areas rather than levels typically found in rural areas of low population density. The peak concentration of ozone in a production area in Wyoming exceeded the ambient air quality standard and was compared to levels observed in Los Angeles [53]. VOC and ozone pollution related to hydraulic fracturing have also been reported in Utah [43]. In urban areas, oil and gas activity may contribute to concerns about air quality non-attainment in those areas.

Depending on the type of fuel production, wet gas, dry gas or oil, different types of emissions can be expected. Dry gas contains primarily methane but wet gas contains more high molecular weight hydrocarbons such as ethane, propane and butane [36]. In wells producing oil, the hydrocarbons are primarily long chain, high molecular weight hydrocarbons and the VOC and methane emissions are typically much less [29].

Other than emissions associated with fracturing sands, the types of air emissions from hydraulic fracturing operations are essentially those of any oil and gas production activity. There is essentially no difference between air emissions from a hydraulically fractured well and a conventional well. The increased oil and gas activity as a result of hydraulic fracturing and the greater percentage of wells devoted to gas production, however, has increased the overall air emissions from the oil and gas industry. The individual sources of air pollutants from hydraulic fracturing operations are discussed below.

3.1 Venting and Flaring

Venting and flaring typically occur during the production phase after a well has been hydraulically fractured. This results in the release of natural gas or its combustion products to the atmosphere. The production of flowback or other liquids from the well will decrease gas pressure and flowrate. Separation of gas from the liquids may not be economical at this point and the gas will be flared. In some areas, for example in the Bakken shale, there is little infrastructure to collect and process the gas, and so much of the gas is flared. Although this is a waste of the energy content of the gas, flaring does reduce the direct release of the potent greenhouse gas methane, instead releasing the less potent form of carbon dioxide.

Venting from tanks or open impoundments containing VOCs in water can also be an important air pollution source. BTEX compounds can be present in vapor spaces at absolute concentrations approaching their concentration in the water. In an open impoundment, trace BTEX compounds in water will typically be evaporated in periods of less than a day. If present in oil or liquid hydrocarbon phases, their relative volatility is much less than if found in water but they may still pose a substantial source of volatile release since they may be present at much higher concentrations in the oily phase.

3.2 Fugitive Dust

Drilling and hydraulic fracturing operations are also a source of fugitive dust. One source is the normal industrial activity including equipment use and truck traffic on sand and gravel pads and roads. The transportation and use of sand as a proppant can be a significant contributor to fugitive dust. Hydraulic fracturing fluids typically contain more than 4 % proppant in order to create or enlarge the fracture in the geological formation, and exposure to repairable silica dust can be significant at different steps of this process [28]. Sand is commonly offloaded from trucks using compressed air, a process that can require 30–45 min. The sand is then blended with water and transferred to the wellbore. This overall process includes a variety of major dust producing points during this process. The concentration and migration direction of this respirable dust can be affected by wind speed and direction as well as equipment type and configuration.

Crystalline silica sand within the respirable size can be categorized as a HAP and a carcinogen. Long term exposure to crystalline silica can not only increase the risk of lung cancer but can also cause a persistent silicosis inflammation [16]. Autoimmune diseases, kidney failure, an increased risk of tuberculosis, and other respiratory diseases such as chronic bronchitis, emphysema, and asthma are other health hazards of silica dust exposure [58]. These hazards rarely pose an offsite problem but worker exposure controls may be necessary.

3.3 Fugitive Emissions of VOCs and Greenhouse Gases

Perhaps the most serious potential releases from oil and gas activities involving hydraulic fracturing include fugitive emissions of natural gas and VOCs (including

HAPs) from sources ranging from surface impoundments to leaks from piping and storage facilities [16, 70]. It is difficult to accurately account for these emission because they are hard to identify and their sources are often transient and random [29].

Methane is a key concern because it is a potent greenhouse gas (25 times more than carbon dioxide on a relative basis over a 100 year period). Methane can escape into the atmosphere at multiple steps of the hydraulic fracturing process. During well completion, flowback water might contain large quantities of methane under pressure which can be released at the surface. Methane can also be released at piping connections and, by design, through vents if high pressure is encountered. Surface gas processing may also lead to fugitive emissions of methane. It has been estimated that anywhere from less than 1 % [52] or less to 7.9 % [45] of methane produced in natural gas wells is ultimately released to the atmosphere. At the lower estimate, there are clear advantages of producing natural gas as a fuel relative to coal and other fossil fuels with respect to greenhouse gas emissions. At the higher estimate, the advantages are not so clear or are perhaps reversed. Recent efforts to estimate the emissions of methane suggest that losses from gas completion efforts which remove liquids from a well prior to gas production are less than previous estimates but that fugitive emissions for piping and valves can be much greater [2]. The overall conclusion of the recent measurements are consistent with a total methane release fraction that is about 0.4 % of the total methane produced annually.

VOCs can also be released by surface processing. Produced gas is normally subjected to dehydration to reduce extra water and heavy hydrocarbons. Glycol is often used to absorb water and VOCs, followed by regeneration of glycol in a reboiler unit which may release the VOCs [29]. Natural gas production is also typically accompanied by other gases and fluids such as water and liquid hydrocarbons. This condensate can be stored in tanks which may vent the evaporated chemicals into the atmosphere without controls or flaring [29]. The waters produced may be accumulated in impoundments. Since these ponds are not encased, emissions of VOC and other fugitive organic compounds are possible especially during warm weather when higher temperatures can intensify evaporation [29]. Even filled ponds can retain VOCs that slowly evaporate into the air adding to direct exposure to these compounds and secondary exposures to ozone. Measuring and detecting emissions from these open ponds are difficult and sometimes inaccurate [76].

3.4 Truck Traffic

There is significant industrial transportation activity in the vicinity of an active oil and gas well. The substantial quantities of water required for fracturing each well and also the necessary chemical components and drilling equipment and materials all need to be transported to the sites which are often remote and not connected by permanent infrastructure [70, 73]. Flowback and produced water as well as drill cuttings and other waste materials are aalso normally transferred offsite with trucks. Nitrogen oxides, carbon monoxide and hydrocarbons are emitted from running engines. And the use of dirt roads increases fugitive dust emissions, as indicated previously. It is been reported that roughly 3950 truck trips per well are needed for developing a horizontal hydraulic fracturing well [59]. This number is significantly larger than the number of trucks used in regular vertical wells. It has been estimated that construction of a new oil or gas well in the Uinta Basin of northeastern Utah requires between 365 and 1730 truckloads of equipment, materials, and supplies [75]. A solution to decrease this number could be using pipelines between sites in lieu of trucks for transitioning required water and generated wastewater but concerns about fugitive emission and leaks and spills could increase in such a scenario. In general, the greater on-site management of waters, for example, using on-site source waters, recycling produced water or disposal of water on-site, would all significantly reduce truck traffic and the associated concerns.

4 Geologic Risks

The possibility of increasing seismic activity of an area because of hydraulic fracturing has become a serious concern. Cleburne, Texas, felt some small earthquakes in 2008 and 2009. Because of no reported earthquakes for more than a century in this city, public concerns were raised as to whether hydraulic fracturing processes in Barnett shale which could induced these microseismic activities [14]. Since that time, there has been a number of areas that experienced increased seismic activity, including Ohio, northern Texas and Oklahoma. Given the sparse monitoring network normally available, it is often difficult to define the specific source of this activity although it has been most commonly linked to injection of large volumes of produced water in specific disposal wells that are located in or near natural subsurface faults. This issue is also not specific to hydraulic fracturing but it is exacerbated by the growth of oil and gas activity as a result of hydraulic fracturing and, to a small extent, the additional water (flowback water) generated by hydraulically fractured wells.

Oil and gas activity involves several processes that can increase the seismic activity of surrounding areas. Well drilling, generating or enlarging the fractures by injecting pressurized fluid, extracting gas and fluids and finally disposing the flowback and produced water in salt water disposal well are all potential reasons for triggering small earthquakes [33]. Seismicity associated with the drilling and extraction process is typically low in magnitude and often it cannot be felt at the surface.

However, the disposal of produced fluids plays the key role in inducing the microseimic activity. Disposal wells tend to collect produced waters from multiple wells for injection and thus the water volumes typically dwarf the volume of water injected during fracturing of a single well. The vast majority of these disposal wells show little or no resulting seismic activity. In some cases, however, seismic activity has been linked to specific disposal wells or disposal wells in a region [31–33, 44] Investigations have found that small earthquakes occur at places close to the disposal well and around the time of injection of salt water in these wells. To date, these induced earthquakes are small and have not caused serious damage at the surface. There is concern, however, that these earthquakes may ultimately become more serious. Moreover, any earthquakes that are felt at the surface in areas where little or no seismicity was previously observed is of obvious concern to the public.

Based upon the available information, the only apparent solution to increased seismicity is to reduce the volume of water injected or to avoid areas where seismicity is generated by water disposal. Reduction in injected water volumes can be accomplished by greater amounts of water recycling, that is the use of the produced water for other applications. This might be as a fracturing fluid or with treatment, reuse in other applications. Normally the very high dissolved solids of produced water makes reuse for anything other than as a fracturing fluid very difficult and cost prohibitive. Where recycling of produced water is not appropriate or available, deep well injection is likely to remain the dominant disposal method. Identification and avoidance of injection into faults is likely the only means of avoiding increased seismicity and, unfortunately, it is difficult if not impossible to identify these faults prior to drilling an injection well. More are needed on the seismic risks of water disposal and to help identify potential problematic formations which should be avoided for injection [33].

5 Summary

A variety of environmental concerns of hydraulic fracturing were identified and summarized. Many of these concerns are of low probability, for example, migration of fracturing fluids directly from deep formations. There are, however, a number of environmental concerns that are likely to occur and will lead to adverse consequences if not adequately monitored and addressed. These likely potential environmental effects of hydraulic fracturing are primarily associated with

- Constraints on water availability in water scare areas
- Groundwater contamination by methane and other hydrocarbons as a result of casing failures
- Soil, groundwater and surface water contamination by formation fluids as a result of spills and discharges on the surface
- Methane and VOC release to the atmosphere
- Seismicity associated with injection of disposal fluids

Other concerns include fugitive dust emissions and concerns associated with any industrial activity including erosion, ecosystem destruction, light pollution, noise, aesthetics and impacts to cultural resources. Most of these environmental issues are not unique to hydraulic fracturing but instead are common to all oil and gas activities. The rapid growth of the oil and gas industry as a result of the ability to stimulate oil and gas production by hydraulic fracturing, however, has exacerbated the likelihood of these potential concerns and effects.

Hydraulic fracturing does place greater pressure on water availability and much oil and gas activity are in water scarce locations. Greater use of recycling of produced water for hydraulic fracturing could help manage disposal costs and concerns (seismicity) as well as reduce demand for water. The other environmental concerns can be managed through a greater focus on well integrity and more efficient and controlled management of surface processing of produced oil and gas as well as produced formation waters.

The environmental concerns of hydraulic fracturing have led some to believe that the technology should not be applied, or be practiced in a much more limited fashion than is currently the case. As noted herein, however, it is generally not the hydraulic fracturing that leads to environmental concerns but poor management of wells or fluids at the surface or deep well injection of produced fluids. Better regulation or management of those steps in the process most likely to lead to environmental impacts are more likely to be protective of the environment than direct regulation of hydraulic fracturing. Stronger regulation and management of these problems will also have benefits in terms of greater oil and gas efficiency (by better control of leaks and spills) or in terms of encouraging water recycling (by restrictions on deep well injection of produced waters). By directing environmental management efforts at the most important issues and concerns, it may be possible to fully achieve the potential benefits of oil and gas produced through hydraulic fracturing, which extend from greater energy independence and replacement of relatively high carbon fuels such as coal with low-carbon fuels like natural gas.

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Chapter 7
Drilling and Production Discharges in the Marine Environment

S.S.R. Pappworth and D.D. Caudle

1 Introduction

The widespread exploration and development of offshore oil and gas fields first occurred in the United States' Gulf of Mexico in the early 1950s. Gas was not produced from the British sector of the southern North Sea until 1967 and the large North Sea oilfields were developed in the 1970s. Offshore developments in the Middle East (including Dubai, UAE and Yemen) started in the 1960s, as the initial developments in the area were onshore. More recently offshore exploration and production development has expanded to include the Far East (including Indonesia, Vietnam and China) and West Africa (including Nigeria, Gabon and Ghana). Initially the environmental impact of offshore operations was unknown and there were few, if any, regulations or standards in place to control discharges. However, it was not long before concerns arose about the potential environmental impacts of exploration and production activities. The initial attempts at minimizing any potential impacts involved controlling end of pipe discharges while studies were undertaken to determine what the impacts might be. Over the years, treaties, laws and regulations have been promulgated so that now drilling and production discharges are strictly controlled by a complex system of limits. A complicating factor in the early stages of offshore development was that the technology was rapidly developing at the same time, which presented a moving target. Interestingly, after the initial period, many years of relatively stable technology ensured, until the expansion into deep waters and severe environments. However, the objective of the rules and

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_7

regulations has always been, and still is, to allow offshore exploration and production to occur while minimizing any associated environmental impacts.

In order to develop effective regulations and the technology required to ensure that that the discharges meet the limits, it is necessary to understand both the nature and volumes of the discharges and the sensitivity of the receiving environment. To further complicate matters, offshore operations can be in international, national, or waters under local jurisdictional control. This can result in situations where more than one regulatory body is involved.

The wastes generated by oil and gas exploration and production operations fall into two broad categories: those directly resulting from oil and gas operations; and those associated with support activities [10]. The high volume wastes associated with exploration and production activities include:

- Produced water
- Excess water based drilling muds
- Drill cuttings; and
- Wastes generated during the abandonment and removal of offshore structures.

This waste category had increased significantly over recent years, as a number of developments in the North Sea and Gulf of Mexico become depleted and the aging infrastructure and any associated waste piles have been required to be removed.

The lower volume wastes include:

- Deck drainage
- Tanks bottoms
- Produced sand
- Excess chemicals and chemical containers; and household wastes.

The nature and volumes of the wastes that are actually discharges is affected and controlled by:

- Regulations
- Industry standards
- Individual operator policies and practices
- Limits imposed but financial institutions
- Public interest groups

The characteristics of the water bodies that receive the wastes vary widely, which in turn affects the sensitivity to the impact from the wastes. These include:

- Water depth
- Distance from shore
- Wind and wave forces in the area
- The presence of sensitive marine flora and fauna, and
- The chemical and physical characteristics of the waste.

Depending on the chemical and physical characteristics of the waste and the receiving waterbody, the discharge of the higher volume wastes may or may not be allowed, whereas most of the minor wastes are taken onshore for treatment and disposal.

2 Nature of Offshore Discharges

2.1 Produced Water

Produced water is the water generated from the oil and gas extraction process. It includes: the water native to the producing formation, water injected into the formation to increase reservoir pressure and to sweep oil from the formation and traces of various well treatment solutions and chemicals added during production and the oil/water separation process. The volume of produced water varies over the life cycle of an oilfield, typically increasing over time.

Formation water which comprises the bulk of the produced water, is found in the same rock formation as the crude oil and gas or an adjoining level of the same formation (e.g. below the oil/gas cap). Formation water is classified as meteoric, connate or mixed. Meteoric water comes from rain water that percolates through bedding planes and permeable layers. Connate water (seawater in which marine sediments were originally deposited) contains chlorides, mainly sodium chloride (NaCl), and dissolved solids in concentrations often many times greater than common seawater. Mixed water is characterized by both a high chloride and sulfate-carbonate-bicarbonate content, which suggests multiple origins.

Besides its ionic constituents, produced water may also contain dissolved and dispersed organic compounds, including hydrocarbons (both aliphatic and aromatic) oxygen, nitrogen and sulphur containing compounds (e.g. carbon dioxide, hydrogen sulphide, ammonia and small quantities of heavy metals). Normally formation water is low in sulphate ion and may contain significant quantities of calcium, barium and/or strontium ions. Produced water is usually in a reduced state and it may have both a significant chemical oxygen demand (COD) and biological oxygen demand (BOD).

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Treating chemicals are typically added to produced water and may significantly affect its environmental impact. These chemicals are used to accomplish several functions, including the following most common uses:

- Breaking emulsions to aid in the separation of oil and water
- Preventing the formation of water-formed scales
- Controlling the growth of bacteria in the producing wells and production system
- Aiding in the treating of water to remove oil

The industry magazine, World Oil, annually publishes a list of chemicals currently used in production treating applications. Specific information on the properties of these materials can be obtained from the suppliers' Safety Data Sheets (SDS).

2.2 Drilling Waste

Drilling wastes include drilling fluids (or muds) and the formation fragments (known as cuttings) removed in the drilling process. Drilling fluids are suspensions of solids and other materials in a liquid base. The composition and properties of drilling fluids are determined by their functions. Three of the primary functions that drilling muds perform are:

- Lubricating and cooling the drilling bit
- Maintaining downhole hydrostatic pressure
- Cleaning out the hole by bringing cuttings to the surface

In order to work, muds must have a high density, a high viscosity and lubricity. To meet these requirements the muds contain weighting agents such as barium sulfate (Barite) or ion (III) oxide to increase the density of the mud, clays (bentonite, etc.) or polymers to adjust viscosity and chemical to increase the mud properties. The industry magazine, World Oil, annually published a list of chemicals used in the formulation of drilling muds. Information on the properties of these materials can be obtained from their suppliers from their Safety Data Sheets (SDS). In recent years, great emphasis has been given to selecting mud components that both perform well and are environmentally friendly.

Drilling fluids fall into one the three classes based on the fluid comprising the mud:

- Water based muds
- Oil base muds
- Synthetic based muds

More than one type of mud may be used in a single well depending on the conditions encountered.

A water based drilling fluid or mud is one in which water is the continuous phase and the suspending medium for solids and other liquids, whether or not oil is present [8]. Water based drilling muds are relatively inexpensive. Modern formulations are generally not-toxic to marine fauna. Discharged cuttings will disperse in the water column.

The water in water based muds can be fresh or salt water. Clays or organic polymers are added to achieve the proper viscosity. Barite is added to achieve the correct mud weight (density), and other components are added to mud systems to create the desired characteristics. The United States Environmental Protection Agency (EPA) recognizes eight generic water based mud types (OCS Guidelines).

Oil based drilling fluids are ones in which the continuous phase is oil: diesel, mineral or some other oil [8]. Simplistically they can be viewed as water based muds dispersed in oil. One important difference from water based muds is that viscosity is achieved by emulsification of water in oil as well as through the use of clay. They are also more expensive to use that water based muds.

Oil based drilling fluids are used to solve drilling problems that water based muds cannot handle efficiently, or at all. Conditions warranting the use of oil based muds include: required thermal stability when drilling high-temperature wells, required specific lubricating characteristics when drilling deviated wells, the ability to reduce stuck pipe or hole wash-out problems when drilling thick, water-sensitive formations and drilling through water soluble formations such as salt. Most offshore wells fall into one or more of these classes.

Concerns over the potential toxicity of oil based drilling fluids led to the development of synthetic based drilling muds (SBMs). Synthetic based muds are drilling fluids that use synthetic organic chemicals, principally containing carbon, hydrogen and oxygen, as base fluids. Synthetic based muds are more expensive than oil based fluids, but are more environmentally benign and have increasingly replaced the old oil based muds. SBMs have low toxicity because of the elimination of the polynuclear aromatic hydrocarbons (PAHs). They were also designed to have faster biodegradability, lower bioaccumulation potential and, in some instances, less drilling waste volume. This means that the discharge of SBM cuttings may be permitted. Like oil based drilling fluids, synthetic based fluids are hauled to shore after use to be reprocessed and reused.

Cuttings are small pieces of formation rock that are generated by the crushing action of the drill bit. Drill cuttings are carried out of the borehole by the drilling fluids. Drill cuttings themselves are inert solids from the formation. However, drill cuttings discharges also contain drilling fluids that adhere to the cuttings. The volume of the mud that adheres to the cuttings can vary considerably depending on the formation being drilled and the cuttings' particle size distribution [8]. An old, but still valid general rule of thumb is that 5 % mud, by volume, is associated with the cuttings [13]. In the case of some water based drilling fluids, the formation materials drilled up will become part of the mud solids and chemical adjustments have to be made to accommodate them. This results in an increase in mud volume that is not needed in the drilling process. Some drilling mud then becomes a waste and must be disposed of. Therefore, drilling mud itself becomes a waste material in two ways: as a coating on cuttings and as excess mud.

Drilling fluids are designed to have the required characteristics to aid in the drilling of the well, while at the same time limiting their potential environmental impact. Their potential for environmental impact is partially determined by where they end up in the environment as well as their intrinsic properties. Water based mud and cuttings tend to disperse into the water column on discharge. The dispersion is broken and the solid components slowly settle to the sediment layer at the bottom of the sea. Because of the cuttings are rapidly dispersed and their liquid components diluted, their potential impact should be less than that of oil based, or synthetic muds, but spreads over a much wider area.

Cuttings from oil based mud drilling have oil on their outer surfaces and do not tend to disperse in the water column. The solid components tend to settle rapidly to the bottom and collect in piles under the platforms of drilling rigs. Depending on water depth, free oil on the cuttings tends to rise to the surface of the water and spread over the surface of the water. The environmental impact of the cuttings tends to be highly localized initially and persist over a long time in the sediment and water column immediately above it.

In addition to drilling muds, the offshore oil and gas industry uses a number of water based fluids. These include:

- Completion fluids
- Packer fluids
- Workover fluids

Completion fluids are typically solutions of salts in water. They are used to clean out wells after drilling is complete and aid in the setting of downhole equipment. Packer fluids are concentrated salt solutions placed between the tubing and the casing of a well. Their purpose is to hold pressure on the formation in case the packer fails. They must have a high density in order to be heavy enough to exert sufficient pressure on the producing formation. Workover fluids, such as hydrochloric acid, are used in cleaning, repairing, and stimulating wells. Typical operations include washing sand from the tubing or wellbore, fracturing water-formed scales and corrosion products. The salts used to make these fluids include the cations of sodium, potassium, calcium, barium and zinc, and the anions of chloride, bromide and sulfate.

Completion fluids can be either transported offshore as water solutions, or alternatively the solid salt can be taken offshore and the solution prepared on-site. Spills of completion fluids could result from broken flow lines on the platform or on boats, or from tank failures. When large volumes of completion fluids are needed they are generally transported on work boats. In the event that the vessel has an accident, the completion fluids could be released.

2.3 Magnitude of Waste Discharges

The volume of drilling and production discharges varies over time due to two factors:

The level of drilling and production activity
The fraction of wastes discharged to the environment

The American Petroleum Institute (API) estimated that in 1985 in the United States that oil and gas industry (both onshore and offshore) generated 361 million barrels of drilling wastes (1.5 % of the total) and 20.9 billion barrels of produced water (98 % of the total). Another 118 million barrels of associated waste (0.5 %) were generated for a total of 21.4 billion barrels [9]. From this it is clear that the majority of the waste generated by oil and gas operations is in the form of produced water. In 1995, the API web site's waste prevention data showed that the total volume of waste generated declined to 18.1 billion barrels, a reduction of 3.3 billion barrels. This included an increase of 9 % in produced water discharges and decrease in drilling discharges of 53 %. In 2007 produced water generation in the US was 21 billion barrels and remained generally stable in 2012, when 21.2 billion barrels of produced water was produced [17]. In 2012, the produced water was handled as follows [17]:

- approximately 9.2 billion bbls was injected for enhanced recovery
- approximately 8.0 billion bbls was injected for disposal
- approximately 1.1 billion bbls was discharged to the surface
- approximately 0.7 billion bbls was evaporated
- approximately 1.4 billion bbls was sent to an offsite commercial disposal facility
- approximately 0.1 billion bbls was beneficially reused

Produced water volumes are much greater for structures producing oil or a combination of both oil and gas as compared to gas-only platforms. Although the gas-only platforms generate less produced water, the concentration of the chemical constituents of the water is considerably higher than those from oil producing platforms (op ten [12]). The volume of produced water at a given platform is site-specific. For example, in some instances, no formation water is encountered whilst in others there is an excessive amount of formation water encountered at the start of production. It has been estimated that the volume of water produced for every barrel of oil recovered is between 5:1 and 8:1 in the US and between 2:1 and 3:1 worldwide, with an anticipated increase in the US to 12:1, to as much as 50:1 by 2020 [15].

There is increased attention to addressing produced water issues, partly because of aging developments with the associated increase in produced water volumes, as well as the increased volumes associated with horizontal drilling and the expanded use of hydraulic fracturing. In Norway there are some operators who are trying to reduce the amount of oil in the water to as close to zero as possible, in conjunction with regulators beginning to monitor soluble components as well as free and dispersed droplets of oil [15].

In the North Sea, the method of reporting of waste discharge volumes has changed over the years. Initially reports were made on the volumes of waste such as produced water and drill cuttings. For example, the International Association of Oil and Gas Producers (OGP), formerly known as E&P Forum, have estimated that in 1991, oil and gas platforms in the northern North Sea discharged 160 million cubic meters (1 billion barrels) of produced water, with about 5 % of the total volume coming from gas platforms [7]. Recently the practice is to report only oil in the waste. For example, the Oslo Paris Commission (OSPAR) reports that the total oil discharged (including oil in produced water and displacement waters and accidental spills) in the maritime area of OSPAR was 9053 tonnes in 1999, 9420 tonnes in 2000 and 9317 tonnes in 2001. This did not include oil from oil based mud since discharges of cuttings generated when using these muds are prohibited.

Whatever method is used to account for waste generation, oilfield operations anywhere in the world will generate comparable amounts of waste. However, countries have different regulatory schemes that may prohibit certain discharges. Regulations controlling the types and quantities of waste that can be discharged are discussed later in this chapter.

2.4 Accidental Discharges

Materials that might be accidentally discharged to the sea include:

- Crude oil and tanker fuel oil from tankers
- Crude oil from well blowouts
- Crude oil from tank ruptures on onshore installations
- Crude oil from pipeline and gathering line ruptures
- Fuel and chemicals from storage vessel ruptures on offshore installations and supply boat accidents
- Drilling fluids
- Completion fluids
- Packer fluids
- Workover fluids

Oil spilled at sea will disperse into the receiving environment. This is a result of a number of chemical and physical processes that occur to “weather” the oil. The exact nature of the weathering depends on the type of oil that is involved. Part of the weathering process, for example, the natural dispersion of the oil into the water, results in some of the oil leaving the sea surface, whereas other, such as evaporation or the formation of water in oil emulsions, results in the oil components that stay on the surface becoming more persistent.

How spilled oil reacts depends largely on how persistent the oil is. Light products, such as condensate, tend to evaporate and dissipate quickly and naturally, and are classed as non-persistent oils. They do not usually require any extensive cleanup or response actions. Alternatively, in the case of persistent oils, like most crude, the oil is much slower to dissipate and evaporate and so response actions are required. In addition to the chemical changes, the oil's physical properties including: density, viscosity and pour point all affect behavior.

The oil does not immediately disperse. The time required depends on a series of factors, including: the amount and type of oil spilled; the weather conditions; and whether the oil stays in the marine environment or is washed ashore. The whole process can move quickly or slowly depending on the oil involved and the conditions. For example, dispersion will be quicker in rough seas than in shallow, sheltered, calm waters.

There are generally eight main processes that cause oil to weather. The first of these is spreading. Any oil that is spilled will immediately spread out over the sea surface. The viscosity of the oil dictates how quickly the oil spreads. The lower the viscosity, the quicker the spreading occurs. However, even high viscosity oils still spread relatively quickly. Typically the slick that forms will vary in thickness. Due to the action of the wind, waves and water turbulence, over the next few hours the initial slick will begin to break up and form narrow windrows parallel to the wind direction. The water and the air temperatures, currents and wind speeds also have an effect on how quickly windrows are formed – typically, the rougher the conditions, the quicker that the windrows will form.

The second process is evaporation of the lighter components of the oil. The volatility of the oil, that is the amount of light and volatile components in the oil, governs the volume of oil that will evaporate and how quickly this will happen. For example, aviation fluid and condensate will evaporate almost completely in a few days. On the other hand, heavier crude and heavy fuel oil will hardly evaporate. Evaporation tends to increase as the oil spreads out, and in rougher seas and higher temperatures.

The third process is dispersion. Wave action and turbulence on the sea surface will break up the oil slick into separate slicks and individual oil droplets. The droplets become mixed into the upper part of the water column. Some of the smaller droplets will remain suspended in the water column. Larger droplets will rise to the surface and will either attach onto other droplets and make a new slick or, alternatively, will spread out on the surface to form a very thin oil film. The oil droplets that remain in the water column have a larger surface area, which makes it easier for biodegradation and sedimentation to occur. The sea conditions and the viscosity of the oil are the principle factors in determining how quickly a particular oil will disperse. The use of chemical dispersants can accelerate the process.

Emulsification is the fourth process. An emulsion is formed when two liquids combine, with one ending up suspended in the other. Emulsification of crude oil refers to the process whereby seawater droplets become suspended in the oil. This occurs by physical mixing promoted by turbulence at the sea surface. The emulsion that is formed is usually very viscous and more persistent than the original oil and is often referred to as chocolate mousse because of its appearance. Apart from increasing the persistence of the oil, the formation of an emulsion increases the volume of material that has to be recovered by three to four times. The higher the asphaltene content of the oil, the more likely it is that an emulsion will be formed.

Typically oils with asphaltene contents greater than 0.5 % form stable emulsions. It is possible for emulsions to separate into oil and water if the emulsion is in calm seas or on shore and the material is heated by sunlight.

Dissolution is the fifth process. Water soluble compounds in an oil may dissolve into the surrounding water. This depends on the composition and state of the oil, and occurs quickly when the oil is finely dispersed in the water column. Components that are most soluble in seawater are the light aromatic hydrocarbon compounds such as benzene and toluene. However, these compounds are also those first to be lost through evaporation, a process which is 10–100 times faster than dissolution. Oil contains only a small amount of these compounds making dissolution one of the less important processes.

The sixth process is oxidation. Oils react chemically with oxygen. In the reaction, the oil either forms a persistent "tar" or breaks down into soluble products. The rate and extent of oxidation is generally dependent upon the type of oil involved and sunlight. Oxidation is an extremely slow process and, even in favorable conditions, will only break down 0.1 % per day. Tar balls are formed when the oxidation process forms a protective layer of heavy compounds around a less weathered, soft center. The outer layer makes the tar balls very persistent.

Sedimentation or sinking is the seventh process. In the case of heavy crude oils or refined products with densities greater than one, the oil will sink in fresh or brackish water. There are very few crude oils or refined products with a density greater than the 1.025 for seawater, and so the materially will typically not sink when spilled at sea. However, as the oil adheres to particles, flora, fauna or other organic material, it may sink. Oil that impacts a beach or shoreline may become mixed with sands or other sediment. If this material is washed out to sea, it may sink. The residue from spilled oil that has caught fire, or been burned, can also be sufficiently dense to sink. Interestingly, however, it has been reported that oil particles remained suspended in the water column during the Deepwater Horizon spill.

The eighth process is biodegradation. There are naturally occurring microorganisms that live in the marine environment that can degrade oil to water stable compounds and even eventually to carbon dioxide and water. Not all oils are equally susceptible to biodegradation. The amount of nitrogen and phosphorous in the water, the temperature and the oxygen concentration all affect the ability of the microbes to degrade the oil. The degradation can only take place in an anaerobic environment and so the degradation is usually limited to the oil-water interface. Converting the oil into droplets, both through natural processes or by the use of chemical dispersants, increases the surface area available to the microbes and hence raises the rate of biodegradation.

In the early stages of a spill, spreading, evaporation, dispersion, emulsification and dissolution are the most prevalent processes. Oxidation, biodegradation and sedimentation become more important later in the spill and tend to determine the eventually fate of the oil.

Accidental discharges fall naturally into two classes: those that can be recovered and those that cannot. Oil spills can be recovered, assuming that equipment and manpower is available to recover the oil before it reaches the shoreline, evaporates into the air or sinks. Sometimes bad weather or other conditions can interfere with recovery. Water based fluids usually cannot be recovered. Since they are miscible with water they rapidly dilute on reaching the sea and some undergo chemical reactions with seawater constituents.

In a similar way that the Exxon Valdiz spill changed policies, regulations and responses to reduce the potential for releases from oil tankers and the associated response efforts, the Deepwater Horizon blowout and associated spill has significantly changed the industry, regulatory and public response to releases from exploration and production. Previously preparedness and response was predicated on the assumption that any blowout could be quickly capped to prevent the ongoing release of oil, gas and other fluids. The fact that it took 87 days to stop it had not been included in the response strategies and has resulted in more significant and persistent environmental impacts.

According to studies directed by the US regulatory agency, the Bureau of Ocean Energy Management (BOEM), some of the effects of the spill were mitigated by the knowledge, understanding, expertise and mechanisms in place. However, severe hurricanes and flooding increased the spill's potential impacts. The fate and movement of spilled oil in surface waters were identified using multiple remote sensing platforms. The data from the remote sensing platforms was combined with the best existing algorithms for determining surface oil spatial extent and thickness, which have been very important in determining the extent and characterization of surface oil, which in turn has been used in the Natural Resource Damage Assessment (NRDA) process. Some of the most severe and complex economic effects of the Deepwater Horizon Spill were on the Gulf of Mexico seafood industry [2].

2.5 Wastes that Require Handling During Site Abandonment

Although platform disposal is discussed in a separate chapter in this book, site abandonment has the potential for discharging materials to the sea. Platforms having large integral storage vessels might have residual oil or chemicals in the vessels; the presence of the platform or its residue modifies the local environmental habitat by its very existence. For example, most of the northern Gulf of Mexico is a mud bottomed body with few coral reefs or other bottom relief. Abandoned platforms will tend to act as artificial reefs and attract fish species that live around reefs.

Abandoned platforms could be hazardous to shipping or fishing boats. This would be especially troublesome if they were not visible from the surface.

In the North Sea there is the additional problem of old cuttings piles beneath some of the older platforms. These piles resulted from drilling with oil based muds during the period when discharge of such cuttings was allowed. The interior of these piles may be wet with oil and contain no continuous water. Degradation of these cuttings is dependent on wind and wave action and bacterial degradation of any oil. Wind and wave action does not normally reach the bottom of the northern North Sea and with little water content the piles will not rapidly bacterially degrade. Removing a platform without removing the cuttings piles would leave them as hazard to trawling and other activities for periods estimated to be up to 100 years.

There are a number of wastes that are generated as part of the abandonment process. These include wastes resulting from:

- Cleaning and purging vessels resulting in wastes including:
  - scale
  - tank bottoms
  - washwater
- Seabed clean-up

These wastes have to be treated, handled and disposed of if they cannot be reused or recycled.

3 Potential Impacts on the Environment

3.1 Introduction

The term "environmental impact" covers a variety of effects that discharges might have on the receiving environment. These effects range from very minor variations in the chemical composition of water to complex changes in the chemical, physical and biological nature of water columns, sediments, flora and fauna. Even if an environmental effect is defined, it may be very difficult to identify or quantify it in an actual environment. Therefore, in this document, "environmental impact" will be interpreted as any issue that raises concerns in public or regulatory bodies, whether or not actual lasting effects have been proven to occur.

Toxicity is a concern both in the water column and on the sediment. Toxicity is a measure of the power to interfere with the life processes of an organism. The concern is for both immediate lethal toxicity (acute) and sub-lethal (chronic) effects. Acute toxicity is a measure of the immediate danger of poisoning while chronic toxicity is a measure of sub-lethal impacts. These affect such things as growth and reproduction. Toxic impacts are measured by:

- A minimum concentration
- A minimum exposure time
- A time to recover after exposure

Organic materials are removed from the aquatic environment through either aerobic or anaerobic biodegradation. Organic material in both the water column and sediment are consumed by bacteria and converted into simpler material and ultimately into carbon dioxide and water. Aerobic biodegradation requires an oxygen source in the effected environment. The oxygen necessary for biodegradation is termed the biochemical oxygen demand (BOD). Neither the water column nor the sediment contain much oxygen, and a high concentration of organic material will consume available oxygen rapidly making the environment unable to support life. Oxygen is easily replaced in the water column because wind, waves and currents act to replace the oxygen at a rate higher than most degradation depletes it. On the other hand, oxygen is the sediment is easily depleted by biodegradation. In anoxic (oxygen free) sediments anaerobic (non-oxygen) biodegradation takes place.

The persistence of the contaminant in the environment also plays a role in determining the overall impact to the environment. Persistence is the ability to remain in the environment in a detrimental form and not be broken down into more innocuous material. The only materials that might persist in the aquatic environment are highly stable, complex aromatic compounds that degrade very slowly. The materials that would persist in the environment are generally present in very low concentrations and the threat of buildup is low.

3.2 Potential Impacts from Produced Water

The chemical composition of produced water can change the ionic strength of the receiving waters. The individual constituents of produced water can potentially have toxic effects on the flora and fauna in the water column and the sediments. Chemical reactions with seawater can produce solids that can change the nature of sediments both chemically and physically. All these effects can result in significant impacts on the biological communities living in the water and sediments. The organic constituents of produced water can also deplete oxygen in the receiving water body and the sediments under it due both the chemical and biological reactions.

Laboratory tests have demonstrated that produced water has an intrinsically low toxicity level [7]. Therefore, acute toxicity should not be a significant issue for produced water. However, toxicity limits are imposed on produced water by some regulatory authorities.

In the early development of the offshore oil industry it was feared that both the inorganic and organic constituents of produced water would result in:

- Bioaccumulation and fish tainting
- BOD
- Persistence in the environment
- Contamination of the sediments

Many years of intensive investigations and studies have shown that most of these fears have not proven to be a significant threat to the environment.

However, salinity has been shown to have a serious impact on shallow receiving waters, such as bays and estuaries. Consequently the discharge of produced water to these areas has been banned in many places, including the United States.

On the other hand, a large study done jointly in the Gulf of Mexico by various industry groups and government agencies found no bioaccumulation of heavy metals from produced water [4].

The biodegradation of organic compounds in produced water is known to deplete oxygen in limited water bodies such as ponds, streams and shallow bays. Oxygen recharge from wind and wave action minimizes oxygen depletion in the open sea. The oxidation of inorganic compounds does not create significant oxygen demand [7].

It is anticipated that the results of the investigations following the Deepwater Horizon spill will be able to update the understanding of the impacts of major releases.

3.3 *Potential Impacts from Drilling Waste*

Potential impacts to the marine environment from drilling waste generated by oil and gas operation include:

- Toxicity
- Bioaccumulation and fishing tainting
- Disturbance to the physical environment
- BOD
- Persistence

Both organic and inorganic components in drilling mud can cause impacts. Oil is one of the organic components of drilling muds as even water based muds can contain some amounts of oil from solvents for other components or oil from the formation. Inorganic components consist mainly of inorganic salts, with trace metals and nutrients.

Toxicity is a concern of both in the water column and on the sediment. The chemical components of the drilling fluids have the most obvious potential for toxicity. However, the effect if the chemicals in drilling mud can be significantly impacted by reactions within the mud itself and with the constituents of seawater.

Mud toxicity can occur in both water column and in sediments. Exposure to a toxic concentration in the water column can be due to dissolved chemicals and dispersed solids and droplets. Exposure to a toxic concentration in the sediments is due to the accumulation of the solid portion of the mud and cuttings. Regulations in most areas ensure that toxicity is not a serious problem.

When solid containing wastes such as cuttings are discharged, the solid portion will eventually end up in the sediment layer. For water based buds the area of sediment covered may be very large because many of the solids tend to disperse into water column and settle slowly over a longer period of time. Furthermore, in shallow waters such as continental shelf of the Gulf of Mexico hurricanes regularly stir up sediments and effectively dilute accumulated cuttings. For oil based muds the cuttings are oil encapsulated particles which are heavy enough that they settle very near the discharge point. The result, after drilling several wells from the same platform, is a large pile of oily material. Since the oil in this pile is not exposed to water containing bacteria it might last a century or more. The environmental concern is that these piles will be a fishing and navigation hazard when the platform is removed and oil escaping from them can affect the environment. In both cases modification to the sediment layer is deemed undesirable.

Since drilling cuttings usually end up on the sediment, if they have an oxygen demand impact it is in the sediment, not in the water column [5]. However, it should be noted that the floor of the ocean in deep water, such as the northern North Sea, is sparsely populated, and so the impact is small and the aerial extent is limited. This concern is recognized and addressed by most regulatory bodies.

3.4 Potential Impacts from Treating Chemicals

Chemicals are used in all phases of offshore oil and gas production. Many of these chemicals have either surface active properties, toxicity, or react chemically with the constituents of seawater. Potential effects include toxicity, oxygen demand and physical fouling of sediments and structures. The oil industry publication, World Oil, publishes lists of all types of treating chemicals annually. These lists provide information on the composition and properties of these materials.

The solubility of treating chemicals can determine where they end up and whether or not they are discharged. For example, many chemicals are water soluble and will end up in the produced water that is discharged. Others are preferentially oil soluble and will end up in the oil stream and will not be discharged. Chemicals used in drilling muds will be in the mud discharged but may have reacted with other chemicals prior to discharge.

To understand the environmental impact of chemicals one must consider:

- The amount of chemical used
- The chemical's properties
- Any reactions it undergoes
- Whether it is discharged

These factors influence the limits that are established in the regulations.

3.5 Potential Impacts from Accidental Discharges

Almost all accidental discharges are of liquid materials. It is important to understand where these liquids will end up when discharged. Some crude oils are relatively volatile and, if spilled, most of the spilled liquid will evaporate into the air. Other crude oils have components that have low volatility. These oils will spread on the surface of the water initially and if not recovered will ultimately end up on the sea floor due to emulsification and absorption of solids. When oil spills reach shorelines and sediments they can physically and chemically impact biological communities as well as physical impact beaches.

The amount of material spilled is an important factor in determining any potential impacts. The size of the release can vary from a few milliliters from a dripping hose connection to thousands of tons in the event of major tanker grounding, or, for example in the case of the Deepwater Horizon the US District Court for the Eastern District of Louisiana ruled that 4 million barrels of oil were released [16]. Water based accidental discharges typically release a much smaller volume than oil spills. They also have a different pathway in the environment. For example, water based fluids such as completion fluids will disperse in the water column and be diluted.

Accidental discharges differ from the waste discharges in that they are generated one time, usually instantaneous events. The maximum volume discharged can be significantly more than routine waste discharges. In addition, there is little control where and when the material is released. Consequently, the discharge may occur in, or close to, very sensitive areas that cannot easily tolerate the discharged material; for example, a tanker spill that impacts a mangrove. In the case of a tanker spill, the response equipment and containment and cleanup crews have to be mobilized. Equipment and crews may be stationed significant distances away from the oil spill site. This potentially allows the spilled material to impact sensitive areas before the spill response equipment arrives. Fortunately however, large tanker spills are extremely rare and represent a very small percentage of the hydrocarbons that enter the environment [11].

Most accidental discharges into the marine environment are crude oil or refined petroleum products. Although the environment impacts of crude oil might be assumed to be similar to the impacts of drilling fluids, they are in fact very different. The highest concerns are for:

- Fouling of beaches and shorelines including manmade structures
- Fouling of birds and sea mammals
- Fouling of sediments
- Impact on breeding habitats

Some of the factors affecting environmental impact include:

- Speed and effectiveness of recovery of the spill and cleanup of the environment, which in turn can be influenced by cleanup liability issues
- Remediation of fouling of birds, mammals and habitats

In the early stages of a spill, spreading, evaporation, dispersion, emulsification and dissolution are the most prevalent processes. Oxidation, biodegradation and sedimentation become much more important later in the spill and tend to determine the eventual fate of the oil.

Recovery and cleanup operations are most effective when performed immediately, or soon after, the spill has occurred. Recovery operations are often made harder when the oil starts to emulsify. Emulsification starts soon after discharge and is exacerbated by wind and wave forces. Emulsified oil does more damage to beaches and habitats than free oil.

If the spill reaches the shoreline, part of the recovery will be decontaminating birds and mammals as well as the beaches and sediments. The sooner remediation starts the higher the effectiveness of the recovery.

With the advent of the use of supertankers in the 1960s the potential for large releases of hydrocarbons was created. The tanker, Torrey Canyon, was the first major spill from a super tanker. It grounded on the southwest coast of England in 1967 and 860,000 barrels of oil leaked into the sea. Much of the south coast of England was affected when oil coated rocky coastlines. The damage was compounded when laundry detergent was applied in an attempt to de-oil rocks, beaches and wildlife and when kerosene was used as the carrier for the oil dispersant which resulted in it being highly toxic to marine fauna. The effects of these efforts retarded the development of non-toxic dispersants for treating oil spills for years.

In 1978, the Amoco Cadiz was grounded off the coast of France and approximately 1,635,715 barrels of crude oil was spilled. Bad weather slowed the response to the spill and rapidly emulsified the oil. Much of this oil ended up on sandy beaches. The removal of large amount of oiled sand severely impacted the beaches.

In 1989, the Exxon Valdez ran aground on a reef in Prince William Sound offshore the State of Alaska. This area is biologically rich and large numbers of sea birds, ducks and sea otters and other animals were coated with oil and had to be rescued and cleaned.

There have been extensive industry, government and privately funded studies to determine the impact of the spill. These studies have come to a variety of conclusions from there being no long-term impact to significant impacts on the flora and fauna in the area.

The UK Royal Commission On Environmental Pollution, Oil Pollution of the Sea (1981) [14], after reviewing a substantial body of information on the environmental effects of actual oil spills, concluded that there is no evidence to substantiate claims for long-term irreversible impact to the marine environment. On the other hand, the short term consequences in relation to amenity loss, interruption of fishing activities and impact on individual sea birds (although not typically on bird populations) are sufficiently serious to justify efforts to develop and implement effective means of oil spill cleanup.

The Deepwater Horizon Semi-Submersible Drilling Rig 2010 oil spill, as explained above, was different from previous releases because of the length and volume of oil released. This has resulted in more significant actual environmental impacts as well as amenity losses, and, for example, interruption of fishing and tourism.

4 Regulatory Approaches

4.1 Regulations for Waste Discharges

It is important to balance the development of natural resources with protection of the environment. Oil and gas exploration activities generate wastes that must be properly handled and disposed of. As previously discussed, some of these, for example produced water, are high volume, low toxicity waste streams that would be very expensive to transport to shore for disposal. Other wastes, such as oil based fluids, have the potential to cause significant environmental impacts. Regulations addressing offshore waste discharges were developed to ensure that the environment is protected while still allowing disposal offshore where possible. A key ingredient in developing and protecting the environment has been obtaining input from all stake holders, including regulatory authorities, industry and environmental groups. Each group has brought data, information and perspective on the issues. The steps in regulatory development include:

- Identifying wastes
- Determining their volumes, properties, potential impacts
- Assessing the sensitivity of the receiving environment
- Determining control strategies
- Implementing systems for monitoring and control

Typically, regional, national and local government authorities are responsible for gathering this information. Industry groups, various industry organizations and environmental groups help identify concerns and supplement the available data.

There are a number of different schemes that are used to regulate waste discharges. In some areas the impact of discharges is controlled by limiting the chemicals that are used in systems that will ultimately be discharged. Other regions apply "end of the pipe" controls. That is they put a limit on the volume and content of the effluent. Generally, there are three major regulatory systems that are used:

- Those for the waters of the United States
- Those for the waters around northern Europe
- Those for Russia and former Soviet Republic waters

There are other additional regional and national regulatory systems. Most of these are modeled on the United States and European systems with local modifications. The following provides an overview of the three different regulatory schemes.

4.2 OSPAR Agreements and National Regulations for the OSPAR Area

The regulations for the North Sea, the Baltic Ocean and the northeast Atlantic Ocean are the result of a treaty organization, the OSPAR Commission, between 15 countries bordering these waters and the European Union. The OSPAR commission identifies issues, investigates impacts and sets goals for controlling pollution of the seas form several sources including offshore oil and gas waste discharges. The member countries through national regulations then implement these goals. For example, the department of Trade and Industry in the United Kingdom issues regulations and limits for the United Kingdom waters.

Information on these types of waste controlled and the limits set on them is available from the OSPAR Commission. The issues covered include, abandoned platforms and pipelines, the discharge of treating chemicals and oil in produced water and the discharge of drilling wastes among others. The approach used is primarily to control waste at the source. For example, treating chemicals are controlled by limiting the chemicals and the amounts used in the oil industry process. Both drilling chemicals and production treating chemicals are classified according to their potential impacts into several classes. These classes range from materials too hazardous to discharge down to those considered having very little impact on the environment. The first class cannot be discharged and no limits are placed on monitoring the waste discharged. Limitations on oil in produced water are an exception. Since oil originates in the underground formation the concentrations in the waste discharge stream are limited.

Discharges are of interest to groups other than regulators. Industry members and organizations and environmental organizations also give input to regulations. For the OSPAR areas organizations industry groups such as the International Association of Oil and Gas Producers (IOGP), Oil & Gas UK, the Netherlands Oil and Gas Exploration and Production Association (NOGEPA), and others input industry views and data. The IOGP is an international organization whose members are oil and gas companies around the world. They respond to regulations and develop environmental standards for oil companies to use where no definitive standards exist locally. Oil & Gas UK and NOGEPA are associations of oil and gas operators in the United Kingdom and the Netherlands. The other member countries of the OSPAR also have national associations of operators. In addition, suppliers to the oil industry provide information on environmental impacts. The European Oilfield Specialty Chemicals Association's (EOSCA) members supply chemicals to the North Sea offshore oil industry. The Environmental groups such a Green Peace and Friends of the Earth are active in lobbying for strong environmental regulations and have an impact on regulatory development. Information and data is available from all these organizations on environmental impacts and regulations.

Over time the limits placed on the chemical use and discharge of oil have evolved and changed. Initially oil concentration in produced water was subject to a concentration limit. Now the emphasis has changed to reducing the total amount of oil permitted to be discharged annually. OSPAR published data on volumes of produced water and amounts of oil discharged annually.

Drilling waste concerns have focused on the oil used to make the oil based drilling muds commonly used offshore. Initially there were no limits on what type of oil was used and diesel oil muds were common. Concerns over the toxicity of diesel oils led to a ban on them and muds were prepared using refined mineral oils, which did not contain aromatic compounds and other more toxic components. Later, all refined oils were banned from discharge and manufactured oils with a controlled composition were used until finally the discharge of drill cuttings containing more than 1 % oil, were banned. Current information on discharge regulations for areas controlled by the OSPAR Commission can be obtained from their offices in London or from their web site. Many of the same groups mentioned above for produced water also provide information and lobbying for drilling waste issues. In addition supply groups such as the International Association of Drilling Contractors (IADC) are active on behalf of drilling suppliers.

4.3 United States Regulations

The EPA develops regulations for the discharge of oil industry wastes of the United States waters. All waters of the United States are regulated. The environmental impacts of principle concern are toxicity and oxygen depletion.

In the United States discharges are separated into five (5) subcategories by potential impact:

- Subpart A: Offshore
- Subpart C: Onshore
- Subpart D: Coastal
- Subpart E: Agricultural and Wildlife Water Use (Beneficial)
- Subpart F: Stripper Wells

The waste streams covered include:

- Produced water
- Produced Sand
- Drilling Fluids
- Drill cuttings
- Well treatment, workover and completion fluids
- Domestic*
- Sanitary*
- Deck drainage*

*Subparts A and D only

EPA issued a proposed rule in March 2015 that will cover wastewater pollutant discharges from unconventional oil and gas extraction facilities to municipal treatment plants to address, for example, the handling of water used in the fracing process.

The previously proposed effort to develop effluent limitation guidelines for coalbed methane (CBM) facilities was discontinued in 2014.

The national office of the EPA identifies and classifies waste discharges and develops guidelines for issuing permits to operators wishing to discharge to these waters. Discharges are not allowed in some of these categories and are very restricted in others. For example, no discharge is permitted in the onshore subcategory because produced water and cuttings are biotreated in the aquatic environment and this process uses up the oxygen in the water faster than if can be replenished. There is also concern about the impact of hazardous substances that might be present in the waste.

In two of these subcategories, beneficial use and stripper wells, discharge volumes are very minor. In some dry areas of the United States, produced water is very low in salinity and can be used for watering livestock and for irrigation. These types of produced water discharges are in Subpart E. In one older area of the United States, very old gas wells producing very small amounts of water (stripper wells) are allowed to discharge to rivers as they have done for many years prior to the implementation of regulations. If discharge were not allowed, the wells would be uneconomical.

The coastal subcategory is that area inside the recognized coastline and outside the brine line, the distance inland that is covered in brackish or salty water. Subpart A is divided into the territorial seas and the Outer Continental Shelf (OCS). The territorial seas are those areas outside the recognized coast line to a distance of usually three miles. These waters are deemed to be part of a state. The OCS is the area outside the three mile limit and is controlled by the federal government and not an individual state. In these three subcategories discharge of waste to the waters was the traditional method of disposal. Over time it was shown that in the coastal areas oxygen depletion and increased salinity were affecting the local environmental and discharges to the coastal subcategory are now banned. In the territorial seas and the outer continental shelf waste discharge is allowed under a permit issued by EPA.

For regulatory purposes the EPA divides the United States into ten regions. The identification of wastes and the determination of their potential impacts are done by the national office of the EPA. These findings are published as guidelines for the preparation of permits. The regional offices can then develop and issue permits to discharge for each industry category based on the applicable guidelines. Originally all permits were developed and issued by an EPA Region. Now individual states can apply to the EPA for the right (called primacy) to issue permits to discharge. These permits are based on EPA guidelines and are subject to the approval of the applicable EPA Regional Office. In the case of the offshore oil and gas industry, discharges were deemed to be similar for all operators in a given EPA region and a system of general permits was developed. For each regional subcategory one permit is issued and all oil and gas operators in that area can apply to be covered by that permit.

Environmental concerns for oil industry discharges to United States waters are similar to those in the OSPAR countries. In both produced water discharges and drilling discharges toxic impacts, oil and oxygen depletion are the major issues. Where discharge of produced water is allowed the discharges have a toxicity limit and a limit on oil in produced water. Drilling waste discharges depend on the type of mud used. For water based muds, cuttings and excess mud can be discharged if a toxicity limit is met and the discharge does not produce a sheen on the water. For non-water based muds, discharges are forbidden for all mud bases except synthetic oils. The characteristics of these synthetic oils are specified in EPA guidelines. These discharges are limited to an average of 6 % oil on the cuttings over the discharge portion for the well being drilled. One additional limit on drilling discharges is that the barite used for weighting the mud must meet limits on the trace amounts of cadmium and mercury.

In addition to the major waste streams several minor discharge streams are also limited. These include treated cooling water, deck drainage from platforms, pipeline pressure test water, sewage from platforms and others. Each general permit for a regulated subcategory in a specified EPA region lists the waste streams discharged and the limits placed on them.

4.4 Comparing and Contrasting OSPAR and United States EPA Regulations

OSPAR tends to control what goes into the exploration and productions processes. The chemicals used are limited by the amount or concentration allowed. All treating chemicals and additives are placed in one of a number of specific classes. Each class is assigned a maximum amount to be used. Chemicals in the most toxic class may not be used at all. The theory behind this approach is that controlling chemicals that might have an adverse impact will control the potential impact. In contrast, the philosophy of the United States EPA is that how oil and gas operators conduct their business is for them to determine. However, the operator's actions must not impact the environmental. Control is exerted through so-called end of pipe limits. In this approach control is accomplished by measuring the composition of toxicity of the discharge, not specific additives used in operations. The major exception in United States EPA regulations is the ban on oil in drill cuttings discharged. A minor exception is the limits on cadmium and mercury in barite.

OSPAR regulations do set limits on oil discharged, but the emphasis is on controlling the total amount going into a particular water body not the concentration of individual discharges. In addition to the overall controls, there are also limits on individual discharges. The United States EPA limits oil in produced water as an indicator of toxic pollutants, not for the potential harm caused by the oil itself. This is in contrast to the OSPAR regulations, which assume that the oil itself might harm the environment. This ignores that fact that along the edge of the continental shelf all over the world natural seeps leak tonnes of oil into the marine environment every day. Although it should be noted that the flora and fauna around these naturally occurring seeps has adapted over time to be able to tolerate and/or live symbiotically.

4.5 Russian and Former Soviet Republic Regulations

In Russia and many of the former Soviet Republic States, there is a general prohibition on the discharge of effluents into the marine environment. Then, on a case-by-case basis, approval is obtained to discharge certain materials. The process involves testing the chemicals that will be used in the process to determine their toxicity and potential impact. Those chemicals that pass are given specific limits to control the impact of the discharge. Then discharges of the material are allowed if a compensation payment is made. The monies are generally considered not payment for damage, but rather a usage fee.

4.6 Other Regulatory Systems

Countries outside Europe and the United States tend to base their regulatory systems on features from both the OSPAR system and the United States EPA system. For example, the Arabian Gulf countries have developed a regional organization similar to OSPAR, but have included some United States features. The body is called the Regional Organization for the Protection of the Marine Environment (ROPME), and is comprised of Bahrain, Iran, Iraq, Kuwait, Oman, Qatar, Saudi Arabia and United Arab Emirates. It also acts as the secretariat for the Kuwait Convention and Plan. In addition almost all countries where the offshore oil industry is active have national regulations. There have been a number of attempts to summarize the regulatory limits for all the countries of the World but in a rapidly changing world these efforts can only be considered to provide preliminary guidance and specific, current information would be needed to get an accurate understanding of discharge limits for a particular country.

4.7 Accidental Discharges

Accidental discharges differ from waste discharges in several ways. Waste discharges are necessary and intentional. They are expected and always occur at a specific site. The impact on the receiving environment has been considered and is controlled by the conditions of the discharge permit. Accidental discharges are unplanned; occur randomly at unexpected locations; and discharge volumes are sometimes large in comparison to waste discharges. For waste discharges the regulatory emphasis is on controlling the discharge composition and rate. In addition, equipment should always be in place to maintain the permitted conditions for discharge.

The goal of waste discharge regulations is to control the treatment of waste, the rate of discharge and the potential impact on the environment. In contrast, the aims of accidental discharge regulations are:

- Prevention of releases
- Recovery of the discharge where possible
- Remediation of any damage that occurs
- Determining compensation for damages caused by the discharge

4.7.1 Summary of Accidental Discharge Regulatory History

Much of the regulatory emphasis has been on reducing and responding to accidental releases form transportation-related incidents. As production of oil and gas has expanded throughout much of the world, a concerted effort to address how to respond to accidental releases has been made. The initial steps in this direction tended to come as a direct response to a specific incident.

The first such incident to attract massive public attention was the grounding of the Torrey Canyon off the southwest coast of England in April 1967, which resulted in pollution of the English and French beaches. As a result of the Torrey Canyon, a number of individual governments began to urgently study the situation and look for remedies. However, they quickly realized that oil spills do not recognize or respect international boundaries and, as such, unilateral action would be of very little use. It was clear that were was a need to handle these issues internationally, and so the governments went to what was then called the Intergovernmental Maritime Consultative Organization (IMCO) – a specialized organization of the United Nations – and asked for help. IMCO has since changed its name to the International Maritime Organization (IMO) but it continues to this day to take the lead in this area.

In the meantime during the late 1960s, while IMCO began its work, the tanker and oil industries decided to move ahead with their own plans to address the problem of accidental releases. The objective of the work was to develop a scheme that would ensure that governments and people adversely impacted by oil spills anywhere in the world would be promptly and fairly compensated for any damage that they had suffered. Industry also endeavored to come up with a scheme that would help ensure that cargo and tanker owners would take immediate steps to prevent or mitigate any environmental damage.

In order to meet their objectives, the tanker and oil industries entered into two voluntary agreements:

- The Tanker Owners Voluntary Agreement Concerning Liability for Oil Pollution (TOVALOP)

- The Contract Regarding and Interim Supplement to Tanker Liability for Oil Pollution (CRISTAL)

Both these agreements terminated on February 20, 1997, when they were superseded by international spill compensation conventions.

In November 1969, IMCO convened the International Legal Conference on Marine Pollution in Brussels. The majority of the Governments attending signed the Civil Liability for Oil Pollution Damage Convention (CLC), which closely matched TOVALOP. On November 29, 1969, the CLC was adopted to ensure that anyone who suffered damage as a result of a spill from an oil carrying vessel would be compensated.

In December 1971, the Convention on the Establishment of an International Fund for Compensation for Oil Pollution Damage (FUND) was signed. The Fund Convention is in addition to CLC and was adopted with the purpose of providing additional compensation to those who could not obtain full and adequate compensation for oil pollution damage under the CLC. The Fund Convention set up the International Oil Pollution Compensation Fund. Companies who receive crude oil and heavy fuel oil in member states, after transport by sea, finance the Fund. The Fund Convention came into force in October 1978, at which time the IOPC Fund was established.

The CLC entered into force on June 19, 1975. Under the convention the liability for the damage rests solely with the owner of the ship. There are a number of exceptions to this strict liability (for example an accident as a result of an act of war). It is the responsibility of the ship owner to prove that one of the exceptions applies. The owner can, however, limit liability per incident unless the owner has been guilty of actual fault.

The CLC applies to all seagoing vessels that carry a cargo of oil. The owner of any vessels covered by CLC must also maintain insurance or some other financial security in an amount equal to the total liability for a release, although only ships that carry a cargo of over 2000 tonnes of oil are required to carry oil pollution insurance. The CLC does not apply to warships. However, vessels in commercial service that are owned by a participating State are covered by the CLC. The State owned vessels are not required to carry pollution insurance but must instead carry a certificate from the appropriate authority of the State in which the vessel is registered certifying that the ship's liability under the CLC is covered. The CLC covers pollution damages that results from a spill of oil in the territory, including the territorial seas of a State that is a Party to the Convention. It applies only to vessels that are carrying bulk oil as a cargo (for example laden tankers). It does not cover spills of ballast or oil that is used as fuel by ship. Nor, ironically, is it possible to recover any cost for the response to the incident if the actions result in no actual release of oil.

There have been a number of protocols adopted over the years in an ongoing effort to improve the Convention and help make it more manageable. The 1976 Protocol came into force on April 8, 1981. The original CLC had used the "Poincaré franc" which was based on the "official" value of gold as the unit in the compensation fund. It was very difficult to convert the gold franc into national currencies and so an alternative unit was found. The alternative was based on the Special Drawing Rights (SDR) as used by the International Monetary Fund (IMF). However, in cases where a member State was not a member of the IMF and it was against the law of the country to use SDR, a mechanism was put in place to use an alternative monetary unit based on the value of gold. The daily conversion rates for the SDR can be found on the IMP web site (http://www.imf.org).

The 1984 Protocol was adopted on May 25, 1984 and was to enter into force 12 months after being accepted by 10 States, including six with tanker fleets of at least 1 million gross tonnes. The Protocol was developed to address the fact that by the mid-1980s it was generally accepted that with the prevalence of the super tankers, the limits of liability in the original CLC were not high enough to adequately respond to a large incident. However, it never came into force and was eventually superseded by the 1992 Protocol. This was largely because the United States did not want to accept the Protocol. The USA preferred a system that did not limit liability, much more the Oil Pollution act of 1990 (OPA) that was passed by the USA largely in response to the Exxon Valdez spill. Therefore, the 1992 Protocol was written in such a way that the ratification of the USA was not needed in order for the Protocol to be ratified.

The Protocol of 1992 was adopted on November 27, 1992 and entered into force on May 30, 1996. The Protocol changed the entry into force requirements so that only four (4) instead of six (6) States with tanker fleets of at least 1 million gross tonnes were needed to ratify the Protocol. The compensation limits were the same as those adopted in the 1984 Protocol. In addition to raising the compensation limits from the CLC, the 1992 Protocol added that a ship owner cannot limit liability if it is shown that owner's act or omission caused the spill. It also widened the scope of the Convention to cover pollution damage caused in the exclusive economic zone (EEZ) or equivalent area of a State Party. The Protocol added a limit to environmental damage compensation to the actual costs associated with reasonable efforts to restore the contaminated environment. You can also recover the costs associated with preventative measure to be covered, even if there was no actual spill, as long as there was a "grave and imminent" threat of pollution damage. An added quirk is that Parties to the 1969 CLC. as a result of a provision in the 1992 Protocol, on May 16, 1968 ceased to be Parties to the 1969 CLC as a result of a provision in the 1992 Protocol that resulted in the compulsory denunciation of the "old" regime. The two regimes are currently co-existing because there are a number of States that are Party to the 1969 CLC, but have not yet ratified the 1992 Protocol as it establishes higher levels of liability. The 1992 Protocol permits States that are Party to the 1992 Protocol to issue certificates to ships that are registered in States that are not Party to the 1992 Protocol. This allows an owner to obtain certificates to 1969 and 1992 CLC, even if the vessel is registered in a State that is not a 1969 CLC State, may be able to do business in a country that is a Party to the 1992 Protocol without the appropriate 1992 Protocol certificate, as higher limits liability are established in the 1992 Protocol.

The 2000 Amendments were adopted on October 18, 2000 and entered into force, by tacit acceptance, on November 1, 2003. The amendments raised the compensation limits by 50 % over those established in the 1992 Protocol. The liability limit for a ship of less than 5000 gross tonnage is 4.51 million SDRs, or approximately $6.27 million at the exchange rates in 2015. For a ship of 5000–140,000 gross tonnage, the liability limit is 4.51 million SDRs plus 631 SDRs ($877.09) for each additional gross tonne. For vessels over 140,000 gross tonnage the limit is 89.77 million SDRs ($124.78 million).

Finally, the 2003 Protocol establishing an International Oil Pollution Compensation Supplementary Fund entered into force on March 3, 2005. The purpose of the supplementary fund is to supplement the compensation available under the 1992 CLC and Fund Convention with an additional third tier of compensation. Participation in the fund is optional, but is open to all States that are Party to the 1992 Fund Convention. The total amount of compensation that is payable for an incident will be limited to 750 million SRDs (just over $1042.5 million at 2015 exchange rates). The purpose of the supplementary fund is to ensure that victims of oil pollution damage will be fully compensated. It is expected that increasing the liability limit will end the practice of pro-rating payment of claims that exceeded the old limit. This practice, although unavoidable, had led to criticism of the 1992 Fund.

An International Convention on Civil Liability for Bunker Oil Pollution Damage, 2001, was adopted on March 23, 2001, and entered into force on 21 November 2008. The Convention was adopted to ensure that adequate, prompt and effective compensation is available to those affected by a release of oil that was carried as fuel in the ship's bunkers. It is generally modeled on the CLC and follows the same liabilities. It differs in requiring the registered owners of ships over 1000 gross tonnes (gt) to maintain insurance, or other equivalent financial instrument, to cover damages for pollution resulting from bunker oil releases up to the amount specified in CLC.

4.7.2 International Conventions on Prevention of Pollution

In addition to developing International Conventions that address liability and compensation issues associated with accidental discharges, there are also a number of International Conventions that address pollution prevention. The first international convention on the prevention of oil pollution at sea, was the International Convention for the Prevention of Pollution of the Sea by Oil, OILPOL 1954. It specifically controlled oily water discharges from general shipping and oil tanker transportation operations. OILPOL has now been largely superseded by "MARPOL: 73/78", the International Convention for the Prevention of Pollution from Ships 1973, as Modified by the Protocol of 1978. MARPOL 73/78 defines a ship to include "floating craft and fixed or floating platforms" and, as such, oil production platforms are covered by the Convention. This means, for example, that drainage discharges must not exceed 15 ppm, and so, in the UK, offshore installations are required to maintain an oil record book of all such discharges. Over the years MARPOL has been expanded and now addresses such issues as the phasing out of single hull tankers. For example, the December 2003 amendments to MARPOL 73/78 revising regulation 13G of Annex I of MARPOL, brought forward to April 5, 2005 from 2007, the final phasing out of Category 1 single hull tankers for ships delivered on April 5, 1982, or earlier and Category 2 ships delivered on, or before April 5, 1977. The amendments also banned the carriage of heavy grade oil in single hull tankers after April 5, 2005. The October 2004 amendments to MARPOL came into force on January 1, 2007. They include additional construction and equipment provision designed to help prevent accidental discharges. The amendments also establish the Oman Sea as a special area. Existing special areas under Annex I of MARPOL are the Mediterranean Sea, Baltic Sea, Black Sea, Red Sea, "Gulfs" Area, Gulf of Aden, Antarctic, North West European Waters, Oman area of the Arabian Sea and Southern South African Waters. There are stricter controls in the special areas.

The latest convention concerning oil pollution at sea is the International Convention on Oil Pollution Preparedness, Response and Cooperation 1990 (OPRC). It was adopted in November 1990, and entered into force on May 13, 1995. The objective of OPRC is to improve the level of preparation and preparedness to respond to an oil pollution incident, and to increase and promote international cooperation. OPRC seeks to build on the regional agreements (such as the Bonn Agreement for the North Sea area) to establish an interlocking series of plans that will ensure that all affected countries can adequately respond to any oil pollution incident in a coordinated, effective and rapid manner.

The impetus for the development of the OPRC was the much publicized Exxon Valdez spill in Prince William Sound, Alaska. The incident pointed out that to some extent governments and industry, having developed spill prevention and response plans, had become complacent, and some of the plans had become merely paperwork exercises to meet a regulatory requirement, rather than working documents. The Oil Pollution Act of 1990 (OPA 90) was passed in the United States largely in response to the same incident.

4.7.3 Government and Industry Initiatives to Help Prevent Accidental Releases

The previous section addressed the conventions and agreements that govern the response to an accidental release. This section will discuss some of the initiatives that have been taken to prevent accidental releases, and to minimize the impact of any releases that might occur. Obviously, as stated elsewhere, the best method of avoiding environmental damage from an accidental release of oil is to prevent the release from ever occurring. To this end, industry groups and governments have developed voluntary and regulatory requirements to ensure that plans are in place with the objective of prevention, control and cleanup of any release. The plans range from individual facility prevention and response plans, to regional intergovernmental and industry plans, as oil spills do not recognize or respect international boundaries.

To be effective, it is necessary to develop spill prevention planning on site-specific, local and regional bases. This is because successful planning has to start with prevention at the source, but then must address the potential regional impact of a spill, and how best to respond quickly and decisively to minimize any potential negative impact.

The first generation of facility spill plans was fairly rudimentary. They covered a description of the facilities involved, discussed the possible type and size of releases that could occur, identified appropriate control measures that would be employed to prevent a release, addressed what to do in the event of a release, and listed both the internal and external notifications that must be made in the event of an reportable spill, as well as some of the contractors who could help in a cleanup. A good example of such a plan is the Spill Prevention, Control and Countermeasure (SPCC) Plan that is required in the US under the Clean Water Act. The regulations also require that all personnel be adequately trained to respond appropriately in the event of a release.

Although the SPCC type of plans were an excellent start to a good spill prevention planning, over the years they have the tendency to become merely paperwork exercises. This was graphically illustrated with the Exxon Valdez spill in Prince William Sound, Alaska. The contingency planning that had been done, when tested, did not perform as had been anticipated. Consequently the new breed of spill planning requires not only extensive reviews of the potential impact of any release, but also requires detailed planning that ensures that responders will know exactly how to respond to all types of releases. Equipment has to be either on-site, or available on-site within specified time limits. In order to do this, operators have to enter into binding contracts with equipment providers who will guarantee a certain level of response within a specific time. The equipment had to be regularly inspected for operability, and the equipment has to actually be used in drills or actual responses on a specified schedule. Company and agency personnel who would be responsible for responding to a release have to receive regularly scheduled training that must include classroom and field segments. A good example of this type of plan is the Facility Response Plan required under the Oil Pollution Act of 1990 (OPA 90) in the United States.

In the case of the Deepwater Horizon release, although the companies involved had developed and implemented prevention and response plans, they were based on worst case discharge volumes that assumed that any blowout could be relatively quickly brought under control. This obviously did not happen, as it took 87 days to finally stop the releases. On May 21, 2010, President Barack Obama issued Executive Order 13543 to create the National Commission on the BP Deepwater Horizon Oil Spill and Offshore Drilling. The final report from the commission was released in January 2011. It resulted in a comprehensive reorganization and internal reforms to remove the complex and sometimes conflicting missions of the former Minerals Management Service (MMS). An interim agency, the Bureau of Ocean Energy Management, Regulation and Enforcement (BOEMRE) replaced the MMS for 18-months until the creation of three (3), independent agencies on October 1, 2011 with clearly defined roles and missions: the Bureau of Ocean Energy

Management (BOEM), the Bureau of Safety and Environmental Enforcement (BSEE) and the Office of Natural Resources Revenue (ONRR). In addition, the Oil Spill Commission Action was formed to periodically assess and provide updates on the Deepwater Horizon reform and recovery efforts. Some of the changes that have occurred since 2010 are:

- Reducing risk through enhanced well design and casing standards
- Increasing the inspection and engineering workforce within the agency
- Promoting safety culture and continuous improvement at all levels of the industry
- Enhancing blow-out preventer (BOP) testing and maintenance review
- Requirement for operators to demonstrate that they have subsea containment capabilities
- Developing a well control rule that requires, for example, increased equipment reliability
- Strengthening environmental review by requiring site specific environmental assessments for all deep water exploration plans
- Improving worst case discharge calculations
- Increasing limits of liability from $75 million to $134 million for offshore oil and gas facilities, with a mechanism in place to increase the limits over time to keep pace with inflation.
- Developing proposed shared international standards for the Arctic to help ensure that operators will take the steps necessary to ensure that the appropriate steps are taken to plan for and conduct safe drilling operations.

A more detailed description of some of these measures can be found at www.boem.gov [1].

On a regional basis, industry groups and governments have recognized the need for a cooperative effort to pool resources so that spill response can be as quick and effective as possible. The initial thrust came from industry that formed regional equipment cooperatives, which allowed each company to have access to a stockpile of equipment usually stored at strategic locations, for example the Clean Gulf and Clean Seas in the United States. In the UK the Maritime and Coastal Guard Agency (MCA) maintains some stockpiles of equipment. The Oil Spill Prevention and Response Advisory Group (OSPRAG) conducts periodic reviews of response capabilities and equipment and makes recommendations for improvements and updates. On a worldwide basis, groups, such as the Marine Spill Response Corporation (MSRC), and Oil Spill Response Limited, stockpile equipment at strategic locations throughout the world.

Again, in response to a series of usually tanker spills, although there were also a few exploration and production releases (Ixtoc blowout, Ekofisk and the Santa Barbara release), individual governments began to set up their own response groups. Each country has established a program that meets its individual needs, and as such they vary from country to country.

As the programs are developed to meet specific needs, there is a wide variation in the nature and type of system that is established and how it operates. However, their objective is to be as prepared as possible to respond to any oil pollution incident.

For example, in the United Kingdom, the Coastguard Agency's Marine Pollution Control Unit (MPCU) was formed in 1967 following the Torrey Canyon incident, to provide a command and control structure for decision making and response following a shipping incident that causes, or threatens to cause, pollution in UK waters. This replaced the previous non-dedicated central government organization for dealing with oil and chemical pollution at sea, with a small dedicated unit. This change came about as a result of the work done by the United Kingdom Royal Commission on Environmental Pollution which, amongst other things, stated that they considered it essential that the response to a major spill should be a single coordinated operation overseeing the response at sea, inshore and on the land, hence the MPCU. MPCU was then restructured during the merger between Marine Safety Agency and the Coastguard Agency in 1998, to become the Counter Pollution and Response (CPR) Branch of the MCA. MCA's CPR is now based on a regional response with central operational, technical and scientific support. A Counter Pollution & Salvage Officer (CPSO) is based in each region, supported by scientists, mariners, cost recovery specialist and logistics support specialists in the MCA's headquarters in Southampton.

The 2012 "National Contingency Plan for Marine Pollution from Shipping and Offshore Installations" (NCP), is currently under review. The Plan explains the procedures and arrangements that have been established to deal with pollution, or the threat of pollution as a result of accidental releases from ships and offshore installations. It also details that responsibilities of the Department for Transport, the Department of Energy and Climate Change and the Maritime and Coastguard Agency, harbour authorities, offshore installations operators and other bodies with relevant functions. These procedures have built-in thresholds to allow for flexibility of response to different degrees of incident.

The UK has studied carefully the short and long term impacts an accidental release could have on the environment and leisure activities, and established its resources within financial limits set by the level of impact anticipated. Generally, for example having government owned, strategically located stockpiles of equipment, coordinating the government owned stockpiles with the industry cooperative stockpiles, and the Bonn signatory government ones.

The MCA's CPR manages a series of framework agreements with technical experts to assist the MCA during incidents. Computer programs are used to model the fate and trajectory of both oil and hazardous substance spills. This information assists MCA decision making, to determine the appropriate response level for all types of threat to the UK interests.

In addition to the MCA, there are a number of other organizations in the UK that have a responsibility to respond to accidental releases. For example, offshore oil and gas facilities have the statutory responsibility to be able to respond to and clean up any release associate with their activities. Local authorities, or the Northern

Ireland Environment Agency have the non-statutory responsibility for shore cleanup.

The MCA runs and participates in many spill drills and also runs a series of training courses for local authorities to prepare their personnel to respond to shoreline pollution. CPR also runs courses in Oil Spill Response, aimed at local authority Beachmasters, which are hosted by local authorities. Both courses are accredited by the Nautical Institute. In addition, MCA runs Decision Making in Oil Spill Response Courses to prepare the statutory nature conservation agencies, the environmental regulators and the Government fisheries departments for their role in the Environmental Group set up in response to maritime incident. Counter Pollution & Response works closely with international colleagues. This includes the European Marine Safety Agency (EMSA) and the Bonn Agreement, which it currently chairs.

In contrast to the UK, which is well established program that has developed over many years, China has taken a different approach, which more close meets its specific needs. Unlike the UK, China is a vast country, which did not open up to oil exploration and production until the 1990s. The initial program was based on requiring the operator to do the spill contingency planning and to maintain any equipment necessary to provide an initial response until the international spill response community could get equipment and expertise into the area, if needed. The China National Offshore Oil Company (CNOC) was charged with reviewing the contingency planning and equipment to ensure that is adequate. Subsequently, the Chinese Government instituted the State "Emergency Plan for Oil Pollution Management on the High Seas" and formed an emergency response team for pollution in port areas [3].

RPC follows International Conventions including OPRC 1990 and OPRC-HNS Protocol and the International Convention relating to Intervention on the High Seas in Cases of Oil Pollution casualties, 1969, and has passed the following domestic laws:

- Marine Environment Protection Law of the People's Republic of China (PRC)
- Law of the PRC on Emergency Response Regulations on Administration of the Prevention and Control of Marine Environmental Pollution Caused by Vessels.

Several new regulations have been developed to implement these International Conventions and Domestic Laws. These include Regulations on Emergency Preparedness and Response on Marine Environmental Pollution from Ships (Ministerial Order No. 4 2011) as well as rules issued by China MSA.

The law requires that an environmental impact statement must be completed, submitted and approved by the National Environmental Protection Agency prior to a company being able to begin exploration and production activities. The information collected in the environmental impact statement is used for contingency planning. The contingency planning must include, at a minimum, the following elements: a general description of the project; the environmental conditions of the area, including the oceanography, meteorology, and the sensitive environmental zones; risk analysis; response organization and responsibilities; oil spill response procedures; and how spilled oil will be handled (in particular taking into account that most of the offshore discoveries have been high density, high pour point, waxy crudes, which means that standard skimmers and dispersants might not be effective).

Regulations of the PRC on the prevention and control of marine pollution from ships were issued in 2010 and were most recently updated in January 2012. The Regulations which came into effect on 1 March 2010 require owners/operators of (a) any ship carrying polluting and hazardous cargoes in bulk or (b) any other vessel above 10,000 gt to enter into a pollution clean-up contract with a Maritime Safety Agency (MSA) approved Ship Pollution Response Organization before the vessel enters a PRC port. The Maritime Safety Agency (MSA) of the PRC published Detailed Rules on the implementation of the Administration Regime of Agreement for Ship Pollution Response (Detailed Rules) which came into effect on 1 January 2012. On 14 September 2012, MSA revised the Detailed Rules (Revised Detailed Rules) and the Revised Detailed Rules came into effect on 14 September 2012 [3].

The Ivory Coast, West Africa, has developed a coordinated approach to responding to oil spills. In early 1990s the government teamed with the Danish International Development Agency (DANDIA) who sponsored a study to determine the current situation, to propose and implement any needed changes, and to purchase any necessary equipment. The Centre Ivoirien Antipollution (CIAPOL) under the Ministry of Environment, is the organization that deals with marine pollution problems. CIAPOL has three divisions: an administrative division; a division that deals with combating oil and chemical spills at sea, known as the Centre Ivoirien de lute contre les Pollution Marines et Lagunaires (CIPOMAR); and the Central Laboratory for the Environment (LCE) which carries out most types of water analyses, including analyses for total and individual hydrocarbons.

The national oil and spill plan, Plan Pollumar, was originally developed in the early 1980s, and has since been completely revised. The government has decided that CIAPOL will act as the national authority, and so is responsible for all matters related to marine oil and chemical spill contingency planning for Ivory Coast. The day-to-day running of the program and the implementation of the Plan Pollumar have been delegated to the CIAOMAR division. CIPOMAR has been organized into three sections, namely Operations, Maintenance and Administration. The Operation Section has setup a national communications center, which receives the reports of spills in the Ivory Coast response area, as well as pollution reports from neighboring countries within the West and Central Africa region (Cŏte d'Ivoire is a signatory of the Abidjan Convention). The duty officer at the communications center evaluates the report, and decides on the appropriate response, including for example, enacting Plan Pollumar.

The Maintenance Section is responsible for maintaining the spill response equipment. The Administrative Section is responsible for creating all the documentation that will be used for the claim and compensation procedures. Employees from all three sections have been trained to perform the functions of the Incident Commander and On-scene Coordinators. CIAPOL currently has nine (9) pollution response vessels for releases in coastal lagoons and near shore areas as well as boom, skimmers, pumps and inflatable storage barges.

However a country organizes its Spill Contingency Planning; all countries have recognized the importance of conducting regular drills. In some cases the drills are self -contained within the country. In other cases combined drills are held by neighboring states.

5 Should the Release Be Remediated?

Since the first oil spill and resultant cleanup, the question has been raised as to how clean is clean? Over the years considerable effort and resources have been expanded to determine not only impact of spilled crude oil on the environment, but also the impact of the cleanup. In the early days the cure was often worse than original incident. For example, as previously mentioned, the dispersants used on the Torrey Canyon Spill were several orders of magnitude more toxic than the oil that they were trying to disperse. Eventually the recommendation arising from the results of individual companies and by the agencies responsible for a Country's response planning. It began to be an accepted credo that the net impact on the environment should be important factor in deciding on the appropriate response to an accidental release.

However, it is important to remember political reality will not always allow the responders to a spill to base their decisions solely on what is best for the environment.

For example, natural biodegradation, and bioremediation of a beach may be the best ecological solution, however, the company responsible for the spill, and cleanup, and the agency overseeing the response may have to attempt to clean up the area in order to be seen as responsive.

In spite of political pressures, it is important to try and always make the minimum net environmental impact the objective of a responsive plan. Exactly how to do this will depend on the nature of the crude oil spilled the location of the oil, and the systems that are or maybe, impacted. For example, it is generally accepted that crude oil spilled in a salt marsh is best left to degrade naturally, as any attempt to mechanically remove the oil will result in a much greater impact on the biosystem.

Another critical component of the "how clean is clean" debate is the importance of the stakeholders coming to an agreement on the appropriate end point, beyond which cost of remediation far exceeds the net benefit to the environment.

6 Sources of Data on Discharges to the Marine Environment

Much of the information on oil industry discharges to the sea is not reported in scientific studies but in industry technical documents or legal documents. At the present time the best sources of such information on discharges to the sea from oil industry operations are the websites of the various regulatory and industry bodies. These organizations include:

- Regulatory bodies
- Industry associations
- Technical societies
- Industry support groups and suppliers
- Environmental activist organizations

Some of the important regulatory bodies are:

- The Oslo Paris Commission (OSPAR)
- The United States Environmental Protection Agency (USEPA)
- The United Kingdom Department of Energy & Climate Change
- The UN Regional Organization for the Protection of the Marine Environment
- International Maritime Organization (IMO)

Some of the important industry associations are:

- The International Association of Oil & Gas Producers (OGP)
- The American Petroleum Institute (API)
- Oil & Gas UK
- The Society of Petroleum Engineers International (SPEI)

Some important industry support groups and suppliers associations are:

- European Oilfield Specialty Chemicals Association, (EOSCA)
- International Association of Drilling Contractors, (IADC)

Some important environmental groups are:

- Friends of Earth
- The Natural Resources Defense Council (NRDC)

These organizations can be assessed on the Internet by entering their names or acronyms into a search engine. Much of the information in this chapter was verified using these web sites.

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Chapter 8
Decommissioning of Offshore Oil and Gas Installations

M.D. Day and A. Gusmitta

1 Introduction

The offshore oil and gas industry had its beginnings in the Gulf of Mexico in 1947. The first offshore development used a multipiled steel jacket to support the topside production facilities, a design which has since been used extensively. Now there are more than 7000 drilling and production platforms located on the Continental Shelves of 53 countries [1]. Some of these structures have been installed in areas of deep water and treacherous climates, and consequently structure designs have adapted to withstand the environmental conditions of these areas. Some typical designs are shown in Figs. 8.1, 8.2, 8.3, 8.4, and 8.5. In the North Sea, which is an area that experiences some extreme environmental conditions, more than 600 structures have been installed [5], about 25 % of which are in water depths greater than 75 m and can be exposed to maximum storm wave heights of 30 m. This combination of deep waters and extreme storm forces dictates large structures, some with component weights that exceed 50,000 tonnes [6]. For instance, Troll A Platform, which is located in the Northern North Sea and considered one of the heaviest subsea structure in the world, weights 650,000 tonnes. This particular substructure was installed in 1996 and has a height of around 472 m [7] (Petro global news,

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_8

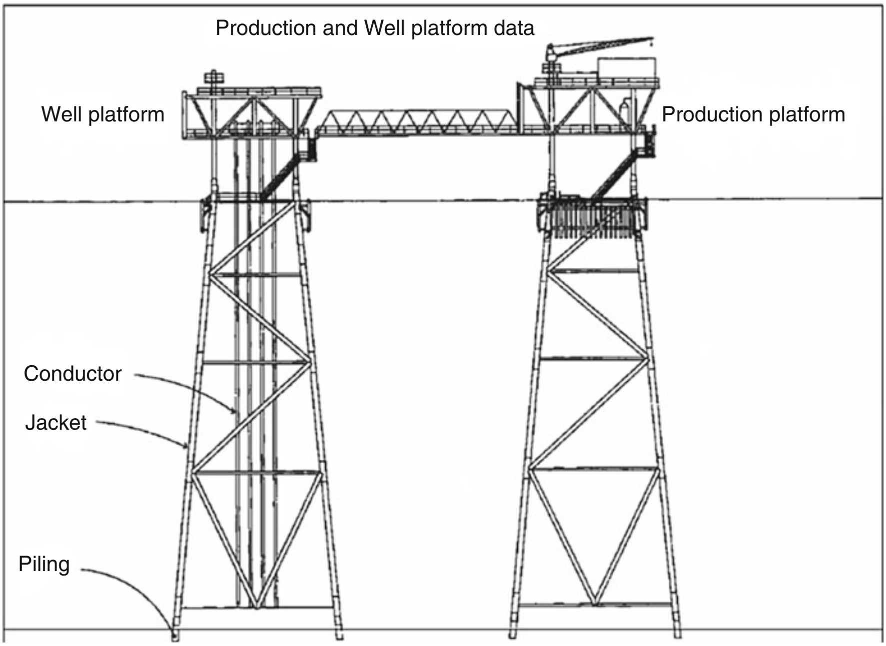


Fig. 8.1 Steel-jacketed structure [2]

2013). Now, as oil and gas fields begin to deplete their reserves, the concern has turned to the removal and disposal of these structures at the end of their producing lives. Estimates indicate that the cost of some removals may exceed the cost of the original installation. The structures located on the Norwegian Continental Shelf contain only 1 % of the world's offshore structures, but will account for nearly 20 % of the worldwide removal costs [4]. Innovative removal and disposal techniques must be developed to limit costs and minimize the impact on the environment. Differently than all the other regions in the world, the offshore structures located within the North East Atlantic have to be removed and disposed onshore. More specifically, the Oslo Paris Convention (OSPAR) 98/3 regulation, issued in 1998, regulates the disposal of offshore structure within the area [5, 8]. Because of this regulation and the fact that decommissioning in the area is a relatively new phenomenon, the Oil and Gas operators operating within the North Sea are under a lot of pressure and are looking for ways to reduce the cost of it [8]. Organisations such as Decom North Sea, are helping the supply chain and operators to interact and collaborate in order to reduce risks and costs of decommissioning process [9].

The Gulf of Mexico, the western and central coasts of Africa, the Persian Gulf, the bulk of the Pacific region and the Mediterranean Sea are all examples of areas with more moderate environments. The majority of structures in these areas are in water depths from 3 to 300 m with maximum storm wave heights of 12 m. With a few exceptions, platforms in these areas will probably be totally removed at the end of their producing lives. The major implication with total removal is in choosing the

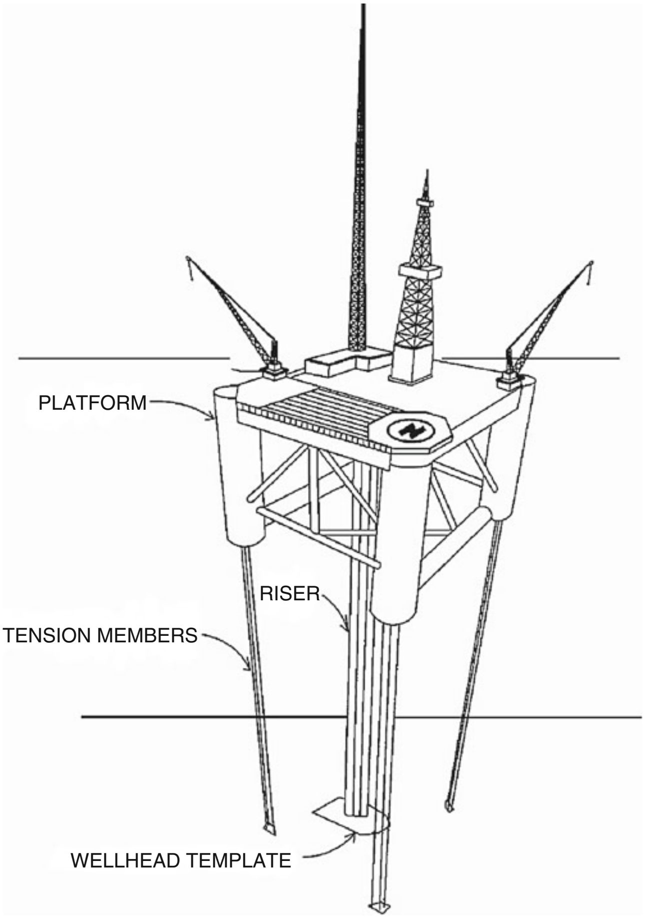


Fig. 8.2 Tension leg platform [3]

method to dislodge the structure from the sea-bed and an issue in remote areas of the world is the availability of support equipment to perform the removals.

2 Legal Framework of Platform Decommissioning

International law provides the basic foundation of the legal requirements for the removal and disposal of offshore structures. The removal of installations was addressed by the 1958 Geneva Convention on the Continental Shelf, which stated that any installations which are abandoned or disused must be entirely removed. However, several parties to the Convention were soon adopting some form of local standards to allow for partial or non-removal. The more widely accepted statement of international law is contained in the United Nations Convention on the Law of

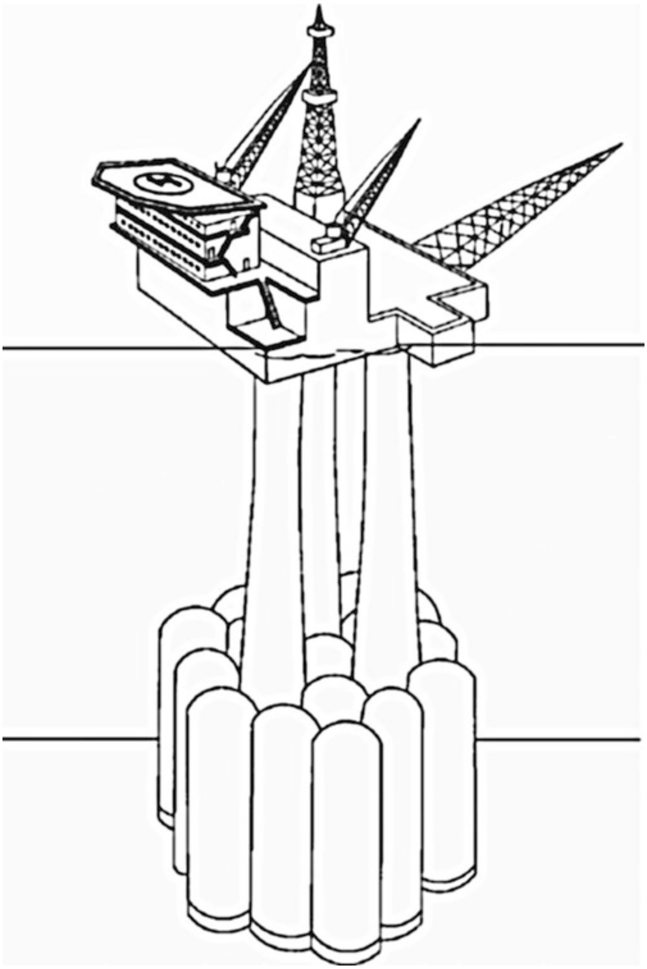


Fig. 8.3 Concrete gravity base structure [3]

the Sea (UNCLOS), which allows for partial removal and has been widely accepted as it appears to represent customary international law in relation to abandonment [10]. The International Maritime Organization (IMO) guidelines were issued using UNCLOS as a basis. These guidelines state that if the structure exists in less than 75 m of water and weighs less than 4000 tonnes, it must be totally removed [10]. Structures installed after January 1988 will have a water depth criterion of 100 m, forcing the owner to plan for the eventual abandonment in the initial design. If the removal is done partially, the installation must maintain a 55 m clear water column. There are exceptions in the guideline that allow for non-removal, e.g. if the structure can serve a new use after hydrocarbon production including enhancement of a living resource, if the structure can be left without causing undue interference

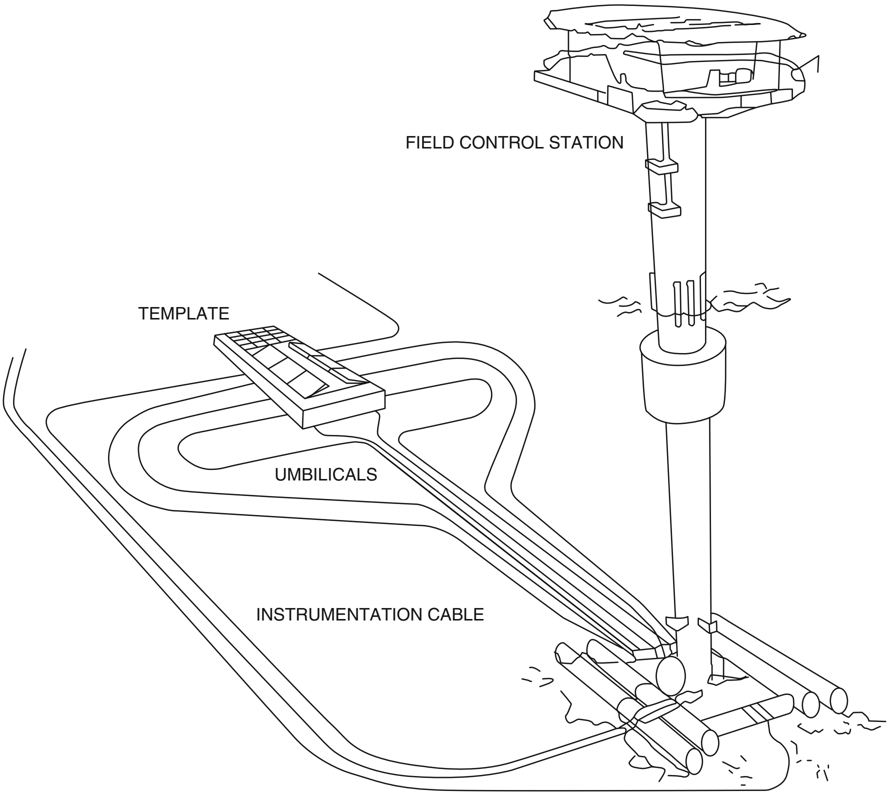


Fig. 8.4 Floating production system [4]

with other uses of the sea or where removal is technically not feasible or an unacceptable risk to the environment or personnel [10]. If the installation is to remain in place, it must be adequately maintained to prevent structural failure.

Basic disposal stipulations can be traced to international dumping conventions. The Oslo Convention of 1972 for the Prevention of Marine Pollution by Dumping from Ships and Aircraft provides some guidelines.

However, it is not clear if this Convention applies to dumping of platforms in place. The London Convention of 1972 on the Prevention of Marine Pollution by Dumping of Wastes and other Matter also supplies guidelines for deliberate disposal of platforms or other artificial structures at sea. UNCLOS deals with dumping, and states that 'dumping within the territorial sea and the exclusive zone or onto their continental shelf will not be carried out without the express prior approval of the coastal state . . .' [10].

The Convention for the Protection of the Marine Environment of the North East Atlantic (Paris 1992) is relevant. It provides that 'no disused structures . . . be dumped and no disused offshore installation shall be left wholly or partly in place in the Maritime area without a permit issued by the appropriate competent authority

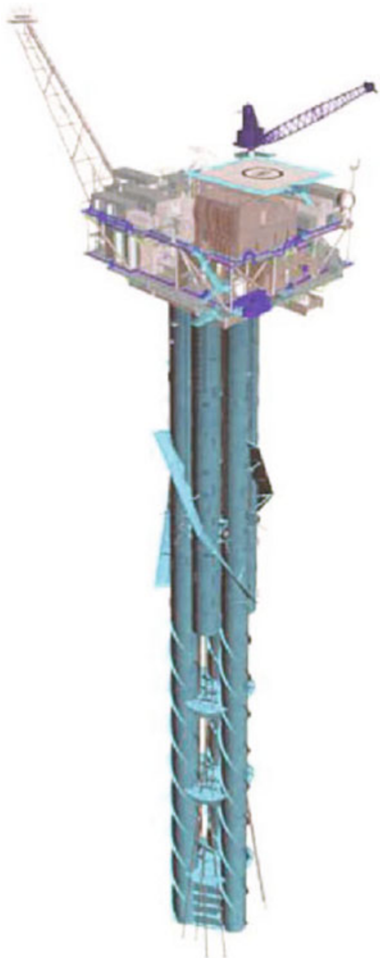


Fig. 8.5 Cell spar (See *color* plates)

of the contracting party on a case-by-case basis', and that 'dumping does not include the leaving wholly or partly in place of a disused installation . . . provided that such operation takes place in accordance with any relevant Convention and with relevant international law' [10].

The body established by the 1991 Oslo Convention, the Oslo Paris (OSPAR) Commission, adopted guidelines on a trial basis to exercise overall supervision over the implementation of the Convention. These guidelines are complementary to the IMO guidelines and aim to minimize pollution to the sea by hazardous residues left in parts of installations disposed of at sea [10]. (The latest regulation of the OSPAR convention about this topic is the 98/3 regulation). The removal of offshore structures in Nord East Atlantic area is regulated by the 98/3 regulation, which prohibit the sea disposal of any offshore structure. However, there are some

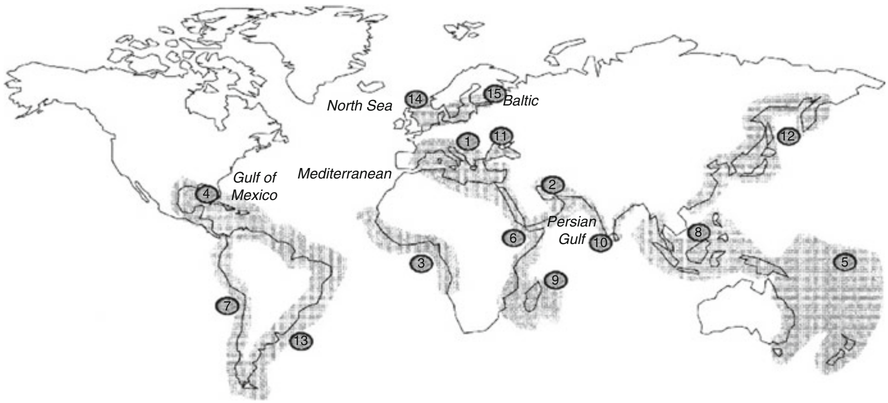


Fig. 8.6 UNEP regional seas program and other conventions

derogations that allow the owner of the structure to ask the permission to leave the structure or part of it in these specific cases:

– The substructure weights more than 10,000 tones
– The removal of a part is considered highly expensive and the operations of removal can highly affect the environment,

While all of the above are basic guidelines to removal and disposal, they do not account for all of the issues involved with the abandonment or disposal of offshore structures. Thus, local states are left to decipher the issues, and to generate legislation to cover loopholes in international law in accordance with their priorities. By 1992, 15 United Nations Environment Programme (UNEP) regional conventions had been held (Fig. 8.6). Here, local states have adopted varying degrees of guidelines for potential legal concerns such as determination of the party responsible for removal, responsibility and methods of payment, responsibility of owners in default situations, owner designation upon non-use, maintenance responsibility and liability for items left in place and such site-specific issues as bottom debris removal and moratoriums for marine migrations.

The complexity of issues has stymied most countries from adopting specific guidelines and standards for platform removal, but most do require abandonment procedures to be submitted to designated regulatory agencies for approval on a case-by-case basis. Some countries, depending on their experience with removals, are fairly mature in their regulatory standards for abandonment, whereas others still have great strides to make in enacting requirements for removals within their coastal waters.

3 Planning

The most critical and time-consuming task of the abandonment process is the planning phase. This phase should be initiated years in advance when depletion plans for a field are recommended. The planning phase can be effectively organized with the aid of commercially available computer software. A software package which allows for input of schedules, tasks, resources and contingencies is recommended. This will be beneficial in establishing the critical path of the project and will help keep the project on schedule for the available construction weather window. A project management software package will enable the project engineer to maintain accurate cost accounting and to keep the project organised, on schedule and within budget.

4 Abandonment Phases

The entire abandonment process, also called decommissioning can be broken down into seven discrete activities [11]:

1. *Well abandonment*: the permanent plugging and abandonment of nonproductive well bores.
2. *Pre-abandonment surveys/data gathering*: information-gathering phase to gain knowledge about the existing platform and its condition. Governing ministries or standards organisations should be contacted to determine permit and environmental requirements.
3. *Engineering*: development of an abandonment plan based on information gathered during pre-abandonment surveys.
4. *Production shutdown*: the shutdown of all process equipment and facilities, removal of waste streams and associated activities to ready the platform for a safe and environmentally sound demolition.
5. *Structure removal*: removal of the deck or floating production facility from the site, followed by removal of the jacket, bottom tether structures or gravity base.
6. *Disposal*: the disposal, recycle, or reuse of platform components onshore or offshore.
7. *Site clearance*: final clean-up of sea-floor debris.

The following is a brief discussion of the sequence of processes involved with structure decommissioning.

4.1 Well Abandonment

The exact timing of cessation of production can be difficult to predict. However, a close working relationship between the reservoir, downhole and salvage engineers should be developed to establish the timing of a well and platform abandonment project. Before abandonment can begin, the salvage engineer must confirm that all wells on the platform are abandoned. The wells should be permanently abandoned according to the recommended procedures of the governing body. Generally this means isolating productive zones of the well with cement, removing some or all of the production tubing and setting a surface cement plug in the well with the top of the plug approximately 30–50 m below the mudline. The inner casing string should be checked to ensure that adequate diameter and depths are available for the lowering of explosives or cutting tools. If the well plug and abandonment are not performed properly, removal of the conductor by explosive or mechanical means becomes unsafe and much more expensive.

There are mainly three ways to operate:

1. Using a mobile drill rig
2. Using a platform rig
3. Using a rigless intervention system

To ensure no delays in structure removal, all well plug and abandonments should be completed several months prior to commencement of offshore decommissioning. After well plug and abandonment responsibility and schedules have been established, the next step is an information-gathering phase.

According to the latest forecast, in the UK continental Shelf area alone, 930 wells are going to be decommissioned in the next decade. [5]

4.2 Pre-abandonment Surveys/Data Gathering

Critical to a successful abandonment program is planning. Proper planning requires that as much as possible about the platform be known. Information must be gathered on the topside deck and support structure design, fabrication and installation as well as any structural modifications that may have occurred since installation. The pre-abandonment survey should assess the condition of the platform facilities and structure prior to beginning the abandonment. The survey should include the following:

(a) *File surveys*. All available documentation concerning the platform design, fabrication, installation, commissioning, start-up and continuing operations should be investigated. The file survey will familiarise the project engineer with the other appurtenances to the platform facility such as living quarters, process equipment, piping, flare system and pipelines and any additions/deletions or structural repairs to the jacket or the topside since the original installation. The project engineer must remain aware that platform records may be incomplete or unreliable. After an extensive search of all available files, the engineer should be able to define the abandonment scope of work and the objectives of subsequent surveys.

(b) *Geophysical survey*. Depending on the results of the file survey, the engineer may choose to have additional data gathered by means of sidescan sonar. This survey will indicate the amount of debris on the seafloor. In the case of deep-sea disposal, the sonar can determine if there are any obstructions at the dump site. Proximity of an available dump site or ‘rigs to reef’ site, water depths and obstructions along the tow route should be investigated as part of the geophysical survey.

(c) *Environmental survey*. This consists of an environmental audit of the offshore platform to identify waste streams or other government controlled materials. At this time items such as naturally occurring radioactive materials (NORM), asbestos, PCBs, sludges, slop oils and hazardous/toxic wastes should be identified and quantified. The problem of dealing with these waste streams should be addressed in the scope of work for handling during the decommissioning phase of the project. The project engineer should determine what permits or operating parameters are required by the host government or international standards.

(d) *Structural survey*. A structural engineer can use observation and non-destructive ultrasonic testing techniques to evaluate the structural integrity. Items inspected will include condition and accessibility of lifting eyes, obstructions on the deck which may require removal and interfaces between production modules/deck and deck/jacket which may require cutting for disassembly. Discrepancies between actual conditions and as-built information identified in the files should be noted during this phase. The platform legs should be checked for damage that may obstruct explosives or cutting tools from accessing the proper cutting depth. If obstruction from damage is anticipated or found, smaller diameter charges or cutting tools should be provided by the removal contractor as a contingency. Information concerning the underwater condition of the structure should be available from previous underwater inspections. If not available, consideration should be given for gathering this information by divers or remote-operated vehicles (ROVs).

4.3 Engineering

Upon completion of pre-abandonment surveys, a strategy for decommissioning and abandonment can be developed. The engineering phase takes all of the data previously gathered and pieces it together to form a logical, planned approach to a safe abandonment. Of major concern during the development of this strategy is the safety of the operations. As with all offshore operations, there exists a high potential for accidents involving bodily injury or loss of life and the accidental discharge of oil and flammable, corrosive or toxic material into the environment.

A risk analysis for all phases of the decommissioning should be performed. The results of this risk analysis are used to develop a decommissioning safety plan. Safety targets can be set and achieved provided the appropriate attention is devoted to the elements of the decommissioning plan. These procedural elements include the following items:

- regularly scheduled safety meetings;
- identification of safe work areas;
- safety equipment and training for emergency situations;

- working at high elevations and over water;
- safe operations of cutting tools and explosives;
- safe demolition to maintain structural integrity;
- proper use of rescue and evacuation equipment;
- diving and ROV operations;
- testing for and monitoring of toxic/explosive gases;
- pollution controls and containment;
- methods for handling and disposal of oil wastes, corrosive, NORM, or toxic materials;
- weather monitoring/night watch procedures;

Addressing each of the above-mentioned elements will help in the development of a safe decommissioning and salvage plan. After all the safety and environmental aspects of the project have been considered, details of the salvage process need to be identified. The sequence of process equipment and structure decommissioning and the salvage and disposal methods need to be determined. Any required government permits should be submitted for approval.

A major determination for an effective and efficient abandonment program is proper selection of the salvage equipment. Equipment selection for lifting purposes is determined by maximum weights of components to be lifted. Heavy Lift Vessels (HLV) currently available to the industry range from approximately 135 to 48,000 tonnes (Fig. 8.7).

Early 2015, a new HLV, called Pioneering Spirit has been launched. It has been considered part of the next generation for HLV, as it has the ability to lift a jacket that weights 25,000 tons max or a topside that weights 48,000 tons max [5, 12]. This vessel will play a fundamental role in the next period since there will be a need for more time efficient removals.

Other lower capacity, less expensive lift spreads can be used if the lift weights can be broken down through equipment removal or by cutting the components into smaller lifts.

Cost comparisons must be made between the time savings afforded by heavier lift, more expensive equipment and time-consuming, lighter lift, less expensive equipment. In addition to costs, the project engineer must assess the safety and environmental risks associated with sectional removal. Sectional removal will require significant time at the site for dismemberment and removal of production piping and equipment prior to cutting the topside deck into pieces. Additional hazardous tasks involved with decommissioning, lifting and rigging operations need to be performed offshore in a sectional removal, thus the time during which personnel will be exposed to increased workplace hazards will be increased. More details pertaining to sectional removal will be addressed in Sect. 4.5.

Once the sizing of equipment is complete, a qualified list of contractors can be generated based on equipment availability and the area of the world in which the salvage is to take place. Awarding of the job based on the list of qualified contractors can be carried out in many ways. Two often used methods are bidding out the job for award to the lowest bidder or by negotiating a contract with the

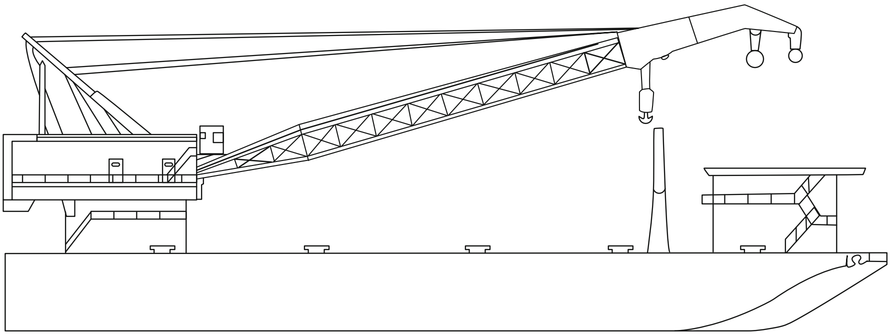


Fig. 8.7 Derrick barge

contractor who is most capable of performing the work. The job scope could include all aspects of the abandonment from the well abandonment to the final site clearance. Another method might be to award each portion of the abandonment and salvage as individual components similar to the breakdown of the seven phases of abandonment.

4.4 Production Shutdown

A primary objective during the production shutdown is to protect the marine environment and the ecosystem by proper collection, control, transport and disposal of various waste streams. Production shutdown is a dangerous phase of the abandonment operation and creates the possibility of environmental pollution. Shutdown and removal or abandonment in place should be carried out by personnel who have specific knowledge and experience in safety, process flows, platform operations, marine transportation, structural systems and pipeline operations. All contractors involved with the shutdown should be brought in early in the planning stage to further assure a smooth decommissioning project.

The sequence of shutting down the process system, utilities, power supplies and life support systems is important. The platform's power, communications and life support systems should be maintained for as long as practicable to support the decommissioning effort.

Process systems throughout the platform will have to be flushed, purged and degassed in order to remove any trapped hydrocarbons. Safe lock-out, tag-out, hot work and vessel entry procedures must be in place to ensure safety. Procedures must outline all duties of the standby/rescue teams including the use of breathing apparatus, air purging and lighting and caution must be exercised in removing all amounts of gases, oils and solids which may still remain in valves, production headers, filter housings, vessels and pipework that could present hazards to the crew.

Platform decommissioning will result in large amounts of waste liquids and solids. Where possible, waste liquids can be dealt with most cost effectively by placing them in existing pipelines and sending them to existing operating facilities. If no ongoing operations are available, then the waste streams will have to be pumped into storage containers and transported onshore for disposal or recycling. The constituents of the waste stream will dictate the cost of disposal. Solid wastes such as discarded batteries, glycol filters and absorbent rags will also have to be handled onshore according to acceptable disposal practices. Many platforms will have chemical treatment additives as well as possible toxic/hazardous materials such as methanol, biocides, antifoams, oxygen scavengers, corrosion inhibitors, paints and solvents, some of which may cause damage to the marine environment if accidentally discharged. Therefore, the procedures for handling and containing should be followed. The presence of radioactive scale, NORM, PCBs, hydrogen sulfide, etc., should have been detected during the environmental survey and a disposal plan developed. Disposal will generally mean transporting this material in drums to disposal wells or approved landfills.

Prior to removal, a detailed plan on how each material will be disposed of should be developed. The plan should identify recyclable materials such as steel, rubber and aluminium and the recycling centres that will take delivery of these materials. For those items not to be recycled, the abandonment plan should include the environmental impact that disposal will have on the dump site.

After the process piping and vessels have been cleaned and it has been determined that there is no future utility for the pipelines, pipeline decommissioning should commence. Pipelines departing the platform will either board another platform or commingle with another pipeline via a sub-sea tie-in. A surface to surface decommissioning is the least costly to perform. This requires pigging the line to vacate any residual hydrocarbons followed by flushing with one line volume of detergent water followed by final rinsing with one line volume of sea water. Upon completion of the pipeline purging operation, pipeline ends should be cut, plugs inserted and the ends buried below the sea-bed. In the case of a sub-sea tie-in, details of the sub-sea tap will have to be obtained so that pipeline decommissioning plans can be developed. The flowline can be pigged, flushed and disconnected if the receiving platform can accept the fluids, otherwise the pipeline segment will have to be isolated from the adjoining trunkline and then decommissioned. This will generally involve a boat capable of mooring over the sub-sea tie-in, connecting flexible piping to the tie-in using divers or ROVs, then pumping pigs, detergent water and rinsing water toward the platform for handling.

Decommissioning involves a variety of waste streams, disposal handling methods and specialty contractors. This phase more than any other will determine the success of the abandonment and salvage.

4.5 *Structure Removal*

The method of a structure removal will be determined by the structure design, availability of removal equipment, method of disposal and the legal requirements governing the jurisdiction in which the abandonment is to take place. The legal requirements will usually be based on the social, economic, environmental and safety concerns of the local governing bodies. All of these issues are interrelated and will have a direct effect on the overall cost of the removal operation. The economics of the removal are of prime importance to the party responsible for the removal, whether it is a contractor, local government or producer. Each structure consists primarily of the topsides or deck above the water line and the jacket below the waterline.

4.5.1 Deck Removal

Topsides removal is essentially the reverse sequence of the installation. Any piece of equipment obstructing the deck lifting eyes must be removed prior to the lift. The deck section is removed by cutting the welded connection between the piles and the deck legs. Slings are attached to the deck lifting eyes and the crane hook on the heavy lifting vessel (HLV). The HLV's crane lifts the deck section from the jacket. The deck is then placed on the cargo barge and readied for transportation to a land based facility for offloading [13].

4.5.2 Jacket Removal

The jacket portion of the platform consists of the steel template which resides in the water column. Prior to removing the jacket, the piles must be cut to dislodge the jacket from the seafloor. The majority of structures in moderate environments will be totally removed. Most regulatory bodies throughout the world require that the structure be removed anywhere from the mudline to 5 m below. The chief consideration when developing a removal procedure is to determine if the piles or well bores will be severed using explosive or non-explosive methods.

(a) *Removals using explosives*. Severing platform piles and well bores with explosives is relatively effective compared with using non-explosive methods, as multiple cuts can be made in a short period of time. This limits the amount of time that removal support equipment must be on the site and limits personnel exposure to unsafe working conditions. Generally, explosives are the least expensive and the method of choice for structure removal. However, when explosives are used, more stringent regulations may become effective, including consultations with the local fishery or natural resource agencies. A project plan should allow lead time for consultations and permit approval from these agencies. Explosives emit high-energy shock waves that can be harmful to habitat fisheries immediately adjacent to a removal site and some endangered species, such as marine turtles or mammals, in close proximity to the detonations may be mortally affected by these shock waves. Local regulations should be researched to determine limits to the amount and size of charges allowed and to determine if moratorium periods exist during marine migration periods.

In some areas, a condition for approval requires that observers from the local regulatory agencies and/or resource groups be present at the removal site prior to detonations, to observe that permit requirements are being met and to ensure that no harm is done to endangered species that may be in the area. Other conditions that may be imposed to limit the effects of explosives on habitat fisheries are pre-detonation aerial surveys, daylight-only working hours and staggered detonations.

Numerous studies are ongoing to reduce the harmful effects on local fish populations during detonations. Focus or shaped charges concentrate the detonation energy to the target, requiring less explosive weight with the same cut efficiency. The disadvantage of focus charges is that they need to be properly set in the well bore or pile and corrosion scale or damage in the piles can inhibit the charge from applying its full energy to the target.

A technique to reduce the effects of explosives on habitat fisheries is to evacuate the platform piles of all water. This reduces the resistance of the shock wave from the charge to the target. Also, special shock-attenuating blankets can be placed at the mudline to limit the energy emitted from the seafloor. Another technique may be to deter fish from entering the blast area. Small, preset charges set off prior to the detonation of the severing charges, known as scare charges, have been used. However, there are risks that scare charges may actually draw some species of curious fish toward the blast site. The use of strobe lights similar to those used to keep fish away from dam intakes may be effective.

(b) *Non-explosive removals*. An option for the project engineer is to eliminate the use of explosives in the removal. Use of non-explosive removal techniques eliminates the impact due to shock waves. Consequently, costs and time associated with observers and additional permit conditions may be eliminated. However, salvages using non-explosive methods can be more costly since only one pile or well bore can in practice be severed at one time. Each non-explosive cut will typically take several hours to perform. The additional time and cost can be minimised depending on the scope of work and with proper project planning. The project engineer should perform a precise cost estimate, evaluating the costs and risks between using explosive and non-explosive methods of severing. The following is a discussion of some non-explosive severing techniques.

High-pressure water/abrasive cutters. This system uses a high-pressure water jet operating at anywhere from 200 to 4000 bar to perform the cut. In some systems, sand, garnet or other type of abrasive is injected into the water stream to aid in the cutting process. The nozzle is lowered into the hole attached to an umbilical hose line or a hard pipe supply line. The nozzle is rotated 360° inside of the pile or well bore until the cut comes back on itself. One of the advantages to the system is its effective cutting ability. The casing strings do not have to be concentric in the well bore. The wall thickness of the platform piles is typically not a concern. The reaction of the water spray and the returns of the water give the operator an indication that the cut is actually being made. Some disadvantages are the tendency for system breakdowns due to the high working pressures, electrical and mechanical complexities, the delicate characteristics of the abrasive injection and wear and tear on the nozzle. Interrupting the cutting operation requires that the tool be placed in the exact location of the cut to avoid incomplete cuts. The effectiveness of these cuts is reduced at deeper cutting depths owing to the hydrostatic head that the water jet needs to overcome. As with all cutters, the tool must be centred in the pipe to maximize cutting efficiency. This can be difficult in heavily scaled pipes or in battered piles. Topside instrumentation can be used to monitor the position of the cutting tool during the cut. Camera technology has been used to inspect visually the status and effectiveness of a cut.

Mechanical cutters. Mechanical cutters use tungsten bit cutters that are extended from a housing tool with hydraulic rams. The tool is rotated continuously using friction to perform the cut. Disadvantages include frequent breakdowns of the tool due to frictional wear and tear, high labour intensity in handling heavy and bulky tools, the need for a work platform around the piling/well bore to be cut and poor cutting performance on non-concentric casing strings. Also, it can be difficult for the operator to determine if a cut is complete. Shifting of the well strings or platform piles downward can jam the tool into the kerf of the cut.

Diver cut. Internal or external pile or well bore cuts can be made with divers using underwater burning equipment. This type of cut can be made internally if there is access for the diver into a large-diameter casing or piling. If there is no internal access and the cut must be made below the mudline, a trench must be excavated to afford the diver access to the area to be severed. In some soils, keeping a trench open to the required 5 m depth may be impractical and may put the diver at undue risk from trench collapse. If the cut must be made below the mudline, the local regulatory agencies should be consulted as to the required depth of the cut. This may require obtaining a waiver to reduce the required cutting depth due to local soil characteristics and safety concerns for the diver personnel. Another concern to the diver's safety is oxygen entrapment in the soil near the cut or on the backside of the pipe being cut. Oxygen build-up can lead to an explosion if contacted with a flammable source such as a burning rod.

Cryogenics. Cryogenics is a little used technology that consists of freezing the platform pile in the area of a cut with CO_2. A relatively small explosive charge is then placed at the elevation to be cut and detonated. The brittle behaviour of the frozen steel theoretically requires little energy to sever the pile. To use cryogenics, water must be completely evacuated from the pile, which can be a time-consuming operation. Also, the cutting efficiency is hindered by the freezing of the mud on the exterior of the pile to be severed.

Plasma arc cutting. Plasma arc cutting is achieved by an extremely high velocity plasma gas jet formed by an arc and an inert gas flowing from a small-diameter orifice [14]. The arc energy is concentrated on a small area of metal, thus forcing the molten metal through the kerf and out of the backside of the pipe. Water can be used as a shielding agent to cool and constrict the arc [14]. The process requires a high arc voltage provided by specialised power sources. This method has not been used often, and is therefore not highly developed. For it to be effective, the tool must be set properly in the cut pipe. It is difficult to determine if a cut is being made unless camera technology is used.

Whether using explosives or non-explosive methods of severing, obstructions in the pile can hinder the proper placement of charges or cutting tools in the well bore or pile. Examples of obstructions include scale build-up, damaged piling, mud or pile stabbing guides. The removal of mud from the pile is generally accomplished with the use of a combination of a water jet and air lifting tools. When properly designed, these work well. This task is traditionally performed after the topside deck has been removed by the heavy lift contractor. A more cost-effective technique is the use of a submersible pump to excavate mud from the platform pile prior to removal. A small inexpensive work spread can be mobilised to the site prior to the arrival of the heavy lift equipment to perform this task. A window is cut into the jacket leg/pile and the submersible pump is then lowered down the jacket leg on a soft umbilical line.

(c) *Alternative removal techniques*. Most structures are removed with heavy lift equipment such as oceangoing derrick barges. In remote areas of the world, another concern in dislodging the platform from the seafloor is the availability of salvage support equipment. International Maritime Organization (IMO) guidelines permit the host government to allow a structure to remain in place provided that the structure is properly maintained to prevent failure. Maintenance costs over the life of the installation may eventually exceed the cost of the removal. When left in place, the platform may remain a hazard to navigation, exposed to collapse during storms or become a haven for refugees. These risks and liabilities may outweigh high removal costs to the host government and the operator, thus the decision to remove the platform may prevail.

Innovative methods of decommissioning, removal and disposal must be proposed to offset the lack of available salvage equipment and the high cost of equipment mobilisation to remote areas. An alternative approach is cutting the platform into small, manageable components that lighter, more cost-effective equipment work spreads can handle. The equipment that may be used includes crawler cranes, A-frames and portable hydraulic cranes mounted on a cargo barge and these methods use readily available equipment that can be rigged up inexpensively.

Besides additional decommissioning hazards, other precautions must be taken during a sectional removal. Caution should be taken when cutting into a structural member as gases from scale or other sources may have built up over time inside of the member, and flame cutting into the member could result in an explosion. Each member should be drilled and checked for gases prior to any flame cutting operations. Sectional removal requires a detailed plan for lift sling connections and cut locations for each component to be removed. Lift slings should be properly attached so that a safe, level lift can be made, and a level, controlled lift will eliminate load shifting and allow for proper setdown on the transport barge without undo risk to personnel or equipment. Removal of a structure in sections may require multiple cuts underwater. The same concerns with load shifting and sling placement exist for underwater cuts as they do for above-water cuts. These cuts should be performed and/or supervised by skilled divers. Divers' activities can be reduced by using small shaped charges to sever members or by performing cuts with ROVs.

Other forms of less expensive salvage support equipment include bargemounted 'stiff legs' and converted jack-up drilling rigs. Stiff legs have the capability to handle large lifts, but generally have limited hook height and are not easily manoeuvrable during the lifting and setting of components on transport barges. Stiff legs are generally built to work in protected waters and are affected by rough seas.

Converted jack-up drilling rigs are becoming more common in the abandonment industry. Companies are converting obsolete rigs to lift vessels to take advantage of the increased need to supply salvage support equipment. This type of equipment can work in heavy seas when in the jacked-up position, but in the floating condition manoeuvrability is limited.

Extreme caution must be taken when bringing transport barges near the jack-up rig to accept platform components. The legs of a jack-up rig cannot withstand any severe impact loading.

Another technique that can be used for the lifting of platform topsides is the Versatruss system (Fig. 8.8). The method uses a series of A-frames mounted on tandem cargo barges. The combination of the A-frames, tension slings and the topside deck create a catamaran and truss effect for lift stability. This lift method also uses available equipment and requires relatively low-cost preparation.

(d) *Alternative structure uses*. In some areas of the world, the host government is either wholly responsible for structure removal or, through participation by a national oil company, is partially responsible for the cost of structure removal. The political entity may not want to dedicate funds to a nonrevenue generating project. These states may decide that leaving the structure in place is the only alternative. IMO guidelines give local states the discretion to allow offshore structures to remain in place if the removal is not economically feasible. In these situations, operators will need to review the contract terms for possible ongoing or future liabilities.

Alternative uses for the platform should be explored. The benefit of the alternative use should offset the costs to maintain the structure in place. Some alternative uses may be as follows:

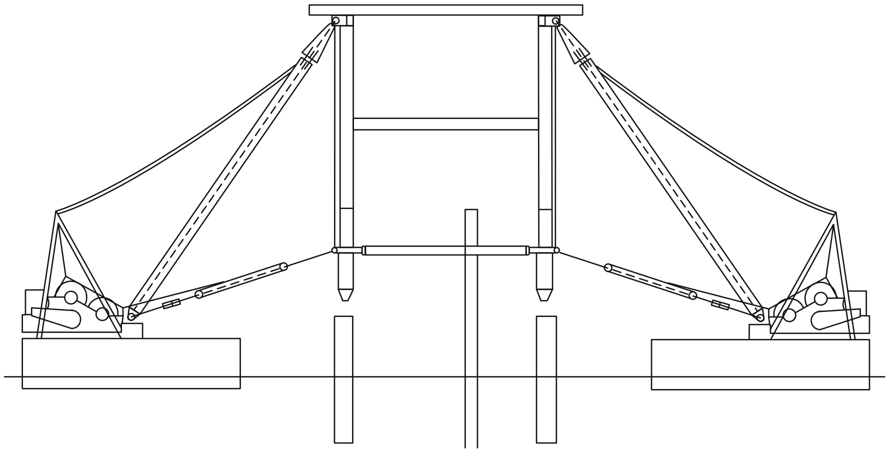


Fig. 8.8 Versatruss method (Source: Versabar Inc)

- fish farm;
- marine laboratory;
- military radar support structure;
- weather station;
- oil loading station;
- spur for deep-water developments;
- aviation/navigation beacon;
- tourism/recreational;
- power generation, i.e. wind/wave.

Leaving the structure in place should not create a hazard to local fishing industries or to navigation in the area.

(e) *Platform reuse*. Reuse is another option. If a potential development can finance the removal of a structure, this relieves the non-revenue producing property from absorbing the salvage costs. Platform reuse can reduce the cycle time to get the new development in production, generating cash. However, an immediate reuse should be identified when decommissioning is undertaken. Storage of the platform onshore prior to identifying a reuse can result in costs that may offset the savings from reuse.

One of the latest examples of platform reuse is the Welland 53/4a, operated by Perenco. The platform topside was refurbished and brought to West Africa, more specifically offshore Cameroon where now is part of a operational gas field [15].

(f) *Partial removals*. The Partial removal consists of leaving part of the structure in the sea. This process is considered beneficial for oil and gas companies and the environment. The cost of the decommissioning process will be reduced and the structure left will generate a new marine ecosystem around it [5, 8]. These partial removal methods will consist of the following (Fig. 8.9):

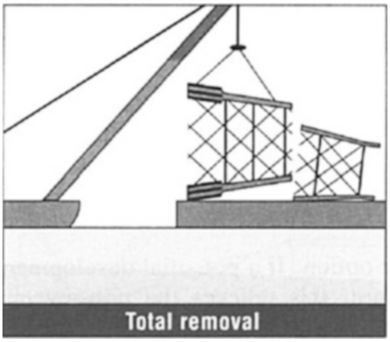


Fig. 8.9 Total removal [16]

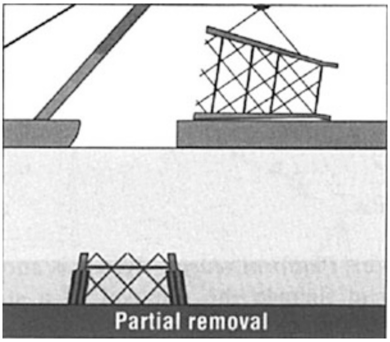


Fig. 8.10 Partial removal [16]

- partial removal of jacket component (Fig 8.10);
- toppling in place (Fig. 8.11);
- total removal of topside and toppling in place of the jacket only (Fig. 8.12);
- emplacement (Fig. 8.13);
- transport to rigs to reef site;
- deep-water dumping.

The choice of removal method will depend on cost, proximity to disposal sites, availability of removal equipment, location of the removal relative to shipping lanes and fishing interests, and safety and environmental issues. In addition, the disposal method will play a key role in the decision on the removal method. The next section summarises the alternatives and key issues concerned with structure disposal.

4.6 Disposal

Once a platform or portions of a platform have been removed, the structure must be disposed of. Some disposal options include the following:

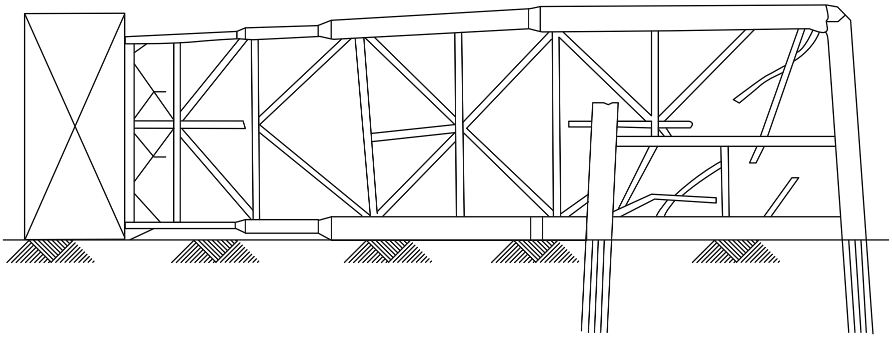


Fig. 8.11 Hinge point in jacket leg

- transport inshore for disposal, storage or recycling;
- toppling in place;
- disposal at a remote rigs to reef site;
- emplacement;
- deep-water dumping.

The owner must be aware of the social and political climate in the area where abandonment and disposal are to occur. Public perception will play a key role in performing a successful disposal program. All environmental issues should be addressed by the operator up front, all stakeholder groups and regulatory agencies should be informed of the disposal plans and environmental effects of the plan and alternatives must be addressed. Miscommunication and misinformation to or from interested stakeholders could lead to the downfall of an otherwise well planned abandonment strategy.

Non-jacketed designs such as floating production systems, concrete structures, steel gravity structures and spar loading buoys will probably be refloated in whole or in part and towed away, and disposed of in deep-ocean disposal sites or brought inland for dismantling. Steel-jacketed structures will probably be disposed of in one or any combination of the ways mentioned above. Explanations of these methods are detailed below.

(a) *Disposal inshore*. Generally, topside deck facilities will be disposed of inshore because of the difficulty and expense in completely removing all of the hydrocarbons and their by-products at the installation site rather than shore-side. When disposal inshore is chosen, the structural component will be either totally or partially cut up for scrap. Portions may be disposed of in landfills or hazardous waste sites or recycled. The component may also be stored for future use or refurbished immediately if a reuse is identified. Once a structure has been removed for inland disposal, possession of the removed structure and their components is usually turned over to the removal contractor in exchange for a portion of the scrap value. The steel in offshore structures is of relatively good quality and is readily taken by steel mills for recycling. The handling and

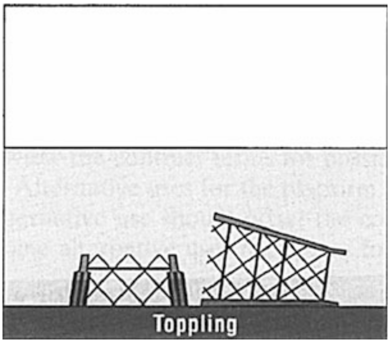


Fig. 8.12 Toppling [17]

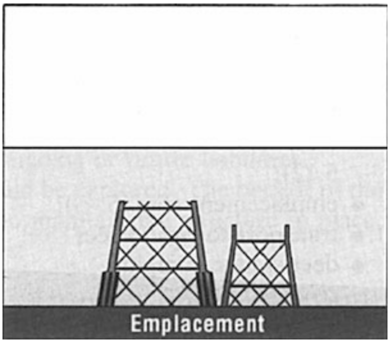


Fig. 8.13 Emplacement [16]

disposal of all other materials associated with the removal should be detailed in the pre-abandonment disposal plan.

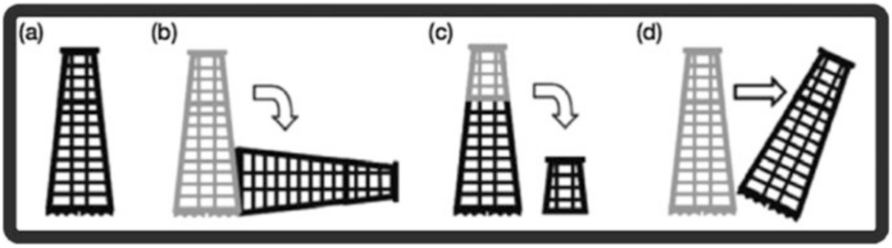
The UK Offshore Operators Association performed a detailed assessment of the amount of waste materials projected from the disposal of offshore structures from the North Sea. Disposal amounts were calculated and the effect on the available landfill space was determined [18]. Another study, performed by planners for a removal in Norway, detailed costs and benefits of recycling an old structure. The study compared the emissions placed in the atmosphere by melting and breakdown to the cost of the energy and associated emissions generated if the same component was built new [4].

An environmental assessment could be made based on these studies. These types of analyses would be beneficial to the operator and regulatory bodies when the decision is made to bring offshore components inshore.

(b) *Rigs to reef*. This technique consists in creating an artificial reef using part of the existing structure of a platform. Normally during this process the topside is removed and the jacket is used to create the reef. When an offshore structure is removed, a habitat for fisheries and a source of recreational fishing is lost. It has been estimated by the Gulf of Mexico Fishery Management Council that oil and gas structures account for 23 % of the hard bottom habitat in that area [2]. Prior to the emplacement of petroleum-related structures, suitable habitats in which new species could expand their range did not exist. Countries may establish a rigs to reef program to maintain the hard bottom habitats that these structures provide. When performing a cost comparison between dumping a platform at a reef site or disposal inshore, the size of the platform, location of the platform in relation to the placement site and the transport costs are the main factors.

There are four main techniques that can be used to generate an artificial reef [8, 19]:

1. Leaving part of the structure as it was during the operations (a).
2. Sinking the entire structure by shifting it (b).
3. Cutting the top part of the structure at 85 ft below the sea and placing the cut part on the sea bed (c).
4. Towing the structure to another site (d).



Rigs to reef options (Source: Mecreadie et al. [19])

By choosing these techniques, both the environment and the operators may benefit. The marine environment will benefit because the created marine habitat won't be entirely destroyed and the pollution generated by the decommissioning operation activities will be reduced (ibid; [8]). In addition, Oil and Gas operators will not face the cost of total removal and will be able to invest more money in other projects [8].

The first two options consist in leaving the structure as it was and in placing it on the sea bed. These two options are easier to perform than the other ones.

The third option consists in toppling the structure. The toppled structure must maintain 85 ft of clear water column clearance as required by IMO guidelines. Another method is to cut the top section completely from the lower section, lift it off, place it on the bottom to the side and topple it with heavy-lift marine equipment. In the Gulf of Mexico, toppling may only be performed in established reef sites. The site should be clearly marked with buoys. In the Gulf of Mexico, the buoys are maintained by the state, whereas in the North Sea the responsibility remains with the operator to mark and maintain the site. In other parts of the world, marking is negotiable between the operator and the host government. The site should also be placed on navigation charts. Similar to the rigs to reef option the toppling in place will reduce costs for the oil and gas companies and will benefit the environment.

A common method of transportation is to tow the structure while on the hook of the removal barge crane. Derrick barges are not constructed for this purpose, so extreme caution should be taken if this method is used. Weather and obstructions both below and above the water along the tow route should be anticipated. If the heavy-lift equipment has to accompany the structure to the placement site, this subjects the project to costly weather and operational delays. The need for the derrick barge at the disposal site can be avoided by setting up a winch and snatch block system to push the structure off the transport barge. These costs have to be weighed against the removal and transport of the platform components inshore. A rigs to reef program benefits the fish population and provides a popular source of recreational fishing while giving the project engineer an additional option to reduce platform removal costs.

The toppled structure must maintain 55 ft clear water column clearance as required by IMO guidelines. Another method is to cut the top section completely from the lower section, lift it off, place it on the bottom to the side and topple it with heavy-lift marine equipment (Fig. 8.12). In the Gulf of Mexico, toppling may only be performed in established reef sites. The site should be clearly marked with buoys. In the Gulf of Mexico, the buoys are maintained by the state, whereas in the North Sea the responsibility remains with the operator to mark and maintain the site. In other parts of the world, marking is negotiable between the operator and the host government. The site should also be placed on navigation charts. Similar to the rigs to reef option the toppling in place will reduce costs for the oil and gas companies and will benefit the environment.

(d) *Emplacement*. Emplacement (Fig. 8.13) is much the same procedure as toppling except that the top section is completely cut from the lower section, lifted off and placed next to the lower section.
(e) *Deep-water dumping*. Essentially, the structure is disconnected from its moorings and towed to the deep ocean waters where it is then flooded and sunk. Prior to any dumping operations, it is important to confirm that all components placed in the ocean waters are free of hydrocarbons in harmful quantities to avoid pollution of the open sea.

Partial removal may consist of any combination of the above-listed options. The method of structure and component disposal should be based on legal, environmental, safety, financial and timing issues. Identification of a disposal site and its proximity to the removal site must be considered to perform a cost analysis on the most effective disposal method.

An inherent concern with any disposal method is tying down the salvaged component on the transport barges, which can be particularly difficult and dangerous in rough weather. A well thought out plan has to be enacted to assure a safe and stable lift and placement on the transport barges. All components should be tied down with a system that provides the same integrity as when the platform was towed offshore for installation.

A marine surveyor should be available on-site to monitor the tie-down operations. The marine surveyor's responsibilities include confirming that the structure is secure for tow, certifying that the tow route is free of overhead, width or bottom obstructions and verifying proper ballast of the transport barge.

4.7 Site Clearance

The final phase of the abandonment process involves restoration of the site to its original predevelopment conditions by clearing the seafloor of debris and obstructions after platform removal. If the abandonment was a partial removal, site clearance procedures may vary from a total removal. In the case of total removal, debris should be removed, leaving the site trawlable and safe for fishing or other maritime uses.

A site clearance plan may consist of two or three phases, depending on the information gathered during the pre-abandonment surveys and the water depth at the location. The first phase may occur before actual removal with divers making sector sweeps around the platform site during pipeline decommissioning. High-frequency sonar can be used to locate obstructions and direct divers to debris. Searches should be performed inside and outside the platform a distance of at least 100 m. Following this initial debris removal, site clearance can be discontinued until the structure removal has taken place.

Once the structure has been removed, the site is ready for a final clean-up if required. In shallow waters, a trawling vessel can be used to simulate typical trawling activities that may occur in the area after the platform removal.

Deeper water sites may not require trawling simulations to clear the area. Proper planning prior to the removal of debris can make a significant difference in controlling the costs. The geophysical survey performed with the side scan sonar during the pre-abandonment survey phase should identify the major debris, and this information will provide the basis for selecting the most effective equipment, personnel and timing. Equipment and personnel can range from a dive crew retrieving debris off a boat during pipeline abandonment, through a small derrick barge with divers to a boat capable of mooring over debris targets away from the platform. In deep waters, it is crucial to determine the amount and type of debris to size the equipment and work crews properly. Upon completion of the bottom clean-up, job completion summaries should be submitted to the proper governing body.

5 Conclusion

The offshore oil and gas industry will be faced with more than 7000 platform removals, each of which will include a multitude of tasks, involving interaction between operators, contractors, regulatory agencies, governing bodies and the public. Of importance to the operator will be the cost effectiveness of the removal. The operator will also share in the public and regulator's concern on the effect that the removal will have on the environment. The operator should focus on early interaction with regulatory agencies, detailed pre-removal planning and engineering, efficient interface and timing of equipment and personnel movements, safety and disposal to assure a cost-effective removal with minimum impact on the environment. Finally, all stakeholders should continuously pursue advances in rulemaking and technology to ensure each abandonment program improves on the one that preceded it.

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Chapter 9
Tanker Design and Safety: Historical Developments and Future Trends

Apostolos Papanikolaou

Nomenclature

CAF	Cost for averting one fatality
CATS	Cost of Averting one Tonne of Spilled oil
CSR	Common structural rules
DH	Double-hull ships
DWT	Deadweight
EEDI	Energy efficiency design index
EEOI	Energy efficiency operational indicator
ESP	Enhanced program survey
ETS	European telecommunications standards
FSA	Formal safety assessment
GCAF	Gross cost of averting a fatality
GISIS	Global integrated shipping information system
IACS	International Association of Classification Societies
ICAF	Implied cost of averting a fatality
IEA	International Energy Agency
IHS	IHS Fairplay [formerly LRF (Lloyd's Register Fairplay)]
IMO	International Maritime Organization
IOPCF	International Oil Pollution Compensation Fund
IPCC	Intergovernmental Panel on Climate Change
ISM	International Safety Management Code
LMIU	Lloyd's Maritime Intelligence Unit
LOWI	Loss of watertight integrity
MARPOL	International Convention for the Prevention of Pollution from Ships

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_9

MEPC	Marine Environment Protection Committee
NCAF	Net cost of averting a fatality
NASF	Non-accidental structural failure
NTUA-SDL	National Technical University of Athens–Ship Design Laboratory
OILPOL	International Convention on the Prevention of Pollution of the Sea by Oil
OOI	Oil outflow index
OPA 90	Oil Pollution Act
Paris MoU	Paris Memorandum of Understanding on Port State Control
PLC	Potential loss of cargo
PLL	Potential loss of life
RBD	Risk-based design
RCO	Risk control option
SECA	Sulfur emission controlled areas
SEEMP	Ship energy efficiency management plan
SOLAS	International Convention for the Safety of Life at Sea
SFOC	Specific fuel oil consumption
STCW	International Convention on Standards of Training Certification and Watch Keeping for Seafarers
ULCC	Ultra-large crude carrier
VLCC	Very large crude carrier

1 Introduction: Tanker Design and Operation from an Environmental Perspective

The main objective of the present section of this chapter is a critical historical review of oil transportation by tankers and an assessment of their safety performance with focus on the past 25 years. It is a prime concern of the maritime industry and of governmental and regulatory authorities to continuously enhance ship safety and to reduce marine pollution related to ship incidents and accidents. Despite the introduction of a variety of safety-enhancing measures, regulations, and technologies related to the avoidance of accidents, tanker as well as marine accidents in general continue to happen, and this is not likely to change in the future. Thus, a reasonable goal for the maritime industry and relevant authorities is mitigation of the risk connected with accidents in terms of minimizing the probability of an occurrence and the associated consequences. In this respect, it is of paramount importance to critically review past accidents and assess the associated risk in terms of frequencies of the occurrence of accidents and their consequences.

The present chapter constitutes a critical review of historical developments in oil tanker design and of relevant regulations referring to the prevention of marine oil spills and the protection of the marine and the atmospheric environment. It presents a comprehensive analysis and critical review of recorded accidents of medium and large oil tankers (deadweight more than 20,000 tonnes) that occurred after the introduction of OPA 90 and up to the present. Raw casualty data were reviewed and reanalyzed to produce appropriate statistics useful for the implementation of risk-based assessment methodologies. The study includes the identification and quantification of the principal hazards that may lead to a tanker's loss of watertight integrity and consequently cause environmental damage. Finally, the chapter looks into future developments in oil tanker design and operation in the framework of risk-based design and operation.

Relevant research work started in the framework of the EU-funded project POP&C (2004–2007 [33]), in which casualty data of the Aframax class of tankers were systematically analyzed and post-processed as necessary for the application of a risk-based methodology regarding pollution prevention and control in view of tanker accidents. Further studies, beyond those of the POP&C project, were conducted in the frame of another EU-funded project SAFEDOR (2005–2009) by the Ship Design Laboratory of NTUA (NTUA-SDL), in collaboration with Germanischer Lloyd, Hamburg, namely, addressing the Suezmax, VLCC, and ULCC tankers, thus practically all large-size tankers. Based on this research, project SAFEDOR developed a Formal Safety Assessment for large tankers, which was submitted for consideration to IMO by Denmark (IMO-MEPC 58/17/2 and IMO-MEPC58/INF.2 [15, 16]). Even more, project SAFEDOR introduced the risk-based design concept to the wider maritime field and presented a variety of demonstration studies with respect to both ship design and maritime regulations [30]. Among these was the risk-based design of an innovative Aframax tanker [31]. To identify possible effects of *tanker size* on accident statistics, NTUA-SDL complemented these studies more recently by the analysis of medium-size tankers, namely, in the range 20,000–60,000 t DWT, thus, Handysize and Handymax tankers [4, 5].

The main outcome of the conducted research on accident statistics is the identification of significant qualitative historical trends of tanker accidents and of quantitative characteristics of particular tanker accidents, such as overall accidental frequencies per ship year; frequencies of each major accident category; and per tanker ship size, ship type/design and age, degree of accident severity, and oil spill tonne rates per ship year. Thus, besides the identification of important trends in the safety of oil transport by tankers, important risk elements were also quantified as necessary for the implementation of risk-based methodologies in tanker design and operation. Finally, the conducted analysis identifies heavily polluted geographic areas worldwide resulting from tanker accidents, which is of prime importance to society, the maritime industry, and governmental authorities around the world.

As per today, future developments in tanker design and operation appear to be driven more by efficiency aspects and the protection of the aerial environment issues, namely, the MARPOL regulations on the Energy Efficiency Design and Operation Indices (EEDI and EEOI), affecting a ship's speed–power characteristics in relationship to her hydrodynamic performance in calm water and in seaways (IMO-MEPC Resolution 212(63), [19]).

2 Brief History of Oil Transport by Sea: The Evolution of Tanker Design

Crude oil and petroleum products have been carried in ships since the late nineteenth century, that is, along with the first significant oil discoveries and the development of the oil industry in the early 1850s. Beginning at the very first, oil waterborne transportation was accomplished by general cargo ships carrying the oil in barrels or casks. The practice of carrying the oil in bulk mode *inside the single hull* of a ship became common practice after the introduction of the tanker ship type in 1886.[1] Tanker ship design established in that period remained virtually unchanged until shortly after World War II. Until then, the common tanker ship size varied from 10,000 to 15,000 tons DWT, with ships having a single skin construction in the cargo area, without double bottom, the engine room abaft, and multiple compartmentation with either two or three tanks across.

After World War II, rapid growth of the world economy triggered a huge demand on energy in terms of crude or refined oil products and a new oil transport pattern evolved: crude oil began being transported from distant, oil-producing areas, such as the Persian Gulf, Southeast Asia, and South America, to major markets/consumption areas, notably North America, Northern Europe, and Japan, where the crude oil was refined and redistributed as product. These long voyages set the stage for a dramatic increase in ship size, reflecting the *economy of scale* of the transport vehicles. Between 1950 and 1975, the largest tanker ship in the world grew from about 25,000 tons DWT to more than 500,000 tons DWT. The share of tanker ships in the world fleet also drastically increased over the years, reaching today about 33 % of the world tonnage.

After that period and to date, significant developments in shipbuilding technology, relevant regulations, and operational procedures were introduced, aiming at reducing the probability of accidents (frequencies), for example, by improved navigational equipment and crew training, and at mitigating the consequences in terms of oil cargo release in case of accidents, notably, the introduction of the double-hull tanker concept. Although technologically tankers of even larger capacity could have been built, reducing even further the required freight rates, the risk of marine pollution in case of such a tanker accident was considered unacceptable, as well as the constraints resulting from navigational limitations (maximum ship draft). This consideration led to freezing of the uppermost size of crude oil tankers and even the gradual withdrawal and disappearance of the ultra-large crude carrier ship type (ULCCs, with a deadweight capacity of more than 320,000 tons and up to about 500,000 tons) from the market.

[1] The first modern times oil tanker is believed to be the *Glücksauf (Good Luck)*, built in 1886 by the Armstrong Mitchell yard in Newcastle upon Tyne for the German H. Reidemann, which was chartered by the Standard Oil Company. It was the first steam-driven, ocean-going oil tanker into which oil could be pumped directly to its internally subdivided, eight-compartment hull; she featured all the main elements of a modern tanker, such as cargo main piping and valves, operated from the main deck, vapor lines, and cofferdams, and the ability to receive ballast water when empty of cargo. She was lost in 1893 after grounding near Long Island (New York) in fog.

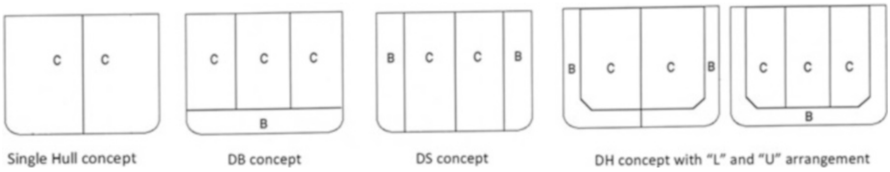


Fig. 9.1 Typical tanker hull designs. *B* ballast, *C* cargo oil

The basic generic hull configurations with respect to the internal watertight subdivision, namely, the double-hull ships and the non-double-hull ships, are sketched in Fig. 9.1:

- The double-hull (*DH*) concept is characterized by the full, all-around, double-hull concept according to MARPOL requirements currently in force.
- The non-double-hull (*non-DH*) definition includes single-hull (SH, with or without segregated ballast tanks/protectively located), double-bottom (DB), and double-sides (DS) oil tankers.

3 Marine Oil Pollution

The potential for oil released to the marine environment was recognized by the International Convention for the Prevention of Pollution of the Sea by Oil, 1954 (OILPOL 1954), but marine oil pollution had become an issue of international concern after the first major oil tanker accident in 1967 (*Torrey Canyon*). Although the major part of marine oil pollution is coming from land-based sources/operations (about 80 % according to UNESCO data, in Global Ocean Commission Summary Report 2014 [8]), a significant amount of the oil released to the sea environment is still the result of shipping and maritime activities. Among them, the most important pollutant activity is the transportation of oil by tankers, related mainly (in terms of *released amount* of oil) to tanker accidents, whereas in *terms of frequency* the most polluting activities are terminal operations of all types of ships. Tanker ship accidents, if they happen, immediately draw the attention of local governments and public media; thus, their importance is multiplied by a nonaccountable factor of significance.

3.1 Review of Major Tanker Accidents

Although ships appear by statistics to be the safest mode of transportation, marine incidents and accidents have always happened and will continue to happen. Therefore, the prime concern of ship safety is to minimize or reduce the probability of occurrence of such incidents, as well as to mitigate the serious consequences of an incident/accident.

Investigations into some tragic tanker accidents have provided in-depth knowledge and experience governing the changes in the safety regime in the past years, as well as the change in basic tanker ship hull internal configuration that is described in detail by Papanikolaou et al. [29]. Significant outcomes of some catastrophic casualties that were investigated led to improvements of the IMO regulatory framework and eventually of maritime safety and operation. In the following, some spectacular tanker casualties are listed that led to the adoption of new regulations or/and amendments of the existing ones:

- The grounding of the *Torrey Canyon*, in 1967, with 119,000 tonnes of Kuwait crude oil released off the western coast of Cornwall, England, was the first catastrophic marine pollution accident since the introduction of modern tankers. The associated accident investigations and conclusions led to the introduction of MARPOL 1973, STCW 1978, and SOLAS 1974 (fire safety provisions for tankers).
- The grounding of the *Argo Merchant* on Nantucket Shoals, off Massachusetts, USA, in 1976, with 28,000 tonnes of oil released, contributed to the development of Protocol 1978 of MARPOL.
- The grounding of *Amoco Cadiz* off the coast of Brittany in the northwest of France, in 1978, with 227,000 tonnes spillage, led to the implementation of MARPOL 1978 Protocol; it also formed also the basis for the introduction of Paris Memorandum of Understanding on Port State Control (Paris MOU).
- The grounding of the *Exxon Valdez* on Bligh Reef in Prince William Sound, Alaska, in 1989, with about 37,000 tonnes spillage, led in year 1990 to the adoption of the first major *regional agreement* for tanker operations in US waters (introduction of the double-hull tanker concept), through the Oil Pollution Act (OPA 90) in the USA in 1990.
- The *Erika* disaster, in which the ship broke in two in a severe storm in the Bay of Biscay in 1999, with about 20,000 tonnes spillage, contributed to the revision of MARPOL 73/78 (Reg. 13G), and led to an accelerated phase-out of single-hull tankers (MEPC–IMO). Furthermore, this particular accident led the European Union to the adoption of the ERIKA I- and ERIKA II-enhanced safety regulatory packages.
- Following the "*Prestige* accident" in 2002, which suffered hull damage in heavy seas off northern Spain, with 77,000 tonnes carried cargo, the European Union adopted Reg. 1726/2003, regulating the accelerated single-hull tanker phase-out, carriage of heavy-grade oils in double-hull tankers, and enhanced hull condition assessment. This regulation took effect within the EU on 21 October 2003. The IMO's Marine Environment Protection Committee (MEPC) adopted amendments to Regulation 13G and produced Regulation 13H to Annex I of MARPOL on 4 December 2003 (Resolution MEPC.111(50) [12] and Resolution MEPC.112(50) [13]).
- The "Deepwater Horizon" drilling rig explosion in 2010 (Mexican Gulf), with a spillage of about 600,000 tonnes of oil, is the largest marine accidental oil spill in the history of the petroleum industry. In contrast to spillages related to accidents of ships, which operate internationally and need to comply with international

safety regulations (IMO), the safety of offshore platforms is governed by safety codes of the petroleum industry and of the authorities certifying their proper design, construction, and operation (classification societies and governmental authorities).

3.2 Review of Major International Regulations and Recent Debates at IMO

3.2.1 MARPOL 73/78: On the Prevention of Oil Pollution from Ships

The likely pollution of the marine environment is regulated by MARPOL 73/78, the International Convention for the Prevention of Pollution from Ships, 1973, as modified by the Protocol of 1978; it is the most important international marine environmental convention. Its objective is to minimize pollution of the seas, including dumping, oil pollution, and areal pollution by toxic exhaust gas emissions. In the course of the years, after its introduction in 1973, MARPOL underwent several amendments and improvements that contributed to today's quite satisfactory state of affairs in tanker safety, namely, in terms of recorded tanker accidents and environmental consequences (Fig. 9.2, [6]; updated frequencies after 2007 in later section).

Following a series of catastrophic single-hull tanker accidents, current MARPOL regulations (and long before US OPA 90) recognized double-hull tanker designs as the only acceptable solution for the safe carriage of oil in tanker ships. According to current MARPOL regulations, the tank arrangement of the cargo block of an oil tanker should be properly designed to provide adequate protection against accidental oil outflow, as expressed by the so-called *mean outflow parameter*. According to Resolution MEPC.122(52) [14], the mean outflow parameter, O_M, is the non-dimensionalized statistical *mean* or *expected* outflow, as percentage of ship's cargo capacity, and provides an indication of a design's overall effectiveness in limiting oil outflow.

The mean outflow equals the sum of the products of the probability of occurrence of a likely damage case and of the associated oil outflow; thus, O_M equals the mean outflow divided by the total quantity of oil onboard the vessel; the *maximum permissible mean outflow parameter* is set as a function of ship's deadweight, as follows:

$$O_M \leq 0.015\big(\text{for } C \leq 200{,}000 \text{ m}^3\big) \tag{9.1}$$

$$\begin{aligned} O_M \leq\, & 0.012 + (0.003/200{,}000)(400{,}000 - C) \\ & (\text{for } 200{,}000 \text{ m}^3 < C < 400{,}000 \text{ m}^3) \end{aligned} \tag{9.2}$$

$$O_M \leq 0.012\big(\text{for } C \geq 400{,}000 \text{ m}^3\big) \tag{9.3}$$

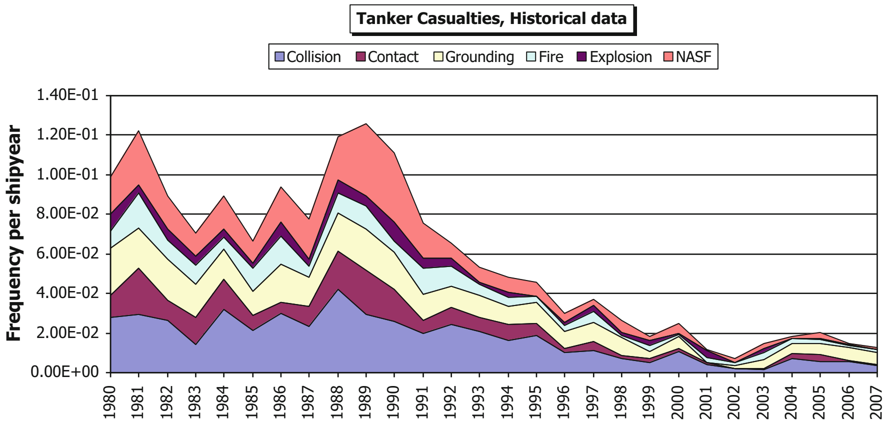


Fig. 9.2 Frequency of large tanker accidents per ship year

where *C* is the tanker's oil cargo capacity (in m^3). The foregoing provisions mean, essentially, that the societally accepted mean oil outflow of an oil tanker is in the range of 1.2–1.5 % of its cargo capacity. Clearly the *mean outflow parameter*, as some additional indicators expressing ship oil outflow performance (such as the *probability of zero oil outflow*, etc.), is a major design constraint of tanker design and directly affects ship cargo space compartmentation and the sizing of oil tanks.

The entire MARPOL 73/78 provisions are actually elaborated in six Annexes, as follows:

1. Annex I Prevention of pollution by oil
2. Annex II Control of pollution by noxious liquid substances in bulk
3. Annex III Prevention of pollution by harmful substances carried by sea in packaged form
4. Annex IV Pollution by sewage from ships
5. Annex V Pollution by garbage from ships
6. Annex VI Prevention of air pollution from ships

3.2.2 MARPOL 73/78: On the Prevention of Air Pollution by Ships

Beyond the prevention of marine pollution by oil, significant importance with respect to ship design and operation has been gained recently by ANNEX VI of MARPOL, and thus the prevention of air pollution by ships. It is today well established that human activities have a significant impact upon the levels of

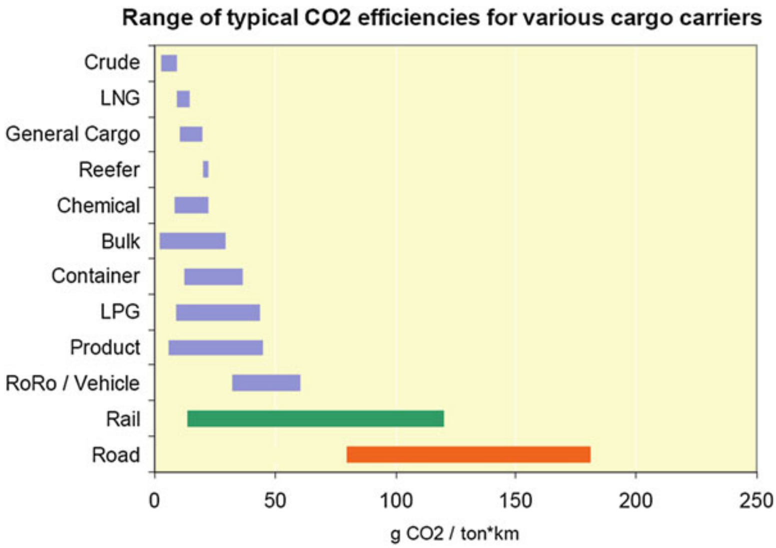


Fig. 9.3 Typical range of CO_2 efficiency of ships compared with rail and road transport [2]

greenhouse gases in the atmosphere, those gases that absorb and emit radiation within the thermal infrared range. The gases with the most important release to the atmosphere are, in descending order: water vapor, carbon dioxide (CO_2), methane, and ozone. The Intergovernmental Panel on Climate Change (IPCC) recently released a report stating that "*most of the observed increase in global average temperatures since the mid-20th century is very likely due to the observed increase in anthropogenic greenhouse gas concentrations*" [36]. One of the main contributors to emissions of greenhouse gases by human activity is the burning of fossil fuels. The total CO_2 emissions from shipping (domestic and international) amount to about 3.3 % of the global emissions from fuel consumption, according to the International Energy Agency (IEA) [2] (Fig. 9.3).

Climate stabilization will require significant reductions of CO_2 emissions by 2050, and the international shipping industry needs to participate in this process. Independently of the fact that maritime transport is the most efficient mode of transport (ton-km) and the least polluting in terms of greenhouse gas emissions, current discussions and expected regulatory measures suggest the collaboration of all major stakeholders of shipbuilding and ship operations to efficiently address this complex techno-economic and highly political problem, and to call, ultimately, for the development of proper design, operational knowledge, and assessment tools for energy-efficient design and operation of ships [1]. In this respect, an energy efficiency design index (EEDI)[2] has been introduced for most types of merchant

[2] The Energy Efficiency Design Index (EEDI) was made mandatory for *new* ships, as of 1 January 2013; this was decided at MEPC 62 (July 2011) with the adoption of amendments to MARPOL Annex VI (resolution MEPC.203(62)) and accompanied the introduction of a Ship Energy Efficiency Management Plan (SEEMP) for *all ships*.

ships, which needs to be kept below a certain limiting value that is specific to the ship type and size.

Typical design and outfitting measures for reducing CO_2 emissions are related to hull form optimization for least power (and fuel consumption), improved diesel engine combustion, improved fuel technology, etc.; last, but not least, a drastic operational measure for reducing CO_2 emissions is reduction of service speed, with major impact on a ship's competitiveness and economy, especially when the ship is in liner service (e.g., for container and passenger ships).

The energy efficiency design index (EEDI) of a ship is a measure of the ship's energy efficiency (g/t*nm) and is calculated by the following formula (see Resolution MEPC 212(63) [19]):

$$\frac{\begin{array}{c}\left(\left(\prod_{j=1}^{n} f_j\right)\left(\sum_{i=1}^{nME} P_{ME(i)} C_{FME\,(i)}\, SFC_{ME(i)}\right) + \left(P_{AE}\, C_{FAE} SFC_{AE}\right) + \right. \\ \left.\left(\left(\prod_{j=1}^{n} f_j \cdot \sum_{i=1}^{nPTI} P_{PTI(i)} - \sum_{i=1}^{n_{eff}} f_{eff(i)} \cdot P_{AEeff(i)}\right) C_{FAE} SFC_{AE}\right) - \left(\sum_{i=1}^{n_{eff}} f_{eff(i)} \cdot P_{eff(i)} C_{FME} SFC_{ME}\right)\right)\end{array}}{\left(f_i \cdot f_c \cdot f_l \cdot \text{Capacity} \cdot f_w \cdot V_{ref}\right)} \tag{9.4}$$

where C_F is a nondimensional conversion factor between fuel consumption measured in grams (g) and CO_2 emission, also measured in grams (g) based on carbon content. The subscripts $_{MEi}$ and $_{AEi}$ refer to the main and auxiliary engine(s), respectively. For details in the usage of this formula, see Resolution MEPC 212(63) [19].

According to Regulation 20 of Annex VI of Chapter 4 MARPOL 73/78, the attained EEDI shall be calculated for each new ship, or any ship that has undergone a major conversion. The attained EEDI shall be verified, based on the EEDI technical file, either by the administration or by any organization duly authorized by it. According to Regulation 21 of Annex VI of Chapter 4 MARPOL 73/78, the attained EEDI shall be less than or equal to a required level, set by regulation, as follows:

$$\text{Attained EEDI} \leq \text{Required EEDI} = (1 - x)\text{Reference Line Value} \tag{9.5}$$

where x is the reduction factor specified in Table 9.1 for the required EEDI compared to the EEDI reference line.

Table 9.1 Reduction factors (in percentage) for the EEDI relative to the EEDI reference line for tankers

Ship type	Size	Phase 0 1 Jan 2013–31 Dec 2014	Phase 1 1 Jan 2015–31 Dec 2019	Phase 2 1 Jan 2020–31 Dec 2024	Phase 3 1 Jan 2025 and onwards
Tankers	20,000 DWT and above	0	10	20	30
	4000–20,000 DWT	n/a	0–10*	0–20*	0–30*

*The reduction factor is to be linearly interpolated between the two values dependent upon ship size. The lower value of the reduction factor is to be applied to the smaller ship size

The reference line values shall be calculated as follows:

$$\text{Reference line value} = a \times b - c$$

where a, b, and c are the parameters given in Table 9.2.

The following figures, Figs. 9.4 and 9.5, represent typical reference lines for tanker ships to be used in the assessment of EEDI according to the IMO-MEPC 62/6/4 [17].

The key measures for reducing gaseous toxic emissions from marine engines, which accompanies the reduction of fuel consumption, are as follows:

- Reduction of fuel consumption through reduction of ship's resistance and powering
- Optimization of ship's hull form leading to a reduction of the required propulsion power for specified speed (calm water performance and added resistance in seaways: *new ship buildings*)

Table 9.2 Parameters for determination of reference values for the different ship types

Ship type defined in Regulation 2 of Annex VI of Chapter 1 MARPOL 73/78	*a*	Capacity	*c*
2.25 Bulk carrier	961.79	DWT	0.477
2.26 Gas carrier	1120.00	DWT	0.456
2.27 Tanker	1218.80	DWT	0.488
2.28 Container ship	174.22	DWT	0.201
2.29 General cargo ship	107.48	DWT	0.216
2.30 Refrigerated cargo carrier	227.01	DWT	0.244
2.31 Combination carrier	1219.00	DWT	0.488

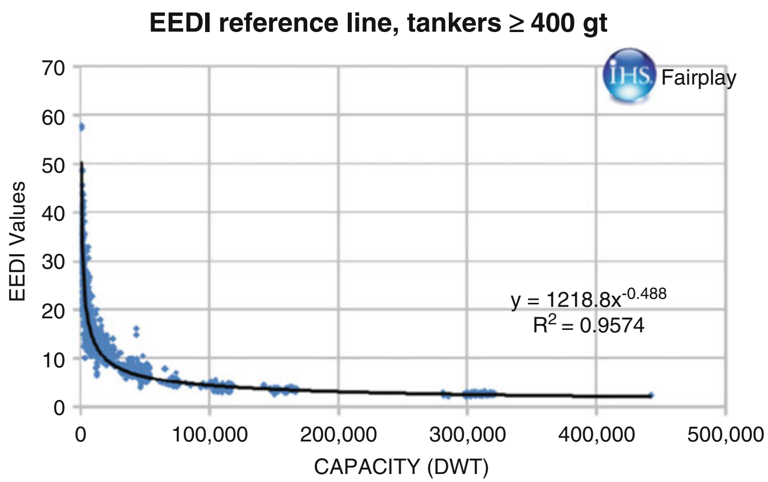


Fig. 9.4 Typical reference lines for tankers (IMO-MEPC 62/6/4) [18]

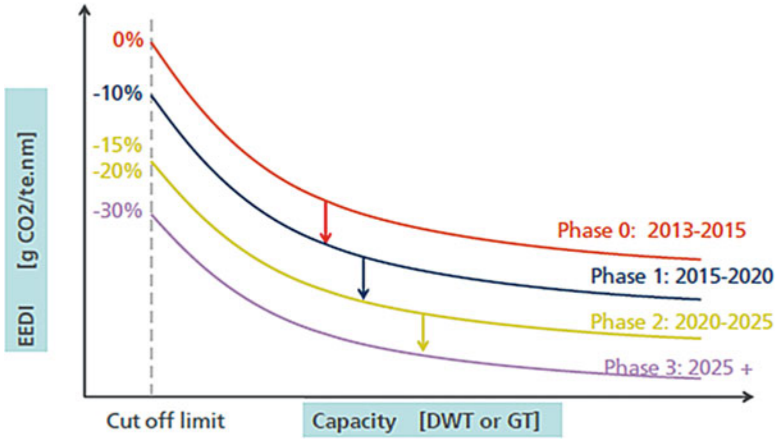


Fig. 9.5 Energy efficiency design index (EEDI) concept (Lloyd's Register, [25])

- Fitting of propulsive efficiency-enhancing devices (stern flow ducts, spoilers, controllable-pitch CPT propellers, etc., for *existing ships and to some extent new ship buildings*)
- Refitting of bulbous bow (*existing ships*)
- Optimization of operational trim (*existing ships*)
- Minimization of the amount of carried ballast water (*new buildings and existing ships*)
- Reduction of viscous resistance through special treatment of wetted surface (paints, etc.) and other innovation measures (release of air bubbles, etc.) *(mainly new ship buildings*)
- Optimization of ship routing
- Reduction of service speed (*slow steaming*)
- Improvement of marine engine technology
- Reduction of specific fuel oil consumption (SFOC)
- Reduction of toxic gas emissions
- Dual fuel consumption (heavy fuel oil, HFO; marine diesel oil, MDO; liquefied natural gas, LNG)
- Improvement of fuel quality
- Introduction of biofuels for marine engines

3.2.3 Formal Safety Assessment of Tankers (FSA)

The FSA is a structured and systematic methodology aimed at enhancing maritime safety, including the protection of life, health, marine environment, and property, by using risk analysis and cost–benefit assessment (CBA). FSA can be used as a tool to help in the evaluation of new regulations for maritime safety and protection of the marine environment or in making a comparison between existing and possibly improved regulations, with a view to achieving a balance between the various technical and operational issues, including the human element, and between maritime safety or protection of the marine environment and costs. FSA consists of five main steps:

1. Identification of hazards (a list of all relevant accident scenarios with potential causes and outcomes)
2. Assessment of risks (evaluation of risk factors)
3. Risk control options (devising regulatory measures to control and reduce the identified risks)
4. Cost–benefit assessment (determining cost-effectiveness of each risk control option)
5. Recommendations for decision making (information about the hazards, their associated risks, and the cost-effectiveness of alternative risk control options is provided)

FSA, which was originally developed as a response to the *Piper Alpha* offshore platform disaster in 1988, is now being applied routinely to the IMO rule-making process. The Guidelines for Formal Safety Assessment (FSA) for use in the IMO rule-making process were approved in 2002 (MSC/Circ.1023/MEPC/Circ.392 [21]). At its 80th session in May 2005, the MSC reviewed the report of the Joint MSC/MEPC Working Group on Formal Safety Assessment (FSA). The MSC also agreed on the establishment, when necessary, of an FSA Group of Experts (GoE) for the purpose of reviewing an FSA study if the Committee plans to use the study for making a decision on a particular issue. The MSC also agreed in principle that the proposed GoE would undertake to review FSA studies on specific subjects submitted to the organization, as directed by the Committee(s), and to prepare relevant reports for submission to the Committee(s). The structure of the group of experts was left open for future discussion, although the Committee agreed, in principle, that members participating in the expert group should have risk assessment experience, a maritime background, and knowledge and training in the application of the FSA Guidelines.

Following this, the Experts Group on Formal Safety Assessment (FSA) met in November 2012 under the chairmanship of Mr. K. Yoshida from Japan (MSC 91/WP.6 [23]). The group considered, among others, documents MEPC 58/17/2 and MEPC 58/INF.2, referring to the Formal Safety Assessment of Tankers developed by the EU-funded project SAFEDOR. The group also considered documents MSC 90/19/4 and Corr. 1 (Japan) [22], containing information on the reanalysis of the FSA study on crude oil tankers, as well as documents MSC 91/16/1 and MSC 91/INF.5 submitted to MSC 91 by Japan, providing further background information and data used for the recalculation and reanalysis. The Experts Group noted the following:

- *Regarding the differences of the values for potential loss of cargo (PLC) between those in document MEPC 58/INF.2 (Denmark-SAFEDOR) and MSC 91/INF.5 (Japan), the expert presenting the FSA pointed out that SAFEDOR* *created a database using other data sources in addition to IHS Fairplay to cross-check amounts of oil spillage and modify them as necessary, particularly those of very serious accidents. The group was satisfied with the explanation that the presented information was reliable in view of cross-checking by public domain information*

- Regarding the values for branching frequency, *the SAFEDOR study had based their estimates on databases and expert judgments*
- Regarding the cost-effectiveness of the structure-related RCOs, *the SAFEDOR FSA study used the original CATS criteria (cost of averting a tonne of oil spilt) of 60,000 USD/tonne spilled oil, while the environmental risk evaluation criteria were more recently agreed by MEPC 62*

With regard to the environmental risk evaluation criteria, the group agreed that the criteria agreed by MEPC 62, which is included in the Revised FSA Guidelines, should be used when conducting FSA studies. Further important issues of general interest noted by the GoE are the following:

- *Validity of the input data*

The group noted that the tanker FSA study developed a database using *several data sources in addition to LMIU and LRFP (IHS Fairplay)*, which might contain errors or insufficient data, while affirming the importance of transparency and availability of data. *The group expressed concern that commonly used databases sometimes do not contain oil spill information even on large-scale oil spill accidents.* In this regard, the group reaffirmed its view that databases that are accessible and contain detailed root causes are important, and that commercially available data should be examined and corrected and recommended to the Committee, that the GISIS module for that purpose should be further enhanced, and that the Committee encourage Member States to submit casualty data to GISIS.

- *Whether it is necessary to improve the FSA Guidelines, and, if so, prepare proposals for their improvement*

The group noted a concern that the calculated societal oil spill costs (SC) described in Appendix 7 of the draft Revised FSA Guidelines, if the assurance and uncertainty factor is unity, *may be too low for large spillages and it would discourage any effort of reducing potential oil spill risk*, and that these values should be reviewed, as well as GCAF and NCAF.

Also, the group reiterated its view that when analyzing historical casualty data, it should be kept in mind that safety levels might be improved by implementing safety measures and should be analyzed taking into account the virtue of today's mandatory instruments. For example, they should be careful when using casualty data of single-hull tankers.

Finally, the group generally agreed that *the tanker FSA was conducted in accordance with the Guidelines, recognizing that the FSA used the CATS criterion, which is different from the environmental risk evaluation criteria that were recently agreed by MEPC 62.*

3.2.4 Assessment Criteria: The Cost for Averting Fatalities and Spillages (CAF and CATS)

An important step of any FSA is (step 4) the cost–benefit assessment (CBA) determining the cost-effectiveness of each investigated risk control option (RCO). In the tanker FSA, a series of RCOs referring to both design changes, improvement of equipment, and operational and training measures were investigated and assessed in terms of cost-effectiveness with respect to both the potential loss of lives (PLL) of crew and the potential loss of cargo (PLC). Herein a cost for averting fatalities (CAF) of USD 3.0 million/fatality and a cost for averting of 1 tonne spillage (CATS) of USD 60,000/tonne spilled oil were considered in the tanker FSA. Based on these criteria, some investigated RCOs were found cost-effective and could be recommended for implementation.

However, both the foregoing assessment criteria are nowadays disputed; namely, considering the increase of the worldwide living standard in the past two decades, the EU project GOALDS ([9], 2010–2013) recommended recently an increase of CAF to USD 7.45 million/fatality, and this was acknowledged during the discussion of the passenger ship FSA at the Experts Group on Formal Safety Assessment MSC93/6/2 (18 November 2013 [24]).

Regarding the CATS criterion, MEPC 62 concluded after lengthy deliberations that CATS should be a *volume-dependent, nonlinear spill cost function*, in which the per tonne spillage cost should decrease when the spillage size increases, because this better accounts for the cost of actual spillages around the world (IOPCF database[3]).

Following the deliberations of a working group, MEPC 62 (2011) endorsed the consolidated database and the foregoing functions (Table 9.3), although it made clear that *FSA analysts are free to use other formulae, so long as these are well documented by the data*. MEPC 62 also decided to put the consolidated database in the public domain.

In the foregoing deliberations, an open issue remained: the determination of the so-called *assurance factor*, expressing *society's willingness to pay to prevent an oil spill instead of sustaining its damages*. For instance, an assurance factor of 2.0 means that society would rather spend two dollars to prevent an oil spill than pay one dollar in the form of spill cost if the spill occurs. A critical review of the developments leading to this CATS criterion may be found in Psaraftis [32].

Table 9.3 Nonlinear total spill cost functions, based on consolidated oil spill database (V, spill size in tonnes)

Spill dataset (IOPCF, USA, Norway)	Total spill cost (2009 US dollars)
All spills	$67{,}275\ V^{0.5893}$
$V > 0.1$ tonnes	$42{,}301\ V^{0.7233}$

[3] Note that the most prominent *Exxon Valdez* 37,000-tonne oil spill in 1989, which led to the introduction of OPA 90, had a cleanup cost of USD 107,000/tonne (2007 dollars), whereas the cleanup cost of the *Braer* 85,000-tonne oil spill in 1993 was as low as USD 6/tonne ([32]).

3.2.5 Implementation and Enforcement of IMO Regulations

For IMO standards to be binding, they must first be ratified by a total number of member countries whose combined gross tonnage represents at least 50 % of the world's gross tonnage, a process that can be lengthy. A system of tacit acceptance has therefore been put into place, whereby if no objections are heard from a member state after a certain time period has elapsed, it is assumed they have assented to the treaty.

Regarding MARPOL 73/78, all six annexes have been ratified by the requisite number of nations; the most recent is Annex VI, which took effect in May 2005. In Europe, on 1 January 2015 maritime shipping levels are to become legally subject to new MARPOL directives because the SECA (Sulfur Emission Controlled Areas) zone is scheduled to increase in size. This larger SECA zone will include the North Sea, Scandinavia, and parts of the English Channel. This area is set to include all the international waters of the Republic of Ireland in 2020, culminating in all of Western Europe's subjection to the MARPOL directive. This decision has proven controversial for shipping and ferry operators across Europe.

4 Assessment of Tanker Safety

In the following we assess tanker safety by a statistical analysis of recorded accidents and their consequences on the marine environment.

4.1 Statistical Analysis of Tanker Accidents

A statistical analysis of tanker accidents performed for the time period 1978–2003 showed that the frequency of Aframax tanker accident occurrences presented remarkable downward trends [6]. A series of IMO regulations concerning the prevention of incidents/accidents have apparently contributed to the observed declining trends of accident rates, particularly in the post-1990s period, marked by the introduction of OPA 90 in the USA. Figure 9.6 [26] presents the navigational accident rates of Aframax tankers along with some key relevant regulations that could be held responsible for the declining trends of particular rates. Note that relevant regulations were herein presented according to their year of implementation, and it can be expected that their effect should be noticeable with some phase lag, depending on the nature of each regulation. Moreover, the significant MARPOL 73/78 is not indicated in this graph, although herein of importance, as it is falling in the pre-1978s period not studied by Mikelis et al. [26], and the same applies to the European ERIKA I, II, and III tanker safety packages and the more recent IMO-MEPC-50 provisions regarding the phaseout of single-skin tankers.

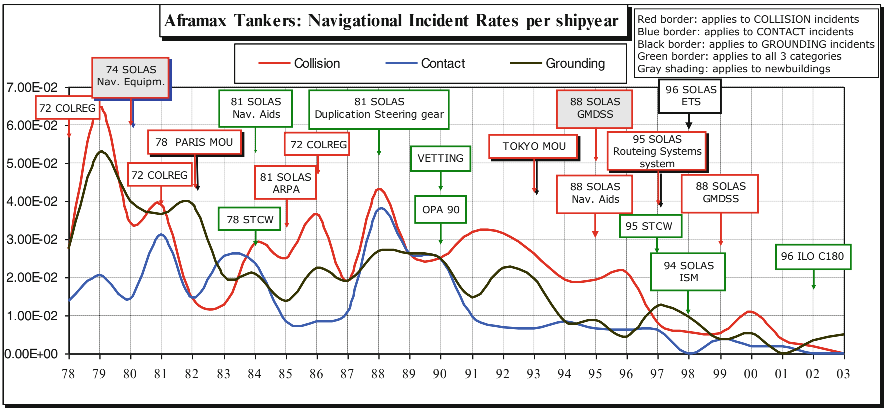


Fig. 9.6 Timeline of navigational accident rates (frequency per ship year) versus introduced international regulations, guidelines, and safety codes

4.2 *Frequencies of Serious Accidents*

The loss of a ship's watertight integrity (LOWI) by breach of a tanker's outside shell that causes release of the oil cargo to the sea is the consequence of a *serious* accident. In most, LOWI may result as a consequence of *navigational* accidents (collision, contact, and grounding), *fire/explosions*, and *structural failures*. The following accident categorization is based on the definition adopted by IMO-MSC/Circ.953 [20]:

Collision: striking or being struck by another ship (regardless of whether under way, anchored, or moored).

Stranding or grounding: being aground or hitting/touching shore or sea bottom or underwater objects (wrecks, etc.).

Contact: striking any fixed or floating object other than those included in *collisions* or *groundings*.

Fire and explosion: events are defined such that the event in question is the first initiative event reported.

Non-accidental structural failure (NASF): cases of hull damage in view of non-accidental structural failure, such as cracks and fractures, affecting ship's seaworthiness or efficiency. Damage to a vessel's rudder or rudder-adjoining parts is also considered as structural damage.

4.2.1 Employed Database Model

To conduct a risk analysis assessment, historical casualty data were extracted from the IHS Fairplay commercial casualty database and post-processed by a new purposely designed database (NTUA-SDL database) to capture/analyze the available textual information in a proper manner (using checklists, pull-down menus, etc.). Recorded raw data were then critically assessed and enhanced by other publicly available information. This procedure is considered of paramount importance for the reliability of the conducted risk analysis in the following, for these reasons:

- Commercial databases, such as IHS Fairplay or LMIU, were originally not designed for potential application in risk assessment procedures.
- Their information is to a great extent available in textual form, whereas details of importance for formal risk assessment procedures (FSA) are missing.
- In several cases, there was lack of or erratic information about principal issues for the accident analysis, namely, on the consequences of the incident or on several steps of event tree analysis (missing or erroneous spillage extent for important and well-publicized major tanker accidents).
- The data in hand were reanalyzed and post-processed in such a way to produce input to a developed global risk model. Note that all captured accidents were assigned to one of the predefined main incident categories according to the last "accidental event."

4.2.2 Sampling Plan

The following study is focused on tanker casualties that happened after the year 1990 (Table 9.4). Year 1990 is considered a landmark year because of the introduction of the double-hull tanker concept through OPA 90 in USA (in the aftermath of the catastrophic *Exxon Valdez* accident in 1989) and its tremendous effect on related regulatory developments and tanker design practice thereafter. It is believed that this period is quite representative for assessing today's situation. It is noted that previous studies on the same subject showed a significant reduction of accident occurrence in the post-1990s period, taking into consideration that a series of introduced key regulations was found to be related to the significant decrease of the frequency of tanker accidents [3].

Concerning the size of tanker ships involved in the incidents, the following DWT size segments were herein considered:

Medium oil tankers (studied period: 1990–Oct. 2009) refer to Handysize tankers (20,000–34,999 DWT) and Handymax tankers (35,000–60,000 DWT).

Large oil tankers (studied period: 1990–2011) refer to Panamax tankers (60,000–79,999 DWT), Aframax tankers (80,000–119,999 DWT), Suezmax tankers (120,000–199,999 DWT), VLCC tankers (200,000–319,999 DWT), and ULCC tankers (greater than 320,000 DWT).

With respect to the tanker subtypes/subcategories, only categories relevant to *crude oil tankers* were considered in the current investigation, namely, according to the definition of the IHS casualty database: *oil tankers*, *crude tankers*, *shuttle tankers*, *product carriers*, and *chemical/oil tankers*. It is noted that OBOs, ore/oilers, and chemical tankers (and the related accidents that may have led to maritime pollution) were excluded from the present analysis, because these ship subtypes have special design/layout and operational features that are not representative of the whole class of tankers.

4.2.3 Casualty Basic Data

The present study focuses on accidents that potentially lead to ship loss of watertight integrity (LOWI) and to accidental oil pollution; thus, only the first six (6) categories of accidents are investigated. In total, focusing on medium tankers, 722 accidents occurred in the study period, whereas for large tankers 903 accidents happened within a studied period (Table 9.4).

The listed statistics of casualty categories show quite similar results for medium and large tankers, except for the groundings and contacts (of which medium-size tankers have an increased share) and the NASF (which are more pronounced for the large tankers). This pattern may be justified by the operational profiles of the study ship types.

4.2.4 Operational Fleet at Risk

A critical review of tanker safety cannot be conducted on the basis of absolute numbers, but rather by relating the number of accidents to the relevant worldwide operating fleet of vessels. The *annual operational fleet at risk* is defined as the number of ships that is operated worldwide in the corresponding period; it was calculated by considering the monthly operation of each tanker vessel registered in the IHS database. Figure 9.7 presents the corresponding *fleet at risk of large and medium tankers* along with the annual distributions of the double-hull (DH) fleet and non-double-hull fleet.

The gradual and, after the year 1999, more rapid decrease of the share of the non-DH fleet as a consequence of the introduction of OPA 90 and later on of MARPOL 73/78 and ERIKA I and II is clearly shown.

Table 9.4 Sample of casualty data

	Medium tankers (1990–2009)		Large tankers (1990–2011)	
Casualties	Number	%	Number	%
Collision	238	33	317	35
Contact	116	16	100	11
Grounding	214	30	217	24
Fire	53	7	74	8
Explosion	31	4	36	4
NASF	70	10	159	18
Total	***722***		***903***	

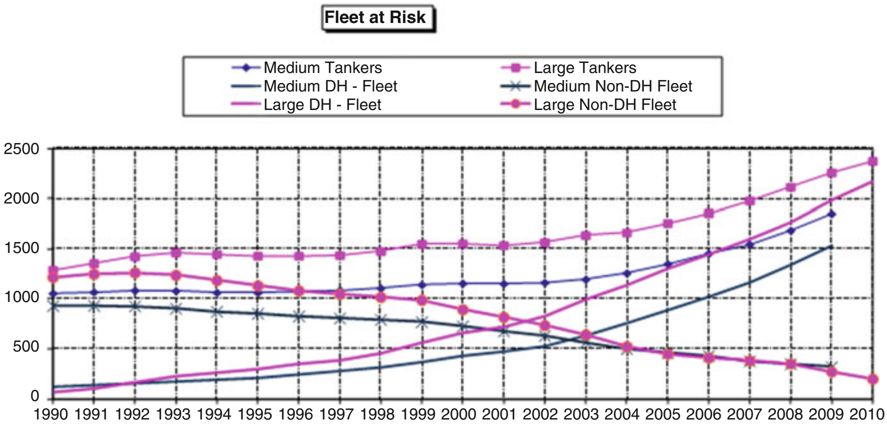


Fig. 9.7 Double-hull fleet and non-double-hull fleet

4.2.5 Frequency of Tanker Accidents Leading to LOWI

Presented accident frequencies were calculated by dividing the total annual number of registered accidents by the number of ships operating in that year (annual operational fleet at risk). Figure 9.8 presents the annual frequency of the sum of the six predefined accident categories in the post-1990 period.

The accident frequency behavior confirms a significantly decreased trend and is quite similar for both tanker sizes, with significant high peaks observed in year 1990 and progressively decreasing in the years after, presenting a significant decrease after 1999. After 1999, the DH fleet begins to show a considerable share in the overall operational fleet (Fig. 9.7), which means that the new (ship) buildings that entered the operational fleet at the year of census have had enhanced implemented formal IMO procedures, which were in compliance with stricter rules; they displayed improved design (double-hull concept) and their crew underwent enhanced training (STCW). Furthermore, the existing (non-DH) fleet at that time had to comply with a series of stricter regulations until their phaseout, so that as a consequence the overall frequency of accidents decreased.

Accident frequencies were much reduced in the past decade, namely, in the post-2000 period, compared to the preceding decade (Table 9.5). In addition, statistical values after year 2000 are almost unchanged for both tanker sizes. Serious events and oil pollution cases (which is a subset of the serious events) also present a slightly downward trend over the years.

The current study presents results of a systematic analysis of accidents pertaining to medium and large oil tankers (deadweight greater than 20,000 tonnes) and covering the period after the introduction of OPA 90, namely, 1990 to 2009 (October), continuing earlier studies of NTUA-SDL on the design and safety of tankers. Calculated values derived from the statistics must be used with caution, because available databases do not consider all accidents (problem of

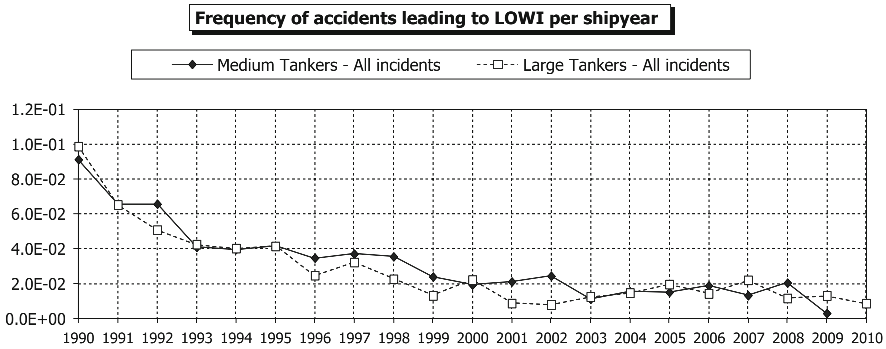


Fig. 9.8 Annual frequency of accidents potentially leading to loss of watertight integrity (LOWI)

Table 9.5 Average frequency of events

	Medium tankers	Large tankers
	1990–2008	**1990–2010**
All types of accidents	2.93E−02	2.54E−02
Serious cases	1.14E−02	9.59E−03
Cases with oil release to the sea	2.56E−03	3.21E−03
	2000–2008	**2000–2010**
All types of accidents	1.54E−02	1.37E−02
Serious cases	9.71E−03	9.46E−03
Cases with oil release to the sea	4.34E−04	2.41E−03

underreporting) and provide always a snapshot based on a certain observation period. Thus, single accidents may have a significant impact on the accident frequencies and especially on the indentified consequences. Figure 9.9 presents the frequency of accident occurrence with the confidence interval to show the uncertainty of calculated values.

The data in this chapter provide the basis for the development of a risk model for medium tankers, which complements studies for large tankers conducted earlier. Such a risk model should consider the uncertainty in the initial accident frequencies as well as in the dependent probabilities in the scenarios; this would allow considering the effect of uncertainty also in subsequent analyses, for instance, in a cost–benefit analysis of design modifications [10].

4.2.6 Navigational Accidents

Focusing on navigational accidents (collision, contact, and grounding), both main tanker sizes exhibit reduced frequencies within the studied period (Fig. 9.10). Practically, after year 1999, the annual frequency does not further decrease, but starts oscillating close to an upper limit (2.0E−02). Apart from the entrance of new construction of the DH concept, some enhanced safety regulations were introduced

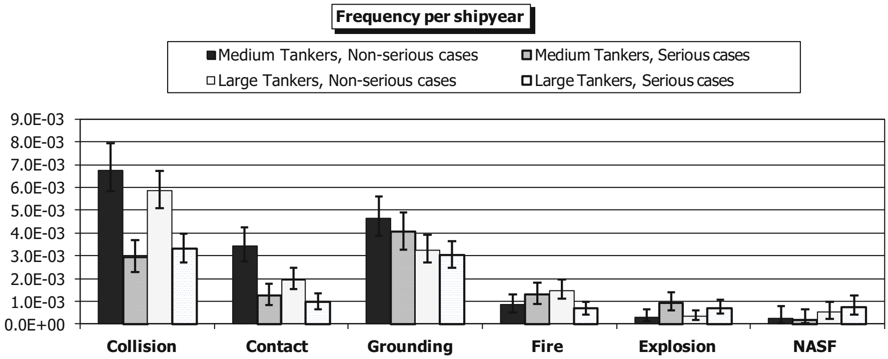


Fig. 9.9 Frequency of occurrence of main accident categories potentially leading to LOWI

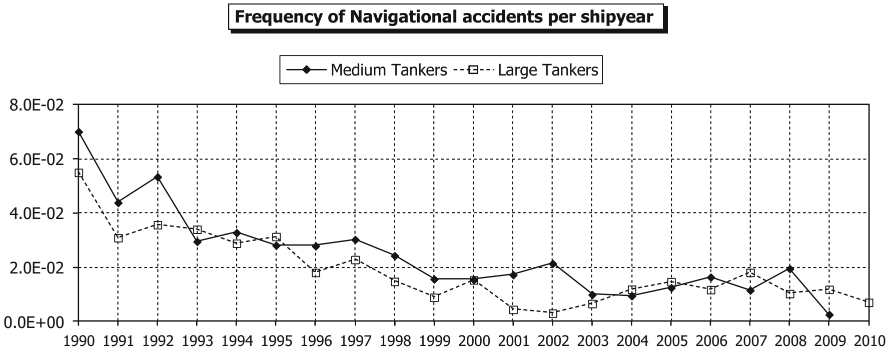


Fig. 9.10 Navigational accidents: frequency per ship year

and applied to existing (non-DH) ships as well, such as ISM Code, STCW, ETS, and SOLAS provisions on routing systems, and all these factors possibly led to the resultant frequency decrease.

Table 9.6 presents frequencies for each accident category. Collision frequencies have almost similar values and could be considered as independent of ship size. Medium and large tankers have almost the same frequency with respect to serious contact cases. Higher grounding frequencies appeared for medium tankers.

4.2.7 Fire and Explosion Accidents

A slight decreasing tendency can be observed in annual frequency during the studied period (Fig. 9.11). Especially in the second decade (after 1999), annual frequencies are confined within significantly smaller margins compared to the corresponding date of the first decade of statistical analysis. It is believed that the ISM Code has had a significant impact on the crisis management onboard ships and in the reduction of the potential of accidents of this type.

Table 9.6 Frequency of collision, contact, and grounding events (full period)

	Medium tankers	Large tankers	Medium tankers	Large tankers
	All incidents		Serious cases	
Collision	9.66E−03	9.16E−03	2.92E−03	3.30E−03
Contact	4.71E−03	2.89E−03	1.26E−03	9.54E−04
Grounding	8.69E−03	6.27E−03	4.06E−03	3.01E−03

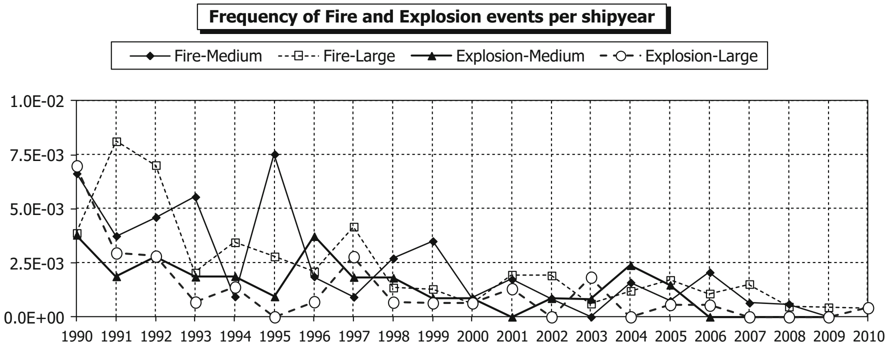


Fig. 9.11 Fire and Explosion accidents: Frequency per ship year

Table 9.7 Frequency of fire and explosion events (full period)

	Medium tankers	Large tankers	Medium tankers	Large tankers
	All incidents		Serious cases	
Fire	2.15E−03	2.14E−03	1.30E−03	6.65E−04
Explosion	1.26E−03	1.04E−03	9.34E−04	6.94E−04

Table 9.7 presents the frequencies of fire and explosion events. Considering all events, regardless of the degree of accident severity, the calculated frequencies exhibit almost the same values for both tanker sizes.

4.2.8 Non-accidental Structural Failures (NASF)

Figure 9.12 presents the annual frequency of non-accidental structural failures for both tanker sizes within the studied period. This particular accident is highly dependent on the basic hull type, namely, double-hull and non-double-hull ships; consequently, all related frequencies are herein calculated for double-hull ships only.

The diminishing frequencies, especially after year 2000, indicate improved shipbuilding technology, even though we can observe, from other statistics, that minor structural failures occur for relatively young tanker ships as a consequence of inferior shipbuilding practices [28].

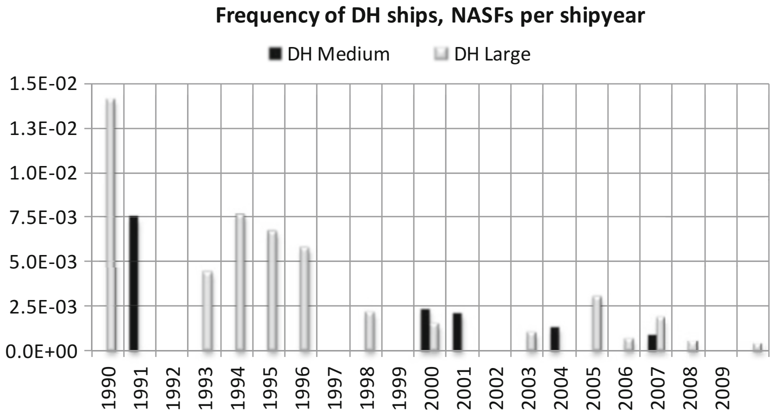


Fig. 9.12 Non-accidental structural failure: frequency per ship year

4.3 Consequences and Impact on the Marine Environment

4.3.1 Total Losses

Figure 9.13 illustrates the frequency of tanker ship total losses per accident category per tanker size, noting that there was no total loss of a ship because of a contact event.

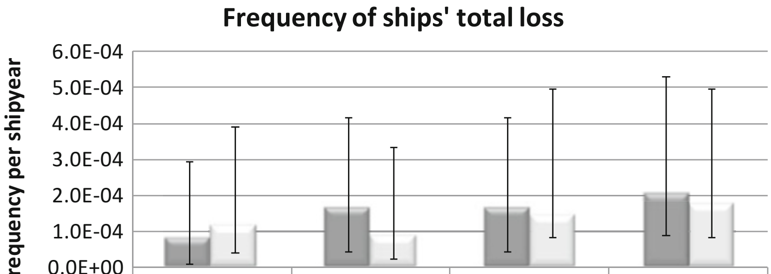
Both medium and large tankers present highest frequencies for ship total loss in explosion accidents. It must be noted that although explosion accidents have a relatively low frequency of occurrence, when they happen, the consequences are severe.

Furthermore, there was, up to now, no DH ship total loss from a *non-accidental structural failure*, which may be justified by the fact that the DH fleet is relatively new, whereas older DH ships are replaced earlier than former non-DH ships in view of the reduced life cycle of more recent new construction.

4.3.2 Marine Pollution

For the investigated tanker ship sizes, it is trivially confirmed that the larger the ship, the more severe is the environmental impact in the case of accidental loss of her watertight integrity as a consequence of the larger cargo tank sizes. Figures 9.14 and 9.15 present the oil released to the sea as a consequence of medium- and large-size oil tanker accidents during the studied time period. Note that for non-accidental structural failure, all ships independent of basic hull type (thus, both DH and non-DH ships) are included.

Year 1994 was the worst year within the studied period as related to oil release to the sea from *medium-size tankers*. Two significant accidents led to an annual



	Collision	Grounding	Fire	Explosion
Medium	8.1E-05	1.6E-04	1.6E-04	2.0E-04
Large	1.2E-04	8.7E-05	1.4E-04	1.7E-04

Fig. 9.13 Ship total loss: frequency per ship year

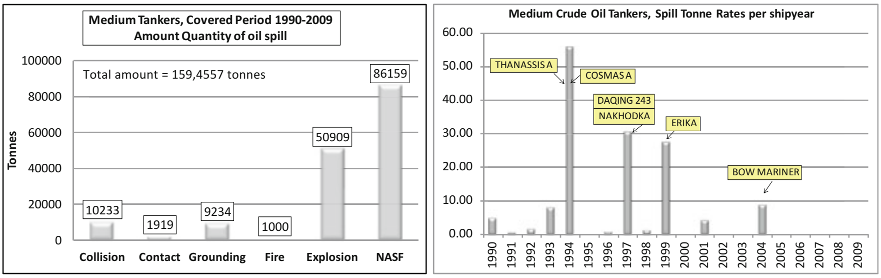


Fig. 9.14 Medium tanker marine pollution over the studied period and yearly spill tonne rate

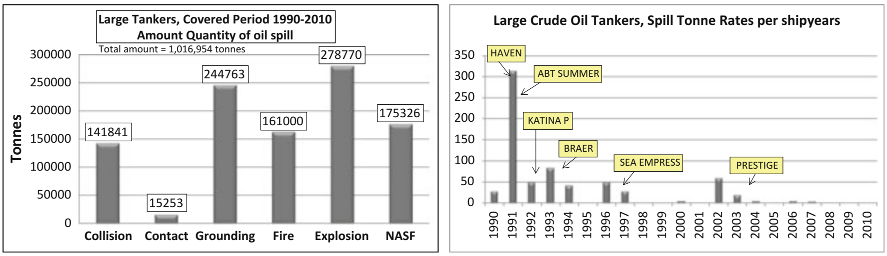


Fig. 9.15 Large tanker marine pollution over the studied period and yearly spill tonne rate

average spill tonne rate of 56 tonnes per ship year. The single-hull tanker *Thanassis A*, built in 1976, broke into two pieces during typhoon "Teresa" 700 km off Hong Kong, spilling 35,020 tonnes oil into the sea. Fifteen crewmembers were reported missing and one killed. After a tank explosion, the medium single-hull tanker *Cosmas A*, built in 1974, also broke in two 150 miles off Luzon, causing an oil release of 23,370 tonnes. Nine crewmembers were reported missing and one killed.

For *large tankers* (and *overall*), the worst year ever (up to the present) was 1991, corresponding to an average annual spill rate of 313 tonnes per ship year, mainly because of two catastrophic types of accidents related to very large crude carriers (VLCCs). The *Haven* caught fire and exploded during offloading to the Multedo floating platform, 7 miles off the coast of Genoa (Italy). The ship was originally loaded with 230,000 tons of crude oil, while the accident happened with about 144,000 tonnes of crude oil onboard; she broke into two parts and sank after burning for 3 days. About 50,000 tonnes crude oil are believed to have polluted the Mediterranean coast of Italy and France for the next 12 years; six crew members were reported killed. The *ABT Summer* sustained a deck explosion while 1287 km off the coast of Angola (Africa). The ship sank after 3 days of burning in the open sea while loaded with about 260,000 tonnes of heavy crude oil. Four crewmembers were reported missing and one person killed. As the accident occurred far from the coast, the environmental impact was limited.

4.4 World Geography of Spillage Areas

Regarding the geographic areas in which tanker accidents have occurred, the Marsden square mapping or Marsden square grid of the IHS database is used; the particular system subdivides the surface of the earth into 100 "squares" bounded by meridians and parallels at intervals of 10° (Fig. 9.16). Following this zoning system, the geographic areas with more frequent accidents are identified, independent of the accident category, namely, areas with more than 15 absolute number of accidents per ship type (red circles in Fig. 9.16) within the studied period. However, and independent of absolute accident statistics, more accurate conclusions on this subject can be drawn only by comparing the number of accidents to the operating fleet in the corresponding geographic areas.

Navigational events present a concentration of events in specific areas, whereas fire, explosion, and NASF could be considered as unrelated to geographic areas. Table 9.8 presents the most frequent areas per accident category in terms of absolute accident numbers; in Table 9.9, the areas of the most frequent oil release to the sea are presented in terms of absolute amount of oil released to the sea.

In Fig. 9.16, a Marsden grid with *green* squares presents geographic areas with the *highest numbers of navigational accidents* that occurred within studied periods (results of Table 9.8), whereas the *red* squares present areas with the *greatest amount of oil release to the sea* (results listed in Table 9.9).

5 Risk-Based Design of Tankers

Risk-based ship design (RBD) is a relatively new scientific and engineering field of growing interest to researchers, engineers, and professionals from various disciplines related to ship design, construction, operation, and regulation. Applications of risk-based approaches in the maritime industry started in the early 1960s with the

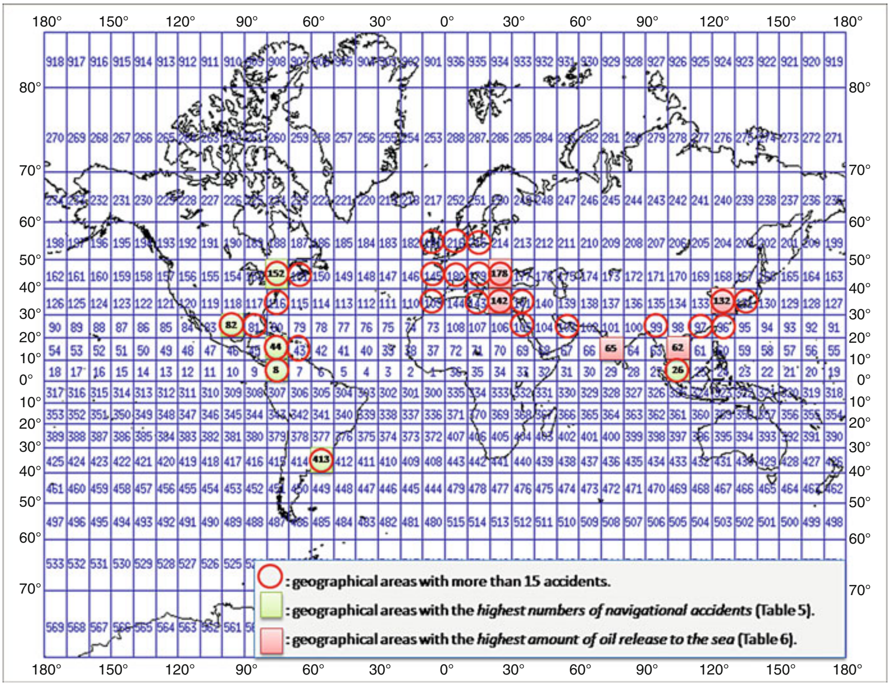


Fig. 9.16 Geography of medium (*1990–Oct. 2009)* and large (*1990–2011)* crude oil tanker accidents

Table 9.8 Marsden grid of geographic areas with highest numbers of accidents occurred within studied periods

	Medium tankers (1990–Oct. 2009)	Large tankers (1990–2011)
Collision	26	26
Contact	152	8 and 82
Grounding	152 and 413	82 and 44

Table 9.9 Marsden grid of geographic areas with greatest amount of oil release to the sea within studied period

	Medium tankers	Large tankers
Collisions	62 and 142	178 and 26
Contact	62 and 564	132
Grounding	132 and 178	65

introduction of the concept of probabilistic ship damage stability. In the following years, they were widely applied within the offshore sector and are now being adapted and utilized more and more within the ship technology and shipping sector.

The main motivation to use risk-based approaches is twofold: to implement a novel ship design that is considered safe but, for some formal reason related to current regulations, cannot be approved today, and/or to rationally optimize an existing design with respect to safety, without compromising on efficiency and performance, noting here that safety is not a design constraint but rather one aim of a multi-objective design procedure.

RBD was introduced to the maritime field by the EU-funded project SAFEDOR (Design, Operation, and Regulation for Safety [34]), an integrated project under the sixth framework program of the European Commission (see Papanikolaou [30]). The project started in February 2005 and was completed in April 2009. Under the coordination of Germanischer Lloyd, 52 European organizations, representing all stakeholders of the European maritime industry, took part in this important R&D project that prepared and submitted a variety of FSA studies and other regulatory procedures for consideration to IMO.

As part of the SAFEDOR project, a team of RTD project members developed an innovative Aframax tanker design of enhanced efficiency and safety [31]. The developed risk-based design procedure was later on extended by NTUA-SDL and Germanischer Lloyd to include more objectives representing ship's efficiency (such as EEDI and cost of transport) in the frame of a holistic approach to ship design. This approach led to an innovative tanker design concept, namely, the BEST design concept (Better Economics with Safer Tankers) [35]. Some characteristic results of this research are briefly reproduced next.

The developed design approach integrates hull form, hull layout, and hull structure optimization. Assessment tools that were developed using the NAPA software system (www.napa.fi [27]) were linked to the optimization environment of the FRIENDSHIP–Framework (FFW; www.friendship-systems.com) [7]. A general flowchart of the optimization is presented in Fig. 9.17. The optimization loop comprises the generation of models and the assessment of each design variant according to the selected objective functions.

A parametric model was created for each main part of the design problem: the hull, the layout, and the structure, with the latter the most time consuming to establish. This model included information about the main particulars of the vessel, plate distribution, and stiffener arrangement of primary and secondary members, tank arrangement, and load definitions. The parametric model was realized by providing the principal structural design as a POSEIDON template database that delivered a complete structural model by combining it with the main structural design parameters. Figure 9.18 shows the POSEIDON model, which is then used to check compliance with the International Association of Classification Societies (IACS) Common Structural Rules (CSR) hull structure requirements.

Results

The optimization process started with a so-called design of experiments (DoE), which enables the exploration of the design space in such a way that each design parameter was varied between the allowed minimum and maximum values (see Harries et al. [11]). About 2000 design variants were generated and all the design parameters were systematically varied. Plots of primary and secondary design parameters (e.g., length between perpendiculars, beam, draft, double hull width

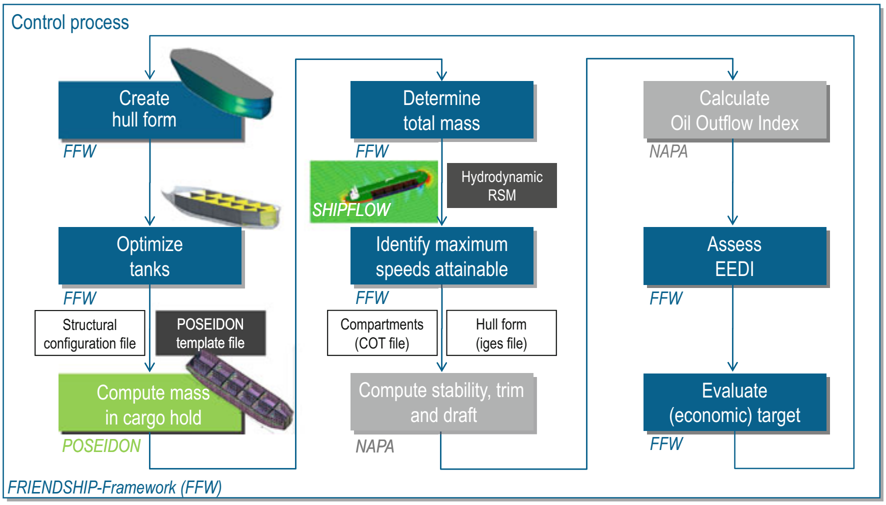


Fig. 9.17 Flowchart of innovative tanker design optimization

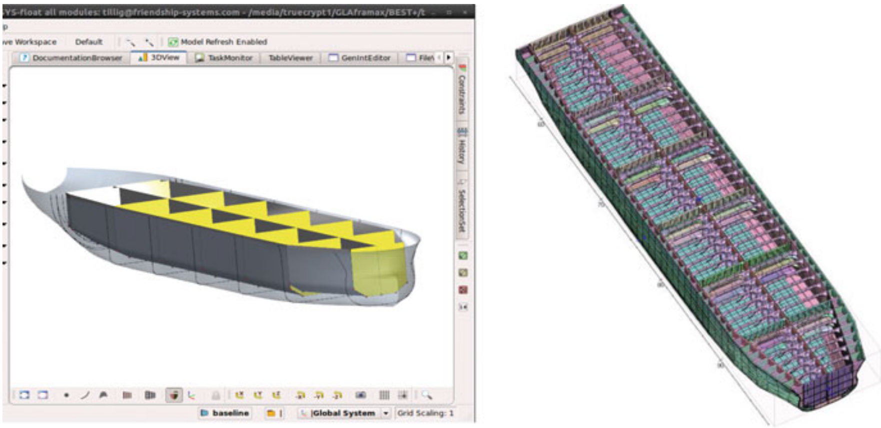


Fig. 9.18 Parametric models for hull layout created within Friendship-Framwork (FFW) (*left*) and hull structure created by POSEIDON (*right*)

and height) versus design targets (e.g., speeds at different drafts, EEDI, cargo capacity, oil outflow index) were used to visually identify design trends and to refine the design focus for the next round of DoE. The final DoE delivered about 400 design variants and design targets (cargo volume, oil outflow index, EEDI, and cost of transport) presented again in scatter plots to identify the optimum design variants (see Fig. 9.19, which shows selected scatter plots including the Pareto fronts).

The final DoE was used to identify the most promising design variants for the next level of optimization, which was conducted to fine-tune the design with a

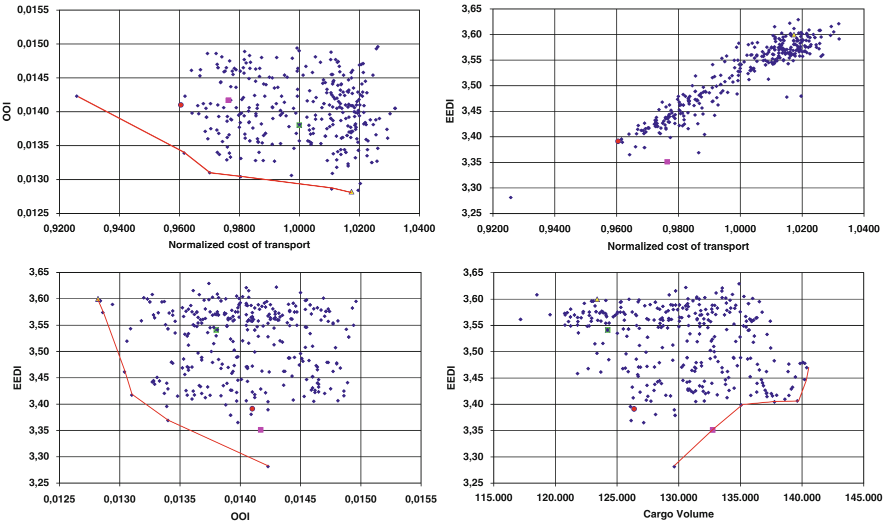


Fig. 9.19 Selected scatter plots of vessel key particulars and design targets

particular focus on hydrodynamic improvement to increase attained ship speed. Cost of transport (the ratio of annual total costs to annual cargo transported) was used to guide the optimization in the final stages (see Fig. 9.20). In Fig. 9.20, the cost of transport has been normalized by the respective value of the reference design. The reference design is an existing Aframax oil tanker design, developed and built before the Common Structural Rules (CSR) entered into force, and it is considered to be a very good design in terms of cargo capacity and oil outflow index. The Pareto front of optimum designs is clearly visible, and the best designs in terms of oil outflow index (OOI), EEDI, and cost of transport are labeled explicitly. It can be seen that the best design in terms of EEDI is a large DWT design; this is because the EEDI favors larger vessels. On the other hand, the best design in terms of oil outflow index is a small DWT design with higher cost of transport, which is the result of the larger double-hull clearances for this design variant.

The design with the lowest cost of transport was used as a starting point for the final hydrodynamic optimization. This local hydrodynamic optimization, utilizing a deterministic search strategy, was undertaken only for the aft body, focusing on the quality of the wake field as an objective. The aft body was allowed to change such that the impact on the cargo tanks previously established in the global optimization was negligible.

The resulting optimal design (Fig. 9.21) and main particulars (Table 9.10) are characterized by the following aspects:

- The hull and cargo oil tank layout is conventional with a uniform tank length distribution and a mostly constant double-hull width and double-bottom height. Note that when optimizing the same tanker for *minimum oil outflow* only, thus considering only environmental aspects, then the tank length of the forward

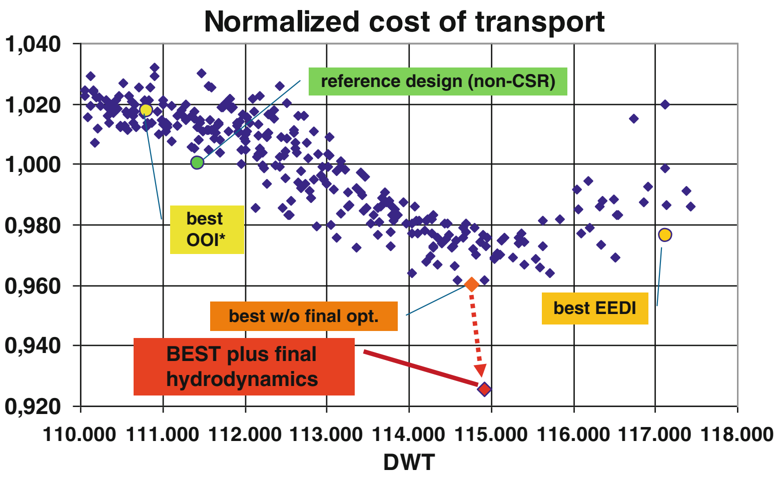


Fig. 9.20 Cost of transport for design variants

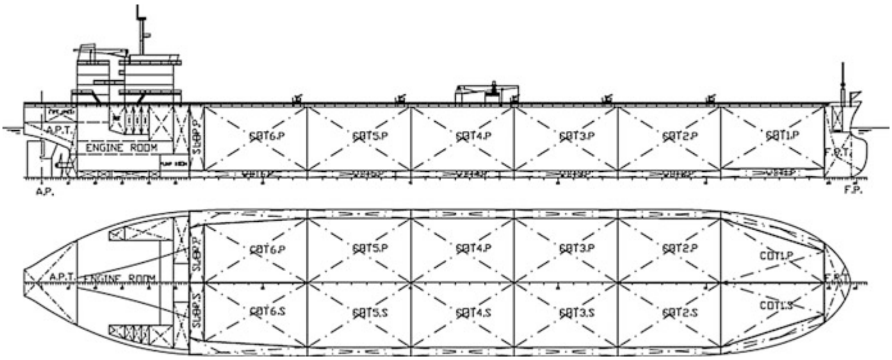


Fig. 9.21 General arrangement of Better Economics with Safer Tankers (BEST) design

Table 9.10 Main particulars of BEST design

DWT	114,923	t	Double bottom height	2.1	m
Cargo volume	129,644	m^3	DB height in COT1	2.75	m
Loa	250.0	m	Double hull width	2.65	m
Beam	44.0	m	Oil outflow index	0.0142	
Depth	21.5	m	Speed at scantling draft	15.3	kn
Design draft	13.7	m	Speed at design draft	15.6	kn
Block coefficient	0.85		Speed at ballast draft	16.8	kn
			EEDI	3.281	g CO2/(t*nm)

tanks was reduced, whereas the tanks placed more astern tended to have greater lengths and cargo capacity.

- (See Papanikolaou [31]).
- The double hull width is larger than compared to similar designs to facilitate low oil outflow in accidental conditions. The raised double-bottom height in the cargo oil tank no. 1 area also reduces oil outflow in accidents. To ensure structural continuity, an inclined inner bottom is located over two frames in cargo oil tank no. 2.
- Slop, fuel, and ballast tank capacities have been kept similar to existing designs. Only the marine gas oil (MGO) tank capacity was increased, to 700 t, to enable longer voyages inside the emission control area (ECA).
- The large cargo volume was realized, with main dimensions being constrained by port facilities, by providing a greater depth than found on similar designs. The relatively large block coefficient, defined at scantling draft, also contributes to the large cargo capacity of this design.
- The installed power was limited to the power available from a typical Aframax oil tanker engine, a MAN 6S60-MC, and the speed performance of the hull was optimized for scantling draft, design draft, and ballast draft. The speed power curves with 95 % confidence intervals are shown in Fig. 9.22, documenting the high speed potential of the optimized hull form. In this figure, a sea margin of 10 % has been included. The speed was determined for three drafts simultaneously, that is, scantling, design, and ballast, and the final hull form was the one considered to be optimal for all three drafts.

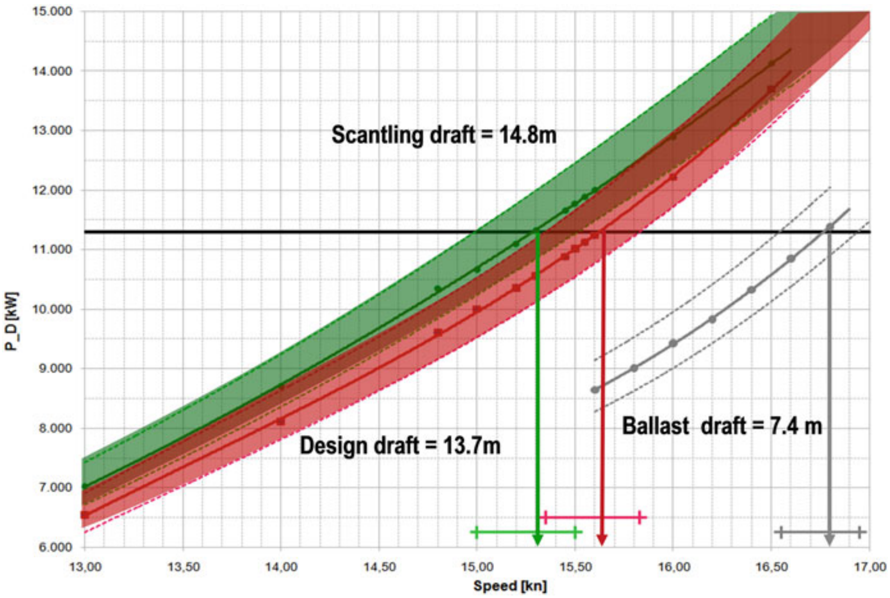


Fig. 9.22 Speed–power curves with 95 % confidence intervals. A sea margin of 10 % has been integrated into the curves

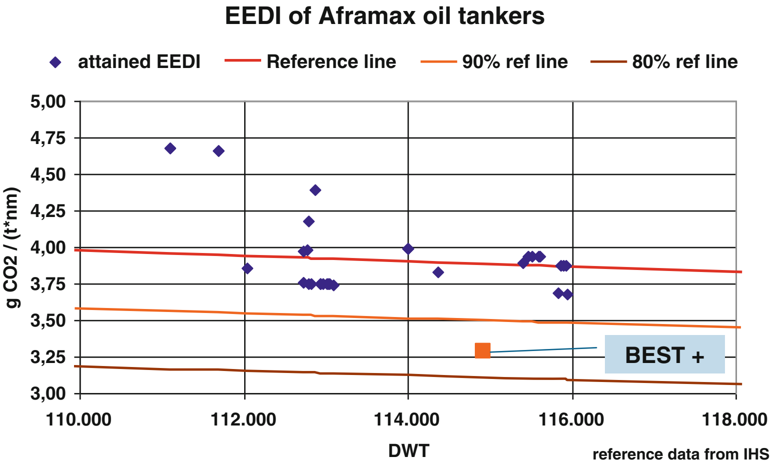


Fig. 9.23 Energy efficiency design index (EEDI) of optimal design compared to similar designs

The EEDI criterion is a mandatory new building standard, as of 1 January 2013, and greatly influences current and future ship designs of all ship types. With the first reduction of the EEDI requirement, 10 % becoming effective for vessels being contracted on or after 1 January 2015 (see Regulation 21 of revised MARPOL Annex VI), current new buildings will be facing stiff competition in less than 10 years from now. Therefore, the target for the new design was to have an attained EEDI of less than 90 % of the current reference line value to ensure competitiveness after the first reduction of the EEDI requirement will have entered into force. The resulting optimum design features a 16 % lower EEDI than required by the reference line (see Fig. 9.23).

6 Summary: Epilogue

The present chapter presented a critical review of historical developments in oil tanker design and of relevant regulations referring to the prevention of marine oil spills and the protection of the marine and the aerial environment; it showed the main results of a comprehensive analysis and critical review of recorded accidents of medium- and large-size oil tankers (deadweight greater than 20,000 tonnes), which occurred after the introduction of OPA 90 and until today. It shows that the frequency of tanker accidents significantly decreased over the years; accidental pollution rates, however, did not follow the same pattern of significant decrease, because rates are determined by the "catastrophic" type of accidents, which continued to happen from time to time. Finally, the chapter considered future developments in oil tanker design and operation in the frame of risk-based design and operation, targeting tankers of enhanced efficiency and safety within a holistic approach to ship design and operation.

Future regulatory developments in relationship to tanker design, operation, and safety, after the concluding discussion of the SAFEDOR tanker FSA by the Group of Experts at IMO (2012) and the conclusion of discussions at IMO-MEPC about the estimation of the cost for averting 1 tonne spilled oil (CATS), are not expected to be on the IMO agenda. However, past experience has taught us that this situation will rapidly change with the next catastrophic type of pollution accident near a coastline. ULCCs, representing an incredibly high risk in case of an accident, seem to be withdrawing from the world market anyway, while the limited lifespan of recent tanker ship buildings calls for an increased pace of replacement of old tonnage. All these factors may let us hope that the catastrophic type of pollution of the marine environment by tanker accidents will be gradually reduced in the future.

Future ship design developments approach highly competitive oil tanker design concepts by use of advanced multi-objective optimization frameworks, which integrate hull form, hull layout, and hull structure assessment to facilitate evaluation of many design variants. This knowhow was applied to design an Aframax oil tanker targeting Caribbean trades, and the resulting design is safer, greener, and smarter at the same time. The oil outflow index is 9 % lower than required by MAPROL, the EEDI is 16 % lower than the current reference line, and the cost of transport is 7 % lower compared to a reference design. Taken together, the new design concept demonstrates that better economics and higher safety can be realized in one design.

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Chapter 10
Pipeline Technology and the Environment

A.A. Ryder, S.C. Rapson, and R.A. Domeney

1 Introduction

Thousands of years ago – long before the Romans – the Chinese were making use of timber to construct primitive interlinked conduits/pipelines for the transportation of irrigation water. Throughout history, pipelines have consistently been the most efficient mass-transportation method for liquids. However, it is only in the last century that pipeline design, construction and operation have affected the evolution of the pipeline into a safe and reliable method of transporting vast quantities of hydrocarbons over long distances.

High-profile sea-tanker incidents such as the 1978 Amoco Cadiz (220,000 tonnes), the 1989 Exxon Valdez (38,000 tonnes), the 1993 Braer (80,000 tonnes) and the 1996 Sea Empress (72,000 tonnes) caused widespread detrimental impact on the environment. In 1999, Erika spilled 13,000 tonnes of heavy diesel oil off the coast of Brittany, causing $860m of damage and sparking EU legislation to ban tankers more than 25 years old. In April 2001, the International Maritime Organisation (IMO) decided single-hulled tankers built in 1973 or earlier should be withdrawn by 2007, and more recent ones by 2015. This timetable was subsequently accelerated. There has been a significant improvement in sea-tanker safety with a reduction from an average of 7.7 spills/year between 1990 and 1999 to 1.8 spills/year between 2010 and 2014. Though the volumes of product transported in a single road tanker are much smaller than anything a pipeline or sea tanker could contain, the consequences can still be devastating. In 2012, at Okobie, Nigeria, a road tanker attempted to avoid a collision with two cars and a bus, veered into a

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_10

ditch, and spilled fuel. Hundreds of locals rushed to the scene to take some of the spilled petrol. About 40 min after the accident, the tanker exploded killing 120 people and injuring at least 75. (https://en.wikipedia.org/wiki/Okobie_road_tanker_explosion).

Rail transportation has a similar potentiality for disaster. Since 2010 there has been an alarming increase in accidents in the USA and Canada with the expansion of the extraction of shale oil and gas. Railcar accidents in the USA resulted in the spillage of more than 1.15 million gallons of crude oil in 2013, compared with an average of just 22,000 gallons a year between 1975 and 2012 (www.desmogblog.com). The largest crude-by-rail disaster in recent memory was in July 2013, at Lac-Mégantic, Quebec, when a freight train carrying Bakken formation crude oil derailed, caught fire and exploded. Forty seven people died, 30 buildings were destroyed and a further 36 demolished due to petroleum contamination. (https://en.wikipedia.org/wiki/Lac-Mégantic_rail_disaster). Trains carrying volatile crude oil from this formation have been subject to several subsequent accidents including three within a single three week period in 2015, in North Dakota, West Virginia and Ontario. The West Virginia incident required the evacuation of hundreds of people from their homes in bitterly cold weather.

Overall, the pipeline industry has had relatively few major disasters. In 1998, 1000 were killed in a pipeline blast in Warri (Nigeria), and in 2000 a further 300 died in a similar explosion adjacent to Warri – though this was the result of direct sabotage rather than inherent pipeline flaws. More recently, in 2004, a major natural gas pipeline exploded in Ghislenghien, Belgium near Ath, killing 24 people and leaving 122 wounded, some critically (www.iab-atex.nl/publicaties/database/Ghislenghien%20Dossier.pdf). The explosion of two petroleum pipelines and subsequent fire in the port of Dalian, in northern China's Liaoning province in 2010, caused fatalities and wide-spread environmental damage after releasing 11,000 barrels of oil into the Yellow Sea.

In recent times, many noticeable incidents of pipeline malfunction have been in Russia, where the problems tend to be related to the age of the pipelines, their length and severe climatic regimes. In addition, Russian pipelines are characterised by a lack of pigging facilities – a moot point given that most are un-piggable, due to varying pipe diameters and other inherent problems. Typical pipeline failures include pipes floating up in bogs or, due to the freezing conditions, metal fatigue resulting from the formation of ravines and crevasses in the ground [5]. One of the most famous pipeline failures occurred on 3 June 1989, when a train ignited a gas cloud between the towns of Ufa and Asha, southeast of Moscow, leaving a reported 706 people hospitalised and 462 dead or missing. Instead of investigating a leak, engineers had increased the pumping rate to keep up the pressure, causing LPG to escape and form pockets in two low-lying areas. The turbulence caused by the presence of two trains mixed the LPG with the air to form a flammable cloud, which was then sparked by one of the trains. The scale of the explosions is illustrated by the fact that trees 4 km away were flattened and windows 13 km away were broken [4]. Another well-known incident is the mass leakages from the 43 km Vozey–Usinsk pipeline in Russia's Arctic Komi Republic. Built in 1975, the leaks began in

1988. By 1994, leaks averaged 17 a month and in August 1994, a record 23 leaks were recorded. Dams were built to contain the oil that was saturating the marshy ground. In August 1994 multiple leak-resulted spills totalled an estimated 30,000 tonnes. Further spills occurred on 16 September and on 28 September one of the dams broke. The other dams collapsed soon after. Ironically, the Russian media learned of the disaster from US sources (*Russian Petroleum Investor*, Dec. 1994/ Jan. 1995). The total loss varied from the official estimate of 14,000 tonnes to the 270,000 tonnes claimed by American oil workers in the area (*Moscow Tribune*, 9 November 1994).

Fortunately, it is better news for the West according to the oil industry group CONCAWE, whose 2015 report of oil industry pipeline failures from 1971 to 2013 identified 26 spillage incidents in 2013, corresponding to 0.23 spillages per 1000 km of line. This was above the 5-year average of 0.18 but well below the long-term running average of 0.48, which has been steadily decreasing over the years from a value of 1.2 in the mid-70s. No associated fires, fatalities or injuries were recorded. Three incidents were due to mechanical failure, one to operational error, one to corrosion, and three were the result of third-party activity. Worryingly, 18 were due to attempted theft of product which was a dramatic increase on previous years. Over the long term, third party activities are the main cause of spillage incidents and the apparent rise of theft attempts is likely to increase this proportion. However, overall pipelines continue to represent a safe, efficient means of transporting a variety of products.

In this chapter, we consider the environmental pressures on pipeline owners and operators in the twenty-first century and examine the ways in which the industry is responding to these pressures during design, construction and operation. It focuses on European and, in particular, UK experience, but in many cases this has international implications. A description of the main techniques used in onshore and offshore pipeline construction is included.

For convenience, the remainder of this chapter is divided into four parts. Environmental Pressures looks briefly at environmental awareness in the pipeline industry. The sections on Onshore Pipelines, Offshore Pipelines and Pipeline Landfalls consider the measures taken by pipeline operators to initiate, implement and monitor environmentally sound working practices. These last three sections use illustrative examples of the ways in which the industry is responding to the pressures.

2 Environmental Pressures

In recent years, academic and public concern over the state of our environment has trigged a proliferation of legislation designed to mitigate the impact of any form of development. UK pipelines have always been subject to controlling measures to ensure safe operation though increasingly there have been calls for closer attention to be paid to health and safety, their visual and environmental impact. Consequently, this has been mirrored in legislation.

The authorisations, consents and specifications for building and operating pipelines in the UK are contained in numerous Acts of Parliament, the most prominent being The Pipe-lines Act 1962 (onshore) and The Petroleum Act 1998 (offshore). Various clauses in these acts proclaim that steps must be taken to avoid, or reduce, danger to wildlife and human activity.

In addition, a pipeline must be designed, constructed and operated in a manner that ensures it is safeguarded from damage. In the UK this is governed by The Pipeline Safety Regulations 1996.

However, it was not until June 1985, when the member states of the European Community adopted Directive 85/337/EEC on the assessment of the environmental effects of certain public and private projects, that environmental assessment became formalised, widely recognised and methodically implemented.

The result of this Directive, and subsequent Directives, including 97/11/EC, with the latest being 2014/52/EU has been the widespread adoption of environmental assessment, in which information about the environmental effects of a project is gathered and evaluated. Where significant effects are identified, measures for reducing those effects are also included. Normally, the developer will commission environmental specialists to produce an environmental statement for inclusion in the application to the planning authority.

Proposed onshore pipes in the UK (except those of public gas transporters, the Government and the water companies) that are more than 16 km long require a pipeline construction authorisation (PCA) from the Secretary of State under section 1 of the Pipe-lines Act 1962. Such applications are subject to Environmental Impact Assessment (EIA) by virtue of the Pipe-line Works (Environmental Impact Assessment) Regulations 2000. These Regulations implemented the above EU Directives on EIA. Under the 2000 Regulations, an EIA has to be carried out for all relevant pipes (regulation 3(1)(a)) unless the Secretary of State has given a direction under regulation 4 that EIA is not required. (Relevant pipes are those pipes subject to the requirement for a PCA that are either oil or gas pipes or are chemical pipes more than 800 mm in diameter and more than 40 km in length.). However, such a direction cannot be given in respect of a proposed oil, gas or chemical pipeline that is more than 800 mm in diameter and more than 40 km in length - EIA for such pipes is mandatory by virtue of an amending Directive.

Where an EIA is required, the Regulations lay down a procedure for public consultation on the environmental statement (and on any further information supplementing it) after which the Secretary of State may issue a PCA, with or without environmental conditions, if he judges it appropriate to do so, taking into account the environmental statement and consultation. A proposed pipe cannot be installed until a PCA has been issued.

Other EIA legislation relating to UK pipelines includes The Public Gas Transporter Pipeline (Environmental Impact Assessment) Regulations 1999 which requires the Public Gas Transporter (as defined by the Gas Act 1986) to apply for a ‘determination’ (a form of screening) as to whether EIA is required and thereafter submit an environmental statement, or submit a voluntary ES, for any such pipelines that meet the necessary criteria.

By law, an environmental statement must comprise:

- a description of the proposed pipeline;
- the data necessary to identify and assess the main effects of the pipeline on the environment;
- a description of the likely significant effects; and
- a description of measures envisaged to avoid or remedy those effects.

Amongst the environmental aspects in need of consideration are human beings, plants, animals, soil, water, air, climate, landscape, material assets and cultural heritage.

Offshore oil and gas-field developments (including any associated developments) are required to be subject to environmental assessment through special additions attached to a licence. Such Environmental Statements have to comply with the requirements of the Directive [1].

In recent years the UK government has introduced The Planning Act (2008), together with The Infrastructure Planning (Environmental Impact Assessment) Regulations 2009 to change the way in which applications for specified applications for Nationally Significant Infrastructure Projects are progressed, with the consenting authority being placed latterly with a branch of the Planning Inspectorate. Included within the various categories of infrastructure are both “Gas transporter pipe-lines” (Section 20) and “Other pipe-lines” (Section 21). With threshold criteria similar to those in the The Public Gas Transporter Pipeline (Environmental Impact Assessment) Regulations 1999 and The Pipe-lines Act 1962, this legislation provides for an additional screening process for UK pipelines which meet the criteria.

In addition to EIA legislation as above, there are a great many other EU Directives and pieces of UK environmental legislation, too numerous to mention here, that can apply to pipelines e.g. in relation to ecology, pollution and consenting.

3 Onshore Pipelines

Onshore pipelines are generally one of three types: those built within the oil and gas fields for the collection of oil (infield lines), those built to cover longer distances between the point of production and consumption (cross-country pipelines) and smaller diameter, low-pressure pipelines used for distribution and supply (usually natural gas).

With the exception of the low-pressure distribution and supply pipelines, the traditional material used in construction is high tensile steel. Individual joints of pipe are welded together to form a continuous tube. Valves and tee pieces may be installed along the length of the pipeline and pig traps may also be installed at intervals along the pipeline as well as at the ends. A valve is used to restrict or prevent flow, a tee piece for diverting flow and a pig trap for the launch and recovery of pipeline ‘pigs’ (devices put into the pipeline for construction or operational reasons). Pigs are often spherical or cylindrical in shape and have all manner of uses, e.g. cleaning, separating batches of product and the gathering of information. A pipeline, therefore, should be thought of not just in terms of the pipe, but also the associated apparatus that makes up the system, including valves, tees, pig traps, pumps or compressors and other miscellaneous infrastructure.

3.1 Design

3.1.1 Preliminary Design

The real opportunity to minimise the environmental impact of a pipeline is at the early design stage. This is the point that the route is being chosen and it is here that environmentally sensitive areas can be avoided. By avoiding sensitive ecological areas such as ancient woodlands, species-rich grasslands, heaths and archaeological sites, many impacts can be avoided completely. It is often easier and more cost-effective to avoid a site completely than it is to implement specialised construction and reinstatement practices.

In particular, sites designated at international, European and national level, such as Special Protection Areas, Special Areas of Conservation, Ramsar sites and Sites of Special Scientific Interest, as well as locally designated sites, landfills, mineral extraction sites and areas of archaeological importance are typically avoided at this stage.

Today it is standard practice for environmental impact assessment to begin during the preliminary design stage of an onshore pipeline project. Typically, a 2 km wide topographically defined corridor that avoids centres of population is established and screened for features that would have a direct bearing on route considerations. At this stage, the environmental impact assessment has a dual purpose: the identification of environments on which a pipeline would have a significant impact and the identification of environments that would have a significant impact on the pipeline. The opportunity is also taken to identify other linear developments – including other pipelines – as there may be advantages in parallel and adjacent routeing. In particular, it minimises the cumulative effect on land use and offers definite advantages in reducing impact to woodland and other areas that may already have an easement cut through them.

The route concept stage takes into account both engineering and environmental issues, which can include:

- existing linear developments and established corridors including motorways, trunk roads, railways, canals, overhead electricity cables and pipelines;
- ecologically and other designated sites;
- historic buildings;
- archaeological sites;

- areas subject to subsidence;
- geographical features;
- estuaries and rivers;
- geology and mineral resources;
- aquifers and water resources;
- conservation areas and landscape; and
- areas of woodland.

By utlising the right design, construction, materials and restoration techniques, there are few onshore environments where it is impossible to lay a pipeline. Nevertheless, the aforementioned issues will present varying degrees of construction difficulty and may necessitate increased expenditure on construction materials and/or restoration. The objective at the routeing stage is to achieve the most cost-effective route by attempting to minimise the length and ensure that risk to the environment and public is minimised.

The assessment is usually conducted as a desk-top exercise, aided by bespoke aerial surveillance or use of existing aerial photography of the route. Screening a 2 km wide corridor for fundamental features should ensure that there is no need to undertake a reassessment – so long as the route remains within the appraised corridor.

Information needed at the design stage is frequently available commercially as digital data, which can be quickly overlain onto aerial photography or mapping within a geographic information system (GIS).

Following an initial gathering of data, consultation with organisations that have a responsibility for environmental protection at national, regional and local levels can assist in the identification of areas that may require mitigation or protection and should form an important part of the assessment process. The overall process should lead to the identification of all major sites of environmental interest and set the parameters for the subsequent ecological and archaeological surveys. Consultation, field surveys, the study of maps and aerial photographs/videos then enables a composite set of constraint maps to be produced. A project GIS is initiated at the conceptual stage and added to as information from various stages of the pipeline's evolution are undertaken - surveys, constraints, construction, etc. They allow project teams to share a common platform for information storage, retrieval and display and can be intranet mounted for remote user access.

3.1.2 Detailed Design

Once the principal features affecting the pipeline route have been identified, the role of the environmental assessment is to identify in detail the possible impacts of the proposal. The corridor principle still applies and its width can be reduced to around 500 m, though this may vary between different pipeline promoters, length of pipeline and with the environment traversed. Within this zone, significant environmental features are identified.

(a) *Consultation*. Once a preliminary route has been established, it is usual for representatives from the pipeline company to visit statutory authorities along the proposed route to discuss the possible implications. After these preliminary discussions, numerous meetings are organised to focus on regional and local issues associated with pipeline construction. The authorities are usually extremely helpful in providing detailed information about their districts. Throughout the project's lifecycle, consultation with other statutory and non-statutory bodies responsible for nature conservation, archaeology, landscape and recreation should be maintained.

(b) *Examination of the existing environment*. A vital part of the environmental assessment is the acquisition of good baseline data. A qualitative and quantitative description of all aspects of the environment is required to provide the basis for design and assessment, as well as to maintain a record of the existing situation. The following phased studies are typically associated with pipeline development:

- a geological investigation of the pipeline route, to inform engineering design and to identify potential areas of contamination, mining risk etc;
- an ecological assessment in three or more phases;
- an archaeological assessment in five or more phases;
- an agricultural assessment;
- a landscape assessment;
- the distribution of soils; and
- a study of hydrological implications.

The multitude of work phases reflects the requirements for an increasing amount of detail. For instance, an archaeological assessment may involve five phases. Phase 1 would screen a 2 km wide corridor for known sites of national importance; Phase 2 would screen a 500 m wide corridor for all other known monuments and sites; Phase 3 comprises field survey work along a c.40 m wide corridor; Phase 4 involves the excavation of sites that are threatened by construction; and Phase 5 would comprise a watching brief throughout construction and the subsequent publication of results.

(c) *Impact appraisal and prediction*. Environmental data generated from baseline survey work and considered in conjunction with detailed project studies is used to identify the probable environmental implications of the development. Examples of studies that might be undertaken are as follows:

- atmospheric emissions during construction and operation;
- noise implication of construction and operation;
- blasting and vibration;
- a study of potential traffic impacts;
- agricultural implications of construction;
- socio-economic implications of pipeline construction;
- an assessment of sustainability, waste generation and resource use;
- strategic-economic appraisal of the project; and
- safety.

The techniques used for impact prediction are established and well documented. Some aspects such as the propagation of noise and dispersal of contaminants in the atmosphere are relatively easily modeled and produce quantitative outputs to reasonable degrees of accuracy. Others require a more qualitative approach and rely more on the judgement of experts than on comparison with accepted criteria.

Some issues have well-defined criteria that have been established by standards against which to assess impacts. These are associated with the physical, chemical and hydrological impacts connected with construction and operation. Other impacts such as on landscape tend to be presented as qualitative descriptions and the demonstrations that impacts have been minimised by design and other mitigative measures.

Criteria for assessing environmental risk are not well established, although presentation of risk helps to put certain impacts into perspective. The overall perception of environmental risk is influenced by the concept of risk acceptability – the process that has been applied when considering the effects of major accidents on the people living adjacent to the route.

(d) *Identification of mitigative measures*. For large pipeline projects adverse environmental impacts as a result of disturbance to the land surface is usually inevitable. These effects can be minimized by considering details of routeing, construction techniques and site-specific reinstatement and aftercare programmes. For example, one recently constructed UK pipeline managed to reduce the normal working width of 20 m to 12 m, and topsoil-stripping operations were restricted to the width of the pipe track only, when crossing most moorland sites. Instead of stripping topsoil across the whole width, a sand, bog mat or subsoil road was constructed directly on the vegetation. Turves were lifted from the pipe trench area, stored to one side and put back. The road was then lifted and the working area scavenged for debris. Seasonal restrictions or limits on the duration of works through a particular area are also commonly used.

(e) *Proposals for future monitoring*. The environmental statement broadly identifies the potential environmental impacts of the development. Monitoring programmes need to be established to:

- obtain, where appropriate, baseline data for the environment prior to the construction, commissioning and operation of the pipeline;
- monitor any significant alteration to the biological, chemical and physical characteristics of the local environment;
- monitor emissions and discharges at all stages of the development to ensure they meet national, local and developer management standards;
- monitor any alteration to the inter-relationships of different aspects of the environment;
- determine whether any environmental changes that may occur are the result of the development or result of natural variation.

The intention is to determine, where appropriate, both the natural fluctuations of environmental parameters and the extent of other anthropogenically induced changes before, during and after construction of the pipeline and throughout its operational life.

(f) *Preparation of the environmental statement*. Environmental assessment is the process of environmental input to project planning and the prediction of its likely impacts. The products of the process are often a series of technical reports that are summarized in a more user-friendly form as an environmental statement. The report may be submitted to the statutory authorities in draft form. Then, after further consultation, the final document can be made available to the public and other interested parties.

(g) *Contract documentation*. The key to effective environmental management is to translate the products of the environmental assessment into action. For the environmental assessment to have some impact upon the reality of construction, the results must be built into the technical specifications and included where necessary in contract documents and plans.

There is no single way to achieve this and, as with all contractual matters, a balance between providing the contractor with too much and too little information needs to be found. It has been argued that too much environmental information will cause the potential contractor to react adversely and charge a premium on the basis that perceived environmental sensitivity presents a risk. Conversely, if inadequate information is provided then there is a risk of claims for additional work and the possibility that adequate environmental controls will not be implemented.

An ES will usually contain a section on environmental management which will include a summary of the mitigation measures to be taken forward. A Construction Environmental Management Plan (CEMP) is usually provided, either as part of the ES, and/or as part of contract documentation, which sets out all of the environmental requirements of the appointed contractor. Often tenderers are then asked to provide their own EMP that adds detail to the information provided by the design engineers in the contract. This allows the approach to environmental issues to be evaluated at tender phase.

3.2 Construction

It is clear that during the planning and design phase of a pipeline considerable effort is expended in the identification of potential environmental impacts, the identification of suitable mitigation measures, the inclusion of mitigation measures into the design and, where appropriate, their stipulation in contract documentation. For those mitigation measures to be implemented effectively during construction, they must be *known, understood* and *implemented* by all relevant personnel. These three basic requirements are the cornerstones of effective environmental management and arguably the most difficult to meet.

3.2.1 Raising Awareness and Understanding

Raising awareness is perhaps the first step towards achieving satisfactory environmental performance. Management must appreciate the significance of environmental issues and be committed to achieving a high standard of environmental performance. This commitment will be strongly influenced by the level of importance the company's senior management ascribes to environmental issues. A company with a strong commitment to environmental protection and a visible environmental policy is more likely to achieve the commitment of its project management team.

A project's workforce will need to become familiar with the environmental issues specific to the project. This can be achieved in a number of ways, for example:

- A full- or part-time environmental supervisor may be appointed to the client or main works contractor's management team from the outset of the project. He or she would have the responsibility for briefing the project, construction and engineering managers on environmental issues;
- Monthly health, safety and environment meetings may be held, allowing issues of concern to be discussed by the management team;
- Site-specific method statements, each engineering method statement will usually contain an environmental section to ensure mitigation is cascaded to all site staff.
- Informal workshops may take place. For example, on one recent project, an archaeological dig took place along the pipeline prior to construction and many members of the project team took part under the supervision of trained archaeologists. In the evenings, there were presentations about archaeology and what had been found along the pipeline route during the preconstruction surveys and what was likely to be found during construction;
- Health, safety and environment and/or sustainability workshops may be held once construction contractors have been selected. Members of the client team and the construction contractors participate to ensure that all senior management appreciates the importance of environmental/sustainability issues on that project and understand the mitigating measures that have been designed and incorporated into the contract documents;
- All personnel should go through a programme of induction training before they are allowed to work on-site. This may take the form of a talk from the site safety and/or environmental officer;
- Toolbox talks may be held on an as-required basis with different construction crews. Typically, these are held on weekly basis, or before entering a special section by the supervisor or foreman. However, if a special environmental crossing is about to be encountered, an environmental officer would explain what is important about a site and how to protect it; and
- Signs should be erected along the spread indicating the beginning and end points of areas where special precautions have to be taken.

3.2.2 Site Supervision

The number of inspection staff required is always contentious, with financial constraints likely to mean the reduction of such staff. Nevertheless, quality assurance philosophy maintains that well-written procedures and the use of appropriately trained staff can help to reduce the number of inspection staff required. Experience suggests that the higher the level of supervision, the better end product.

It is essential that environment, like safety, is perceived as a line responsibility and not the sole responsibility of the environmental officer. All supervisors and inspectors can help ensure that environmental requirements are implemented. However, the effectiveness of this is dependent upon the supervisor appreciating and implementing a project's environmental controls. In sensitive areas, a greater input will be needed from an environmental officer. They will most likely have been involved in designing mitigation measures and will therefore know how flexible those measures are. A well-informed environmental officer with knowledge of the site will be better placed to advise on how to overcome any potential problems, with the support of specialists in particular disciplines e.g. in archaeology, ecology, contamination etc where required.

3.2.3 Reporting

A client-appointed manager and a dedicated project team manage the construction of most pipelines. Reporting to that manager will be various management disciplines, such as construction, engineering, health, safety and environment (HSE). Most organizations have a corporate HSE group, so it is useful to maintain a link between a project's HSE group and the corporate HSE group. This provides a mechanism whereby a project manager can be circumvented if need be.

3.2.4 Contractor Plans

As above, contractors should be encouraged to prepare their own environmental management plans. This will allow the contractor to implement procedures that are tailored to their organization and way of working. Plans may be required to cover:

- archaeology – what to do in the event of an archaeological find;
- waste management – including waste minimization, reuse, recycling and disposal; and
- pollution prevention – including avoidance, containment, clean-up and reporting arrangements.

3.2.5 Construction Methods

The standard method for the construction of welded steel cross-country pipelines across normal agricultural land is based upon the spread technique. A 'spread' consists of all the people and equipment necessary to conduct the construction operation, from surveying the route to restoration. The work is carried out on a continually moving assembly line basis, with each sequential activity maintaining a consistent rate of progress. On a long pipeline, there may be a number of spreads with work being undertaken by different contractors on different spreads. Progress may be as much as 1 km per day. In the UK, wherever possible construction is usually timed to take place within the period March to October when weather conditions are most favourable, though works in lower-risk areas and preliminary works such as vegetation clearance and fencing may be timed outside of this 'season'.

Each spread contractor will need a number of different crews. They will undertake the following tasks.

(a) Location of existing services

The main route surveys will have identified the existence of third-party services such as pipelines and cables that cross the Right of Way (ROW) and it is important to establish their exact location and depth and mark them so that the operations that follow avoid damaging them. Overhead cables also need to be identified and clearly indicated so that they can be seen by approaching plant operators.

(b) Setting out and fencing

The ROW is pegged out and the working width fenced on both sides. Fencing should be designed to suit the nature of the terrain and will range from simple demarcation fencing (to indicate the working width to operators working on the spread) to stock proof fencing for pasture. It may also be necessary to erect additional barriers as a part of the fencing to prevent protected species such as great crested newts from straying onto the working width.

(c) Preparation of the working width

The preparation of the working width includes a number of activities depending on the terrain. For cultivated land, it is likely to include topsoil stripping and storage, diverting ditches and minor drainage channels to prevent water entering the pipeline trench, clearing hedges and trees and preparing access to the working width. It may also be necessary to undertake the same work for designated pipe storage areas and office compounds. In all cases, measures should be taken to mitigate damage to the underlying ground by using geotextile fabrics. Vegetation removal should ideally be undertaken outside of the bird nesting season (usually March to August).

(d) Land drainage

Land drainage issues are relevant to pipeline routes that pass through cultivated areas with land drains leading to watercourses. The requirement is to survey the existing drainage to ensure that temporary drainage is provided during the construction works and reinstate to at least the original condition. It is essential to ensure that water run-off from drainage systems affected by the construction works is not contaminated and, therefore is non-polluting.

(e) Line pipe stringing

Pipe is usually procured in 12 m lengths and is delivered to site with corrosion protection coatings applied and with end caps to prevent ingress of debris. For long pipelines, it is usual to have delivery areas at intervals along the route where pipe is stockpiled ready for transportation along the working width. The stringing operation entails distributing pipe along the spread ready for welding.

(f) Field bending

Field bends are used to allow the welded pipeline to accommodate the vertical and horizontal profile of the route. The route surveys determine the radius that is necessary and individual pipes are bent to suit using field bending machines. The limits to which a pipe can be bent and still remain within allowable metallurgical parameters for the pressure design depends on the diameter, thickness and grade of steel. If a bend radius below this limit is necessary, forged or fabricated bends may be used. Small radius bends are used for crossings of ditches and other features, whereas larger radius bends are used to accommodate the natural undulations of the route where they are beyond the natural radius of the welded pipe.

(g) Welding

The pipeline is welded into a continuous length alongside the trench. There are two types of weld – sleeve or butt. Butt-welding is the most common for high-pressure oil and gas pipelines.

During the design stage, a welding procedure will be prepared specifying the end preparation requirements, the alignment and gap dimensions between pipe ends and the number and type of weld pass that will be necessary to complete the joint. A weld pass is an individual run of weld. Several passes are required to complete a butt-welded pipe joint. Test welds are carried out to verify the welding procedure with non-destructive (radiographic or ultrasonic) and destructive metallurgical techniques used to check that the weld material and weld effected zone meet requirements.

Pipes that have been strung along the working width will have had their ends prepared for welding at the manufacturing stage or on site prior to stringing. The ends will be checked and if necessary mechanically cleaned to remove any oxidation or other impurities that will impair the weld. The pipes will then be aligned using an internal line-up clamp that will control the roundness and gap between pipes to within the required tolerances.

Manual welding is the most common method for pipelines although automatic welding machines, initially developed for offshore laybarges, are also used for land pipelines. With both methods, the welding procedure will dictate the number of passes required, the weld material and any preheat requirements. Typically for manual welding these will include an initial root pass, filler passes depending on the wall thickness and a final capping pass. Fewer passes are necessary with automatic welding.

The welding process is usually carried out sequentially starting with a welding station for the root pass. As each root pass is completed, the welding station is moved down the line to the next joint and the process of alignment and welding is repeated. Welding stations for the filler passes and the capping pass follow, also in sequence. Welding equipment for the various passes is portable and often mounted on tracked side-boom lifting machines.

Welding is a highly specialised technology and there are many national and international codes and standards that govern requirements.

(h) X-ray and inspection

All welds for high-pressure pipelines are 100 % non-destructively tested using radiographic techniques with X-rays as the source. The testing procedures are carried out by specialists trained to handle radioactive isotopes and in the interpretation of the resulting X-ray photographs of the weld area. Imperfections such as weld slag intrusion or hairline cracks are cut out and re-welded.

(i) Coating and wrapping field joints

When the weld has been tested and passed as satisfactory, the external and internal surfaces of the weld and adjacent pipe are mechanically cleaned by shot blasting or other means. Corrosion protection coatings compatible with the main part of the pipe are applied to complete the joint.

(j) Trenching and lowering

Trench excavation follows the welding, testing and joint completion work, which is carried out alongside the route centreline with sufficient clearance to allow trenching equipment to operate safely adjacent to the fabricated pipeline. Trench excavation can be undertaken with standard backhoes or with proprietary pipeline trenching machines. In both cases, the excavated material is stockpiled separately to topsoil alongside the trench for reuse as backfill.

If rock is present it may be necessary to use explosives or specialist rock excavation plant to excavate the trench and a bedding material may be required to prevent damage to the pipeline when it is lowered into the trench.

Wet conditions may also require specialist attention to achieve a ‘dry’ trench. Suction pumps can be deployed to remove water that drains from the surrounding area and in extreme conditions where the excavation is below the water table, it may be necessary to use a well point dewatering system. This consists of suction tubes that are driven into the ground alongside the trench. The tubes are connected to a pipeline manifold suction arrangement driven by pumps that discharge into adjacent watercourses. The system lowers the water table to below the bottom level of the trench. In extreme conditions where the ground is highly permeable and well point dewatering systems cannot cope with the quantities of water, ground-freezing techniques using liquid nitrogen can be used. Discharge arrangements may require consents from the regulating authority and mitigation measures may be required.

As with all excavations, it is necessary to comply with safety regulations and procedures to ensure that adequate precautions are taken to prevent people or equipment from accidentally falling into the trench. If people are required to work within the trench, trench sheeting should be used to prevent the sides collapsing and causing injury.

Immediately behind the trenching operation, side booms are used to lift the fabricated pipeline from the temporary supports on the welding line. The pipeline is supported within rollers suspended from the side booms so that they can progressively move forward and, at the same time, 'snake' the pipeline into the trench maintaining a predetermined safe curvature that will prevent overstressing.

(k) Backfill

Backfill supports the pipeline structurally and, if placed correctly, prevents future settlement along the pipeline route. Structural support is particularly important with large diameters and is achieved by placing and compacting granular material or lean mix concrete around the pipeline and immediately above it. This initial backfill should be placed carefully to prevent damage to the corrosion coating. The excavated material can then be used to fill the trench providing it consists of readily compactable soil, i.e. substantially free of clay and organic material such as tree roots. Compaction will be necessary to prevent settlement and it is good practice to replace the excavated material in as near as possible the same sequence of layers that it was originally excavated in.

(l) Reinstatement and restoration

Reinstatement and restoration of all land affected by the pipeline construction works, including access roads, office or storage areas, is one of the last operations to be carried out and involves replacing top soil, land drains, natural features and boundaries such as hedges. Programming may also be affected by seasonal weather conditions and it may be necessary to wait for dry weather or conditions that suit seeding and planting vegetation or hedgerows.

(m) Hydrotesting

As with reinstatement, this is one of the last operations to be undertaken and is used to prove the fitness of purpose of the completed pipeline including above ground installations. Long pipelines are often tested initially in sections with a final full-length test on completion of tie-ins between sections.

The test procedure will include pigging to remove debris, the use of gauging pigs to check for damage that may have occurred during construction, filling and pressurising with test water and subsequent removal of test water to approved disposal points.

Test water may be moved from one section of the pipeline to another for reuse during the sectional tests. Test water may require additives to act as oxygen scavengers and biocides. They prevent corrosion to the pipe material and inhibit formation of microorganisms.

The test procedure will stipulate the pressures to be used and the duration that pressures are to be maintained for. The usual requirement is to have an initial low-pressure stage to check for leaks and a higher-pressure stage applied to test the integrity of the pipeline system as a whole. The higher-pressure stage is set at a level above the operating pressure and will generally be specified in design codes and standards. Before applying pressure, the ambient temperature and test water temperature have to be monitored so that variations during the test period that will alter the pressure can be allowed for.

(n) Commissioning

When the final tie-ins and hydrotesting have been completed, commissioning operations can commence and generally consist of purging and drying the pipeline system to remove test water. Slugs of chemicals that are readily miscible with water, such as methanol, are driven through the pipeline system between pigs. Alternatively, vacuum drying or dry air can be used. The product to be transported governs this choice and when the process is complete, nitrogen may be used as inert filler before the product is introduced.

The commissioning process should also be used to check control and monitoring systems. This will be aimed at testing the telemetry systems that remotely actuate valves and safety systems, such as emergency shut-off valves.

(o) Post construction documentation and records

As-built records and drawings are developed throughout the construction and commissioning phases and are usually stored within a GIS. The same system is typically used to record events during the life of the pipeline system and can incorporate risk assessment processes to enable integrity monitoring to take place.

3.2.6 Monitoring

Most environmental monitoring will take the form of checks to ensure that the contractor is complying with contractual requirements such as waste management and the use of designated disposal sites. Some special forms of environmental monitoring may be required at particular locations. For example, at river crossings it may be necessary to monitor dissolved oxygen and suspended solids. When working in close proximity to residential areas, it will be important to monitor noise levels.

3.2.7 Audits

Any management system should be subjected to audits to allow shortcomings to be identified and, importantly, to allow improvements to be made. For example, corporate HSE may audit the project's HSE group and the project's HSE group may audit the construction contractor or specialist environmental contractors.

3.2.8 Special Crossings

In environmentally sensitive areas such as Sites of Special Scientific Interest (SSSIs), special construction methods are often needed. Each of the areas of concern will need to be the subject of a separate study prior to construction to determine the best crossing method. Possible methods at such sites include reducing the working width, use of temporary roads, stripping for only the pipe trench, rather than the whole of the working width, turfing, fluming and boring beneath. Some of these techniques are discussed further elsewhere within this chapter.

3.2.9 Case Study: The North Western Ethylene Pipeline, UK

Such special construction methods are well illustrated, and were rigorously tested during the construction of the UK's largest pipeline, Shell's North Western Ethylene Pipeline in 1991–1992 (Fig. 10.1). The 10 in. (25 cm) diameter pipeline was built because ethylene, which is made from natural gas from the North Sea, needed to be transported from Grangemouth (near Edinburgh) to Shell's petrochemicals plant at Stanlow in Cheshire, where it is used in the manufacture of plastics and solvents. It was the first pipeline to be subject to the Electricity and Pipe-line Works (Assessment of Environmental Effects) Regulations, 1989, which emerged as a result of EC Directive 85/337/EEC. Nowadays, the pipeline – 411 km in length, 10 in. in diameter and containing 17,100 tonnes of steel – lies buried 1 m underground and is invisible to all but the informed eye.

As it was such a long pipeline, and because it had to follow a line that was already littered with other pipelines, railways and roads, it was impossible to establish a route that did not affect any important areas. In particular, it had to cross two Roman walls (the Antonine Wall and Hadrian's Wall), both of which are Scheduled Ancient Monuments and are protected by law. In addition, it had to cross four SSSIs that were also protected by law. After a public inquiry and careful negotiations, Shell was allowed to cross these and other important features [8].

Shell took care to ensure that all construction was undertaken in an environmentally sound manner. Four environmentalists and four archaeologists monitored day-to-day construction.

Special construction methods were agreed for all the sensitive environmental and archaeological sites. Carstairs Kames, near Lanark in Scotland, with its important geomorphological features surviving from the last ice age and a designated SSSI, had to be crossed. A low point was chosen for the crossing, and where the pipeline had to run parallel to the edge of the kames, the width of the working area was reduced to as little as 4 m.

Lazonby Fell, an area of heathland near Penrith, is another SSSI that required special attention. Before construction began, the heather was cut to promote new growth in the following year. A 12 m wide strip was fenced off, a temporary road was laid and turves were only removed from the area of the pipe trench. After the

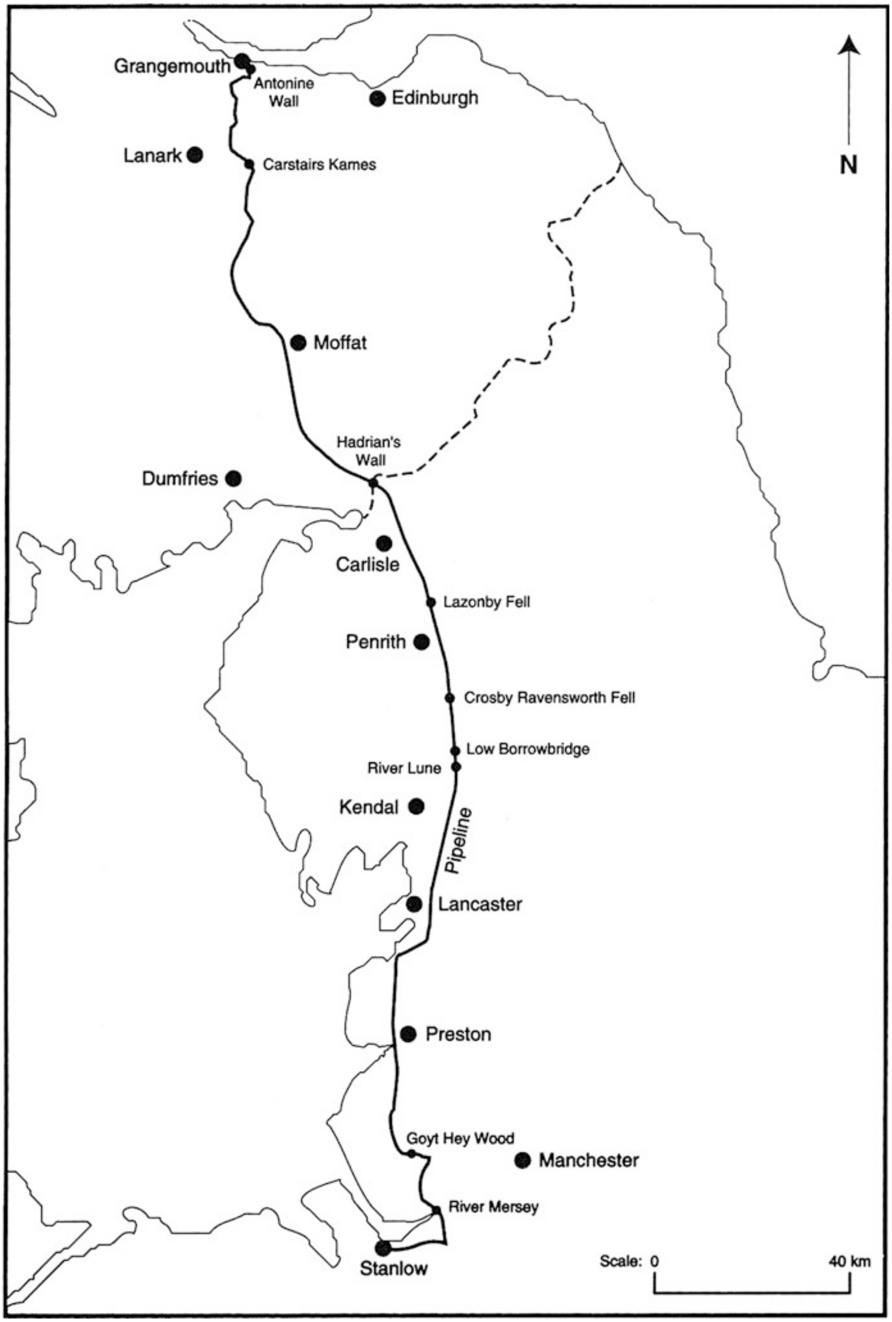

Fig. 10.1 Map showing the route of the North Western Ethylene Pipeline and the sites mentioned in the text

turves had been replaced, collected heather cuttings were spread over the area to help new growth. By the summer of 1992, new heather plants were growing in the thinly vegetated areas, demonstrating how successful reinstatement had been.

Similar methods were used at SSSI, Crosby Ravensworth Fell, near Shap in Cumbria. As a large area of upland, it was not considered practicable or necessary to turf the whole area; instead, turfing was confined to floristically rich areas that had been identified by botanists before construction began. In remaining areas, the vegetation layer was scraped off using an excavator bucket and stored separately from the topsoil and subsoil beneath, so that it could be replaced on the surface at a later date, thus encouraging existing plants to grow and to maintain the plant rhizomes and the seedbank.

Subsequent monitoring has shown that the turved areas recovered extremely well within a very short time. The remaining areas fared less well, and a special upland grassland seed-mix had to be applied to aid vegetation. Nevertheless, this was expected, as wet upland areas take a long time to recover and, in general, reinstatement is considered satisfactory.

A narrow strip of woodland called Goyt Hey Wood, near St Helens, had to be crossed. A point was chosen where it was not necessary to fell any mature trees, the working width was reduced to only 4.5 m and special small excavators were used. The soil containing the bulbs and seeds of the important ground flora was carefully stored and replaced. It was encouraging to see bluebells growing on the working width the following spring.

Shell had to cross several rivers along the pipeline route, including the River Lune in the Tebay Gorge. Here excavators working in the river caused much sediment to be disturbed, but by working quickly and by stopping for periods to allow clear water through, the effect was reduced. However, the River Mersey was too large for this method to be used and the horizontal directional drilling technique was used.

Archaeological sites called for a different approach. Some required excavation before construction began. For example, near Grangemouth, where archaeologists knew the exact location of the Antonine Wall, an excavation was carried out. Evidence of the wall and of a fort was found. Other sites could not be excavated beforehand because no one knew they were there. This was the case at Low Borrowbridge, where construction stopped whilst a Roman cemetery was uncovered.

Shell was committed to looking after the land along the pipeline route for the life of the pipeline, which is at least 25 years. For 5 years, they monitored the success of reinstatement of its 40 most sensitive sites. They also conducted checks on the growth of the hedges and trees planted to replace those felled.

(a) *Case study:* Environmental and Social Assessment of Azerbaijan Sector of BTC Pipeline

The Caspian Sea has long been known to be a significant hydrocarbon reserve by major oil companies. That the resources existed was seldom in dispute, the challenge was how they could be developed, transported and integrated into the world market.

Formerly a part of the Soviet Union and landlocked, Azerbaijan had been unable to fully develop its offshore oil and gas resources and find a viable method of export to international markets.

With the introduction of foreign oil companies as operators of oil and gas fields in the early 1990s, additional focus was placed on securing safe export routes from Azerbaijan. The two first export routes developed, which became operational in the mid to late 1990s, were the Western Route Export Pipeline (WREP, Baku – Supsa) and the Northern Route Export Pipeline (NREP, Baku – Novorossiysk).

While undoubtedly important, these two pipelines, with a combined capacity of approximately 220,000 bpd, did not have the capacity to enable full development of the Azerbaijani offshore fields. To further complicate matters, the oil from each of these pipelines had to be transported to market by tanker, through the already congested and environmentally sensitive Turkish Straits.

A solution was devised when a consortium of international oil companies led by BP came up with an ambitious export solution: the Baku-Tbilisi-Ceyhan (BTC) pipeline project.

In one of the world's largest energy transportation schemes, the plan envisaged a pipeline traversing Azerbaijan, Georgia and Turkey and finishing on the Mediterranean coast at Ceyhan, from where the oil would be available to the world market.

Consisting of more than 1760 km of buried pipeline, constructed from over 150,000 individual joints and with the capacity to transport 1 million barrels of oil a day, the statistics are certainly impressive.

Following competitive tender, the contract to carry out the Environmental Impact Assessment (EIA) of the 443 km section of the BTC pipeline within Azerbaijan was awarded to RSK Group's Azeri subsidiary company AETC (Azerbaijan Environment and Technology Centre). AETC worked closely with the Social Impact Assessment (SIA) consultants to produce a combined Environmental and Social Impact Assessment (ESIA) report.

Given that the same methodology of ESIA had to be employed throughout all three of the host countries, all consultants were required to work closely together, in doing so setting a precedent for scope, quality and consistency.

As the BTC project was part financed by a group of lending institutions, including the International Finance Corporation (IFC) and the European Bank for Reconstruction and Development (EBRD), it was required to achieve their rigorous standards of environmental and social performance. In addition, the requirements of the host governments had to be met.

During the ESIA process, all potential impacts of the pipeline were evaluated against applicable environmental and social standards, regulations and guidelines, existing environmental conditions and issues raised by stakeholders.

Though the potential for media and pressure group interest was ever present, ERM (who carried out the Social Impact Assessment) found that local opinion on the project was largely positive.

Of the 83 communities identified along the route in Azerbaijan, 94 % were optimistic about the benefits the pipeline would offer them and their country (the majority had already experienced the construction of the Azerigaz and WREP pipelines).

Initial studies, including an Environmental Risk Assessment (ERA) to determine the relative risk of oil spills, had already discounted a succession of other transportation options before it was decided to opt for the pipeline method. For instance, it was estimated that the BTC route would eliminate the need for an additional 350 tanker cargos per year through the Bosphorous and Dardanelles straits.

Though the route from Azerbaijan to Turkey had been shown to be the most feasible method during initial routeing studies, it was not without its problems. Within the Azerbaijan section alone, the pipeline crossed a number of fault zones, major rivers and ran through areas of archaeological and ecological importance.

As a starting point, a Scoping Process was conducted to identify key issues and develop appropriate terms of reference for a full assessment. At this stage, it was considered essential to identify the likely environmental and social impacts and to define the project's area of influence. It was integral to the ESIA that the scoping process was initiated early and in an open manner that involved appropriate degrees of disclosure and consultation with relevant stakeholders.

The Project set about disseminating information to affected local communities, national scientists, academic institutions and NGOs, as well as the authorities and regulatory bodies. A period of sustained consultation followed, with the purpose of focusing the ESIA on issues of local as well as international importance. Through this process, it was possible to define the project in sufficient detail to allow the Scoping exercise to effectively and efficiently shape the full ESIA. Crucially, gaps in baseline data were identified and agreements with stakeholders were made on any necessary fieldwork and studies to fill these gaps.

Using a combination of local scientists and international experts, detailed environmental baseline studies of a 100m corridor centred on the proposed BTC pipeline route was conducted. In addition, BTC surveyed the region and identified potential sites for construction camps, pipe yards and above ground installations (AGIs), which were then assessed against environmental and social criteria. Sensitive receptors and pathways to oil spill were also noted over a wider area.

A considerable amount of baseline environmental information applicable to the BTC project was already available from previous projects including WREP. However, where data were lacking or out of date (particularly in relation to assessing oil spill sensitivities), additional environmental baseline data were collected.

The survey work included initial routeing surveys, baseline field surveys of the optimum route (botany, zoology, archaeology, landuse, hydrology, soils and geology), detailed botanical and zoological studies of areas of high sensitivity, pump station surveys (noise, landscape and air quality), traffic surveys, and contamination baseline and river corridor surveys. Geographical Information Systems (GIS) were used to manage, interrogate and interpret all data.

AETC and ERM considered the impact upon all environmental and social receptors that could potentially be affected by the development of the BTC pipeline in Azerbaijan that, according to ISO 14001's definition of environmental impact encompasses any change to the environment, whether adverse or beneficial, wholly or partially resulting from an organization's activities, products or services.

It was determined that the most tangible impacts were likely to arise during the construction phase, and would include transient construction noise, increased traffic, infrastructure disruption and other temporary impacts.

Some potential impacts upon ecological and archaeological features were identified and mitigation measures to remove or minimise these impacts were developed.

During the operation of the pipeline, the most significant risk was determined to be oil spills. The impacts of a spill could be significant depending on the scale of the event, site conditions and the local metrological, geographical and hydrological conditions. However, the environmental assessment showed that the probability of a spill occurring was extremely remote, and in the unlikely event of a spill a comprehensive oil spill response plan would be in place to mitigate its impact.

The ESIA specified that during construction impacts would be mitigated through the implementation of good construction practice, the development of management plans and through the application of localised measures to protect specific or sensitive receptors.

AETC's conclusions suggested that careful management and adherence to the mitigation measures outlined in the comprehensive ESIA document would ultimately reduce any potential impacts and, importantly, bring about a series of short and long-term benefits to the region.

Most mitigation measures diminished impacts to Low or even to Beneficial. Some remained at Medium or High (for example ecological studies in the Gobustan desert, estimated that it would take 10–12 years for full habitat revival), but overall the positive effects—sociological, political and environmental—far outweighed the negative.

On 18 May 2005, oil began flowing into the BTC pipeline from the Sangachal terminal outside of Baku, heralding a new chapter in oil pipeline history. Since then BP has produced an environmental and social report every year, which summarises information from the various environmental and social audits that are undertaken regularly (BTC Project Environmental and Social Annual Report (Operations Phase), 2013). The ESIAs for the BTC pipeline were undoubtedly a huge step forward compared to previous assessments, but lessons were also learnt that have influenced subsequent assessments. The most important of these are reviewed in the IFC publication 'Lessons of Experience: The BTC Pipeline Project' (2006).

3.3 Operation

Pipelines are generally believed to be the safest means of transporting large quantities of hazardous fluids and gases over long distances. From an environmental perspective, pipelines remain the preferred mode of transport: there is a reduced likelihood of accidents and spillage of products, and the environmental impact of operating pipelines is less than for rail or road transport. However, as a follow-on effect from increasing public awareness of environmental issues and tightening legislation throughout the world, pipeline operators are under continual pressure to make pipelines even safer. This becomes increasingly important as pressures on land increase and pipelines become squeezed into narrower and narrower corridors.

Pipelines can fail through material defect, corrosion, natural causes (e.g. earthquakes) and third-party interference [2]. Through rigorous adherence to design code standards and stringent monitoring procedures, failure from material defect, corrosion or natural causes is now much less of an issue. To ensure that pipelines have a minimal impact during operation, there are two areas that require action:

- avoidance of spills resulting from pipeline failure and adoption of plans to deal with potential leaks;
- preparation and implementation of a restoration plan.

To achieve these aims, a number of actions are required, many of which are simple components of a good management system, e.g. pipeline integrity monitoring and maintenance, prevention of third-party interference, emergency planning, record keeping, monitoring and audits and reviews.

3.3.1 Testing, Commissioning and Operation

After pipelaying, a pipeline must be cleaned and checked. Pipeline pigs are used to clean and check the pipe in the initial stages before hydrostatic testing takes place. Where possible, water for testing is drawn from a nearby river after agreement with the relevant authority. If this is not possible, tankers will be required. In instances that require this procedure, pressure will be generated by a diesel-driven reciprocating pump, creating some noise, though if normal standards of noise control are in place (e.g. exhaust silencer and standard enclosures), noise levels would be expected to be no greater than from other normal pipeline construction activities. The water is then discharged at a controlled rate to a site agreed with the appropriate authority. After dewatering, pumps may be used to dry the pipe. These pumps may have to operate over a period of several days so strict noise targets may have to be imposed. As an alternative/addition to vacuum drying, the tested sections may be swabbed to remove residual water by passing specially designed pigs propelled by compressed air/gas through the pipeline.

During normal operation, there will be no significant impacts on the environment resulting from an onshore pipeline, although there may be some noise from pump units. Careful planning at the design stage should ensure that these noise levels are not sufficient to cause nuisance to nearby residents.

3.3.2 Pipeline Integrity Monitoring

Today’s pipelines have sophisticated loss monitoring detection systems. One such example is the supervisory control and data acquisition (SCADA) system, which can indentify leaks through a drop in pressure. This kind of system enables early detection of leaks, and allows the operators to shut down the pipeline, identify the location of the leak and isolate it by shutting off block valves on either side. Remote operation of the compressors and block valves from a central control unit means that a shutdown can take place within minutes. To enact the same process manually would take hours. Sophisticated telemetry enables the system to be continually checked to ensure failures are identified and rectified.

Also built into today's pipelines are facilities to pre-empt and detect corrosion. Pipelines are in the first instance protected from corrosion by the application of a protective coating or wrapping in the factory. A similar coating or wrapping of joints will also occur in the field. The pipeline's protection will also be bolstered by cathodic protection, which stops corrosion by preventing current flow from the pipe (the cause of corrosion is the removal of metal ions by the flow of current). The metal is made electronegative to its environment to such a degree that no current can leave at any point. The current, which under natural conditions would leave the metal, is opposed by the flow of the current in the opposite direction. This opposing current is either equal to or greater than the total of all the currents naturally leaving the structure. The power-impressed systems traditionally used on onshore pipelines comprise a DC power supply with the negative connected to the pipeline and the positive connected to an earth electrode. The latter is normally referred to as the groundbed.

Pipeline integrity can be further maintained by regular internal checks using a remotely operated spherical or cylindrical pig. Some pigs will simply clean the pipeline, whilst more sophisticated models will record data about wall thickness, corrosion, the location and size of dents and other pipeline deformities.

3.3.3 Prevention of Third-Party Interference

Third-party interference is widely recognized as the most probable cause of pipeline failure. It can arise from four major sources: landowners and tenants, utility companies, contractors and local authorities. Research on recent UK pipelines has shown that, despite pipeline operators expending considerable time and money informing landowners and tenants, a third of those questioned did not inform staff or contractors about what precautions to take when working near pipelines. Furthermore, they were unclear about the safe working distance from a pipeline and the kind of work that needed to be brought to the pipeline operator's attention. Most interviewees judged the pipeline route from marker posts and did not have accurate maps showing the route. Although most had an emergency contact telephone number to hand, one third were unaware of the full range of services and advice that the operators provided free of charge [9].

The study also found that many cross-country pipeline operators are not included in the routine contacts made by utility companies and their contractors before beginning an excavation. It is possible that the current trend towards deregulation of the utility companies could make this situation worse. It was also discovered that local authority planners responsible for identifying planning applications adjacent to pipelines, often held poor information on the pipeline routes.

Third-party education about the risks associated with pipelines is clearly an essential part of a pipeline operator's job and will help to reduce risk of pipeline failure. Within the industry itself, most pipeline operators operate geographical information systems, one-call systems and improved surveillance techniques.

Geographical information systems (GIS) are useful in a number of respects. First, they allow root cause analysis to be carried out on excavation work, authorized and unauthorized, near a pipeline. Regular analysis of the cause and nature of infringements will help pipeline operators target those parties most likely to offend more effectively. Affordable, tailored PC-based systems that can manage data relating to the day-to-day operation and inspection of pipelines are widespread, and analysis of third-party activity is quick and efficient. Thematic maps can be produced showing the location and type of offenders, excavation hot spots and notifications of works in roads, in the vicinity of rivers, *et cetera*. A further benefit of GIS output is its capability to produce customized maps for third-party use. In the USA, the Office Of Pipeline Safety has implemented a national mapping system.

One-call systems, where those wishing to carry out an excavation can telephone a central number to register their intentions, are used, while similar web-based systems (linewatch.co.uk is one example), enable the user to register an intention to dig and receive immediate confirmation as to the location of nearby utilities. Should the location fall within a particular distance of other utilities, that operator will be informed immediately. Two types of system are in operation: those that cover a defined geographical area and include all or most utilities (requiring a great deal of investment and utility company cooperation), and those that are utility specific and provide data only on the location of their particular underground pipe (quicker and cheaper but of limited scope). The Netherlands already has a legal requirement to subscribe to a countrywide all-utility scheme, with a similar scheme being proposed in the USA. In the UK, there is no such government-led incentive, though companies are moving towards these kind of schemes as a means of fulfilling their safety obligations.

Surveillance techniques to detect third-party interference have traditionally involved helicopter or aeroplane flights along pipelines. These enable an observer to spot any violations of the easement from the air and, if a helicopter is used, to land in order to stop interference taking place. However, it has been observed that flights of this nature, even if done on a regular basis, only identify infringements that occur within a very short time span. In addition, such flights do not allow an observer to examine the pipeline in detail and vital clues may be missed, though this may be overcome by the use of a real-time video record made at the time of the flight.

Advances in pipeline inspection technologies, primarily Pipe Integrity Gauge (PIG) surveys, have led to improvements in identifying and locating pipeline defects. Use of inertial navigation systems coupled with above ground Global Positioning Satellites (GPS) surveys mean that individual features and defects can be located immediately, irrespective of alignment sheet inaccuracies, new above ground developments etc.

At least one pipeline operator in the UK has decided to increase the effectiveness of its ground survey techniques. To this end, it commissioned a risk analysis to determine which parts of its pipeline were likely to cause most risk to people. Pipelines through heavily built-up areas were deemed to pose most threat whilst remote upland areas pose least threat. Consequently, they developed a strategy that involved frequent monitoring of the highest risk areas, less frequent survey of medium risk areas and infrequent monitoring of low risk areas.

3.3.4 Emergency Planning in the Event of a Spill

All pipeline operators have plans that can be acted upon in an emergency. These clearly state the line of responsibility in such an event and detail what will happen. Emergency response vehicles containing necessary equipment are held by the operators at convenient locations, and regular training is given to the staff involved. The emergency services will also be familiarized with the plans.

3.3.5 Record Keeping

GIS allows huge amounts of information to be easily accessed and readily updated. For a given point on the pipeline route, this could include:

- name, address and telephone number of the landowner;
- engineering data, e.g. depth of burial, pipe wall thickness;
- crop compensation data since pipe installation; and
- aerial photographs, video images or other photographs of the site.

Any information needed by a pipeline manager can be added to the GIS, making it a central store for everything relating to a pipeline. Information can be inputted manually but increasingly is provided in the field with GIS updated with live data via tablets.

GIS can also be used to give the answers to 'what if' questions – if the pipeline were to leak at a particular location, the GIS could tell:

- the best access route to that section of pipeline;
- who to contact (including with name and telephone number); and
- which settlements fall within the area affected by the release.

GIS can interface with simulation models and present the results in an easily understood form; for example, in the case of a gas cloud, its size and travel route under certain weather conditions.

However, GIS records are only as accurate and comprehensive as the data inputted. Complete, up-to-date records are essential, irrespective of whether or not GIS is used. These records must be diverse and manifold, i.e. environmental records and waste management records.

Information about the state of the environment is essential. Data should be kept on the location of archaeological sites, recreational areas, water resources (including aquifer protection zones), areas of conservation importance (including SSSI), landfill sites, landscape features and so forth. Information on the location of these sites and the reason for their sensitivity is beneficial when planning maintenance work or responding to emergencies. If this information is unavailable it may be a good investment to undertake an environmental review of the pipeline system to focus upon the location of environmentally sensitive sites, the company's relationship with third parties and the availability of emergency response equipment.

It is vital that records are kept on the subject of waste management. In the UK, the 'Duty of Care' requires that the originators of waste keep records of what was disposed of, who transported it and what the final destination was.

3.3.6 Monitoring of Reinstatement

It is important that the success of reinstatement is measured and that unsatisfactory areas are improved. In agricultural land, this is often a question of repairing damage to soil structure and/or drainage. In particular, environmentally sensitive areas such as moorland, heathland, unimproved grasslands, species-rich wetlands and deciduous woodlands often require detailed monitoring. Hedgerows can be added to this category, as they are often the most publicly visible. The type of monitoring required will depend on the nature of the site and the purpose of the monitoring. In some cases, a simple 'look see' and brief report will suffice. In other cases a detailed ecological survey will be needed, using, for example, quadrats across a permanent transect.

The only additional monitoring that is likely to be required is noise monitoring in the vicinity of pumps/compressors. This will be of particular importance if the pump house or compressor station is located adjacent to a residential area. If there are other emission sources it may be necessary to undertake monitoring, although these are likely to be associated with activities other than the pipeline.

3.4 Decommissioning

To date, few onshore oil and gas pipelines have been decommissioned. Generally, they are cleansed and simply left *in situ*. It is important to ensure that the entire entity and associated products are removed from the line in order to prevent pollution of soil and groundwater. Usually, the removal of the pipeline would cause greater environmental impact than leaving it in place.

4 Offshore Pipelines

Three functions of offshore pipelines have been defined [6]. Intrafield lines carry product from one offshore installation to another installation; the installations may be entirely sub-sea, or above sea-level (such as a production platform). Pipelines between two neighbouring platforms within the same field are also usually classified in this manner. Interfield pipelines carry product from one production facility to another or connect into another pipeline, and their function is normally to transport the oil or gas to the next link in the system: another pipeline or perhaps a tanker. Lastly, trunk lines link the pipeline transportation system to the shore terminal.

However, an increasing number of subsea pipelines comprise interconnectors between different parts of Europe in particular.

Most pipelines in the UK Continental Shelf are constructed of carbon–manganese steel or low-alloy steel and are cathodically protected (most commonly by the use of zinc- or aluminium-based sacrificial anodes). They are also externally coated to protect against erosion. Many pipelines have a concrete coating that provides additional protection, though the primary purpose of this method is to add weight to the pipeline to prevent buoyancy. When building pipelines in the UK sector of the North Sea, it is a mandatory requirement that a Pipeline Works Authorisation (PWA) or a PWA Variation, regulated by the Oil and Gas Authority, is in place before any construction work takes place, in addition to other regulatory documents.

4.1 Design

As with cross-country pipelines, environmental assessment is a process that begins at the preliminary design stage and continues throughout detailed design. Consultations with relevant statutory and non-statutory bodies are essential. Examination of the existing environment is required together with impact appraisal, impact prediction and the identification of mitigative measures where necessary. In addition, proposals for the future monitoring of the environment will be needed together with an environmental management programme to ensure contract documentation takes account of the findings of the assessment. The end product is the environmental statement, which will be required as part of the application for the Pipeline Works Authorization.

There will, however, be essential differences in the nature of the existing environment. Consequently, the resultant impacts, the proposed mitigation measures and the requirements for future monitoring will differ. These are discussed in some detail below.

4.1.1 Preliminary Design

During the preliminary design stage, engineers and environmental scientists are concerned with finding a broad corridor for the pipeline route. This is normally determined by:

- seabed topography – a seabed that is too rough could lead to spanning of the pipe;

- potential landfall sites – these will limit the location of the end-points of a pipeline route;
- flora and fauna of the area – known sensitive sites (such as Natura 2000 sites) should be avoided if at all possible at an early stage; and
- any military activity in the area – including military exercises and munitions dumps.

4.1.2 Detailed Design

(a) *Consultation*. The importance of consultations with both statutory and non-statutory bodies through the detailed design stage of a pipeline project cannot be overemphasized.

(b) *Examination of the existing environment*. At this stage, as with onshore pipelines, it is essential to gather good baseline data. However, as the offshore environment is very different from the onshore environment, there is clearly a need for a different set of criteria. For an offshore pipeline, these will generally include:

   - physical conditions – bathymetry, seabed geology and sediments, sediment transport, tidal range, water currents, water temperature, winds and waves;
   - biological environment – nearshore benthic communities, offshore benthic communities, nearshore and offshore fish, plankton, seabirds and shore-birds, marine mammals; and
   - human activities – commercial fishing, shipping and navigation, Ministry of Defence areas, cables and oil and gas exploration, renewable energy installations, minerals and dredging, marine archaeology, conservation designations, recreation, waste disposal and planning policies.

(c) *Impact appraisal and prediction*. Baseline surveys and other detailed project work will generate the data required to appraise and predict the likely impacts of a sub-sea pipeline. As with onshore pipelines, some of the predictive techniques are necessarily qualitative and some quantitative. The main studies at this stage are likely to concentrate on:

   - physical conditions – the effects on Annex 1 Habitats such as sandbanks (effects can be caused when installing the pipeline);
   - biological conditions – the effects of physical intervention; sediment disturbance and noise on benthic communities, fish, plankton, bird and mammal communities; and the reef effect of the pipeline (a well-documented phenomenon whereby fish are attracted to structures providing shelter, causing some to fishermen trawl the length of the pipeline to benefit from the extra fish); and
   - human activities – the effects of exclusion of vessels from an area during construction, on fishing, on cables, on munitions dumps, minerals and dredging, marine archaeology and waste disposal.

(d) *Identification of mitigative measures*. As with onshore pipelines, mitigative measures are often not needed if the pipeline route has been carefully selected in the initial phases of design. If special measures need to be taken, these might include:

- removal, or partial removal, of anchor mounds (if they are created from installation works);
- avoidance of environmentally sensitive areas;
- adaptation of working methods within them to minimize disturbance (such as avoiding particularly sensitive seasons), carefully planned crossing of existing sea-bed infrastructure such as cables and other pipelines; and
- avoidance of munitions dumps, aggregate extraction areas and archaeological features.

(e) *Proposals for future monitoring, preparation of the environmental statement and contract documentation*. There may be a need for construction and post-construction monitoring; requirement for the production of an environmental statement to accompany the PWA application and, subsequently, a need for contract documentation incorporating the environmental requirements of a project.

4.2 Construction

Construction methods for an offshore pipeline are clearly very different from those required for an onshore pipeline. A brief summary of the main methods employed is given below together with two case studies.

4.2.1 Good Site Practice

Raising awareness, site supervision, good reporting procedures, preparation of contractor plans and regular monitoring and audits are all essential elements of a good health, safety and environment programme and should be well-established before the start of construction.

4.2.2 Construction Methods

There are three standard methods of laying submarine pipelines:

- reel barge method – this is only used for laying small diameter pipelines in shallow waters;
- bottom pull method – this is used in inshore waters; the pipe is fully prepared on land and is pulled into the sea by barge. Welding and concrete coating can take

place on land, and any damage to the pipe is more likely to result from friction along the seabed than from bending the pipe; and

- lay-barge method – this is the most common way of laying pipe. The barge acts as the pipeline factory, where pipelines are welded, x-rayed and the joints coated. Lowering the pipe into the sea is difficult, and the pipe may need to be supported by a 'stinger' so that the bend does not exceed a maximum permitted curvature. Such barges propel themselves along the pipeline route by pulling on anchors which are continually being re-set by anchor handling vessels. Alternatively, in water depths of greater than 20 m dynamically positioned (DP) pipelay vessels are used to lay the pipeline. These vessels maintain position using thrusters.

There are several different methods for laying pipelines on the seabed; including partial trenching, complete trenching, trenching and back-filling and rock armouring. In UK shallow waters, pipelines are trenched and buried where possible, regardless of their dimensions, due to the potential for exposure that can be caused by the action of currents and waves. In soft, sandy sediments, the trench tends to backfill itself with time. The most common method of trenching is 'jetting', where a 'trencher', a saddle-shaped construction, is placed on top of the pipe (which has already been lowered on to the seabed). The trencher is equipped with water jetting nozzles or plough shares (depending on the sediment), and the apparatus is towed along the pipeline. Jetting locally fluidizes the seabed and the pipeline sinks below the sediment surface. If ploughing is the technique used, the spoil is pushed to the sides of the created trench. The spoil may and may be pushed back over the pipeline if the plough has another set of rear shares, or left to naturally fall back into the trench under the influence of the tide and current movements. Where trenching is not possible due to a hard seabed, the pipeline may be laid on the seabed and rock armoured. In deeper waters (>60 m), it is usually unnecessary to trench or bury larger pipelines for engineering reasons. However, even where the pipeline has been left proud, it may sink over time.

There has been much dispute over the value of trenching and burial. Trenching and burial have the advantage of protecting a pipeline from some of the most frequent physical impacts such as those from fishing gear, strong currents and occasionally, dropped objects. Clearly, there will be no impact on fishing gear if the pipeline is buried. Trenching and burial may also minimize problems associated with scouring and spanning, making it possible to offset some of the additional costs of burial against costs incurred in span correction. In addition, burial may make future abandonment a more viable option. When Shell and Esso began plans for the 36 in. Flags (Far North Liquids and Associated Gas System) gas line, they initiated a series of studies to test the theory that large pipelines in deep water did not need to be trenched. The studies found that impacts from fishing gear were unlikely to result in serious damage to pipelines, that buried pipelines were not protected from anchors from large ships, and that concrete coating does a more reliable job of weighting the pipe to provide stability. It is now generally accepted that large diameter, proud pipelines in deep water are unproblematic.

Special construction methods in environmentally sensitive areas can involve the minimization of disturbance of sediments, minimization of rock blasting, reduction of noise levels emitted from plant and machinery, careful timing of operations in order to avoid bird breeding periods and even directionally drilling under particularly sensitive nearshore habitats.

4.2.3 Case Study: Scotland to Northern Ireland Natural Gas Pipeline (SNIPS)

This 42 km long pipeline (Fig. 10.2), built in 1995, was laid using a pipeline largely anchored to the seabed. Where feasible the pipeline was trenched, although in certain areas the nature of the seabed did not permit this, making it necessary to place rock over the pipeline.

At the preliminary design stage, 16 possible crossings of the North Channel, from the Rhins Peninsula in South West Scotland to Islandmagee on the east coast of Northern Ireland, were considered [7]. The cliffs along much of the coastline precluded wide areas of the coast as landfall sites, though it was possible to identify two potential areas on each side of the North Channel.

Coastal surveys were undertaken at each of the sites to assess the seabed and coastal conditions. Offshore surveys were undertaken to assess the physical conditions along the potential routes across the North Sea. The main factors influencing the selection of the corridor were:

- the operational risks associated with laying a pipeline across Beaufort's Dyke, owing to the steep slopes on the faces of the dyke and the sediment conditions;
- an independent assessment of the landfall options that identified areas within the North Cairn, Browns Bay, Ferris Bay and Port Muck survey areas as the most suitable for the pipeline landfalls;
- the desire for the selected route to minimize the amount of disruption to the seabed that would be required; and
- the need for the selected route to avoid Danger Area D411 and the munitions dump area identified by the Ministry of Defence.

During the detailed design stage, a number of potential environmental impacts had been identified by environmental scientists. Many of the impacts would have been associated with any offshore pipeline, such as the creation of anchor mounds, temporary exclusion of fishing, changes in the habitats of benthic flora and fauna, stress to plankton organisms, change in behaviour of fish species and localized avoidance of the area by some seabirds. Others, discussed below, were specific to the area concerned.

With regard to the physical environment, one of the main concerns was the presence of a dredge spoil dump to the north of Larne. It was believed that the dumping may have led to contamination of sediment within the pipeline corridor. Dredging close to Larne could disturb the sediments, causing pollution and if

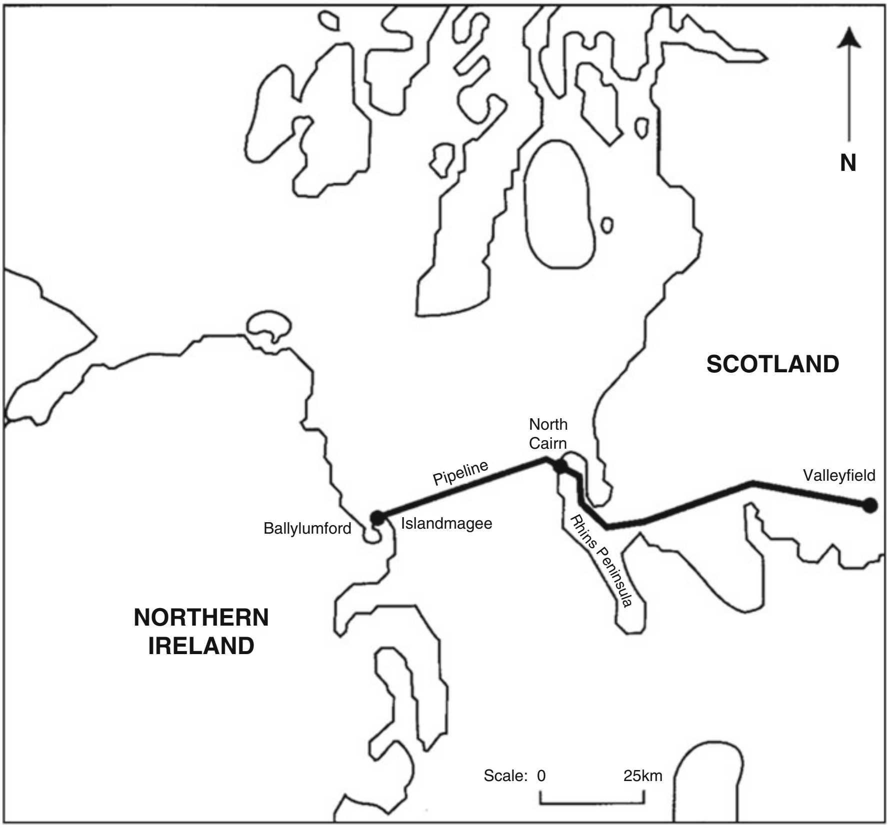

Fig. 10.2 Map showing the route of the Scotland to Northern Ireland Natural Gas Pipeline (SNIPS)

contaminated sediments had to be removed from the seabed there could be problems obtaining a licence for disposal.

Also of concern were three environmentally sensitive Irish coastal areas close to the pipeline route: the bird nesting and roosting areas on the Isle of Muck and Skernaghan Point, and the diverse benthic habitats of Castle Robin. At the Isle of Muck (a bird reserve) and Skernaghan Point, there was concern about the effects of construction noise. At Castle Robin, there was concern about the effects of near-shore blasting through hard rock on the diverse benthic communities. Options for minimizing the effects on birds included avoidance of sensitive areas where possible, careful timing of construction to avoid the breeding season in spring and early summer, careful choice of plant in order to minimize noise, including the fitting of noise attenuators. Mitigation measures identified for Castle Robin included possible avoidance of blasting if a suitable route through softer sediments could be identified, minimizing the use of explosives and rock-ripping, using controlled rock splitting where possible, and avoiding the most sensitive benthic communities where possible.

It was apparent that before construction could begin, there was a need for further studies of the pipeline route close to the sensitive areas described above. These studies led to the inclusion of detailed specifications in contractors' documentation to ensure that the correct procedures were carried out during construction.

4.2.4 Case Study: The Gas Interconnector Pipeline (GIP)

The Gas Interconnector Pipeline was built by Bord Gais Eireann between Moffat, South West Scotland, and Ballough (20 km north of Dublin, Ireland), in order to supply gas to Ireland from the North Sea (Fig. 10.3). As with the SNIPS project, the detailed design stage of this pipeline was concerned primarily with the identification of landfalls on the Irish and Scottish coasts and the identification of broad corridors across the Irish Sea suitable for the pipeline. In particular, the landfalls were the subject of extensive study (the exact methods employed for the Scottish landfall at Brighouse Bay are discussed later in this chapter). During consultations with affected bodies, Bord Gais Eireann discovered that fishermen were concerned with the proposal not to bury some of the pipeline. The project managers eventually agreed to bury the whole length of the pipe; however, because much of the pipeline was expected to sink into the soft clays present, it did not involve trenching the whole length. During detailed design, the environmental assessment identified many of the same potential impacts as on the SNIPS pipeline, though some were specific to the GIP. One aspect which needed particular attention was the temporary loss of access to a 15 m wide strip along the nearshore fishing grounds at Kirkcudbright. To enable the pipeline to be laid, fixed gear such as creel pots had to be moved and mobile gear such as trawling nets would have to be restricted in their operations. Unlike fishermen working further out at sea, the shellfish fleet operating out of Kirkcudbright has limited alternative areas in which to fish. In order to minimize problems associated with the shellfish fishing, the fishermen were fully involved in the decision making process: they were given early notice of the timing of the work, and they were contracted to lay the approach channel buoys. However, during the actual pipelaying operation, there was no choice but to exclude the fishermen from the pipelaying zone.

4.2.5 Case Study: The Gas Interconnector Pipeline 2

By 1997, over 80 % of Irish gas was being imported via the first Gas Interconnector pipeline. The magnitude of the supply meant that capacity constraints were beginning to surface and if any supply interruptions were to occur, they would cause substantial negative economic impacts. In 1998, Bord Gais Eireann, in collaboration with the Department of Public Enterprise, undertook a study to identify Ireland's long-term gas infrastructural requirements. Known as the Gas 2025 Study, its purpose was to facilitate a detailed analysis of future gas supply options to ensure that supply would meet demand until 2025. The data gathered suggested

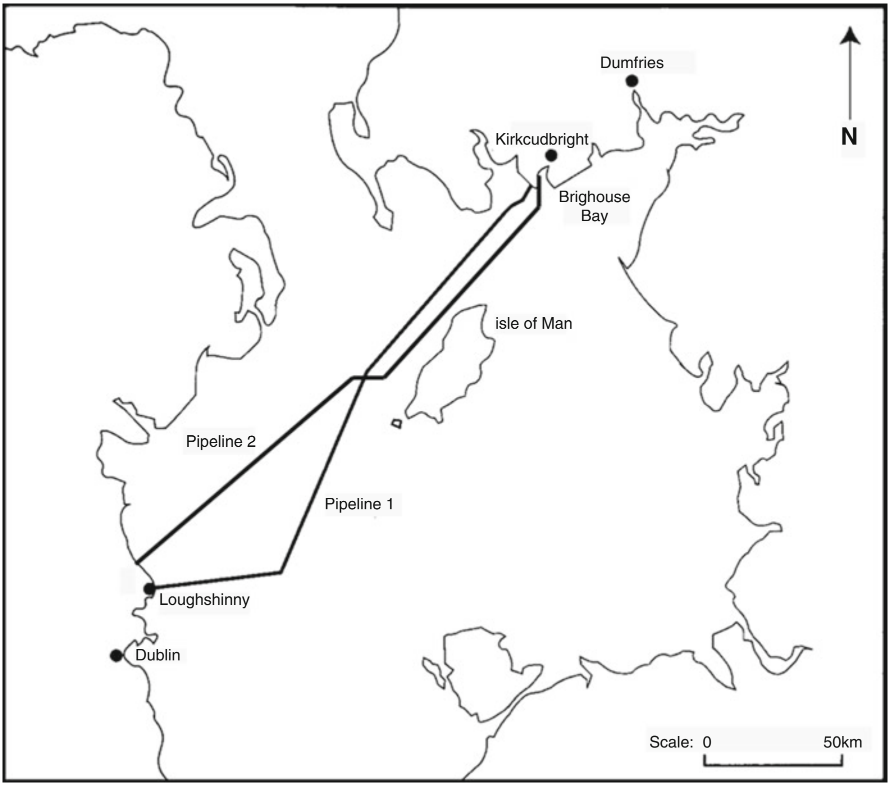

Fig. 10.3 Map showing the route of the Gas Interconnector Pipeline

that one of the options to achieve this would be to construct a second interconnector pipeline linking Beattock in south-west Scotland to Ballough, north of Dublin in Ireland. The selected route would include three associated above ground infrastructure developments at Beattock and Brighouse Bay in Scotland and Gormanston in Dublin. The design phase conformed to DNV 2000 standards, while the Scottish Isle of Man onshore sections in Scotland conformed to BS 8010, and the Irish section to IS 328. Costs were minimised by selecting a route that traversed the shortest possible distance. To record seabed bathymetry, a multi-beam Seabat and DTM were extensively used, supplemented by a series of on-line assessment systems onboard the engineering survey vessel. For Interconnector 2 to become reality, considerable consultation had to be carried out. Spanning UK, Irish and Manx authorities, 11 separate bodies (excluding third-party crossing operators) were engaged with. The discussions noted that 20 permits would be required, 226 conditions had to be satisfied and that a treaty explicitly designating ownership of the seabed (thus avoiding the 'dog leg' that was feature of IC1) had to be enforced. Amongst the various parties' concerns were issues pertaining to anchor mounds, trench spoil heaps, turbidity and the impact on fishing activity.

Anchor mounds became less of an issue once a DP vessel was used for the main offshore lay. In the nearshore sections, the mounds were surveyed following pipelaying and levelled where required. Trench depth was minimised during the design phase, partly to minimise any spoil heaps. One of the consent conditions included levelling/backfill of any excessive heaps. Turbidity was not permitted in the northern half of the route, where, ironically, filter feeding scallops were blocked by too much food in the water column. Subsequently, no jetting was permitted in the north. Largely as a result of IC1, fishermen had a number of concerns – including the impact the IC2 might have on very specific fishing techniques utilised for scallops to the north and off the Isle of Man, and prawns to the south in a clay basin. As a result, a considerable effort went into alleviating fears and mitigating impact. So in addition to addressing specific concerns, agreements were reached to allow the fishing organisations to contribute to the project success. To optimise continuity, a full-time engineer, who was originally a member of the EIS survey team, supervised the environmental aspects of construction. Through being involved in the project from the outset, the environmental engineer was knowledgeable about the various seasonal and other constraints.

A particular environmental challenge was the routeing into Ross Bay in Scotland where a geological SSSI skirts most of the coast-line. Following a number of site surveys in the area, a gap in the exposed rock was found on the north side of Ross bay. This shingle beach gave the access required with a heading that was compatible with the offshore route, thus avoiding the need for special construction techniques. Project ecologists and archaeologists representing Duchas (an Irish heritage organisation) were integrated into project management team. This meant that any unforeseen environmental conditions could be dealt with as they arose. Examples included the appearance of the marsh fritillary butterfly adjacent to the working area in County Clare and the need to ensure that the bats inhabiting the caves of southern Galloway were not prevented from reaching their feeding grounds at night due to the lack of hedgerows across the working spread. Other issues dealt with by the environmental specialists included waste management practices on the various sites and liaison with local media and environmental interests when issues of interest arose. The presence of the archaeologist proved to be particularly serendipitous when his expertise prompted the discovery of a 3000-year-old boat (which can now be found at a museum in Portsmouth). The realisation of the IC2 represented the culmination of 5 years of detailed feasibility, planning, design and construction to preset objectives, programme constraints and control budgets. The project was completed within budget and on schedule.

4.3 Operation

During testing, commissioning and normal operation, there will be little effect from sub-sea pipelines on the marine environment. Severe effects will be felt only in the event of a spill. In order to prevent such a spill, pipeline operators commission regular inspections of their sub-sea pipelines, and carry out repair and maintenance where necessary. This is clearly much more difficult in a sub-sea environment than on land and has necessitated the development of sophisticated sub-sea equipment and machinery.

4.3.1 Testing, Commissioning and Normal Operation

The possible effects on the physical and biological environment and on human activities of offshore pipeline commissioning are related primarily to the discharge of test water. The composition of the test water for a pipeline will need to be the subject of study, and dispersion modelling is often required in order to determine its effects on the area concerned. The use of hydrotest chemicals such as biocides and corrosion inhibitors is subject to prior statutory or regulatory authorization. However, in general it is likely that any effects, relating principally to the toxicity of the test waters, will be minor and short term.

During operation, the main concern is the effect of the pipelines and associated debris on fishermen. The Scottish Fishermen's Federation claimed that debris on the sea floor was much more damaging to fishing gear than the damage caused by pipelines and their associated rock dumps, yet some fishermen regularly claim that they lose or damage their gear on submarine pipelines. However, it is difficult to prove that this is the true origin of the damage. According to de Groot [3], fishing gear often hits rocks and ship wrecks, which cause the same sort of damage and effect as a pipeline would.

4.3.2 Emergency Planning in the Event of a Spill

Severe and long-term damage to the offshore environment, and in turn to human activities, can occur in the event of a pipeline spill. As a result, operators of sub-sea pipelines are required to prepare emergency response plans. In the North Sea there have only been two significant spills from pipelines [6]. One was on 7 April 1980 from the Thistle–Dunlin pipeline. The rupture, believed to have been caused by a vessel dragging an anchor over the line, was identified after a drop in pressure in the pipeline, and it was thought that about 1000 tonnes of oil was lost over a period of 25 minutes. The other was from Occidental's Claymore pipeline on 26 November 1986. In this instance the leak was from a valve spool and it was estimated that between 1000 and 2000 tonnes of oil was spilled. The slick moved towards the Norwegian coast, and when after 8 days of extremely rough weather it had still not broken up, Norwegian pollution control vessels were mobilized to monitor and to attempt recovery of the oil as it approached the coast. On 6 December, the wind changed direction taking the slick offshore and by 7 December the slick had dispersed. In view of the nature of the Norwegian coastline, and in particular the large numbers of fish farms, environmental teams were mobilized to survey the area, but only minor traces of oil that may have resulted from the spill were found.

4.3.3 Pipeline Integrity Monitoring

Sub-sea pipelines are regularly monitored to check for corrosion (to which they are particularly subject because of the salt water, despite cathodic protection measures), third-party interference (interaction with vessel anchors and fishing gear) and scouring and spanning (removal of the sea bed from beneath the pipe due to currents). A range of monitoring techniques are available:

- visual;
- electrical potential difference;
- magnetic particle inspection; and
- acoustic.

These are carried out using a variety of sensor packages towed by a survey vessel, mounted on a remotely operated vehicle or by pigging. The towed arrays contain an acoustic profiler which accurately images the pipeline and the seabed around it, and a side scan sonar which can be used to check for spans. Undersea vehicles are generally unmanned, remotely operated vehicles (ROVs). ROVs usually have on board a video camera, a trench profiler, a pipe tracker and a cathodic protection probing system. Pigs may be used for cleaning and for measuring pipe condition, diameter, roundness and wall thickness.

4.3.4 Pipeline Maintenance and Repair

Pipelines in a marine environment will require more maintenance and repair than land-based pipelines. In particular, they will need protection against scouring and spanning. This can be provided by a number of methods [6]:

- mechanical supports can be installed using diver-less installation systems;
- grout bag supports can be installed by divers or by ROVs;
- rock infill is particularly suitable where the seabed is hard and where long distances are involved; and
- trenching of shoulders is useful for short spans.

Other techniques tested include anti-scour mattresses and artificial seaweed. In some instances, it may be necessary to anchor a pipeline to the seabed using concrete, piles or clamps to prevent it from moving.

Pipelines may also need additional protection from third-party interference. This can be provided by trenching the pipeline or adding protective mattresses which can also be used on special sections such as tie-ins. In addition, cathodic protection anodes may need periodic replacement owing to excessive use, loss or damage.

Repair of a sub-sea pipeline may require a section to be cut out and replaced, which can be a very difficult or a relatively simple operation depending on the conditions. In shallow water divers may be used, but in deeper water this will not be possible and remote-controlled repair systems must be used.

4.3.5 Record Keeping, Monitoring and Audits and Reviews

Monitoring and auditing are becoming more important as companies have to become more and more accountable for their actions and, where information is not available, perhaps because it was not collected at the pipeline design and construction stage, reviews sometimes need to be carried out.

4.4 Decommissioning

Decommissioning of offshore pipelines is becoming an issue as many offshore oil and gas fields reach the end of their economic lifetimes. There may be some pipelines where removal is the favoured option because leaving them in place could cause possible interference with fishing gear. However, this may not be a viable option where the pipeline is buried, as its removal may cause more disturbance to the seabed, and thus to fishermen, than if it was left in place. It may become necessary to accurately map broken sections of decommissioned pipelines in order to make the information available to fishermen and other users of the sea [6].

5 Pipeline Landfalls

The term landfall is used to describe the connection between the marine or sub-sea section of a pipeline and the onshore section. In general terms, they cross the foreshore or intertidal area and any significant topographic features on land such as dunes or cliffs. Landfalls are part of the shore approach, which starts at the location that the main laybarge for the submarine section can operate in and commence laying pipe away from the coast towards the offshore destination. In some cases, the landfall has an intermediate section and a smaller first generation type laybarge capable of operating in inshore waters that will lay the pipeline between the main barge and the landfall. This is with an extended coastal shelf, or as mentioned above, under crossing classifications, which is often the case when deepwater gives way to inter-island areas. The point where an offshore pipeline comes ashore is known as a landfall. This interface of the land and the sea is the single critical element in a pipeline route that crosses the boundary between the two; often the energy levels impacting on the pipe from the marine environment, and hence the potential to damage the integrity of the pipeline, are greatest at this point and therefore the decision of where the landfall should be located requires considerable forward planning. Because of the critical nature of the landfall, it is considered here, in detail, as a separate issue.

5.1 Design

The planning process required essentially follows the same steps as for an onshore pipeline through the preliminary and detailed design phases, and an application for permission to construct a landfall is generally included within the same environmental statement as the application for the onshore pipeline associated with it. However, because both environmental and engineering constraints are often severe, it is particularly important that both are considered in great detail and that neither is considered in isolation. Environmental protection measures during landfall construction, while also following the same basic principles as for onshore pipelines, may require specialized techniques not used elsewhere. For these reasons, the landfall is often subject to separate study and separate technical reports can be produced.

5.1.1 Preliminary Design

At the preliminary design stage, it will, as with the remainder of the pipeline, be necessary to carry out consultations and undertake surveys to identify a location for the landfall. As the route of the cross-country pipeline and the sub-sea pipeline will depend on the landfall, it is clear that getting the siting right as soon as possible is of fundamental importance. The nature of the coastline bears a direct relationship to the ease of construction of the pipeline, and therefore a study of its physical characteristics will prove invaluable in helping identify a suitable location. However, in addition to such a study, a number of other parameters play a controlling role in the suitability of a particular stretch of coast for the construction of a landfall:

- the form and nature of the seabed close to the coast;
- marine energy levels; and
- technical constraints.

In order to determine the suitability of a particular location for a landfall, a list of features that are considered desirable can be compiled together with a list of features that would be considered undesirable. These are shown in Table 10.1. In simplistic terms, it is easier to construct a pipeline across a narrow, sandy beach than a coastline in which rocky outcrops predominate. In addition, sandy beaches are generally far easier to reinstate than rocky shores. Sandy beaches need little extra protection for the pipe whereas a rocky landfall needs the importation of sand for bedding the pipe. Marine energy levels are often higher on rocky coastlines.

However, environmental constraints cannot be categorized according to the coastline landform alone. All constraints need to be identified, and by careful planning individual constraints must be minimized or avoided. In general terms, landfalls should avoid population centres, specific wildlife sites and areas of outstanding scenic beauty. The planning of a prospective landfall must also assess

Table 10.1 Desirable and undesirable features of a landfall

Desirable features	Undesirable features
Stable beach – long-term integrity of the pipeline is preserved due to the sediment transport being minimal	*Population centres* – it is preferable to avoid population centres due to the effect of construction on the quality of life of residents
Water depth – a water depth of 15 m is preferable within 2–3 km of the shore; this reduces the amount and scale of excavation/dredging	*Rocky coastline* – span problems can occur; blasting may be required and restoration becomes difficult
Direct routeing (linearity) of the shore approach – this would minimize length and ensure a less complicated construction technique; there would be less disturbance to the intertidal zone	*Exposed area of coastline* – exposed coasts may lead to the exposure of the pipeline by marine processes
Ease of reinstatement – the ability to achieve 'full' restoration of the landfall is of importance	*Long shallow approach* – extensive dredging required and hence the impact on marine life is greater; scale of construction operations would be larger
Trenchable seabed to deep water – a trenchable sea-bed avoids 'free spans' that may lead to stress failure of the pipe	*Steep slopes* – pipeline installation and long-term stable reinstatement difficult
Sandy beach – sandy beach provides a soft bedding for the pipe, it is easily excavated and can be readily reinstated	*Non-cohesive sediments* – these are unstable and susceptible to bearing strength failures and sediment mass movement
Good land access – minimize the upgrading of the road that is necessary to allow plant access to the beach	*High-velocity nearshore currents* – these can interfere with pipe-laying activities and may entail additional protective measures
	Coastline designated as having landscape value and possibly experiencing recreational pressure – disruption must be minimized
	Nature conservation areas – the potential disruption of species and loss of habitat are to be avoided

the surrounding land in terms of access for heavy construction plant and for any infrastructure that will be necessary for the operation of the pipeline, such as a receiving terminal, a compressor station or a pressure reduction station. Other particular problems encountered in some types of coastline include the low load-bearing capabilities of some intertidal muds and salt marshes and the longer term stability and reinstatement problems associated with cliffs. The visual element is equally important in this regard, where the results of pipeline construction may be visible for a number of years. If hard structures are required to protect the pipeline and provide stability, then the construction may be visible for as long as the life of the pipeline. An ideal landfall would be a stable, sandy, sheltered, low-angle beach with no statuary designations relating to flora, fauna or scenic value.

It can be seen that, with all the constraints discussed above, a long stretch of coastline may have to be investigated before a suitable location for a landfall can be found.

5.1.2 Detailed Design

Once a suitable landfall site has been found, detailed field studies of the existing environment will be required, a precise route chosen and impact appraisal and prediction carried out in the same manner as for onshore pipelines. However, proposals for mitigative measures to overcome predicted impacts will often have to be innovative and very site specific.

5.2 Construction

5.2.1 Construction Methods

(a) Pull Ashore

In this case, the pipeline is welded on the laybarge and pulled ashore using winches. As mentioned above under the laybarge method for major crossings the laybarge anchor winches can be used with a sheave block on land providing they have sufficient capacity for the weight of pipe to be pulled. For bigger diameters and longer pulling lengths, winches will be on land and sized to suit the weight of pipe. Typically, 200 to 250 tonne linear constant tension winches will be used in tandem with an anchoring arrangement consisting of sheet steel piles or rock anchors. Depending on the number of purchases within the wire layout, up to 1200 tonnes of pipe can be pulled ashore in this way covering distances of up to 5 km.

The length of the landfall depends on the location that the laybarge can safely station itself at near the shore, and for a second or third generation laybarge of the sponson variety this will be around the 10 or 12 m contour relative to lowest astronomical tides (LAT). The larger ship-shaped third generation barges are more limited and cannot usually operate within the 15 m to 20 m contour. When selecting the landfall location, apart from the feasibility of laying the land section, water depths and the resulting length of landfall should be considered. If the length results in excessively high pulling loads, buoyancy may be considered or a smaller laybarge may be necessary to fill in the gap. Burial of the landfall section is usual, and the trench would normally be dredged using cutter suction dredgers or a combination of trailer and cutter suction. Trailer dredgers are ideal for bulk removal of material in open water whereas cutter suction dredgers can operate close inshore and can deal with consolidated sediments and clays. Blasting may be necessary before dredgers can be used in order to fragment hard material such as rock or over consolidated sediments. The immediate foreshore section of trench that cannot be reached by the dredger will be excavated by land-based equipment working off the beach or if this is not possible on a raised causeway or jetty. Trenches in the foreshore area are generally relatively unstable and can easily be in-filled especially during rough sea conditions. If this is likely, retaining walls using sheet steel piles will be constructed with the added advantage of reducing the disturbed area. Alternatives to dredging where ground conditions permit are post lay trenching systems such as underwater mechanical cutters or jetting machines. The need to backfill landfall trenches will again depend on ground conditions and self-restoration of the seabed may be environmentally more desirable than stockpiling excavated material for reuse or importing new material.

(b) Pull Offshore

This is the reverse of the pull ashore where pipe is fabricated into strings onshore and a barge mounted pulling system used to pull the pipe into the sea. The process is similar to the open cut method described for intermediate crossings, but with the pipeline end left capped on the seabed for recovery by the laybarge so that offshore pipe laying can commence. The reasons for doing this are usually associated with programming the laybarge to best suit the weather conditions, and where the landfall is long and complex in pulling terms, thus avoiding the expense of the laybarge during the landfall programme and the risk of expensive delays should the operation take longer than expected. The comments regarding trenching mentioned above under the pull ashore method (3.1) apply.

(c) Horizontal Directional Drilling

The methodology for directional drilling is discussed above under the minor and intermediate crossing sections and is much the same for a landfall. It becomes particularly attractive to use directional drilling when there are environmentally sensitive features such as reefs, tidal mud flats, cliffs and dunes, and has the obvious advantages shared by all the no-dig techniques. The length that can be directionally drilled is a limitation and should not be greater than approximately 1000 m. Consequently, the use of a small inshore laybarge may be considered to bridge the gap to where the main laybarge can operate. The usual arrangement is to drill from the shore and to use a laybarge or work barge at the offshore end to handle the reamers and eventually fabricate the pipeline. In order to avoid the stop start process of a laybarge, a length of pipe equivalent to the full length of the landfall is laid onto the seabed and connected to the final reaming run so that it can be pulled into the drilled hole. A variation to this is to forward ream using winches on a barge to pull the reamer from the drilling rig and eventually to pull the pipeline into the hole from a shore fabrication area, thereby avoiding the need for the laybarge. The risks of the drilling, reaming and pipe pulling operations are discussed above where directional drilling is mentioned for the minor and intermediate crossings. Undertaking the operation for a landfall introduces further risks associated with the complexity of handling drill or wash over pipe offshore and with the escape of drilling fluids onto the seabed. As with all methods, a full environmental impact assessment should be carried out to identify the risks and to enable mitigation measures to be introduced at an early stage. Despite these risks, horizontally drilled landfalls have been successfully carried out with significant cost savings compared to open cut methods and with minimal disturbance to the seabed and intertidal areas.

(d) Tunnelling

Tunnelling using the methods described above has been used for a number of landfalls and is particularly worthwhile where more than one pipeline is required to share the same landfall location. Notable examples are in Norwegian Fjords where the foreshore is rock and slopes steeply into the water enabling laybarges to lay pipe that can be pulled directly into the tunnel. The choice of construction method will be determined by the nature of the onshore and nearshore environment. As each landfall is unique, whichever is chosen will have to be adapted to suit the individual needs of the site. The examples discussed below serve to illustrate some of the ways that coastal environment environmental constraints have been managed in recent years.

5.2.2 Case Study: The Gas Interconnector Project (GIP) Landfall at Brighouse Bay

The critical points on the GIP pipeline that determined its route were the landfalls on the Irish and Scottish coasts. In particular, the landfall on the Scottish coast is in an area of significant environmental sensitivity and is classified as an area of Regional Scenic Significance and as a Site of Special Scientific Interest (SSSI); it is that landfall that is considered here (Fig. 10.4).

The steps outlined below indicate the planning stages followed to determine the optimum landfall location:

- determination of the area of interest, in this case the coastline of Dumfries and Galloway (obeying the straight-line principle between Moffat and Ballough);
- identification of all marine and terrestrial constraints in the vicinity of the landfall that may impact on the construction of the landfall. These were plotted on a constraints map; and
- hand-in-hand with the above approach, constraints had to be identified on both the subsea and landfall routes that may preclude a particular landfall option. This was considered by tabulating matrices having identified the parameters crucial to the construction of the pipeline.

Sub-sea constraints ranged from water depth and the nature and topography of the seabed to the presence of fishing grounds and military bombing ranges. Landline constraints included such considerations as landform relief, protected areas and the number of road and river crossings. An additional consideration in the early planning stages was the requirement for a compressor station as close to the Scottish landfall as possible. This was needed to generate sufficient pressure to permit the transmission of gas to Ireland. Owing to the attractiveness of the Dumfries and Galloway coastline, the siting of the compressor station was a crucial issue. Zones of Visual Influence (ZVIs) were identified to help identify the optimum location and hidden line perspectives were generated to ensure that any visual intrusion was minimized.

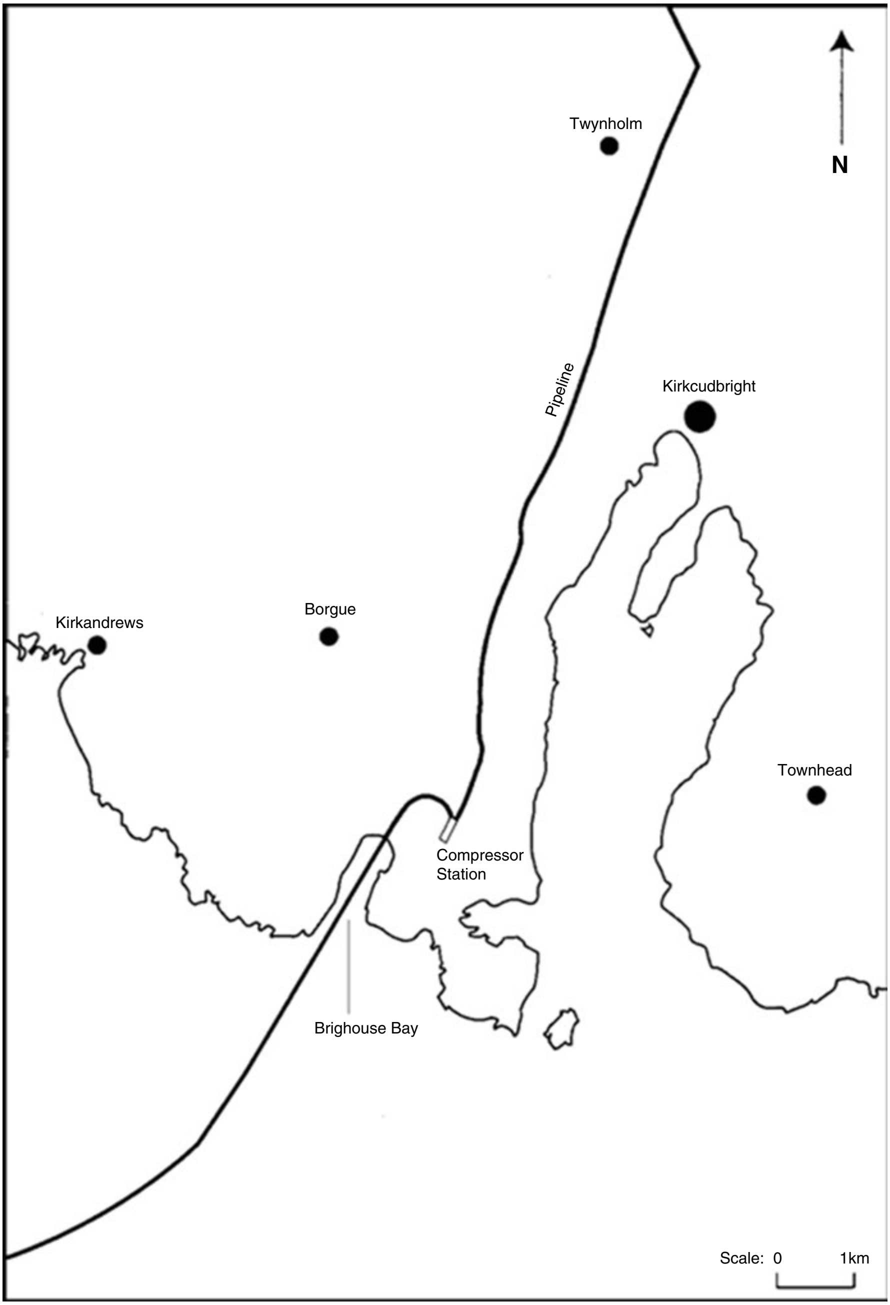

Fig. 10.4 Map showing the Gas Interconnector Pipeline landfall at Brighouse Bay

The exercise outlined above indicated that 13 potential sites were worthy of further consideration. In order to evaluate these sites, a matrix was completed that identified the following parameters grouped under six headings:

- marine environment: tidal streams, maximum fetch, site exposure, wave activity, tidal range, predominant wind direction, military activity;
- physical constraints: beach composition, beach dynamics, beach and nearshore profile, shore topography, sea access, presence of bedrock, water depth, land access;
- biological constraints: fragile habitats (land and marine);
- environmental constraints: recreational pressure, land designation, archaeology;
- availability of land for compressor; and
- construction: technical notes, resultant impact, restoration problems, relative extent of landfall construction.

The completion of a matrix identifying all the parameters considered to have an impact on the landfall location enabled a more considered judgement to be made as to the optimum landfall location. One of the most important criteria was the ability of a site to be fully reinstated. Having considered all the options, Brighouse Bay, near Kirkcudbright, was selected as being the optimum landfall location on the Solway coast.

Because of the environmental sensitivity of the Brighouse Bay landfall, it was more important that the constraints and specifications particular to the landfall location were made known to the contractor prior to their appointment. The constraints arose from a number of sources, including:

- the environmental statement;
- specific technical reports commissioned during the environmental assessment;
- stipulations attached to the Pipeline Construction Authorization;
- planning permission requirements;
- requirements detailed by statutory and non-statutory bodies; and
- general requirements as a result of far-ranging dialogue.

From the wealth of information arising from the project, the contractor for the Brighouse Bay landfall had to ascertain the environmental and engineering controls imposed on construction, and devise measures by which the environment and particularly sensitive areas would be protected. These were written into method statements by the contractor prior to construction and had to be submitted to Bord Gais Eireann, the planning authorities and other statutory bodies for approval.

Brighouse Bay was identified as the optimum landfall location in the south west of Scotland primarily because of the sandy nature of the bay and hence the ability of the landfall to be fully reinstated. However, because it experiences heavy recreational pressure and is designated as important for its landscape, wildlife and geological value, special construction methods were essential.

Scheduling construction activities for the winter months overcame, to a large extent, the problems associated with recreational pressure. However, Brighouse Bay is part of the extensive Borgue Coast SSSI and is particularly sensitive on botanical grounds. In particular, the presence of perennial blue flax, the pyramidal orchid and lesser meadow rue provides considerable botanical interest. A detailed botanical survey identified a zone where the distribution of the above species was sparse and therefore the line of the pipe was centred on this area. In fact, not one flax plant was identified within the 26 m working width. Therefore, although at first sight the bay appeared an unlikely choice for a landfall, the fact that full reinstatement could be achieved and that the botanical interest was not being compromised determined that Brighouse Bay was the optimum choice.

It was decided by environmental specialists that the best way to ensure rapid reinstatement of the sensitive dune area crossed by the pipeline at Brighouse Bay was to turf it. From the nine specific habitats that were identified by an ecologist, turfs 1 m square and 20 cm deep were cut, lifted on to pallets and transported some 500 m to a laydown area for the duration of the construction period. The location of the habitats and turves from each habitat were clearly identified and the turves from the different habitats were stored separately. In total, almost 3000 m^2 of turf were lifted and stored for reinstatement. In addition, hawthorn bushes up to 2 m high were transplanted, using a large excavator bucket to dig out the complete root system. The method proved to be very successful, and the following year it was only necessary to supplement the turves with seed collected from the site the previous summer.

5.2.3 Case Study: The Gas Interconnector Project (GIP) Landfall at Loughshinny

Loughshinny is the location of the Gas Interconnector Pipeline landfall on the Irish coast just to the north of Dublin (Fig. 10.5). It provides an example of landfall construction through a boulder clay cliff some 15 m high. Slumping on the face indicated that there was potential for erosion, although historical records showed that the current position of the cliff face was within 1 m of a survey conducted over 150 years ago.

The main concern at Loughshinny was to ensure that the methods utilized to stabilize the cliff face were in keeping with the surrounding area so as not to create a visually intrusive monument. The neighbouring headland and Martello Tower are a favoured area for walkers. To this end, a gabion base at the toe of the cliff was constructed as the main support. Layers of terram folded back on itself provided stability at the face. The cliff was seeded to provide protection against erosion and to blend in with the surrounding cliffs.

5.2.4 Case Study: The Theddlethorpe Landfall, Lincolnshire

In 1992, Conoco UK installed a 26 in. diameter natural gas pipe from the Murdoch Platform to the Theddlethorpe Gas Terminal (Fig. 10.6). This was the fourth landfall to be brought ashore over a short stretch of coastline.

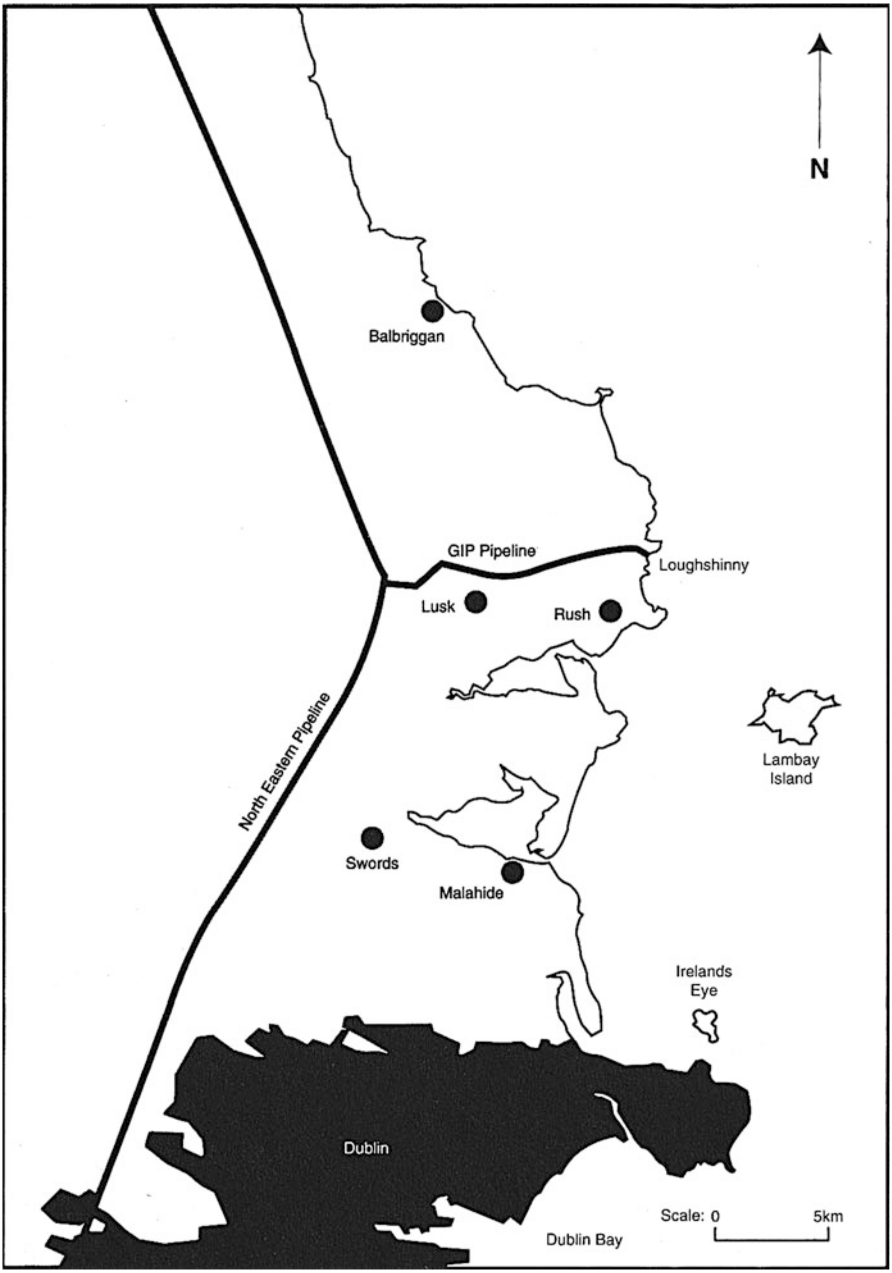

Fig. 10.5 Map showing the Gas Interconnector Pipeline landfall at Loughshinny

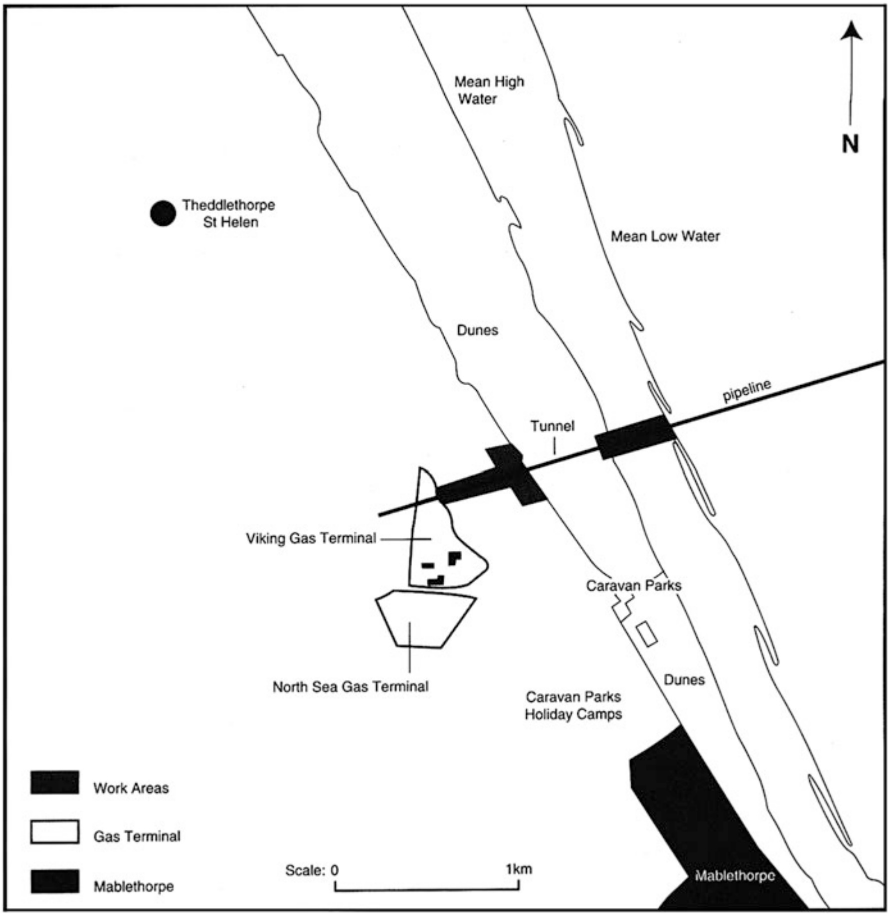

Fig. 10.6 Map showing the Theddlethorpe pipeline landfall

The flat, sandy beach at Theddlethorpe is backed by an ancient dune system that is designated as a National Nature Reserve. The previous three landfalls had utilized an open cut through the dune system. However, for this landfall Conoco proposed the construction of a concrete-lined tunnel, using conventional pipe-jacking techniques, in order to leave the ancient dune system intact. The pipe-jacking operation was successful with the majority of the ancient dunes remaining undisturbed, although the final 75 m of the operation had to be open-cut owing to a survey problem resulting in the concrete casing being off-line. The dunes affected at the edge of the ancient dune system, were covered by sea buckthorn, which grows vigorously, and were considered to be the least sensitive part of the system by English Nature. In order to aid dune stability, a marram replanting exercise was undertaken over the embryonic dunes adjacent to the beach.

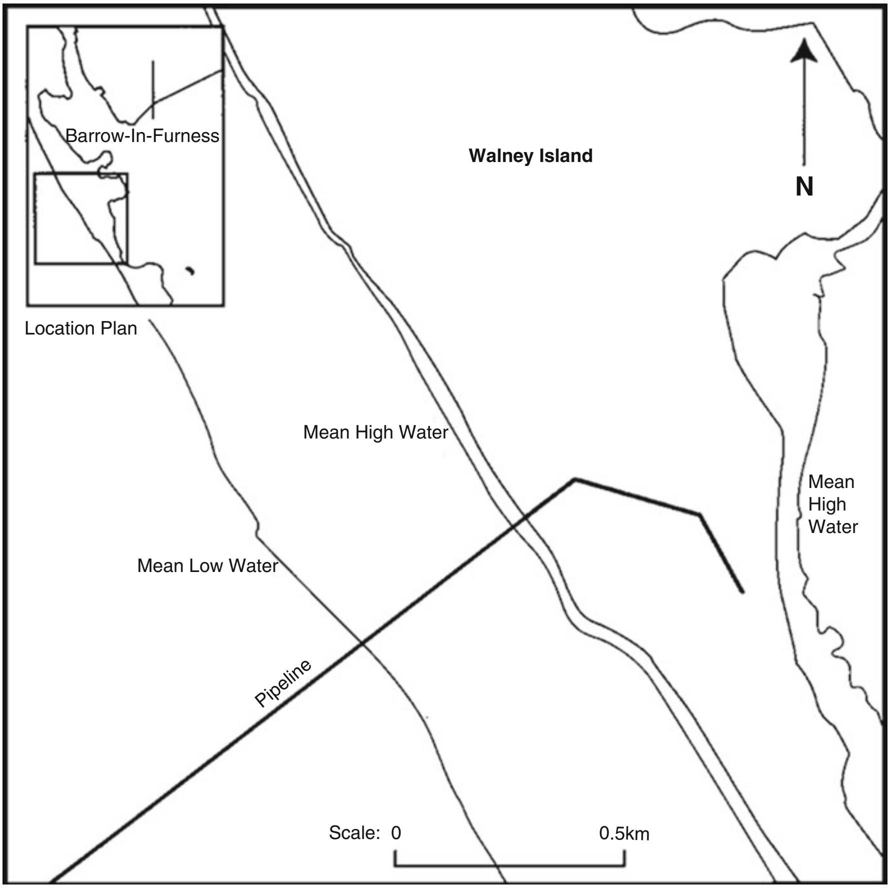

Fig. 10.7 Map showing the Walney Island pipeline landfall

5.2.5 Case Study: The Walney Island Landfall, Cumbria

British Gas constructed a 3.5 km long pipeline across Walney Channel, a tidal estuary comprising saltmarsh and intertidal flats near Barrow-in-Furness (Fig. 10.7). The pipe, which was winched from a string fabrication yard on the mainland across to Walney Island, forms part of a larger project to bring gas from the North Morecambe Bay gas field to a gas terminal at Westfield Point, to the south-east of Barrow-in-Furness.

Virtually, the whole length of the pipeline falls within the South Walney and Piel Channel Flats SSSI, and therefore it was not surprising that special construction techniques were needed to overcome a number of botanical issues. The most sensitive of these was the fact that the intertidal area contained the only recorded site in North West England of the nationally scarce *Zostera angustifolia* (narrow eelgrass). It was decided that it was not possible to store the sediment containing the

Zostera for the duration of construction in a manner that would allow the diurnal tidal inundation on which it thrives and at the same time prevent erosion of the material. Instead, in the hope that the plant would survive, and in the knowledge that this layer would contain the rhizomes and seed of the *Zostera* as well as a significant invertebrate population, shallow (10 cm) cuts of sediment were transferred from the most densely populated areas on the pipeline route to a ready excavated site away from the working area which contained relatively few plants but had similar tidal conditions. In this way, although the plants could not be replaced in their original location, disturbance was minimized.

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Chapter 11
Environmental Management and Technology in Oil Refineries

Michelle Grist

1 Purpose of an Oil Refinery

The process of petroleum refining is the physical, thermal and chemical separation of crude oil into marketable products. The primary products are:

- Fuels (e.g. motor gasoline, diesel and distillate fuel oil, liquefied petroleum gas (LPG), jet fuel, residual fuel oil, kerosene);
- Chemical industry feedstock (e.g. naphtha, gasoils and gases);
- Finished non fuel products:
  - Lubricating oils, greases and waxes
  - Bitumen and Asphalt
  - Petroleum Coke
  - Sulphur
- Energy as a by-product in the form of heat (steam) and power (electricity).

Crude oil is a mixture of many different hydrocarbons, other organic compounds and impurities (e.g. oxygen, nitrogen, sulphur, salt and water), with widely ranging properties from gases to substances with very high boiling points. As a result crude oils can vary greatly in their physical and chemical characteristics, depending on their origin. The size, configuration and complexity of a refinery are influenced by the market demand for the type of products, the available crude quality and requirements set by authorities. As these factors vary from location to location, no two refineries are identical.

In 2012 there were 655 refineries worldwide, with a total capacity of around 4400 Mta^{-1} [1]. The world's largest refining region is Asia (25 %), followed by North America and Europe (around 20 % each). In 2013 there were approximately

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_11

120 crude oil refineries in Europe. Due to overcapacity in the European refinery sector, very few refineries have been built in the last 35 years, with 95 % being built before 1981 and 44 % before 1991, i.e. in an era largely before environmental concerns were a major issue for the public, government or industry. Most refineries have since had upgrades and new units built but their overall structure will have remained essentially unchanged.

Refining can be separated into two phases (also sometimes known as simple and complex refineries) and a number of supporting processes.

- **Simple Refinery** which separates the crude oil into its various components or fractions based on different boiling ranges in a distillation column at atmospheric pressure. Vacuum distillation is used to lower the temperature at which the heavier fractions can be separated without thermal decomposition. The desired fractions are collected separately and sent for further processing. This is followed by a further distillation of the lighter components and naphtha to recover methane and ethane to fuel the refinery operations, LPG, gasoline-blending components and petrochemical feedstocks. The yield reflects the crude oil composition. Generally this gives relatively low yields of light products and high yields of residual fuel oil. An increasing number of refineries also have an isomerisation unit to enhance the octane rating of light naphthas. Some simple refineries have bitumen manufacturing facilities involving vacuum distillation and possibly bitumen blowing.
- **Complex refinery** which alters the molecular structure of some of the heavier distillation fractions into lighter molecules, with a higher commercial value, through a range of cracking, coking, reforming, and alkylation processes. This gives higher yields of light products and lower yields of heavy products than in a simple refinery. The majority of refineries worldwide have a fluid catalytic cracking (FCC) unit and an alkylation unit to increase yield and quality of the gasoline pool. In North America, where heavy fuel oil markets are limited, most refineries have a coker. In the European Union (EU), visbreakers are usually installed to reduce the quantity of residual oil produced in the distillation of crude oil and to increase the yield of more valuable middle distillates (heating oil and diesel) by the refinery. A visbreaker thermally cracks large hydrocarbon molecules in the oil by heating in a furnace to reduce its viscosity and to produce small quantities of light hydrocarbons. An Integrated Gasification Combined Cycle (IGCC) unit may also be used to convert the visbreaker residue to power, steam, hydrogen, and some waste streams. Very complex refineries can be designed to produce no residual fuel oil.

  An example of a complex refinery configuration is shown in Fig. 11.1.
- **Supporting operations** may include waste water treatment, energy generation, sulphur recovery, additive production, waste gas treatment, heat exchanger cleaning, blowdown systems, product blending and storage.

A refinery therefore consists of a complex system of stills, crackers, processing and blending units and vessels in which the various reactions take place, bulk storage tanks, and packaging units for products for immediate distribution to the retailer. Bulk storage tanks are usually grouped together in bunded tank farms. These “farms” are used for storage of both crude and refined products.

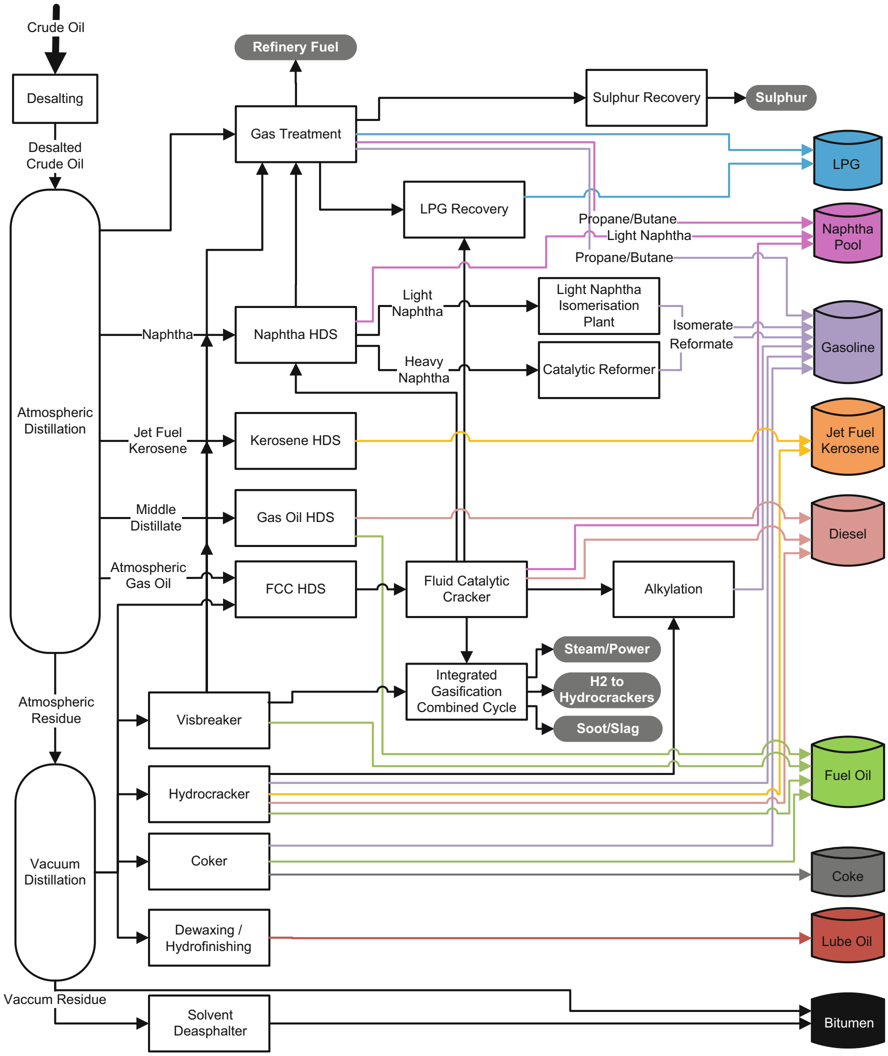

Fig. 11.1 Illustrative complex refinery configuration

Crude oil is transferred into the refinery by a combination of pipeline, roads, rail and marine tanker. Finished products are transferred out of a refinery to smaller distribution terminals by direct pipeline, marine tanker, road or rail.

2 Main Environmental Issues

Crude oil refineries process large amounts of raw materials and consume substantial amounts of energy and water. Emissions to air, water and soil are generated as well as various solid and liquid waste streams.

2.1 Emissions to Atmosphere

Oil refining is responsible for a significant proportion of air emissions from industrial activities. Table 11.1 provides an estimation of the contribution to key atmospheric emissions parameters reported for 2007–2012 by EU Member States, Iceland, Liechtenstein, Norway, Serbia and Switzerland in the oil and gas refinery sector.

Typically more than 60 % of refinery air emissions are related to the production of energy for the various processes. Power plants, boilers, heaters and catalytic cracking are the main sources of emissions of carbon monoxide and dioxide, nitrogen oxides (NOx), particulates, and sulphur oxides (SOx) to the atmosphere. Sulphur recovery units and flares also contribute to these emissions. Nitrous oxide (N_2O) is released principally from FCC regenerators. Catalyst changeovers and cokers release particulates. Volatile organic compounds (VOCs) are released from storage, product loading and handling facilities, oil/water separation systems and, as fugitive emissions, from flanges, valves, seals and drains. Other emissions to the atmosphere are H_2S, NH_3, BTX (mixtures of benzene, toluene, and the three xylene isomers), CS_2, COS, HF; heavy metals are also released as particulates.

Refineries will typically have large numbers of permitted routine process release points, which will vary in size and throughput from very small to stacks from large combustion plant. Permits stipulate limits for specific, named pollutants. In order to control these emissions, the facility will be required to monitor emissions and submit findings to the regulatory authorities. In most instances it will be illegal to operate and emit pollutants to the atmosphere without a valid permit. In Europe this is controlled by the Industrial Emissions Directive 2010/75/EU (Integrated Pollution Prevention and Control).

2.1.1 Combustion Related Emissions

NOx Control

Nitrogen oxides are generated in the combustion process from the oxidation of atmospheric nitrogen and nitrogen in the fuel. The primary or process related techniques to prevent NOx emissions to air, as listed in Table 11.2, are: to reduce the nitrogen content in the fuel; to reduce the atmospheric nitrogen oxidised in the combustion process through reduction in oxygen; to reduce the residence time; and to reduce the combustion temperature. Secondary or end-of-pipe techniques serve to reduce or eliminate NOx from the discharges.

Dust and Metal Emissions Control

Particulate emissions are of interest because of their potential adverse impact on health, especially those with a diameter less than 10 μm (PM_{10}) and less than 2.5 μm

Table 11.1 Contribution of oil refining to the European air emissions (2007–2012) [2]

	Greenhouse Gases (CO_2 Equivalent)		Carbon Monoxide (CO)		Non-Methane Volatile Organic Compounds (NMVOC)		Nitrogen Oxides (NOx)		Sulphur Oxides (SOx)		Heavy Metals		Fine Particulates (PM10)		Chlorinated Organic Substances		Other Organic Substances	
Reporting year	kt	#sites	kt	#sites	kt	#sites	kt	#sites	kt	#sites	kt	#sites	kt	#sites	kt	#sites	kt	#sites
2007	185,059	217	76	31	206	116	201	126	567	116	0.2	193	7.7	43	0.0	9	2.2	79
2008	191,767	232	86	32	182	117	189	129	504	110	0.2	204	8.4	42	0.1	11	2.0	84
2009	182,638	236	76	30	158	113	172	128	433	110	0.2	199	6.9	41	0.1	10	1.9	80
2010	175,353	231	51	29	135	106	152	120	373	106	0.2	178	6.0	38	0.1	10	1.3	74
2011	172,951	207	56	27	118	96	142	110	353	103	0.1	144	5.2	34	0.1	9	1.2	69
2012	170,134	208	53	29	131	100	139	110	305	101	0.1	134	5.4	33	0.1	10	1.3	62

Table 11.2 Control techniques to prevent or reduce NOx emission from combustion

Approach	Technique
Selection or treatment of fuel	Use of gas to replace liquid fuel
	Use of low nitrogen refinery fuel oil e.g. by selection or by hydrotreatment
Combustion modifications	Staged combustion: air staging and fuel staging
	Optimisation of combustion
	Flue-gas recirculation
	Diluent injection
	Use of low-NO_X burners
Secondary or end-of-pipe techniques	Selective catalytic reduction
	Selective non-catalytic reduction
	Low temperature oxidation
	SNOx combined technique. Dust is removed first using electrostatic precipitation and is followed by catalytic processes to remove sulphur compounds as commercial grade sulphuric acid and NOx as N_2. SOx removal is in the range of 94–96.6 % and NOx removal is in the range of 87–90 % [1]

($PM_{2.5}$). Emitted refinery particulates may range in size from less than a nanometre to the coarse dusts arising from the attrition of catalyst.

The most hazardous refinery particulates contain heavy metals and polycyclic aromatic hydrocarbons, therefore, a reduction in the particle content reduces the metal emissions from the refinery.

Particulate emissions from refineries come from:

- Flue-gas from furnaces, particularly soot when firing liquid refinery fuels if there is sub-optimal combustion;
- Catalyst fines emitted from FCC regeneration units and other catalyst-based processes;
- CO boilers;
- Handling of coke, coke fines and ash generated during the incineration of sludges.

Particulate minimisation techniques include avoidance by replacement or treatment of the fuel, improved combustion and secondary particulate removal as shown in Table 11.3.

Particulate removal techniques are dry, wet, or a combination of the two. The main dry techniques include cyclones, electrostatic precipitators and bag filters. Some wet techniques such as scrubbers may also be used mainly as finishing treatment.

The range of emissions from the majority of European refineries is between 4 and 75 tonnes of particulates per million tonnes of crude oil processed [1]. The lower end of the range being achieved in refineries using substantial amounts of gas combined with effective dust removal.

Table 11.3 Control techniques to prevent or reduce dust and metal emissions

Approach	Technique
Selection or treatment of fuel	Use of gas to replace some or all liquid fuel
	Use of low nitrogen refinery fuel oil e.g. by selection or by hydrotreatment
Selection of catalyst	Higher quality FCC catalyst
	Attrition-resistant catalyst
Combustion modifications	Optimisation of combustion, e.g. improved air-fuel mixing; increase excess air; use of combustion improver additives; increase air pre-heat
	Atomisation of liquid fuel
Secondary or end-of-pipe techniques	Electrostatic precipitator
	Centrifugal separation, i.e. cyclones
	Fabric and solid bundle blowback filter
	Wet scrubbing

Table 11.4 Control techniques to prevent or reduce SOx emissions

Approach	Technique
Selection or treatment of fuel	Use of gas to replace liquid fuel
	Treatment of refinery fuel gas
	Use of low sulphur refinery fuel oil e.g. by selection or by hydrotreatment
Combustion modifications	Optimisation of combustion
	Atomisation of liquid fuel
Secondary or end-of-pipe techniques	Non-regenerative scrubbing
	Regenerative scrubbing
	SNOx combined technique

SOx Emissions Control

The main source of SOx emissions in the refinery is during energy production. During combustion, the sulphur in the fuel is transformed to a mixture of SO_2 and SO_3. As sulphur is a component of crude oil there is a direct relation between the sulphur in the feed to a combustion process and the sulphur oxides in its flue-gas.

SOx emissions also emanate from the catalytic cracking process and sulphur removal and recovery operations. To control SOx emissions, refiners can adopt one or more of the measures in Table 11.4.

In a Sulphur Recovery Unit, the fuel gases (methane and ethane) are separated from the hydrogen sulphide (H_2S) using a solvent (typically amine) to dissolve the H_2S. The fuel gases are removed for use in other refinery processes and the solution is heated and the steam stripped to remove the H_2S gas. The H_2S rich gas streams are then treated in a high efficiency sulphur recovery unit using the Claus process for bulk sulphur removal and a tail gas treatment process to bring sulphur recovery yield to 99 % or more [3].

CO Emissions Control

Carbon monoxide (CO) is an intermediate product of the combustion processes, in particular in understoichiometric combustion conditions. CO emissions may actually be increased with the application of combustion modifications to reduce NOx emissions. This can be limited by careful control of the operational parameters. In addition, the following techniques may also be used:

- Constant delivery of liquid fuel in the secondary heating;
- Good mixing of the exhaust gases;
- Catalytic afterburning;
- Catalysts with oxidation promoters.

CO_2 Emissions Control

A feasible abatement technology for CO_2 is not available. CO_2 separation techniques are available but the problem is the storage and the recycling of the CO_2 and therefore the emphasis must be on emissions reduction. Options to reduce CO_2 emissions are:

- Effective energy management;
- Use of fuels with high hydrogen contents;
- Effective energy production techniques.

2.1.2 Flare-Related Emissions

Flares are used for safety and the environmental control of discharges of undesired or excess combustibles and for surges of gases in emergency situations, upsets, unplanned events or unanticipated equipment failure. Flaring is a source of air emissions and leads to the burning of potential valuable products.

Techniques for the reduction of emissions are given in Table 11.5.

Table 11.5 Control techniques to prevent or reduce flare-related emissions

Approach	Technique
Correct plant design	Sufficient flare gas recovery system capacity.
	Use flaring only as a safety system for other than normal operations (start-up, shut down, emergency).
Plant management	Organizational and control measures to reduce the case of flaring.
Flares design	Efficient combustion of excess gases when flaring from non routine operations.
Monitoring and reporting	Continuous monitoring of gas sent to flaring and associated parameters of combustion.

2.1.3 Non-Methane Volatile Organic Compound (NMVOC) Emissions

NMVOC emissions originate from the evaporation and leakage of hydrocarbon fractions associated with potentially all refining activities, e.g. fugitive emissions from pressurised equipment in process units, storage and distribution losses, and waste water treatment evaporation. Typical sources are control valve stems, flanges, compressor/pump seals, tanks and loading facilities.

The main sources are:

- Fugitive emissions from piping;
- The flare system;
- The waste water treatment plant;
- Storage tanks and refinery dispatch stations.

Techniques to reduce NMVOC emissions focus on prevention and detection of fugitive emissions as shown in Table 11.6.

2.1.4 Odours

The majority of all public complaints regarding refineries are due to odours. Hydrogen sulphide and methyl mercaptan are among the most common odorants from a refinery and are typically generated from storage tanks, sewage systems and oil/water separators. Although they have odour thresholds significantly lower than levels known to cause toxicity, they are nonetheless most often associated with annoyance at levels just exceeding their odour threshold.

The main reduction techniques are covered under atmospheric (see Sect. 2.1) and waste water emissions (see Sect. 2.2).

2.2 Emissions to Water

Potential water contaminants in refinery effluent are:

- Acids, alkalis (pH);
- Oil (free and dissolved);
- Sulphides;
- Ammonia/nitrates;
- Cyanides;
- Heavy metals;
- Heat;
- Other organic materials;
- Nutrients;
- Settleable solids;
- Colour;

Table 11.6 Control techniques to prevent or reduce VOC emissions

Approach		
High integrity equipment		Valves with double packing seals.
		Magnetically driven pumps/compressors/agitators.
		Pumps/compressors/agitators fitted with mechanical seals instead of packing.
		High-integrity gaskets (such as spiral wound, ring joints) for critical applications.
		Floating roof storage tanks equipped with high efficiency seals.
		Fixed roof tank with floating covers connected to a vapour recovery system.
Vapour balancing		The expelled mixture is returned to the liquid supply tank and replaces the pumped-out volume.
Vapour recovery	Absorption	Dissolution in a suitable absorption liquid.
	Adsorption	Retention on the surface of adsorbent solid materials e.g. activated carbon (AC) or zeolite.
	Membrane gas separation	Processed through selective membranes to separate the vapour/air mixture into a hydrocarbon enriched phase (permeate), which is subsequently condensed or absorbed, and a hydrocarbon-depleted phase (retentate).
	Two stage refrigeration/condensation:	Cooling to condense and separate as a liquid.
VOC destruction	Thermal oxidation	Refractory-lined oxidisers equipped with gas burner and a stack.
	Catalytic oxidation	Oxidation accelerated by a catalyst by adsorbing the oxygen and the VOCs on its surface
Leak Detection and Repair (LDAR) programme		An LDAR programme is a structured approach to reduce fugitive VOC emissions by detection (e.g. using sniffing or optical gas imaging methods) and subsequent repair or replacement of leaking components.
VOC diffuse emissions monitoring		Full-screening and quantification of site emissions can be undertaken with an appropriate combination of complementary methods,

- Taste and odour producers;
- Toxic compounds.

Table 11.7 shows the contribution of oil and gas refining to European water emissions 2007–2012.

The largest volume of waste water arises from the distillation, catalytic cracking, and catalytic reforming processes. The waste water from distillation includes condensed steam from the tower (called oily sour water), which contains hydrogen sulphide, ammonia, and oily waste water if barometric condensers are used for vacuum distillation.

Table 11.7 Contribution of oil refining to European water emissions (2007–2012) [2]

	Heavy metals		Inorganic substances		Chlorinated organic substances		Other organic substances	
Reporting year	Tonnes	#sites	Tonnes	Count	Tonnes	Count	Tonnes	Count
2007	66	161	136,040	76	20	13	8015	143
2008	69	193	296,781	79	13	14	7413	175
2009	60	207	263,687	80	28	17	6420	180
2010	47	213	259,635	82	39	15	6521	166
2011	41	203	246,777	77	8	12	5929	128
2012	37	199	225,780	76	24	14	6833	140

Table 11.8 Control techniques for the control of aqueous emissions

Treatment stage	Technique
Cooling water reuse	Closed cooling water circuit where water is cooled.
Waste water pre-treatment	Use of sour water strippers to remove H_2S and NH_3 from process waters prior to reuse/treatment.
	Pre-treatment of other water streams to preserve treatment performance,
Waste water treatment	Oil recovery using gravity separators, plate interceptors and buffer/ equalisation tanks.
	Suspended solid and dispersed oil recovery using gas flotation and sand filtration.
	Biological treatment and clarification using fixed bed and suspended systems to reduce the biological oxygen demand and phenolic compounds.
	A polishing step using sand, dual media or multimedia filtration to remove fine particulates.
	External waste water treatment – performed by a plant outside the installation.

Other waste water pollutants include spent potassium hydroxide steam from alkylation, and sour water from visbreaking.

Rainwater falling into process areas may also become contaminated due to entry into production areas, tank systems, secondary containment systems and loading/ off loading areas. Good housekeeping practices are required to minimise such contamination.

A refinery site therefore generates a mix of waste water streams containing both soluble and insoluble substances which become pollutants when released. Historically, treatment techniques were directed at reducing the amount of pollutants and the oxygen demand exerted by the waste water prior to release. These end-of-pipe techniques are mature and emphasis is now shifting to prevention and reduction of contaminated waste water streams prior to final treatment units (Table 11.8).

2.3 Soil and Groundwater Contamination

Contamination of soil and groundwater may arise due to the loss of crude, refined products or water containing hydrocarbons as a result of storage, transfer and transport operations. Most refineries have some areas that are contaminated by historical product losses. Current refinery practices are designed to prevent spillages and leaks to the ground. Historically however, the awareness of the potential risks of these contaminated areas was low. The two main issues therefore are the prevention of new spills and the remediation or the remedial control of historic contamination.

2.3.1 Prevention

Measures to control new spills are basically the same as those to control aqueous emissions together with ensuring that areas where oil is regularly handled are covered with an impermeable surface and drain to a dedicated oily water sewer and than tanks are double lined or bunded.

2.3.2 Remediation

Small quantities of contaminated soils or liquids may be managed as hazardous wastes and either treated on site or removed off site for treatment and/or disposal. Larger quantities and gross contamination may require more significant intervention and clean up, especially where it is a hazard or migrating off site. Monitoring regimes are often necessary.

2.4 Waste

The amount of waste generated by refineries is small if it is compared to the amount of raw materials and products that they process. Table 11.9 shows the generation and different waste routes according to the European Pollutant Release and Transfer Register (E-PRTR) declarations.

Waste is classified in Europe according to the European List of Wastes [4] as either hazardous or non-hazardous depending on properties defined in the Waste Framework Directive (WFD) [5] Annex III. It is a requirement under the WFD that wastes are managed according to the proximity principle i.e. as close to the source as possible, but in some cases e.g. where no appropriate facilities exist within the country, it will be necessary to send the wastes outside the country for disposal or recovery.

Table 11.9 Contribution of oil refining to European waste transfers (2007–2012) [2]

	Hazardous waste outside country			Hazardous waste within country			Non-hazardous waste			
	Disposal	Recovery	Total	Disposal	Recovery	Total	Disposal	Recovery	Total	
Reporting year	kt (#sites)	kt (#sites)	kt	kt (#sites)	kt (#sites)	kt	kt (#sites)	kt (#sites)	kt	Total waste kt
2007	3 (5)	37 (44)	40	822 (147)	459 (136)	1282	484 (69)	699 (75)	1183	2505
2008	14 (13)	29 (50)	43	1172 (171)	495 (171)	1667	967 (69)	773 (78)	1740	3450
2009	4 (8)	41 (52)	45	1215 (166)	484 (164)	1699	338 (71)	683 (75)	1021	2765
2010	3 (12)	43 (47)	46	438 (169)	383 (164)	821	231 (75)	476 (89)	708	1575
2011	3 (5)	83 (44)	86	462 (156)	1014 (162)	1476	299 (76)	627 (96)	927	2488
2012	1 (5)	71 (34)	71	324 (154)	542 (157)	866	368 (71)	602 (84)	969	1906

Table 11.10 Control techniques for the management of waste

Technique	Description
Prevention	Good plant operation, materials handling and storage, housekeeping and economy in the use of chemicals.
Sludge pre-treatment	Prior to final treatment the sludge are dewatered and/or de-oiled (by e.g. centrifugal decanters, gravity separators, filtration or steam dryers) to reduce their volume.
Reuse of sludge in process units	Delayed coking technologies can use oily sludges as part of their feedstock.
Segregation of waste streams	According to waste characteristics to enable management via the waste hierarchy.
Spent solid catalyst management	Return to third party (i.e. manufacture or off-site specialist) for recovery or reuse in off-site facilities or correct disposal.
Removal of catalyst from slurry decant oil	Decant oil sludge from process units (e.g. FCC unit) can contain significant concentrations of catalyst fines. These fines need to be separated prior to the reuse of decant oil as a feedstock.

The WFD introduced the concept of the waste hierarchy which states that wastes should be managed in the following order of priority:

- Prevention;
- Preparing for reuse;
- Recycling;
- Other recovery, particularly energy recovery;
- Disposal.

Most oil refinery waste consists of:

- Sludges, both oily (e.g. tanks bottoms) and non-oily (e.g. from waste water treatment facilities);
- Other refinery wastes in liquid, semi-liquid or solid form (e.g. contaminated soil, spent catalysts from conversion processes, oily wastes, incinerator ash, spent caustic, spent clay, spent chemicals, acid tar);
- Non-refining wastes, e.g. domestic, demolition and construction.

Oil retained in sludges or other types of waste represents a loss of product and, where possible, efforts are made to recover such oil. Waste disposal depends very much on its composition and on the local refinery situation. The high operating costs of waste disposal mean that much priority has been given to waste minimisation schemes and management (Table 11.10).

Segregation of waste by its characteristics is fundamental to ensuring efficient management according to the waste hierarchy. Good plant operation, materials handling and storage, housekeeping and economy in the use of chemicals will result in the minimisation of wastes for disposal.

Recycling waste materials for reuse may in many circumstances provide a cost-effective alternative to treatment and disposal. The success of recycling depends on both the ability to segregate recoverable and valuable materials from a waste and the ability to reuse waste materials as a substitute for an input material.

Petroleum sludge wastes are typically water-in-oil emulsions that are stabilised by fine solids. Sludge accumulates in refineries from equipment failure, training and periodic tank cleaning.

Processes for treating petroleum sludge include centrifugation, thermal desorption, solvent extraction, and hydrothermal processing. Electrokinetics is a developing technology that is used for in situ remediation of heavy metals and organic contaminants from saturated or unsaturated soils and sediments.

Process wastes should be tested and classified as hazardous or non-hazardous based on local regulatory requirements and international good practice and disposed of appropriately using authorised and licensed waste disposal operators.

A significant proportion of the non-petroleum outputs can be recovered and sold as by-products, e.g. sulphur, acetic acid, phosphoric acid and recovered metals from catalysts.

Increased use is made of third party waste contractors for off-site treatment, reclamation and disposal. Materials commonly reprocessed off-site by chemical and physical methods include oils, solvents, and recovered metals from catalysts and scrap metal. A strong commitment is required from the recycler not only to upgrade the waste materials for sale or exchange but also in finding suitable markets. The waste producer has a "duty of care" to ensure that the waste is correctly treated and disposed of by any third parties used.

2.5 Energy Consumption

Refineries consume large amounts of energy to generate electricity, heat and steam. Some refineries have installed combined heat and power plants. Typically more than 60 % of refinery air emissions are related to the production of energy [1].

Typical resource and energy consumption of process crude oil for an oil refinery utilising between 200 and 500 ha for land-use would require [6]:

- Total energy between 2100 and 2900 Mjt^{-1} of processed crude oil;
- Electric power between 25 and 48 kWht^{-1} of processed crude oil;
- Fresh make-up water between 0.07 and 014 $\mathrm{m}^3\mathrm{t}^{-1}$ of processed crude oil.

Good design and management of energy systems are important aspects of minimising the environmental impact of a refinery, bearing in mind the highly integrated and interdependent nature of most processes (Table 11.11).

2.6 Water Consumption

Large volumes of water are used on a continuous basis in a refinery to maintain the water balance in the steam, cooling water, utility service water and emergency fire water supply circuits.

Table 11.11 Control techniques for the management of energy consumption

Technique	Description
Design techniques	
Pinch analysis	Systematic calculation of thermodynamic targets for minimising energy consumption of processes.
Heat integration	Exchanging heat between streams to be heated and streams to be cooled.
Heat and power recovery	Use of energy recovery devices such as waste heat boilers, expanders/power recovery in the FCC unit, use of waste heat in district heating.
Process control and maintenance techniques	
Process optimisation	Automated controlled combustion to lower the fuel consumption combined with heat integration for improving furnace efficiency.
Management and reduction of steam consumption	Mapping of drain valve systems to reduce steam consumption and optimise its use.
Use of energy benchmarking	Participation in ranking and benchmarking activities in order to pursue a continuous improvement by learning from best practice.
Energy efficient production techniques	
Combined heat and power	Production of heat (e.g. steam) and electric power from the same fuel.
Integrated gasification combined cycle (IGCC)	Production of steam, hydrogen and electric power from a variety of fuel types with a high conversion efficiency.

The water usage depends both on purpose and complexity of the refinery. The CONCAWE 2010 survey of 100 refineries [7] reports annual median total fresh water intake of 5.7 Mm^3a^{-1} but these range from 0.14 to 37.8 Mm^3a^{-1} with the annual median fresh water per tonne throughput being 0.70 m^3a^{-1} but similarly ranging from 0.1 to 8.6 m^3a^{-1}.

It is typical for abstraction or water use permits to detail the volumes of water abstraction allowed, as over abstraction can affect local communities and also natural resources.

Drinking water sources, whether public or private, should be protected so that they meet or exceed applicable national standards or in their absence the current edition of World Health Organisation (WHO) Guidelines for Drinking Water Quality [8].

Water requirements for site workers and staff can be met through mains water supply or ground/surface water abstraction which should be properly assessed using testing techniques/lab analysis and water drawdown modelling.

In most refineries, some internal water streams are commonly used as desalter wash water, such as condensate water and steam-stripped sour water. There is scope for increased water reduction and reuse in refineries, which will lead to reduced size and costs of both water make-up and end-of-pipe treatment facilities. This is known as water stream integration where whenever possible steps are taken to prevent, reduce, recycle and reuse process water, rainwater, cooling and even contaminated groundwater to reduce the amount of fresh water intake and process water for end-of-pipe treatment.

Potential improvements include:

- Reusing unstripped/stripped sour water as wash water;
- Passing sour water from atmospheric and vacuum unit condensates to a stripper in enclosed systems;
- Segregation of non-contaminated water streams to enable reuse as process water;
- Prevention of spillages and leaks;
- Use of vacuum pumps to replace steam ejectors;
- Reuse of waste water generated by the overhead reflux drum, e.g. as a desalter wash water;
- Optimising water reuse by application of side-stream softening to blowdown streams.

3 Environmental Management Systems (EMS)

Environmental management is an integral part of the management process in most oil refineries and in Europe it is a permit requirement to demonstrate the application of Best Available Techniques (BAT). This includes that an EMS is implemented and adhered to that incorporates the following features [1]:

1. Commitment of the management, including senior management.
2. Definition of an environmental policy that includes the continuous improvement for the installation by the management.
3. Planning and establishing the necessary procedures, objectives and targets, in conjunction with financial planning and investment.
4. Implementation of the procedures paying particular attention to:
   (a) Structure and responsibility
   (b) Training, awareness and competence
   (c) Communication
   (d) Employee involvement
   (e) Documentation
   (f) Efficient process control
   (g) Maintenance programmes
   (h) Emergency preparedness and response
   (i) Safeguarding compliance with environmental legislation
5. Checking performance and taking corrective action, paying particular attention to:
   (a) Monitoring and measurement
   (b) Corrective and preventive action

(c) Maintenance of records
(d) Independent internal and external auditing in order to determine whether or not the EMS conforms to planned arrangements and has been properly implemented and maintained.

6. Review of the EMS and its continuing suitability, adequacy and effectiveness by senior management.
7. Following the development of cleaner technologies.
8. Consideration for the environmental impacts from the eventual decommissioning of the installation at the stage of designing a new plant, and throughout its operating life.
9. Application of sectoral benchmarking on a regular basis.

The level of detail and nature of the EMS will generally be related to the nature, scale and complexity of the installation, and the range of environmental impacts identified. Many refineries have EMS certified against ISO 14001:2004 [9] or EMAS [10] which require continuous improvement in performance.

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Chapter 12
The Marketing, Distribution and Use of Petroleum Fuels

Malcolm F. Fox

1 Introduction

The oil industry is a very complex business, as described elsewhere in this book, comprising exploration, extraction, transport, refining, distribution and the final use of its products. Exploration and extraction are examined elsewhere; the marketing, distribution and use implications of this complex business are best examined in the logical order of:

– transport of crude oil by tankers, vessels in general and pipelines,
– refinery operations on crude oil to produce hydrocarbon products,
– distribution issues of refined hydrocarbon products,
– environmental issues of the final use of hydrocarbon products,
– trends in global fuel consumption in the next decade.

2 Transport of Crude Petroleum and Refined Products

2.1 Potential Risks in Transport and Delivery

2.1.1 Ocean Tankers and Waterway Barges

To commence at the initial production, oilfield production of crude oil is usually distant from the refineries which process it into petroleum products. Pipelines transport crude oil within continents; between continents, the economics of delivery requires very large tankers to transport crude oil to refineries. Increasingly countries

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_12

producing crude oil construct or expand their own refinery capacity and export refined fuel products by specialist tankers.

2.1.2 Ocean and Waterway Contamination

The transport economics for large volumes of crude oil between continents requires very large vessels of the order of 250–500 k dwt capacity, or more. There are complex global flows of crude oil between source oil fields and consuming nations/continents, graphically shown in Fig. 12.1. The inherent collision hazards of moving large volumes across oceans are addressed by improvements in vessel design and construction, advanced navigation aids and increasingly sophisticated meteorological predictions.

Various incidents have occurred when these operational conditions were not fully applied. Highly publicised tanker incidents have caused massive spillages of crude oil or heavy oils; increasingly sophisticated and effective emergency containment devices recovered major amounts of the spilled oil material; but the residual, unrecovered, oils caused extensive long term damage to plant life, sea animals, birds and fish.

The previous, conventional, construction of oil tankers was single hulled, where the tank walls were very close to or formed the outer skin of the vessel. Double hulls, or double bottoms, are now required in specific marine regions to give additional protection against accidental damage from vessel collisions, collision with solid obstacles or grounding on rocks and reefs which cause leaks and spillages. Advanced navigation systems only deliver enhanced navigation standards when maintained and calibrated to high standards and then operated by competently trained and informed staff.

Crude oil spillages may occur during transfer to, or from, the tankers and jetties resulting from equipment failure, malfunction and or human error. Central to achieving and maintaining high standards of pollution risk prevention in the transport and storage of crude oils, as also for refined petroleum products, is:

– high quality training of operators,
– careful, experienced design of tanks, pipelines and further bund containment,
– well-maintained secure connection couplings,
– a regular program of hardware and procedural inspections.

Automated metering of pipe flows, tank volumes and continuous/periodic inspection devices complement the surveillance of crude oil petroleum distribution and storage. Whereas inadvertent collisions and vessel damage can cause very heavy but very localized crude oil pollution of the oceans, more widespread sea water pollution can occur when tankers discharge ‘oily water’ wastes. These wastes arise from tank washings and cleaning between cargoes, as crude oil usually throws down deposits on standing in tanks, from water used for ballast and from the bilges. The ‘Marpol Convention’, the International Convention for the Prevention of Pollution from Ships (1973) [1] has steadily developed under the auspices of the

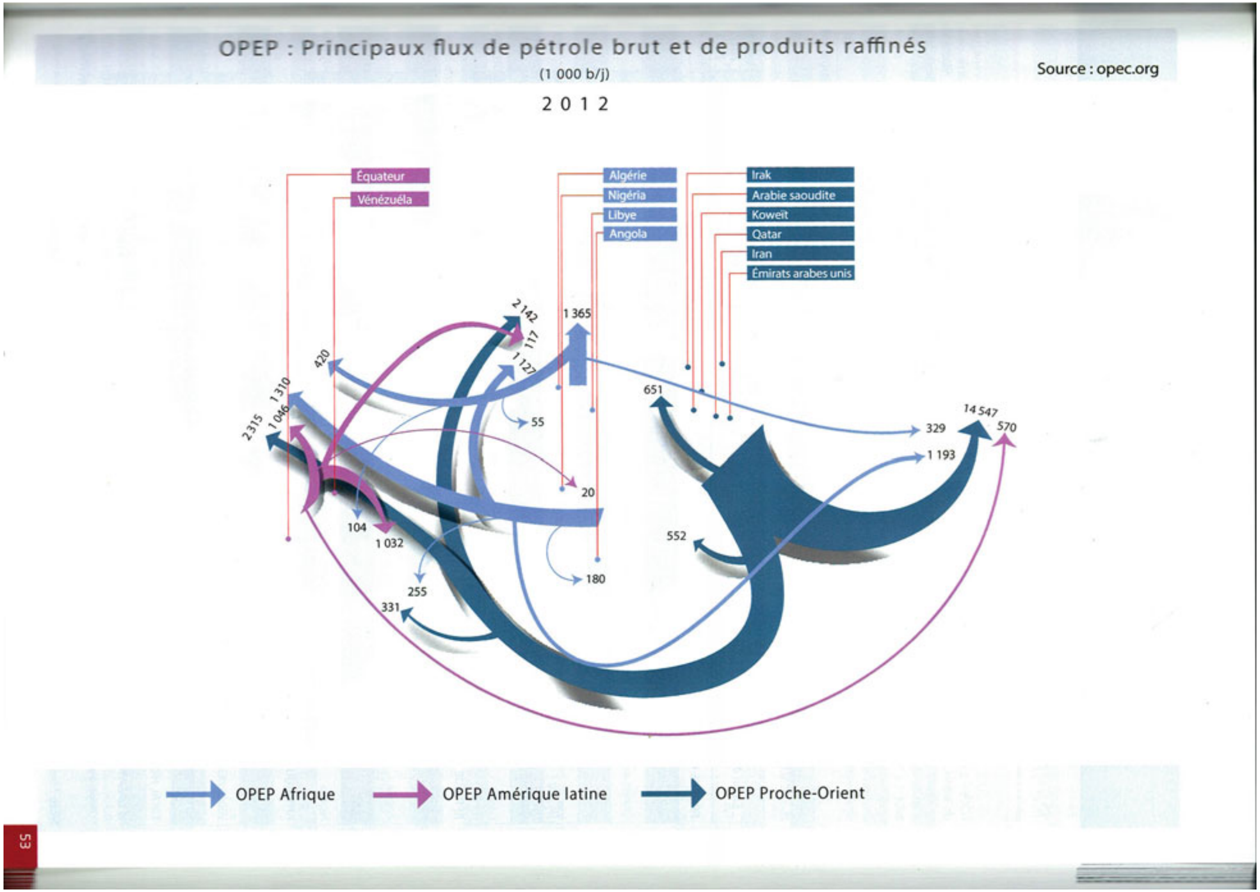


Fig. 12.1 Global crude oil distribution patterns, 2013, between continents (From Recueil des Notes D'Information Economique, Edition Janvier 2014, Comite' Professional du Petrole, ISSN 1156-2560)

International Maritime Organisation [2]. Oil-contaminated water from tank cleaning, ballasting and from the bilges must be drained to.

a 'slop tank' or separator tank to recover the oil and settle the aqueous phase. Contaminated water is either stored for discharge to shore tanks and subsequent appropriate treatment there, or if the oil content is below 15 ppm it may be discharged to ocean, provided the vessel is not in certain defined areas. Discharging oil-contaminated water to oceans must be fully recorded and documented; standards are closely regulated to IMO standard and subject to inspection at all times. But an increasing number of seas ***totally*** prohibit the discharge of oil-contaminated water; since 1999 contaminated water discharges from vessels are banned around the coastline of the UK and North Western Europe, the North Sea (1991), the Baltic Sea, enclosed seas such as the Mediterranean, Black and Red Seas, the Gulf of Aden (1989) the wider Caribbean (1993) and Antartica (1992). All vessels, ocean going and coastal, must store their contaminated water washings or bilge waters and discharge them to special treatment systems on shore.

2.1.3 Emission Control of Hydrocarbon and Other Vapours from Distribution

The odour of crude oil varies according to geographical source from the unpleasant to the very nauseous; the vapours above crude oil and heavy oils almost always contain hydrogen sulphide, which is extremely unpleasant but also very toxic with an OSHA TWA 8 h limit of 10 ppm, together with other similarly unpleasant compounds. Hydrogen sulphide can be treated with nitrogen heterocyclic compounds to sequester sulphur into relatively innocuous compounds with the associated emission of alkyl amines. Whilst this treatment removes the offensive smell of hydrogen sulphide, it does not reduce the sulphur content of the crude oil/heavy fuel.

The vapours of refined oils are potentially flammable, forming explosive mixtures with air within tanks or confined spaces during loading and transport. 'Volatile Organic Compounds' (VOC's), must be carefully controlled to avoid fire and/or explosion hazards or asphyxiation of staff. IMO has established standards for vapour collection and control for ocean vessels, coastal and inland tankers and also at loading/unloading terminals. In addition, uncontrolled VOC emissions from oil company sites such as refineries, storage and distribution sites are increasingly required to be controlled by government environmental control policies, e.g., the EU countries [3].

When tanks are loaded with hydrocarbon fuels, equivalent volumes of fuel vapour/air mixture are expelled by discharge through high level and/or high velocity vents. The more volatile the fuel, such as petrol, the greater the potential hazard; the explosive mixture range for petrol is between 1 and 10 %. When loading petrol into tanks or barges, several studies have shown the hydrocarbon/air mixture above the liquid to be within the explosive limits for up to 80 % loading time. This potential hazard requires a very high level of operational care and technical plant for safe operation, for recalling first, that loading a volume of liquid into a tank, whether fixed on land or in a vessel will displace an equivalent volume of an air/VOC vapour mix and second, that the uncontrolled expelled vapour can vary between 5 and 35 % hydrocarbon, indicates the scale of the problem. The potential of the aggregate emission levels from volatile petrol and jet fuel on a continental basis such as Europe is high and must be controlled.

Whilst vapour control systems were initially installed for the protection of staff operating coastal tankers and barges, the emphasis has expanded to include vapour recovery as well. Vapour control and collection systems have become more important as the number of refineries has decreased to a smaller number of larger units from which distribution of hydrocarbon fuels by sea and inland waterway has necessarily increased. The principle is to contain the volatile hydrocarbon vapours within a tank which has (i) a vapour collection header with a high velocity vent to atmosphere, so that vapours are dispersed and do not 'pool' in the vicinity of the tank or vessel, (ii) a pressure/vacuum releasing vent, (iii) a detonation arrestor unit, and (iv) a connector to an on-shore vapour recovery unit.

Vapour recovery on loading/unloading has the form of liquid and vapour exchange using a closed, liquid/vapour piped system. Very similar systems are used for road and rail tanker loading/unloading. Several technologies are available for vapour recovery and separation/recovery when loading/unloading small tankers and barges. These include absorption into liquids of low volatility, onto activated charcoal, low temperature condensation or differential diffusion through a specific membrane. Of these, only diffusion separation is a single operation; vapour recovery following separation by the other various means requires either separate desorption or liquid separation and vapour regeneration. The initial requirements for vapour emission control and recovery were set by the German/French/Dutch authorities controlling the Rhine commercial inland waterway.

2.1.4 Road and Rail Tankers

Tanks by rail or road are used as secondary distribution where coastal and inland waterways do not reach and also where areas and depots are not supplied by pipeline. Delivery by rail has further and wider geographic penetration of areas than river transport and an economically effective distribution method which is safer than road tanker distribution and reduces heavy vehicle congestion. Rail tankers were usually top-loaded from gantries at refineries or major fuel depots and unloaded from a bottom connection into a reception tank. Bottom loading is now preferred because it reduces VOC emissions because of less liquid turbulence than top loading. Light fuels such as petrol and jet fuel are usually transported in un-insulated tanks. For fuels of much higher viscosities and waxing potential, insulated and/or heated/able tanks are used to prevent partial solidification. It is important to recall that the flow-point temperature of the heavier fuels is also time dependent – a tank car left to stand for several days in cold temperatures ***above*** the measured flow point temperature of that fuel can slowly form wax in that time.

The main commodities transported by rail tank cars in North America are crude oil and ethanol, together accounting for 68 % of the total. Other major flammable commodities transported by rail tank car are methanol, benzene and styrene. Detailed construction and use regulations apply to rail tankers and the design, operation and use of road tankers is similar. High standards of tanker design, maintenance, driver training and operation are enforced and the accident rate is low. But not low enough – recent freight tank car accidents in North America:

– Cherry Valley, Ill., one fatality, 31 tank cars involved, 885 m^3 of ethanol released and burned (2009),
– Arcadia, Ohio, 3006 m^3 of methanol released and burned (2011),
– Lac Megantic, Quebec, 47 fatalities and 6000 m^3 crude oil burned (2013),
– Heirndal, North Dakota, 684 m^3 crude oil burned (2015),

have led to increased construction standards, DoT 117 (US) and TC-117 (Canada). From October 1st. 2015, new tank cars must have thicker steel walls, more protection at each end, thermal insulation and improved protection for pressure relief and bottom-outlet valves. A program to replace or upgrade the existing tank car fleet must begin in 2017 and by 2021 tank cars must have electronically actuated pneumatic brakes which act simultaneously, rather than sequentially, to prevent 'accordion-type' pile-ups. Tank cars can form very long trains of up to 120 tank cars, between 1 and 2 km long, containing millions of gallons of the same commodity, 'unit trains', whereas finished hydrocarbon products can be delivered as smaller volumes within 'manifest' trains mixed in with other cars, both goods ('boxcars') and non-flammable, tank cars.

From the enormous volumes conveyed by single ocean tankers through to the multiple volumes delivered by many rail or road tankers, the potential risk increases from multiple transfers and transport as spills, leaks, evaporation and catastrophic releases from accidents. The petroleum industry has many years' experience of handling its products, incorporated into Regulations (of individual country's Acts as primary legislation) and 'Codes of Practice', nominally/essentially voluntary but guidance for 'good practice' which is wise and prudent to follow. The Regulations, Codes of Practice and Guidelines seek to minimise or avoid pollution of the oceans, coastal waters, rivers and canals, soil and groundwater and the atmosphere. One example is 'Guidelines for the Design, Installation and Operation of Petrol Vapour Emissions at Distribution Terminals', by the Energy Institute [4]. These controls, in their various forms, are closely and continually reviewed as a process of continuous improvement; continuing issues are the proper application of the extant legislation and good practice. New issues arise as the technology of measurement develops and more appropriate, rigorous, legislation is introduced.

2.1.5 Pipelines

Pipelines divide broadly into those which (i) carry crude oil from oil field to refinery across a continent or to a terminal for loading onto tankers for transport between continents, or (ii) those which distribute large masses/volumes of refined products to major consumption sites such as airports or major distribution terminals. Pipelines are unobtrusive, being well buried, yet economical because of their high transport throughput capacity. The maps in Figs. 12.2 and 12.3 shows the extensive

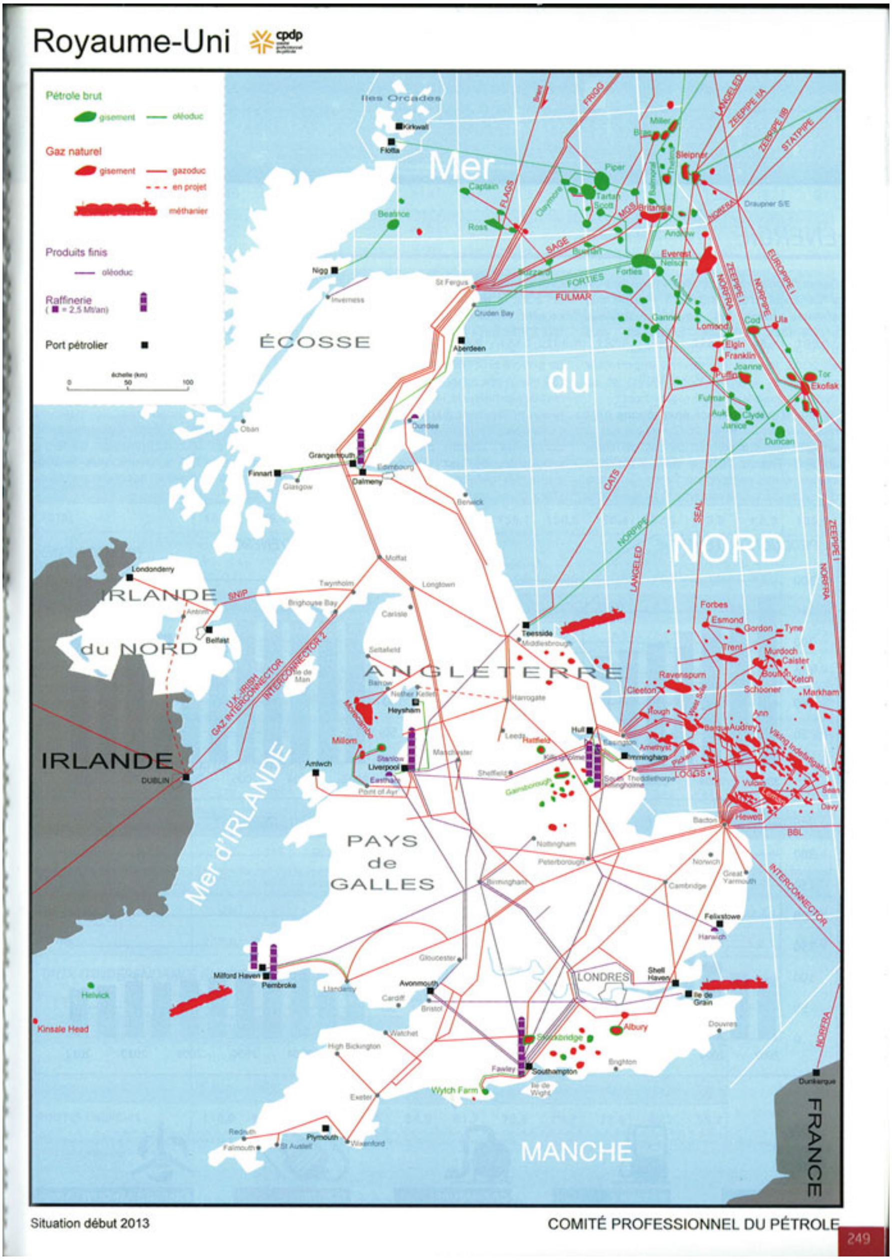


Fig. 12.2 Crude oil, refined product and natural gas pipelines in the United Kingdom 2013 (From Recueil des Notes D'Information Economique, Edition Janvier 2014, Comite' Professional du Petrole, ISSN 1156-2560)

Fig. 12.3 Oilfields and crude oil, refined product and natural gas pipelines in Northern Europe and the United Kingdom 2013 (From the International Petroleum Encyclopaedia, Penwell Corporation, Tulsa, Oklahama, USA, www.penwellbooks.com)

network of both crude oil and product pipelines across the UK and Northern Europe, respectively, which are surprisingly comprehensive; similar complexity exists for North American pipelines. As pipelines are buried in the permeable ground they are potential sources of contamination if they physically fail or are damaged by a third party. 90 % of pipeline leakage incidents are caused by the actions of third parties.

The fore-seeable, preventive, operational/design measures of pipe weld integrity and corrosion prevention are used to preserve the integrity of pipelines. The nature of the ground in which the pipeline is buried determines further corrosion protection measures, such as cathodic protection or an impressed current to counteract corrosion processes. Performance of the pipeline integrity measures has been of a high standard when a constant program of maintenance, protection and testing/assessment has been established and followed. When these standards are not maintained, pipelines corrode, leak and burst. ‘Third party’ incidents typically occur where a construction vehicle severs a sub-surface pipeline. These incidents may be rare but nevertheless occur due to a lack of communication or due diligence by a building contractor as to what is beneath the site they are working on. In some developing countries criminal activity drills or hacks into pipelines to steal petrol, kerosene or diesel, whatever is passing through at the time. The consequences are usually dire and catastrophic, leading to severe fires when the stolen refined products ignite.

Product pipeline utility is enhanced by sending consecutive batches of refined product separated by travelling ‘plugs’, colloquially known as ‘pigs’, propelled by the hydraulic pressure within the pipelines. Complex pipework allows the introduction and removal of the ‘pigs’, which are potential sources of spills. Different designs of ‘pig’ can remove deposits from the walls of pipelines to maintain their efficiency or measure pipeline wall thickness to assess corrosion effects. Long distance pipelines from refineries to refined product distribution depots allow the final delivery of fuel to service stations as a relatively short road tanker journey.

Whilst raising the level of technological control, the introduction of electronic flow and tank level measurement control devices brings their own, new, set of issues. The Buncefield (UK) fuel storage depot catastrophic fire and explosion on 11th December 2005 was a major devastating incident for the depot and surrounding area. Occurring early on a Sunday morning, the explosion measured 2.4 on the Richter Scale; it was fortunate that the full, weekday, complement of staff was not on site and that no one was killed there nor in the surrounding housing. The Buncefield Depot had a capacity of 270 M litres of fuel. The (UK) Major Incident Investigation Board (MIIB) concluded [5] the incident was due to failure of a single liquid level alarm on a petrol storage tank. The malfunctioning single level switch alarm allowed the tank to overflow when loading through a long pipeline from a distant refinery. The excess fuel pool around the tank eventually ignited and the ensuing fire and explosion wrecked the entire site, a major regional storage and distribution centre, together with extensive damage to surrounding property. The MIIB Report also identified a range of improvements in the construction and operation of fuel storage depots. New measurement and control technologies bring their own new safety issues.

2.1.6 Soil and Groundwater Contamination

EU countries protect soil groundwater from hydrocarbon contamination from inadvertent spillage or deliberate discharge through site licensing, enforced by substantial fines for pollution incidents [3]. Hydrocarbon pollution of soil and groundwater is aesthetically unpleasant but groundwater is a major source of drinking water. The presence of trace hydrocarbons taints water and is detectable by taste at sub-ppb levels. Lighter hydrocarbons will evaporate in short time, but then present a flammability or explosion hazard in confined spaces such as drains and sewers. Heavier hydrocarbons discharged to waters as fuel or lubricating oil do not evaporate and their surface film excludes oxygen from watercourses to kill fish and aquatic life; heavier hydrocarbons also kill wildlife by coating them with oil, or a partial emulsion of oil and water, upsetting their digestive and respiratory organs and killing off their food source.

The first action to prevent contamination of soil and groundwater is ‘good site housekeeping’ to prevent leakages, seeps, weeps and spills of hydrocarbons from their transport and use. ‘Good site housekeeping’ practice, however mundane but properly practiced, is very effective in reducing hydrocarbon pollution of soil and groundwater. ‘Good site housekeeping’ commences with proven, effective design for containment of hydrocarbon spillages as hard, impermeable, surface standing for storage areas with substantial bunding (containment) structures to contain equally substantial spill volumes. Good practice in high standards of pipe connector design and maintenance, together with high standards of connection procedures, are proven to reduce hydrocarbon spillage. Equally important is good stock volume keeping such that tanks are not over-filled. Tank closure security is important to the extent of locking tank valves against criminals stealing the contents but in the process spilling large volumes of hydrocarbons; it also protects against mindless vandalism; the last two issues are increasingly important for relatively isolated or single tanks on factory premises.

The importance of preventing hydrocarbon environmental pollution is further emphasized by the high costs of cleaning soil, groundwater and watercourses together with the associated substantial fines. Water and river authorities are very competent at finding the sources of hydrocarbon emissions, quickly containing the environmental pollution, sampling and rapidly identifying the detailed nature of the contaminating material, obtaining interim legal intervention and enforcement as necessary and then prosecuting those controlling the source of the pollution.

Legislative limits are set for the maximum concentrations of hydrocarbons emitted to air or water from an industrial site, not solely for depots dealing with hydrocarbons. Maximum hydrocarbon contaminants in water are set for surface water flows, river water, effluent discharges to surface water and to sewer. The concentration limits for environmental pollution are usually set for an individual industrial site in a ‘consent to discharge’ legal document, monitored by either periodic manual or continuous automatic sampling. Effluent limits to surface water or sewer are set having regard to the manageable load upon the downstream treatment system and charged accordingly. Whilst the form of the legal controls on emissions from business premises may appear to vary from one country to another, the underlying principles of control established by European Directives ensure that they are very similar in operation [3].

The effluent discharge limits to surface water or sewer from business premises are drawn from whatever is appropriate to control the business activity conducted on the site, such as the temperature increase between input and output water flows, the pH, dissolved, suspended and precipitated solids, turbidity, colour, taste and odour in, or of, the effluents, together with dissolved organic carbon (DOC), total organic carbon (TOC), biological or chemical oxygen demand, (BOD & COD). Each of these is determined by international established and maintained standards of analysis.

2.1.7 Contamination Protection Above Ground

Solid, impermeable surfaces are used to protect ground soil from contaminating hydrocarbon spills and leaks at distribution and delivery depots. These surfaces are installed in areas used for storage tanks as containment bunds, beneath raised tanks, loading and unloading areas, from where spilled hydrocarbon fluids can be collected and retrieved. The integrity of the surfaces is crucial; the Inquiry into the Buncefield disaster [4] noted leaks in the integrity of some of the storage tank bunds.

Overfilling of tanks is a major source of hydrocarbon spills, arising from miscalculation of the volumes already in the tank and the amount to be delivered, or inattention to the completion of tank filling and the consequent overflow. Attention to detail and/or an automatic cut-off are preventative measures.

2.1.8 Hydrocarbon Recovery and Treatment

Oil recovery technology directly from spillages has improved such that high percentage efficiency can be achieved. But the recovery efficiency depends upon the nature of the soil, the water course and the nature of the hydrocarbon spilled. Complete recovery/removal of the spilled hydrocarbons is usually not achieved and further treatment of contaminated soil is necessary. Disposal of land contaminated by hydrocarbons to landfill is now more restricted as to the hydrocarbon content, from higher standards/lower allowed concentration limits, and recognition that the problem is not being addressed but moved ‘along the line’ for other people to deal with the problem at a later time. The soil volumes to be treated can be very high. Previous minor/moderate contamination of a development site might require removal of the top 0.5 m, or up to 1 m, of the site topsoil, very large volumes to be lifted, transported and disposed in a safe manner. Alternative on-site treatment methods can be used – incineration to destroy hydrocarbons present in soil can be destructive of the soil and expensive of fuel to operate;

solvent extraction is effective but care must be taken to avoid extra emissions arising from the solvent used. Biological treatment of hydrocarbon-contaminated soil can be effective for appropriate combinations of soil type and grade/type of hydrocarbon but requires time and space to be effective.

Contaminated groundwater is recovered using oil/water separators in the first instance, as in drainage sumps for water run-off from hard surfaces/hard standing, specified in the Building Regulation site consent. The efficiency of simple oil/water separators does not give sufficiently acceptable purity for the separated water and it must be treated further. Techniques for further water purification include (i) relatively gentle physical separation using tank settlement or plate impingement separators, (ii) more active physical treatment such as fine filtration, sedimentation settling, flocculation by settlement-promoting additives or air/froth flotation, or (iii) biological treatments using biofilters of various designs such as reed beds, air pumped through aerated ponds of the water being treated, or very intensive treatment by the activated sludge process. After further slow settlement, high quality water effluent from these treatments can be discharged to a water course.

2.1.9 Final Storage and Distribution

The manner that refined oil products, primarily fuels, are delivered to the final customer depends upon the volume size by final user, frequency of demand/use, nature of the oil product and the way in which the fuel will be used. ‘Use’ can vary between the limits of a fixed site, high daily consumption of a heavy fuel oil to the distribution of multiple light distillate fuel transactions in relatively small volumes of ~50 l to light road vehicles from a service station:

– **Single High Volume Users:** Building oil-fuelled electricity power stations, or utilities, close to, or contiguous to, an oil refinery was practiced in the late 1900s. Fuel oil for the power station was readily pumped ‘through the fence’ from the adjacent, or close by, refinery site, minimising large transport costs. Oil fuel is stored in above-ground tank farms on impervious hard standing within containment bunds as a reserve supply and extra capacity when the power station fuel consumption is greater than the refinery can supply, as may occur during winter.

Oil-fuelled electricity generation by steam-raising and its subsequent use in turbines has declined in Europe because of the increasing price of fuel oil (up to mid-2014!) and has lost out to gas-fired generation. Natural gas fuel allows:

– a primary gas turbine to directly drive an electrical generator,
– use the exhaust in a waste heat boiler in a second cycle to raise steam and generate electricity through a separate turbine,
– some systems use the second cycle exhaust to generate hot water as a third stage of heat and thermal transformation.

The scheme is a ‘Combined Cycle Gas Turbine’ electricity generation, CCGT, with a substantially higher thermal efficiency than coal or oil firing to raise steam for electricity generation. The ready availability of natural gas in Europe, from its own sources on land or North Sea or through pipelines from Norway, Russia or Aral/Caspian Independent States has reduced the electricity generation market for fuel oil. Some countries such as Japan are heavily dependent upon importing liquefied natural gas, LNG, in specialized, refrigerated and pressurized tankers. The development of ‘fracking’ in North America has led to the United States becoming one of the, if not the, major global hydrocarbon producer nations and a net exporter of natural gas and other condensible gases such as ethane.

Similar siting and supply considerations apply to petrochemical complexes adjacent, or close to, refineries. If there is no fuel oil pipeline supply to a power station or petrochemical complex, then they are supplied by rail tank car deliveries. As emphasized previously, ‘good housekeeping’ on site is necessary to minimize fuel oil spillage by preventive maintenance of pipelines and standard operating procedures for the filling/drawdown of tanks, to prevent over-filling and associated spillage hazards.

– **Small/Medium Industrial Users and Service Stations:** The design, construction and use regulations for oil storage tanks and pipework in small to medium factories are set to a high standard. Regulatory formats may differ between countries but they are very similar in technical design. The EU Directive 94/63/EC [6] controls Volatile Organic Compounds emissions with the aim of reducing them by 90 %. ‘Stage 1’ controls apply to the loading/unloading of petrol into road and rail tankers, inland waterway vessels and petrol stations. ‘Stage II’ controls apply more stringent controls to service stations above a certain size and to the construction of new sites. Unfortunate experience has shown that without these controls oil storage installations will contribute to soil and ground water contamination by leaks, seeps and weeps and to water course contamination by run-off.

Fixed oil product tank storage for small/medium industries divide into ‘above ground’ and ‘buried’. The operational hazards are either over-filling in the short term or leakage by corrosion in the long term. Both eventualities lead to the requirement of the tank being sited on an impermeable surface or with a containment device of sufficient volume beneath. ‘Over-filling’ is prevented by ‘good housekeeping’ tank management and a high status level alarm; regular ‘dipping’ by a gauge length is recommended to check that the calculated or indicated volume of hydrocarbon fuel is actually present. The Energy Institute ‘Guidance on Design and Operating Limits for Fuel Storage Tanks at Retail Filling Stations’ [7], sets common standards for the definition of operating limits for retail fuel storage tanks. The Guidance also links to Approved Code of Practices (ACOPs) and the (UK) Health and Safety Executive (HSE) ‘Dangerous Substances and Explosive Atmospheres Regulations Approved Code of Practice and Guidance, L133, ‘Unloading Petrol from Road Tankers’. The Guidance is intended for sites fitted with overfill prevention devices and/or high level alarms. The Energy Institute has also prudently established ‘Guidelines for an Emergency Action Plan for Fire and Explosion Risks at Filling Stations’ [8].

The number of UK service stations as retail outlets has steadily declined from a peak of ~40,000 in 1967 down to ~8600 in 2014 [9]. The main loss has been smaller service stations, particularly for those without other viable supporting commercial activities such as garages, car sales or shops. A major effect has been the growth of the supermarket service stations now with a market share of 43 % of total UK fuel sales. Vehicle numbers in the UK increased to 35.9 M in 2014, giving 4170 vehicles/service station in 2014, compared to only 319 in 1967! The importance of the safety controls described previously is emphasised by the average total fuel throughput per service station of 3270 t/pa. The undifferentiated (petrol + diesel) average fuel consumption/vehicle in ton/year has steadily decreased by 11.5 % from 2004 to 2014, reflecting real increases in the vehicle fleet fuel efficiency.

Steel tanks/containers corrode; the issue is controlling the corrosion rate which can be minimized by applying, and maintaining, appropriate coatings and also various anti-corrosion electrochemical methods. Nevertheless, as entrained or dissolved water settles to the bottom of all tanks, corrosion and subsequent leaks occur. To anticipate these leaks in due course, a 'double bottom' is increasingly specified for above ground oil storage tanks on the basis that the inner tank surface will corrode and leak into the second containment, with a leak detector to notify operators. For smaller tank capacities, rotationally moulded polyethylene/polypropylene tanks, internally treated to reduce long term diffusion, are increasingly used for industrial and domestic installations.

The immediately preceding paragraphs assume that the hydrocarbon product storage is fixed. A development over the last 20 years has been the extensive use of 'Intermediate Bulk Containers', commonly referred to as 'IBC's', to conveniently transport and store liquids and solids, including hydrocarbons. IBC's have various forms and constructions: for liquids they are rotationally moulded thick wall polythene 1 m^3 cube tanks held within a stout wire lattice framework. Bottom drain and top filling connections are recessed to prevent damage and the base is designed for fork lift truck handling. IBC's are ubiquitous and bridge the gap between drums of various sizes and fixed tank installations; for the same external volume they contain a significantly greater volume than an assembly of drums. IBC's combine the advantages of a transport and storage capability and may be stacked. The intrinsic pollution problem with IBCs arises when they are damaged and leak, most frequently punctured by the mis-directed blades of a fork lift truck; the preventive, corrective, action is extensive training of fork lift truck operators.

It has been common practice for service stations to bury oil storage tanks 2–3 m below ground so that leaks are minimized by containment for the more volatile fuels, particularly for petrol. Previous practice of a minimal anti-corrosion coating on a buried steel tank has shown, over time, that corrosion in soil can be severe and the fuel gently leaks into the subsoil until the rate of loss is noticed. Best practice is to place the tank into a buried impermeable bund, combined with an impermeable lining to the steel tank. With these extra cost requirements, a GRP (glass reinforced plastic) storage tank becomes competitive because of the intrinsically corrosion resistant nature of its material. The same design considerations for the associated buried steel pipework must also be applied, such as being laid in impervious channels and regularly tested for leaks. Service station pipework systems are extensive because the filling connections for several tanks of different fuel grades are to the side of the site for operational convenience, for the delivery pipes to the filling pumps and also a pipework system to collect fuel tank vapours in an absorbent canister such that filling the tanks does not emit hydrocarbons to the atmosphere, EU Stage 1 or II controls, as described previously [6]. As the fuel is drawn down from the tank, the flow of replacement air through the absorbent canister desorbs the fuel vapours into the tank.

Delivering volatile fuels from a service station pump into a vehicle's tank displaces an equivalent volume of fuel vapour. Where hydrocarbon emissions are strictly controlled to minimize overall emissions, as in California, a large rectangular corrugated rubber shroud surrounds the petrol nozzle, connected to a vapour return pipe. The rubber shroud must be pressed firmly against the side of the vehicle to ensure a seal; a pressure microswitch ensures that sufficient pressure is applied to make the seal. When the nozzle handle is pressed to deliver the fuel, the vapour displaced from the vehicle tank is exchanged for the liquid fuel delivered from the storage tank and not emitted to atmosphere.

2.1.10 Overall Reductions in Volatile Organic Compound Emissions

VOC emission reduction is one of the environmental policy objectives of both the EU and North America because VOC's interact with pollutants and sunlight to generate photochemical smog. There are also health and resource conservation issues in containing these compounds, including Green House Gas (GHG) emissions. The European Union is committed to reducing 2030 Green House Gas emissions by 40 % relative to a baseline of 1990.

VOC emissions from industrial plant and service stations above certain sizes and throughputs are now controlled by absorption/desorption devices. The transfer loading of volatile organic compound liquids above a certain volume is now required to use vapour/liquid exchange systems.

3 Oil Product Refining

3.1 Nature of Refining

Oil refineries operate continuously with very high throughputs of crude oil to produce a large range of products. The composition of the input crude oil varies from one oilfield source to another; in the past European and North American refineries were configured to process crude oil from a particular, distant, oilfield source. Now, refineries are flexibly configured to process crude oil from a range of sources. In addition, refineries have been built on, or close to, the far oilfield sites. All of the crude oil input is used to produce a wide range of major and minor products for varied uses and applications. Refining crude oil is a worldwide activity and extremely competitive; only the most cost-effective survive. Every refinery seeks the maximum return from the crude oil input value by separating and upgrading products for specific markets to give maximum added value. The amount of waste from refining crude oil is extremely low and necessarily so; 0.1 % waste from a throughput of 10Mt/pa would be 10,000 tons of a highly viscous, unpleasant material which has to be stored or disposed of somewhere. The economics and waste disposal issues of crude oil refining push the operators to utilise and upgrade all materials such that maximum value is obtained and waste is absolutely minimal. Refinery products vary from:

– gases such as Liquefied Petroleum Gases, LPG,
– automotive fuels such as petrol/gasoline and diesel,
– jet fuel for aviation and paraffin/kerosine for heating,
– solvents of varying volatility,
– heating oil,
– residual fuel for marine fuel oils and heating oils,
– lubricant base oils,
– waxes,
– bitumen
– and also petrochemical feedstocks for further processes.

Increasingly refineries have to formulate each product to meet tighter performance and environmental specifications, as described later in this Chapter. A constant theme is the demand for increased product performance and quality, as in automotive petrol, diesel and marine fuels, to which refineries must respond by reconfiguring their processes. Further, new processes upgrade heavier, lower value products into lighter, high value products, e.g., by cracking or converting fuel oil grades into diesel. The demand for transport fuels as a percentage of the first distillation of an average crude oil is not sufficient for demand; therefore, the lower value, heavier fuels are cracked into lighter fractions to increase supply. Investment is needed for upgrading processes and replacement of older plant. In a very competitive business environment, the number of refineries in the UK alone has reduced from 19 in 1975 to six in 2015, albeit by concentration into larger units. An interesting trend is for the major oil companies to withdraw from refining and sell these assets to specialized refining companies.

Whilst the applications of refinery products are wide and various, almost all are fuels in one form or another and are consumed by combustion to provide motive power. The basic refinery operation itself uses between 2 and 3 % of the crude oil input for the thermal energy of the initial distillation and separation process, followed by reforming and hydrogen treatment, ‘hydrotreating’. Modern refineries use more ‘severe, i.e., higher temperature and pressure’ processing to catalytically crack heavier product grades into lighter grades such as petrol and diesel fuel. This not only increases their proportion from the original crude oil distillation value, and meet market demand for these products, but also increases their value. It also requires more energy; for a complex refinery which extensively upgrades initial distillation products into highly specified fuels and lubricants, the energy required can be 7–9 % of crude oil input.

3.2 The Main Types of Refinery Products

3.2.1 Light Fuels

The major part, around 80 %, of refinery products are light fuels classified by boiling point ranges. The lightest are petrol/gasolines, mainly used in piston-driven internal combustion engines for passenger motor vehicles, small propeller-driven light aircraft and small portable power sources for generators, mowers and chainsaws, etc.

3.2.2 Middle Distillates

The next boiling range is designated as the beginning of the 'middle distillates', the kerosine/paraffin where the aviation grade is very tightly specified for gas turbine jet engines, either by direct propulsion or turbine driven propellers, 'turbo props'. Heating kerosine has roughly the same boiling point/molecular weight ranges as aviation kerosene but is much less specified. Diesel fuel is used for heavier road vehicles such as buses, lorries and agricultural tractors but has also 50 % or more of the small passenger car market in some European countries. Heavier grades in this boiling range are also used for industrial heating as 'gas oil' and in smaller marine engines.

3.2.3 Residual Oils

Beyond the 'middle distillate oils' are the 'residual oils' from the non-distilled residue of crude oil, used as diesel fuel in very large slow speed, 60–90 rpm, marine engines, industrial power generation and heating systems. Used in marine engines these fuels are known as Marine Fuel Oils (MFO's), defined by ISO 8217:2010, et.seq [10].

3.3 An Example of Fuel Specification Upgrading

An example of refinery fuel upgrading is the sulphur content of 'residual oils', which gradually increase as the lighter fractions are removed from the crude oil. Stringent reductions in the sulphur content of Marine Fuel Oils, MFO's, are required by various jurisdictions under the Emission Control Areas, ECA's, defined by IMO. ECA's are established for the European North and Baltic seas and also within 200 miles of the North American coast, including Canada and Mexico, not solely the USA. The sulphur content could previously be up to 4 %, higher for some crude oil sources but was limited, pre-2015, to 3.5 %, outside ECA's coastal waters of the European Union and North American States. Within those ECA's the pre-2015 MFO sulphur limit was 1.0 %; post January 2015, vessels must now use 0.1 % sulphur DMA fuel or liquefied natural gas. Future limits on MFO's used outside of ECA's are proposed to be 0.5 % by 2020, although this step may be delayed to 2025, in part due to the availability of refinery capacity to produce sufficient quantities of this fuel quality. These requirements complicate the operation of vessels; two qualities of fuel must be carried in two fuel tank systems. When the fuel quality is switched as a vessel approaches or leaves an ECA, the lubricant formulation should be switched as well, an additional duplication. The two fuels operate at different temperatures and ‘switchover’ between them needs careful management otherwise problems occur with engine operating continuity causing a ‘Loss Of Propulsion’, (LOP), event [13]. The United States Coast Guard recorded 93 vessel LOP incidents in Californian waters in 2014 of which 16 % were related to fuel switching on entry to an ECA. Carrying this data over to the 60,000 annual vessel transits of the Channel between England and France predicts 102 LOP incidents due to fuel switching each year, or one LOP every 3 days.

Combustion of MFO’s forms sulphur dioxide (and nitrogen oxides), which contribute to acid rain. An alternative way to reduce sulphur emissions is to apply the proven chemical engineering process of physically ‘washing out’ sulphur oxide emissions from engine exhausts by water scrubbing and, in this case, discharge of the acidified effluent into the sea. Whilst initially interesting because of the fuel cost differential of around $300/t. between the 3.5 and 1 % sulphur content fuels, the water scrubbing apparatus requires useful and expensive space on board the vessel. More fundamentally, the oceans are already shown to be acidifying due to carbon dioxide absorption; to accelerate this process by adding aqueous, acidic, sulphur and nitrogen oxides is unlikely to be accepted as a long term solution.

Addressing one problem usually leads to another; sulphur is very effectively reduced/removed from high sulphur Marine Fuel Oils by catalytic hydrogenation. The treated fuel then contains ppm-levels of silicon and aluminium oxides as very fine, extremely hard, particulates from the ceramic-based catalyst which can cause rapid wear in the engine components of high pressure fuel pumps, injectors and cylinder bores. The standard has been set by IMO in ISO 8217:2010(E), Appendix J, for Marine Fuel Oils [10] as 60 ppm for their combined aluminium and silicon content.

3.4 Other Refinery Products

Other than the fuels described above, other products from crude oil distillation and processing are the Liquefied Petroleum Gases, LPG, comprised of propane/propylene and butane/butylene in seasonally varying proportions, solvents equivalent to unreformed petrol/kerosene/diesel, paraffin wax extracted from fuels and lubricant base oils by solvent extraction, solid petroleum coke residuals used as solid fuel and heavy, viscous bitumen for road asphalt.

3.5 Trends in World Fuel Consumption

The world is a developing place, subject to the different forces of economic development requiring more power from fuels on one hand and the increasing restrictions of fuel efficiency and emission reduction on the other. Different world

Table 12.1 1993/2003/2013 fuel consumptions, in Mb/day, by global region

Product	Europe	Asia/Pacific	N.America	Total
Light distillates	4.1/4.0/3.0	3.7/6.2/9.6	9.0/10.7/10.7	16.8/20.9/23.3
Middle distillates	5.9/7.1/7.5	6.0/8.3/10.8	5.6/6.9/6.5	17.5/22.3/24.8
Fuel oil	2.4/2.0/1.0	3.6/3.4/3.3	1.6/1.3/0.6	7.6/6.7/4.9
Other products[a]	2.6/3.2/2.8	2.7/4.7/6.8	4.4/5.3/5.5	9.7/13.2/15.1
Total	15.0/16.3/14.3	16.0/22.6/30.5	20.6/24.2/23.3	51.6/63.1/68.1

Product	OECD	NonOECD	Total
Light distillates	15.1/10.7/10.7	–/7.9/12.4	
Middle distillates	14.0/16.7/16.5	–/11.2/17.0	
Fuel oil	5.3/4.3/2.9	–/5.4/6.0	
Other products	8 5/9.9/9.7	–/6.8/10.3	
Total	42.9/41.6/39.8	–/31.3/45.7	

[a]'Other products' are petroleum coke solids, bitumen, wax, solvents, LPG, refinery gas/fuel and losses

Figures are rounded. 'Total' is the sum of Europe + Asia/Pacific + N.America. 1993 Figures for non-OECD countries are on a different geographical basis and therefore excluded

regions are subject to these in different time scales. Table 12.1 shows the different trends in the European, North America, Asia/Pacific and 'Other' world regions for the successive decades of 1993, 2003 and 2013. It is particularly useful to look at the first entry for 'gasolines' in Europe, where consumption has declined from 1994 to 2014 from the emphasis on fuel efficiency for petrol vehicles together with a market shift towards small diesel vehicles. In the three other regions, petrol consumption has markedly increased, mainly due to increased vehicle numbers but without the emphasis on fuel efficiency.

4 Environmental Issues of Using Refined Hydrocarbon

4.1 Specifications, Use and Emissions of Fuels

The initial purpose of fuel specifications was to assure the user that the product conformed to standards of suitability, purity and performance. Specifications added since include handling, safety, conformity with legal requirements, reliability and environmental issues. 'Specifications' as a wider term includes not only the specific individual fuel specifications, such as for marine fuel oils in ISO 8217:2010(E) [10] and the European automotive diesel, EN590 [11], and petrol, EN228 [12], specifications but must also have regard to the respective Material Specification Data Sheets, MSDS, and further must also conform to the various environmental legislation of various continental blocks such as the EU, individual countries, even various port authorities. Specifications vary as appropriate to each category of fuel and include dynamic performance characteristics such as cetane and octane numbers for diesel and petrol.

The sulphur content of fuels is a major environmental issue and reducing its concentration has had a dramatic effect on fuel formulation to maintain performance. Marine fuel oil is the heaviest fuel considered and with the highest potential level of sulphur content.

4.2 Marine Fuel Oil and ISO 8217:2010(E)

For economy, large vessels have very large, very efficient, single engines which operate on the turbocharged two-stroke cycle at low speeds of the order 60–80 rpm. The power output is very high, of the order of 20 MW or more and the low rotational speed enables the engine to be directly connected to the propeller without an energy-absorbing gearbox. Piston diameters can be of the order of 900 mm. The engine uses low quality, low cost residual fuel oils, termed 'bunker fuels', defined as the 'Residual Marine Fuel Oils', the RM series, in ISO 8217:2010(E). The term 'residual' is apt as the fuel contains the concentrated molecular debris of the crude oil from which the lighter, higher quality, fuels have been removed by distillation. However 'residual' the RM fuels have been in the past, standards have risen in the light of operating and environmental experience and many physical and chemical parameters are now controlled by specifications such as ISO 8217:2010(E) and its many Appendices. Generators and pumps auxiliary to the main engine use smaller, higher speed engines using distillate fuels, the DM series, as used by smaller vessels.

Residual fuel oil is a viscous, foul, material which requires on-board treatment before use. Because of its high viscosity it must be heated for pumping and the specified temperature for entry into a centrifugal solids separator/filter is 98 °C, to reduce solids, particularly catalyst fines initially at 60 ppm or less, to a level less than 15 mg/kg., as recommended by engine manufacturers, to minimise abrasive wear of engine components.

4.2.1 Ignition Quality

The Cetane Index of a fuel measures its ability for spontaneous ignition under pressure and temperature when injected as an atomised spray into the compressed air mass in an engine cylinder. The cetane number for automotive diesel is of the order of 50–55, i.e., a short delay between compression and ignition. MFOs have much lower cetane numbers, around 10–15, and the ignition delay correspondingly longer, accommodated by the very much lower cylinder speeds of large marine diesel engines.

4.2.2 Fuel Sulphur Levels and Fuel Desulphurisation

The marine fuel sulphur content reduction issue is now into its second phase of resolution. The essential issue is that fuel sulphur forms sulphur dioxide and trioxide (‘sulphur oxides’) when burned in an engine; when emitted to the environment the sulphur oxides react with water to form sulphurous/sulphuric acids and thereby acidify the environment. The sulphur content of solid and liquid land fuels was reduced from the 1960s to very low levels; use of high sulphur residual fuels by vessels on oceans, coastal waters and harbours was increasingly noticeable, environmentally incongruous and could not be justified. The successive Clean Air Acts of the UK [3], commencing in 1956, sought to restrict polluting emissions, including acid gases such as sulphur dioxide, from vessels in port. It is not now meaningful to follow the decrease in sulphur levels standards of marine fuels oils with time but to note that the starting point in the late twentieth century was up to 4.5 % sulphur content used on oceans away from continental waters: the 2015 situation is that within ECA’s, for post-January 2015 vessels must use 0.1 % sulphur DMA fuel or liquefied natural gas and a maximum of 1 % sulphur outside ECA’s on oceans. Future MFO limits outside of ECA’s are proposed as 0.5 % by 2020, but may be delayed to 2025 because of supply capacity issues.

Fuel desulphurisation is either a refinery operation or post-combustion washing. At refineries, sulphur is removed by reaction of the residual oil with hydrogen at increased pressures and high temperatures using a catalyst. The catalyst has an alumino-silicate support base and is partially physically degraded in use to give aluminium and silicon oxides as ‘fines’; these are very hard, fine, particles which could cause substantial abrasive wear in engine components unless reduced prior to use in engines. The context to the IMO limits on total aluminium and silicon are described in S.3.2 The process is effective up to 85 % reduction of the MFO sulphur content but requires considerable investment in refinery plant for a defined throughput. The sulphur is eventually recovered as elemental sulphur and used in fertiliser production, amongst other uses. Any refinery operation has substantial financial implications; the processes to remove up to 85 % sulphur from residual fuel substantially increase the price of the resulting low sulphur fuel.

Commercial shipping is intensively financially competitive; the higher cost of reduced sulphur marine fuel oil is a substantial increased operating expense and alternatives are looked for. ‘Scrubbing’, as a chemical process operation, of the engine exhaust by sea water is the major alternative which absorbs and neutralises the acidic sulphur oxides. Sea water is sprayed into engine exhaust within a chamber to cool the gases by evaporation; the cooled gases then pass into a packed chamber where a further sea water counterflow washes out the sulphur oxides. The acidified effluent from the scrubber is discharged into the vessel’s wake where it is rapidly dispersed and neutralized by the very slightly alkaline seawater. The gases are re-heated by an exhaust heat exchanger to raise their dewpoint and reduce the density of the white plume of exhaust vapour. Whilst the higher sulphur content/ lower cost marine fuel oils can be used if exhaust scrubbing is used, there is an investment cost for the scrubbing equipment and also a significant space requirement on vessels where every space has commercial value. The final issue is the addition of acid effluent to open waters when the oceans are already acidifying by carbon dioxide absorption.

4.2.3 The ISO 8217:2010(E) Fuel Oil Specification [10]

The importance of definitions and standards for fuel, and marine fuel in particular, is illustrated by the current, 2015, specification for marine fuel oil, ISO 8217:2010 (E), prepared by ISO Technical Committee ISO/TC 28, *'Petroleum products and lubricants, Subcommittee SC 4, Classifications and specifications'.* The specification document consists of 48 pages and has many references to other specifications and standards. It covers all of the specification requirements gained by custom and practice over many years.

The first part comprises sections of a Foreword, Introduction, Scope, Normative References, Application, Sampling, General and New Requirements, Test Methods and the Precision and Interpretation of Test Results.

The second part consists of 'informative' Annexes for (a) Bio-derived products and Fatty Acid Methyl Esters (FAMEs), (B) Deleterious materials, (C) Sulphur content, (D) Hydrogen sulphide, (E) Specific energy, (F) Ignition Characteristics of residual marine fuels, (G) Flash Point, (H) Acidity, (I) Sodium and Vanadium, (J) Catalyst fines, (K) Used Lubricating Oil and (L) Precision and Interpretation of test results, completed by a Bibliography. Whilst the Annexes are labeled as 'informative' the stated standards and procedures within them are usually written as obligations within the contract for the supply of marine fuel oil or in the fuel clauses of a charterparty agreement between Owners and Charterers for a vessel charter. The centre of the ISO 8217 standard is two tables setting out the physical and chemical characteristics of Distillate Marine fuels, the 'DM' series and the same for Residual Marine fuels, the 'RM' series.

The *'-2010'* part of the specification title indicates that there have been previous specifications, e.g., ISO8217:2005, and that there will be subsequent, further, revisions in due course. Six revisions/amendments to the DM series were made between the 2005 and 2010 version of ISO 8217 and ten revisions/amendments to the RM series. Four new annexes were added. Whilst all changes were significant, one is chosen here to demonstrate the attention to detail of the evolving marine fuel oil market – in Annex J the 2010 permissible level of catalyst fines in Marine Fuel Oil was reduced from 80 mg/kg to 60 mg/kg. The change arose from the engine manufacturers recommendation that following on-board treatment the fuel entering the engine should contain less than 15 mg/kg Aluminium + Silicon/Fuel to ensure minimum risk of abrasive wear to engine components. The reduction recognizes an overall lower operational cleaning efficiency of the fuel than had been previously determined on-board ship. Annex J also specifies the conditions for adequate pre-treatment of fuel.

The RM series of Marine Fuel Oils (MFO), defined within ISO 8217:2010(E), is one of the few hydrocarbon fuel types that require extensive onboard purification treatment before it can be used in an engine. The RM fuels are so viscous at normal temperatures that they must be heated to dissolve any wax/hydrocarbon solids and also for pumping for delivery to a settling tank. From this tank the MFO is pumped through a centrifugal filter to remove solids and sludges into a service tank and then to the engine injectors. The efficiency of separation by this method of 'hard solids' from the marine fuel oil in the presence of soft sludges is interdependent on their concentration dependence – high sludge levels will decrease the 'hard' solid removal efficiency, and vice versa. ISO 8217:2010(E) specifies a level of 0.1 % for 'sediments'. Another separation performance parameter is the operating temperature of the centrifugal filter; ISO 8217:2010(E) specifies 98 °C as the MFO temperature for optimum efficiency. The rate of MFO passing through the centrifugal filters also affects the separation efficiency. As at least two centrifugal filters are usually installed on a vessel, they may be used in parallel, to maximise throughput with lower separation efficiency, or in series to maximize separation efficiency but with lower throughput, dependent upon the overall fuel flow rate required. The purpose of the centrifugal filters is reduce suspended solids such as sludges and the hard catalyst fines, from the maximum allowed in Marine Fuel.

Oils under ISO 8217:2010(E) of 60 mg/kg down to less than the 15 mg/kg recommended by the engine.

4.3 Fixed Large Industrial Boiler and Power Plants Fuels

The last decade has seen a substantial decline in the use of high viscosity/high sulphur oils as boiler fuel for electricity power generation, process steam raising and other industrial operations such as pumping. The cost of heavy fuel oil has increased in line with the increased price of crude oil. Gas is easier to use and fouls boilers less, for increased longer term efficiency.

A further reason for the replacement of heavy fuel oil by natural gas is the increased fuel efficiency gained by changing to Combined Cycle Gas Turbine electricity generation technology from conventional (heavy fuel) oil fired furnaces raising steam to drive steam turbine generators. CCGT technology, for the same generating capacity, is requires less footprint, less capital investment and is quicker to build than conventional oil-fired, steam raising, turbine generation.

Being land-based and fixed installations, the acid sulphur oxides emissions from plant burning high sulphur are more tightly controlled than emissions from vessel's engines on the ocean. Flue Gas Desulphurisation, FGD, has been proposed to reduce sulphur oxide emissions but requires substantial investment; large scale FGD has only been applied to coal-fired plant in Britain. The utility and availability of cleaner alternative fuels for industrial use together with restrictions on sulphur oxides emissions has considerably reduced the use of high sulphur, high viscosity fuel oil.

4.4 Small Industrial and Domestic Fuels

'Gas oil' is a distillate similar to automotive diesel but less tightly specified. The tendency to form smoke, the 'smoking tendency', arises from higher boiling point components in the fuel which take longer to burn; if the residence time of the fuel within the combustion chamber is less than the time to burn these components, then partial combustion results, forming smoke. The ISO 3405 [14] distillation procedure standard defines gas oil, amongst other hydrocarbon fuel grades, as a fuel for which 65 % (minimum) is recovered by distillation at 250 °C and 85 % (minimum) at 350 °C. A 1.5–5.5 cSt viscosity fuel is used with pressure jet burners which turbulently mix the fuel with combustion air for complete combustion.

Home heating oil/domestic kerosene has been used in the past in wick-fed convenient, low cost and portable heaters. As heating facilities and standards have increased in Europe, the US and Japan, the use of these heaters has drastically decreased although they are still used extensively for heating and cooking in Asia, particularly in rural areas. For domestic use in the EU, the fuel sulphur content must be low; for flued burners 0.2 % sulphur is the specified maximum, for unflued, wick-type, burners, the specified maximum sulphur concentration is 0.04 %. Maximum sulphur specifications vary across countries, from 0.25 % m/m in India down to 0.015 % m/m in Japan.

Further considerations, in addition to the sulphur content, are the smoke point (which should be high) and the char value (which should be low). Both are influenced by the distillation end point, reducing the overall sulphur content and by 'sweetening' the fuel by removing any organic sulphur compounds.

4.5 Automotive Diesel Fuel

Heavy vehicles worldwide, buses, trucks and construction vehicles, are almost entirely powered by diesel engines. The striking feature of light diesel vehicle registrations over the past decade is their rapid increase in Europe and Asia because of their superior fuel consumption relative to petrol vehicles; in some EU countries the light vehicle penetration of diesel vehicles is over 50 %; the 2014 UK market penetration was 40 %. Equally striking is their very low penetration in the North American light vehicle market.

Diesel engines operate with a substantial excess of air, i.e., a high air/fuel ratio, on the Diesel thermodynamic cycle which, together with the fuel and its method of addition/injection, allows a much higher compression ratio to be used than the Otto (petrol) cycle. The high compression ratio of diesel engines gives a better thermodynamic efficiency than the Otto (petrol) cycle which translates into lower/better fuel consumption than petrol vehicles. When compared to petrol engines, developments over the last two decades in diesel engine overall operation have been improved performance, reduced noise and vibration, reduced emissions and also reduced price differential. These improvements have been achieved through turbo-charging, intercooling, higher injection pressures from a very high pressure 'common rail' fuel system, electronic control of injectors and their timing, exhaust catalysts and particulate traps. Larger capacity engines may have an exhaust gas recirculation (EGR) system to reduce nitrogen oxide emissions by reduction in peak combustion temperatures. Sophisticated electronic engine management systems adjust the amount of fuel injected at the optimum time in each cycle, according to the engine operating condition of load and speed. These systems optimize overall performance of the engine and reduce fuel consumption and also emissions.

4.5.1 Diesel Fuel Composition

The composition of diesel fuel is specified within Europe by the EN590 [11] standard, introduced in concert with the European diesel emission standards, 'Euro 1' (1993) [15] in 1993 and has been systematically revised since to 'Euro 6' in 2014. The US standard for diesel fuel is ASTM D975.

The EU diesel sulphur content [11] has reduced from 0.2 % (2000 ppm) in 1993 to 10 ppm in 2009, now known as 'ultra low sulphur diesel'. Whilst the reduction in sulphur is beneficial in performance and environmental effects, the sulphur compounds previously present had a lubricity function which is replaced by additives to prevent excessive wear of fuel pumps and injectors, as tested by EN ISO 12156-1 [16]. The physical test requirements of EN 590 is set out in Table 12.2, the Russian GOST R 52368-2005 [17] diesel regulations are similar except that the sulphur content is much higher at 350 ppm and the Fatty Acid Methyl Ester content restricted to 5 %.

Diesel fuel forms waxes when exposed to prolonged low temperatures; these clog fuel lines and the fine particulate filters used to protect the precision engineering of injectors. Up to 20 % of the gas oil components used to formulate automotive diesel can be heavier hydrocarbons of limited solubility/compatibility with the lighter hydrocarbons forming the rest of the fuel and will separate as wax at lower temperatures. The separation process depends both upon the temperature at which the fuel is held and the time for which it is held. A further sub-set of EN 590 defines 'Winter Diesel' which is formulated to meet certain winter weather conditions in specific countries of the European Union, e.g., the climatic differences between southern Italy and northern Finland. The primary division divides standard EN590 into 'temperate' and 'arctic' climatic zones.

The temperate climatic zones are divided into six Classes, A-F, solely on the basis of the Cold Filter Plugging Point (CFPP, ASTM D6371 [18]) value. The other properties of density at 15 °C index, viscosity at 40 °C, Cetane Index and Number are the same for Classes A-F. The CFPP test estimates the lowest temperature at which a fuel will flow through without difficulty in a fuel system, i.e., without wax crystals forming a blocking mass within the fuel pipes or filter. The Class A CFPP value is +5 °C; the subsequent CFPP values for Classes B-F progressively decrease by 5 °C increments to a CFPP of −20 °C for Class F. Many northern and eastern European countries require diesel fuel to meet a specific class in winter, thus

Table 12.2 Physical test requirements for the diesel EN590 standard

Property	Unit	Lower limit	Upper limit	ENISO Std.
Cetane index/number		46.0/51.0	–	4264/5165
Density, 15 °C	kg/m^3	820	845	3675/12185
PAH's	%(m/m)	–	11	12916
Sulphur content	mg/kg	–	10	20846/20884
Flash point	°C	>55	–	2719
Carbon residue	%(m/m)	–	0.3	10370
Ash content	%	–	0.01	6245
Water content	mg/kg	–	200	12937
Total contamination	mg/kg	–	24	12662
Cu strip corrosion	Rating	Class 1	Class 1	2160
Oxidation stability	g/m^3	–	25	12205
Lubricity wear scar	µm	–	460	12156-1
Viscosity @ 40 °C	mm^2/s	2.00	4.50	3104
Distillation. rec'd 250/350 °C, %V/V	–	<65	85	3405
95 %(V/V) recovered at °C	–	360		
Fatty acid methyl ester %(V/V)	–	7		14078

Western and Central European governments require diesel fuel to meet Class F specification during winter, at least from the end of November to the beginning of March, known as 'winter diesel', 'vinterdiesel', 'diesel d'hiver'.

For colder winter seasons, as in Scandinavia, a more demanding set of diesel fuel specifications are set, Table 12.3. Diesel fuel for winter in Scandinavia must meet Class 2, commonly known as 'Polar Diesel', 'diesel polaires'.

'Cloud Point' [19] is the temperature at which a haze occurs in a cooling, clear, fuel, determined by ASTM 2500. 'Cold Flow' additives alter the characteristics of the wax crystals as they form to reduce the CFPP value significantly below the Cloud Point, e.g., with current additives a CFPP of −20 °C for diesel fuel can be achieved for a Cloud Point of −7 °C. Other additives used in diesel fuel are:

– polydimethysiloxanes, or 'silicones' of optimized molecular weight, at the low ppm level as anti-foam agents to prevent foaming spills when fuelling,
– friction modifiers which deposit in the engine upper cylinder and piston ring pack to reduce friction and improve fuel efficiency,
– detergents to remove thermally produced deposits from injectors,
– anti-wear and lubricity additive compounds to reduce fuel system and storage wear at the high pressure and shear rates used in current systems,
– corrosion inhibitors to protect metal fuel delivery and storage systems,
– cetane improvers, for easier starting,
– stabilizing compounds to prevent formation of gums and deposits,
– in some cases, a 'pleasant odourant' to counter the pervasive and sometimes unpleasant odour of diesel fuel, to some,

Table 12.3 Arctic climate zone diesel fuel specifications

Characteristic	Class 0	Class1	Class 2	Class 3	Class4	Unit
CFPP	−20	−26	−32	−38	−44	°C
Cloud point	−10	−16	−22	−28	−34	°C
Density @ 15 °C	←-----800–845-----→			←800–840→		kg/m^3
Viscosity @ 40 °C	←------1.5–4.0-----→			1.4–4.0	1.2–4.0	mm^2/s
Cetane index	46	46	45	43	43	
Cetane number	47	47	46	45	45	

Diesel fuel quality has substantially improved over the two decades prior to 2014 and the direction of further improvement is not clear. Diesel fuel is formulated from various difference sources of 'gas oils', from the 'straight run' gas oil distilled from crude oil, 'hydrocracked' gas oil, thermally cracked gas oil and synthetic gas oil from natural gas. All of these components have different densities and cetane numbers yet must be combined into a closely defined fuel between 820 and 845 kg/m^3 density and a cetane number of over 51. Premium diesel fuels are now offered with cetane values of 55 or more with decreased consumption and noticeably smoother operation.

4.5.2 'Bio-Diesel'

The physical properties of diesel fuel are suitable for the addition/substitution/supplementation of biofuels in the form of 'Fatty Acid Methyl Esters, FAME' from vegetable oils. The use of vegetable oils as diesel engine fuel has been demonstrated, e.g., tractors running on peanut oil, but their combustion tends to form internal engine deposits which limit engine between overhauls, and the oils are not stable against 'hardening' oxidation deposits during storage. Vegetable oils are 'triglcerides', with three organic acid groups esterified with the tri-hydric glycerol to form one molecule which can form solids, 'fats'. 'Methyl esterification' of vegetable oils is analogous to making soap where methyl alcohol is the reactant with sodium hydroxide as the catalyst, to separate the three attached organic groups into individual esters. The methyl esters formed have much lower melting points than the triglycerides and are physically oils rather than fats; chemically they are single, separate, esters of the long chain organic acids. FAME is physically compatible/miscible with standard diesel oil and EN590 allows up to 7 % FAME content, although in 2014/5 the amount added is around 5 %.

An issue with bio-diesel is the considerably differential volatility of 'mineral' diesel and FAME. Under low energy operation conditions of an engine, i.e., relatively cool operation, fuel dilution of the lubricant occurs by deposited FAME. This decreases lubricant viscosity and increases the apparent volume of the lubricant. When the engine is subsequently operated at a higher energy, higher temperature level, the 'mineral diesel' evaporates but the FAME component evaporates more slowly and may build up in the lubricant.

4.5.3 Combustion of Diesel Fuel

Diesel combustion is initiated by a very high pressure, highly atomized and dispersed, spray of fuel injected into an adiabatically compressed, high temperature, charge of air in the engine cylinder head. The adiabatic compression process of the air drawn in is transiently thermally isolated from its surroundings. At the temperature of the compressed air charge, the injected fuel spray spontaneously ignites to generate a turbulent flame front. This accelerates across the cylinder to consume the fuel, generating heat and pressure which drives down the piston to generate mechanical power.

Improvements in diesel fuel, as described, engine design and operation have reduced diesel particulate emissions, and therefore smoke, to very low levels. There is a parabolic relationship in the diesel combustion process between particulate formation and nitrogen oxide formation, Fig. 12.4. If ignition timing is retarded then the peak combustion pressure and temperature is reduced, particulate emission increases and nitrogen oxides formation decreases. Alternatively, if ignition timing is advanced then the peak combustion pressure and temperature is increased, nitrogen oxide formation increases and particulate formation decreases. The particulates emitted have very small diameters and are characterized as PM_{10}, $PM_{2.5}$, etc., as a definition of their average diameters. These particulates are retained in human lungs following inhalation [3].

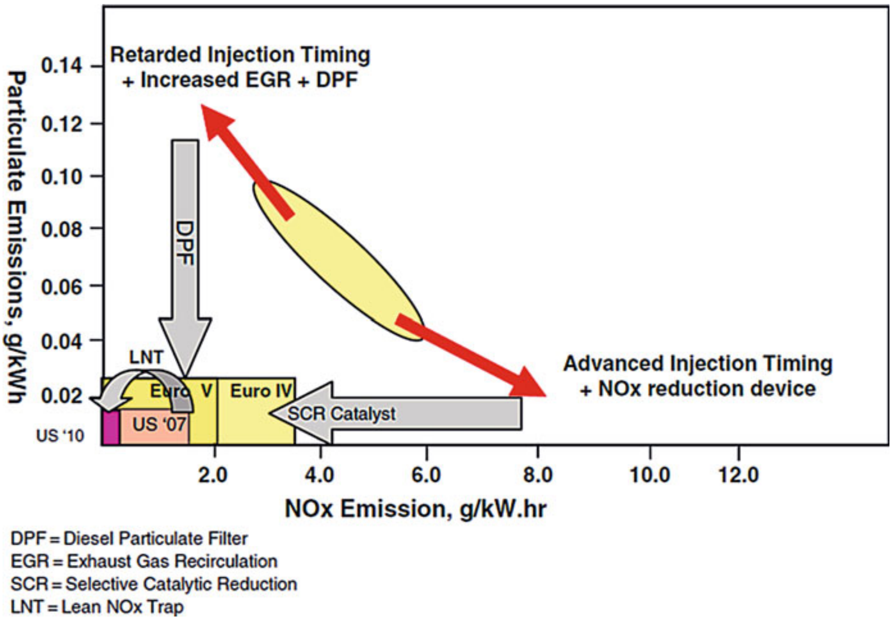


Fig. 12.4 Required decreases in diesel particulates and NO_x, showing the after treatment technologies (DPF, EGR, SCR and LNT) required to meet exhaust emission standards. Note the parabolic relationship between particulate and NO_x emissions in diesel combustion (From Atkinson D, Brown AJ, Jilbert D, Lamb G (2009) Chapter 9, 'formulation of automotive lubricants. In: Mortier RM, Orzulik S, Fox MF (eds) Chemistry and Technology of Lubricants, 3rd.Edn., Springer

Both nitrogen oxide and particulate emissions must be reduced to very low levels. A policy decision has been made to concentrate on reducing nitrogen oxides by configuring diesel engine combustion. The residual nitrogen oxides are reduced by Selective Catalytic Reduction to nitrogen and oxygen using a urea solution. North America and the EU have required substantial decreases in diesel emissions over the last two decades.

The particulates are filtered out using a coarse in-line ceramic filter. As the filtered layer of particulates builds up, the pressure drop across the filter system increases and the particulates must be removed. Almost all of the trapped particulate is carbon and is removed by increasing the filter temperature to burn it off. When sufficient pressure drop across the filter is sensed, additional fuel is programmed in the engine management system to be injected into the engine, or alternatively, into the exhaust system and ignited in the ceramic filter, to burn off the carbon.

4.6 Aviation Jet Kerosine

Aviation kerosene jet fuels are distillate fuels between petrol/gasoline and diesel, with carbon numbers between C_5 and C_{16}. Aviation fuel quality is strictly controlled to prevent engine failure in flight and such problems are extremely rare. The basic issue is to maintain that strict quality control whilst large jet fuel volumes are stored, often for long periods, transported and then transferred into the fuel tanks of aircraft. In doing so, the jet fuels contact with a range of materials and fuel-related problems can occur. Anti-oxidants and metal de-activators are added to jet fuel to improve its stability against degradation, leading to gum and sediment formation. Addition of corrosion inhibitors and lubricity additives protect the jet aircraft fuel system of tanks, pipes, filters and pumps from wear and corrosion. Anti-icing additives dissolve any free water in the fuel to prevent it freezing at high altitude temperatures, causing blockages in fuel lines and filters, and added biocides stop bacterial/fungal growth which can block pipes and filters and also corrode fuel systems metals. It was surprising to find that bacteria and fungi could grow under anaerobic conditions in jet fuel hydrocarbons within tanks; now biocides are added to prevent their growth.

Water in jet fuel has a specification limit of 30 ppm, a level at which water is absorbed, dissolved or dispersed in the jet fuel, semantic points for the presence of a polar substance, water, in a non-polar, low permittivity medium, the jet fuel. At 20 °C 30 ppm water in jet fuel gives a single phase. The presence of water in jet fuel is a constant and serious problem. It is a constant problem because movement of large volumes of jet fuel into and from storage tanks, with the associated contact with humid air which deposits water onto the cold tank walls – a problem for handling all hydrocarbons but it is particularly important that jet fuel be free from water contamination. It is a particular problem for jet fuel because upper atmosphere flights decrease fuel temperatures due to low external temperatures at which dissolved water precipitates out and falls to the bottom of the tank because of its higher density. Fine water droplets can supercool below 0 °C but on impact with surfaces, they freeze and may suddenly block fuel inlet pipes, the cause of the British Airways Flight 38 [20] accident at London Heathrow. It is impractical to remove all water from jet fuel and fuel line heaters are used on commercial aircraft to prevent water from freezing in fuel.

Stringent procedures are used to keep the water content of jet fuel below 30 ppm. Land-based vehicle jet fuel delivery tankers have a large water filter assembly in their final delivery line. Several methods are used to detect water in jet fuel, the simplest is a visual check to detect high concentrations of suspended water in fuel as a 'hazy' appearance, only meaningful as a wholly unacceptable level. More relevant is a standard chemical test to detect free water in jet fuel using a filter pad sensitive to water which indicates 'green' if the specification limit of 30 ppm 'free water' is exceeded.

4.6.1 Aviation Jet Fuel Specifications

Jet fuel specifications are stringent and rigidly enforced, subject to specifications led by the US ASTM, UK MoD DEF STANDARD and GOST for the CIS and associated states:

- Jet A-1 fuel must meet DEF STAN 91-91 (Jet A-1), ASTM specification D1655 (Jet A-1), and IATA Guidance Material (Kerosene Type) [21], NATO Code F-35 [22]. Jet A-1 is the standard specification fuel in the rest of the world,
- Jet A fuel must meet ASTM specification D1655 (Jet A) [23], and has been available within the United States since the 1950s but not usually available outside (Table 12.4).

Both Jet A and Jet A-1, with carbon numbers between 8 and 16, have flash points higher than 38 °C and a primary difference between them is the lower freezing point of Jet A-1 at −47 °C compared to Jet A at −40 °C. Another difference between Jet A and Jet A-1 is the mandatory addition of an anti-static additive to Jet A-1. DEF STAN 91-91 (UK) and ASTM D1655 (international) specifications allow for certain additives in jet fuel:

- antioxidants to prevent gum formation, usually based on alkylated phenols,
- antistatic agents, as static electricity dissipators and prevent gum formation, based on dinonylnaphthylsulfonic acid,
- corrosion inhibitors,
- fuel system icing inhibitor agents,
- biocides, to stop bacterial/fungal growth in aircraft fuel systems,
- metal deactivators, to remediate deleterious effects of trace metals on fuel autoxidation/thermal stability, such as N,N′-disalicylidene 1,2-propanediamine.

Jet B is a lighter composition, C_{5-15} naphtha/kerosene fuel, approx. 30 % kerosene and 70 % gasoline, used for enhanced cold-weather performance. Its lighter composition gives a higher volatility and a low flash point, therefore it is

Table 12.4 Typical physical properties for Jet A/Jet A-1, Jet B and TS-1

Fuel	Jet A	Jet A-1	TS-1	Jet B
Specification	ASTM D 1655	DEF STAN 91-91	GOST 10227 [24]	CGSB-3.32
Acidity, mg KOH/g	0.10	0.015	0.7 mg KOH/100 ml	0.10
Aromatic, %vol.max	25	25.0	22 (% mass)	25.0
Sulphur, mass %	0.30	0.30	0.25	0.40
Sulphur, mercaptan, mass %	0.003	0.003	0.005	0.003
Distillation, °C				
Initial boiling point		Report	150	Report
10 % recovered, max.	205	205	165	Report
50 % recovered, max	Report	Report	195	Min.125, max 190
90 % recovered, max	Report	Report	230	Report
End point	300	300	250	270
Vapour pressure, kPa, max.	–	–	–	21
Flash point, °C, min	38	38	28	–
Autoignition temperature	245	245		
Density, 15 °C, kg/m^3	775–840	775–840	min.774@20 °C	750–801
Freezing point, °C	−40	−47	−50 (Chilling Point)	−51
Viscosity, −40 °C,mm^2/s, max	8	8.0	8.0 @ −40 °C	–
Net heat of combustion, MJ/kg, min	42.8	42.8	42.9	42.8
Smoke point, min., min	18	19.0	25	20
Naphthalene, vol.%, max	3.0	3.00	–	3.0
Cu corrosion, 2 h.@ 100 °C, max rating	No.1	No.1	Pass (3 h @ 100 °C)	No.1
Thermal stability				
Filter pressure drop, mm.Hg, max.	25	25	–	25
Visual tube rating	<3	<3	–	<3
Static test 4 h@150 °C, mg/100 ml, max	–	–	18	–
Existent Gum, gm/100 ml, max	7	7	5	–

more potentially dangerous to handle and rarely used except in very cold climates. It has a very low freezing point of −60 °C and is primarily used in some military aircraft and also Canada because of its low freezing point.

As aviation transport has increased, so the demand for aviation jet fuel kerosine has increased to >5 % of all refined products from crude oil. Refineries have optimized the yield of jet fuel, a high value product, by varying process techniques. New refinery processes for jet fuel use flexible choice of crudes and coal tar sands and the production of synthetic blend stocks, sometimes requiring additives.

4.6.2 Military 'JP Fuels'

Some of JP ("Jet Propellant") military jet fuel classifications systems are almost identical to civilian classifications, differing only by the treat rates of some additives. Military fuels are highly specialized formulations and developed for very specific applications. Thus, JP-8 [25] is similar to Jet A-1 and JP-4 is similar to Jet B. JP-8 is specified and widely used by the US Military as a fuel for both jet aircraft and diesel fueled vehicles. Specifications MIL-DTL-83133, Def. Std. 91-87 and NATO code F-34 for JP-8 are projected to remain until 2025. The U.S. Navy uses a similar formula, JP-5, but with a higher flash point of >60 °C because of the greater fire risk on aircraft carriers. When JP-8 is used as a single fuel it greatly simplifies military logistics, for in addition to an aircraft fuel, JP-8 is used as a fuel for heaters and stoves and also as a fuel in the diesel engines of nearly all NATO tactical ground vehicles and electrical generators. It is used as a coolant in engines and some other aircraft components. The JP-8 formulation has icing and corrosion inhibitors, lubricants, and antistatic agents but less benzene and *n*-hexane than JP-4.

There are other JP fuel numbers for increasingly particular applications but of minor interest. There were two threads to the development of further 'JP' fuels – the first was the development of fuels for very specialized aircraft, some of which have been overtaken by other technologies, e.g., the SR-71 high altitude reconnaissance aircraft required specialised fuel development but its function is now overtaken by satellite photography. The second thread has been the development of renewable jet fuels to reduce US dependence on imported petroleum and develop secure domestic sources for military energy. However, the extensive development of 'fracking' has led the US becoming self-sufficient in hydrocarbons and then a net exporter.

Jet A-1 and Jet A is identified in trucks and storage by the UN Hazardous Material Sign with the number '1863'. Jet A trucks, storage tanks and plumbing carrying Jet A are marked with a black sticker with "Jet A" in white printed on it, adjacent to another black stripe.

4.7 Spark Ignition (Petrol/Gasoline) Fuels

Spark ignition engines operate at lower compression ratios than diesels at around 8:1. The fuel is mixed outside of the engine in the inlet manifold, now by multi-port fuel injection, previously by carburettors and drawn in by the induction stroke, then compressed and ignited close to the Top Dead Centre piston position. (GDR engines are rather different in the induction/fuel injection procedure) There have been significant improvements in engine performance over the past two decades in terms of fuel efficiency and emissions and also in the composition of petrol fuel.

Improved engine efficiency has been achieved by design changes including multiple valves per cylinder, such as three, four or even five instead of two, as one inlet and one exhaust valve. The timing of the valve opening/closing has been fixed in the past; a further development is variable valve timing of either one or both inlet and outlet valves to a pre-programmed engine speed profile, to further increase the efficiency of fluid gas transfer into and out of the engine.

Combustion modeling has contributed to improvements in efficiency and reductions in emissions. Changes in the shape of piston crowns and the corresponding combustion chamber have enhanced turbulence as the mixed air charge and petrol fuel are compressed and then ignited, improving the efficiency of combustion and reducing emissions. Overarching these development are microprocessor engine management systems, which continue to develop. The basic microprocessor inputs are engine speed, load, input air/fuel mixture, temperature and exhaust composition. The input air/fuel mixture is measured by an air flow meter and the injected fuel mass. The exhaust composition is measured by a solid state zirconia electrode. Whilst these developments reduce exhaust emissions, the levels of pollutants remaining are still too high to meet exhaust emission regulations.

The problem of controlling hydrocarbon, carbon monoxide and nitrogen oxide emissions from petrol-fuelled, spark ignition engines commences with the basic chemical equation for the combustion of petrol, taken overall as C_6H_{11} from the various types and ranges of hydrocarbons, is:

$$C_6H_{11} + 8.75O_2 = 6CO_2 + 5.5H_2O$$

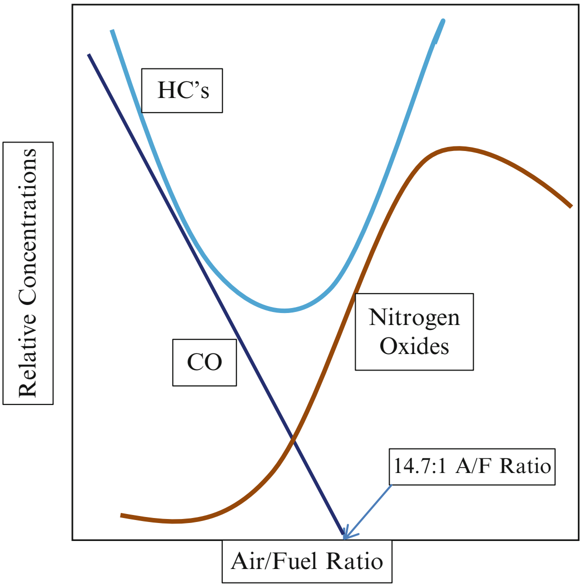
A mass balance includes the nitrogen in the combustion air at 21 % oxygen and 78 % nitrogen, as a first approximation, not including the argon, atmospheric water vapour and carbon dioxide contents, as:

$$C_6H_{11} + 8.75O_2 + 32.5N_2 = 6CO_2 + 5.5H_2O + 32.5N_2$$

Nitrogen appears on both sides of the equation because it passes through engines without reaction, other than the marginal formation of nitrogen oxides. Using simple unitary atomic weights and only considering petrol, oxygen and nitrogen, the stoichiometric, or exact chemical balance, Air/Fuel (A/F) ratio is 14.34. Allowing for trace components as described and using exact, fractional, atomic weights, the Air/Fuel Ratio is 14.7. This value is the stoichiometric value which is fundamental and pivotal to considering petrol-fuelled engine emissions:

– for above this value, ***greater*** than an Air/Fuel ratio of 14.7, the mixture is ***lean*** (of fuel), there is an excess of combustion air (oxygen) and the light blue peak

Fig. 12.5 Generalised petrol engine emissions plot against air/fuel ratio



flame front combustion temperatures are maximized, therefore nitrogen oxide formation increases,

– for below this value, ***less*** than an Air/Fuel ratio of 14.7, the mixture is ***rich*** (in fuel) and the yellow(-ish) peak flame front combustion temperatures are lower. There is insufficient air (oxygen) for complete combustion, therefore carbon monoxide is formed rather than carbon dioxide and hydrocarbons are either not burned or partially burned.

The combustion chemistry and resulting emissions of operating petrol-engined vehicles is set out in Fig. 12.5 as a general, illustrative, non-quantified scheme. It is striking that carbon monoxide emissions decrease almost linearly down to the stoichiometric value from the rich-fuel side, whereas nitrogen oxide emissions increase beyond the stoichiometric value as the combustion temperature increases until the excess air dilutes the reacting air/fuel mixture and the temperature falls.

The hydrocarbon emissions are complex with respect to changes in the Air/Fuel ratio. As the Air/Fuel ratio increases towards stoichiometric, hydrocarbon emissions decrease, as the available combustion air/oxygen increases, but then become constant. Beyond the stoichiometric point, the hydrocarbons increase, despite the excess combustion air. This non-chemical behaviour is a physical effect, that of a 'boundary layer' at the piston and bore metal surfaces, where the combustion flame front is quenched by a boundary layer of relatively cool hydrocarbon/combustion air. Increasing the turbulence of the flame front by asymetric in-piston component such as pistons and combustion chambers dramatically increases turbulence and shears the boundary layer of hydrocarbons into the main combustion process.

Overall emission reduction from petrol-fuelled engines cannot be achieved by varying the Air/Fuel ratio as a two-dimensional variation. One exhaust pollutant can be reduced by varying the Air/Fuel ratio but at the expense of increasing others. ***There is no solution to reducing overall exhaust emissions by varying the Air/Fuel ratio.*** A new, different, solution to reducing overall emissions is required, a third dimension.

That different solution to reducing overall exhaust emissions uses a catalytic convertor system. The issue is to oxidise the carbon monoxide and hydrocarbons at the same time as reducing the nitrogen oxides within the same volume. The catalyst system to do this uses platinum, palladium and rhodium variously, very finely dispersed on a fine ceramic matrix at a narrowly defined air/fuel ratio close to the stoichiometric Air/Fuel ratio condition, which can only be achieved using fuel injection systems. Hence, fuel carburetors have been replaced by fuel injection systems which are much more precise over a range of fuel mass flow. These systems are called 'three way converters' and have been mandatory for automotive emission control in Europe since 1993, in Japan and North America since 1975. They are self-heating from the destructive combustion of the polluting emissions and become fully effective at a 'light-off' temperature of around 320 °C. This means that 'three way converters' are ineffective immediately after starting the engine until that temperature is reached; equally, idling engines in congested traffic do not maintain the required temperature for the catalyst system to be effective in reducing emissions. This effect is probably a contributing factor to national environmental levels of automotive emissions not decreasing in concert with the emissions reduction achieved in the standard bench tests.

4.7.1 Petrol Composition

('gasoline' in North America), specified by EN 228 [12]in the EU has developed significantly in the last two decades to respond to substantial developments in engine technology and environmental regulation. The removal of octane improver organolead compounds on environmental and health grounds is now a historical issue; the 95/85 (Research/Motor) octane rating of petrol had to be maintained by other means to give a Euro-standard fuel. The very low level of lead allowed in EN 228, Table 12.5, reflects the low level of intrinsic/natural lead found in petroleum products but excludes added organolead compounds. Added benzene, to improve octane ratings, was replaced by up to 35 % of other aromatics with benzene limited to 1 %. Sulphur at 10 ppm is at a cost-benefit minimum, sufficient to prevent noticeable formation of reduced sulphur in the catalytic convertor system, i.e., unpleasant hydrogen sulphide emissions. The low sulphur level also protects the three way catalyst system from corrosion. Volatility is reduced due to fuel injection systems instead of evaporative, carburettor, systems. Petrol has been 'reformulated' to reduce the photochemical activity of emissions, both in the EU and North America. The oxygenates specification allows for a range of alcohols, ethers and 'others' but actuality lies with the use of ethanol up to 5–7 %, with an eventual

Table 12.5 EN 228 highway petrol fuel specification [12]

	Unit	Minimum	Maximum
Research Octane Number, RON		95	–
Motor Octane Number, MON		85	
Vapour pressure, summer,	kPa		60.0
Distillation, % evaporated at 100/150 °C	% v/v	46/75	–
Hydrocarbon composition			
Olefins	% v/v		18.0
Aromatics	"		35.0
Benzene	"		1.0
Oxygenates			
Methanol	% v/v		3.0
Ethanol	"		10.0
i-Propyl alcohol	"		12.0
t-Butyl alcohol	"		15.0
i-Butyl alcohol	"		15.0
Ethers with >5 °C-atoms/molecule	"		22.0
Other oxygenates	"		15.0
Sulphur content	mg/kg		10.0
Lead content	g/l		0.005

target of 10 %. Issues with ethanol addition to petrol are the availability of the large volumes required, the enhanced absorption of water which can lead to an aqueous ethanol phase separating from the hydrocarbon component at low temperatures and enhanced corrosion of ferrous/non-ferrous metal components of fuel systems. 98 RON value petrol formulations are available for higher performance vehicles.

4.7.2 Avgas

'Avgas' is petrol (gasoline) fuel for reciprocating piston engined aircraft spraying. Aero-piston engines operate the same as vehicle spark ignition engines but at a higher performance level. Total global Avgas volumes are low because piston aircraft are much smaller than jet-fuelled aircraft although greater in number. A range of previous grades was necessarily rationalized into two main Avgas grades, '100' and '100LL low lead', to maintain supply in an otherwise uneconomic market.

Avgas grades are defined first by their octane rating; two ratings are used, the lean mixture rating (lower) and the rich mixture rating (higher), giving a multiple numbering system, e.g. Avgas 100/130 (a lean mixture performance rating of 100 and a rich mixture rating of 130). To avoid confusion and minimise handling errors, common practice initially designates the Avgas grade by the lean mixture performance, i.e. Avgas 100/130 is designated as 'Avgas 100'.

– **Avgas 100** is standard high octane fuel for aviation piston engines with a high organolead content, dyed green for identification, specified by ASTM D 910 and UK DEF STAN 91-90 [26]. The two specifications are essentially the same but with different antioxidancy, related oxidation stability requirements and maximum lead contents.

- **Avgas 100LL** is the 'low lead' version of Avgas 100 (a relative term!), with a limit of 0.56 g lead/l. It has the same specifications as Avgas 100, namely ASTM D 910 and UK DEF STAN 91-90. Avgas 100LL is dyed blue.
- **Avgas 82 UL**, specified by ASTM D 6227 [27], is a specialised, relatively new grade formulated for low compression ratio engines which do not require the high octane rating of Avgas 100 and could run on unleaded fuel. Avgas 82 UL has a higher vapour pressure and can be formulated from automotive petrol; it is dyed purple.

To avoid confusion and the wrong fuels being used, all equipment using, and facilities handling the Avgas grades are colour coded for the fuel to be used; they are also prominently marked with the API designations denoting the actual fuel grade carried, stored or used.

4.7.3 The Two-Stroke Cycle and Engines

The use of two-stroke engines has been seriously restricted by environmental emission controls and are no longer used in new automotive applications other than large marine vessels. Their positive attraction is their simplicity of construction, with a minimal number of moving parts additional to the central components of crankshaft, connecting rods and pistons. In its simplest form, a two stroke engine mixes lubricant with the fuel, so no lubricant system of pump, filters, oilways and pipework is required. The lubricant is delivered as a 'once through' 'system, in itself is a potential source of hydrocarbon emissions.

A two stroke petrol engine uses a conventional carburettor to generate an air/fuel mixture drawn into the crankcase. This is gently compressed into the cylinder through the inlet port uncovered when the piston is close to Bottom Dead Centre (BDC). The piston crown is shaped to deflect the incoming air/fuel charge upwards. As the piston rises from BDC it closes off the inlet port and then the exhaust port and compresses the air/fuel mixture. Close to Top Dead Centre the mixture is ignited by a spark plug and the power stroke converts the thermal energy of fuel combustion into mechanical energy, as in other engines. As the power stroke proceeds with the descending piston, the exhaust port is uncovered and the burned mixture is expelled from the system by its remaining pressure. It could be said that gas flow dynamics and sequential exhaust/inlet ports are used to replace the inlet and exhaust valves.

The advantage of the two-stroke cycle is its construction simplicity with only three major moving parts, plus the carburetor. Ignition is by a magneto-type system with a simple bob weight advance/retard timing. Power output is relatively high for the engine volumetric capacity as there is a power stroke for each complete engine rotation, hence the term 'two stroke' as the cycle only has induction/compression and power/exhaust strokes. The simplicity of construction of two stroke engines gives the additional advantage of being cheap to make.

The disadvantages of the two stroke cycle stem from the inevitable partial mixing of the inlet and exhaust gases, causing a high level of hydrocarbon emissions in addition to the residual, unburned, lubricant in the exhaust. Lubricant overtreatment of the fuel leads to blue smoke emission, a severe emission problem. Two stroke engine power output is limited by the inherent problem of not being able to achieve a high compression ratio. The power stroke in each rotation can lead to over-heating of the cylinder and piston, leading to pre-ignition. The torque curve of a two stroke engine is usually gentle and engine speed must be increased to a high level to generate power for acceleration. Whilst various measures can be taken to reduce emissions from two-stroke engines they are not effective enough to meet modern standards. The main problems are high hydrocarbon, HC, and carbon monoxide, CO, emissions from a number of processes:

(i) the lubricant is burned with the fuel prior to the power stroke; hydrocarbons from the lubricant and fuel can pass through the engine into the exhaust, effectively a 'short-circuited' gas flow between the inlet and exhaust ports,
(ii) high lubricant treat rates in pre-mix systems, up to 3 % lubricant treat rate,
(iii) an accumulation, 'pooling', of lubricant in the engine crankcase when idling, which causes high smoke emissions levels during subsequent acceleration.

Positive aspects of emissions from two-stroke engines are low NO_x emissions resulting from (i) exhaust gas recirculation (EGR) port scavenging where a small percentage of exhaust gas remains during each induction cycle, reducing peak combustion temperatures, and (ii) lower compression ratios, also reducing peak combustion temperatures.

Technical improvements reducing two stroke emissions include 'low smoke lubricants', graduated 'auto-lube' systems with minimal oiling rates at low engine speeds, fuel injection once the transfer ports are closed to negate 'short circuiting' in the crankcase and oxidation catalysts for two stroke applications. Despite these improvements, the four-stroke engine has become the dominant power unit for today's motorcycles; two-stroke engines are now restricted to off-road and racing applications, small, $<50\ cm^3$ motorcycles, motor scooters, snowmobiles, boating and portable equipment such as chainsaws, blowers and strimmers. Biodegradable lubricants based on ester-based technology are available for off-road use.

Two main applications remain for two stroke engines, as cheap, small, portable power sources and for very large marine engines. For the first, two issues obtrude, (i) tightening environmental legislation which may extend to, and therefore exclude, small gardening equipment and small transport vehicles, and (ii) advances of small electrical power sources. The power density of rechargeable batteries is increasing steadily and electric motors are decreasing in size with the use of rare earth magnets. It is possible within the next decade that small implements could powered by relatively powerful motors driven from rechargeable batteries, displacing small two stroke motors.

For the second, very large two-stroke engines are the norm for marine propulsion and no alternatives are currently envisaged. A measure of 'very large' engine size is the 800–900 mm piston diameter. Large marine engines are usually turbo-charged, fuel injected, cross-head designs with low speed rotation, of the order of 65 rpm. A speed reduction gearbox is not needed as this rpm value is suitable for direct connection to the vessel's propeller. The low rpm value is also advantageous for the turbocharged air introduction/exhaust gas scavenging system. Bore lubrication is by direct distribution/delivery of a high Base Number lubricant, to counter the high sulphur fuel content, through a series of quills around the circumference of the bore, with associated 'moustache' machined features to spread the lubricant. The lower end of two-stroke marine engines are conventionally pressure lubricated by a separate system using a different formulation to that used in the top end of the engine. Low speed, two-stroke, marine engines achieve very high efficiencies (for automotive systems). Their relative construction simplicity enables them to be rebuilt during a voyage, such as when a cylinder liner develops cracks.

5 Fuel Trends in the Next Decade

5.1 Predicting the Future

Predicting the future is always a hostage to fortune for any activity; predicting the future of the oil industry should be more stable because of its broad global base and ubiquity. There are many separate predictions of future Energy Demand, Gross Domestic Product and Population; a recent Outlook for Energy study by ExxonMobil Chemical Ltd. [28] brings these three trends together and shows different trends for OECD and non-OECD countries.

5.2 Trends in World Population, GDP and Energy Demand

World population will rise by more than 25 % to 2040 from 2000, Fig. 12.4, with a slight increase in OECD countries, the major increase being in non-OECD countries [25]. Whereas GDP will increase by ~200 % 2000–2040, the increase divides roughly equally between OECD and non-OECD countries. Figure 12.6 shows that OECD countries energy demand will be stable or slightly decline whereas overall, OECD plus non-OECD, energy demand could rise in line with GDP unless energy efficiency improves. The fundamental difference is that whereas OECD countries will double their GDP at constant energy consumption, non-OECD countries will treble their GDP whilst potentially increasing their energy demand by a factor of five. Energy saving measures could reduce the increase in non-OECD energy demand to a factor of between two and three. The UK reduced primary energy consumption by 3.1 % (on a temperature adjusted basis) in 2014, in a year of national economic growth, continuing the trend of the previous 9 years. The Energy

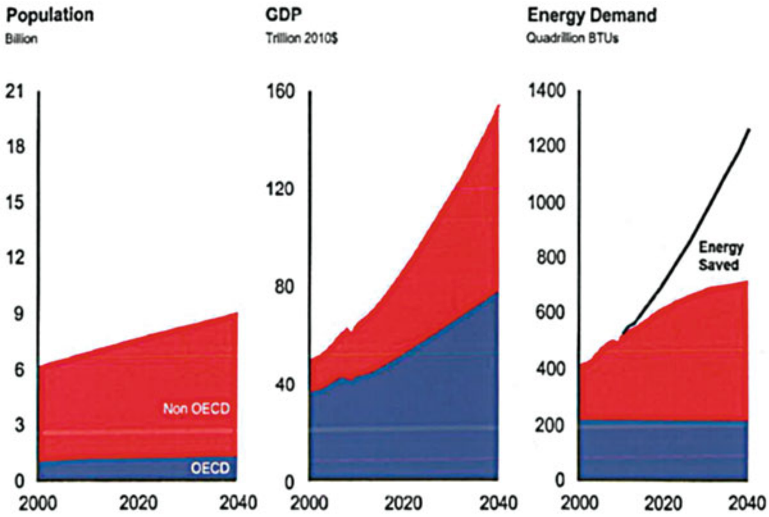


Fig. 12.6 Predicted trends in population, Gross Domestic Product (GDP) and energy demand for 2000–2040 (From Ref. [28])

Demand composition, Fig. 12.6, for 2000–2040 includes oil, gas, coal, nuclear and renewable energies.

But the energy industry, particularly the oil industry, operates in unstable economic and political times. The issue of 'Peak Oil', when the production of crude oil and natural gas will reach a natural capacity maximum and then decline, has been partially overtaken by extraction of 'tight oil' (and gas) by the technological developments of 'fracking' and also successful prospecting developments in new areas such as deep off-shore. But the factors leading to the sudden, unexpected 60 % collapse of the crude oil price from a peak of $115 per barrel in June 2014 to $46 per barrel in January 2015 has forced re-assessment of many petroleum fuel predictions, activities and investments. There have been four oil 'bear markets' between 1864 and 2008 of depressed oil prices, each taking between 11 and 20 years before previous prices were regained. Assuming that, in the relatively immediate term the crude oil price will stabilize between $57 and 82 per barrel to the end of 2016, then various future trends can be discussed and assessed.

5.3 Petrol, Jet and Diesel Fuels

On the demand side the conventional fuels of petrol, jet fuel and diesel will almost certainly maintain their predominant position as fuels for prime movers for the next decade, as part of World Energy Demand, Fig. 12.4. Whilst the 'Energy Demand' plot in Fig. 12.6 is for all energy sources, the International Energy Agency estimates that 64 % of world energy demand is for transport, mainly for petrol, contributing to

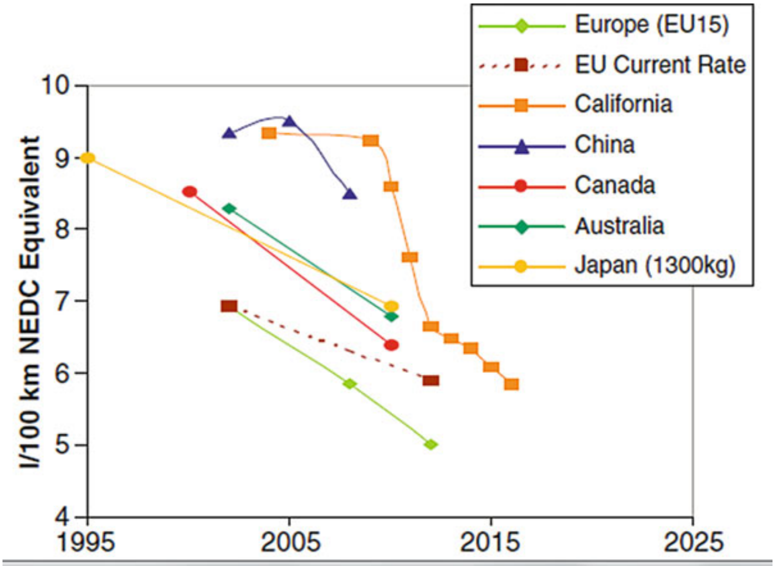


Fig. 12.7 Past and Future Fuel Consumption Standards for Light Vehicles in World Countries and Regions

the projected increase in energy demand. However, the two largest vehicle markets, China and North America, are required to reduce emissions by 30 % by 2020, in turn requiring increased fuel efficiency and thus energy saving,. The mandatory emissions of carbon dioxide, as a measure of vehicle fuel efficiency, for 100 km, in different countries are at different stages of development for different vehicle fleet compositions but the overall, inexorable, direction is to reduce carbon dioxide emissions per 1000 km and therefore improve fuel efficiency, as shown in Fig. 12.5.

For fuel specifications, after two decades of rapid change in specifications in concert with rapid changes in engine design and operation, the rate of change has now substantially decreased. Thus for petrol, lead compounds and sulphur have been severely reduced to very low levels, benzene reduced to low levels, chemical components have been reformulated, 5–10 % ethanol added and a standard octane rating of 95 established. Petrol, and now diesel, is now much more environmentally acceptable, in the older sense, with lead, benzene and sulphur drastically reduced or essentially removed. Emission regulations, such as the Euro1-6 regulations, have progressively tightened, as for passenger cars, Table 12.6.

However, the new sense of environmental definition regards petrol, and the other liquid fuels, as polluting because their combustion generates carbon dioxide. Therefore, in due, but probably longer, course they will be replaced, at least in part, by renewable sources of energy, as described in the next section. Because the changes in fuel specifications have been both extensive and thorough, it is not clear how they can be improved further. Therefore, any future changes in petrol specification are likely to be limited to small incremental change. Jet fuel specifications

Table 12.6 Euro emission standards for petrol and diesel cars, g/km

Stage	Date	Petrol cars				Diesel cars			
		CO	***HC + NO_x***	***PM***		***CO***	***HC + NO_x***	***NOx***	***PM***
1	07/92(1/93)	2.72	0.97	–		2.72	0.97	–	0.14
2	01/96(1/97)	2.2	0.50	–		1.0	0.7	–	0.08
		CO	***HC***	***NO_x***	***PM***				
3	01/00(1/01)	2.3	0.20	0.15	–	0.64	0.56	0.50	0.05
4	01/05(1/06)	1.0	0.10	0.08	–	0.50	0.30	0.25	0.025
5	09/09(1/11)	1.0	0.10	0.06	0.005(di)	0.50	0.23	0.18	0.005
6	09/14(9/15)	1.0	0.10	0.06	0.005(di)	0.50	0.17	0.08	0.005

(di) – direct injection only. From 'Euro emission Standards', Automobile Association Website, 15/12/14
Implementation dates given are for vehicle type ***approvals***, dates in brackets for all new vehicle ***registrations***

are set until 2020 and diesel fuel specifications are not expected to change significantly as well. The major change in fuel compositions will be in the area of ethanol addition levels in petrol and the percentage FAME addition in diesel. Diesel fuel has drastically reduced its sulphur content level and reformulated its composition whilst establishing a cetane number of over 50. The emphasis in the next decade is on developments in diesel engine and fuel technology to concentrate on reducing Particulate Matter emissions, such as PM_{10} or $PM_{2.5}$.

All vehicles will continue to improve their fuel efficiency, continuing the progress made so far in light vehicle technologies such as advanced engine management systems, stop/start engines, lighter construction, hybrid propulsion and the effect of electric vehicles. The vehicle fleet will continue to further improve fuel economy. The total net level of vehicle emissions is a net sum, from the emissions of an increasing of number of vehicles set against their increasing efficiency and reduced emissions per vehicle, together with reduced emissions from the overall vehicle fleet as the older, more polluting, vehicles phase out.

Heavy duty vehicles will continue to be diesel driven with improved fuel efficiencies. The main issue to resolve the discrepancy between the stable level of polluting nitrogen oxides and particulates in the urban environment and the reducing trend in engine bench test emissions required by successive Euro Engine programs. The reductions in diesel engine emissions achieved on the test bed for successive Euro-emission standards are not being seen in the environment.

5.4 The Alternative Fuels

Alternative fuels such as hydrogen still wait to fulfill their potential and demonstration projects need considerable subsidy. Hydrogen's power density when compressed into high pressure bottles is only 5.6 MJ/l against 32.4 MJ/l for petrol at atmospheric pressure – the gas compression is an additional cost. The other alternative fuel, Liquefied Petroleum Gas, LPG, has an established market penetration, with an acceptable energy density, being readily liquefied on compression to around 10 bar with a specific density of 0.5. It is a clean burning fuel and propane, its main component, is increasingly available from natural gas sources and fracking as a very minor component.

Alternative liquid fuels arise regularly, some from biological sources such as plants or algae or from the controlled thermal degradation of refuse. The Fisher Tropsch process can take 'synthesis gas' produced from a range of sources and convert it into various hydrocarbons by varying the process conditions. The issues are:

– availability of the raw material on the very large scale required. If new syntheses of hydrocarbons from new sources are successful at the pilot plant stage, then further development into a viable real alternative source requires substantial infrastructure investment and development. As an example, the jatropha plant can supply a plant oil to 'extend' mineral hydrocarbon fuels, can grow on otherwise arid land and is inedible. It has the advantage of not posing a threat to human food supply on marginal land. But development of 'jatropha farms' on a scale to produce a meaningful supply of alternative hydrocarbons requires substantial investment over a prolonged period, as jatropha plants take several years to mature in arid, marginal desert, regions which may not have the necessary political stability to develop long term business. It is often seen that significant developments in 'alternative hydrocarbon synthesis' are not supported by the necessary raw material supply, a capacity problem.

The land use issue is of real concern, seeking to ensure that land for food production is not compromised by diversion to 'energy crops'. To address that issue, the European Union Parliament's target of 10 % renewable energy is limited to 6 % from land-based bio-fuels to 6 %, to include inedible energy crops. The remaining 4 % is intended to come from 'advanced biofuels' from algae or waste.

– the large and sustained, over years, investment required to develop alternative fuel crops; similarly, the investment required in slightly different technologies to process the new raw materials into useful hydrocarbon fuels, a financial resource issue,
– the acceptability of alternative fuels; Sect. 12.4 sets out the detailed specifications for petrol, jet and diesel fuels, part of which concern the molecular specification in terms of distillation 'bands', aromatic content, sulphur content, etc. To meet these specification requirements from alternative sources needs process developments to deliver acceptable fuels.

5.5 Conclusion

The demand for alternative fuels is predicated upon a constrained supply of mineral crude oil. The recent technological developments in producing crude oil from 'tight oil or gas' through what is known colloquially known as 'fracking' have changed the balance of that scenario. As one example, the United States of America has moved from a net importer/consumer of hydrocarbons to a net exporter. How long that situation applies will play out in the decade after the next.

It is clear that demand for hydrocarbon fuels will continue to increase worldwide but that within the OECD it may 'flatline' or decrease. Within the non-OECD countries, energy demand (including hydrocarbon fuels) will substantially increase, the extent of that increase is dependent upon whether energy efficiency measures can be effectively introduced and maintained.

Within established markets, the 'clean fuels' such as petrol, jet and diesel fuel specifications will only change by small increments. The 'heavier (dirty)' fuels such as Marine Fuel Oils will have their sulphur and solids contents drastically reduced in a substantial market whereas land-based heavier fuel oils are losing/has lost market share to the availability of relatively clean and convenient natural gas.

In conclusion, the quality of current fuels of diesel, jet fuel and petrol has been raised and for the foreseeable decade will continue to power prime movers. The next decade after may begin to see the expected and predicted fundamental and substantial changes in the fuel demand market.

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21. DEF STAN 91-91, ASTM D1655, IATA Guidance Material (Kerosene Type) Jet Fuel Standard
22. NATO Code F-35 Jet Fuel Standard
23. ASTM D1655 Jet A Fuel Standard
24. TS-1, GOST 10227, for CIS Jet Fuel Standard
25. JP-8, MIL-DTL-83133, Def. Std. 91-87 and NATO code F-34
26. Avgas specifications ASTM D910 and UK DEF STAN 91-90
27. Avgas 82 UL, specified by ASTM D 6227
28. ‘Energy and Lubricants. A View to the Future. The Outlook for Energy: A View to 2040’, S. Reid-Peters, ‘Lube Magazine, 126, April 2015, p 20

Chapter 13
Lubricants

C.I. Betton

1 Introduction

The activities of the oil industry are aimed primarily at the production of fuel. The proportion of crude oil that is refined into a lubricant base oil is only 1 % of the total [28]. It could be argued that the base oils produced by a refinery are a by-product of the refining process and that the integrated oil company regards lubricant production accordingly. Lubricants, however, represent a high technology, specialist, high added value group of products with high potential environmental impact. The environmental aspects of lubricants extend beyond the obvious direct impacts to secondary impacts such as energy savings due to improved performance.

The perfect lubricant from an environmental point of view would consist of a material that:

- was obtained from a renewable resource;
- did not require a large amount of energy to produce;
- was a perfect lubricant in that it reduced friction to very low levels;
- was unaffected by heat and pressure;
- did not contain any potentially toxic or harmful components;
- was not 'used up' during the process of lubrication;
- was not dependent on temperature in order to function;
- was readily degradable to non-harmful components if spilled;
- worked for the lifetime of the device being lubricated;
- was recoverable and reusable.

Unfortunately, such a material does not exist nor, based on the current state of knowledge of how lubricants work [34], is it ever likely to exist.

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_13

Since the publication of the first edition of this chapter, the priority governing environmental issues affecting regulators and scientists alike have changed. Fifteen years ago, the concept of global warming was an object of discussion among environmentalists and theoretical ecologists but few other groups, and certainly not Tribologists. Now however with metereological records showing that the ten warmest years on record have all occurred within the past 15 years and CO_2 measurements taken from ice-cores able to show that the amount of atmospheric CO_2 is now at an unprecedented level, the environmental priorities and emphasis are different.

The environmental grouping previously suggested of

- performance;
- components;
- effect on the environment if spilled (toxicity);
- rate of removal from the environment if spilled (degradability).

Has been skewed significantly in favour of performance. Today when CO_2 and emissions of other greenhouse gasses are continuing to rise, the performance of lubricants in reducing friction and increasing efficiency is of greater importance than ever before. Environmental advantages related to reduced toxicity and biodegradability are increasingly met by management and it is important that these are in addition to, not instead of, the maximum level of performance that can be attained. To take an example of a motor car engine oil, modern engines are not capable of existing on the lubricants based on castor oil that were adequate for the engines of the 1920s, even though such a lubricant would meet many of the ‘environmental’ criteria listed above. What it is easy to ignore are the substantial benefits in fuel efficiency and emissions reduction that are achievable from a modern engine, compared with an early ‘gas guzzler’. If an old-fashioned oil were used in a modern engine, the engine would be destroyed in a few thousand miles and the environmental costs of replacing that engine in terms of the energy and foundry emissions, etc., from the production plant would far outweigh any benefits from the use of the ‘old-style’ lubricant. The impact of improved performance can be seen in the service intervals of today’s vehicles. In the 1970s the typical service interval was 5000 km, today the norm is 15,000 km with many manufacturers offering 20,000 km and some recommending 50,000 km. This is now possible by advanced lubricant technology but also electronic in-car monitoring of the lubricant itself, “condition monitoring”. It is often the case that the service interval is now determined by wear and tear on components such as spark plugs and that the lubricant is still well within performance spec. This is shown by a reduction in the total volume of lubricants being used over the past 10 years, at a time when the number of cars has increased significantly [24].

Performance is and must always be paramount when assessing the environmental aspects of any lubricant; that is not to say, however, that it should be performance at any cost. Recent developments in metalworking oil technology with the elimination of materials such as chlorinated paraffins from some formulations [27] demonstrate that as knowledge of environmental and health effects increases, formulations can change accordingly. Such changes are not without cost and are not easily achieved, as in all cases performance needs to be maintained if not improved.

2 Performance

Performance of lubricants is measured in different ways depending upon the use to which the lubricant will be put. There are standard tests for some types of lubricant such as engine oils that convey to the customer some information concerning the quality of the oil that is purchased [42]. It is not my intention to describe or review these methods here. There are, however, some points regarding the standard industry tests that are worth making, particularly when considering the most up-to-date lubricant technology and the environmental benefits that can be accrued.

Performance tests for lubricants are controlled by national (API) and international (ACEA) organizations, and some individual motor manufacturers also have their own test requirements [42]. The tests are based upon the principles of ready availability and reproducibility. A test that is run by one institution must be, and be seen to be, the same as that by a different institution; the results must be comparable. As can be imagined, huge investment is put into establishing test methods and setting up facilities to run the tests; companies are therefore reluctant to chop and change tests without compelling reasons. The result of these restrictions is that the tests used to classify lubricants according to the internationally recognized standards are often lagging behind contemporary technology. The major lubricant companies and the motor manufacturers, being aware of the deficiencies in the standard classification tests, have developed their own methods of assessing performance that are in addition to the standard requirements. A series of motor car engine oils, for example, may all meet a particular standard but the performance of oils may be very different in actual driving conditions, with those of the major lubricant producers being far more effective than some others that are not designed to the same high standards. With lubricants you really do get what you pay for.

In conclusion, when considering the environmental benefits of any lubricant, the most important factor to be considered is the performance. A quality lubricant formulated according to recognized standard performance criteria from a major manufacturer will confer the highest level of environmental benefit possible by conferring long life due to reduced wear, lowest possible emissions due to reduced friction and maximum protection from corrosive attack due to correct formulation and lowest possible losses due to low consumption in use and compatibility with seal materials, reducing leaks.

3 Components

As mentioned earlier, a performance lubricant requires the presence of additive chemicals in order to enable it to work effectively. A typical lubricant therefore consists of a base fluid in which are dissolved a number of different chemicals, each performing a unique function. The additive chemicals are generally more expensive than the base fluid, so from a business point of view it is important to formulate the lubricant with sufficient additives to achieve the desired performance – but no more. Environmentally, the principle ‘the least is best’ applies. In a perfect world, no lubricant would ever reach the environment except in those instances where the design makes such losses inevitable, e.g. greases on railway points systems, chain bar lubricants on chain saws and any two-stroke engine oil such as those used in outboard motors, motor cycles etc.

4 Base Fluids

The choice of a base fluid for a lubricant is dependent upon the desired characteristics of the final product. I shall not consider this aspect of performance in this section. If further information is required, several excellent reference works are available that will assist the reader in understanding the performance aspects of base fluids [37, 39].

From an environmental point of view, base fluids can be split into three categories: mineral oils, synthetic oils such as poly-α-olefins and esters, and highly refined and hydrocracked mineral oils, which some people regard as synthetic whilst others consider to be of natural origin depending perhaps on whether one is a buyer or a seller!.

5 Mineral Oils

Mineral oils are produced to a performance specification from the refining of crude oil. They vary in viscosity and composition, the major constituents being *n*-alkanes, isoalkanes, cycloalkanes (also known as naphthenics) and aromatics. The molecular weight distribution of the various components largely determines the performance characteristics [37]. Analytical determination of the individual hydrocarbon components in a base oil is not a simple procedure [6, 9, 25]. Gas chromatography in conjunction with mass spectrometry (GC–MS) is used to demonstrate the components of an oil. Typical CG–MS traces for two formulated oil products are shown in Fig. 13.1 [6]. The oils themselves are characterized by an unresolved hump (unresolved complex mixture or UCM) starting at 20 min retention time [25]. This reveals that a typical base oil consists in part of monoalkyl and T-branched alkanes; there are 536 possible acyclic T-branched alkane structures with carbon numbers between C_{20} and C_{30} [25]. Of this complex mixture of hydrocarbons, only a small proportion are water soluble. The presence of ring components (naphthenics and aromatics) further increases the complexity of the base oil mix. Comparison of the traces of the whole product shown in Fig. 13.1 with those for the water-soluble fraction of the same oil shows that the identities of the majority of the water-soluble components are attributable to the oil additives used to enhance the base oil properties (i.e. imido-succinates, sulphur compounds,

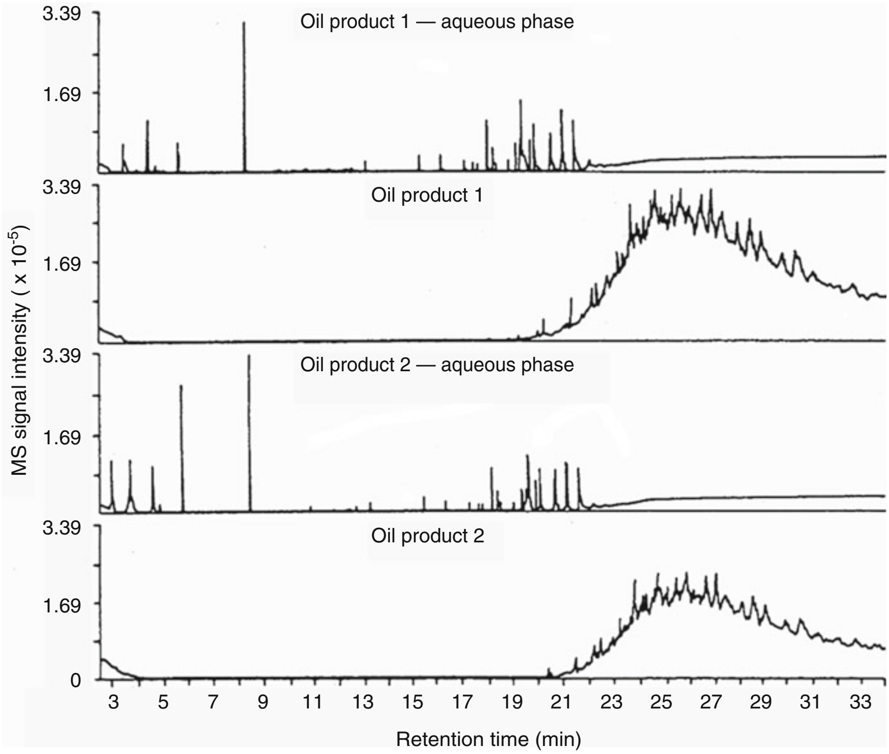

Fig. 13.1 GC–MS trace for two formulated oil products and their aqueous phases at equilibrium (Reproduced from Bennet et al. [6])

methacrylates). Base oil hydrocarbon components in the aqueous phase are present only in minor quantities – the additive components seen in the aqueous phase are not even noticeable when looking at the traces for whole product [6].

The environmental effects of the base oil depend on two factors, the toxicity and the degradability. Toxicity is dependent on the availability of the material and, as we have seen, only a small proportion of the total mix is water soluble. Soluble components tend to be the lower molecular weight hydrocarbons; the higher the molecular weight, however, the higher is the acute toxicity [14]. The outcome of this paradox is that mineral base oils have low acute toxicity to aquatic organisms [3, 5, 9, 18]. However, the rate of degradability has a capacity to affect the environmental impact of the base oil.

Bacteria can utilize various molecules as an energy source or by incorporating them into new bacteria – biomass. This process is known as biodegradation. In general, the more linear a molecule is then the easier it is for bacteria to make use of it. As we have seen earlier, the various molecular structures present in mineral base oils are branched and ring structures with only a small proportion of linear hydrocarbons. For this reason, mineral base oils are regarded as poorly degradable. Such materials do ultimately degrade, however, as has been dramatically shown by the various catastrophic spills of crude oil that have occurred in Alaska and the coasts around Europe and the Middle East [7, 13, 26, 38].

If, however, it is desired to improve the environmental performance of the base fluid, then alternatives to mineral oil are required. Fortunately, bearing in mind our prime concern regarding product performance, the alternatives to mineral oil are also 'better' performers technologically.

6 Synthetic Base Oils

There are two principle types of synthetic base fluids in use, polyol esters and poly-α-olefins (PAOs). A full description of the technology of these materials is given elsewhere [34]. The advantages, environmentally of these materials are described below.

6.1 Polyol Esters

There are three main types of polyol ester used in lubricants [39]:

- pentaerythritol esters $C(CH_2OCOR)_4$
- trimethylolpropane esters $CH_3CH_2C(CH_2OCOR)_3$
- neopentyl glycol esters $(CH_3)_2C(CH_2OCOR)_2$

These materials are structurally very similar to the naturally occurring glycerides (fatty acid esters of glycerol) found in living systems [10, 20]. As bacteria have evolved systems capable of metabolizing glycerides, they are readily able to make any small biochemical adjustments necessary to utilize the polyol esters as sources of energy or as anabolic feedstocks. In consequence, the polyol esters are generally readily biodegradable [4, 10].

6.2 Poly-α-olefins

Poly-α-olefins (PAOs) are generally hydrogenated oligomers of an α-olefin, usually α-decene. Full details of production techniques can be found elsewhere [39]. For the purposes of the current discussion, it is important to recognize that PAOs are produced to meet viscosity requirements, and are classed according to the viscosity at 100 °C, i.e. PAO 2, PAO 4, PAO 6, etc. The larger and more complex the structure of the molecule, the higher is the viscosity and the lower the degree of biodegradability.

7 Hydrocracked Mineral Oils

As mentioned earlier, mineral oils consist of a mixture of different classes of hydrocarbon. Further treatment of the 'standard' base oil by a combination of high pressure, hydrogen and passing over a catalyst (for details see [37]) causes the following changes in composition:

- hydrogenation of aromatics and other unsaturated molecules;
- ring opening, especially of multi-ring molecules;
- cracking to lower molecular weight products;
- isomerization of alkanes and alkyl side-chains;
- desulphurization;
- denitrogenation;
- reorganization of reactive intermediates, e.g. to form traces of stable polycyclic aromatics.

The environmental consequence of these changes is to increase the proportion of molecules present that are able to be utilized by bacteria, hence these products tend to exhibit excellent biodegradability [10].

8 Additives

The purpose of an additive in a lubricant is to impart those properties to the lubricant that are essential to its function but are not present in the base fluid. In consequence, the number and type of additives required to make any lubricant effective is dependent on the base fluid and end use of the lubricant. For details of the function of additives, see Mortier and Orszulik [34].

Additive chemistry is a combination of high technology and alchemy (to the outsider!) and the additive companies spend much time, effort and money developing additives to meet the requirements of the equipment manufacturers and the lubricant companies. Exact formulations of both individual components and additive packages are jealously guarded commercial secrets. The additive manufacturers under the guise of the Additives Technical Committee (ATC) have, however, published some background information on the effects of additives and their potential environmental impact [30]. They have also commissioned research into the toxicity and biodegradability of various component additives in order to generate data required for the classification and labelling of dangerous substances. These data have shown that the component additives have generally low aquatic toxicity when studied using standard test methodology in fish, daphnia and single-celled algae. The most toxic of the components are the zinc-based antiwear/antioxidant additives. These are normally present in a formulated engine oil at approximately 1–2 %.

As the virgin oil and neat additive rarely enter the environment, other than as a result of an accidental spill, and bearing in mind the low toxicity of the base oil component, it can be legitimately argued that the composition of an oil does not present a hazard. The benefits that are gained from a quality lubricant in terms of extended engine life, reduced emissions and fuel savings clearly outweigh any minimal detrimental effects that may occur due to the components.

9 Actual Environmental Effects

It is not virgin oil that enters the environment. Used oil either leaking from cars via faulty seals and joints, or via the exhaust, and do-it-yourself oil changes, the proceeds of which are simply dumped on the soil or down the drain, are the major environmental inputs of lubricants. Estimates of the fate of lubricants sold in the European Union were made by the European oil companies' organization CONCAWE [15] and are shown in Table 13.1.

The result of these estimates can be visualized in the centre of the lanes of any motorway as a black coating of oil or as the stains in any car park bay under the area where the engine comes to rest. The volumes of used oil involved are considerable and have been estimated as representing the equivalent of one *Exxon Valdez* per month over the area of the European Union countries [8]. What are the consequences of such apparently large-scale inputs?

Research was carried out at the University of Sheffield in the UK on the environmental impact of roadway run-off from the M1 motorway at four separate sites [32, 33]. The effects of the lubricants lost from the traffic using the motorway were studied by comparing the biology and chemistry of the receiving water downstream of the run-off entry point with the situation upstream. In this way the only factor affecting the streams was judged to be the run-off from the motorway.

The most striking feature of the studies was the minimal effect on the environment of the run-off. Of the seven streams initially surveyed, only one of those, that with the smallest natural flow of water, showed any effect on the biology of the system. This was measured by comparing the number and diversity of animals and plants in the area downstream of the motorway drainage input with the area immediately upstream. In the one affected site, a decrease in diversity was charactized by fewer sensitive species and an increase in those species typically resistant to the effects of pollution. Hydrocarbons characteristic of used engine oil were found in significant quantities in sediment taken from downstream sites, but not from upstream samples. Water samples were not found to contain any significant contamination. Laboratory investigations in which samples of contaminated sediment were extracted and separated into water-soluble (containing metals), aliphatic, naphthenic and aromatic fractions showed that the principal cause of toxicity was in the aromatic fraction. The other hydrocarbon components and the metal-containing portions did not appear to have any significant toxic effect. This is in line with the low toxicity of the components as discussed earlier.

Table 13.1 Estimates of fate of lubricants sold in the EU [15]

	Tonnes per year ($\times 10^3$)	%
Total EU lubricant sales	4500	100
Consumed	2350	50–55
Recycled	700	15
Burnt as fuel	750	17
Unaccounted for	600	13
Poured down drain deliberately	100	2

Identification of the actual toxic components has revealed that the polycyclic aromatic hydrocarbons (PAHs) phenanthrene, pyrene and fluoranthene account for up to 76 % of the observed toxicity. These particular PAHs have been found not to possess any carcinogenic potential [29].

10 Biodegradability

Oils are biodegradable. Accidents such as the *Torrey Canyon, Amoco Cadiz, Exxon Valdez* and *Braer*, in addition to deliberate pollution such as occurred during the 1991 Gulf War, have led to enormous sums of money being spent on clean-up and scientific investigation not only at the time of the incident but also for prolonged periods where recovery of ecosystems has been followed. Biological activity is primarily responsible for the recovery on both a macro- and micro-scale. Biodegradation by microbes is an essential part of the regenerative process [4, 8, 10, 36]. It should be remembered that even if it were possible to eliminate all lubricant inputs, the environment would still be subjected to large volumes of oils and hydrocarbon materials from natural seepage. We are after all considering a natural product that has leached into the biosphere for many millennia and species have evolved to deal with long-term, low-level exposure to such chemicals.

When tested in standard OECD tests for ready biodegradability [35], oils do not perform well [1, 10]. The standard OECD protocols require either a knowledge of the chemical structure to calculate theoretical values of oxygen uptake or CO_2 evolution or a determination of experimental values for these parameters.

Information on the purity or the relative proportions of major components of the test material is required to interpret the results obtained, especially when the result lies close to the ‘pass’ level.

Of the five test methods currently recommended by OECD for assessing ready biodegradation, the Sturm test is the one that has gained the most widespread acceptance for examining the biodegradability of oil products. A modified version of the MITI test has also been successfully applied. In addition, the Co-ordinating European Council for the Development of Performance Tests for Lubricants and Engine Fuels (CEC) has published a test method, Biodegradability of Two-Stroke Cycle Outboard Engine Oils in Water [11], which has been widely used in Europe by both industry and contract test houses for all types of oil products and poorly soluble hydrocarbons [8, 10]. This method, however, relies on the use of Freon, a substance whose manufacture is no longer permitted under the terms of the Montreal Protocol on ozone-depeleting substances. The life span of the CEC test is therefore severely limited and new methods are under development within the oil industry [16]. For a detailed discussion of the biodegradation of oils, see Cain [10] and Betton [8, 9].

Although it is not appropriate to concentrate here on the mechanism of biodegradation and its relationship to lubricants, it is important to consider the fundamental question of whether the environmentally desirable characteristic discussed in the Introduction need or indeed should be applied to lubricants.

The question of whether biodegradability is a desirable characteristic in a lubricant has been the subject of much, often heated, debate among product developers for many years. In the following paragraphs an attempt is made to highlight some of the areas of concern that have been raised and to give reasons why on balance biodegradability is desirable, always providing, of course, that performance is not compromised.

10.1 Biodegradation Is Not Necessary in a Lubricant

As shown earlier, a large proportion of the lubricant that is sold is 'lost' and unaccounted for. Lubricant *is* deliberately dumped into the environment. This total environmental burden does degrade, albeit at a relatively slow rate. Lubricants specifically designed to be more readily degradable will be less likely to foul the environment via leaks, spills or deliberate dumping.

10.2 A Biodegradable Lubricant Will Encourage Dumping at the Expense of Collection and Disposal

It is fundamental that environmental benefits should be in addition to performance, as was discussed earlier. If that is the case in a product it is probable that a biodegradable lubricant will be at the upper end of the price range. Individuals who specify such lubricants and who are prepared to pay for them are not the type of people who will deliberately dump oil. It is uninformed and socially unconcerned people and those who buy the cheapest product in a chain store who are likely to be involved in dumping.

10.3 A Biodegradable Lubricant Will Degrade in the Engine

Biodegradability depends on bacteria to do the degrading. The environment of a motor car engine, with its extremes of temperature and pressure, is not conducive to the maintenance of bacterial life. In addition, bacteria tend to live in water and not oil; it is only when dealing with emulsions and water contamination that conditions conducive to bacterial growth and degradation of lubricants can occur.

10.4 A Biodegradable Lubricant Will Result in High Concentrations of Toxic Residues That Are Detrimental to the Environment

As we have seen, the additive components of oils are not particularly toxic, and degradation of the base oil will not leave a toxic residue. The work on road run-off has shown that it is PAHs, formed during combustion and deposited in the lubricant, that are responsible for the small degree of toxicity found. These materials are also those with the simplest structure and possess some degradative potential, in addition to which they are subject to degradation by ultraviolet light. It should also be remembered that PAHs are naturally occurring products of combustion and have been present in the environment for as long as there have been fires. Systems have evolved to cope with these materials.

10.5 Biodegradation Is Not Necessary, as Motor Manufacturers are Now Producing Sealed Lubricant Systems

A motor car may well not leak oil for the first few years of its life, although as examination of the Chief Executive's parking space will eloquently demonstrate, this is not always the case! Motor cars are now lasting for much longer periods and it is apparent that there are and will always be a large proportion of the cars on the road that leak oil to the environment. A biodegradable lubricant would be effective in minimizing the effects of those losses.

11 Collection and Recycling of Used Oils

The recycling of used lubricants has been practised to various degrees since the 1930s and particularly during the Second World War when the scarcity of adequate supplies of crude oil during the conflict encouraged the reuse of all types of materials, including lubricants. Environmental considerations regarding the conservation of resources and sundry 'oil crises' have maintained interest in the concept of recycling up to the present day. A recent review [17] has examined the environmental costs and potential benefits of the whole issue of collection and disposal of used oil in great detail. More recently, independent organizations have considered whether the concept of recycling is environmentally valid and whether the regulatory requirements actually deliver environmental benefits [24]. (IMech E 2004). Irrespective of this however there are currently legislative requirements for the recycling of used oils [21, 22].

It is essential to recognize that all used oils should be collected for controlled disposal. Some products, such as transformer oils and hydraulic oils, can be readily collected from large industrial concerns, regenerated to a recognized standard and returned to the original source.

Oils from automotive sources will include mono- and multi-grade crankcase oils from petrol and diesel engines, together with gear oils and transmission fluids. Used industrial lubricants that have been inadequately segregated may also be included. Apart from any degradation products from the in-service use of the oil, a wide range of contamination is possible, including the following:

- water – combustion by-product, rainwater/salt water ingress;
- fuels – residual components of gasoline and diesel fuel;
- solids – soot, additive and wear metals together with rust, dirt, etc.;
- chemicals – used oil can be used as an unauthorized means of hazardous waste disposal;
- industrial oils – inadequate segregation of oil types can allow contamination by fatty or naphthenic products.

Provided that efficient management systems are in place, many industrial oils should be largely contained and not escape into the environment. There are many potential sources of used industrial products; however, reprocessing is not an option for a large number of these products which are synthetic and fatty-oil based. Some specific types of industrial oils are suitable for relatively simple reprocessing before being returned to their original service. Typical processing methods involve filtration and removal of water and volatile decomposition products under vacuum, and can sometimes be carried out at the plant using mobile equipment.

Legislation around the globe is increasingly controlling the collection and disposal of all waste materials, including lubricants. Large-scale (greater than 3 m^3) waste oil collection vessels at service stations must now be licensed in the UK, as must any company that transports or treats waste lubricants.

The method of disposal that is utilized will be dependent on many different factors, however. Availability of appropriate treatment facilities, raw materials, type of product being collected, levels of contamination and so on will all affect which is the most appropriate disposal route. A full life-cycle analysis of each situation would be required before a definitive choice of disposal option could be made. However, such analyses are complex, time consuming and necessarily subjective. The following used oil disposal routes are considered to offer the 'best environmental option':

- re-refining to base oil using modern technology to reduce PAH concentrations to acceptable levels (e.g. using severe hydrotreatment or solvent extraction);
- reprocessing to industrial fuel using modern technology (e.g. Trail-blazer process);
- recycling through a refinery as a low-sulphur fuel oil blendstock;
- direct burning as fuel in cement kilns;
- burning after mild processing in road stone coating plants (care must be taken to ensure that emissions of chlorine containing components do not exceed acceptable limits);
- gasification to produce fuel gas or petrochemical feedstock.

The following disposal routes are considered to involve unacceptable levels of pollution due to emissions to soil, air or watercourses and should not be countenanced under any circumstances:

- direct burning in space heaters (emissions of heavy metals and other products of low-level combustion causing localized pollution);
- re-refining using acid/clay and other old technologies (the majority of plants currently in operation) producing acid tars and oiled clay requiring specialist disposal;
- road oiling (high risk of groundwater contamination).

The economics of environmentally acceptable used oil disposal will be dependent upon the availability of local facilities. None of the environmentally acceptable methods listed above are considered to be financially self-sufficient without the application of some form of subsidy. This is largely related to costs of collection and transport. For a full discussion of the economic arguments, see CONCAWE [17]. This greater understanding of the total environmental impacts of waste oil recycling has led the EU to question the assumption that regeneration is always the favoured option and has entered into consultation on 1975 Waste Oil Directive. The EU has yet to report [23], but it is to be hoped that a more environmentally aware policy may yet result and that the stated aims of the consultation process, namely that ....“*from an environmental point of view, each treatment operation should be judged principally in terms of how much impact it has on the environment. This approach, differentiating between scarcity and impact as environmental problems, was outlined in the Commission Communication:* ***Towards a Thematic Strategy on the Sustainable Use of Natural Resources(COM/2006/0670/Final)***”. In answer to questions posed to the Commission, on 15th June 2015, the Commission replied as follows (See:- ec.europa.eu/environment/archives/waste/oil/questionnaire.htm:) “DG Environment has commissioned in 2001 the study “Critical Review of Existing Studies and Life Cycle Analysis on the Regeneration and Incineration of Waste Oils”. The study compares regeneration with incineration of waste oils in terms of environmental impact. On the basis of all available life-cycle-assessments, the study concludes that the regeneration of waste oils has advantages and drawbacks in relation to other recovery options, such as incineration in cement kilns and gasification, but no clear overall advantage for regeneration was found.” The

Directive still remains but it is now acknowledged that the legislation is not fit for purpose by requiring used oil recycling. Where we go from here is open for debate, but a more sensible approach is clearly possible

12 REACH Regulation

On the 30th December 2006 the European Union published in the Official Journal of the European Union a piece of legislation that was to change forever the regulation of chemicals around the world REACH [40]. The legislation was:-

> **REGULATION (EC) No 1907/2006 OF THE EUROPEANPARLIAMENT AND OF THE COUNCIL**
>
> of 18 December 2006 concerning the Registration, Evaluation, Authorisation and Restriction of Chemicals (REACH), establishing a European Chemicals Agency, amending Directive 1999/45/EC and repealing Council Regulation (EEC) No 793/93 and Commission Regulation (EC) No 1488/94 as well as Council Directive 76/769/EEC and Commission Directives 91/155/EEC, 93/67/EEC, 93/105/EC and 2000/21/EC

Up until this point chemicals manufactured, imported and used in the EU were controlled by a range of nearly 40 different pieces of legislation and interpreted by the individual member states in their own ways. Governments and the EU took retrospective action: if there was a problem with a chemical or process then there would be regulation. New chemicals (introduced after the 1980s) had to be tested, but there was no control over existing chemicals other than that which followed either disasters or incidents. Legislation had been formulated piecemeal in response to incidents and accidents and was not coherent or common in purpose.

REACH however changed all of that, although it was close to not being passed at all. There was significant lobbying against the introduction of REACH in the EU not just by Industry but also by the US Government [19, 43] against its enactment and a deadline had been set for its introduction into Law that was only just met. One day later and REACH would have never seen the statute books.

Since the introduction in the EU however, China (China REACH [12]), Malaysia (Malaysia REACH [31]) and Korea (AREC [2]) have all produced a similar pieces of legislation and other countries are following suit. REACH is becoming universal and has changed things for ever. Previous chemical laws had generally included “lists” of substances – be on the right list and you could import/export and use chemicals with little or no concern: it was up to the user to ensure that the substance was safe and used in a way that did no harm, and if they were not concerned it was their responsibility.

Governments and international organisations had made attempts to control some substances in the past, but often political considerations found a way into what was being proposed. Discussions and reviews got bogged down by vested interests and political rather than scientific considerations became paramount. The revolutionary thing that REACH achieved was to remove the assessment process from Government and place it where it really belonged: with the companies who make, import or use the chemicals. The basic philosophy of REACH is very simple. If you want to make a substance in the EU or import it into the community and it exists in a form that could enter the market either deliberately or as a result of an industrial accident, then you must:-

1. Know what it is
2. Know how it is used
3. Know what it does to people and the environment
4. Tell people how to handle it
5. Tell people what to do in the event of an accident
6. Register this information with the EU
7. Provide information to customers and the general public, free of charge.

The mantra that was used in the EU prior to the introduction of the REACH Regulation was "No data, no market". This sums up the sea-change in chemical regulation that was introduced by REACH. It is no longer possible for companies to introduce chemicals into the EU market without knowing sufficient information about the substance, what it does and where it goes, for any given use of that substance.

There are of course a plethora of documents and guidance information (REACH [41]) that can be consulted and pored over and there are some limitations to the application of the REACH Regulation. REACH only applies to substances that are manufactured or imported in quantities of 1 tonne per calendar year or more, *per user or importer*. REACH only applies within the EU and it does not apply to manufacturers outside the EU – unless they wish to export to the EU, in which case the importer is treated exactly the same as a manufacturer based within the EU for the purposes of the Regulation: an importer is placing the substance on the EU market and they must follow the same rules that apply to manufacturers based inside the EU. It must be noted that the REACH Regulations in China have no limit on the tonnage of materials in relation to applicability, Polymers and NOT exempt and several other fundamental differences to the EU Scheme exist. REACH may become Universal, but it is unlikely to be Identical in all countries!

All substances must be registered with the European Chemicals agency in respect of their uses and a Risk Assessment must be carried out in relation to the uses of the substance to demonstrate that the effects on people and the environment are known, understood and do not pose a risk. If the substance has certain properties that would result in it being a Substance of Very High Concern (SVHC), such as being Carcinogenic, Mutagenic, toxic to Reproduction (CMRs) or if it has properties that indicate that it may disrupt hormone systems (Endocrine Disrupters), in relation to Human Health effects, or in terms of Environmental Impact, if it is Persistent, Toxic or Bioaccumulative (PBT), then the substance may be subject to controls or restrictions in terms of use.

It is the responsibility of the manufacturers and importers of all substances to carry out the work that is necessary to demonstrate that chemicals are safe for the uses that are intended for that substance. If new uses are proposed for a substance, then additional risk assessments must be performed.

This new emphasis on knowledge and information is aimed at ensuring that the chemical disasters that have been a part of history are not likely to occur in the future. It is not a requirement that all substances are safe, but it is a requirement that an assessment of risk and indeed of the potential benefits of the use of the chemical are considered BEFORE it enters the environment. Performance is a key factor in Lubricant development and an additive that can for example lead to an improvement in engine performance of a few percent, could lead to a very large impact on CO_2 emissions, one of the most significant adverse effects of human activity in the last 100 years. Any Risk Assessment should take the positive benefits as well as any negative impacts into account. REACH is not a block to innovation, it merely means that as well as hundreds of thousands of pounds spent of performance testing, lesser but not insignificant sums must also be set aside to ensure that the wonder chemical that will make millions, does not also decimate wildlife or cause unknown adverse effects before it enters the environment, in which we all must live.

13 Conclusion

Environmental technology as applied to lubricants is related first and foremost to performance. The benefits to be gained from reduced wear and friction are substantial and in far outweigh all other aspects particularly in respect of CO_2, Climate Change and conservation of resources. There are environmental aspects of a lubricants performance, however, that when addressed can reduce what is after all a surprisingly small impact due to the inevitable losses that occur during use.

The perfect ‘environmental’ lubricant that was outlined in the Introduction does not, nor will it probably ever, exist. It is hoped that it is now apparent, however, that some of the ideal characteristics are not needed, and that those that are desirable are so for reasons of aesthetics and a desire to keep the environment clean, rather than for a compelling need to reduce toxicity and impact on ecosystems.

The introduction of the REACH Regulation means that all new chemicals that are introduced must now – by Law – be shown to be safe and not to damage the environment, making performance the major criteria for product developers as, along with financial viability, these factors must now be automatically considered prior to any appearance of any chemical into the EU Marketplace.

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Chapter 14
Climate Change Scenarios and Their Potential Impact on World Agriculture

Craig Wallace, M. Hemming, and D. Viner

1 What Causes the Climate System to Change?

The Earth's climate system is a complex interaction of a number of components, such as the ocean, atmosphere, ice masses (cryosphere) and living organisms (biosphere). Although the system is ultimately driven by solar energy, changes to any of the components, and how they interact with each other, as well as variability in the solar radiation received, can lead to a change in climatic conditions. There are many causes of climate change which operate on a variety of time scales. On the largest time scales are mechanisms such as the Milankovitch-Croll effect and geological processes.

The **Milankovitch-Croll** effect concerns the characteristic of the Earth's orbit around the sun and is thought to be responsible for governing the main glacial and interglacial episodes that are evident in the prehistoric climate record. Over a time scale of thousands of years variability is experienced in three important orbital characteristics. Firstly, the shape of the Earth's orbit is known to vary between that of a near-circle and a more exaggerated ellipse over a period of approximately 93 000 years. This controls how much solar radiation is received by the planet at a particular time during the year; a more circular orbit means less variation but an elliptic orbit will result in larger changes. A highly-elliptical orbit tends to *enhance* the seasons in one hemisphere and *moderate* them in the other. Many researchers cite this mechanism as the most important in triggering a glacial period due to cooler than normal summers which fail to melt seasonal snowfall in the middle and high latitudes.

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4_14

The second Milankovitch-Croll effect concerns the tilt of the Earth's axis of rotation. The axial tilt is known to vary between approximately 21° and 24° over 40 000 years. A larger degree of tilt amplifies the seasons in *both* hemispheres. At present the axial tilt of the Earth is approximately 23.5° and appears to be on a descending leg of a 40 000 year cycle [2].

The final Milankovitch-Croll effect concerns the 'precession' of the north pole, that is where into space the north pole points. The procession has the smallest periodicity, about 20 000 years, and is independent of the axial tilt variations, but can affect the climate of Earth by altering the dates on which the closest and farthest distances to the Sun are achieved. Again, this affects the degree of seasonality which is experienced in each hemisphere. For example, the closest point between the Earth and the Sun at present occurs on January 4th, during the southern hemisphere summer.

Geological processes known to influence climatic conditions occur on an even longer time scale than orbital variations, but produce major changes. Continental drift or plate-tectonics occurs very slowly but can alter the climate by a number of mechanisms. Firstly movement of continental plates can upset and redirect ocean currents moving heat from one sector of the planet to another. Secondly, movement of the major continental plates adjust the latitude at which that particular land mass resides affecting the severity of seasonality and the mean annual temperature. Thirdly, continental drift is responsible for mountain range formation serving not only to cool the climate of the uplifted region, but redirecting atmospheric circulation which has climate implications for adjacent regions. It is important, though, to grasp the tardy nature of these effects; the location of the major continental plates has been approximately unchanged for the last 50 million years.

One geological process which affects climatic conditions on a much shorter time scale is **volcanism**. Large, explosive volcanic eruptions can inject huge amounts of soot and ash into the middle atmosphere where they are beyond the cleansing effect of rainfall forming processes. The strong winds typical of the higher altitudes are effective in transporting these particles around the planet where they reflect solar radiation back into space creating a 'global soot veil'. The climate impacts of volcanic event usually decay after 1 or 2 years, however, some evidence suggests that lower-frequency so-called 'super-eruptions' whereby whole regions are seen to erupt can alter the climate for enough time to cause radical species loss. Fortunately the return periods of these events is close to 50 000 years [16].

In addition to geologic and orbital changes, the climate system is sensitive to inherent and periodic **internal variability** to any one of its components. A good example of this is the well known El-Nino event, where ocean upwelling in the Equatorial Pacific is weaker in one season than is the norm. The resulting changes to the wind patterns produces drought in some regions and floods in others as the weather systems respond to changes in sea surface temperatures. Other internal mechanism producing climatic changes include random (i.e. one off) changes to a particular ocean current which changes the pattern of heat distribution. It is important to acknowledge the **climate feedbacks** which exist and modify not only internal variabilities, but indeed any type of climatic change. For example, the ocean current switch might warm a high latitude region reducing its snow cover meaning more exposed land surface is able to absorb solar heat in the winter leading to even more warming. It is an overriding aim of climate science today to increase our understanding of such relationships and how internal processes relate to one another and might upset one component of the system and what climatic change might occur as a result.

Aside from the natural mechanisms capable of causing widespread changes to climatic conditions discussed so far, there is **anthropogenic climate change**, that is climate change caused by man's activity. This has many guises such as alteration of the planet's reflectivity and thermal properties by changing land cover type, but the most well-known anthropogenic influence concerns the enhanced greenhouse effect. Certain gases within the Earth's atmosphere are transparent to incoming energy, but opaque to outgoing heat and are responsible for maintaining an average global temperature of around 15 °C. The greenhouse effect is natural, but since the industrialisation of many nations in the nineteenth century, additional quantities of greenhouse gases (namely CO_2) have been added to the atmosphere through the burning of carbon-rich fossil fuels. The vast additions to the atmosphere of CO_2 that have occurred in recent decades are now believed to have enhanced the natural greenhouse effect. Greenhouse theory and anthropogenic forcing of the climate system is discussed in greater depth in Sect. 3.

2 Past Climatic Changes

The Earth's climate system is changing today, but has experienced numerous changes in the past. Indeed, it is helpful to think of the climate system as constantly adjusting to the fluctuation in energy inputs and outputs (forcings) which result from the mechanisms explained in Sect. 1. Very recent climatic changes can be detected through analysis of thermometer readings. Reliable thermometer readings are generally accepted to have begun in the mid nineteenth century and accordingly the period from then up to the present is termed the **instrumental period**. However, climatic conditions can also be estimated further back in time through use of non-direct, **proxy**, measurements of climatic variables.

Climate reconstructions using the proxy method rely on a number of techniques, such as tree ring width data, analysis of ice core segments and chemical composition of ocean and geological sediments but to name a few. Proxy methods allow a reasonable estimate of temperature (and in some cases precipitation) for the past few thousand (tree ring) and hundreds of thousands (ice cores) of years. Whilst the *exact* dating of the latter records may be difficult the data are nonetheless sufficient to identify major climatic adjustments and help to place very recent climate change in the context of pre-human variations.

Analysis of oceanic and geological sediment has established that during the course of the past 800 000 years the Earth has experienced a number of warm **interglacial** and cold **glacial** periods, each of which last several (and maybe tens of) thousands of years. It is also possible to determine that we are currently experiencing a warm interglacial period which began approximately 10 000–12 000 years ago and marks the start of the current epoch, the **Holocene** (e.g. [11]). The changes in temperature which accompanied the switch from the last glacial to the present interglacial period were not smooth and varied greatly over the planet. However, work focusing upon the British Isles has estimated that between 13 300 and 12 500 years before present, the mean temperature rose by 7–8 °C in summer and ~25 °C in winter [1].

With the advent of the Holocene Epoch and the flourishment of civilisations in the warmer climates, written historical records point to a number of climatic changes that have occurred over the past 1–2000 years. Lamb [11] notes historical writings that suggest the period between 900 and 300 BC were especially cold over Europe; Roman writers reported severe winters in Italy, which match records of glacial advances within the Alps (Hueberger 1968). Conversely, the final century BC seems to have been warmer and indicative of the onset of a less harsh climatic period. For instance, records suggest that Roman agriculture extended north and the Alpine Glaciers retreated [11].

Several climate reconstructions based upon proxy records (particularly tree ring widths) have recently become available with which to investigate climatic changes in the last 1000 years (Fig. 14.1). The last millennium is generally accepted to have experienced three main climatic epochs. The **'Medieval Warm Period'** characterised the climate of the twelfth and thirteenth centuries, and was followed in the sixteenth and seventeenth centuries by the **'Little Ice Age'**. The final, more recent, climatic event has been **post-industrial warming**. The dates of the first two events are often the topic of much debate, particularly because many of the information pointing to their existence appears to vary in timing for different parts of the planet. Indeed, whether or not the terms are actually applicable in describing the average climatic conditions of the time is also increasingly questioned. Lamb [11] cited colonisation of high-latitude regions and evidence of vine cultivation in Britain as evidence supporting a pronounced Medieval Warm Period (MWP) for Europe at least. However, others (e.g. [10]) question the validity of the MWP pointing to a lack of a distinct rise in the proxy temperature record for the northern hemisphere average at this time and citing other reasons why agricultural changes may have occurred. The caveat is that, whilst some individual evidence may point to a warmer epoch, it is dangerous to infer a widespread warming event without hard and fast facts.

What is evident from many of the curves in Fig. 14.1 is the existence of a cooler period during the sixteenth and seventeenth centuries. Glacial advances within Europe have been shown to be widespread and loss of agricultural land would have resulted. Many reconstructed climate records indicate that the coldest annual temperature in the last 1000 years occurred in 1601 [10]. Nonetheless, the validity of the actual Little Ice Age has, like the MWP come under question itself. Some researchers point to the fact that many individual years during the Little Ice Age period saw temperatures as warm as present levels [10] and glacial advances occurred at different times during the supposed 'cold' centuries.

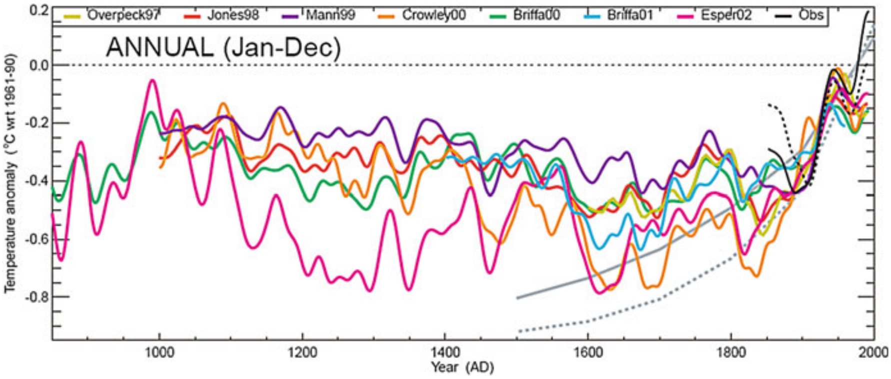

Fig. 14.1 Estimated and observed temperature curves

In 1815, as more reliable instrument-based measurements were becoming more frequent, the Indonesian volcano of Tambora causing a classic soot veil effect. The climatic and agricultural implications of the eruption were severe. Cool weather endured over northeastern USA, Canada and Europe the following year leading to catastrophic crop failures and a year 'without a summer' (e.g. [15]), highlighting the sensitivity of the climate system (and global agricultural) to violent, explosive eruptions.

The third climatic event of the last 1000 years, **Post-industrial warming**, can clearly be seen in the observed instrumental record (the black curve in Fig. 14.1 and a more detailed curve, Fig. 14.2) and lends weight to the argument of human-induced climate change. Two warming events are apparent and these constitute the *only* statistically-significant events of the instrumental record [10]. The first warming period occurred between 1920 and 1945; the second since 1975. Analysis of the observed record, in the context of the last 1000 years, reveals that the warmest temperatures globally were recorded between 2002 and 2014. According to the UK HadCRUT4 global temperature record (Morice et al. 2011), 2010 and 2014 were, jointly, the warmest individual years. Each of the last three decades have been warmer than any over decade since 1850, with the most recent decade succeeding the last. The lower, global curve in Fig. 14.2 shows that compared to temperatures representative of the mid twentieth century the annual global mean temperature of 2014 was ~0.6 °C warmer.

The instrumental record indicates that this warming has affected the middle-high latitudes of the northern hemisphere the most with winter months warming more rapidly than summer months. For these regions, insofar as agriculture is concerned, an extended growing season has also been observed in some records (e.g. Menzel and Fabian 1999), although changes to the rainfall regime of any individual region can complicate potential agricultural benefits.

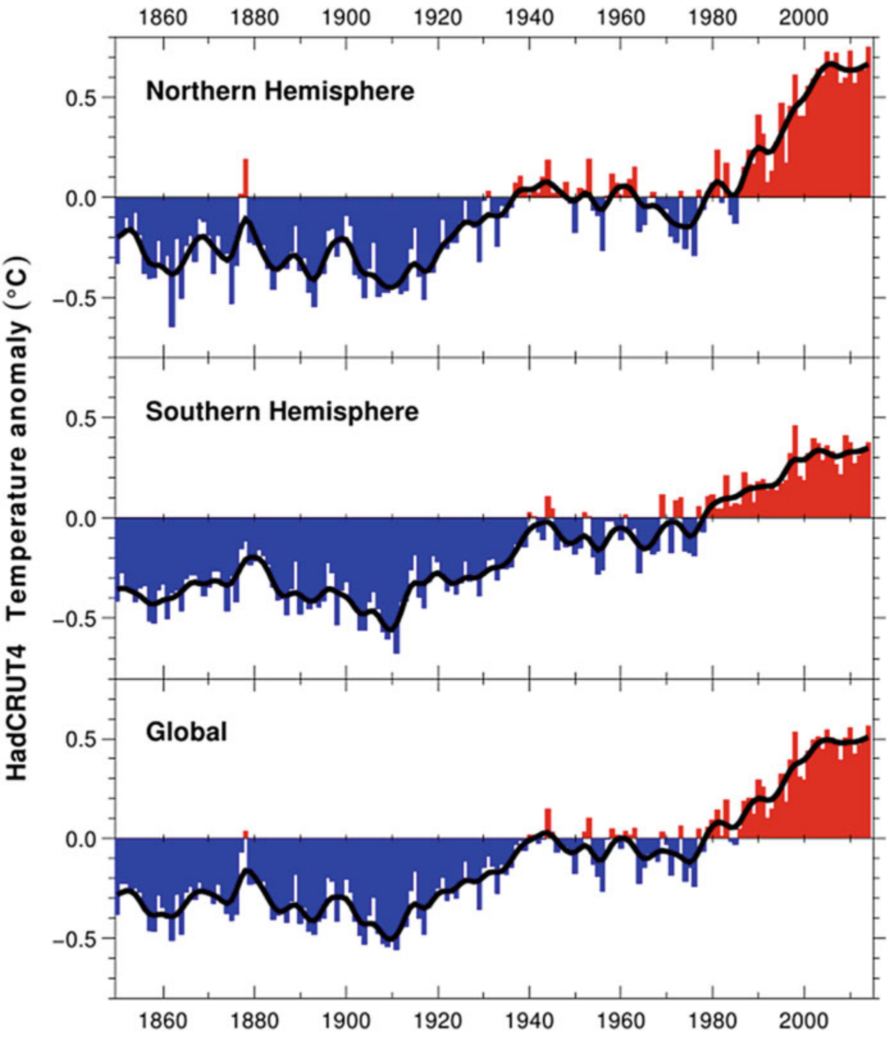

Fig. 14.2 The HadCRUT4 observed temperature record (Source: Climatic Research Unit, University of East Anglia; [12])

3 Anthropogenic Forcing of the Climate System

Anthropogenic forcing of the climate system is primarily achieved through the release of greenhouse gases to the atmosphere as a result of industrial (and to a lesser extent agricultural and domestic) activities. These gases include CO_2, CH_4 (methane) nitrous oxide and halocarbon gases (which also have ozone-depleting characteristics).

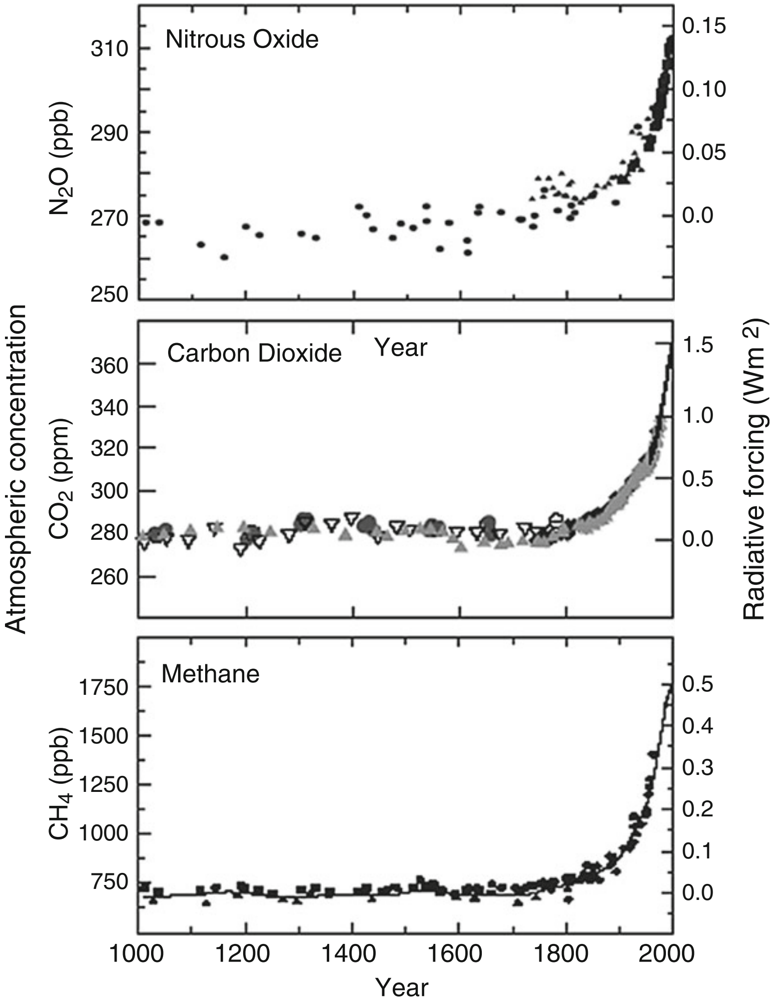

Fig. 14.3 CO_2, NO_X and CH_4 curves over last 1000 years

Greenhouse gases vary in their ability to intercept outgoing radiation. For example methane is a very chemically efficient greenhouse gas, but the gas most commonly associated with anthropogenic forcing is CO_2, due to its greater abundance within the atmosphere. Measured levels of CO_2, methane and nitrous oxides via instrumentation and analysis of air trapped in ice cores for the past 1000 years show marked and unprecedented increases in atmospheric concentrations in recent times (Fig. 14.3). The commencement of these increases coincides with the rapid industrialisation of the northern hemisphere during the late eighteenth and nineteenth centuries.

Since 1750, the global atmospheric concentration of CO_2 has increased by 31 %. Analysis of extended data sources indicate the current atmospheric concentration of CO_2 is the highest for the past 420 000 years, and is likely to be the highest within the last 20 million years [4]. The percentage increase in methane concentrations is greater, having risen 151 % since 1750, whilst concentrations of nitrous oxide have risen by 17 % [7] over the same period.

The impact that changes in the atmospheric concentration of any one greenhouse gas might have on the thermal properties of the atmosphere can be measured in terms of **radiative forcing**. In a steady, or unperturbed, state, the amount of energy leaving the top of the Earth's atmosphere *must* exactly match the amount of energy entering the system. If the energy input or output becomes unbalanced (i.e. does not exactly match) through either an increase in solar energy entering the system *or* a decrease in the energy able to leave the planet's atmosphere, then there is said to be a radiative forcing placed upon the system. This extra energy is expressed in watts per metre squared (the area referring to the top of the Earth's atmosphere, where the climate system is separated from space) and results in the climate system altering its temperature in order to emit more energy and once again achieve a steady balance.

The elevated radiative forcing associated with the increased concentrations of the three main greenhouse gases are shown on the right-hand axis of Fig. 14.3, although there are some uncertainties regarding these values. In total, however, increased atmospheric concentrations of CO_2, CH_4 and nitrous oxides are estimated to have placed an additional 2.1 Wm^2 of radiative forcing onto the climate system since 1750 [4].

Exactly how the climate system might respond to such an alteration to its energy balance has been the quest of climate science for many years. The resulting change in temperature necessary to restore the system to equilibrium depends upon a whole host of factors and is generally referred to as the **climate sensitivity**. Nonetheless, computer simulations of the Earth's climate indicate that the level of observed global warming evident in the instrumental record is consistent with the estimated response to the additional anthropogenic radiative forcing. It is this fact along with the geographical pattern of the observed warming that has led the IPCC to conclude that 'in the light of new evidence and taking into account the remaining uncertainties, most of the observed warming over the past 50 years is likely to have been due to the increase in greenhouse gas concentrations' [4].

4 Future Changes in Anthropogenic Forcing

Projections of future climate change can be developed by computer simulations of the Earth's climate system. Simulations must consider likely future changes to both natural and anthropogenic radiative forcing. In respect of the latter, the IPCC [7–9] has applied four possible future scenarios which attempt to quantify future greenhouse gas concentrations through to the year 2100 [18]. Estimates of greenhouse gas concentrations in each of the four scenarios are based upon changes that may

Table 14.1 Summary conditions of the IPCC RCP (Representative Concentration Pathway) scenarios

Scenario Component	RCP2.6	RCP4.5	RCP6	RCP8.5
Greenhouse gas emissions	Very low	Medium-low mitigation Very low baseline	Medium baseline; high mitigation	High baseline
Agricultural area	Medium for cropland and pasture	Very low for both cropland and pasture	Medium for cropland but vey low for pasture (total low)	Medium for both cropland and pasture
Air pollution	Medium-Low	Medium	Medium	Medium-high

After Ref. [18])

occur in important social and economic factors (e.g. global population, degree of globalisation, investment and use of sustainable energy sources etc.).

The four scenarios and their associated changes in social and economic factors are summarised in Table 14.1 and Fig. 14.4. The first of the four scenarios, **RCP2.6,** represents a world in which rapid economic growth occurs throughout the twenty-first century leading to higher GDP worldwide, along with cleaner more sustainable energy use. These changes lead to medium-low levels of air pollution. Global population increases for the first part of the century, peaking around the year 2070, before falling towards the end of the twenty-first century. Out of the four scenarios, RCP2.6 represents a world where greenhouse gas mitigation has worked most efficiently, with a decrease of global emissions starting in the year 2020 and very low levels throughout the century. Agricultural area is at a medium level for both cropland and pasture.

RCP4.5 represents a future world in which population and GDP growth increases at a relatively similar pace to RCP2.6, but primary energy consumption is higher. This leads to medium levels of air pollution and a continued increase in carbon dioxide emissions until the year 2050. After this, a decrease in CO_2 emissions pursues until 2080, followed by a period of sustained rates of emissions until the end of the century. A very low amount of agricultural land is being used for pasture and cropland.

The third scenario, **RCP6,** has the lowest increase in GDP throughout the century, but a higher rate of population growth, which peaks around 2080. Air pollution is at a medium level, but effort has been made to mitigate climate change. As a result, carbon dioxide emissions increase substantially, peaking in 2060 before declining towards the end of the century. This reflects the trend in primary energy consumption, which also peaks in the year 2060. A greater proportion of agricultural land is used for cropland, rather than for pasture.

Finally, **RCP8.5** represents a bleaker future in which population is a third greater than that in RCP2.6 by the end of the twenty-first century. Primary energy consumption is high, meaning that medium-high level air pollution persists, and considerably more carbon dioxide is emitted throughout the century as a result of

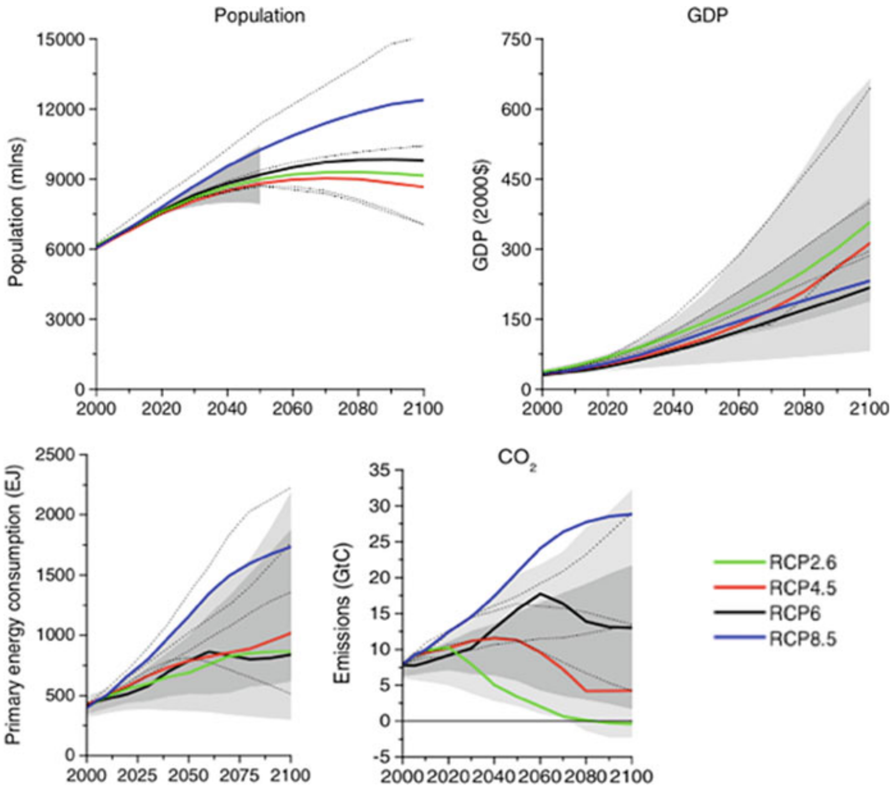

Fig. 14.4 Socio-economic trajectories of each RCP scenario (After [18])

minimum mitigation effort. Similar to RCP2.6, a medium proportion of agricultural area is used equally for cropland and pasture.

5 Implications of RCP Scenarios on Global-Mean Climate

Projections of future climate change during the present century can be made by simulating the Earth's climate using complex global circulation models (GCMs). GCMs are mathematical approximations of the real physical climate system and are able to model the transport and exchange of energy between a number of the climate system's components. For example, all GCMs used by the IPCC to develop future climate change scenarios have interactive atmospheric and oceanic components, including representation of seasonal sea ice. Most GCMs also have an interactive land surface scheme which simulates the moisture and energy fluxes between the ground and the atmosphere; these fluxes change geographically within the model depending upon the imposed land surface type.

Although GCMs represent the most complex and cutting edge tools with which to project future climate change, there are many uncertainties associated with their results, which should be acknowledged. For instance, some real-world climate system components are poorly understood, and so their approximation by mathematical equations is difficult. A good example of this, and an ongoing debate in climate change, is the role that changing characteristics of clouds might play on the future climate. Uncertainties in the future climate projections also arise via the constraints and costs associated with the current level of computing power. For example, although some physical processes are very well understood it is necessary to simulate them on a crude geographical scale so that the cost of running simulations is kept practical. However, specific regional climate models (RCMs) have also been developed for specifically simulating the climate of a singular region only (as opposed to the whole globe). RCMs are able to approximate processes on a finer geographical scale and some of their results are considered in Sect. 6. The focus in this section, however, is the *global* response of the climate system to future changes in forcing.

5.1 Temperature

Due to the abnormally high levels of CO_2 in the Earth's atmosphere at present global-mean temperature increases can be expected during the present century even if all greenhouse gas emissions were to cease immediately. Such an event is, of course very unlikely; the RCP scenarios provide outlines for more likely changes in anthropogenic forcing in the coming century and are described in Sect. 4. The mean global temperature response to each RCP scenario (Fig. 14.5) is different, reflecting the extent to which greenhouse gas concentrations either stabilise, decrease or rise during the twenty-first century. For example, the temperature response in a fossil-fuel intensive future (RCP8.5, red line & uncertainty bar in Fig. 14.5) by the year 2100 could be anywhere between ~2.5 and 4.8 °C above mean 1986–2005 conditions. However, if a RCP2.6-type scenario is followed in the present century (blue line & uncertainty bar in Fig. 14.5) then the temperature response, although positive, may be somewhat lower, in the range of ~0.25–1.75 °C above the 1986–2005 mean. Acknowledging these ranges, the IPCC concluded in their fifth assessment report that 'global surface temperature change for the end of the twenty-first century is likely to exceed 1.5 °C relative to 1850–1900 for all RCP scenarios except RCP2.6'C [7]. With this increase in mean surface air temperature, it is expected that there will be more frequent extreme high temperature events, and a lower frequency of extreme low temperature events.

Some of the projected temperature increases are more conservative than those previously estimated (e.g. IPPC 2007). This is, in part, due to improvements in the model used to simulate future changes in temperature, for example refined cloud and aerosol processes, and a wider representation (though still not complete) of important climate processes. In a general sense, low-level clouds and aerosols, have

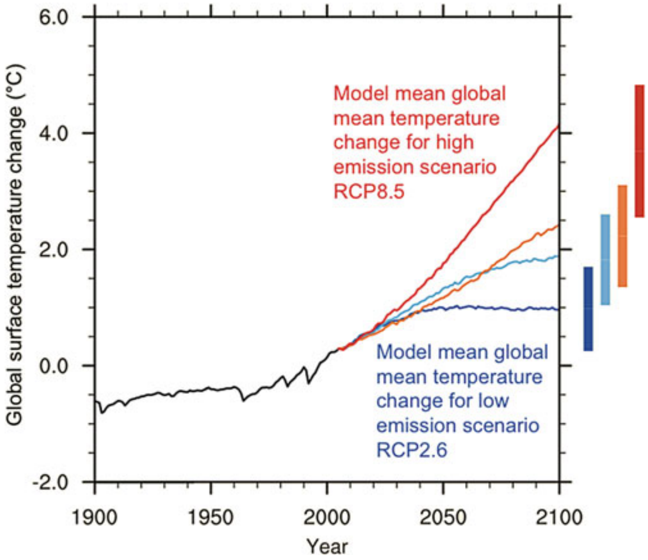

Fig. 14.5 Simulated mean global temperature change in twenty-first century with respect to 1986–2005 values under the four IPCC RCP scenarios (RCP2.6, *dark blue*; RCP4.5, *light blue*; RCP6.0, *orange*; RCP8.5, *red*) [7]

a negative forcing upon the climate system, reflecting incoming solar radiation and acting to offset some of the greenhouse-related warming.

5.2 *Precipitation*

As with temperature, globally-averaged precipitation is projected to rise during the twenty-first century. The precipitation increase can be directly linked to the rise in temperature. Not only do evaporation rates increase under warmer conditions, but a warmer atmosphere is also able to hold more moisture. The IPCC (2013) also indicate that increased levels of precipitation will be accompanied by a simultaneous increase in precipitation variability; although on average more rainfall will fall, this may be delivered by short, intense outbursts leaving other periods prone to drought.

The average global precipitation response under the IPCC RCP2.6 scenario by 2100 amounts to an increase of 0.05 mm day^{-1}, with respect to mean 1986–2005 conditions. The comparative change under the stronger RCP8.5 scenario is 0.15 mm day^{-1} and there are strong regional contrasts in this response in all RCPs (see below). Significant advances in the understanding of precipitation changes under global warming have occurred in recent years, particularly with respect to the rate of change, under warming and the interplay with the energetic budget of the climate system (e.g. [14]). Thus, it is known that the *rate* of global precipitation change, per degree of global warming, is attenuated under warmer conditions – with precipitation rising between 1 and 3 % per degree of global warming but the highest of these rates occurring under the RCP2.6 and RCP4.5 scenarios [7]. Accompanying the trend towards a wetter planet, there is evidence to suggest that the additional precipitation will be delivered by more intense precipitation events [4].

5.3 Sea Level Rise

The range of projected globally averaged sea level rise in the twenty-first century is large, lying between 0.26 and 0.98 m for the full set of RCP scenarios according to the IPCC (Fig. 14.6). The mean increase by the year 2100 is 0.54 m which represents a two to four increase in the rate of sea level rise which was recorded in the twentieth century. The amount of sea level rise experienced in each scenario differs only slightly in the first half of the twenty-first century (for those same reasons outlined in Sect. 5.1). Greater inter-scenario differences can be seen in the years after 2060, with larger rises in sea levels associated with the fossil-fuel intensive scenarios.

The majority of the projected sea level rise is due to thermal expansion of the oceans as the planet becomes warmer. Additional sea level rise is caused by the input of fresh water from glaciers and the major ice sheets of Greenland and the

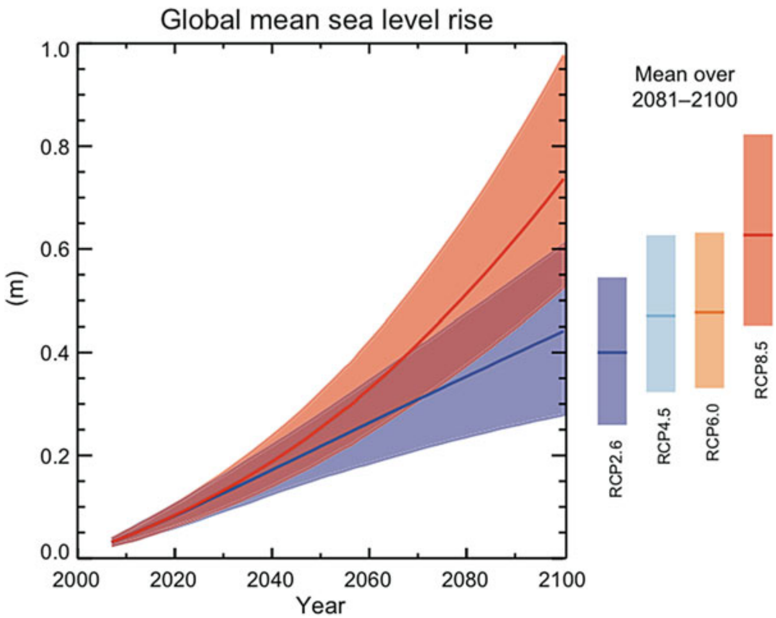

Fig. 14.6 Global sea level rise for each IPCC RCP 2006–2100 [7]

Antarctic. Regional variations around this global mean change will occur due to ocean circulation patterns and the resulting accumulation and distribution of mass that these circulation patterns cause.

5.4 Mitigation Possibilities Within the Agricultural Sector

The magnitude of temperature, precipitation and sea level change depends upon which greenhouse gas scenario best describes the future levels of greenhouse gas emissions. Since the ratification of the Kyoto Protocol many of the world's governments committed to reducing greenhouse gas emissions to at least 5 % beneath their recorded emissions in 1990 with further binding agreements imminent. Much of the focus in meeting mitigation commitments has addressed how to lower greenhouse gas emissions from the major sources, such as transportation and energy production. However, there are opportunities to lower emissions within other sectors and agriculture is no exception, and in itself is responsible for 20 % of all anthropogenic greenhouse gas emissions (mainly in the form of methane and nitrous oxides).

Significant reductions in agriculturally-sourced greenhouse gas emissions can be achieved through a change in a number of agricultural practises, outlined in the 2001 and 2013 report of the Third Working Group [5, 6, 9]. For instance, a reduction in land use intensity and employing conservation tillage techniques (to protect the top soil) would both act to increase (or at least maintain) soil carbon uptake. Rice paddy fields are a major source of methane, the warm, shallow waters being ideal for methanogenisis; a shift towards rice crop varieties which can be grown under drier conditions would reduce emissions from this source. Another source of methane emissions is livestock. Shifting from meat to plant production would help in this case.

Insofar as nitrous oxides are concerned, significant reductions in agricultural emissions could be achieved by altering fertilising methods. One option is to replace the use of synthetic nitrogen sources with organic manures. Slow-release fertilisers and genetically-modified leguminous plants are also available, both of which limit the amount of nitrous oxides released into the atmosphere.

6 Implications of RCP Scenarios on Regional Climate

When viewed globally, the likely future climatic changes to the RCP scenarios can be summarised fairly simply. A warmer, wetter world seems likely. But for each region of the planet, the response is not so straight forward. Changes to the climate may not reflect the global response, or may do for one season but not for another. This section examines in more detail projected regional changes in climate for the current century.

6.1 North America

Surface mean temperatures in North America are projected to be between 0.5 and 1 °C warmer (with respect to 1986–2005 conditions) under an RCP2.6 scenario by 2081–2100. Precipitation is also projected to increase for most parts of the continent, excluding some areas of the south western USA and parts of Mexico. For the 2081–2100 period, simulations based upon multiple GCM experiments indicate the majority of North America may see 0–10 % more mean precipitation. The moderate RCP4.5 projections, with greater greenhouse gas concentrations compared to RCP2.6, suggest mean temperatures could be around 1–3 °C warmer for most parts of the continent, with temperatures reaching up to 7 °C at higher latitudes during the winter time. Precipitation could increase by between 0 and 20 % for most locations excluding, again, parts of the southern USA and Mexico. Precipitation here may decrease by up to 10 %. For RCP8.5, mean temperature and precipitation changes are more prominent. North America could experience temperatures 3–5 °C warmer on average and at some locations between 0 and 50 % more precipitation could be expected. Similar to previously mentioned scenarios, parts of Mexico and the southern United States could expect to see a decrease in precipitation, for example of up to 20 % compared to the 1986–2005 baseline period.

6.2 Europe and Eurasia

In the 'best case' scenario, RCP2.6, GCM simulations indicate that average temperatures could be between 0.5 and 1.5 °C warmer by the 2081–2100 period, with the greatest warming seen in Nordic countries. Average precipitation is projected to increase at most locations (+0–10 %), apart from the Iberian Peninsula, parts of south western France, Turkey, and parts of Greece (−0–10 %). Climate model simulations forced with the RCP4.5 greenhouse gas concentration pathway suggests average temperature increases, for the same period, could range between 0.5 and 3 °C for most parts of Europe and Eurasia. Stronger warming is projected over north eastern Europe, Russia, and Asia exceeding with rises of ~9 °C during the winter season. The mean GCM response for precipitation is a decrease in average totals over a large proportion of western and southern Europe during the spring and summer months by as much as 0–20 %, with respect to 1986–2005 values. In contrast, north eastern Europe, and parts of Eurasia can expect up to 20 % more precipitation in some areas. During the autumn and winter months, however, precipitation is expected to increase by between 0 and 30 % for most locations in Europe and Eurasia, except Spain, parts of France, and neighbouring Mediterranean countries. Under the RCP8.5 scenario, average temperature rises could exceed 2 °C at most locations, with increases of up to 7 °C predicted within some Nordic locations, in Russia, parts of Belarus and Ukraine, and some regions situated in central and southern Asia. When examining average precipitation for this scenario,

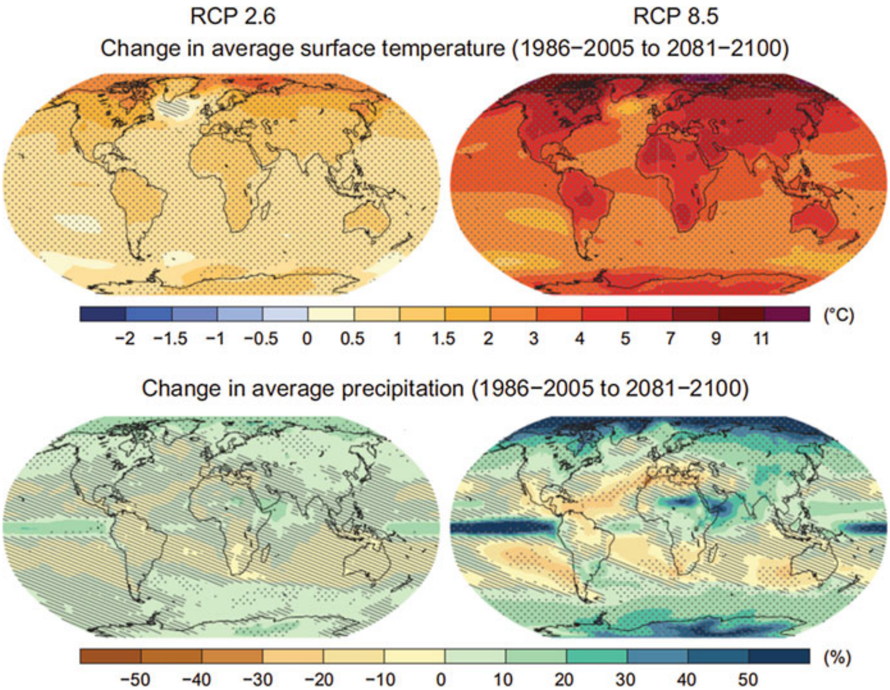

Fig. 14.7 Changes in average annual surface air temperature (*top row*) and precipitation (*bottom row*) by 2081–2100 using multiple GCM simulations under RCP2.6 (*left*) and RCP8.5 (*right*) greenhouse gas concentration pathways (Source: [7])

the Mediterranean region is predicted to receive between 0 and 30 % less rainfall, with parts of southern Spain, Italy, Greece and Turkey being hardest hit. On the other hand, the vast majority of Europe and Asia could record between 0 and 40 % more precipitation on average. Parts of Scandinavia, Siberia, China, and India are projected to experience the largest increases in precipitation (Fig. 14.7).

7 Impacts of Future Climate Change on Agriculture

As much as the effects of future climate change vary from region to region, the same can be said of the implications of any change upon agriculture. For example, projected temperature increases may well be of benefit to some farmers located in the temperature mid-latitudes, but not so beneficial for those within equatorial or tropical regions, where crops already grow close to the limits of their heat tolerance (eg [13]). Indeed, the agricultural implications of any change in climate must consider a number of factors, such as the seasonality of temperature/precipitation changes, changes to the hydrological cycle and possible changes in soil fertility. Nonetheless, from a global standpoint, new simulations of the impact of climate change upon primary crop types (wheat, rice and maize), indicate that just 10 % of projections exhibit yield increases of 10 % or more (relative to late twentieth century levels) for the 2030–2049 period [8, 9]. Simultaneously, 10 % of projections show a 25 % fall in yields for the same time period. Beyond this time-frame the risks of severe agricultural impacts are scaled with the varying degrees of global warming predicted by the varying RCPs. Below, a brief outline of the probable implications upon agriculture within Europe and North America as a result of climate change in the next century is presented.

7.1 Europe

A regional modelling analysis of potential future European agricultural changes shows prevailing north-south (i.e. zonal) separations in response to possible future climate change [8, 9]. These changes are also model dependent – that is they reflect the inter-model variability of the future projections of controlling factors (namely temperature and precipitation), As one of the world's largest cereal producers (and traders) major studies have focussed upon the possible impacts of future climate change upon crops such as wheat, but also oil crops such as sunflower and rapeseed [3].

Possible changes in wheat yield due to climate change by 2030 are depicted in Fig. 14.8 for two climate models, representing the upper and lower limits of model variability. Differences between the patterns of yield decrease (red) and increases (green) in the top two panels are stark and can be attributed to the difference in spatial temperature and precipitation projections in each driving climate model. For the HadCM3 driving climate model (top right) yield increases occur over southern Europe which here is a combination of the co-called carbon fertilization effect and a climatically-driven shortening of the crop cycle, which allows for the avoidance of the maximum (high summer) moisture stress phase. Nonetheless, consistent yield decreases can be seen in both, within the Iberian Penninsula and elements of central/eastern Europe. The regional modelling analyses of Donatelli et al. [3] also allows for the inclusion of rudimentary adaptation practices in future agriculture – for example modification of the sowing phase of crops to best-fit the evolving climatic conditions. In fact, when this is accounted for in the projections, (bottom row), the distribution of yield decreases is severely attenuated (and generally limited to Iberia).

Changes in rapeseed crop yield are less pronounced than wheat, indicating less limitation by future precipitation and co-incidental positive impacts relating to the carbon fertilization effect. Negative changes appear to be very effectively curtailed by adaptation practices – within the 2030 time-frame at least. Yields, however, for sunflower, grown predominantly in central and southern Europe show consistent decreases in Eastern Europe, the strongest of which are simulated over the agricultural zones adjacent to the Black Sea.

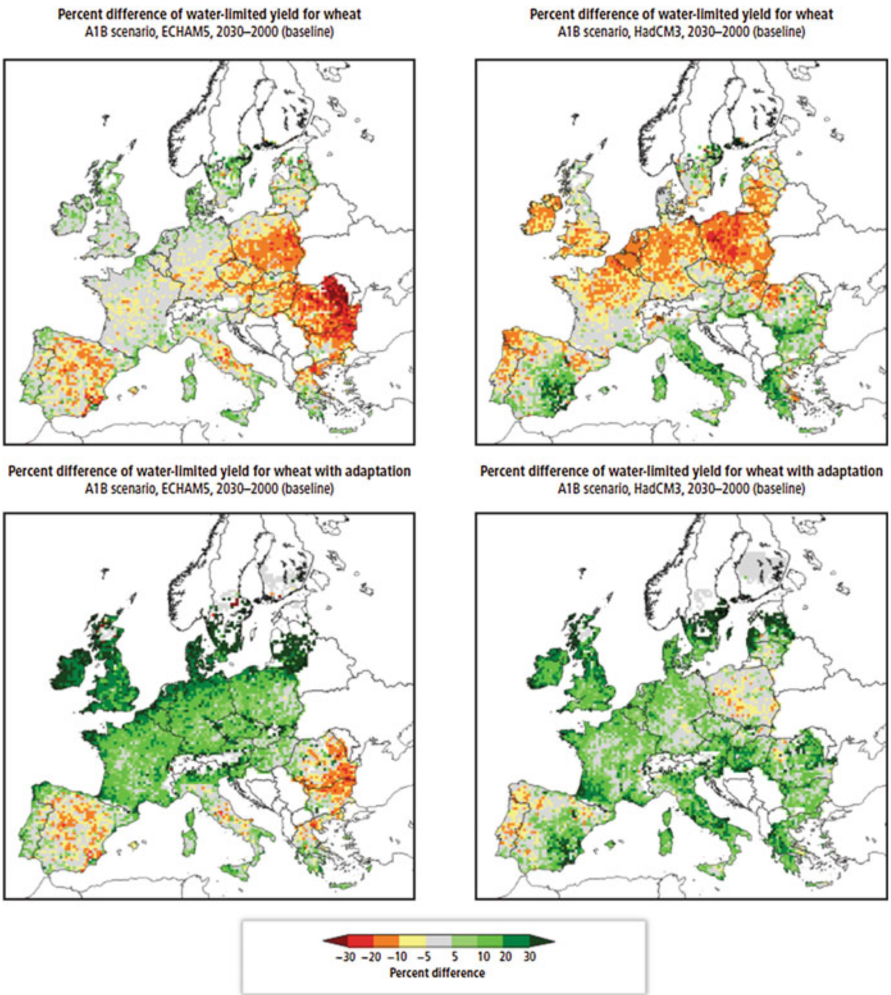

Fig. 14.8 Simulated changes in wheat yield for two GCM simulations (*left* and *right column*) by 2030 under the IPCC AR4 A1B [5] emissions scenario. Changes are expressed with reference to the simulated 2000 baseline. *Top row* shows changes with no assumed adaptation practices and the *lower* shows changes including basic adaptations (Source: [3, 8])

7.2 North America

The diverse regional impacts of potential climate change upon North American agriculture reflects the continent's size and encompassment of several climatic regimes (as with Europe, to a degree). Corn, wheat, vines, cotton and citrus are all important crops in this region, but it is perhaps the first two which are of greatest importance as major mainstay (and exported) human foods both directly and indirectly (via cattle feed). In recent decades crop yields have been observed to increase within the United States (US) due to regional precipitation (and some temperature) change, and in Canada primarily due to changes in temperature [7]. However, it is considered that continuation of temperatures changes will be detrimental, with optimal temperatures for most crops now having been realised.

Yields of all major crops, by mid century, are projected to decrease and decreases are expected to accelerate towards the latter part of the century. GCM and crop model results indicate, for example, that corn is shown to be especially sensitive to projected increases in daily temperatures greater than 29 °C (Schlenker and Roberts 2009) with associated decreases in yields between 30 and 82 % by 2099, depending upon emission scenario. Commensurate changes in soy and cotton yields are also likely. Increases in precipitation, especially within the eastern sector (e.g. Greater Mississippi Basin) will offset (but not totally compensate) temperature-driven decreases in yield, and where both temperature increases and precipitation decreases are projected, decreases in crop yields can be expected to be greater. Such regions include central and western United States and extend into Central America and Mexico [7].

The severity of climate-driven changes will be modulated by future availability of irrigation reserves (e.g. groundwater). Quantities of these reserves are difficult to estimate, but it is known that, already, such North American reserves are under severe stress given that present-day abstraction rates (e.g. Gleeson et al. 2012) exceed natural replenishment. Evolving reliance on groundwater reserves are underway in areas such as California due to limited precipitation and surface water availability in recent years. The volume of water in the High Plains aquifer is of particular importance also given its proximity – and supply – to the vast United States corn belt: again present-day abstraction for use in irrigation far exceed present-dat recharge rates (Gleeson et al. 2012). Sources of irrigation for agriculture in central and western are also reliant upon snow volumes. In this respect, a reduced snow pack (i.e. more liqud precipitation), and projected advances of the melting phase, have detrimental consequences for agriculture, even if mean precipitation levels were to increase [7].

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S. Orszulik (ed.), *Environmental Technology in the Oil Industry*,
DOI 10.1007/978-3-319-24334-4