An Introduction to Oilfield & Drilling Operations

Manual

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1 Introduction

This manual has been prepared in conjunction with the course of the same name.

Material was prepared from various sources during the early part of 2005; you may wish to check some data if reviewing this manual at a much later date.

Prepared in the UK, with research information easier to obtain, there is some emphasis on British operations, and because of the dominance of American companies on this industry there is also some bias towards American operations and terminology.

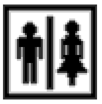
Personal notes pages

2 Domestics

Familiarise yourself with any fire alarm testing that is taking place during your course, know what to do in case of an emergency.

Find out where the fire exits are from the training room and where to assemble. Make certain that you have signed in.

Find out where the toilets are.



Turn off mobile phones and pagers. Urgent messages can be dealt with through reception.

Smokers – Please make yourself aware of the smoking policy of the building and find the designated smoking areas.

Disabled delegates: - if you have any special requirements please let your course leader know.

3 Outline of the Course

3.1 Overview

The course is intended to give employees a basic overview of oilfield operations from discovering oil and gas through to refining and processing; with an emphasis on drilling and **Weatherford Services**.

It is appropriate for all staff, no matter what their previous knowledge or ability.

3.2 Objectives

Personal Objectives

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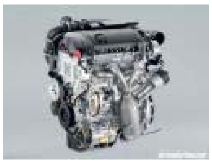
4 History and Overview

The petrochemical industry owes virtually everything to the oil and gas business; without hydrocarbons the petrochemical industry would have to find alternative raw materials. But the versatility and complexity with which hydrogen and carbon molecules can be combined to create new compounds is so immense that alternatives would be very hard, if not impossible, to find. We do however have hydrocarbons and chemists have used their versatile properties to create all manner of compounds and sub-compounds to manufacture so many things which form a part of our every day lives.

We can divide the main groups of products from petroleum into five basic types:

i. Those that explode in combination with air and are used in prime movers such as the internal-combustion engine.

ii. Those that burn and provide space or process heat and light or are transformed into secondary fuels such as electricity.



iii. Those hydrocarbons, whose combustion characteristics are poor but can be used valuably as lubricants, asphalt for roads or roofing, propellants for sprays, solvents, waxes, etc.

iv. Non-hydrocarbon or waste elements such as sulphur, vanadium, acid sludge, etc. which have to be removed as impurities from the finished products but may warrant recovery if their value in the market exceeds the cost of doing so.

v. Feedstocks for the manufacture of further products in conversion to gas, in chemical manufacturing and the growth of protein. Petroleum chemicals can be used to manufacture fertilisers, insecticides, synthetic fibres and rubbers, plastics etc.

For most people the first two groups are what they associate oil and gas with; those hydrocarbons that provide us with transport and power.

Lubricants and road surfaces might also be associated with oil production.

Those other products however, seem to have a less straightforward link to petroleum products however. But both oil and gas are used to manufacture feedstocks which in turn feed petrochemical plants; these plants then make the raw materials for many industries including: plastics, pharmaceuticals and fertilizers. The following list shows some everyday items found around the home and workplace

All of the following items are made from hydrocarbon derivatives, the items highlighted have an intimate realtionship with us!

Ink	Dishwashing liquids	Paint brushes	Telephones
Toys	Unbreakable dishes	Insecticides	Antiseptics
Dolls	Car sound insulation	Fishing lures	Deodorant
Tires	Motorcycle helmets	Linoleum	Sweaters
Tents	Refrigerator linings	Paint rollers	Floor wax
Shoes	Electrician's tape	Plastic wood	Model cars
Glue	Roller-skate wheels	Trash bags	Soap dishes
Skis	Permanent press clothes	Hand lotion	Clothes line
Dyes	Soft contact lenses	Shampoo	Panty hose
Cameras	Food preservatives	Fishing rods	Oil filters
Combs	Transparent tape	Anaesthetics	Upholstery
Dice	Disposable diapers	TV cabinets	Cassettes
Mops	Sports car bodies	Paddling pools	House paint
Purses	Electric blankets	Awnings	Ammonia
Dresses	Car battery cases	Safety glass	Hair curlers
Pyjamas	Synthetic rubber	VCR tapes	Eyeglasses
Pillows	Vitamin capsules	Movie film	Ice chests
Candles	Rubbing alcohol	Loudspeakers	Ice buckets
Boats	Ice cube trays	Credit cards	Fertilizers
Crayons	Insect repellent	Hearing aids	Toilet seats
Caulking	Roofing shingles	Fishing boots	Life jackets
Balloons	Shower curtains	Garden hose	Golf balls
Curtains	Plywood adhesive	Umbrellas	Detergents
Lipstick	Beach umbrellas	Rubber cement	Sun glasses
Putty	Faucet washers	Cold cream	Bandages
Tool racks	Antihistamines	Hair colouring	Nail polish
Slacks	Drinking cups	Guitar strings	False teeth
Aspirin	Petroleum jelly	Toothpaste	Golf bags
Roofing	Tennis rackets	Toothbrushes	Perfume
Luggage	Wire insulation	Folding doors	Shoe polish
Fan belts	Ballpoint pens	Shower doors	Parachutes
Carpeting	Shaving cream	Heart valves	LP records

4.1 The Industry

The oil industry provides us with so much; fuel for our cars and trucks and aeroplanes; electrical power for our homes; road surfaces; plastics of all kinds; even medicines. We rely so heavily on oil and gas and their products, that it would be hard to imagine life without it. Over the past 100 years the oil industry has grown and developed to be one of the most powerful and large industries in the world; with many countries relying on it for money. Poorer countries have gained a lot from oil with revenue in the form of license sharing, taxes and nationalised companies providing lots of money for national governments and over a long period too. Without oil it is hard to see how we would be able to respond to humanitarian disasters around the world; we ship and fly in relief aid immediately after a situation has arisen – all driven by fuel. Then there is us and millions of others like us, provided with good jobs in the industry.

Some people would say that the oil industry today is responsible for a lot of other things too: wars, high cost of living; pollution; destruction of the environment; terrible accidents. Whilst there might be some truth in some of that, overall the oil and gas production business remains one of the most important businesses in the world.

Oil companies spend a lot of time and money on protecting the environment, improving safety, producing other cost-effective energy sources and also on finding alternative energy sources. Without doubt it is an interesting, modern and exciting business to be in.

4.2 History

Petroleum or crude oil is an oily, flammable liquid that occurs naturally in deposits, most often found beneath the surface of the earth. Over millions of years, plant and animal remains fall to the floor of shallow seas. As the seas recede, the plant material is covered by sediment layers, such as silt, sand, clay, & other plant material. Buried deep beneath layers of rock, the organic material partially decomposes, under an absence of oxygen, into petroleum that eventually seeps into the spaces between rock layers. As the earth's tectonic plates move, the rock is bent or warped into folds or it "breaks" along fault lines, allowing the petroleum to collect in pools. Man was not unfamiliar with crude oil. In the Middle East, seepages and escaping petroleum gases burned continuously, giving rise to fire worship. It was also used for building mortar, roads, in a limited way for lighting, but was primarily used for healing everything from headaches to deafness. It was also used in war, for obvious reasons.

Did you know?

Distilled 1000’s of feet below the earth's surface, this remarkable liquid was at one time known as a medicinal liquid. There were few takers of the 19th century elixir that came to be called "snake oil." It was one of the less successful uses of petroleum, but not the first to claim healing properties. Ancient Persians, 10th century Sumatrans and pre-Columbian Indians all believed that crude oil had medicinal benefits. Marco Polo found it used in the Caspian Sea region to treat camels for mange, and the first oil

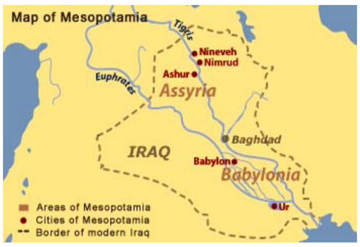


Figure 1 Mesopotamia

exported from Venezuela (in 1539) was intended as a gout treatment for the Holy Roman Emperor Charles V.

The mysterious oil that sometimes seeped to the earth's surface had other uses as well. In Mesopotamia around 4000 B.C., bitumen - a tarry crude - was used as caulking for ships, a setting for jewels and mosaics, and an adhesive to secure weapon handles. Egyptians used it for embalming, and the walls of Babylon and the famed pyramids were held together with it. The Roman orator Cicero carried a crude-oil lamp. In North America, the Senecas and Iroquois used crude oil for body paint and for ceremonial fires..

Crude oil is a remarkably varied substance, both in its use and composition. It can be a straw-coloured liquid or tar-black semi-solid. Red, green and brown hues are not uncommon. The image of James Dean dripping with black oil from his Texas gusher in the 1956 movie "Giant" may have been compelling, but it's not descriptive of today's oil producers. For one thing, the days when a gusher signalled a big discovery are long gone. Since the 1930s, oil producers have used **blowout preventers (BOPs)** to stop gushers. In addition, not all crude oils behave in the Hollywood manner. Some are so thick that they need heaters to soften them to aid production – some are even dug from the ground!

Figure 2 - James Dean in the film *'Giant'*

Until the late 19th century, an oil find often was met with disinterest or dismay. Pioneers who settled the American West dug wells to find water or brine; they were disappointed when they struck oil.

Several historical factors changed that. The kerosene lamp, invented in 1854, ultimately created the first large-scale demand for petroleum. (Kerosene first was made from coal, but by the late 1880s most was derived from crude oil). In 1859, at Titusville, Pennsylvania, Col. Edwin Drake drilled the first successful well through rock and produced crude oil. What some called "Drake's Folly" was the birth of the modern petroleum industry. He sold his "black gold" for $20 a barrel.

Petroleum was prized mostly for its yield of kerosene until the 20th century began. Gasoline was burned off, and bitumen and asphalt (the heavier parts of crude oil) were discarded. But gradually rising in importance were the incandescent light and the internal combustion engine. The former relied on oil-fired generating plants; the latter, on gasoline.

By the 1920s, crude oil as an energy and product source - not just as a curiosity - came into its own.

The demand for oil was now higher than the supply. Many companies and individuals were looking for an alternative and longer lasting source of oil; wells were drilled as fast as possible, to try and make supply meet the demand.

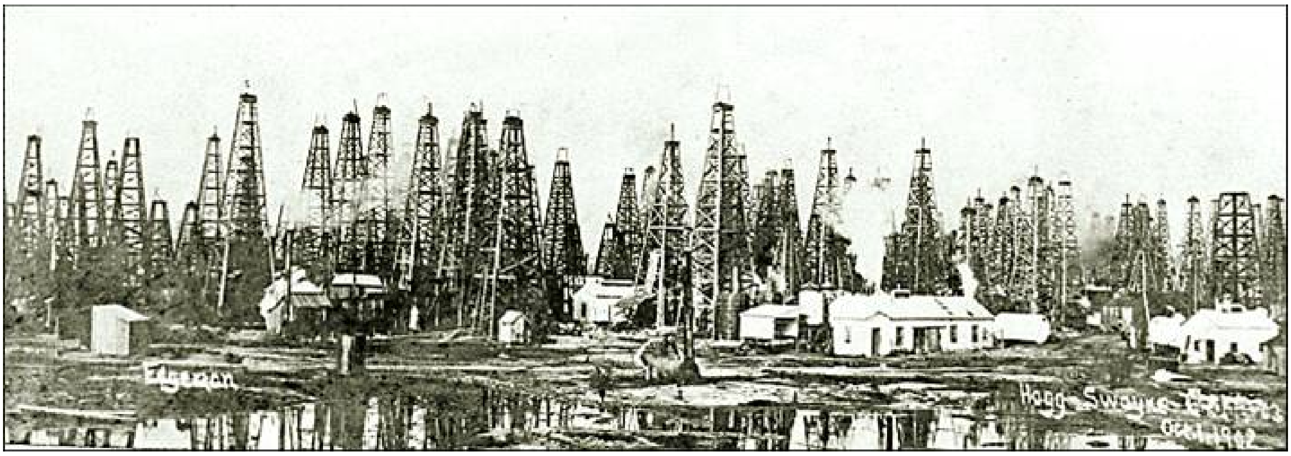


Figure 3 Spindletop 1903

From the first land based rigs, which were developed all over the world by enterprising people and companies; offshore rigs were developed.

The first oil well structures to be built in open waters were in the Gulf of Mexico. They were in water depths of up to 100m and constructed of a piled jacket formation, in which a framed template has piles driven through it to pin the structure to the sea bed. To this, a support frame was added and the working parts of the rig such as the deck and accommodation. These structures were the fore-runners for the massive platforms that now stand in very deep water and in many locations around the world.

Technology has kept pace with the development of the oil industry, delivering new, faster, cheaper and safer ways of producing oil and gas. New tools, techniques and improving education means that today's oil industry is one of the most advanced in many ways.

4.2.1 So how did Geologists know to look for oil beneath the sea?

In the late 1800's, the citizens of Summerland, California, began producing the numerous springs of crude oil and natural gas that dotted their landscape. After drilling a large number of wells, these early oilmen noticed that those nearest the ocean were the best producers. Eventually, they drilled several wells on the beach itself. Then in 1887, one citizen, H.L. Williams, came up with the idea of building a wharf and erecting the drilling rig on it. His first offshore well extended about 300 feet (90 meters) into the ocean. As expected, it was a good producer and before long the entrepreneurs built several more wharfs. The longest stretched over 1,200 feet (nearly 400 meters) to the Pacific.

Almost every year for the next ten years, technology advanced to tap into this precious resource. The valves and controls which gauged the flow of oil - nicknamed the 'Christmas Tree' - was developed in 1922, followed by the creation of drilling control instrumentation in 1925. Scientists also became involved with the search for oil and in 1926, modern seismology was developed.

In 1959 the massive Groningen land gas field was discovered in the Netherlands. Geologists estimated that the same rock formations might be found beneath the southern

North Sea basin in UK waters. They were right and gas was discovered off the English East Coast in the 1960s.

Figure 4 – Massive platform legs being towed into position

Clues around the coast of Greenland gave Geologists the idea that there may be oil and gas around Scottish waters.

There have been land oil wells in Europe since the 1920s. But it wasn't until the 1960s that exploration in the North Sea really begun - without success in the early years. They finally struck oil in 1969 and have been discovering new fields ever since. The subsequent development of the North Sea is one of the greatest investment projects in the world.

The development of the offshore oil industry in hostile waters has been made possible by many achievements comparable with the space industry. Many fields are located far from land and they are getting further away.

Oil and gas is now being produced from many countries around the world, from onshore USA to the deserts of Qatar; from the iceberg infested waters off Newfoundland to the remotest regions of Russia; from Borneo to Lake Maracaibo. And where oil and gas isn't being produced it is being used, in all its many forms by virtually all nations and people; except the remotest and most un-developed.

4.3 Basic Economics

4.3.1 The price of oil

The price of oil, like many other commodities is governed largely by the supply and demand trend. That is to say, if demand is high and the supply is low the price that people are prepared to pay is higher. Taken to the extreme, the Mona Lisa is a painting, the original of which cannot be re-created. The demand for such a beautiful and historic painting is high, but there is only one, so the supply is low, very low. Therefore the price people are willing to pay is very high indeed.

However, many other factors come into effect where the oil price is concerned. The worldwide political situation will have a huge effect on the price of oil and not simply because wars use up many millions of barrels of oil as fuel. Many of the countries on which the world relies for oil supply are volatile politically, perhaps in their relations with another country, therefore their future stability is not certain. If for some reason the volatility materialised into a civil war, political upheaval or unrest, then the future supply of oil could be reduced. This will mean that people in stock markets around the world buying 'oil futures' will be prepared to pay more to secure supply to their refineries; this in turn pushes up today's prices. There are many more political and socio-economic reasons for movements in the price of oil.

Then of course there is OPEC (Organization of Petroleum Exporting Countries).

4.3.2 OPEC

Why was OPEC created?

OPEC was created at a conference in Baghdad in September 1960 to protect the interests of oil-producing countries. At that time, the Arab oil fields were controlled by multinational conglomerates who had picked up the rights to virtually every drop of Middle Eastern oil for next to nothing in the wake of World War I. These so-called ‘Seven Sisters’ were able to raise and lower the oil price as they saw fit. In 1960, faced with a glut of oil, the oil companies lowered oil prices unilaterally, thereby reducing the amounts that the producing companies received in taxes and royalties. Five of the oil producers - Iran, Iraq, Kuwait, Saudi Arabia and Venezuela - came together from a position of weakness to demand higher prices. By 1971, six other countries had joined: Indonesia, Qatar, Libya, Nigeria, Algeria and the United Arab Emirates.

How powerful was OPEC?

In its early days, OPEC had very little power, since the members did not control their own reserves, which mostly belonged to the concessionaires. But that began to change in 1969, following the revolution in Libya when Colonel Gadaffi took power. He instantly demanded that all oil companies operating in Libya raised their royalty payments by 25%. His success paved the way for similar moves in other countries and later for a wave of nationalisations. At first, it made little difference to the oil price, which remained under $4 a barrel. But the oil-producers soon become extremely powerful, since they now had the power to turn the oil taps on or off at their whim. Or as one OPEC member put: “We have the companies - how do you say it? - over a barrel.”

How did OPEC use this power?

In the 1970s, OPEC used its power to wreak havoc on the global economy. In 1973, Arab exporting nations unleashed an oil embargo in protest at the support given by the US and other Western nations to Israel in the Yom Kippur war. They cut production by five million barrels a day, sending the price of oil up 400% from $3 a barrel to $12 in six months, and triggering inflation and recession around the world. Prices then remained relatively flat at around $13 a barrel between 1974 and 1978, but in 1979 prices doubled again to $25 a barrel, this time in response to the loss of production due to the Iran/Iraq war. But prices did not remain at these levels for long. Between 1982 and 1986, the price of oil plummeted and OPEC was fighting to regain control of the market.

Why did the oil price collapse?

Because demand collapsed. This was partly OPEC’s own fault, since high oil prices led to another recession. Another reason was that consumers took steps to reduce their need for oil: they invested in better insulation, more energy-efficient industrial processes and bought more fuel-efficient cars.

Governments invested in alternative sources of energy. Meanwhile, the oil companies took advantage of higher oil prices to scour the world for new reserves. Throughout the 1980s and 1990s, OPEC lost market share to other producers, while its own efforts to meet its price targets were undermined by over-production among its members. Following a spike in oil prices at the time of the first Gulf War, by 1994 inflation-adjusted oil prices had hit their lowest levels since 1973.

Have these problems now been resolved?

With difficulty. In the late 1990s, OPEC found itself tested again. In 1997, OPEC was caught out by the Asian crisis. During the mid-1990s, the success of the Asian economies had given a huge boost to demand for oil, allowing OPEC to ramp up production. But following the Asian crisis in 1997, oil consumption in the region fell for the first time since 1982. But OPEC failed to respond to the slump in demand and continued to pump out oil. As a result, the price slumped to close to $10 a barrel. This was a disaster for many OPEC members, who faced a huge fall in their oil revenues. OPEC eventually made the necessary cuts.

4.4 How much does it cost to drill a well?

Millions of dollars! But how many millions, that is a difficult question to answer. And then, how much will it cost to install a production facility and process systems, and then what about the pipelines or tankers to transport the hydrocarbons away? What if it all goes wrong – and it often does – and the well is a **duster?** Or what if the drill crew gets it wrong and the well has a blow out or is damaged badly – how much will it cost to repair it? The answer to all of these questions cannot be answered unless these particular situations happen. Each and every well drilled for hydrocarbon production is different, due to its location, the way the hydrocarbon is trapped, the rocks we have to penetrate to get to the **pay zone,** the local market place; there are far too many variables to account for everything.

However, experienced companies will have knowledge and experience on hand to reasonably accurately predict the cost of drilling and producing from a particular well. Good planning will then ensure that the well (or field) can be produced from, on a particular date at a certain rate; satisfying the banks and partners and other investors.

The price of oil as we have seen above has varied from $3 to the current value (Sept 2005) of over $70 a barrel. In the last crash, in the 1990s many companies decided that the target production costs should be around $10; a barrel anything under this would be considered **economic production costs** around that figure **marginal** and above it **uneconomic**. With new technology and a stubbornly high oil price, many so-called **marginal** fields have been developed in recent years and the trend has been set to try to develop more marginal fields and get more hydrocarbon out of existing wells, maintaining costs at a low level.

Generally speaking an onshore oil well in the USA in a good location, with easy access to a transportation system, would be far far cheaper to produce from than a subsea well in the middle of the hostile waters of the Atlantic. Likewise a well in the middle of the Saudi desert, surrounded by other similar wells and a good transportation system, would not cost too much to scrap if things go wrong; whereas the same well in the Wytch Farm development in the South of England could cause quite an upset with the commercial team!

It literally does cost millions of dollars to drill a well; it is part Weatherford's job to keep that cost at a minimum.

5 What is a Hydrocarbon?

A hydrocarbon is unsurprisingly made up of two elements – hydrogen and carbon. The many ways, in which the atoms of hydrogen and carbon come together, determines what kind of hydrocarbon is produced. Some examples of how the molecules come together and bond are shown below – there are many, many more. No wonder then that so many products can be made from hydrocarbons.

Methane is made up of one atom of Carbon and four of hydrogen.

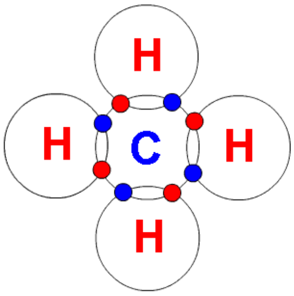


Figure 5 - Methane CH_4

Ethane is made up of two atoms of Carbon and six of Hydrogen.

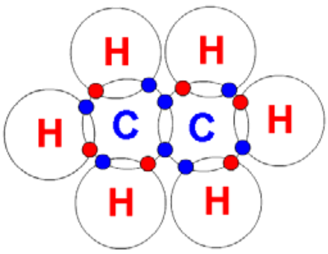
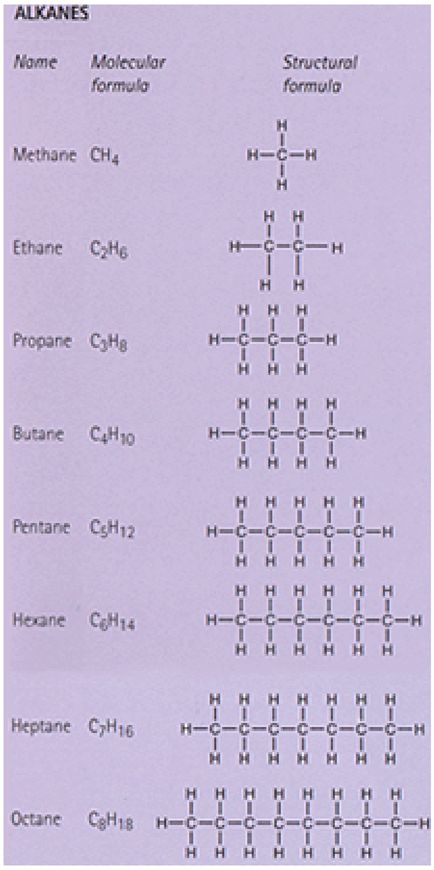


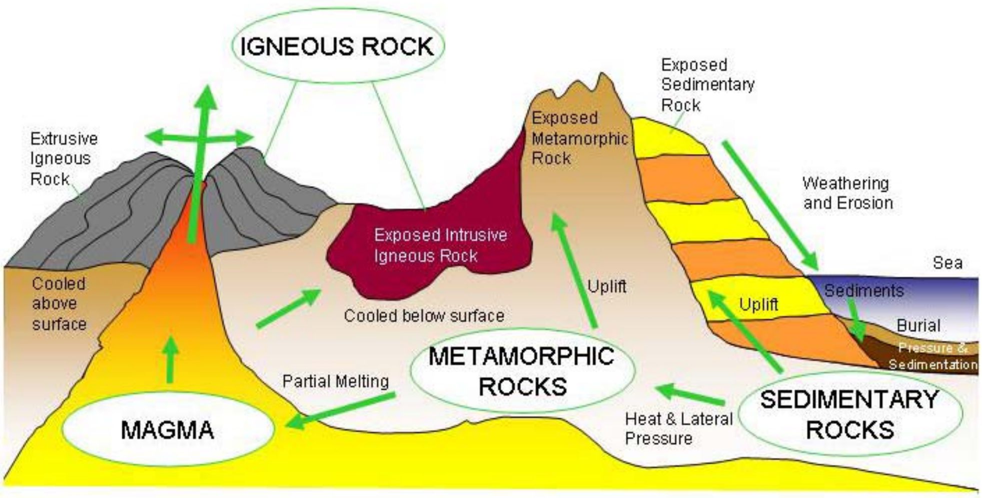
Figure 6 - Ethane C_2H_6



There is a rule which must be followed when these atoms bond: each hydrogen atom needs 1 electron bond; each carbon atom 4 electron bonds. As long as the rule is followed very long chains of hydrogen and carbon atoms can bond together, creating a variety of products from light gases (see methane above) to thick, viscous tars. The longer the chain molecule, the thicker the crude and the higher the boiling point.

5.1 Crude Oil

Geologists generally agree that crude oil was formed over millions of years from the remains of tiny aquatic plants and animals that lived in ancient seas. Petroleum owes its existence largely to one-celled marine organisms. As these organisms died, they sank to the sea bed. Usually buried with sand and mud, they formed an organic-rich layer that eventually turned to sedimentary rock. The process repeated itself, one layer covering another.



Rocks can be classified into 3 groups:

SEDIMENTARY, METAMORPHIC AND IGNEOUS

Over millions of years they may change from one into another. This is called the Rock Cycle.

The Rock Cycle

Exposed surface rocks undergo **'weathering'** where they get broken down 'in situ'. The broken down pieces or particles are carried away **(erosion and transport)** and dropped **(deposition)**, later settling as loose material, often in layers **(sediments)**. Over millions of years these sediments get compressed and cemented, forming **sedimentary rocks.**

They may be brought to the surface by **uplift**.

Pressure from the sides and increased temperatures may change the rocks into **metamorphic rocks**. These may again be uplifted to the surface.

Rocks may become hot enough to melt partly. Liquid rock then rises and cools to form **igneous rocks**. The liquid rock sometimes erupts as a volcano. It may also cool and set below ground.

When rocks return to the surface **(sedimentary, metamorphic or igneous)** the weathering process or the cycle starts again.

Then, over millions of years, the seas withdrew. In lakes and inland seas, a similar process took place with deposits formed of non-marine vegetation.

In some cases, the deposits that formed sedimentary rock didn't contain enough oxygen to completely decompose the organic material. Bacteria broke down the trapped and preserved residue, molecule by molecule, into substances rich in hydrogen and carbon. Increased pressure and heat from the weight of the layers above then caused a partial distillation of the organic remnants, transforming them, ever so slowly, into crude oil and natural gas.

Although various types of hydrocarbons - molecules made of hydrogen and carbon atoms - form the basis of all petroleum, they differ in their configurations. The carbon atoms may be linked in a ring or a chain, each with a full or partial complement of hydrogen atoms. Some hydrocarbons combine easily with other materials, and some resist such bonding.

The number of carbon atoms determines the oil's relative "weight" or density. Gases generally have one to four carbon atoms, while heavy oils and waxes may have 50, and asphalts, hundreds.

Hydrocarbons also differ in their boiling temperatures - a key fact for refiners who separate the different components of crude oil by weight and boiling point. Gases, the lightest hydrocarbons, boil below atmospheric temperature. Crude oil components used to make gasoline boil in the range of 55^{o} F (13^{o} C) to 400^{o} F (205^{o} C). Those used for jet fuel boil in the range of 300^{o} F (149^{o} C) to 550^{o} F (288^{o} C) degrees, and those for diesel, at about 700^{o} C.

There are three essentials in the creation of a crude oil field:

- First, a "source rock" whose geologic history allowed the formation of crude oil. This usually is a fine-grained shale, rich in organic matter.
- Second, migration of the oil from the source rock to a "reservoir rock," usually a sandstone or limestone that's thick and porous enough to hold a sizable accumulation of oil. A reservoir rock that's only a few feet thick may be commercially producible if it's at a relatively shallow depth and near other fields. However, to warrant the cost of producing in more challenging regions (the North Sea, for example) the reservoir may have to be very thick.
- Third, entrapment. The earth is constantly creating irregular geologic structures through both sudden and gradual movements - earthquakes, volcanic eruptions and erosion caused by wind and water. Uplifted rock, for example, can result in domelike structures or arched

folds called anticlines. These often serve as receptacles for hydrocarbons. The probability of discovering oil is greatest when such structures are formed near a source rock. In addition, an overlying, impermeable rock must be present to seal the oil in the structure.

The oldest oil-bearing rocks date back more than 600 million years; the youngest, about 1 million. However, most oil fields have been found in rocks between 10 million and 270 million years old.

Subsurface temperature, which increases with depth, is a critical factor in the creation of oil. Petroleum hydrocarbons rarely are formed at temperatures less than 150^{o} F and generally are carbonized and destroyed at temperatures greater than 500^{o} F. Most hydrocarbons are found at "moderate" temperatures ranging from 225 to 350^{o} F.

It is the particular crude oil's geologic history that is most important in determining its characteristics. Some crudes from Louisiana and Nigeria are similar because both were formed in similar marine deposits. In parts of the Far East, crude oil generally is waxy, black or brown, and low in sulphur. It is similar to crudes found in central Africa because both were formed from non-marine sources. In the Middle East, crude oil is black but less waxy and higher in sulphur. Crude oil from Western Australia can be a light, honey-coloured liquid, while that from the North Sea typically is a waxy, greenish-black liquid. Many kinds of crudes are found in the United States because there is great variety in the geologic history of its different regions.

Crude oil is a surprisingly abundant commodity. The world has produced some 650 billion barrels of oil, but another trillion barrels of **proved reserves** have yet to be produced. An additional 10 trillion barrels of oil resources await development, assuming the price of oil someday justifies production. These resources include bitumen, shale oil and oil in existing fields that might be produced through enhanced recovery methods.

Talk of crude oil oozes with superlatives. Not only was crude oil the basis of the world's first trillion-dollar industry, it also is the largest item in the balance of payments and exchanges between nations. And it employs most of the world's commercial shipping tonnage.

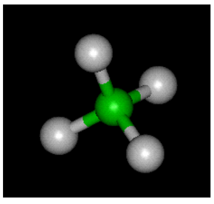
Crude oil may not be the panacea that snake oil claimed to be. But for 20th century industrialized nations, it has proved to be more than good medicine.

On average, crude oils are made of the following elements or compounds:

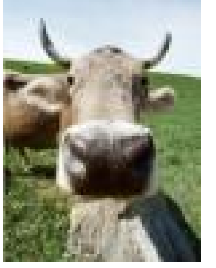
Carbon - 84%
Hydrogen - 14%
Sulphur - 1 to 3% (hydrogen sulphide, sulphides, disulfides, elemental sulphur)
Nitrogen - less than 1% (basic compounds with amine groups)
Oxygen - less than 1% (found in organic compounds such as carbon dioxide, phenols, ketones, carboxylic acids)
Metals - less than 1% (nickel, iron, vanadium, copper, arsenic)

Salts - less than 1% (sodium chloride, magnesium chloride, calcium chloride

5.2 Natural Gas



The simplest form of hydrocarbon, Methane is a gas which is made up of 4 atoms of hydrogen to one of carbon – CH4.



Methane can be produced from hydrocarbon reservoirs under the ground and some other sources you may be familiar with!

Butane and Propane are other gases you may be familiar with – there will be more on these products later in this manual.

Natural gas is often produced with oil and where 20 years ago it was often seen as a complication to oil production, gas is now widely used for power, industry and domestic uses worldwide.

Often in the reservoir the gas is in solution within the oil; but as the oil and gas mix is removed from the reservoir and the pressure reduces gas tends to come out of solution. Sometimes there is **free gas** in the reservoir, usually at the top, forming a **gas cap.** Dissolved gas tends to reduce the viscosity of oil making it easier to flow.

6 Geology

A basic knowledge of the Earth's geology is vital to a proper understanding of how oil and the reservoirs in which it is contained, were formed. This information will also serve to explain why some particular exploration, drilling and production operations must be carried out to optimise the recovery of hydrocarbons from different types of reservoir structures.

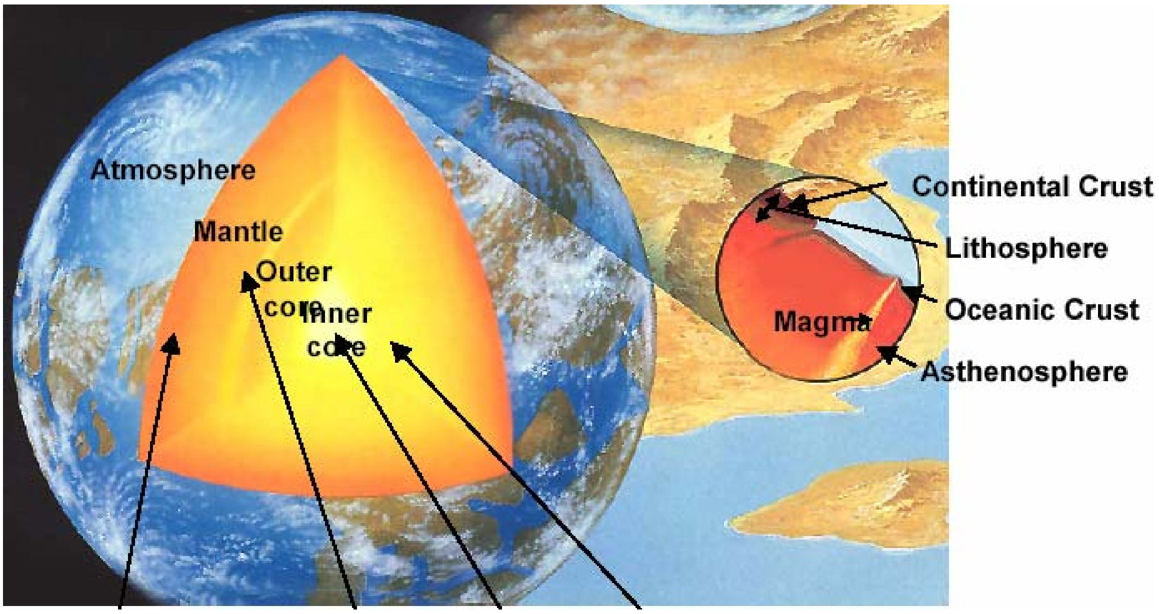


Figure 7 The Earth & It's Core

6.1 The Earth and it's Crust

It is commonly held that the earth formed from a cloud of particles made up of all the different elements which are recognisable today. It is estimated to have been formed between 4,000 and 5,000 million years ago and was for millions of years a blazing, liquid mass. This basic assumption applies to the other planets. As gravity drew the particles together, they were compressed and heated. Dense metallic elements such as iron and nickel collected in the centre of the mass and solidified to form the Earth's inner core. The outer core remains fluid. The effect of the solid inner and fluid outer core is that of a giant electric generator and has created a magnetic field which extends beyond the planets surface. Gradually, the mass cooled and the lighter elements such as magnesium, aluminium and silicon formed the outermost layers, the plastic mantle which supports the solid crust.

Today, the earth is considered to comprise five layers:

An inner core extending 800 miles (1,300 km) from the centre which is possibly solid iron and nickel.
An **outer core,** 1,400 miles (2,250 km) thick, which is possibly molten iron and nickel.
A mantle of solid rock approximately 1,800 miles (2,900 km) thick which is sub-divided into the **lower mantle** and the **upper mantle.**
The crust, which is also sub-divided into oceanic crust and continental crust.

Oceanic crust is approximately 3 to 5 miles thick, (5 to 8 km), and the continental crust is between 35 and 50 miles (60 to 80 km) thick.

The earth is constantly being acted upon by enormous forces and our 'solid world' is constantly changing. The crust itself is made up of various types of rock, lying beneath a thin, ragged layer of soil. The rocks are in turn made up of minerals, and since rocks can provide vital clues about the earth's history, the geologist must be able to recognize their constituents and age. It would therefore be helpful to give an indication of the time scales involved in the world's development.

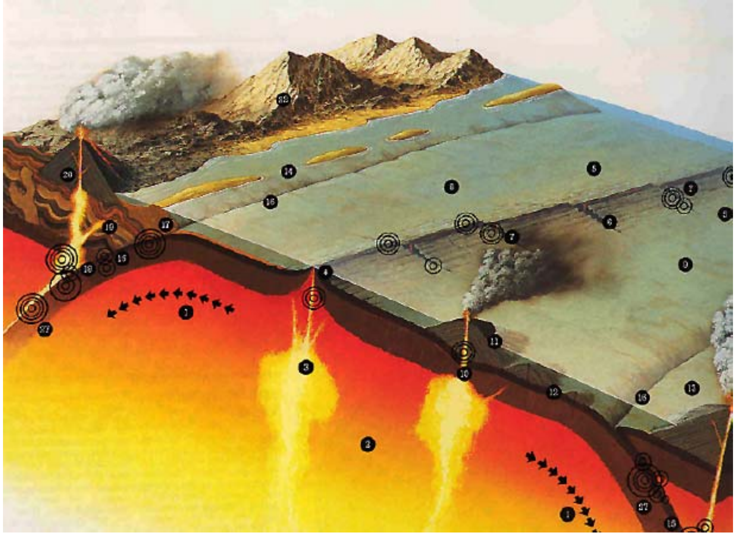


Figure 8 The Movement of Molten Rock

6.2 Rock Classification by Age

The classification of geologic time periods is based largely upon the relative ages of rocks using the radiometric tests, and is divided into Eras, Periods and Epochs. The major eras are briefly described below:

Precambrian: little is known of this era since there are only primitive life form fossils to study and the rocks formed then have since been greatly altered. Sometime during this period photosynthetic algae flourished and began the creation of the atmosphere by using carbon dioxide to release oxygen.

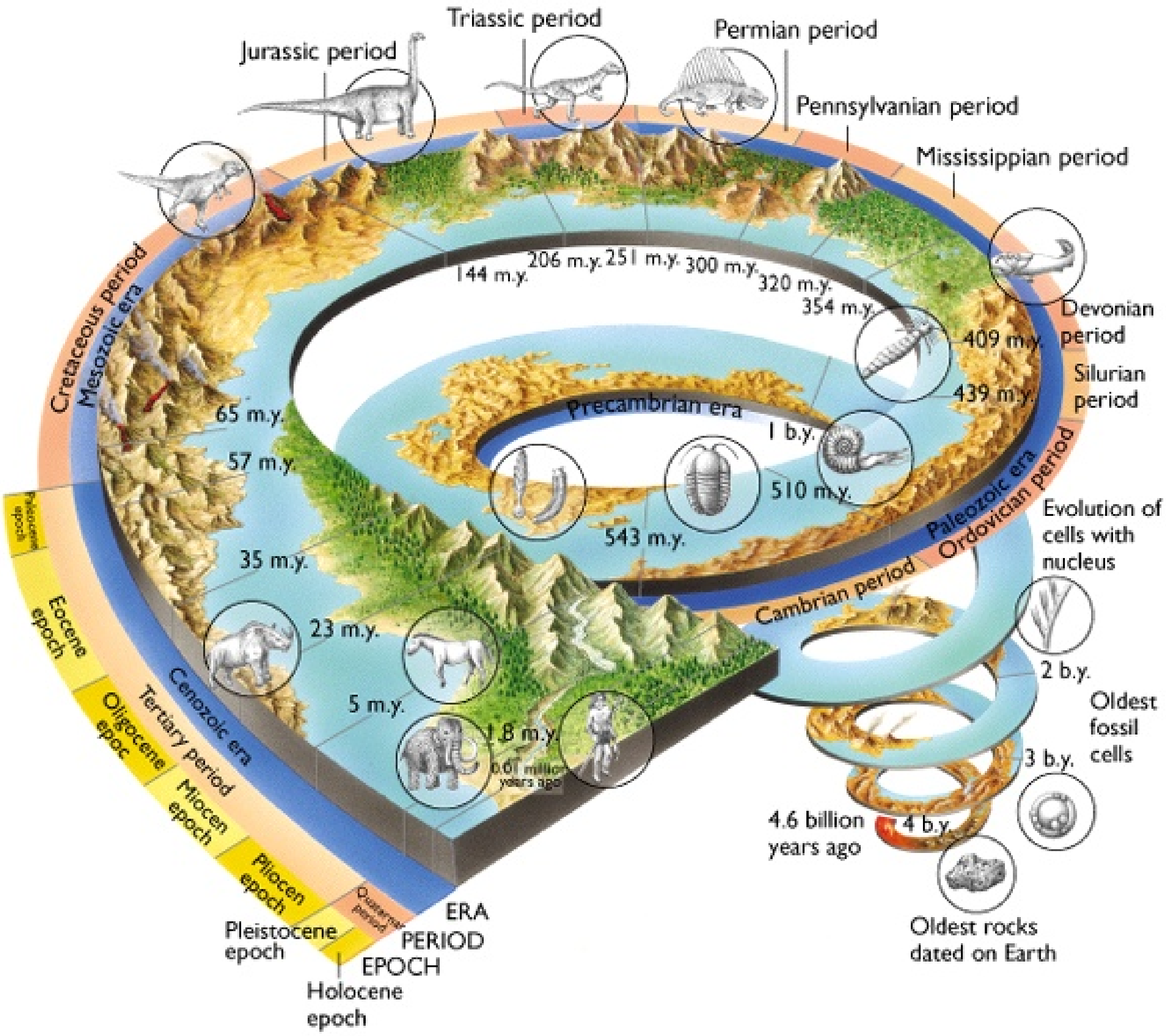
Palaeozoic: Most early life forms developed in this era and plant life began to flourish on land. The oldest deposits of petroleum were formed in this period.

Mesozoic: In this era all land formed one great super continent.

Cenozoic: This period saw the mysterious disappearance of the dinosaurs, the raising of the Rockies, Alps, the Himalayas and the advance and retreat of a number of ice sheets in North America and Europe.

Did you know?

That more than half of the world's petroleum accumulated in the Mesozoic period – after the dinosaurs.



Did you know?

That *Homo Sapiens* evolved from *Homo Erectus* between 250,000 to 500,000 years ago! That the first traces of *Cro-Magnon* man (the family to which modern humans belong) is dated around 40,000 years ago; and that *Neanderthals* disappeared around 10,000 years ago.

6.3 Rock Structures

Some of the most important elements pertaining to the formation and accumulation of oil have now been sketched out. The age when oil was formed, the environmental conditions necessary for its formation and the structure and motion of the earth's crust enabling the oil to be trapped, more of which will be seen later. Another important factor in the process of hydrocarbon formation, accumulation and production is the nature of the rocks themselves.

Rock structures vary greatly and like the different types of hydrocarbon molecule available, they exhibit different properties under similar conditions. Consequently, the existence of oil and the ease with which it can be recovered depends greatly on the actual types of rock in which it exists. The sort of equipment and techniques necessary for drilling and subsequent production are also dependant to a great extent on the rock and structures which must be penetrated to reach the oil deposit. To understand the significance of rock we must learn about the basic properties of the major types of rock.

6.3.1 Types of Reservoir Rock

There are two basic types of rock in which oil and gas are contained: sandstone or carbonate. Both are sedimentary rocks – which mean that they were formed from the laying down of sediments in rivers, estuaries or seas. The process of *lithification* then transformed them into the rock formations we know today. Lithification is where pressure squeezes out air and water pockets, bringing the particles closer together. Then as underground water seeps through minerals (calcite, silica or iron compounds) are deposited. These build up on the sediment particles, cementing them together.

The preponderance of hydrocarbons are found in carbonate reservoirs – mainly due to the vast carbonate reservoirs found in the Middle East. Most sandstone formations derive from river-borne sediments. Carbonate deposits are usually laid down as Calcium Carbonate, originating from a mixture of ground up shells and the excrement of marine organisms. Carbonate reservoirs can be further split into two main types – limestone and dolomite.

6.3.2 Rock Characteristics

Two of the most important properties of an oil-bearing reservoir rock are porosity and permeability. Subsurface reservoirs of oil, gas or water are not simply vast pools of fluid buried deep within the Earth. These reservoirs comprise porous, permeable rock strata into which oil or gas has migrated or in which water has remained from deposition. If you imagine a giant sponge, the type used for washing dishes or the car, whose structure is rock, not soft plastic foam, and then you are close to understanding what a reservoir rock is like. The characteristics of the reservoir rock have a great bearing on the amount and speed of recovery of oil, so we should look closely at them.

Porosity: It is defined as the percentage of void space in a rock. The spaces occur between individual rock particles where they can not be forced closer together due to their shape. Without space in a rock, fluid cannot accumulate within it. Porosity is expressed as a percentage of total rock volume. A highly porous rock has lots of free space for oil or gas storage.

Imagine some round stones taken form the beach, in the order of 2” diameter, if you placed them in a clear 5 litre bucket, there would be a large volume of space around the stones. Now imagine that the bucket reduces in size some 200 times, so that it now only occupies 25ml and the stones are now sand grains 0.25mm diameter. Although the pore space has reduced 200 times in volume, the pores take up the same percentage of space.

The shape of the grains and the material they are stuck together with also have a huge effect on the porosity of the formation. The way in which they were deposited could also have increased or decreased the overall volume they take up.

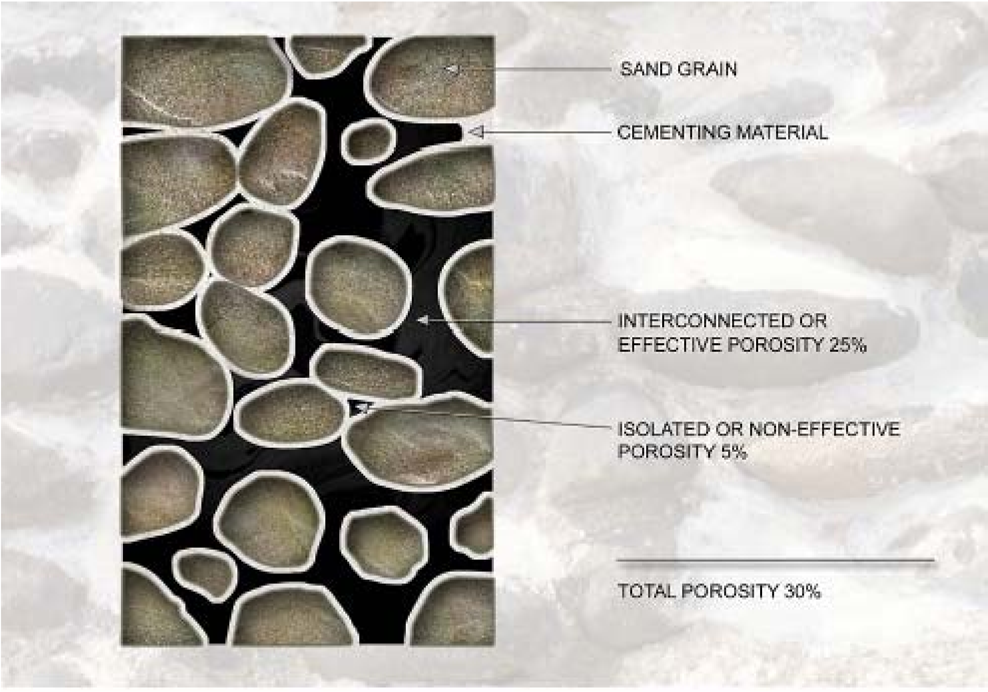
Permeability: This is the degree of interconnection between the pores, and therefore a measure of how easily a fluid can pass through the rock. Vertical and horizontal permeability can also differ according to the arrangement of the rock particles. The unit of permeability is the Darcy or, more commonly, the millidarcy (md). Permeability of less than 1 md are considered poor, 1 - 10 md fair, 10 - 100 md good and 100 - 1000 md very good.

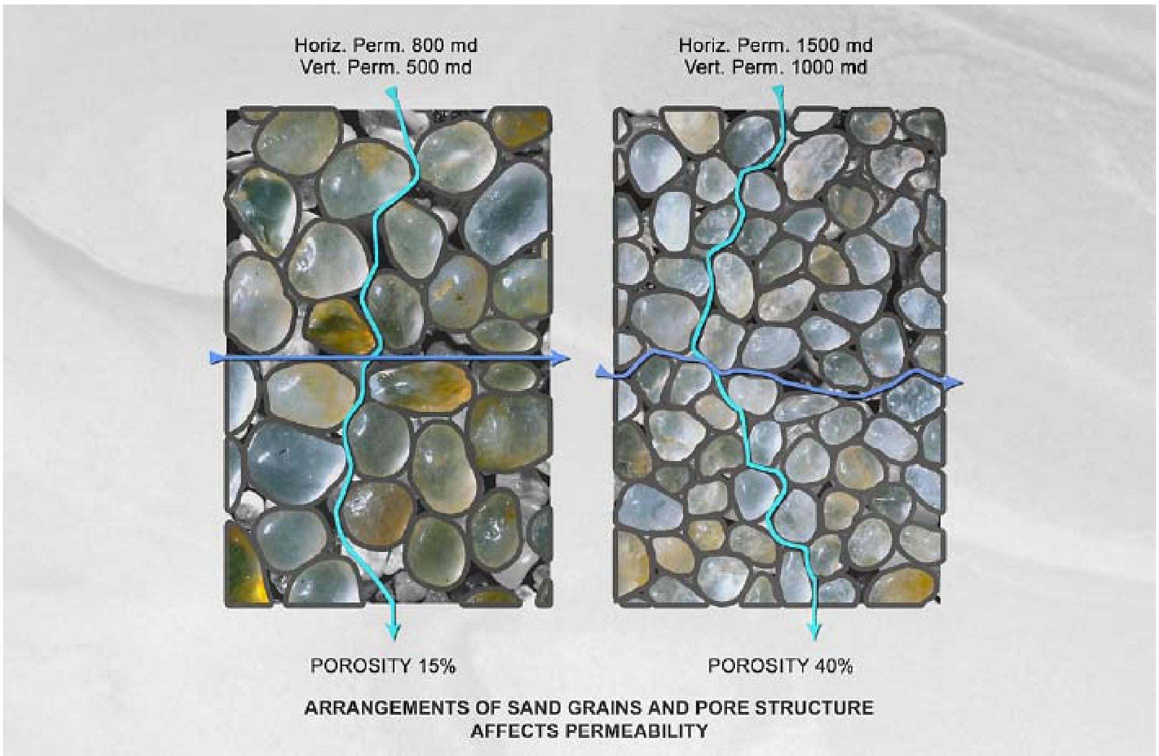
Effective Porosity: Since only those pores which are interconnected can transmit fluid, effective porosity is the ratio of the volume of all the interconnected pores to the total volume of a rock unit.

Effective (or Relative) Permeability: This is the permeability of a rock to one fluid, when **another** is present.

For example; if a rock contains only oil under high pressure the gas has not been allowed to come out of solution – it remains a liquid due to high pressure. As the oil is produced the pressure decreases and gas comes out of solution. Now some gas begins to flow with the oil. As you can imagine, gas flows more easily through the rock pores than oil. As the pressure falls further more gas comes out of solution until eventually only gas is being produced. This shows how the ***relative*** permeability is an important consideration.

In our search for oil we must look to sedimentary basins, porous permeable rock types and strata of an appropriate age.


SAND GRAIN
CEMENTING MATERIAL
INTERCONNECTED OR
EFFECTIVE POROSITY 25%
ISOLATED OR NON-EFFECTIVE
POROSITY 5%
TOTAL POROSITY 30%


Horiz. Perm. 800 md
Vert. Perm. 500 md
Horiz. Perm. 1500 md
Vert. Perm. 1000 md
POROSITY 15%
POROSITY 40%
ARRANGEMENTS OF SAND GRAINS AND PORE STRUCTURE
AFFECTS PERMEABILITY

6.4 Traps

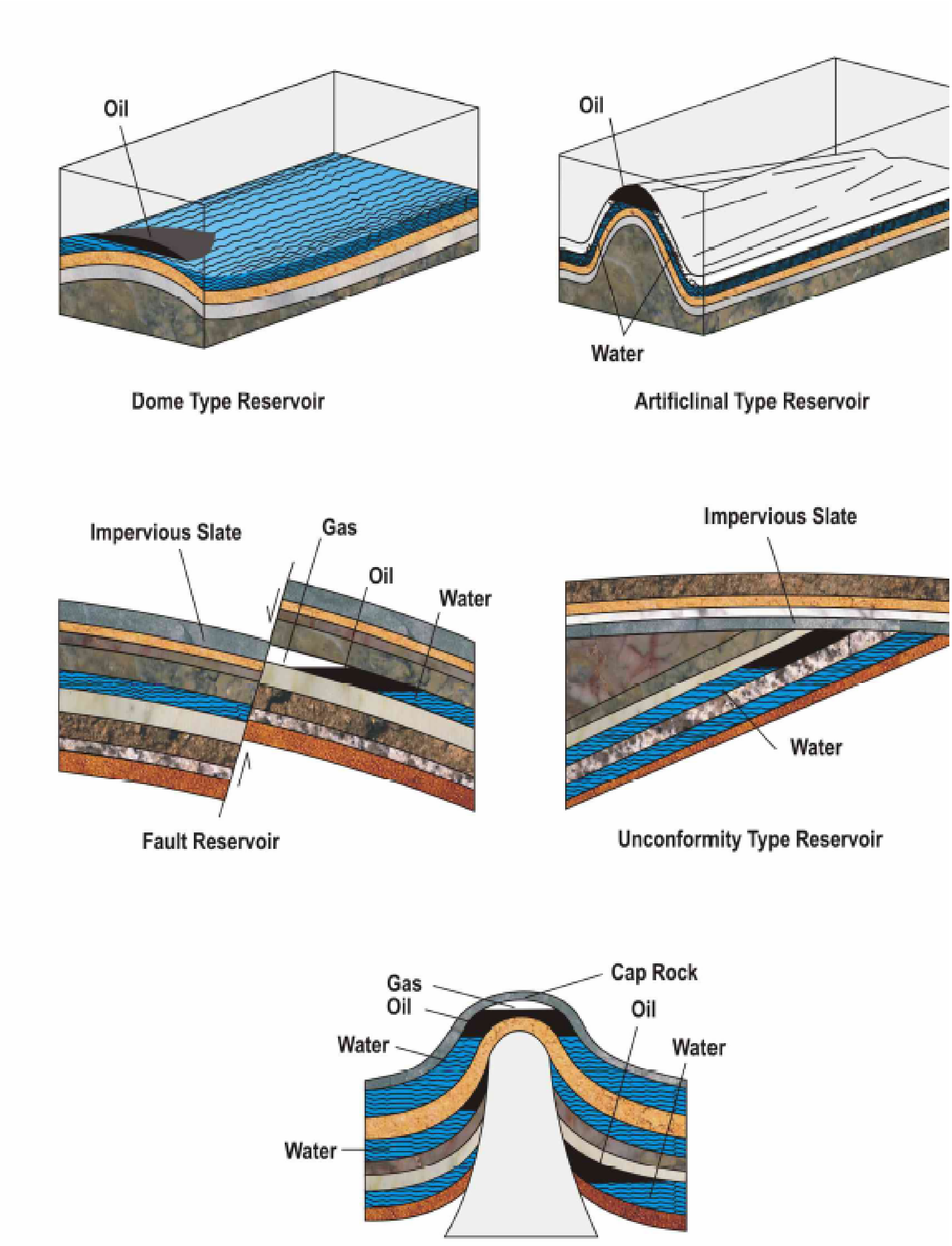


Figure 9 The Common Oil & Gas Reservoir Traps

So we now know that oil and gas can be found in porous rocks under the ground (usually). The next important feature of a hydrocarbon reservoir is a **trap.**

Without some means of keeping the hydrocarbon in place it would seep or spread out in the permeable rock. The above diagrams show how various types of trap can keep the hydrocarbon inside the porous rock. So in order for oil and gas to **accumulate** we need a **trap.**

There are many kinds of trap, formed through the movement of the earth. In fact the earth has moved so much in some instances that marine fossils can be found on the top of the highest mountains. In contrast similar fossils can be found in deep oil wells!

6.4.1 Folds and Warps

Changes in pressure and temperature deep in the earth's crust causes folding and warping of the structure. Mountains are common areas where folding is found; anticlines are where the folds have formed an arch and synclines are where the form a trough.

Figure 10 - Visible folds in the earth

6.4.2 Salt Domes

Another trap can be formed by a salt dome, where hot, molten salt pushes up through the layers of rock deforming them. When it solidifies, a salt dome is left.

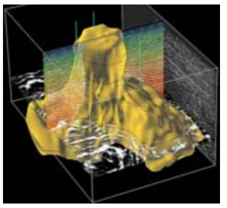


Figure 11 - A 3d computer image of a salt dome

6.4.3 Faults

Faults are created when two rocks or plates, fracture and move relative to each other. Probably, the most famous of this kind of geologic movement is the San Andreas Fault in California. The earth's two largest crustal plates meet here. In the great San Francisco earthquake of 1906, the earth around the fault moved up to 6 m.

Figure 12 - The San Andreas Fault

7 Exploration Methods

We have seen the importance of detailed knowledge of the Earth's geology and how oil and gas reservoirs are more likely to occur in certain types of area and structure. How then does an oil exploration company attempt to gather and interpret the kind of information which will identify locations likely to produce hydrocarbons? There are several phenomena worth analysing: Surface data, earth magnetism, gravity and seismic response. Studying information gleaned from the use of these types of survey will generally reduce the chances of drilling a **dry well (*'duster'*)**.

7.1 Surface Data

The first thing the petroleum geologist must do is narrow the field a little. Some sedimentary basins cover tens of thousands of square miles so that smaller areas must be selected and subjected to highly detailed analysis. Surface topography may help since surface features may reveal evidence of interesting subsurface structures. However, the geologist may wish to study satellite photographs or radar images of certain locations as an aerial perspective can often reveal features which seem insignificant or unrelated to the ground observer. Satellite imaging is much the preferred tool for such work rather than aerial photography because of the expense of flying, the large number of photographs which have to be taken at differing angles and distances and the problems associated in interpreting this vast collection of disparate images. Satellites can also gather images in different light wavelengths such as infrared. These images are useful in determining vegetation and outcrop patterns. When the **concession** area is underwater, other surveying methods must be used to obtain the information required.

Figure 13 - Acoustic Sonar

These include projections from known geographical facts, sonar surveys from vessels and depth plots.

7.2 Magnetic, Gravity and Electromagnetic Surveys

A magnetic survey will allow the geologist to study gross subsurface geology quickly and cheaply. A device called a **magnetometer** will measure local variations in the earth's magnetic field and indirectly, the thickness of likely sedimentary layers. As most igneous or metamorphic base rock which underlies the sedimentary layers contain iron or titanium. These metals affect the earth's magnetic field, and when they do, an **anomaly** is formed. This is a weak distortion of the magnetic field lines and shows a local strengthening of the field. The illustration also shows that areas of low magnetic field strength usually have the thickest sequences of non-magnetic sedimentary rock. Magnetic contours will not reveal details of structure or stratigraphy though and are simply used to reduce the initial area of search.

Gravity surveys can detect the change in density of rocks. They can show how ther generally lower density sedimentary rocks sit over the dense igneous or basement rocks for example.

The electromagnetic method relies on the differing resistances of rocks with differing compositions. Again the naturally occurring electromagnetic fields on the surface are recorded and analysed. This information helps to define the interpretation of all the data gathered.

7.3 Seismic Survey

This is the most widely used geophysical method of exploration and the one which provides most detail. The seismic method is based on sound waves and their travel times in returning to surface receivers. Shock waves, created at the surface by an explosive charge travel down through the earth and are reflected back to the surface from deep rock strata of differing properties. These sound waves enter the rock and are reflected back to the surface, each rock formation and their boundary's respond in a different way. The reflected waves are recorded by sensitive measuring instruments called geophones. As the speed of the sound waves is known, and the time of reflections measured, the depth of each reflecting layer can be calculated. The intensity of the reflection is correlated to rock composition. On land the shock wave can be generated by explosives, dropping weights, or using a vibrating panel.

At sea, compressed air charges are now replacing explosives to make shock waves. This has the advantage of being cheaper and does not harm marine life. At sea hydrophones are used to 'hear' the reflected shock waves.

Seismic is quite an amazing science; the sound wave can travel through 1000s of feet of certain rocks and be reflected back by another. The type of rock determining exactly how the sound wave is reflected. Waves of different frequencies will be generated to make this process provide even more detailed results; i.e. different frequency sound will travel better through certain types of rock, depending on their hardness and composition.

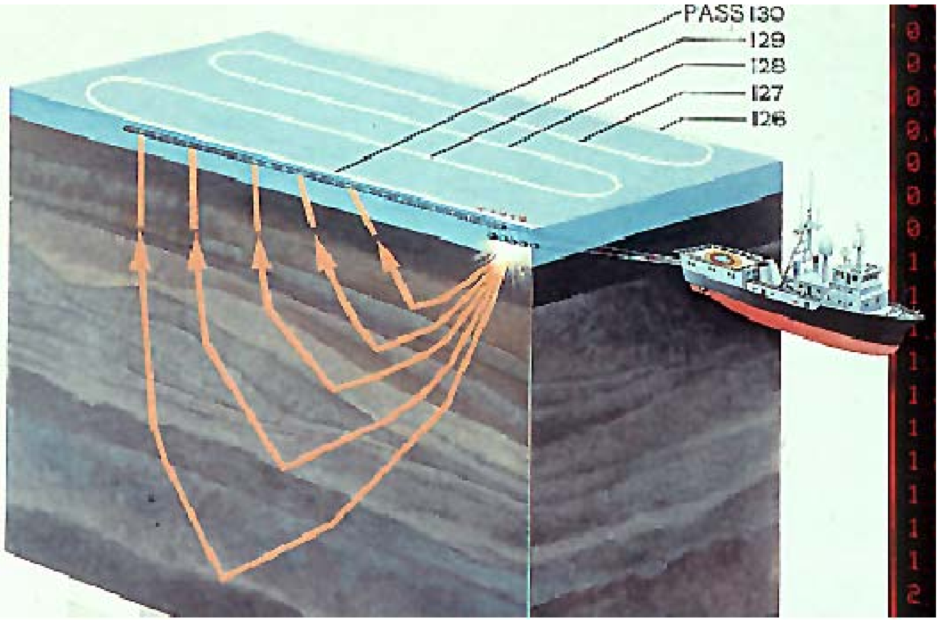


Figure 14 - Marine Reflective Shooting

7.4 2D, 3D and 4D Seismic

Seismic surveys are taken in 2D (2 Dimensional) sections. Slices of the earth are pictured in the results of a 2D seismic survey. Computers can add numerous 2D slices together to form a 3D survey and this is a common method of assessing the potential of a reservoir today.

However, the very latest techniques combine various 2D and 3D surveys taken over a period of time and this is called 4D. Using 4D, including the latest 3D surveys, reservoir engineers can more clearly see the potential in a reservoir, depletion, oil and water contact and more.

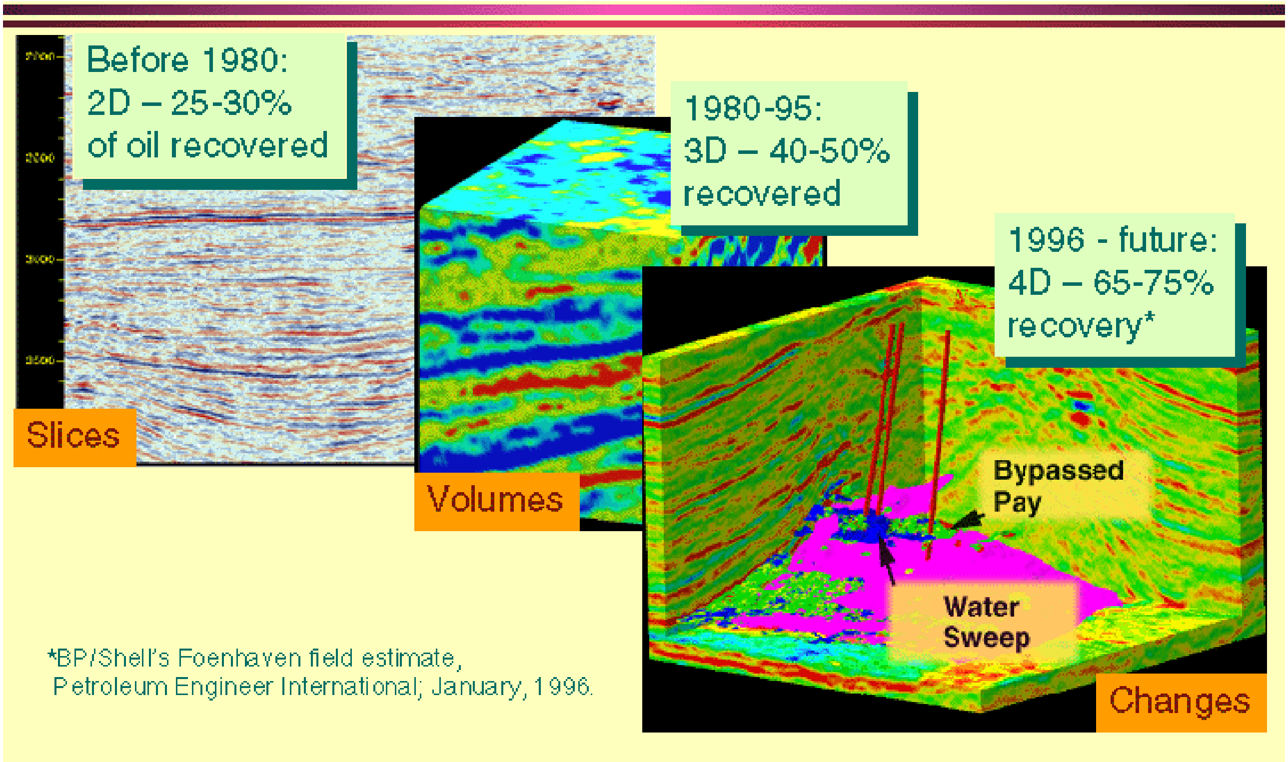


Figure 15 4D Seismic

TIME-LAPSE (4D) SEISMIC

STATOIL

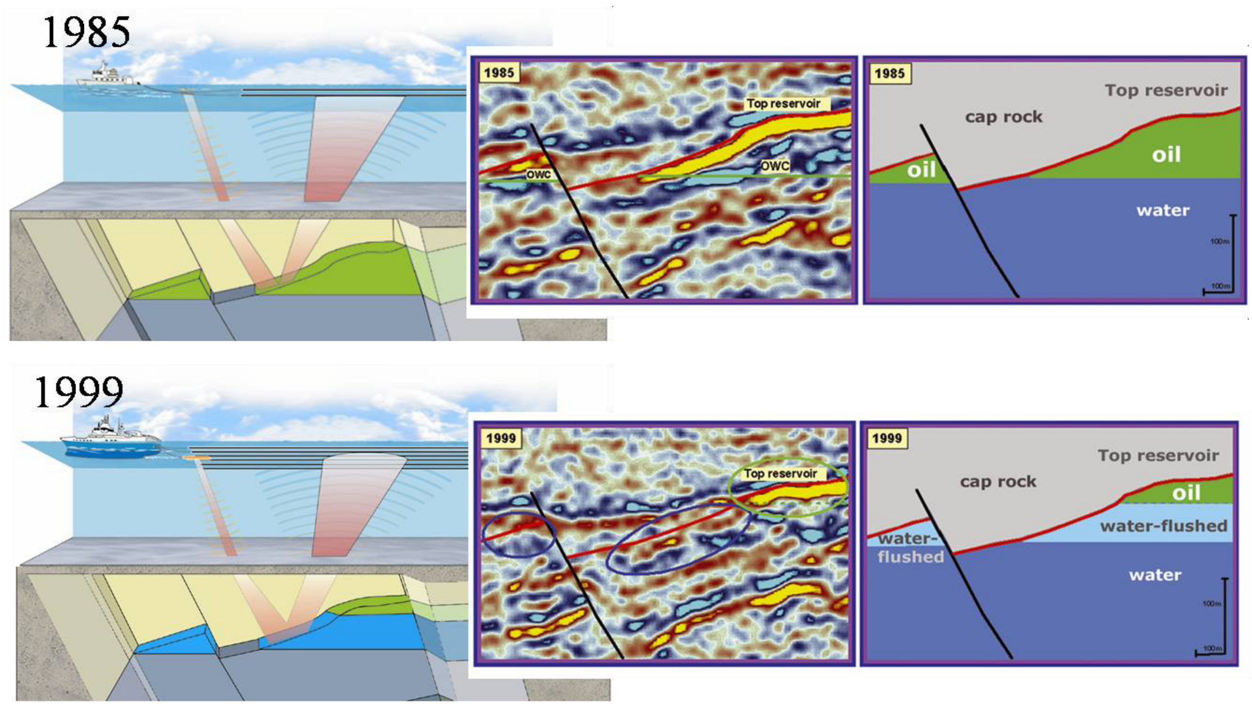


Figure 16 4D Seismic Courtesy of Statoil

Seismic analysis is commonly thought of only being connected with exploration surveys; looking for hydrocarbon reservoirs. But seismic surveys are often used today to assess the current condition and future production capability of existing wells.

The sound waves are collected on sensitive geophones or hydrophones and interpreted. The computer used for analysis in turn can give a 2D or 3D image, almost like a cross sectional view of the rock. Seismic surveys are still a major part of well evaluation and are very valuable in well characterizations and directional clarifications. Water and oil deposits create different reflections and therefore can be shown separately on a seismic chart.

With the advent of enhanced computer ability, 4D images are now being assembled, which are multiple 3D images with a time lapse. The information provided by 4D seismic shows how a reservoir has changed over time and how a new survey, with enhanced equipment, overlaid on an old survey shows clearer pictures.

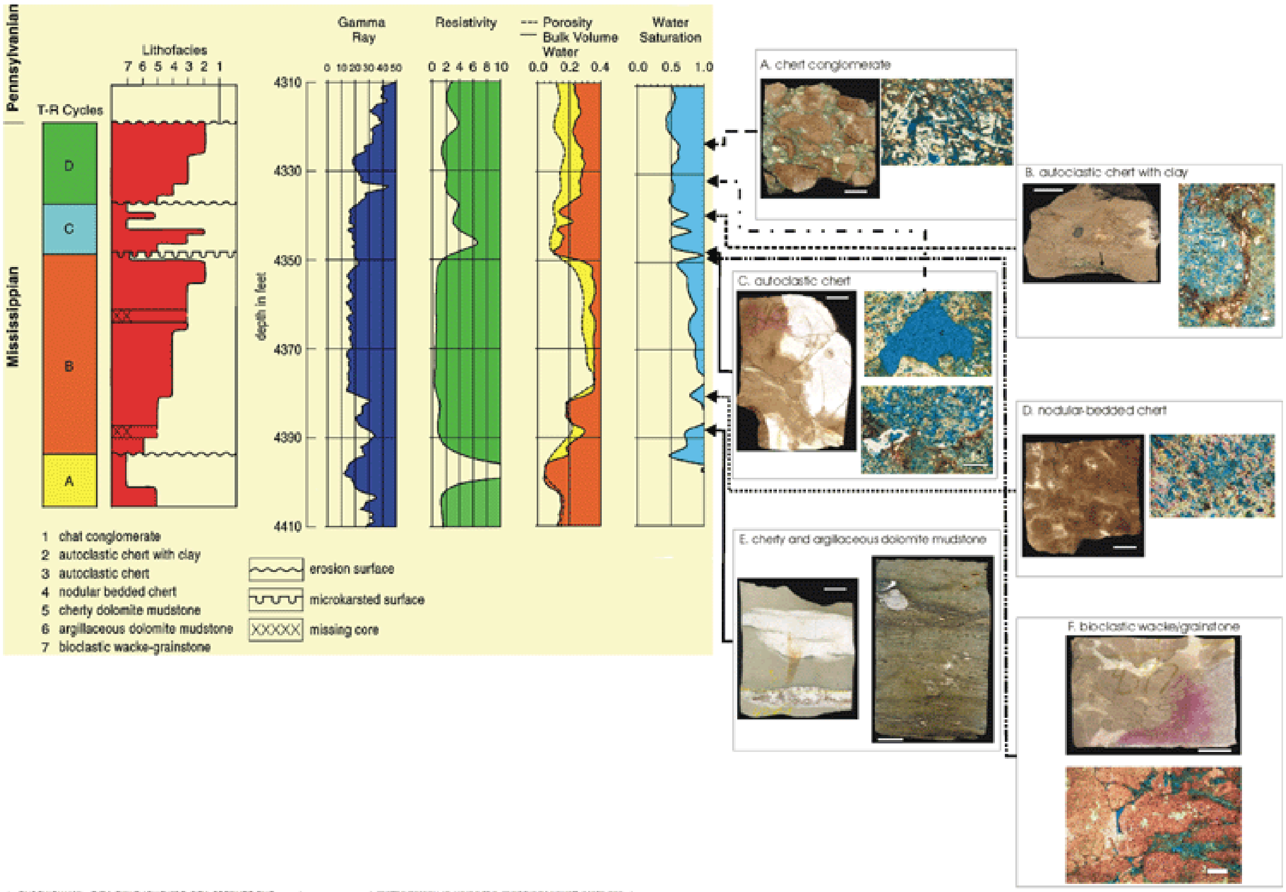


Figure 17 Correlated Logs and Rock Types

7.5 Stratigraphic Testing

The surveys mentioned above provide information on the thickness of sedimentary layers and general trends, but do not give details about the character of the rock. The geologist and reservoir engineer need to know the type of rock in each horizon and more importantly, as much information concerning porosity, permeability and the nature of any fluid which may be present. There are several methods of collecting the samples of rock for the necessary analyses but they all require a well to be drilled.

If a well is being drilled purely to obtain samples of this kind it is known as a 'strat test' hole and is drilled purely to gather data on rock characteristics and sequences. A strat hole is usually smaller in diameter than wells used to recover petroleum, as this saves time and money as the hole can be drilled with a smaller capacity drilling rig. The hole provides rock samples in the form of:

- **Cuttings**: The first samples of rock are produced as small cuttings from the drill bit. These are brought to surface by the circulating fluid 'mud' which is pumped down the drill string and up the well bore. These show the driller which stratum the bit is penetrating and allow the geologist to perform some basic tests.
- **Cores**: In order to perform representative tests, the geologist requires representative samples of rock. Since cuttings are contaminated by drilling mud and are very small, a hollow core barrel can be used to cut 10 – 20 metre (30-60 ft) cylinders of rock, and bring them to surface. Detailed experiments testing porosity and permeability characteristics can be made under laboratory conditions for greatest accuracy. Individual strata can be sampled by means of a hollow steel bullet fired sideways into the downhole formation and retrieved.

It is sometimes better again to test formation rock characteristics *in situ*, and for this, special electronic tools are lowered into the well. These tools and testing techniques will be described in greater detail in Formation Evaluation.

Figure 19 - Core Samples

Figure 20 - Coring Drill Bit

So the geologists and the seismic vessels have located a spot where they have assessed there is a good likelihood that there is some hydrocarbon. The stratigraphic test has shown that the formation has some development potential. The next thing to do is to plan a test well and drill it, to see if at least some of their analysis was correct!

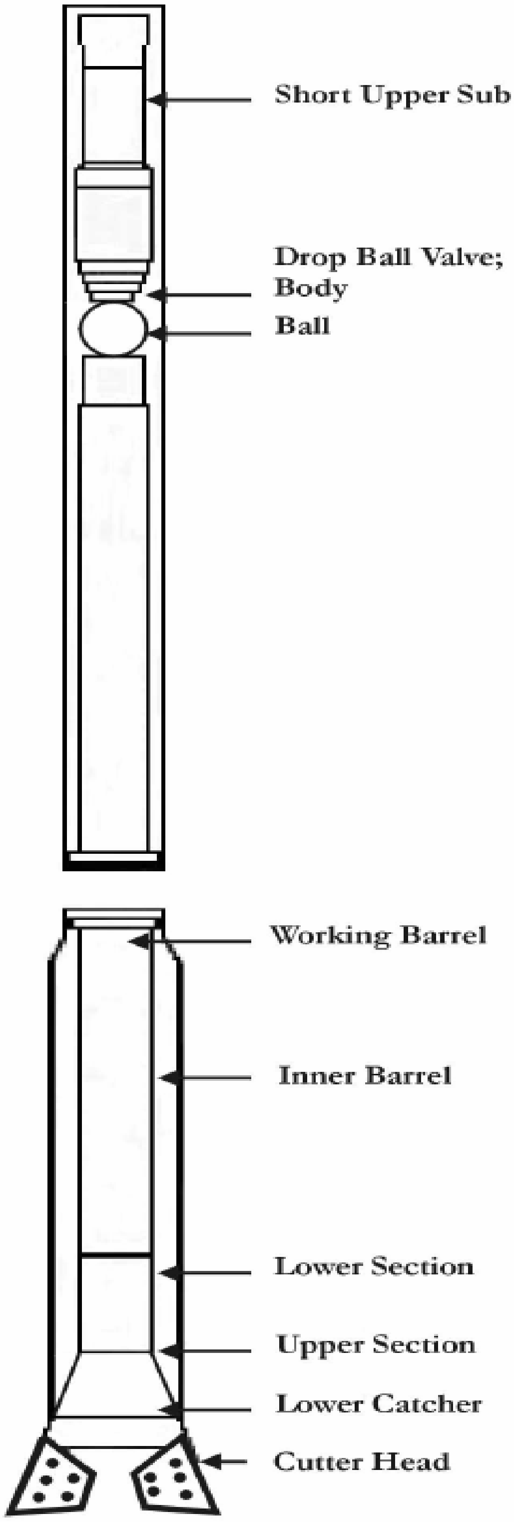


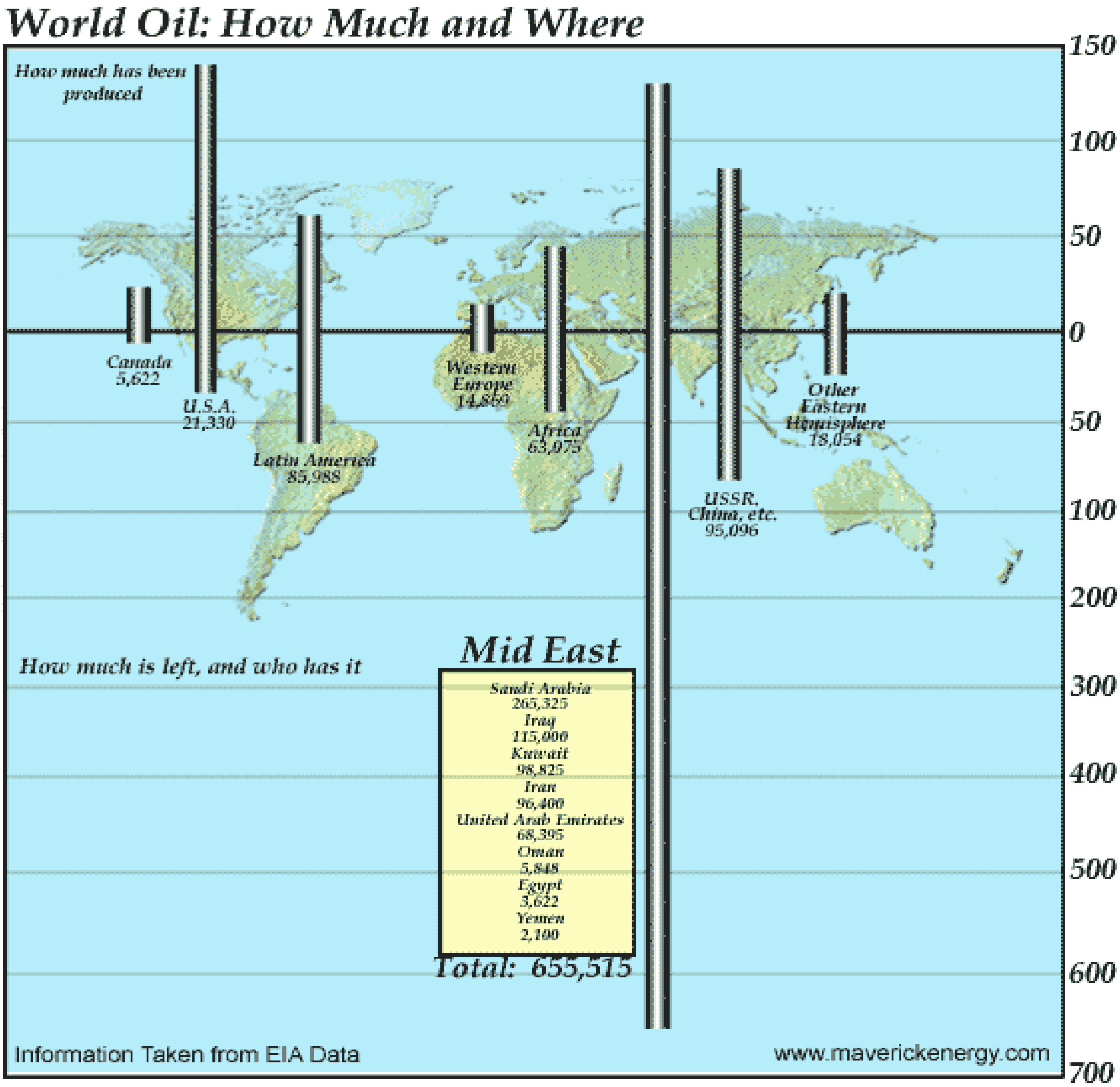
Figure 18 - A coring tool

8 Selecting a Drill site

Prior to any exploration activity taking place, a company must first receive a license. Only after all the appropriate legal formalities are completed can exploration begin. Geological aspects are obviously important but must be weighed against factors such as access, costs of production, and transportation.

8.1 Location

If, for instance, a prospect can only be reached by expensive directional drilling techniques, the company may opt to try in a less difficult location. Also, if the proposed prospect lies in deep water then costs may be higher than for a land based rig and subsequent production facilities. Many fields are being developed today which were deemed un-commercial in the past it is important then to remember that companies, as

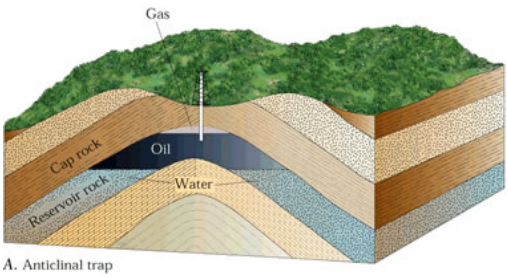


commercial enterprises, must evaluate the practical and economic aspects of a location as well as the technical ones.

What do you think are the important characteristics of a potential commercial development, based on what you have learned so far?

8.2 Source Beds

It is vital that source beds must exist close to or within reasonable distance from the prospect, or it would be unlikely that oil could ever have accumulated within the structure of interest. The source rock must also satisfy a fairly rigorous set of conditions before it can be considered a likely environment for the formation of hydrocarbons. It should have contained sufficient biotic material, been hot and deep enough to form hydrocarbons from this material, and have been sufficiently isolated from oxygen to prevent its oxidation.

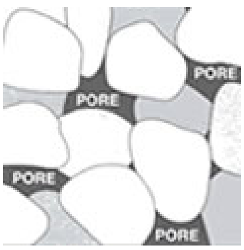


A. Anticlinal trap

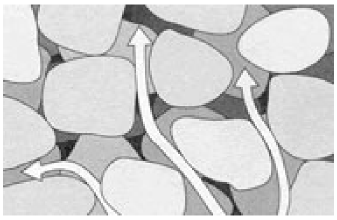
8.3 Traps

To prevent the eventual escape of the hydrocarbons to surface, they must be trapped by some impermeable formation of rock. The geologist must look for faults, overlays, and stratigraphic features indicative of trap formations.

8.4 Zonal Characteristics

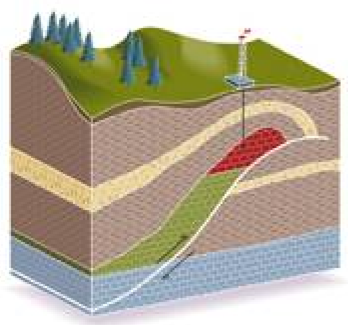


Values of permeability and porosity are vitally important to the geologist and reservoir engineer. Effective porosity and effective permeability are more important also than the gross values. The presence of water and gas in the oil will also affect the performance of a reservoir.



8.5 Reservoir Dimensions

The geologist must also try to calculate the volume of a reservoir in order to assess the economic viability of developing it. This will be a difficult task considering the vertical and horizontal thickness changes and curved contours of most structures. The volume is also a function of the bed thickness, aerial extent, and effective porosity. If the prospect is drilled, the figure will be adjusted as dynamic flow tests are made on the reservoir.



8.6 Conclusion

All the information available, even with careful analysis, can afford no more than the best chance of finding a reasonable prospect. The only certain way to establish the presence and nature of a hydrocarbon reserve is to drill an exploratory well.

9 Safety

9.1 Is the oil and gas industry safe?

Comparing statistics for different industries is not easy as they tend to be calculated differently; generally we know that the construction industry has a lot of accidents; the conditions are difficult and many millions of people work in construction around the globe. We also know that people are injured in the oil and gas industry each year and that a few very unfortunate individuals are killed. In fact 31 people were killed in the drilling industry worldwide in 2003; but for that to happen over 300,000,000,000 man-hours were worked[1]. Accidents happen in every industry, but one thing you can be certain of in the oil and gas industry is that virtually every company and individual involved is making a positive contribution to improving safety at work for all employees. This initiative is starting at the top with the major producers and filtering down to all service and supply companies; wherever they are located. It must be said however, that certain companies in certain countries are not as proactive and safe as they could be but safety is without doubt improving. If statistics don't show the improvement too readily, that may be because individuals and companies are prepared to log more incidents than they used to be, to help avoiding a similar incident occurring again. In the past some incidents would allegedly be 'covered up' to ensure that safety performance bonuses were paid at the end of the period of work!

9.2 New Safety Initiatives

To illustrate how seriously safety is being taken, here is an initiative adopted by the UK industry in 1997.

"The Beginning" September 1997

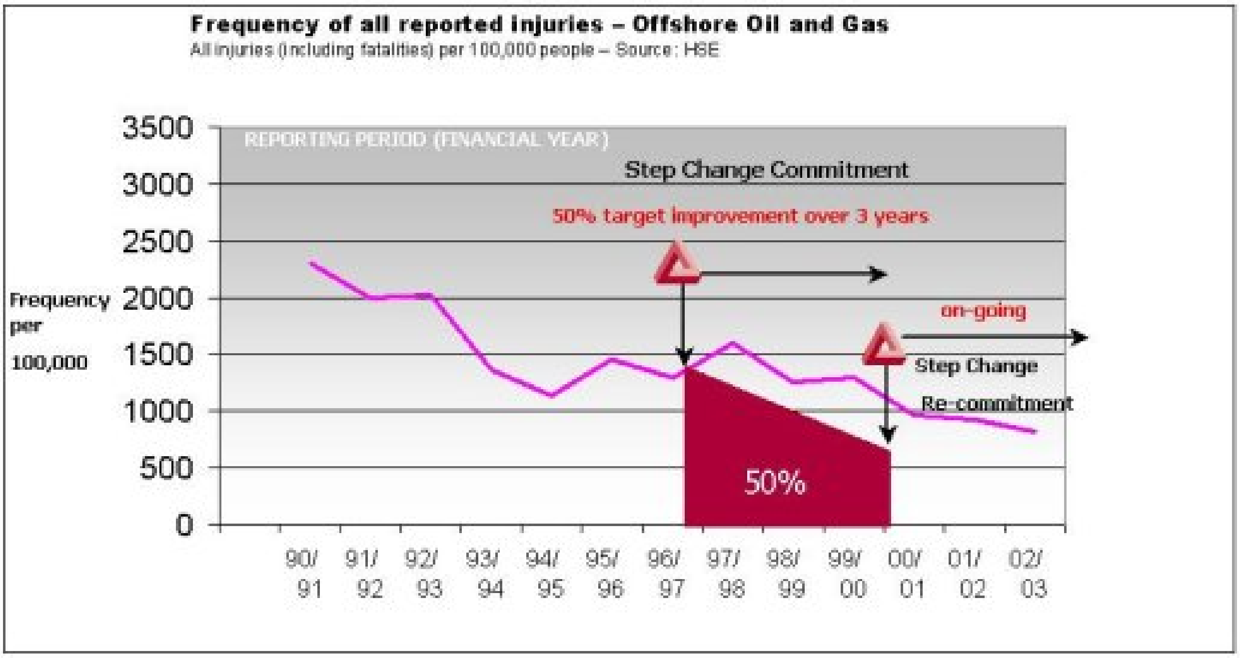
In the years following the Piper Alpha tragedy, the oil and gas industry made significant improvements in safety through the application of hardware, changes in design, modifications, policies and procedures. Dedication and hard work by the workforce and management alike had led to a significant reduction in the number of serious accidents and injuries being reported but the rate of progress in safety performance improvement had begun to slow and plateau. Employees were still getting hurt and this was unacceptable, a "step change" approach in the safety culture was required.

With this in mind the industry leaders and representatives from the three main trade association, UKOOA (United Kingdom Offshore Operators Association), IADC (International Association of Drilling Contractors) and the OCA (Offshore Contractors Association) agreed that enhanced co-operation between the companies operating in the UKCS (United Kingdom Continental Shelf) was the way forward. As a result, the "Step Change in Safety" initiative was launched at the Offshore Europe conference in September 1997. George Watkins, Managing Director, Conoco UK. Ltd. agreed to take the position of Chairman of the initiative.

As an industry a commitment was made to:

[1] Information from the IADC Annual Report

- **Work together to improve sharing of safety information and good practice across the whole industry, through active involvement of employees, service companies, operators, trade unions, regulators and representative bodies;**
- **Establish leadership safety performance contracts, which will demonstrate visibly a personal concern for safety as an equal to business performance;**
- **Deliver a 50% improvement in the whole industry's safety performance over 3 years.**



Whilst this illustrates an initiative by the UK industry, you can be sure that the companies operating these programmes are mostly working worldwide and that they will be looking out for your safety.

9.3 Accidents will happen

An accident is recognized within our industry as being something which could have been avoided and much work is being done to educate people and make systems, procedures and equipment much safer. It is common now for even the slightest of injuries to be investigated thoroughly to ensure that if similar circumstances prevail again; the injury can be avoided AND if slightly different circumstances prevail that a more serious injury could be avoided in the future.

Schemes, awards, statistics and people are working tirelessly to make this industry as safe as it can be.

But we do face dangers; the offshore environment is somewhat inhospitable and usually an offshore platform has to be reached by helicopter. We are dealing with high pressures, high temperatures (and extremely low temperatures), chemicals, flammable oils and gases. We are often expected to lift heavy weights and move around awkward structures.

The onshore environment is similar; we deal with the same pressures and chemicals and in some countries we face the added security problems as well. In addition road traffic accidents on the way to rigs has been a common cause of oilfield injury, even so travel to an offshore platform or rig by helicopter can unsettle people more. This is not uncommon, many people have a fear of flying, yet very few have a fear of driving or being driven; whilst the accident figures show that, in the UK at least, the risk is similar.

TRANSPORT MODE	1992 - 2001 AVERAGE
Offshore Helicopter	4.33
Air	0.01
Rail	0.4
Car	3
Two Wheeled Motor Vehicle	106
Pedal Cycle	42
Pedestrian	58

Figure 21 Comparison of Average Fatality Rates per Billion Passenger Kilometres by Transport Mode 1992 to 2001

9.4 It's up to you!

It is a well known fact that human error contributes a lot to accidents; one little mistake can lead to a trip and a bump or to a catastrophic event. Don't leave safety to chance, make certain that you take care or yourself and others.

Figure 22 - Looking after number 1

So how do you avoid injury, illness or worse? You look out for yourself and your colleagues. You assess risk and take no chances. You will get no bonuses for finishing a job ahead of schedule, but causing harm to yourself or others in the process. Your boss would much rather have you around for the next job than informing next of kin that you've been in injured or worse!

So if it is recognized that people are behind most *accidents* –it really is up to each and every one of you to ensure that the oil industry of the future is one of the safest industries to work in – no matter where you are in the world.

9.5 On the Rig

Safety is a major part of any drilling and operating situation. It is taken very seriously throughout the industry; a lack of safety or a near miss can shut down a highly profitable production well or platform if the risk involved in keeping it operating is deemed to high.

Before you enter any land site or travel to an offshore rig you will undergo a safety induction, this applies to any drill ship and includes refineries, petrochemical plants and applies to any one **working** or **visiting** the site or installation.

What is an induction you may say? Safety Inductions may vary from company to company but are all focused on one thing when on site and that one thing is your personnel safety and your safety towards others and the equipment. There is a lot of emphasis on **YOU**!

Your induction will include all

- Escape routes and muster points
- Warning sirens and their actions
- Rig or site walk around and familiarisation
- Introduction to all the key personnel
- Safe and environmentally friendly waste disposal
- **PPE** (personnel protective clothing) requirements
- Lifeboat location (offshore)
- Fire fighting equipment – where it is and how to use it
- Emergency telephone numbers
- Safety meeting schedule
- Permit to Work system
- Specific things about this installation which you may not normally be aware of.

Figure 23 There are lots of Safety Initiatives Worldwide

Weatherford has its own set of safety guidelines and this will be taught to you on a regular basis and will be periodical reviewed and up dated as the industry changes or sets new legislative regulations.

You will be issued with your own Personal Protective Equipment (PPE) from Weatherford before you travel to your work site.

These will include:

- Protective hard hat
- Safety glasses
- Coveralls
- Safety boots

- Gloves
- Ear protection
- Extreme location clothing (tropical or sub-zero temperatures)

9.6 Hydrocarbons and Worse!

Hydrocarbons are obviously highly flammable, hydrocarbon gas is flammable AND invisible, in it's un-refined state it may have little smell either. Mixed with air and therefore oxygen, hydrocarbons are potentially explosive, so be very careful when working on and around hydrocarbon containing systems.

Figure 24 H_2S Warning Sign

Other gases in common use around a rig are nitrogen and CO2, with nitrogen being the most common. Often stored in cryogenic form, nitrogen is dangerous because of it's ability to asphyxiate you without you realising it. Do not take any risks if you are working with nitrogen; certainly when handling equipment containing cryogenic nitrogen ; be aware that it is stored at -196^{o} C!

Then there is H_2S, a very dangerous gas indeed. If you are going to work on a site where there is an H_2S presence, make certain that you understand ALL of the safety rules and their implications for you and your colleagues. You should receive very good training regarding H_2S.

In addition, there are many other chemicals and gases being produced or in use around rigs – always make yourself aware of the hazards and take no risks with them.

Figure 25 Do not take unnecessary risks!

9.7 Rules Vary Around the World

All North Sea operators insist on personnel taking an ***offshore survival course*** which involves basic helicopter survival, fire fighting and basic first aid training, without this qualification it is not possible to travel offshore. The fire fighting and basic first aid training is a great life skill for everybody.

In addition to you own safety training, whilst being on an offshore rig you will have additional emergency recovery systems such as helicopter and stand by vessels to accommodate an emergency rescue or abandonment.

Slips, trips and falls are said to be the second leading cause for workplace injury according to *Liberty Mutual Research Institute for Safety*. Slips and falls regularly occur as you walk out of your front door, so the chances of them happening on both an onshore and offshore oil rig are going to be high. Obviously such accidents can be avoided by maintaining a proper working environment, providing the appropriate clothing and surface to work in.

Injury while lifting is also common place in our industry. There's no need to be a hero, to prove just how strong you are – get some assistance or a crane!

9.7.1 Near Miss

What is a near miss?

It is an accident which could have happened. Have you ever said to yourself – *'wow, that was lucky.'* If you had been 1 ft closer, maybe you'd have been ……?'

Near Misses are accidents waiting to happen; so when you see one you must report it straight away. Then, the next time those circumstances come together an accident will hopefully be avoided.

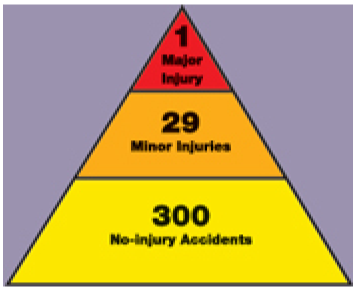


Figure 26 Ratio of Accidents

Of course, if you are faced one day with seeing an actual accident where someone gets injured and the next with a minor near miss; which are you likely to report? Human nature tells us that you may not report the near miss, but please do you could save someone, even you, from a lot of pain and suffering. Again it is up to you to maintain and improve the health and safety of the oil and gas industry – nobody else YOU!

Figure 27 Handling an onshore blowout

Remember that you are entering a very technical, physical and potentially dangerous environment and you must be aware of all that is around you. Never assume that some one or some thing is right.

If you do not understand then ask, **No question is too trivial**, and it may save some one's life or your own one day.

When entering the oil and gas industry you will be exposed to all kinds of different technology using explosives, chemicals, radio-active sources and high pressures all of which have their own terminologies or abbreviations and can seem very alien. The oil industry has its own dictionary and you will soon understand the many phrases and slang names used, to describe the many rig parts and operations.

And of course there's the other pressure – stress! The oil and gas industry is renowned or wanting something done or manufactured ***'yesterday.'***

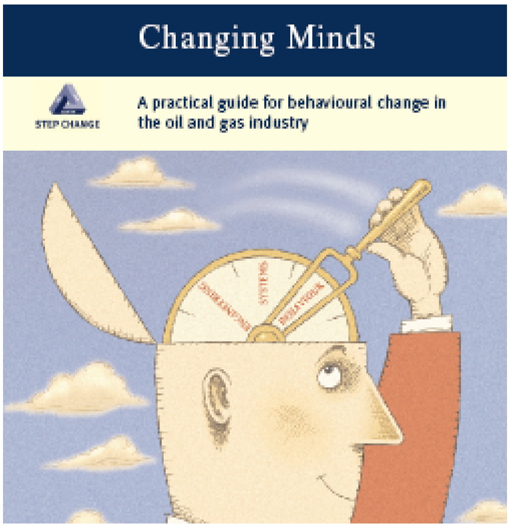


Figure 28 It is well known that improving attitudes & behaviours can positively contribute to safety.

Figure 29 Do not ignore Safety Notices

10 An introduction to Drilling

Armed with information from geophysicists and seismic surveys, it is time to bring in the drilling rig, to drill an exploratory well. This next section tells you how a rig works, the different types of rig, rig systems, about cementing, pressure control and the basic fundamentals of drilling a well.

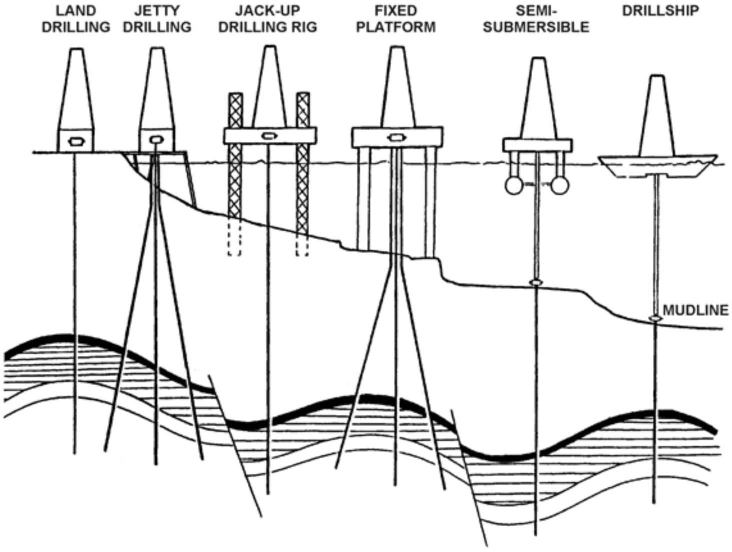
10.1 How a Drilling Rig Works?

The aim of the drilling crew on board the rig is to drill a hole through the layers of earth, sand and rock and ultimately reach the 'pay zone' the location of the trapped hydrocarbon. With wells commonly drilled in excess of 10,000ft (3,000 m) at many angles – some even horizontal – that is no easy task!

So….

10.1.1 What is a drilling rig ?

A drilling rig is a piece of complex machinery used to drill into a hydrocarbon containing rock. Although there are many different types of sub-structures they all carry out the same basic drilling operations. They have evolved substantially since the mid-1800's at the dawn of the oil and gas industry, from the days of wooden rigs and cable–tool (chisel type) drilling; we now have Jack-up Rigs, Land Rigs, Semi-submersible Rigs, Production Platform based Rigs and Drill Ships, all capable of drilling deep, directional wells in very fast times. .



These rigs can be divided into two major categories, **Land rigs** or **Mobile Offshore Drilling Units (MODU)**; however a third could include **drilling barges**, which operate in shallow water lakes and estuaries.

All of these rigs are basically a package of specialist equipment needed to drill a hole in the Earth's surface or sea bed.

No matter which type of rig you find yourself on they all need to be serviced by support vessels or transport of some kind to deliver the essential equipment and supplies required to complete the drilling operation. This can be a mammoth task as some drilling locations can be very remote and in some cases are only accessible during certain periods of the year; for example in Northern Canada. This can create the need for the rig to be disassembled, transported in sections by trucks, or ships, sometimes taking weeks to get to location and then re-assembled on-site. This is however, not as uncommon a practice as you may think and is typical of a dessert or jungle location.

Did you know?

That some wells are drilled at over 35,000ft in depth – that's over 10km!

Supplies to any rig include provisions, personnel crew changes, fresh water, Potable drinking water, diesel and drilling equipment. Much of the drilling equipment is heavy and can be up to 40ft in length, which requires special transport boxes, all adding to the logistic difficulties.

10.1.2 The People

All these different Rigs operate on a twenty four hour, round the clock operation, divided into two twelve hour shifts, with a full crew on each. The drill crew on an offshore rig typically consists of an:

OIM (offshore installation manager)	Is the senior person in charge of the offshore platform – has both marine and oilfield experience.
Company Man (representative of the oil company)	The production company's senior representative on site.
Tool/Tour Pusher	The senior drilling person on site.
Drilling Engineer	A drilling technical specialist.
Medic	The person who looks after sick and/or injured personnel on site.
Driller (may also be called Toolpusher)	Senior Drilling representative, may report to Toolpusher (depends on size of crew)?
Assistant Driller	Reports to the Driller or Toolpusher

Derrick Man	Works up high on the derrick, handles the top end of the drill pipe sections and fluid circulation equipment. Modern rigs do not usually require a derrick man due to automation. Works on the *Monkey Board.*
Roustabouts	Equipment operator on the rig.
Roughneck (rotary helper)	Works on the drill floor doing various jobs, reports to the assistant driller.
Crane operator	Operates the crane – a very important and hazardous job on a rig site.
Motor Man	Mechanic responsible for drilling power and other engines / pumps.
Rig Electrician	Responsible for connecting and maintaining electrical equipment at site.
Rig Mechanic	Responsible for all mechanical repairs and maintenance on site.
Materials Coordinator	Ensures adequate and safe supplies of equipment and goods are brought to site.
Administration Coordinator	Runs the administration of the rig, emails, faxes and other communications, transportation for personnel perhaps.

Additional Service personnel will also be required to carry out specialist services which are key to the drilling operation. These may include:

- Casing Crew – connects lengths of casing together
- Cement Engineer – designs, mixes and runs cement
- Logging Crew – run various logging operations
- Directional Driller – specialist who makes certain that the drilled hole is in the correct position.
- Mud Logging technician – assesses and maintains the correct mud constituents.
- Completions Engineer – organises, engineers and supervises the running of the well completion system.

This is just a short roll call of some of the service personnel required onboard which can bring the Personnel On Board (POB) number from 60 to 100+, depending on the size of rig.

Whilst on the rig you will be using the accommodation facilities which has its own staff, just like a hotel, this staff is responsible for all the duties you would associate with running a hotel. The **Camp Boss** controls the stewards and chefs and makes sure that all the accommodation is clean and that meals are prepared and ready for crew change times.

The **Motor man** is located in the machine (motor) room and maintains the large generators, pumps, compressors and utilities that are essential to keep the rig running through out a twelve hour period.

Controlling all of the activities on the drill floor is the **Driller**, the person in charge. He has the drill crew, **roughnecks,** working for him. These crew members carry out all of the necessary operations on the **rig floor** while drilling the hole, which will be explained further into this section.

Only when **all** these key personnel are in place can the drilling operation begin.

10.2 The Systems

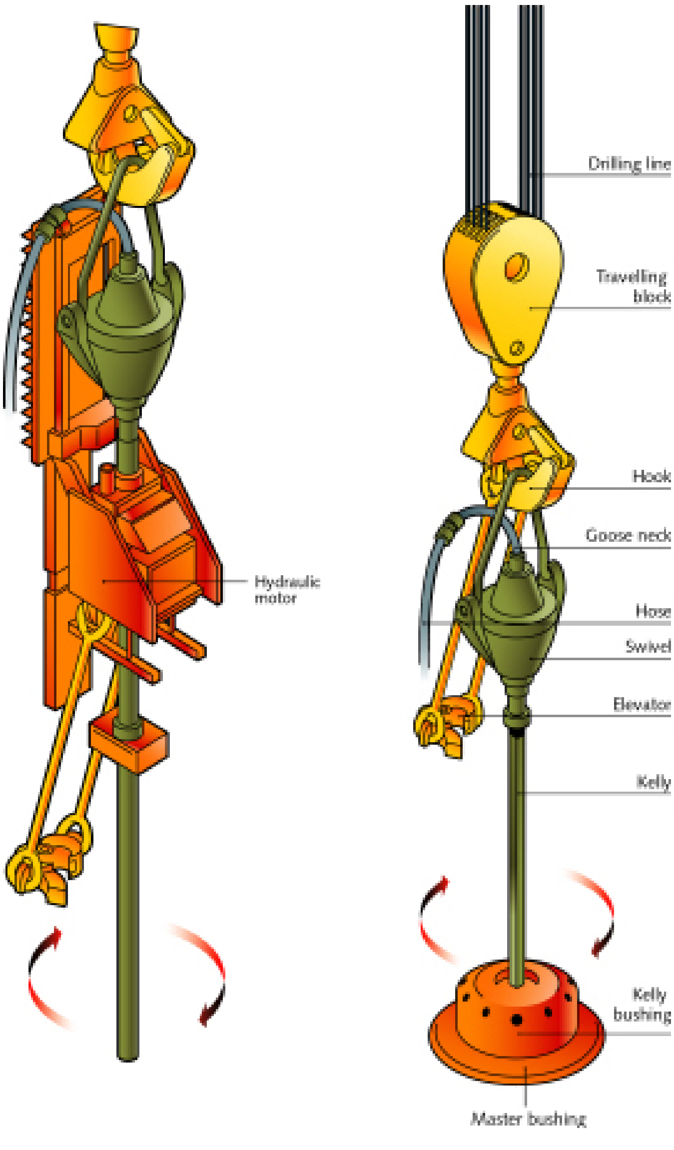
10.2.1 Drive Systems

Any form of drilling requires a **drill bit**, which is screwed on to the bottom of a thirty foot drill pipe section. As the drill bit drills and is lowered into the ground, more sections of drill pipe are added – these pipes connected together are called the **drill string.**

To enable it to drill, the bit is rotated either by means of the **rotary table**, or a **top drive** unit. The rotary table is the more traditional way of drilling and rotates the drill pipe and drill bit via special grips located on the **drill floor**. The top drive unit rotates the drill pipe and bit from the very top of the drill pipe. Top drives are more common now as they provide a safer and more efficient source of drilling power.

Either system has to allow for rotation of the drill bit and for the drill bit and string to be lowered into the well as drilling takes place.

This all happens on and above the rig (or drill) floor, this area of the rig is very active and potentially can be a very dangerous area.



Did you know?

That many rigs are automatic now, requiring very little human input for handling and running drill pipe.

10.2.1.1 Rotary Table Method

The Kelly transmits rotary movement from the rotary table through the drill string to the drill bit. The Kelly bushing also enables the Kelly to move up and down through the rotary table. As only the Kelly can do this, it is necessary to interrupt drilling from time to time to extend the length of the drill string by adding another length of drill pipe. This occurs every 30 ft. (9 m) of hole drilled, this being the length of a joint of drill pipe.

In preparation for adding a length of drill pipe to the drill string, the next section of drill pipe is picked up from the pipe deck and placed in the mouse hole. This is a hole or tube adjacent to the rotary table of sufficient depth to accommodate a length of drill pipe with about 3 ft. (1m) protruding from the top. A small hoist is used independently from the main drilling equipment to handle this length of drill pipe.

When the top of the Kelly is almost down to the rotary table, drilling is stopped. The rotary table and mud pumps are stopped and the Kelly, with the drill string below it, is pulled out of the rotary table until the top of the drill string is clear of the rotary table. It is then held in this position by devices called slips, which are steel wedges inserted into the hole of the rotary table to clamp the drill string, thus supporting it and preventing it from turning independently of the rotary table. The Kelly is now unscrewed from the drill string and swung over the new length of pipe in the mouse hole. The new drill pipe and the Kelly are screwed together and the complete assembly is lifted out of the mouse hole and swung over the drill string clamped in the rotary table.

Figure 30 Rotating Kelly Bushing

The new drill pipe is screwed into the existing drill string thus extending the length of the drill string by some 30 ft. (9 m). The slips can now be removed, the mud pumps started and, after the bit has been lowered to hole bottom, drilling can recommence.

10.2.1.2 Top Drive Systems

The Kelly and rotary table system have been in use since rotary drilling was developed at the beginning of the century. However, the top drive drilling system (TDDS) has been used for some time now. This system eliminates the Kelly and rotary table by suspending a large electric or hydraulic motor from the hook. The motor is screwed directly into a 90 ft. length of drill pipe (3 lengths of 30ft pipe) known as a stand. The advantage of the TDDS is that a connection is only required every 90 ft. (instead of every 30 ft. with a Kelly) and, if the drill string becomes stuck, the top drive can be used to drill out of the hole.

10.2.2 Drill Pipe

Drill pipe is a heavy forged steel tube, with threaded connections at either end. The threaded connections are tapered threads, which allows for a fast and effective **make up** (screwing together). At one end the male thread is called the **pin** and at the other the female thread is called the **box,** the pin end is always pointing downwards. Through the centre of the drill pipe, the driller will pump the drilling fluids – usually mud. The length of a drill pipe joint is approximately 30ft; the outside diameter can vary but common sizes are 4 ½ “, 5” and 5 ½“ outside diameter.

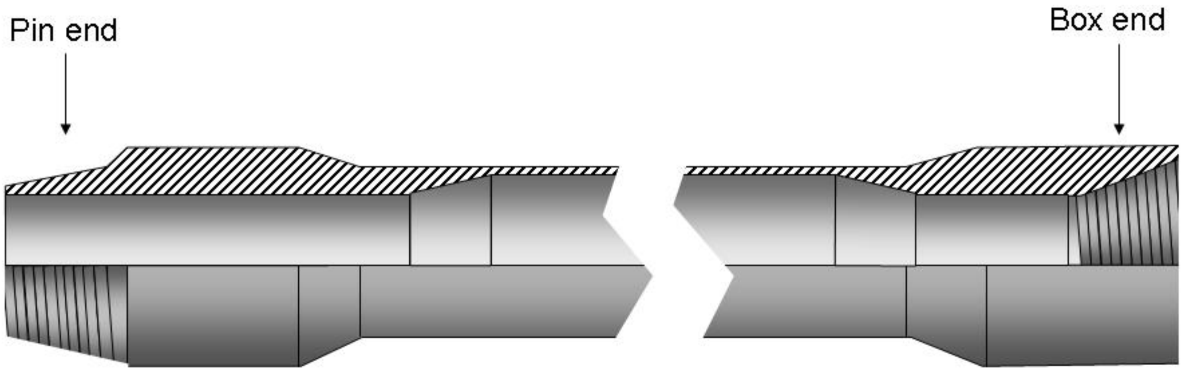


Figure 31 Drill Pipe Cross Section

10.2.3 Tongs

Tongs vary a great deal, but simply put, they are like extremely large pipe wrenches. They are large because of the high torque requirements of drill pipe and casing – from 2000 to 100,000 ft lbs. If the drill pipe or casing were connected as pipe is on a process system, with flanges, then the wrenches used to connect the flanges would be small. But drill pipe and casing connectors need to be smooth so that they can easily be run down hole without snagging; so they are screwed together, and they have sealing faces which require high torques for them to engage properly.

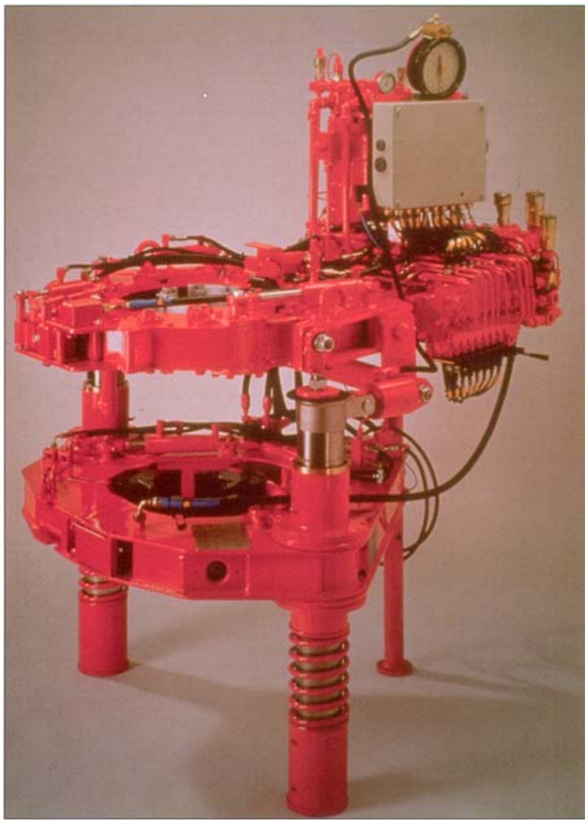


Figure 32 Weatherford Tongs

There are simple manual chain tongs, which are not in much use today. There are manually operated hydraulic tongs and then there are automatic hydraulic tongs.

Weatherford were one of the first companies to realise that the amount of torque and the way it is applied to casing and drill pipe threads is very important. In fact the way the male and female threads of a connection screw together

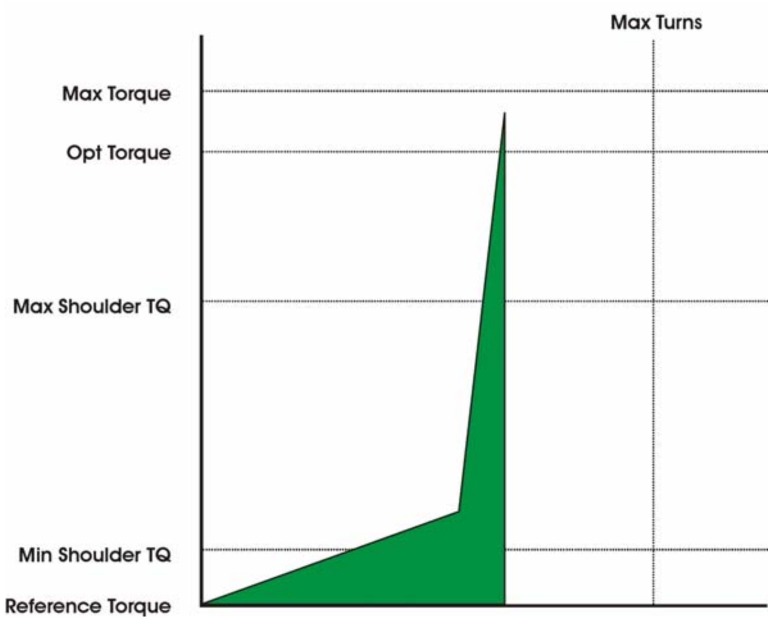
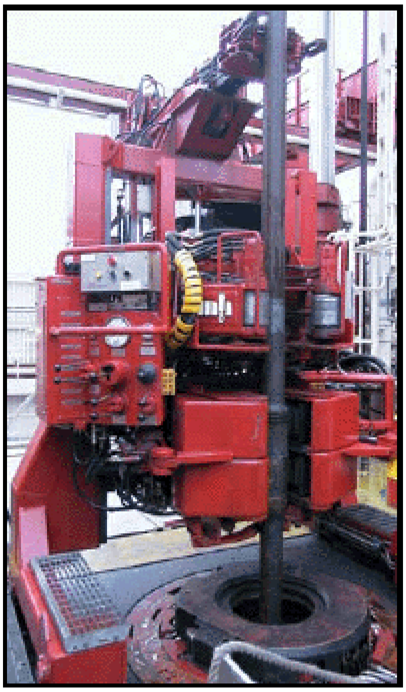


Figure 33 Torque-Turns Graph for Casing Make-Up

can tell an engineer a lot about the condition of the threads, the lubrication and whether the seal has been engaged properly.

The tongs grip the pipes either side of the joint, using serrated, hard steel grips – ***tong dyes***. The bottom pipe is held still by the lower tong dyes and the upper pipe is rotated clockwise to screw it into the bottom pipe. Because most oilfield drilling and casing threads are tapered, initially there is little torque required. But as the tapers engage with each other, the torque power rises quickly. Then as the two seals connect, the torque power rises extremely quickly, until at a pre-determined level, the tongs stop and the joint is connected.



Automatic Roughneck with Stabbing Arm & wide frame

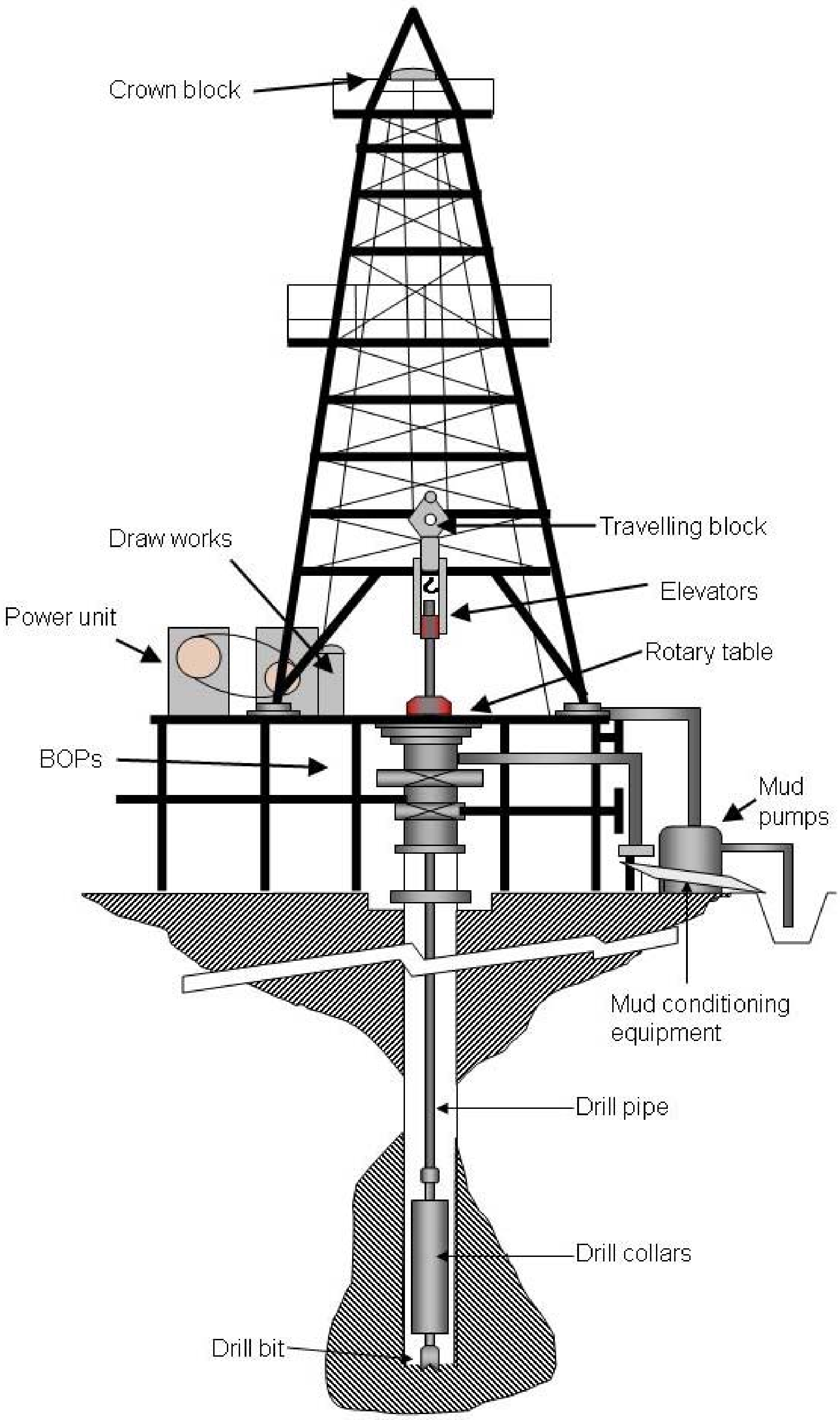
When a connection is screwed together it is termed *'made up,'* when it is un-screwed it is termed *'broken out.'*

Intelligent tongs give a read-out of torque required versus turns made, a graph is drawn and the results analysed see Figure 33 Torque-Turns Graph for Casing Make-Up.

Drill pipe connections are not as critical (regarding leaks) as casing and tubular connections; as drill pipe is only temporarily placed in the well bore. Casing and tubulars are usually permanent placements and should not leak. Where drill pipe connections are critical is in terms of strength and condition of the threads; huge amounts of torque is applied to drill pipe when drilling and it is vitally important that the connection can be *broken out* when the pipe is run out of the hole.

10.2.4 Elevators

Elevators are simple clamping devices which quickly clamp around the drill pipe, casing or tubing. They are connected to the travelling block by the **bail arms** or **links**.



10.2.5 The Derrick

A tall steel framework construction, the derrick houses the lifting equipment for the drilling operation. They are usually built tall enough to be able to handle three sections of drill pipe connected together – a **stand** – which is roughly 90 ft long.

At the top of the derrick is the **crown block** over which the wire from the drawworks runs.

90 ft up from the rig floor is the **finger board**, from where one of the crew works during running and pulling of the drill pipe. On newer, automated rigs there is no need for someone to be working up at this height, as the pipe is automatically, connected to the elevators and stacked.

Approximately, 40 ft up from the rig floor is the **monkey board**, from here a crew member can assist with the running of casing and tubing.

10.2.6 The Draw Works

So we have a drill bit which is fitted to the end of a drill string which is rotated by the rotary table or top drive unit. We need something to raise and lower the drill string and bit out of and into the hole.

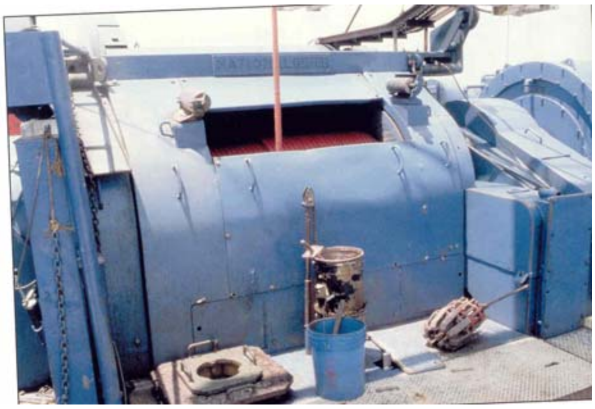


Figure 34 Drawworks

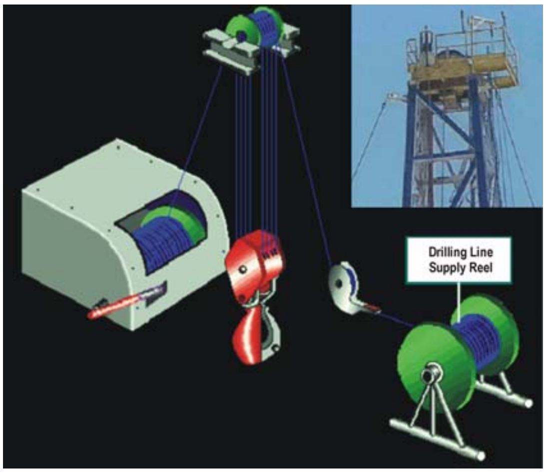
A hoisting system called the **draw works,** which operates like an old fashioned windlass or winch with a drum of heavy cable passed through a series of sheaves, suspends the **travelling block**, which is much like a crane hook. The block is connected to the top of the drill pipe by the **elevators,** which are clamped around the pipe securely.

Just like drilling a hole in your wall at home, the efficiency of the drilling operation is affected by the amount of weight put onto the drill bit. The draw works are controlled by the driller, to ensure that just the right amount of weight is **set down on the bit.**

Did you know?

A joint of 5” drill pipe weighs approximately 600 lbs that’s 272kg. So drilling to 10,000ft with 5” drill pipe you could apply up to 200,000 lbs (91 tonnes) of downward force. Conversely, the draw works has to be capable of lifting that weight and more!

Figure 35 Martin Decker Gauge



The driller has to keep much of the pipe in tension while drilling and has a **Brake** mechanism that allows him to control the weight which is actually applied to the drill bit. A special **load cell** device called a **Martin Decker** gauge indicates the weight on the drawworks and the **drill bit**. During this operation the drill pipe can be rotating from between 70-180 revolutions per minute with 26,000-130,000lbs of force on the bit. During this, the weight of the pipe causes the cutters around the drill bit to grind into the rock or **formation** gouging it away. The cuttings are then returned up the well bore by the drilling **mud**.

10.3 Bottom Hole Assembly

The tools located near to and including the drill bit. The tools have various functions, such as keeping the drill bit drilling in a straight line……

10.3.1 Drill Collars

In reality, not all of the drill pipe weight sits down on the drill bit. There is buoyancy in the mud which reduces the downward force by around 20%. Also, because of the long length of pipe, the upper part of the drill string is in tension whilst the lower part is in compression. In fact if we allowed all of the weight of the drill pipe to push down, it would buckle and twist and send the bit off drilling in the wrong direction. Drilling engineers therefore, carry out some calculations and find out exactly what part of the drill string weight will be sitting down on the bit. They also know what the optimum weight should be for the particular bit in the type of rock they are drilling. It is common therefore, after these calculations, to add **drill collars** to the drill string just above the bit. Drill collars are heavy weight sections of drill pipe, they add just the right amount of additional weight to the bit and add it just behind the bit, giving the driller confidence that the bit is drilling in the desired direction.

10.3.2 Stabilisers

Stabilisers are used to ensure that the drilled hole size is maintained and that the **bottom hole assembly (BHA)**, including the drill bit of course, continues to drill in a straight line. The fins on the stabiliser touch the wall of the drilled hole, they remove any extraneous material and keep the BHA centralised.

10.3.3 The Drill Bit

The **Drill Bit** is at the bottom of the drill pipe and is chosen in accordance with the hardness of the formation to be drilled and can be one of several types. The most common types are the **roller cone** bits and **diamond** bits. They can range in size from 3¾" to 26" diameter, but some of the most commonly used sizes are 17½", 12 ¼", 7 7/8" and 6 ¼".

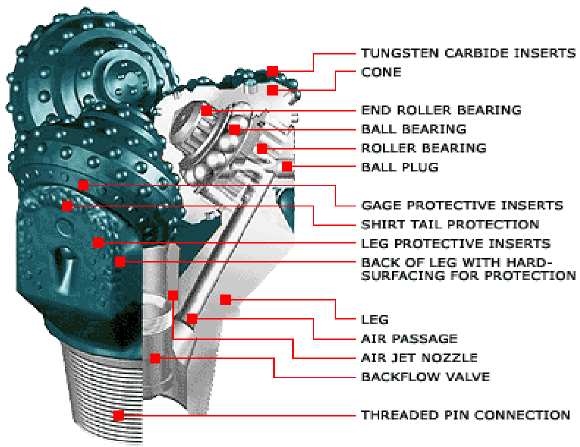


Figure 36 Example of 1st Rotary Drilling Bit

Roller cone bits usually have three or four cone shaped steel noses that are free to turn as the bit rotates with rows of teeth or cutters in each cone. As the bit rotates the teeth in the cone cut or gouge the rock or formation as the cone rolls over it, the teeth may be of made a steel alloy or a tungsten carbide insert fitted to holes machined into the cones.

Most roller bits are "jet bits" that have a series of nozzles in them for the drilling fluid to exit from, just like nozzle on a garden hose. The drilling fluid exits the drill bit through the nozzles at high velocity, striking the bottom of the hole and washing the cuttings away lifting them out from the bit and up the well bore outside the drill pipe. This action keeps the drill bit clear of cuttings and does not impede the drilling.

10.3.4 Diamond Bits

Diamond Bits are not of the same structure as roller bits. Instead of roller cones they are embedded with small industrial diamonds into the sides and bottom of the single fixed head that rotates with the whole drill string. They work using a shearing or slicing motion, un-like the gouging action of the cone bits, and can be used for soft, medium or hard formations. The only down fall of the diamond bit is the higher cost but this can be argued against the longer life that it can give, which results in less bit changes.

Figure 37 PCD Bits

The diamonds used to construct a diamond bit can be either industrial or synthetic (man made) both are equally as expensive to produce but a synthetic diamond can have its size and shape controlled during manufacture, where as a naturally mined diamond can not.

The main types of synthetic diamonds in use today are: polycrystalline diamond compact (PDC) and the Thermal stable polycrystalline (TSP).

One of the biggest disadvantages of using diamonds is that temperatures reached when drilling can easily damage the diamonds. This is where the importance of the drilling mud is highlighted and the circulation and condition of the mud plays a key role in the life of the drill bit. Different from the roller bits, the diamond bit has a single outlet for the mud in the centre which leads the mud through channels across the face of the bit to cool the diamonds.

10.3.5 Hybrid Bits

The term hybrid means that the bit is made up of both natural and synthetic diamonds and can also include tungsten carbide inserts. The format for this type of bit is very much a special build and can be arranged in a manner that suits the type of formation to be drilled and to give the best performance with a long life.

10.3.6 Drilling Fluid (Mud)

Drilling fluid plays several vital roles in rotary drilling –

- Keeps underground pressure in check

- Raises **cuttings** made by the bit to surface
- Stops liquid flowing into the underground rocks
- Cools and lubricates the rotary drill and stem

The **mud** or **drilling fluid** is made up of several different chemicals and additives until the right **"weight"** & thickness/ viscosity is achieved. The job of selecting the correct chemicals and additives is left to the specialist **mud-engineer** in conjunction with the driller. There is a special area on the rig dedicated to the mixing of the mud. As some of the chemical additives come in powder form they can be added, with quite a degree of accuracy and is usually done via a hopper. The mud is then sent to a batch or mixing tank and is tested/sampled before being put into service.

The mud is circulated down the drill pipe, out through the bit and back up outside the drill pipe, between it and the hole that's been drilled.

Do you know why the mud has to be heavy?

Because oil and gas are usually stored under high pressures in their reservoirs; if a drill bit pierces one with little or no weight of fluid around, the oil or gas could rush up the hole and cause a blow out!

The heavier or denser the mud the more pressure it exerts. Water or oil by itself does not weigh enough to exert the necessary pressure especially as the hole gets deeper

Did you know?

A gallon of clean water only weighs about 8.33 pounds (3.77 kilograms). Mud can be made which weighs up to 20 lbs/gallon – that's more than double the weight of water.

In order to make the water or oil exert the correct amount of pressure a weighting material is added. A mineral called 'barite' is a popular weighting material as it is over four times heavier than water. Barite is supplied in powder form and it is gradually added to the mud.

The next job of the mud is to ensure that the cuttings are raised to the surface and for this the mud engineer may add a clay additive. This will gel the mud a little – making it more viscous, so if the mud flow is stopped for any time, the cuttings will not fall back down hole.

If the **mud** is not formulated correctly the cuttings can fall back down the hole, build up around the drill bit and cause it to become **stuck in the hole**.

Another job is to apply a **mud "cake"** or film to the wall of the well bore to stabilize it and seal the well wall to stop any heavy loss of drilling fluids into the formation while drilling. However, mud cake can be a problem, if too much builds up and lots of fluid is lost into a particular zone. The cake can cause the drill string to become stuck and give rise to problems when cementing.

The final job of the mud which we'll deal with here is lubrication and cooling. When metal moves against rock there is friction and heat. Drilling fluids provide lubrication and cooling to keep the process moving along smoothly and to extend the life of the drill bit. The friction will generate heat at the drill bit and anywhere where the drill pipe touches the rock. Therefore lubrication may be especially important on extended reach or horizontal wells where the contact between the drill pipe rock surfaces must be kept to a minimum.

Figure 38 Mud Flowing through Bit

The cuttings will change, the potential reservoir pressure will increase, the characteristics of the rocks being drilled will change as the drill bit drills deeper into changing types of rock; from the information from the geophysicists, both the driller and the mud engineer will know approximately when they may have to change out the drill bit type and alter the mud.

There are three major types of drilling fluids: water-based mud (WBM), oil-based mud (OBM) and synthetic-based mud (SBM).

10.3.7 Mud Pumps and Circulating System

In order to get the mud to the drill bit and to ensure that cuttings are removed when they get back to the surface a rig requires the following circulating equipment:

Mud pump	Rotary hose
Drill pipe	Bit
Return line	Desilter
Mud tanks	Discharge line
Standpipe	Swivel or top drive
Drill collars	Annulus
Shale shaker	Desander
Suction line	The 'Kelly' (on rigs with a rotary- table system)

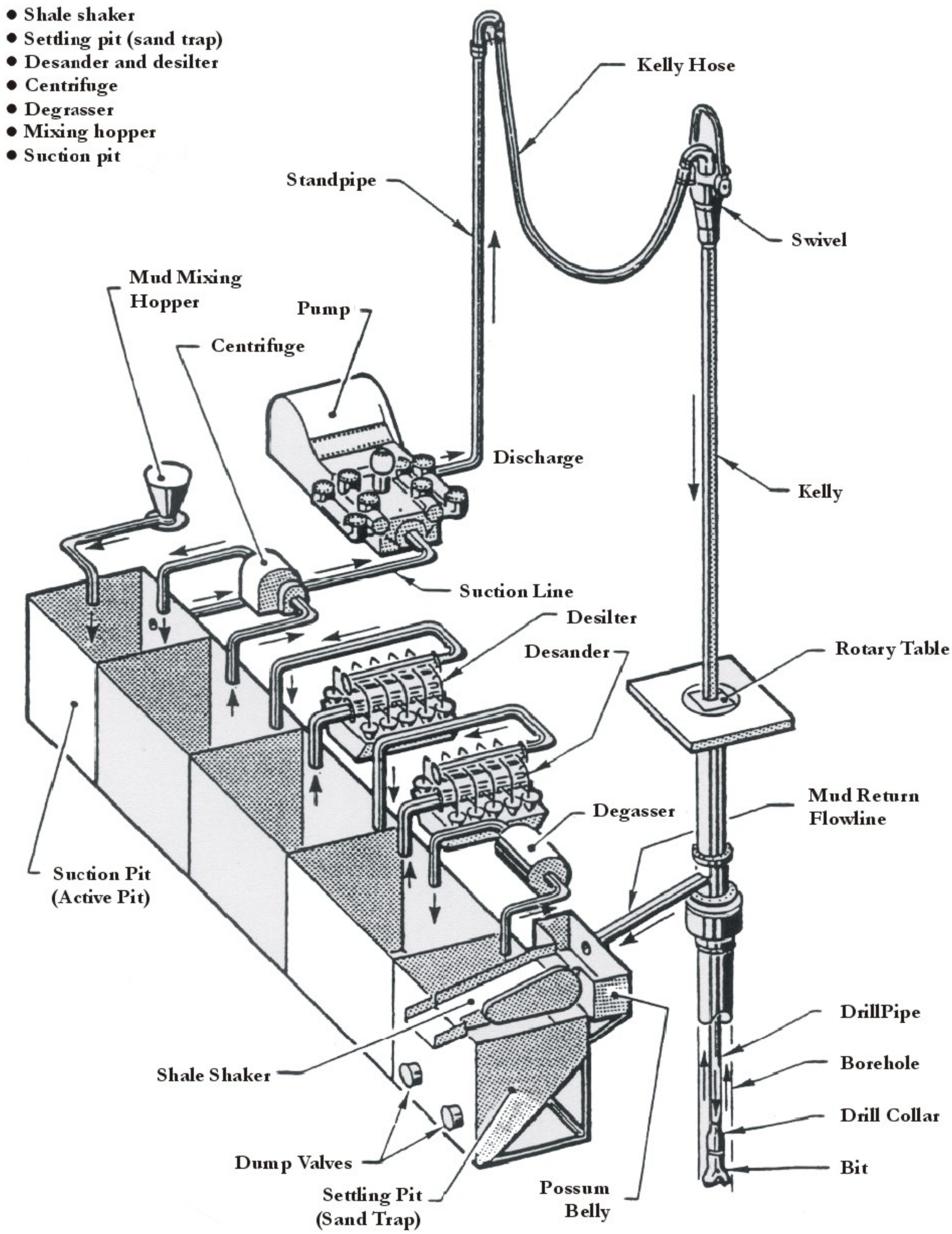


Figure 39 Mud Circulation System

Once the fluid has been mixed in special tanks it is pumped through a series of pipes to the rig floor down the drill pipe and out of the drill bit at the bottom of the well bore. This fluid then returns back to the surface, outside the drill pipe, to be cleaned and made ready to begin the cycle again.

At the heart of the system are the large circulating pumps (mud pumps), in most cases there will be at least two pumps as one will always be used as a back-up pump, although should large volumes of mud be required then both pumps can be used.

The pump picks up the fluid from the mud storage tank (mud pits) which has been made ready by the Mud Engineer, and sends it to the rig floor via the **stand pipe** and to the **Kelly hose** which is connected to the top drive. This flexible hose allows the top drive to travel up and down the derrick allowing the sections of drill pipe to be added or removed during the drilling operation. Once at the Kelly the mud enters the drill pipe through the top drive which is connected to the drill pipe. It then goes down the drill pipe, until it reaches the drill bit, where it is forced out of the nozzles and washes the cuttings away, returning to the surface carrying the cuttings with it. Now out side of the drill pipe the fluid is in the **Annulus** or **Annular space**, this is the space between the outside of the drill string and drill collars and the inside of the well bore.

The cuttings and the mud are returned through the mud return line and sent to the **Shale shakers**, vibrating screens, which act as filters. Here the solids are trapped above allowing the mud to fall through and return to the mud pits. Centrifugal shakers are also common and use a spinning motion to separate the solids (cuttings) from the fluids (mud). This then allows the pumps to take the mud from the tanks, commencing the whole mud circulating process again.

Figure 40 Drill Cuttings

10.3.8 What happens to the cuttings?

After separation the residue cuttings are cleaned and prepared and disposed of in either a barge or special transport containers and in some cases are put back into a specially prepared land fill on site. Offshore however the unwanted cuttings are transported back on shore and go through a further cleaning process allowing them to be re-used in the construction industry. Some of the cuttings are taken to be examined by geologists for clues about what is going on deep down inside the well.

10.3.9 The Environmental Challenge

Water based muds -a drilling fluid where the main component is water rather than oil - are now used wherever possible and the cuttings disposed of on the seabed after cleaning. (By their very nature, water based muds are easily separated from the cuttings in the cleaning process.)

11 Types of Rig

Different types of rigs are used depending on the depth of water and location. Below are some different types of rig. Jack-ups, Semi-submersible and Land Rigs are the three most common types.

11.1 Semi-submersible.

A semi-submersible is constructed using two basic designs and is commonly used in deep water situations.

The semi submersible is commonly known as a *'Semi'*. A semi rig floats on two or more *'pontoons'.* A pontoon is a long, narrow and hollow steel float with a rectangular or round cross section. The pontoons are usually filled with air to enable the rig to be moved to the drill site. Some semis are self propelled and can be sailed from one drill site to another.

Figure 41 Semi-submersible Rig

They are called semi submersible because they float higher in the water when travelling and are ballasted (float lower) when they are drilling. They are anchored but their structure does not touch the sea bed – they are sometimes referred to as a **floater.** The rig is not affected as much by the waves with the pontoons submerged below the water line as it would be if it was floating on top of the water. This makes the semi rig a more stable option than a drill ship that drills while floating on the surface of the water.

From the pontoons, large cylindrical or square columns extend upward and the main deck rest on the top of these. Many semis work in water depths in the range of 1,000 – 3,500 feet (300 – 1,000 metres) although the latest semis are capable of drilling in depths of over 8,000 feet (2,500 metres). Semis can drill hoes 30,000 feet (10,000 metres) deep. Semis are amongst the largest floating structures ever made. For example one of the biggest is over 100 feet (30 metres) high; with a main deck as big as a football field (American) – 6,400 square yards (5,400 square metres).

11.2 Jack Up

A jack up rig is a widely used MODU floated to the drilling location on a hull barge. Modern jack-ups might have three legs with a triangular shaped barge hull; others have four legs with rectangular hulls. A jack up's legs can be cylindrical columns similar to pillars or they can be '*open truss structures'* which resembles an overhead electric pylon or a communications mast.

Figure 42 Jack-Up Rig

When the jack up barge hull is in the drilling position the legs, whether open truss legs or columns are jacked down until they make contact with the sea floor. They then raise or *'jack up'* the hull to a height just above the height of the highest anticipated wave. The drilling equipment is on top of the hull. The largest jack up can drill in water depths of up to 400 feet (120 meters) and are capable of drilling holes up to 30,000 feet (10,000 metres) which is approximately 5 ½ miles deep.

11.3 Drill Ship

A drill ship is also classed as a **floater**. Drill ships are very mobile because they are self propelled and have a streamlined hull, much like a cruise liner. They are chosen as a preference to drill in remote waters, far from land because they can move with speed and they can carry large amounts of equipment and supplies removing the need to have frequent re-supplying from the shore base. The drill ship can operate in water depths ranging from 1,000 feet (300 metres) to 10,000 feet (3,000 metres), drilling holes over 30,000 feet (10,000 metres) deep. There are different sized drill ships with the largest being approximately 800 feet (250 metres) long and about 100 feet (30 metres) wide, imagine three football fields laid end to end. Their hulls are about 60 feet (18 metres) high, that's the height of a six storey building.

Figure 43 Drill Ship

Anchors usually keep the drill ship in place while drilling but in very deep water they require '*dynamic positioning*'. This process uses computers to control and activate thrusters and sophisticated electronic sensors. Thrusters are power units with propellers that are mounted on the hull just below the waterline. The computer is programmed with the exact location which must be maintained and with the use of the sensors information is transmitted to activate the thrusters to maintain the drilling position, in high winds, waves, currents and swells.

11.4 Land Rig

Land rigs usually all look alike but their individual details vary. A major difference is their size, and size determines how deep they can drill. Well depths range form a few hundred feet (metres) to tens of thousands of feet (metres). The depth of the formation that contains, or is believed to contain oil and gas, controls the well depth. Land rigs are classified by size. These are light duty, medium duty, heavy duty and very heavy duty. What is important to remember is that a heavy duty land rig can drill holes shallower than its maximum rated depth, so it could drill a hole 4,000 feet (1,200 metres) instead of the maximum depth of 16,000 feet (5,000 metres) but it could not drill past its maximum rated depth because it could not handle the heavier weight of the drilling equipment required for deeper holes.

Figure 44 Land Rig

Another feature of the land rig is its portability. A rig can drill a hole at one site, be disassembled and moved to another site to drill another hole. Land rigs are so mobile that they are also known as “portable hole factories”.

11.4.1 Land rigs classified by drilling depth

Rig size	Maximum drilling depth, Feet (Metres)
Light duty	3,000 -5,000 (1,000 – 1,500)
Medium Duty	4,000 – 10,000 1,200 – 3,000
Heavy duty	12,000 – 16,000 (3,500 – 5,000)
Very heavy duty	18,000 – 25,000+ (5,500 -7,500+)

11.5 Heli-Transportable Rig

Where the site is very remote and inaccessible by road or sea, a lightweight heli-transportable rig might be used. South America and East Timor, might be places which require these types of rig.

11.6 Platform Based Rigs.

Many larger platforms are fitted with their own rig, so that new wells can be completed and worked-over as necessary without the need to call in a temporary rig.

12 Drilling

12.1 Drilling Surface Hole

Prior to drilling the surface hole; whether subsea or on land, a conductor pipe will have to be put into the ground first. It may be driven in by piling, or a large diameter hole may be drilled first. The purpose of this very short section is to simply stop the earth caving in around the drill pipe, so depending on conditions; the conductor pipe may be a few feet or a few hundred feet long. On top of the conductor sits the BOP (Blow Out Preventer) – probably the most important piece of safety equipment on the rig. ***See 13 Pressure Control***. Only when this is in place can the real drilling operation begin…..

Figure 45 Surface Casing

With all the necessary preparations complete, we are ready to ***Spud*****.** ***Spudding*** is the terminology used for the top section of hole drilled; the drilling of this section is done with a large drill bit, from 16 inches to 36 inches in diameter, attached to a drill pipe and lowered into the conductor pipe. To get the bit to the bottom of the current hole, joints of pipe are added as necessary. Each ***joint*** of drill pipe is 30ft long.

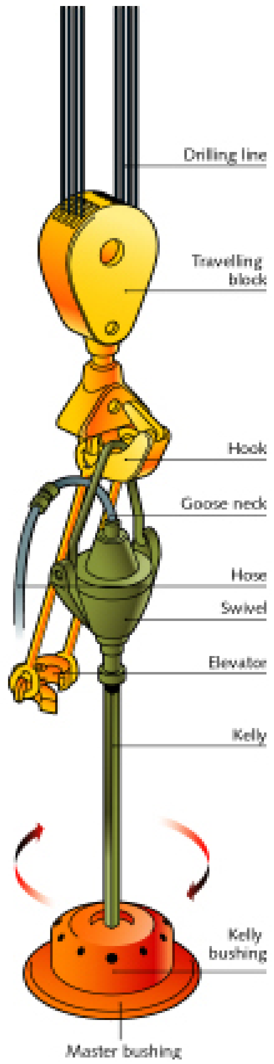
At this point please remember that there are two main types of drilling system – a Rotary Table and a Top Drive. Each operates quite differently. The following description is based upon a Rotary Table system.

When the drill bit is at the bottom of the current hole and conductor pipe, the drill pipe will be lowered into the *slips*. The Kelly is lifted, brought over and screwed onto the top of the drill pipe.

The whole drill string is lifted slightly and the slips removed, the Kelly system drive bushing is then lowered into, and engaged in, the master bushing. *Remember that the driller has used the draw works to lift over the Kelly and the drill pipe.*

Figure 46 Running Casing

BUT WAIT – did anyone switch on the mud pumps? Yes the Driller did that, so that there is some fluid being pumped down through the Kelly, through the drill string and out of the bit. So as soon as drill cuttings are created by the bit, they can be washed up the outside of the drill pipe, inside the conductor and to the mud system.



Just to be clear, we should explain that the Kelly system is a simple but effective way of getting the drill pipe to rotate, allowing free vertical movement and allowing quick and simple additions of drill pipe joints.

As the drill bit cuts in to the ground weight comes off the bit, it is the drillers job to maximise this weight to get the most effect out of the drill bit.

Do you know how the driller adds weight to the bit?

He releases the draw works brake which lowers the travelling block, which is supporting the Kelly. Simply put it is like lowering the hook of a crane.

So as weight is added and the bit cuts into the ground the driller lowers the Kelly down, through the Kelly bushing keeping the weight on the bit. Progress is thus made and the hole is drilled. This is done until the whole length of the Kelly has reached a point just above the Kelly bushing. As the surface section is usually soft this is a quite a quick operation and keeps the drill crew very busy, because they now have to……

Stop drilling and circulating mud, lift up the whole drill string slightly and then lower it into the slips. The slips now hold the weight of the entire drill string (which is not very much at present). Now they disconnect the Kelly, lift it up and place a new joint of pipe in between it and the lower joint.

Do you know how the crew disconnect the Kelly from the drill string?

They use a set of tongs. Tongs are like an enormous pipe wrench, they grip the upper and lower pipes and pull against each other to untwist or **break out** the screwed connection. They are also used to screw the various joints together.

When the conductor pipe is secure, a blowout preventer (BOP stack) is attached to it and on top of the BOP stack a connector for a marine riser which extends from the BOP through the sea, to the drilling vessel. The riser is a cylindrical guide for the drill string and allows drilling mud to be circulated down the drillpipe and back to the rig.

Did you know?

That on an offshore floating rig, the riser will incorporate a motion compensator and slip joint (telescoping) to accommodate movement of the rig due to ocean swell – this is very important and has to be very good at reducing vertical movement. Without a compensator the drill bit weight would constantly change which would affect life of the bit, direction of the hole and the mud circulation system.

12.2 Offshore Drilling

12.2.1 The Drilling Template

Since the seabed that is going to be drilled through for an offshore well cannot provide as stable a base for offshore drilling as land does for onshore drilling, an artificial platform must be created. This artificial platform can take many forms, depending on the characteristics of the well to be drilled, including how far underwater the drilling target is. One of the most important pieces of equipment for offshore drilling is the subsea drilling template. Essentially, this piece of equipment connects the underwater well site to the drilling platform on the surface of the water. This device consists of a framework with multiple holes in it, dependent on the number of wells to be drilled. This drilling template is placed over the well site, usually lowered into the exact position required using satellite and GPS technology. A relatively shallow hole is then excavated with ROV's, into which the drilling template is cemented in place. The drilling template, secured to the sea floor and attached to the drilling platform above with cables, allows for accurate drilling to take place and also allows for the movement of the platform above, which will inevitably be affected by shifting wind and water currents.

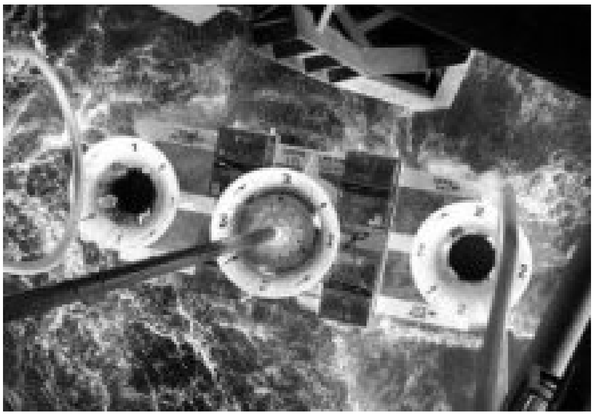


Figure 47 Subsea Drilling Template

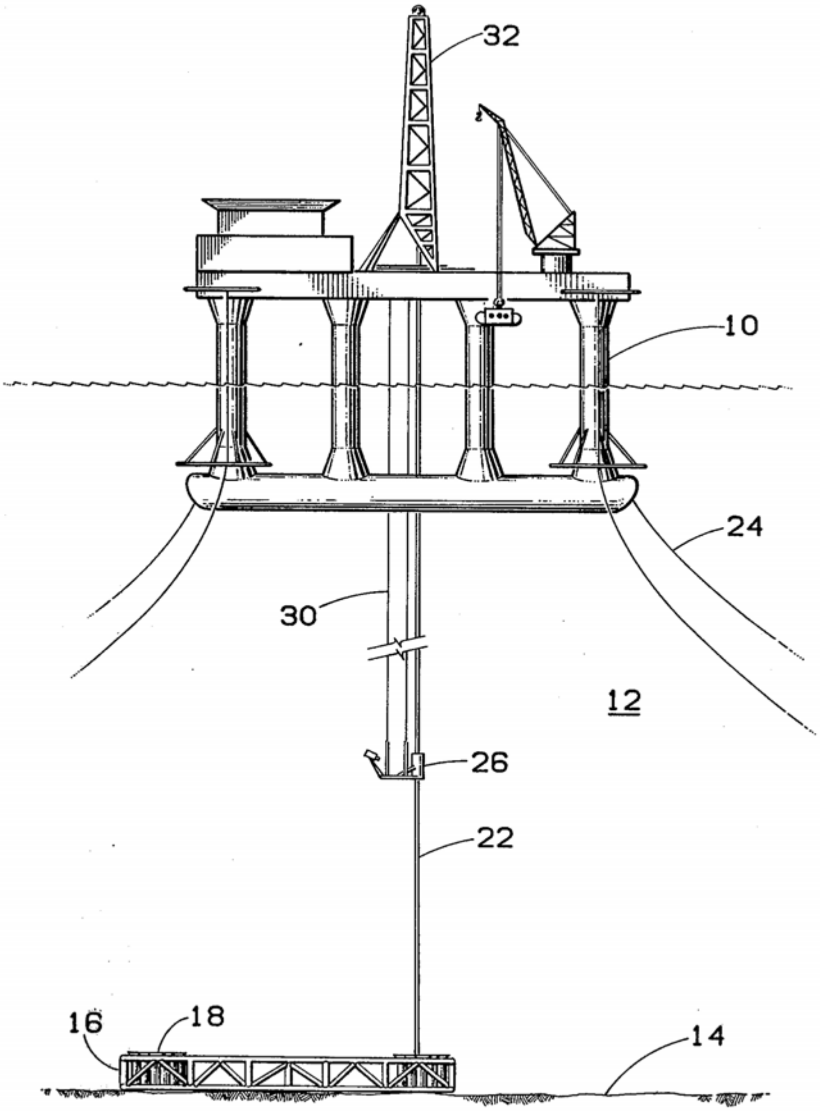


Figure 48 - Diagram showing drilling through subsea template

………On and on goes the drilling operation heading toward the **pay zone.**

In a 10,000ft well, using only 30ft joints, over 330 joints of pipe will need to be added for the bit to reach the target. But there's more to do than just drill a wide deep hole. Wells are not constructed of one long pipe of the same diameter…...

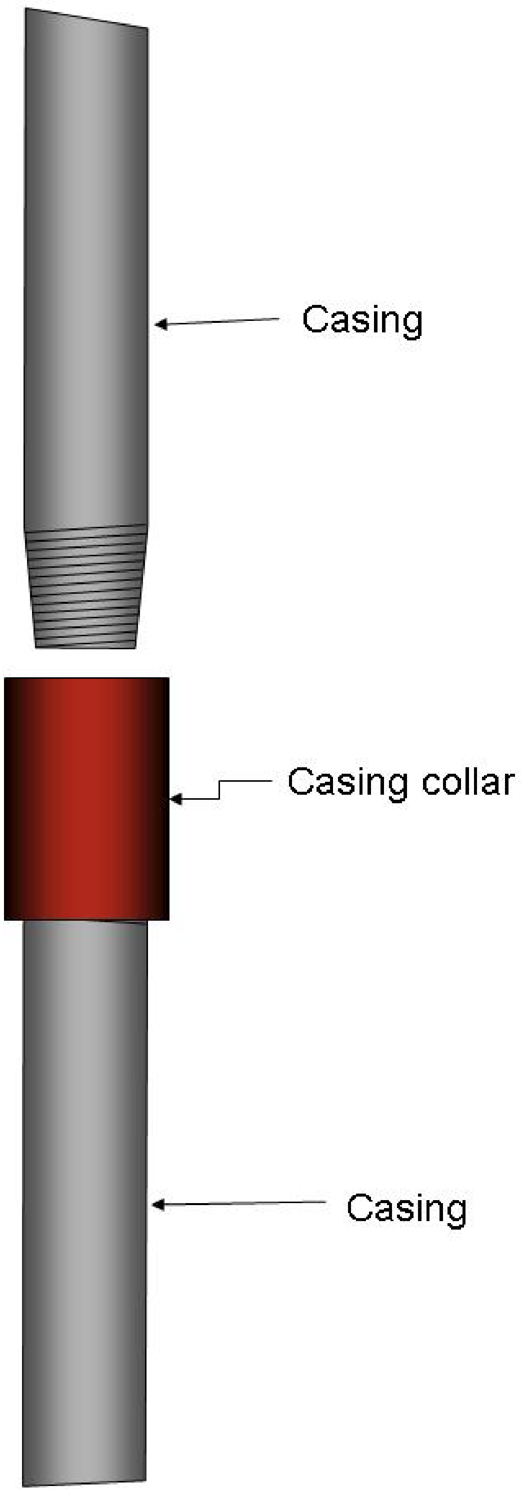
12.3 Well Casing Design

An oil well is drilled usually in 4 or 5 stages, at each stage the hole is drilled at a diameter smaller than the one before it. The length of each hole section is decided before drilling commences and is governed by the rocks to be drilled and the pressure of the fluids within the rock since the casing is used to control these pressures.

12.3.1 Casing Specifications

After each stage of drilling, the hole is cleared of debris and casing is inserted to line the hole to the full depth of that particular diameter. The casing provides a clear conduit to hole bottom for further downhole activity; it prevents cave-ins and isolates pressures in different zones. The casing used is a tubular steel material supplied in approximately 40 ft. (12m) lengths. Each individual length has a male *pin* screw thread at each end and on one end a female *box* connection, allowing casing lengths to be joined together.

Figure 49 Casing Ready To Run



Wells are made up of various sizes of casing; each one is cemented into the earth and larger casing around it. As in Figure 50 Casing Schematic you can see that the conductor casing is large and not very deep. It might be 30” to 36” diameter.

Surface casing is the next type of casing to be installed. It can be anywhere from a few hundred to 2,000 feet long, and is smaller in diameter than the conductor casing, say 20” dia. When installed, the surface casing fits inside the top of the conductor casing. The primary purpose of surface casing, onshore, is to protect fresh water deposits near the surface of the well from being contaminated by leaking hydrocarbons or salt water from deeper underground. It also serves as a conduit for drilling mud returning to the surface, and helps protect the drill hole from being damaged during drilling. Surface casing, like conductor casing, is also cemented into place.

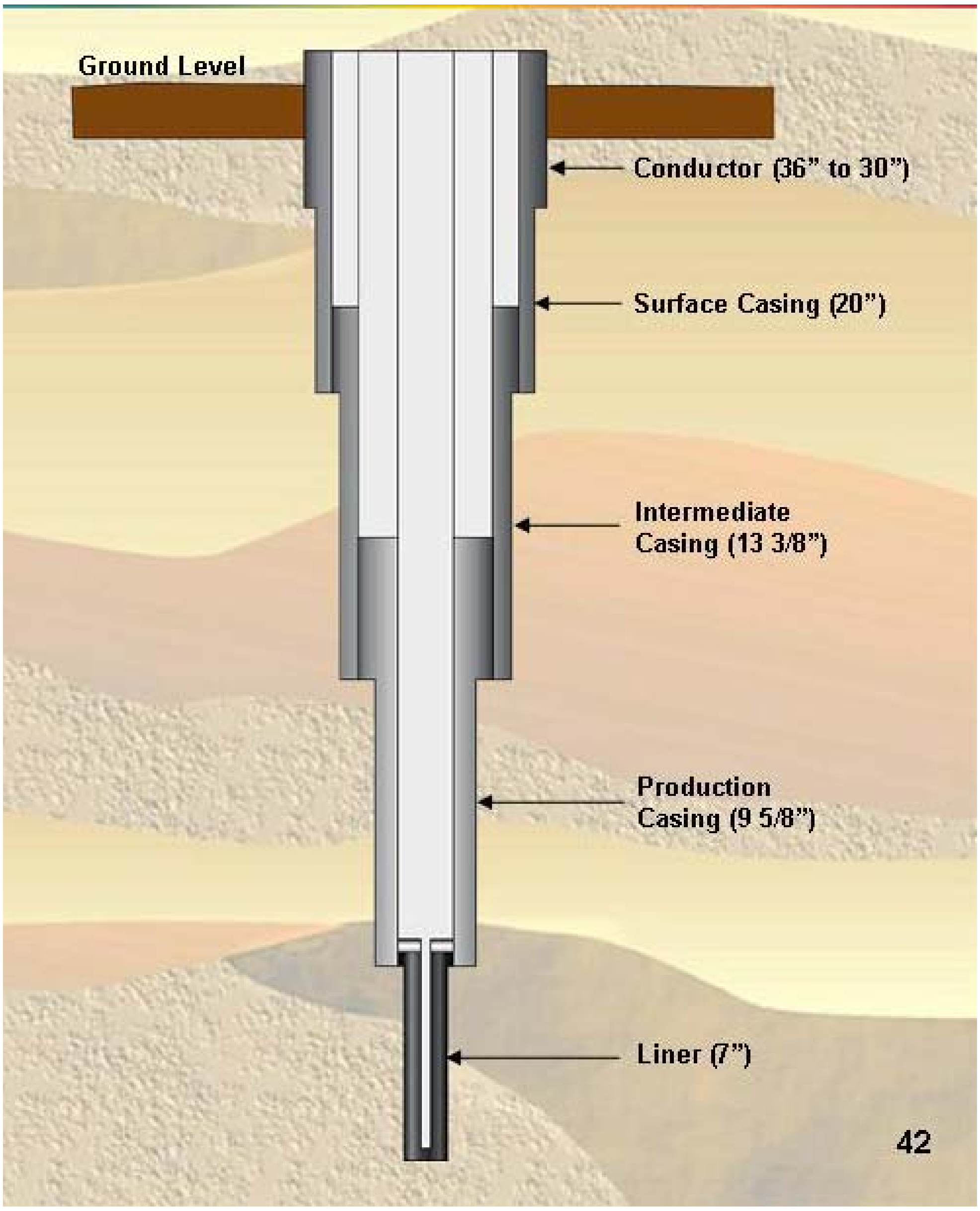


Figure 50 Casing Schematic

Intermediate casing is usually the longest section of casing found in a well and is often 13 3/8" dia. The primary purpose of intermediate casing is to minimize the hazards that come along with subsurface formations that may affect the well. These include abnormal underground pressure zones, underground shales, and formations that might otherwise contaminate the well, such as underground salt-water deposits. In many instances, even though there may be no evidence of an unusual under-ground formation, intermediate casing is run as insurance against the possibility of such a formation affecting the well. The inter-mediate casing is also cemented into place for added protection.

Production casing, alternatively called the 'oil string' or 'long string', is installed last and is the deepest section of casing in a well, it might be 9 5/8" dia. This is the casing that provides a conduit from the surface of the well to the petroleum producing formation. The size of the production casing depends on a number of considerations, including the lifting equipment to be used, the number of completions required, and the possibility of deepening the well at a later time. For example, if it is expected that the well will be deepened at a later date, then the production casing must be wide enough to allow the passage of a drill bit later on.

Of course the sizes above may be changed depending on constraints of a particular well.

Well casing is a very important part of the completed well. In addition to strengthening the well hole, it also provides a conduit to allow hydrocarbons to be extracted without intermingling with other fluids and formations found underground. It is also instrumental in preventing blowouts, allowing the formation to be 'sealed' from the top should dangerous pressure levels be reached.

Once the casing is installed, tubing is inserted inside the casing, from the top, to the formation at the bottom. The hydrocarbons that are extracted will flow up this tubing to the surface. The way this tubing is inserted and sealed will be dealt with in 14 Completing the Well

12.3.2 Liner Systems & Expandables

Liners may be used in many and various applications. Liners are commonly used when sand control is a problem, for example. A liner is a shorter section of pipe than a full run of tubing or casing and is often hung off existing larger bore casing. Because they are shorter and can be removed relatively easily they are a cheaper alternative to full casing or tubing runs. Often pre-slotted to allow for production without sand entering the borehole, the liner can be run on drill pipe and even cemented in place.

Today liners come in many different types and Weatherford is a world leader in their design and application.

Liners are run on drill pipe and are particularly useful in horizontal well bores.

Liner hangers are the packer devices off which the liners are hung. They are a speciality of Weatherford.

Sand Screens are a type of liner system, in which there has been a major development over the past few years and again Weatherford is leading the field. Expandable Sand Screens (ESS) are run into hole in a small diameter, then using a rotating device the screen is expanded into the open hole. These versatile devices are making a huge impact on well completion worldwide.

In addition, expandable casing repairs and other expandable tools are being used more and more. Expandable technology allows small diameter tools to be more easily run in wells and set in difficult conditions.

Weatherford's position in Expandable technology is explained here in a recent press article.

I. STATUS OF EXPANDABLE TECHNOLOGY

WEATHERFORD

Since 1998, Weatherford has led the industry in commercializing/installing Expandable Sand Screen (ESS*) technology that is rapidly becoming standard practice for reducing costs and enhancing production. It is now working toward the end game of providing a range of solid tubular expansion technologies that make the single-diameter (or mono-bore) well a reality, both for high-end, challenging applications and lower profile wells. The company's Expandable Tubular Technologies are classified into three categories: Expandable Slotted Tubulars (EST), Solid Tubular Expansion (STE), and Expansion Systems, as explained here.

Expandable slotted tubulars (EST). The following discussions describe three sub-categories of EST: Expandable Sand Screens (ESS), Alternative Borehole Liners (ABL); and Expandable Completion Liners (ECL).

Expandable Sand Screens (ESS). As a major contributor to ESS technology, Weatherford has completed more than 225 installations worldwide with its range of expandable products, including 22.5 mi of ESS screen (Fig. 1), and the world's longest expansion, more than 4,900 ft of a 7,000-ft ESS. This track record verifies the growing adoption of ESS as a reliable, high-productivity sand control method.

Fig. 1. Weatherford has expanded more than 22.5 miles of ESS screen in hundreds of jobs worldwide, including a record 4,920-ft ESS installation.

ESS is being used extensively in a wide range of applications, including open-hole (74%), cased-hole (26%), multi-zone reservoirs and the world's first deployment in a multilateral North Sea well. Proven benefits include productivity improvements of up to 70%, compared to alternative sand control methods, and cost reductions of more than 20%.

Weatherford has a long ESS track record. An ESS screen first installed over 3-1/2 years ago in a North Sea, subsea, high-rate gas producer is still stable, sand-free and producing consistently.

A notable milestone was achieved in late 2002, when successful installation of 5-1/2-in. ESS with enhanced connectors for ConocoPhillips in Bohai Bay, marked the 150th global application. This was a multi-well project in Peng Lai field. The first six wells included two with cased-hole perforations (no sand control completion) and four with perforated casing, then ESS completions. The open hole deviated completion proved successful, leading to three additional wells being completed in the same manner.

ESS (Fig. 2) is available in sizes ranging from 2-7/8 in. to 5-1/2 in. It is the only compliant expandable screen that offers: borehole support; a large ID; high collapse resistance; and a large open area that resists plugging. With ESS screens, there is no need to use additional mud and fluids that can damage the screen; there is no rearrangement of produced sand into a low-permeability pack; and there are no hotspots.

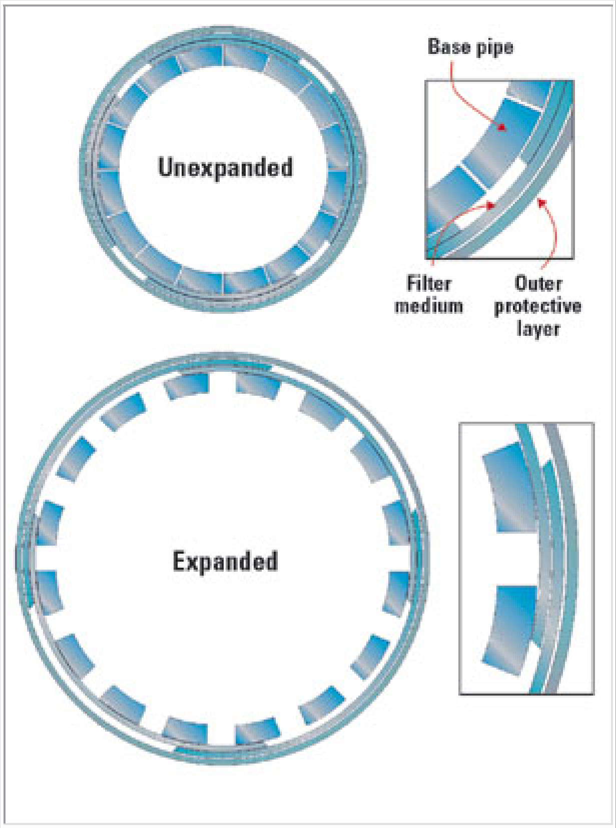


Fig. 2. The ESS design includes a large flow area and optimum strength and stability.

Alternative Borehole Liners (ABL). The ABL has also proved successful, with a strong and growing track record. Operators in many producing areas must set casing strings earlier or higher than desired due to problematic geological zones. Unstable formations can also prevent casing runs from reaching the target depth, resulting in need to run contingency casing strings. In both scenarios, as a result of being forced to run an additional string, wellbore diameter through the reservoir could be compromised, resulting in a well unable to meet production expectations, or even reach planned depths.

The ABL, a cemented, expandable slotted liner, can be used as a metal-to-rock solution to overcome these potential problems. For example, if a 9-5/8-in. casing string with a 8.681-in. ID is set higher than planned, an ABL can be installed below the string. This isolates the problem zone, but retains through bore of 8.681 in. or larger. As a result, operators are able to retain hole size through the next section of the well, which could make the difference between the well being commercially viable or not.

Expandable Completion Liners (ECL). Weatherford has also developed breakthrough ECL technology that can replace conventional slotted liners or cemented/perforated liners. The technology provides increased borehole stabilization, selected isolation and treatment capability, and reduced hole size.

It can be particularly useful in completing reservoir zones in through-tubing sidetracks, achieving a limited reservoir interval while avoiding difficult overall cementing and perforating work. Other benefits to operators include: 1) increased field output, since in certain cases, the larger wellbore created will produce higher flow area; 2) extended well life and increased viability of older wells, since it allows for a return to the reservoir for carrying out future remedial work; 3) flexibility to return to the reservoir to shut off and isolate water breakthrough, by inserting plugs or packers inside definite bore rather than an open hole; and 4) wide-hole-size operating range from 3-1/2 in. to 9-1/2 in.

Solid Tubular Expansion (STE). Under this second category of the company's three contribution areas, two sub-categories, Expandable Liner Hangers (ELH) and the MetalSkin* Casing Repair System are described, as follows.

Expandable Liner Hangers (ELH). The ELH provides a means of deploying ESS and other non-cemented liners. It also provides the hanging for the MetalSkin Casing Repair System. ELH is expanded using a rotary compliant technique (see expansion systems section) that delivers a metal-to-metal fit with the parent casing, resulting in a maximized through bore for future intervention access.

MetalSkin Casing Repair System (Fig. 3). In mid-2003, the company successfully installed four compliantly expanded Solid Expandable MetalSkin casing repair systems for Imperial Oil Resources at its Cold Lake field in Alberta, Canada. The successful installations returned the four wells to service. The new technology is a metal-to-metal expandable casing system designed to solve problems that occur when reservoir and fluid production conditions have changed, or when the casing has been worn, corroded or damaged.

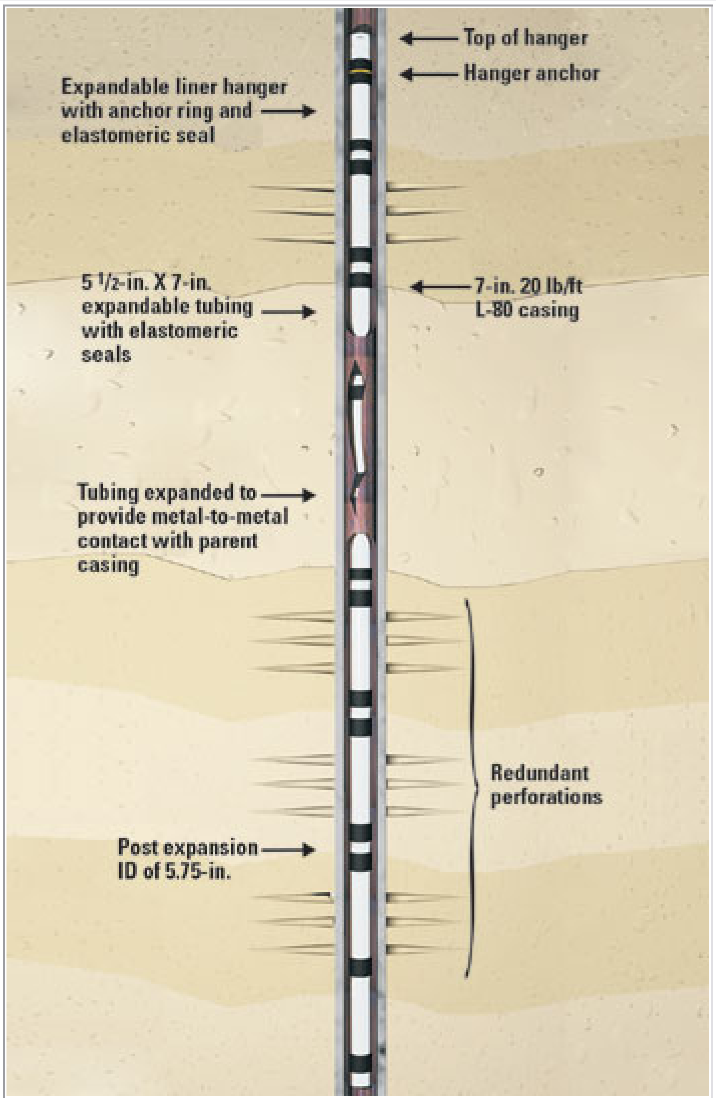


Fig. 3. Example well schematic shows MetalSkin assembly deployed to isolate thief zone comprised of perforations and corroded casing.

At Cold Lake, the system was applied using the company's Compliant Rotary Expansion System (CRES*) to repair casing leaks. This technique forms the MetalSkin to the casing being repaired, accommodating irregularities within the parent casing. This provides metal-to-metal contact around the entire circumference of the casing and a tight seal. After expansion, the system becomes an integral part of the casing string, allowing the wells to be returned to active production.

Expansion systems. In addition to the traditional EST expansion cone, which is a tapered tool used in conjunction with an expansion mandrel, and is designed to swage and expand various slotted tubular products, a fundamental advantage of Weatherford's systems is the use of compliant expansion techniques, such as the two systems described here.

The Axial Compliant Expansion System (ACE*) is designed to expand slotted tubulars. It offers single-trip, metal-to-rock compliant EST expansion, which is the key to elimination of the annulus, provision of borehole support and prevention of particle migration. It is the single-trip system that improves wellbore contact, allows access through restricted ID and improves tool life. ACE features a compliant top-down expansion tool, a retrievable system and a field re-dressable tool. The expansion tool comprises two sections: a fixed roller nose to initiate expansion, and compliant axial rollers to complete the expansion process. The tool is compliant in that pistons can extend or retract as the hole profile changes.

The Compliant Rotary Expansion System (CRES) tool is a hydro-mechanical tool designed to expand solid tubulars. When used with an Expandable Liner Hanger (ELH) deployment tool, it sets and expands the ELH. It is also used to expand long lengths of solid tubulars for the MetalSkin system. CRES provides a top-down, low-axial-load expansion operation that is tolerant to internal casing anomalies. The tool can fit through unexpanded tubulars for easy retrieval and offers a selective expansion capability. Rotary compliant expansion provides a metal-to-metal contact that maximizes burst resistance, with low rolling friction and low axial loads, and maximizes the through bore.

12.4 Primary Cementing

Probably the single most important factor in casing the hole is obtaining a satisfactory primary cementing job. An effective primary cement job is the necessary starting point for all subsequent operations. With a defective primary cement job all remaining operations are adversely affected. While primary cementing is often the responsibility of the drilling group, it is the completion, production and workover groups who are most affected by and perhaps should be most interested in, primary cementing.

12.4.1 Cementing Materials their Function in Oil Wells

In well completion operations, cements are universally used to fill the annular space between casing and open hole. Two principal functions of primary cement are:

1. To support the casing.
2. To restrict fluid movement between formations.

This fluid movement restriction can be split into three further areas…..

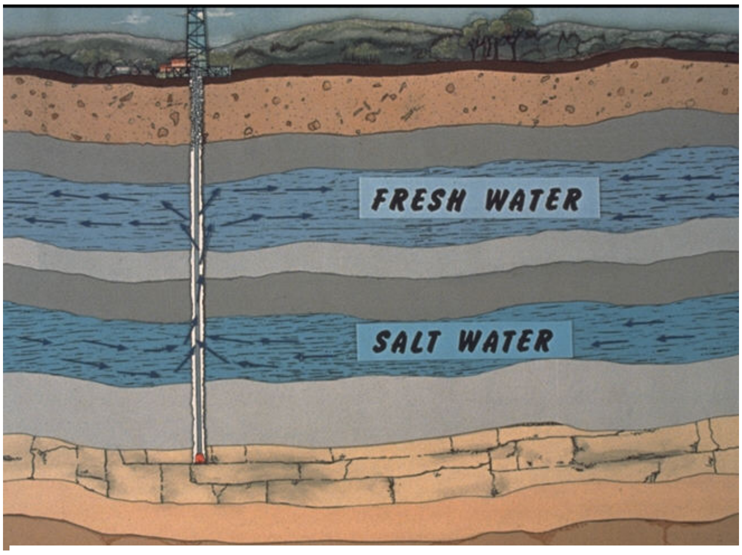


Figure 51 Cementing Protects Aquifers

a) Control of formation pressure whilst drilling ahead.

b) Isolates porous formations and prevents fluid loss.

c) Isolates formations of different pressures.

If you consider an onshore well with fresh water and salt water aquifers, salt water should not be allowed to get into the fresh water – the cement can stop this happening.


Figure 52 Cement Testing

Cement materials properly placed around the casing, having permeability's less than 0.1 md and compressive strengths greater than 100 to 300 psi should be satisfactory for these functions.

The key to success is proper placement of the cement completely around the casing.

12.4.2 Manufacture, Composition and Characteristics of Cement

The first thing to point out is that cement is not like concrete used for construction work; for a start there is no sand included. One of the important factors about oil well cement is that is has a very low permeability.

'Portland cements' are finely ground mixture of calcium compounds. They are made from limestone (or other high calcium carbonate materials) and clay or shale. Some iron and aluminium oxides may be added if necessary. These materials are finely ground and mixed, then heated to 2600^o – 2800^oF in a rotary kiln. The resulting clinker is ground with controlled amount of gypsum to form cement.

Typical cement particle size distribution is such that 85% passes a 325 mesh screen (44 microns), 90% passes a 200 mesh screen (74 microns) and 100% passes a 150 mesh screen (100 microns).

Principal compounds formed in the burning process and their functions are:

- *Tricalcium silicate* (C_3S) is the major compound in most cement and is the principal strength producing material. It is responsible for early strength (1 to 28 days).
- *Dicalcium silicate* (C_2S) is the slow hydrating compound and accounts for the gradual gain in strength which occurs over an extended period.
- *Tricalcium aluminate* (C_3A) promotes rapid hydration and controls the initial set and thickening time. It affects the susceptibility of cement to sulphate attack; high sulphate resistant cement must have 3% or less C_3A.
- *Tetracalciuim aluminoferrite* (C_4AF) is the low-heat of hydration compound in cement. It gives colour to the cement. An excess of iron oxide will increase the amount of C_4AF and decrease the amount of C_3A in the cement.

12.4.3 Selection of Cement for Specific Well Application

The problem of selecting a cementing material for a specific well application is one of designing economical **slurry** (the name for liquid cement) that:

1. Can be placed effectively with the equipment available.
2. Will achieve satisfactory compressive strength soon after placement.
3. Will thereafter retain the properties necessary to isolate zones and to support and protect the casing.

12.5 Cementing Technique

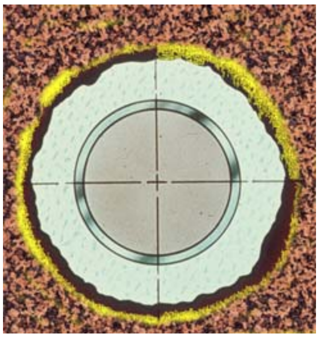


Figure 53 Good Cement Job

Prior to a new string of casing being run a guide shoe was fitted at the very bottom of the bottom joint, by now this is sitting at the total depth of the casing, deep in the well. A cementing head is screwed on top of the casing to allow cement and displacement fluids to be pumped into the well. Very near the bottom of the casing, a float collar (which is a non-return valve) was also fitted prior to running the casing.

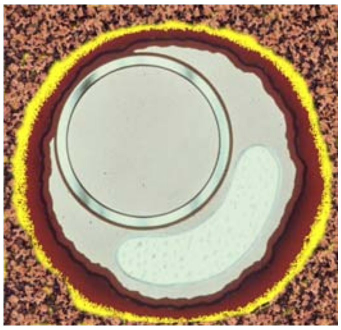


Figure 54 Poor Cement Job

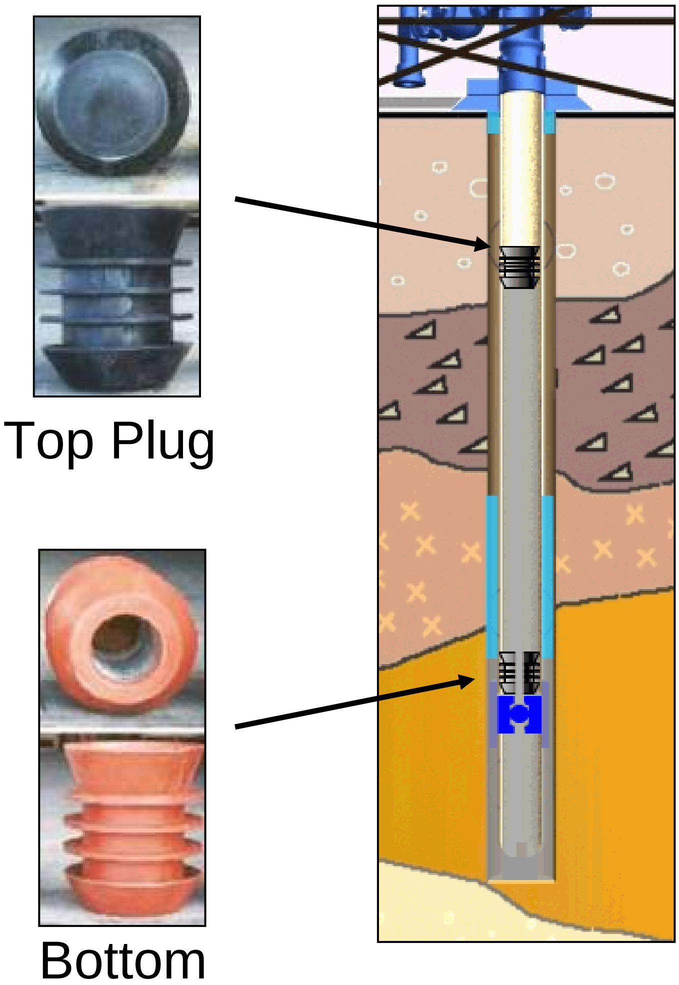


Figure 55 Cement Plugs

Cementing is a critical operation; the cement has to be made quickly and effortlessly (within reason), so that it can be immediately pumped down the well into the exactly correct position and set within a certain time limit. Should something go wrong, there may be partial setting of cement, insufficient bonding around the casing, cement may be plugging the casing and may have to be drilled out. Therefore; volumes of the well and annular space are checked and double checked; the ingredients for the cementing operation are checked and double checked. The cementing equipment and back up equipment is test run.

The volume of cement will have been calculated to ensure that it fills the annular void around the current casing, with allowances being made for some lost cement.

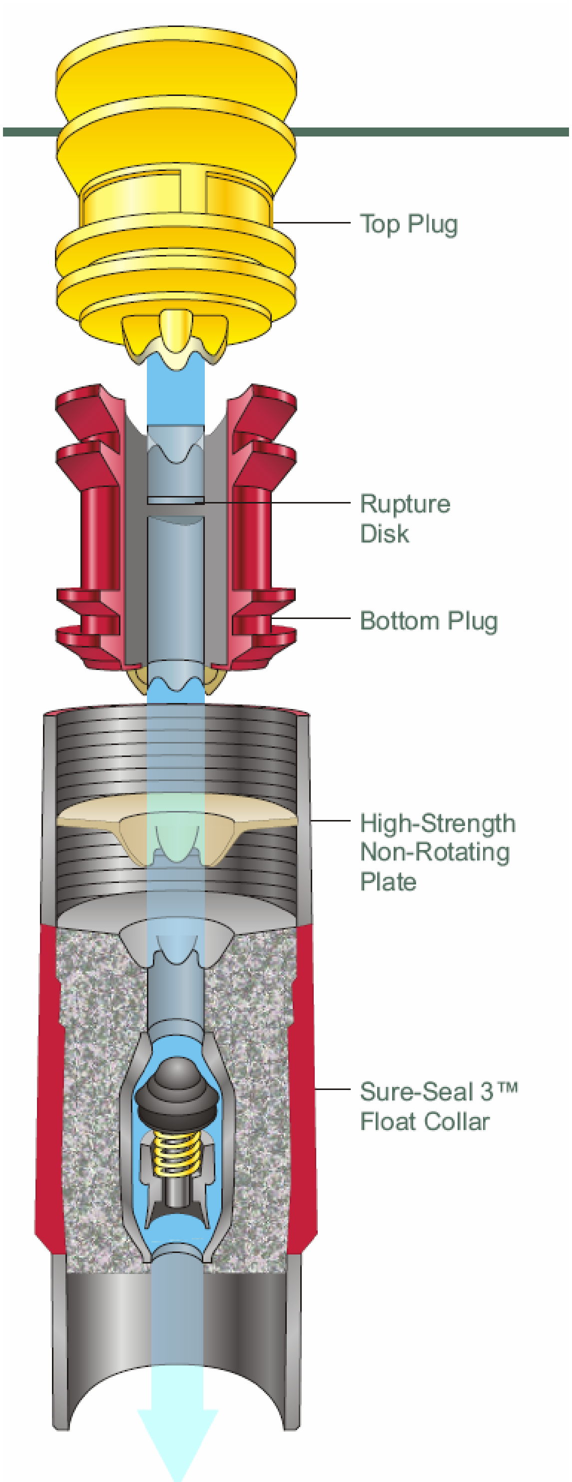


Figure 56 Some Weatherford Cementing Products

When everything is ready, a bottom plug, which is in the cement head, is released and behind cement is then pumped into the casing, forcing the bottom plug downwards. When the correct volume of cement has been pumped into the casing, a top plug is released. The appropriate volume of cement is therefore sandwiched between the top and bottom plugs.

Mud is now pumped into the casing behind the top plug, pushing cement ahead of it. The bottom plug is stopped by the float collar, but increasing pressure from the mud (and cement) causes a diaphragm in the bottom plug to rupture. The cement column can then flow through the guide shoe and up the casing/borehole annulus. When all the cement has been displaced, the top plug will be in contact with the bottom plug. This is indicated by an increase in mud pressure and the pumps are then stopped. After the cement has set, it is necessary to drill out the small volume of cement, the float collar, the guide shoe and the plugs remaining in the bottom of the casing. To assist in obtaining a good cement job, various devices are used. Centralisers hold the casing in the centre of the hole and scraper rings are used to clean up the casing before the cement is pumped.

13 Pressure Control

13.1 Over-balance v Under-balance

The pressure in the reservoir is set; during drilling we may estimate what that pressure is – but we may not know. In addition sometimes gas pockets are situated above where we expect to find the main hydrocarbon. These pressures can cause us severe problems.

However, if we estimate what the pressure downhole will be, we can use the hydrostatic pressure of a liquid to balance that reservoir pressure. If we achieve this, the well is said to be *balanced.* However, most often we require the well to be slightly over-balanced, that is, with the well-bore pressure slightly exceeding the reservoir pressure.

If the well bore fluid is not heavy enough or heavy enough but there is not a tall enough column of it and the reservoir pressure is higher than the well bore pressure, then the well is said to be under balanced.

Figure 57 The Consequences of a Blow Out

Sometimes an under balanced condition is desirable 21 Under-balanced Drilling (UBD); but as a rule it would be good to think of this as an undesirable condition.

There are several methods of controlling down hole pressures including fluid weight and remember, the deeper we go the higher the overburden (and hence reservoir) pressure.

So to prevent ingress of high pressure fluids into the hole while drilling, relatively high density mud is pumped around the well bore. This overbalances the formation rock pressure and prevents ingress of formation fluids into the well. If the mud is too dense however it can overcome the formation rock compressive strength and fracture it causing major problems.

13.2 Primary Well Control

Other than the hole itself, there is no more important subject on the rig than well control.

On average there are 21 blowouts a year?

The primary method of formation pressure control **is** the weight of the mud acting to counteract the pressure in the formation and thus maintain a balance of pressure. If the pressure in the formation shows a steady increase during drilling, then the pressure of the mud can be increased by increasing its density. During drilling, a phenomenon known as a ‘kick’ may occur. This can be caused by many things including: the drill bit entering a pocket of abnormally high pressure; formation fluids entering the borehole or loss of the drilling fluid from the hole. Because a kick is sudden and unexpected, there may not be sufficient time to increase mud weight to overcome the sudden increase in pressure. Another common problem is that of gas 'kicks'. Even though the well may be at a shallow stage, say 1000 ft (300 meters) it is possible to find extremely high pressure pockets of gas filled sand. If the hydrostatic pressure of the mud is insufficient, a gas bubble can enter the well bore and very quickly rise to the surface expanding as it rises and forcing mud from the hole faster than it can be pumped in. If not skilfully dealt with, a blow-out (an uncontrolled flow) can occur.

Pressure control can be divided into three categories:

1. **Primary control**. The proper use of hydrostatic pressure is to overbalance the formation and prevent unwanted formation fluids from entering the well-bore. The advantages of control at this level are self-evident

2. **Secondary control.** The use of equipment to control the well in the event primary control is lost. Formation fluids that have entered the annulus can cause a blowout quickly if not properly controlled.

3. **Tertiary control.** The use of equipment and hydrostatic pressure to regain control once a blowout has occurred. This could involve the drilling of a relief well. Although tertiary control is normally handled by experts, many things can be done during the planning and drilling of a relief well to simplify the final kill procedure and regain control of the well.

13.2.1 Failure of primary control

Any event or chain of events that create a negative differential pressure between the hydrostatic pressure of the drilling fluid and the formation pressure can cause "kick." A kick is an influx of formation fluid into the well.

The most common causes of a kick are:

1. Failure to keep the hole full of mud during trips.
2. Insufficient mud weight.
3. Lost circulation causing the hydrostatic pressure to be reduced.
4. Swabbing in when pulling out of the hole (the action of removing the drill pipe from the hole lessens the weight of the fluid column and could create an under-balanced situation).
5. Improper casing design and pore pressure prediction.

A study of blowouts over a 10-year period lists the following primary causes of blowouts:

Failure to keep the hole full	42%
Insufficient mud weight	15%
Lost circulation	22%
Swabbing	16%
Other	5 %

The study gave evidence showing that after the wells kicked, over 60% were not controlled for the following reasons:

Insufficient blowout equipment	29%
Improperly designed blowout equipment	05%
Improper installation	11%
Improper surface fittings	06%
Improper **casing** and **cementing** program	11%

What the study neglected to report was human error, the major cause of blowouts. In day gone by there may have been an excuse, lack of understanding but in the modern oil industry there is no excuse.

13.3 Secondary Well Control

The first and foremost well control barrier (primary well control) is the drilling fluid, this is explained above. However should the unexpected happen or the primary well control fail we must turn to mechanical control, we call this the secondary well control.

Any valve installed on the pipe or wellhead to control the formation can be classed as a blowout preventer (BOP); with its objective being, to secure a well should the need arise. They can be hydraulically, manually or air operated and in some cases a combination of all three.

Therefore all secondary well control equipment must be included in the preventive maintenance program for the rig. This includes BOP's and Blowout Preventer Equipment "BOPE" such as lines, valves, connections, check valves, inside BOPs and what ever other equipment is installed or used to secure a well. Should such equipment fail the test it must be repaired immediately.

A well kicking is just one element in a string of events that leads to a well getting out of control.

13.3.1 Blow Out Preventer System (BOP)

There are two types of BOP, the annular and the ram

The **annular** BOP consists of a ring of rubber with metal inserts which mates against an internal, metal, conical section. On activation, the rubber is forced upwards against the conical section which also forces the rubber inwards to close tightly around anything in the hole such as the drill pipe or the Kelly. If there is nothing in the hole, the rubber element is sufficiently flexible to completely seal off an open hole. Since the hydraulic activation pressure is in an upwards direction, once closed, the well bore pressure tends to assist in maintaining the annular BOP in the closed position.

The **ram** type has two separate blocks of metal with rubber seals which, when activated, meet in the centre of the well, closing around the pipe that is in the hole. There are three types of ram:

- **Pipe rams – close around the pipe and seal**:

Pipe rams will only fit one specific size of pipe. Therefore, for every size of pipe used, there is a different size of ram. Quite often, an offshore BOP stack will be configured to contain two sets of pipe rams, each fitted with a commonly used pipe size, for example, 3.5 in. and 5 in. drill pipe, thus obviating the need to change pipe rams whenever different sizes of pipe are being used.

- **Blind rams – close against each other and seal**:

To close an empty hole, blind rams are used. These have no cut-outs and are made so that they will mesh into each other when closed, sealing the hole completely.

Shear rams – Cut any pipe, close against themselves and seal:

The shear ram has the same function as the blind ram, but also includes a scissor-action cutting shear, which will cut through any pipe that is in the hole. After cutting the pipe, the shear rams completely seal across the hole.

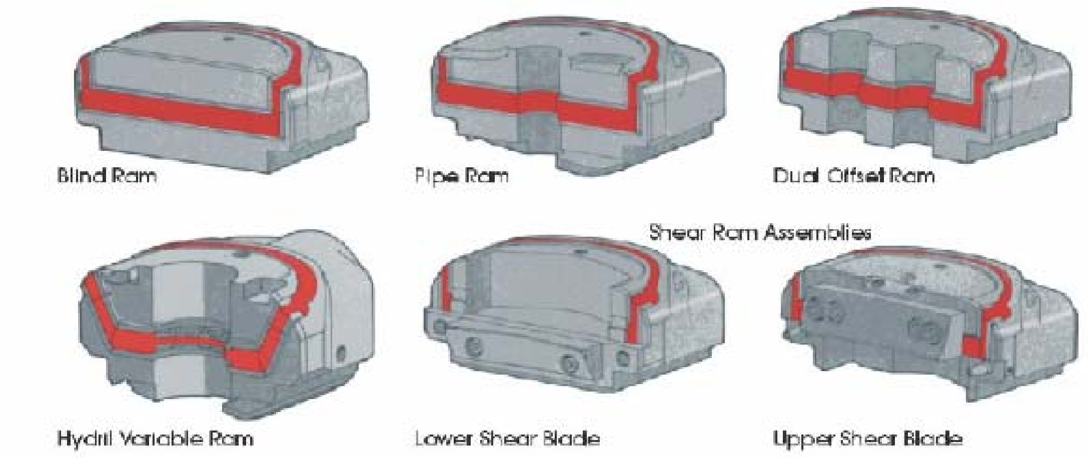


Figure 58 BOP Rams

The ram type BOPs have cylinders on both sides, fixed to the ram carrier. To close the ram, hydraulic fluid is admitted to the cylinders on either side of the BOP, a piston is forced to move, thus moving the ram. Opening is the reverse, with the fluid being admitted to the centre of the cylinders. Changing the rams is, in all cases, a relatively simple matter, though the method does vary. All BOPs are worked in a similar manner, by hydraulic pressure. When it is desired to shut in the BOP, a valve is operated either by the driller or from a remote position, allowing hydraulic pressure to enter the BOP and close the ram. For opening, pressure is applied to the opposite side of the operating mechanism and the BOP is opened.

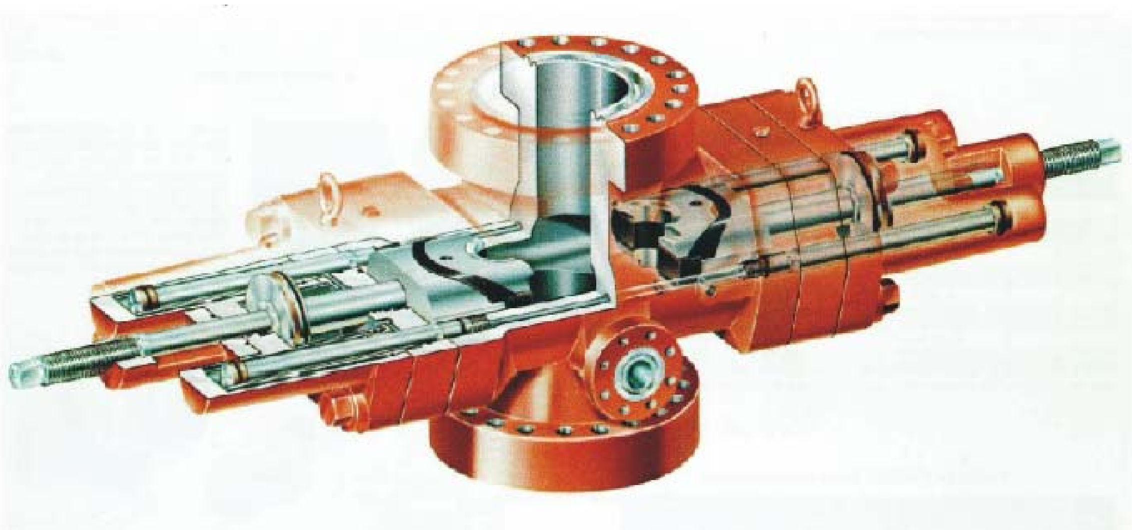


Figure 59 Single BOP ram

The number of BOPs that are used on any hole will vary with the type of hole being drilled.

Onshore, the number of rams will be three or four, consisting of one annular preventer, one pipe ram and one blind ram. If a fourth preventer is added, it will also be a pipe ram. The same configuration will apply on a platform or on a jack-up rig. On a floating rig, with a sea bed system, there will be five or six BOPs, consisting of one or two annular preventers, three pipe ram preventers and one blind or shear ram;

Various combinations of BOPs have evolved into BOP systems or BOP stacks. In addition to the systems or stacks, there are ancillary control devices so that the well can be flowed or excess pressure relieved under controlled conditions. These are the choke and kill manifolds which are intrinsic elements of the BOP system. There will be modifications in the control systems and differences in the outside design of BOPs to cope with the different environments, but the internal functioning portions are the same.

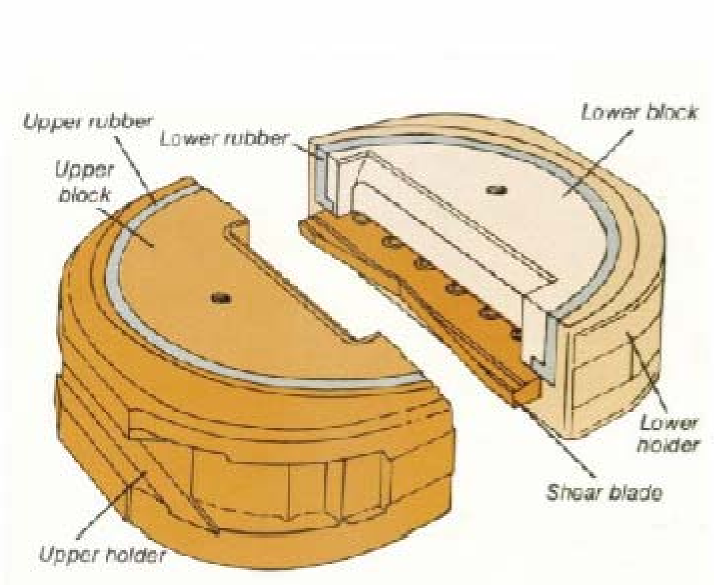


Figure 60 Shear Rams

There is little difference between the BOPs used on land rigs and jack-ups and those used on the seabed. On the jack-up type rig and platform rig, the blow-out preventer stack is on the cellar deck of the rig and is relatively accessible, but in the semi-submersibles, the blow out preventer stack is on the seabed and is controlled by hydraulic lines from the surface. To enable the blow out preventer to be attached to the wellhead on the seabed, guide lines are run and the blow out preventer stack is run down on these guide lines and centered over the well head. The configuration and number of valves incorporated in the BOP stack can be varied to suit particular circumstances or the requirements of operators.

Figure 61 BOP on Cellar deck

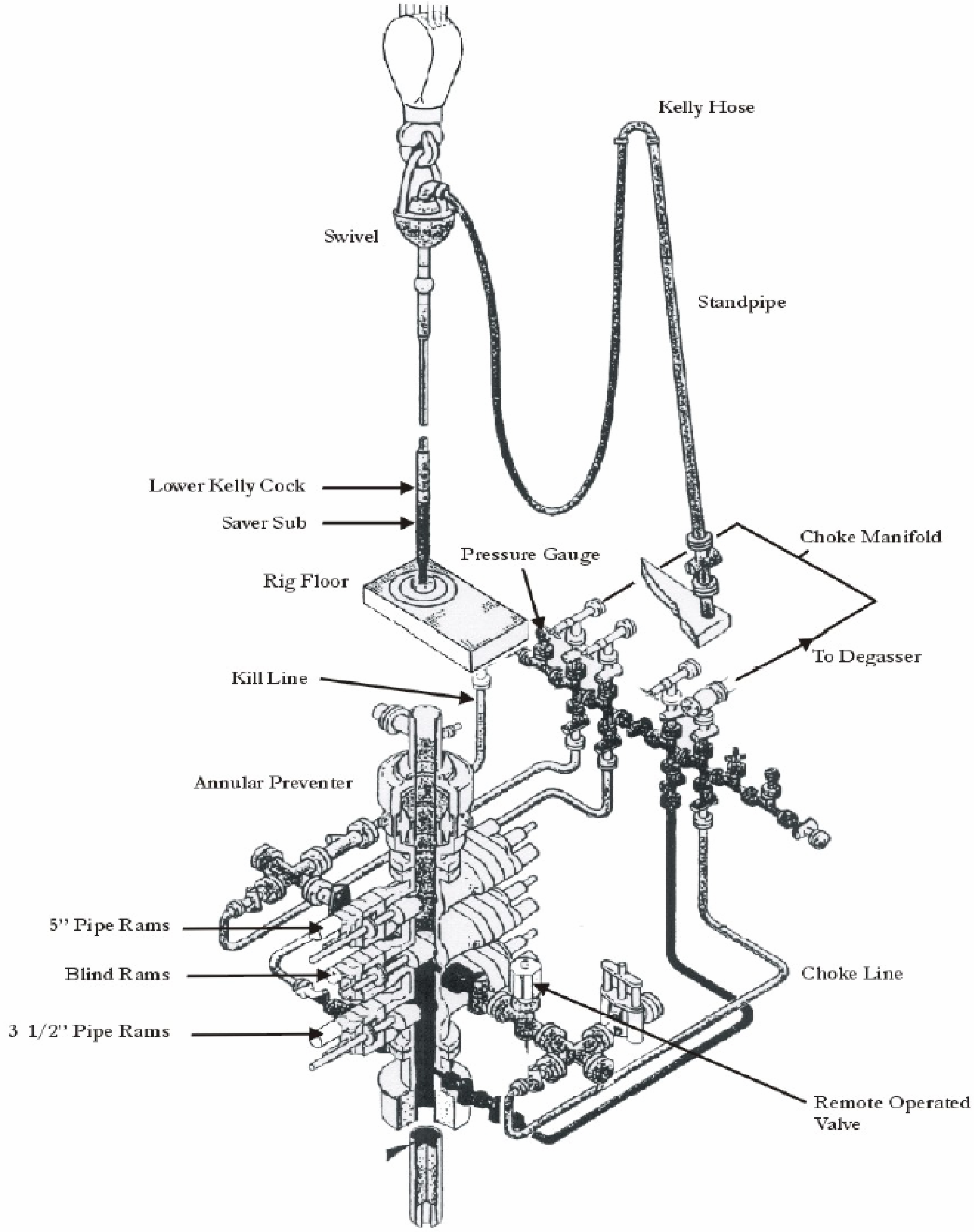


Figure 62 BOP Control System

In conjunction with the drillers shut in controls it is quite common to find situated at strategic points around the rig, **ESD (**Emergency shut down)**,** buttons. These will do the same as the driller's controls only in a single operation and will result in a complete well/rig shut down.

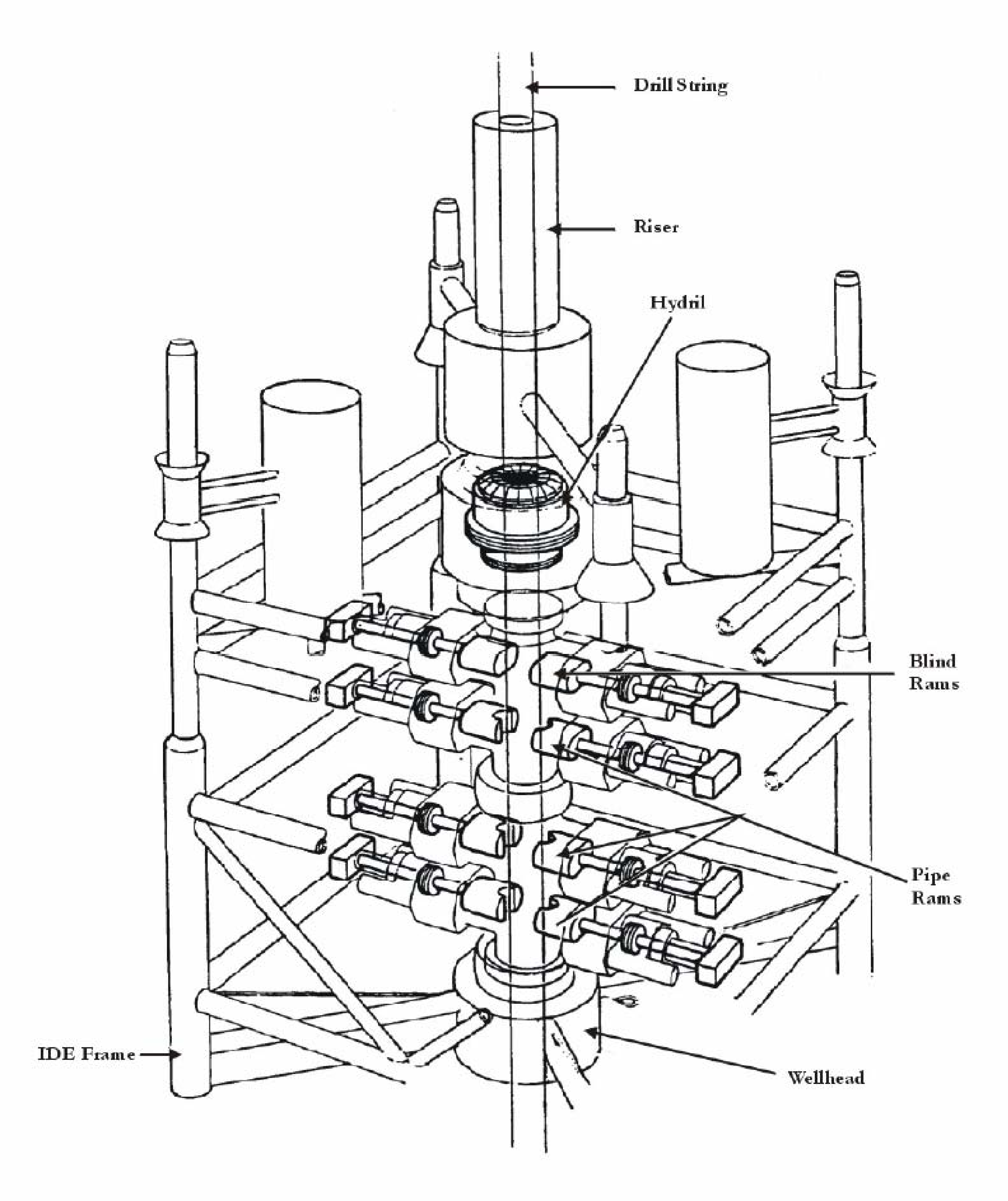


Figure 63 Subsea BOP System

14 Completing the Well

Well completion simply means finishing the construction of a well which has been drilled in order that the reservoir fluids can be produced efficiently and safely to surface. It must take into account phases covering the immediate and the long term requirements of the well, the reservoir and the depletion policy.

Well completion includes the:

- Design of the tubulars (casing and tubing) which are installed in the well.
- Method of providing communications between the reservoir and the borehole.
- Method of raising reservoir fluids to the surface.
- Design and installation of the various tools and accessories used to control and monitor the flow of fluids.
- Design and installation of safety devices which will automatically shut in a well in the event of a hydrocarbon leak.

The individual well is the only communication with the reservoir and it represents a large percentage of the expenditure in the development of an oil or gas field. It is of utmost importance that the well completion be designed correctly at the outset in order that maximum overall profitability of the field may be obtained.

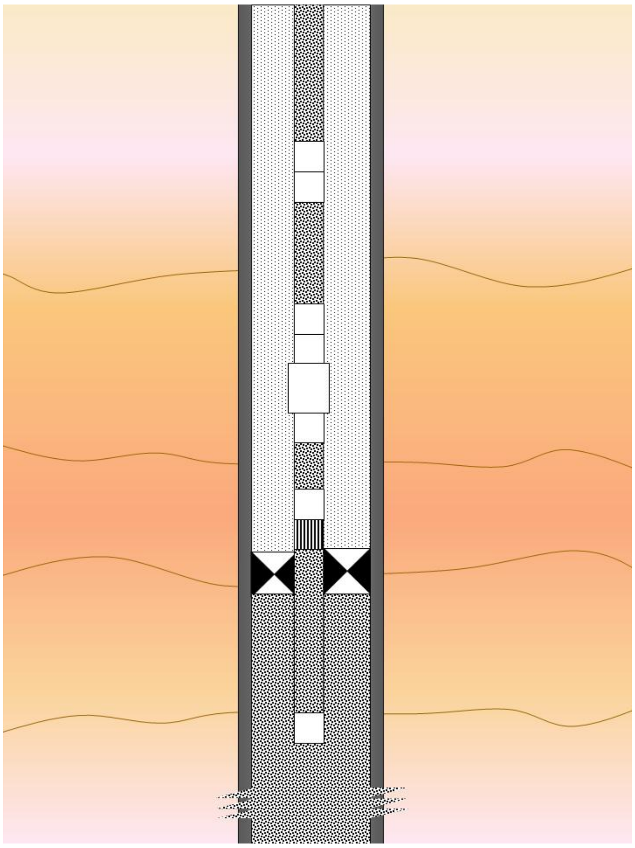


Figure 64 Single Bore Completion

14.1 Well Completion Design

The well is our only communication with the reservoir. The effectiveness of that communication is a large factor in reservoir drainage as well as overall economics. Wells represent the major expenditure in reservoir development. Oil wells, gas wells and injection wells present unique problems depending on the specific operating conditions. The individual well completion must be designed to yield maximum overall profitability on a field basis.

The ideal well completion is one which is safe, cost-effective and meets the mechanical, fluid and reservoir demands placed upon it.

To intelligently design a well completion, a reasonable estimate of the producing characteristics during the life of the well must be made. Reservoir, fluid and mechanical considerations must be evaluated for the life of the well.

14.1.1 Reservoir Considerations

Reservoir considerations involve the location of various fluids in the formations penetrated by the wellbore and the flow of these fluids through the reservoir rock itself.

Producing rate to provide maximum economic recovery is often the starting point for well completion design. Among other factors producing rate should determine the size of the producing conduit.

Multiple reservoirs penetrated by a well pose the problem of multiple completions in one drilled hole. Possibilities include multiple completions inside casing separated by packers, or several strings of smaller casing cemented in one borehole to provide in effect separate wells. Other possibilities include commingling of hydrocarbons from separate reservoirs downhole, or drilling several boreholes from one surface location.

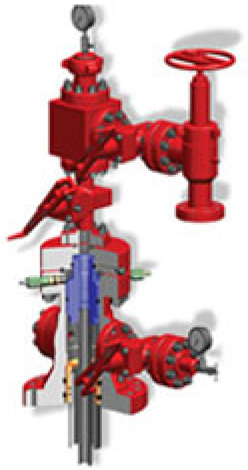


Figure 65 Single Bore Completion Well Head

Reservoir drive mechanism may determine whether or not the completion interval will have to be adjusted as gas-oil or water-oil contacts move. A water drive situation may indicate water production problems. Dissolved gas and gas drive reservoirs usually mean declining productivity index and increasing gas-oil ratio.

Secondary recovery needs may require a completion method conducive to selective injection or production. Water flooding may increase volumes of fluid to be handled. High temperature recovery processes may require special casing and casing cementing materials.

Stimulation may require special perforating patterns to permit zone isolation, perhaps adaptability to high injection rates, and a well hook-up such that after the treatment the zone can be returned to production without contact with killing fluids. High temperature stimulation again may require special cementing procedures, casing and casing landing practices.

Sand Control problems alone may dictate the type of completion method and maximum production rates. On the other hand, reservoir fluid control problems may dictate that a less desirable type of sand control be used. Sand problem zones always dictate a payoff from well completion practices.

Workover frequency may be high where several reservoirs must be drained through one wellbore, often dictate a completion conducive to wireline or through-tubing type re-completion systems.

Artificial lift may mean single completions even where multiple zones exist, as well as larger than normal tubulars and sub-surface pumps may need to be employed.

14.1.2 Mechanical Considerations

The mechanical configuration or '*well hook-up'* is often the key to being able to deplete the reservoir effectively, monitor downhole performance, and modify the well situation when necessary.

The mechanical configuration of the well is the key to being able to do what ought to be done in the well from the standpoint of controlling the flow of reservoir fluids, oil, gas and water.

Formation drainage is related to the well hook-up, both minimizing damage initially and relieving the effects of damage later.

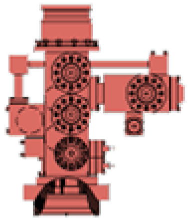
Mechanically, well completion design is a complex engineering problem. Basic philosophy is to design to specific well conditions, field conditions and area conditions.

1. *Maximise profit* considering the time value of money. Economics are sometimes best served by delaying expenditures, particularly in wells where servicing is frequent. The isolated well is the one you can afford to provide the maximum flexibility for the future.
2. *Keep the installation simple,* both from equipment and procedural standpoints – consider level of operator skill available.
3. *Overall reliability* depends on reliability of individual components and the number of components. Design out maintenance, limit moving parts and avoid debris traps. As complexity increases, provide alternatives.
4. *Anticipate all operating conditions,* and associated pressure and temperature forces.
5. *Safety* must be designed into the well. In offshore, populated, or isolated areas, automatic shut-in systems and well pressure control methods must be considered.

Basic decisions to be reached in designing the well completion are:

- The method of completion
- The number of completions within the wellbore
- The casing-tubing configuration
- The diameter of the production conduit
- The completion interval

14.2 Wellheads and Xmas Trees



The wellhead consists of the casing heads and the casing and tubing hangers which hold the down hole tubulars in position and seal the annuli one from one another. Pressure gauges, for each annulus are fitted on the well head and may have bleed valves connected to one or more annulus for pressure relief or testing purposes.

Above the wellhead is the Xmas tree, which is a manifold of valves, all with specific functions, which connect to the tubing of the well. Originally, this assembly of valves, spools, pressure gauges and adapters was constructed from individual components and the appearance of the unit gave rise to its name. Nowadays, the Xmas tree is frequently constructed from a single casting which enables the unit to be neater, smaller and eliminates the danger of leakage between flanges.

Typically, from bottom to top, the Xmas tree will contain the following valves:

Figure 66 Subsea Xmas Tree

- Bottom master valve, manually operated and used to shut off the well in abnormal conditions.
- Top master valve, hydraulically operated and also used to shut off the well in abnormal conditions.
- Flow wing valve, manually operated to permit the passage of hydrocarbons to the choke. This valve would normally be used to close and open the well to prevent wear on the previous two valves.
- Choke valve, manually or mechanically operated to control flow from the well. This is the only valve in the Xmas tree which is used to control or regulate flow.
- Kill wing valve, manually operated to permit entry of kill fluid to the well. Kill fluid is a high-density fluid designed to overcome, control and 'kill' formation pressures in an emergency or if it is necessary to remove the Xmas tree and wellhead.
- Swab valve, manually operated and used to give access to the well for work over or wireline work.

On a production well on a platform, instruments will monitor pressures, temperatures and levels on the surface equipment and will activate the safety valve actuator on the Xmas tree in an emergency.

14.3 Completion String Design

Design of the completion string involves the selection and specification of the component parts of the string.

Selection is done on the basis that the component will provide a specific facility necessary for the completion. Each component makes the completion more complex and its inclusion must be justified as essential or providing desirable flexibility.

14.3.1 Provision of an Annular Pressure Seal

An annular seal is necessary for:

- Production stabilisation
- Protection of the casing and wellhead from corrosive produced fluids and reservoir pressures
- Isolation of different zones during stimulation or production.

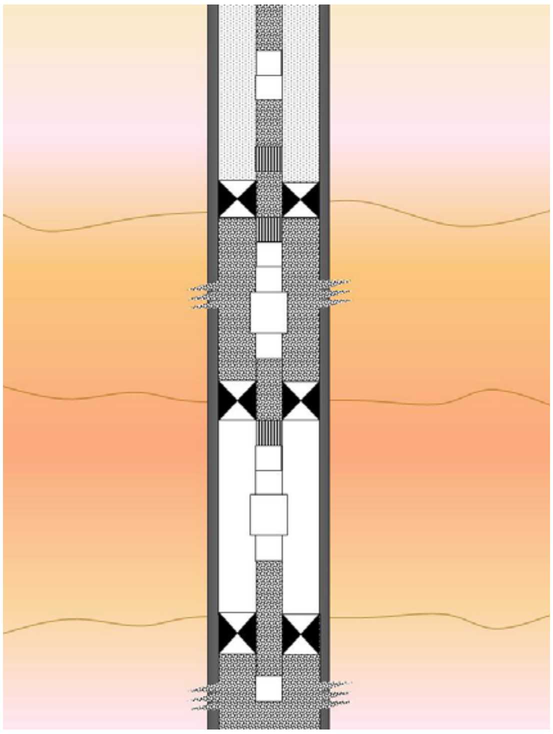


Figure 67 Single Bore Completion, Multiple Reservoirs

The most common method of providing an annular seal is to use a packer. Pack-off is obtained by expanding a rubber element outwards from the packer body until it contacts the casing wall. Basically there are two types of packer:

• **Retrievable**: This type of packer is run as an integral part of the tubing string and the setting mechanism activated by manipulation of the string or hydraulically. This type is relatively robust simple to use and reliable within specified working conditions.

• **Permanent**: A permanent packer is run and set before the tubing string is run. It can be run on an electric line, perhaps the most common method, or on drillpipe. It can be run with or without a tailpipe. This type of packer, while ostensibly 'permanent' can be removed, but only by milling away the internal sleeves to allow the rubber element to collapse. This type is more commonly used where higher bottom hole pressures and differentials are expected.

Setting mechanisms cause compression and extrusion of the rubber element:

- Mechanically, for example, by rotating the string.
- Compression or tension based on suspended tubing weight. Usually, a mechanical device is required, which when activated at setting depth, allows string weight to be transferred to the packer to compress the rubber element.
- Hydraulic pressure generated inside the tubing string. This requires setting a plug in the tubing below the packer to protect the formation or the annulus from the applied pressure.

- Electrical - permanent packers are generally run on electric line. A special adapter and setting tool are connected to the packer. A small explosive charge actuates the setting mechanism.

14.3.2 Provision of a Seal between Tubing and Packer

This refers only to permanent packers. A retrievable packer is run as an integral part of the tubing string and the seal is affected by the tubular connection between packer and tubing.

With permanent packers, it is necessary to introduce a component with the tubing string, which will be run into the internal bore of the packer and effect a pressure seal. Several items of equipment are available for this purpose, their design depending on whether or not allowance has to be made for the tubing to move to compensate for thermal expansion or contraction of the tubing. Thermal expansion will occur for instance when the well begins to flow as the tubing heats up and the tubing will cool down when production ceases or stimulation begins. Figure 7 shows a locator seal assembly and an anchor latch.

14.3.3 Tubing Hanger

The Tubing Hanger is a completion component which sits inside the Tubing Head Spool and provides the following functions:

- Suspends the tubing
- Provides a seal between the tubing and the tubing head spool
- Installation point for barrier protection.
- The Tubing Head Spool provides the following functions:
- Provides a facility to lock the tubing hanger in place
- Provides a facility for fluid access to the ‘A’ annulus
- Provides an appropriate base for the completion Xmas Tree.

Both the Tubing Hanger and Tubing Head Spool are prepared to allow the actuation of an SCSSV.

An example of a Tubing Hanger/Tubing Head Spool system is shown in Figure 8. Such Tubing Hanger systems allow completion tubing to be suspended in neutral (i.e. all the tubing weight minus fluid buoyancy) or the tubing suspended in compression.

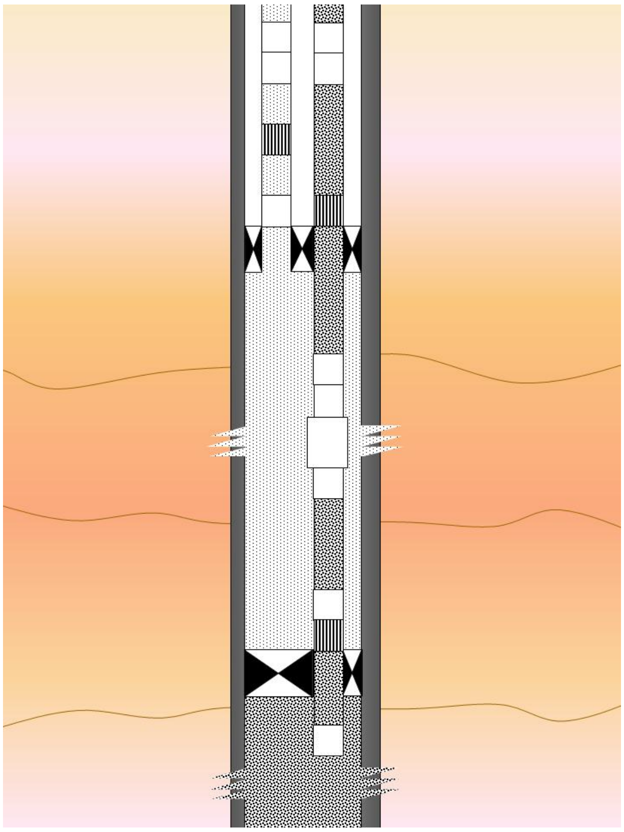


Figure 68 Dual Bore Completion

14.3.4 Surface-Controlled Sub-Surface Safety Valve (SCSSV)

In offshore wells, these valves are incorporated in the tubing string just below sea level. Their purpose is to shut in the well in the event of a catastrophe.

Offshore, these valves are remotely controlled. They rely on hydraulic pressure, supplied via a $^{1}/_{4}$" control line strapped to the outside of the tubing, to keep the valve open. The valve is either a ball type or a flapper device.

There are two types based on how the valve is run and pulled:

- Tubing retrievable, where the valve is run as an integral part of the tubing string and can only be retrieved by pulling the tubing.
- Wireline retrievable, where the valve nipple is run as an integral part of the tubing string and the valve can be subsequently run and retrieved on wireline.

The main advantage of the wireline retrievable SCSSV is that it can be easily and economically retrieved for inspection, repair or replacement. The primary disadvantage is related to the restricted bore through these devices. The valve does present a restriction to flow, and can cause plugging or paraffin problems.

The tubing retrievable SCSSV is run as an integral part of the tubing string and is essentially identical in operation to the wireline retrievable type. The primary advantage of this valve type is that it’s full opening design permits unrestricted flow. The valve does not contribute to plugging. Paraffin removal can be accomplished without the necessity of retrieving any equipment from the tubing.

The main disadvantage of tubing integral valves in the past was that the tubing had to be pulled to repair the valve in event of failure. This can be an extremely expensive operation in many areas. This disadvantage has now been partially overcome by the development of remote controlled tubing removable valves, which, in the event of failure, can be converted to remote controlled wireline retrievable valve service.

14.3.5 Sidepocket Mandrel (SPM)

This contains an off centre pocket with ports into the annulus. A valve can be installed in the pocket on wireline to allow fluid flow between annulus. These include:

• **Gas Lift Valves:** When installed in the SPM, the valve responds to the pressure of gas injected into the annulus by opening and allowing gas injection into the tubing.

• **Chemical Injection Valves:** These allow injection of corrosion inhibitors, pour point dispersants, etc. They are opened by annulus pressure.

• **Shear Valve:** To allow circulation of kill fluids, a valve can be installed with a disc which can be ruptured or sheared by pressure, allowing communication. The port can then only be re-closed by replacing the shear valve by wireline.

14.3.6 Sliding Side Door (SSD)

This allows communication between tubing and annulus. It consists of two concentric cylinders, each with slots or holes. The sleeves can be moved by wireline tools to align the openings. It is used for well killing and circulating fluids to the tubing or annulus.

14.3.7 Landing Nipples

These are short tubular devices with an internally machined profile, which can accommodate and secure a mandrel run on wireline. The nipple also provides a pressure seal against the internal bore of the nipple and the outer surface of the mandrel.

Landing nipples are incorporated at various points in the string. They are used for:

- Setting plugs in the tubing for pressure testing, setting hydraulic packers or isolating zones
- Installing downhole choke
- Hanging off bottom hole pressure gauges.

14.3.8 Perforated Joint

This allows flow into the tubing string even if the base of the string is plugged by, for example, pressure gauges.

14.3.9 Tubing

Although tubing is the last string of tubulars to be run in the well, its requirements often dictate the whole well design. Tubing is run mainly to serve as the flow conduit for the produced fluids. It also serves to isolate these fluids from the annulus when it is used in conjunction with a casing packer and is often the case.

The basic tubing string design criteria are:

- Size, appropriate to producing operations.
- Tensile strength.
- Stress.
- Corrosion resistance.
- Internal and external pressure.

The American Petroleum Institute (API) identifies, assesses and develops standards for oil and gas industry goods. Tubing is considered appropriate to API standard if the following conform to certain specifications:

- Weight per foot
- Length ranges
- Outside diameter
- Wall thickness
- Steel grade
- Method of steel manufacture

and API standards also specify:

- Physical dimensions of the thread connections
- Performance for burst, collapse and tensile strength of the pipe body and thread connections.

There are all manner of threaded connections for tubing, just as there are with casing. Each connection has to be made up correctly so that there is no chance of leakage from the tubing into the annular space.

The tubing design will be such that it can accommodate various devices to allow the well to produce properly and efficiently and for remedial workovers to be carried out more effectively. Some of the following devices may be installed for this reason.

14.3.10 Typical Completions

There are three main options for completing the well across the reservoir:

- Open hole.
- Un-cemented liner either pre-slotted or subsequently perforated.
- Cemented and subsequently perforated casing or liner.

14.3.11 Pre-Slotted Liner Completions

This method has all the disadvantages of the open hole completion with the added cost of the liner thrown in. It is used under the same conditions as an open hole completion, but where unconsolidated sands require to be controlled. The slots prevent sand entering the wellbore.

14.3.12 Cemented and Perforated Casing or Liner

This is the most common completion method. The cement sheath around the casing/liner isolates each zone or layer of the reservoir and permits zones to be selectively perforated, stimulated and produced. The initial cost of completing this way is higher than the others.

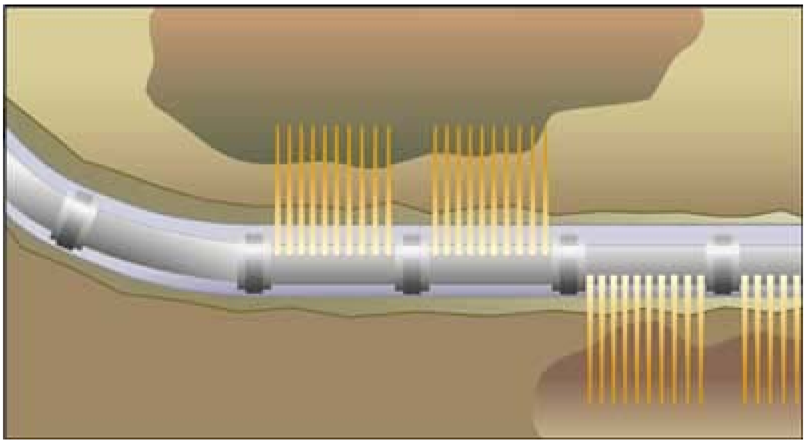
14.3.13 Casing/Tubing/Packer Completion

Also known as a 'conventional completion', it is the most complex of the three methods, but offers definite advantages:

- Stable flow.
- Packers allow independent production from several zones in multiple completions.
- Packers protect the annulus from corrosive produced fluids and producing pressures.

This is the most widely applied method in the world.

15 Perforating

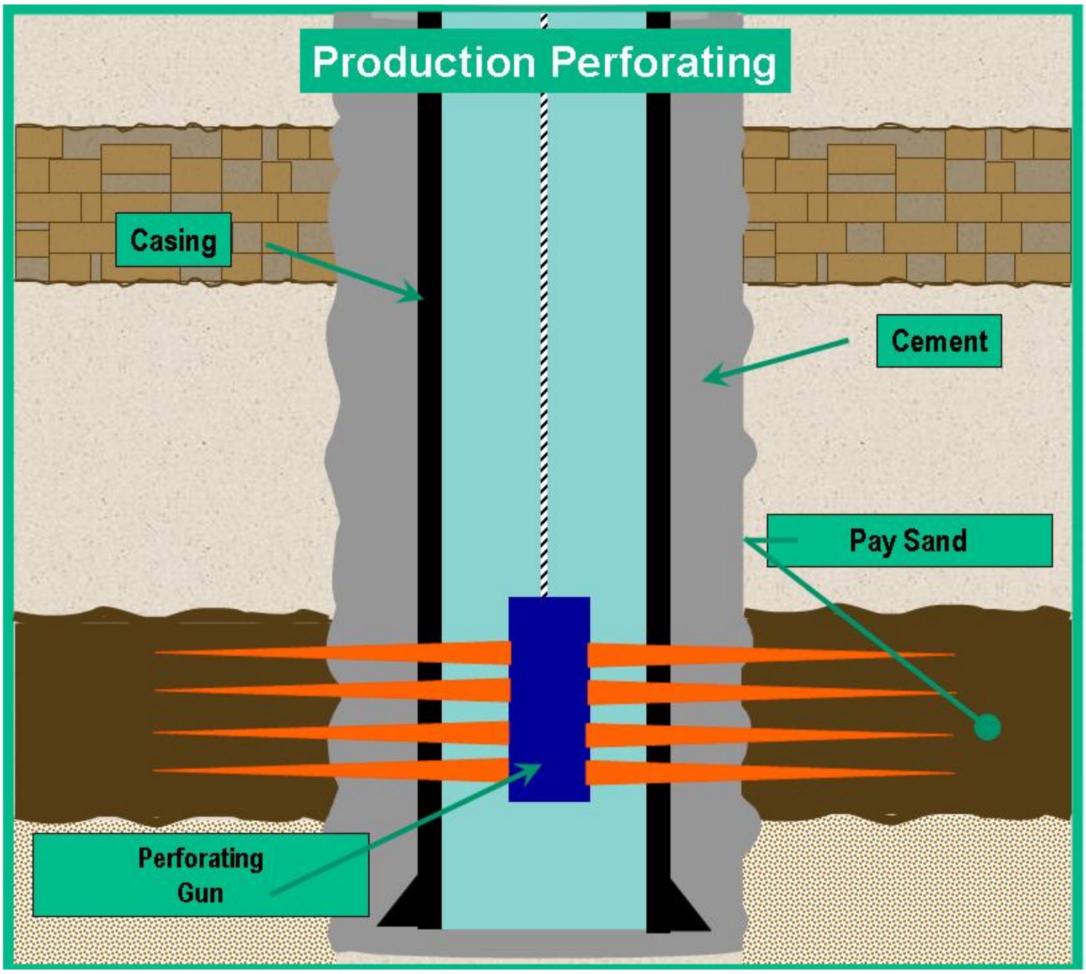


One the well has been completed the next and one of the last important tasks is to perforate the well. A very basic description of well perforation would be to say that an explosive charge or mechanical device is lowered into the well via either drill pipe or wire line cable and under controlled conditions is detonated at a pre-determined depth. The size, weight and type of charge used is dependant on the well formation rock type and the ever evolving technical advancements in down hole perforation methods.

In most cases it will be necessary to perforate the hydrocarbon-bearing formation or production zone (pay-zone) in order to obtain the optimum production. Some wells can flow open-hole (without perforations) but this is very much formation dependable. If flow rates are expected to be high and for additional safety, perforated cased hole is considered as the preferable option.

These holes or *'perforations'* pierce the casing or liner and the cement around the casing and liner and into the producing formation. Formation liquids, which include oil and gas flow through these perforations and into the well.

Figure 69 Shaped Charges



The most common piercing gun uses shaped charges similar to those used in armour-piecing shells. Several high speed, high pressure jets of gas penetrate the steel casing, the cement and the formation next to the cement. The perforating gun is lowered into the hole, usually by a wireline although this operation can be done on drill pipe, TCP (tubing conveyed perforating) to the desired depth. These guns can be up to 40ft long and 5" in diameter and are assembled to perforate the producing zone to give the best chance of good flow from the pay zone. The depth can be determined by a *'collar locator log',* which is a magnetic indicator and identifies the depth of each casing collar. By comparing the log with the overall number and length of the casing joints the depth can be accurately determined. Once in place the gun is set off to make the perforations. The gun is then retrieved. This is a specialist operation and requires minimal personnel on the rig floor during the operation.

15.1 Types of Perforating System

Perforating methods:

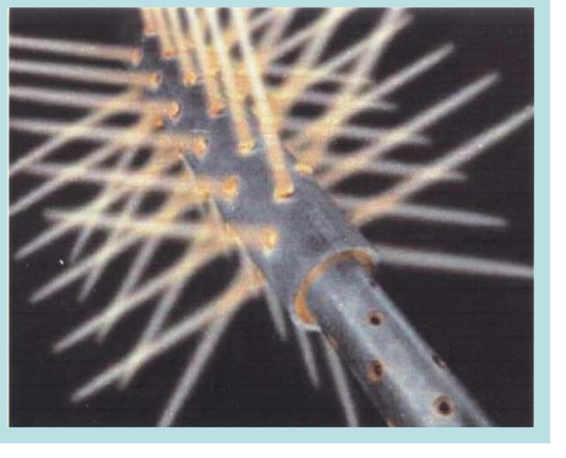
- Mechanical perforators (from 1910)
- Bullet perforators (from 1926)
- Shaped charge (jet) perforators (from 1946).

The most common and effect form of perforating is today done with the use of shaped charge perforators. Although bullet perforators are occasionally used for particular applications.

The mechanical perforator uses a single-knife casing 'ripper' or splitter action, which cuts a slit of any desired length into the casing wall. This was very successfully when operated and run on tubing or drill pipe when the weight of the pipe forced the knife blade out through the casing. Others were developed which cut two or four holes simultaneously.

The first use of a bullet perforator was in 1932 in a Union Oil well in California. The perforator was a steel cylinder with chambers containing the powder charge and bullets. The gun was lowered in the hole on armoured insulated cable and shots could be fired individually or as a group by operating electric controls at surface. As a matter of interest, 80 bullets were shot in eleven runs into the well. It took eight days to fire the eighty shots at a depth of less than 2665 feet. A similar number of shots can be completed today at 30,000 feet in less than 24 hours.

The shaped charge process requires no bullets and the perforations are affected by focusing a high-velocity jet stream against the casing. The process uses the principle of the cavity effect of explosives, known as the Monroe effect or shaped-charge principle, which was utilised in projectiles and rockets during World War 2. After the war, various groups investigated the principle in connection with perforating wells. Today's high tech armoured vehicles use this principle when designing the artillery defence systems.



15.1.1 Theory of Shaped Charges

An over-simplification of the theory states that the shape of an explosive cavity focuses and propagates a progressive wave front against the outside surface of the metal liner. At the pressures generated, the metal acts as a fluid. The extremely high pressure, particle-laden jet stream breaks down and moves aside any material upon which it impinges. Penetration is a result of the amount of pressure and the greater the length of the jet stream, the greater the depth of penetration.

During this sequence of events, the temperature within the jet stream reaches very high values, thought to be in the order of 2000°F. Since the sequence of events happens in the order of four microseconds, there is no time for heat transfer. The pressure increase is in the order of 4.5 million to 5 million psi.

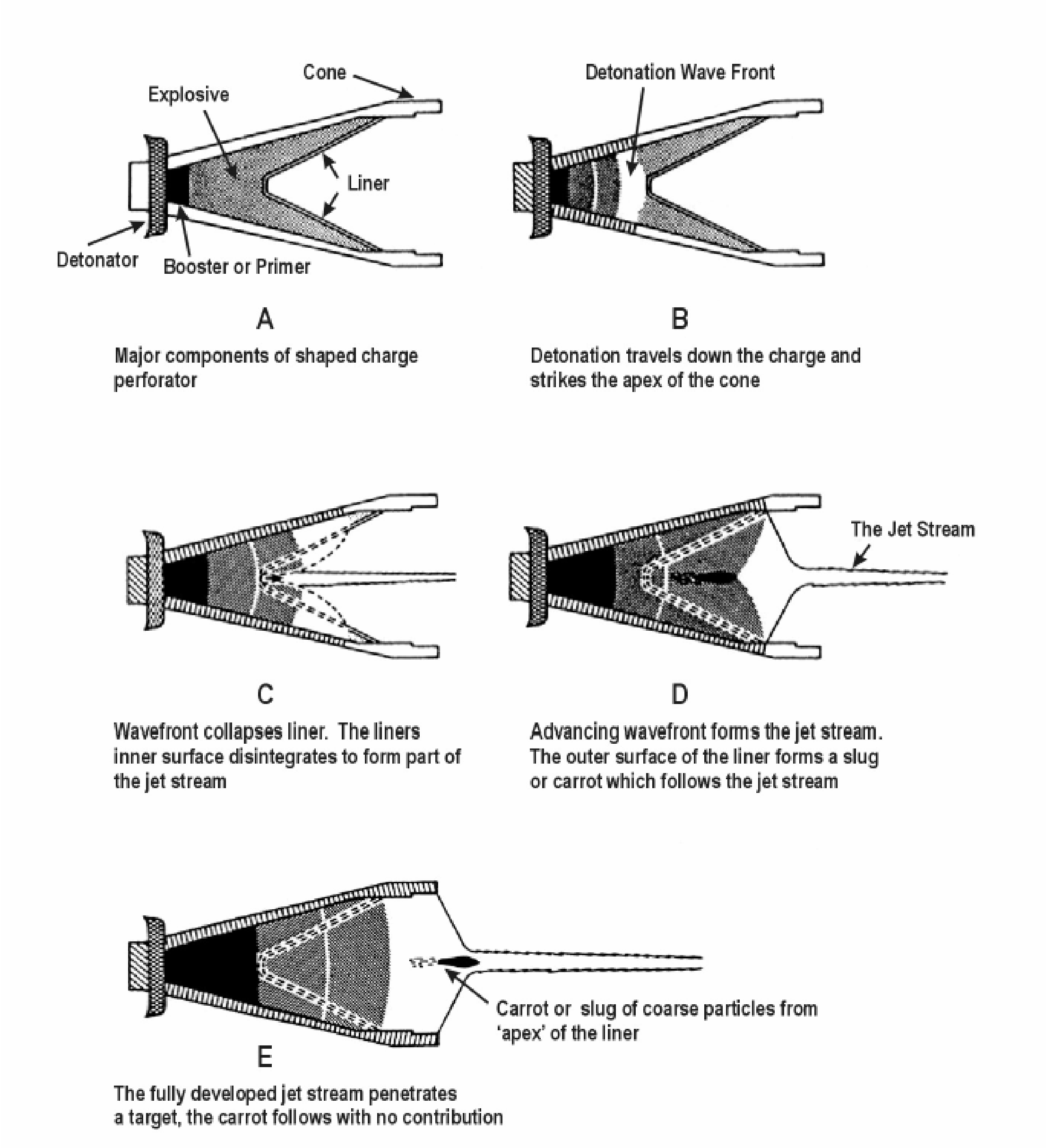


Figure 70 How Shaped Charges Work

15.1.2 Penetration

In the early use of shaped charge perforators, there was a mistaken belief that jets either burned or melted their way through a target. They do neither. Such intense heat would fuse rock. Yet, no fusion of rock targets is disclosed by examination with a microscope after perforation.

Test shots using steel block targets 1 inch x 2 inches x 5 inches lose no weight by reason of having been perforated by a jet. Hence, no material is burned of melted away. However, if the width of the block of steel is only about six times the diameter of the hole, the block will show signs of enlargement concentrically around the hole. Obviously, target material is moved laterally (pushed) away from the point of impact.

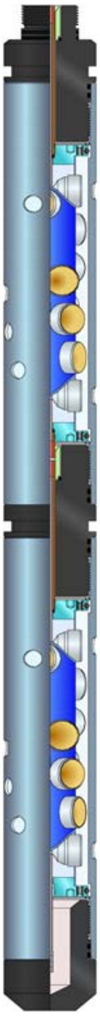
15.1.3 Gun Types

There are three basic gun types:

- Retrievable hollow carrier gun (hard ware brought to surface)
- Non-retrievable or expendable gun (guns “dropped” or left down hole)
- Semi-expendable gun. (Hardware brought to surface, gun carrier/charge debris left down hole)

The retrievable hollow carrier gun consists of a steel tube into which the shaped charge is secured. The charges can be arranged in the carrier in a “phased” or spiral fashion for better formation penetration. The spacing of the charges in the carrier can also be achieved to give “shots per foot” and therefore control the saturation i.e.: “12 shots per foot” or “6 shots per foot”. The gun tube is sealed against hydrostatic pressure using an o-ring system. The charge is surrounded by air at atmospheric pressure and when the charge fires, the explosive forces slightly expand the carrier wall but the gun and the debris within the gun are fully retrieved from the well.

This is a favoured method when junk or debris could be a damaging factor to the well's performance. The non-retrievable or expendable gun consists of individually sealed cases made of a frangible material like aluminium, ceramic or cast iron. The shaped charge is contained within the case and when detonated, blasts the case into small pieces. Debris remains in the well. With semi-expendable guns, the charges are secured on a retrievable wire carrier or metal strip. This reduces the debris left in the well and generally increases the ruggedness of the gun.



15.2 Perforating Methods

There are currently three standard methods for perforating a well using shaped charges:

- Casing gun perforating (run on wireline)
- Through-tubing perforating (run on wireline)
- Tubing conveyed perforating (TCP) (run on tubing coiled tubing, drill pipe).

TCP has developed only during the last 14-15 years. It is currently probably the most widely used technique in the North Sea.

Through-tubing perforating, a commonly used method of initially perforating a well prior to TCP, probably now finds wider application in re-perforating operations.

Casing gun perforating is the oldest method and still finds application.

15.3 Tubing Conveyed Perforating (TCP)

TCP combines the best features of both casing guns and through-tubing guns and not surprisingly is now probably the most widely used perforating technique in the North Sea. The guns are run as an integral part of the completion. They are made up on to the bottom of the completion string or, in the case of ESP completions, on to the bottom of the pump bypass system. The guns are fired only after the packer has been set, the Xmas Tree installed and the entire completion integrity tested. Firing can be done using annulus or tubing pressure, mechanically or electrically in which case a wireline assembly has to be run in the hole. The guns can be jettisoned after firing and allowed to fall to the bottom of the hole below the perforated internal.

The advantages of TCP are:

- Large intervals can be perforated at one time, thus saving on rig time. It is also easier to perforate deviated holes.
- Large size guns can be used with high shot densities leading to more, bigger and better perforations.
- Perforating is carried out with the well under-balanced, leading to cleaner perforations and minimal additional formation damage.
- Safety: TCP is probably the safest way to perforate a well.
- Adaptability: Every completion string can be designed to be TCP compatible.
- No wireline surface pressure control equipment is required as the guns are not retrieved.

The disadvantages of TCP are:

- If there is a misfire, the entire completion string has to be pulled and re-run.

- Additional hole has to be drilled below the reservoir to accommodate the jettisoned guns.

15.3.1 Perforating Risk Factors

Perforating poses operational risks for operators in unconsolidated formations. Additionally, the perforating process can jeopardize well productivity by reducing the area open to flow and damaging the formation.

Generally, well productivity is directly related to the area of flow through a perforation tunnel. The greater the area of flow, the greater the well productivity. Entry-hole diameter and shot density impact flow area. Perforation debris in the perforation tunnel can block the available flow area, as can fractured and compacted zones and broken pieces of formation. The flow restriction caused by crushed zonal rock can also increase skin values, particularly over the life of the well.

15.4 When to Perforate

After the well is perforated, oil and gas can flow into the casing or liner. Sometimes perforating is carried out before and sometimes after the tubing has been run; it al depends on the parameters and design of the well concerned.

16 Formation Evaluation

16.1 Introduction

Well logging began in the 1920s with simple electrical conductivity tests being performed on mines in France by Conrad Schlumberger. Since then, there has been the development of electric logging, with hundreds of different tools, the advent of acoustic logging and nuclear logging.

Technology developed through the 50s and 60s; but the advent of computers into the logging industry in the 1970s meant that far more data could be handled far quicker than ever before. As the speed at which data could be handled increased exponentially; tools and techniques developed also. The latest tools to emerge on the market are Nuclear Magnetic Resonance logging; highly informative information is delivered about porosity and permeability and also the rock formation.

For more history of well logging, please refer to the hand-out sheet '*Logging History Rich with Innovation.'*

Formation evaluation is probably the most important aspect of any hydrocarbon reservoir; without it how would we know what was down there, 1000s of feet beneath us. With formation evaluation we discover hydrocarbon deposits in particular types and shapes of rock. We can establish when they were deposited, whether there is oil, gas or water, how porous the rock is and how easily the hydrocarbon will flow. We can tell how much hydrocarbon is in a reservoir to start with and during the life of production how much is left at any one time. Logging tools can tell us where to set other tools, where to perforate (blast holes into the formation); they can help us find the direction of a drill bit and the angle of a formation.

Formation evaluation begins with seismic which is covered in section 7.3 Seismic Survey.

Did you know?

Reservoirs can take on all kinds of shapes and sizes, but as an example of how powerful formation evaluation techniques are, consider this:

If you draw a circle 1m diameter, consider this as representing a reservoir 10km in diameter. Well depth would be 0.3m (representing a 10,000ft depth) and the diameter of each well would be 0.018mm (representing a 7" diameter tubing). An average hair is 0.1mm diameter!

16.2 What information can we get and why do we want it?

In the early days of oil and gas exploration the term wildcatters was quite common. This was the term that was given to prospectors drilling for oil based on a hunch. This was a very *'hit and miss'* operation which sometimes paid off, but as time went on geologists began to evaluate the soil and the surface of the land to give a more probable chance of striking oil. This worked well in areas that gave a surface indication i.e. knolls or land features that had previously given good results. Unfortunately flat areas such as dessert or West Texas for instance gave no indication at all. This also created difficulties in finding offshore reserves where large amounts of hydrocarbons were expected.

From these early days of simply drilling a hole in the ground because of a hunch; evaluation of the site of a well and its production capability has developed to a highly scientific business.

The only reason we drill oil and gas wells is to produce large quantities of the stuff in a profitable manner. Exploring for hydrocarbon reservoirs and then analysing and developing a field is a very expensive business; so whilst there are no guarantees with the reservoir analysis, the more accurate this process is, the more likely the field is to be developed commercially. Of course the reservoir engineers may give enough information which allows the commercial arm of the company to conclude that the field is not commercially viable.

So it is vitally important to the license holder of the field to assess whether or not they can make a profit producing hydrocarbon by developing a certain reservoir. Their calculations will include all of the costs of exploration, development, construction, operation and even decommissioning at the end of life of the field. They will investigate where their market place is for the produced hydrocarbon, how it will be transported and processed. But some of their most critical information comes from the reservoir engineers at the start and during the life of the reservoir.

Reservoir engineers will be tasked with finding out as much as possible about the reservoir; especially at the early analytical phase of the reservoir:

- How much oil or gas does it contain?
- How porous is the formation?
- How permeable is the formation?
- How much of the hydrocarbon can we extract?
- How will the hydrocarbon be produced – gas drive, water drive, a combination of the two?
- Will artificial lifting (sub-surface pumping) be required?
- Can injection of gas or water increase total production?
- Over what area is the reservoir likely to produce?
- Where should we site the production and injection wells?
- What rocks do we have to drill through to target the formation?

Armed with this and other information, the license holders can make a decision whether or not to develop this reservoir.

16.3 About this section

This section requires a little more explanation as it covers such a wide range of topics.

- Mud logging covers the physical and chemical testing carried out on the returns from the drilling operation. It is a useful early test of the subsurface rocks.
- Open Hole, Cased Hole and Production Logging talks about the changes in the well set up and the different types of logging carried out.
- Then we talk about the different types of scientific wireline logging tools; including electronic, acoustic and nuclear logging tools.
- Finally this section describes Production Logging, the type of logging which tells us about the way in which the reservoir and well are producing the hydrocarbon.

16.4 Mud Logging

This is the simplest/easiest direct evaluation method where geologists and mud loggers can examine actual samples of formation rock or contents. Also, mud logging instrumentation records drilling parameters such as rate of penetration, bit weight, rotary speed, bit number and type, rotary torque, coring intervals, mud temperatures, gas content, chlorides and pore pressures. Mud logging begins very soon after Spudding in and the geologist will examine the rock cuttings returned by the drilling mud. As the drill bit penetrates different rock formations, the geologist can identify each type of rock, through samples from the shakers and correlate the physical evidence against seismic survey and ***strat test*** (if applicable) results. Washing a sample of the rock chips and examining them under ultra-violet light, identifies any hydrocarbons that may be present. Cuttings, however, do suffer from limitations: different types of bit produce different sizes of rock chips which are contaminated by mud, and they may not be large enough to allow meaningful measurements of porosity and permeability. Since the information which can be obtained from these cuttings is limited, more defined methods are used.

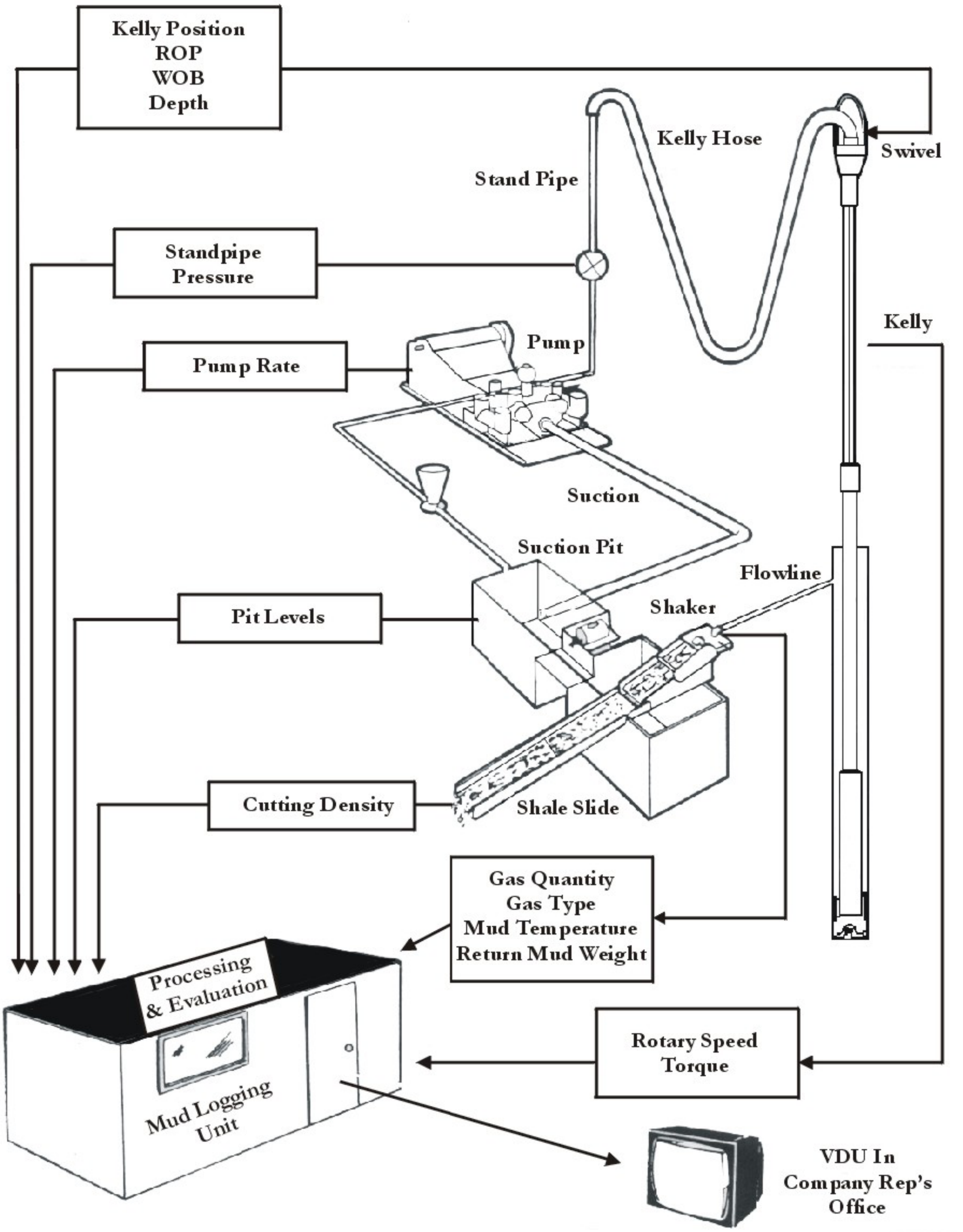


Figure 71 Mud Logging Equipment

16.5 Open Hole, Cased Hole & Production Logging

There are many forms of logging, with hundreds, perhaps thousands of tools and interpretation methods. Two distinct times when logging is performed are before and after casing has been installed in a well. Open hole is without the casing in the hole and Cased Hole, unsurprisingly is when the well has casing in it. The steel pipe obviously has an effect on the way tools react with the formation fluids and rocks, so different logging methods need to be employed. In addition, quite often the casing itself needs to be measured, to see how deep it is, if it has been damaged and what direction it is lying in. Production logging is used during the production phase of the well to determine its producing characteristics – pressure, temperature, flow, gas, oil and water constituents.

16.6 Wireline

Wireline is a common service performed on most if not all oil and gas wells, many offshore platforms will have a permanent wireline unit onboard. Wireline can be used to run various tools into a well for many, many purposes; including logging and mechanical intervention.

There are two basic types of wireline:

1. Slick Line
2. Electric Line – of which there are two main types
   a. Mono Conductor
   b. Multi conductor

Figure 72 Wireline Container

16.6.1 Slick Line

Slick line is a solid steel wire which can be used to mechanically run, operate, latch, open and close tools in a well. Logging can also be performed with slick line using either mechanical logging devices (callipers) or electronic devices with a memory capability. Slick line tends only to be run in cased hole.

Slick line tools are run into the hole from a winch and through a pressure barrier called a *'lubricator.'* Critical information being watched by the operator is *depth run* and *weight* on the wireline winch. Using only this information at the surface the skilled operator can perform any of the following functions:

- Opening and closing SSD
- Running and pulling SCSSV
- Tubing control
- Sand bailing
- Mechanical perforation
- Paraffin scratching
- Running / pulling plugs and gas lift valves…
- Swabbing
- Fishing
- Bottom hole pressure and temperature surveys

Figure 73 Onshore Wireline Unit

- Bottom hole sampling
- Memory production logging

16.6.2 Electric Wireline Services

Figure 74 Seven Conductor Cable

Electric line wireline is a highly technical service; it is used throughout the life of a well and can deliver precise, detailed information about a well. Electric wireline can be used in open hole or cased hole conditions.

Electric line may be single or seven conductor wireline. As you can imagine the power and data which can be transmitted through a 7 core cable far outweighs that which can be transmitted through a single core cable. However, single core electric line certainly has its uses. In addition to the electrical conductors, electric line cables have multiple strong cables which support the weight of the logging tools and provide external protection.

Three main groups of tool exist:

1. Electronic tools – measure induced and natural electrical properties
2. Acoustic/Sonic tools – measure the time it takes for sound waves to travel through a formation
3. Nuclear tools – measure naturally occurring or induced radiation

Using the many and various wireline tools available, electric wireline can collect all sorts of data from the well and perform many physical functions too including:

Physical Functions

- Perforating
- Downhole Tractor Services (horizontal wells)
- Plugs / Packer setting
-

Logging Functions

- Cement Bond Logging
- Production Logging – flow, temperature, pressure
- Calliper Surveys
- Porosity of the rock
- Rock type
- Hole size
- Hole deviation (direction)

- Hole Inclination (angle)
- Fluid Sample
- Formation Sample
- Gas Sample
- Hole Depth

Typical Logging terminology

- Sonic - sound emitting transmitters and receivers
- Bore Hole Imager 360°
- CBL- cement bond log
- Seismic
- Calliper
- Radio-active Neutron logs
- Gamma Ray log

16.7 Electric Logging

Electric logging tools measure natural and induced electrical properties of the formation.

16.7.1 Resistivity Logs

A resistively log will pass a current through the rock and will measure the resistance of the formation to the passage of current. This will, in an oil bearing zone, distinguish between the oil and the water, the latter having a much lower resistance than oil. It is possible then to determine the lower limit of the oil (the oil/water contact). It will tell us things about the rocks in the formation, about the porosity of the formation. How? Well sand is not conductive, so the more sand there is the higher the resistance will be.

The amount of water, the salinity of that water and its temperature will affect the resistivity. The mud used to drill the well, the amount of cake on the wall of the formation and the amount of oil; all have an affect on electrical flow resistance. No wonder computers are needed to sift through all of the logging data and assess what's really down the well!

As technology developed and the demand for more accurate data increased, logging tools became more **focussed.** These tools direct the electrical current directly into the formation as required; which removes much of the inaccuracy caused by muds. The logging tool sends out its signal in a disc like manner, specifically in the formation to be assessed. In addition these tools can penetrate deeper into the formation giving even more data to the reservoir engineer.

16.7.2 Spontaneous Potential (SP) Logs

SP logs measure the natural electrical current generated inside the formation. All rock formations generate some current and with SP logging analysts can detect permeable beds; locate boundaries between beds; obtain an accurate value for formation water resistivity. The reason behind this analysis is that SP logs show quite different results near impermeable shales compared with permeable rocks.

16.7.3 Induction Logs

Induction logs measure the opposite of resistivity logs; conductivity of the formation. They can reduce the influence of the column of mud around the area being surveyed and also give a reading of resistivity as well. They can assess deeper into the formation and also be more focussed.

16.7.4 Calliper Logs

Calliper logs are used to assess the hole size and geometry. Mechanical arms initially held into the tool as it is run to the bottom of the well are then released and held out by spring tension. They press against the walls of the hole as the tool is withdrawn and the arms deflect as the hole size changes. As you can imagine, the more arms on a tool like this the more accurate the picture of the well internals. Knowing the diameter and ovality of a well can assist with packer setting, with cementing volumes and assessing the amount and therefore the effect of mud cake.

Mechanical callipers can be used on slick line also.

16.7.5 Dipmeter Surveying

This logging uses focussed electrical resistivity surveys from a number of electrodes to assess the angle of the formation. Using this reservoir engineers can assess and find folds and faults, formation angles and the best position for more appraisal wells.

16.8 Acoustic Logs

Acoustic logs use sound waves to measure characteristics of the formation and its contents.

Ultrasonic sound is use to measure these features. For example ultrasonic sound in sand or quartz has an expected transit speed of 55.5 microseconds per foot whilst in water 189 microseconds per foot. Therefore if you know that a particular sandstone formation contains water you can determine the porosity of that formation by measuring the speed in which these waves travel.

Ultrasonic sound travels slowest in shale, faster in sandstone and fastest in limestone; so even from this basic knowledge and acoustic log can tell us quite a lot about the rocks we are surveying. In addition sound travels at different speeds through water, oil, methane, air, mud etc. If we know this information and can correlate the acoustic log records with other formation data already recovered, we can begin to build up a clearer picture of the reservoir.

Not usually a problem, but worth remembering – acoustic logs can only be accurately taken when the hole is filled with mud and there is no gas contained within the mud.

16.8.1 Cement Bond Log

Acoustic can also be used to measure the effectiveness of a cement job. A Cement Bond Log or CBL is a common survey run. It will tell the drilling supervisor if the casing has been cemented properly, if there are any gaps and possible paths for one formation to leak into another. He can also tell where the top of the cement is.

16.9 Nuclear Logging

16.9.1 Gamma Ray Log

A gamma ray tool may be used to measure the amount of radiation that is emitted from the formations. All sedimentary rocks contain some radioactive material and we know that they concentrate in shales and clays. Sand usually has low levels of radioactive material – although this is not always the case. Uranium, potassium and thorium are the elements which usually account for the gamma radiation in formations and we know that thorium and potassium are usually contained in shales. Therefore the development of a new tool the **natural gamma ray spectrometry log** has given us even more accurate information: This tool can detect the type of radiation given out by these individual elements and therefore create a much clearer log, defining shales and clays.

These types of log are very useful for determining the varying strata inside a well and across a formation (from well to well).

16.9.2 Neutron Log

A neutron logging tool emits neutrons which bombard the formation. What analysts are looking for is the amount of radioactivity coming back. Hydrogen tends to get in the way of neutrons and therefore the more hydrogen present the less radioactivity coming back. Because oil and water contain hydrogen, the more oil and water there is present, the less radioactivity. So if a lot of gas is present, there will be more radioactivity received. Shales do have an effect on the neutron log, so a prior gamma ray log can determine where the shale is and hence eliminate (or reduce) its effect on the results.

16.9.3 Density Log

Only used in open hole logging, the density log measure the density of the formation rock. Rock which is highly porous is less dense and therefore absorbs less of the gamma radiation which is directed into it. It is only used in open hoe situations because the tool needs to be pressed up against the wall of the well.

16.10 A Plethora of Tools and Terminology

Each service company which provides well logging services has a range of tools which fall into each category of type. For marketing reasons each tool and each derivation gets a new name. With various mergers and acquisitions over the years; there are now literally hundreds of well logging tools available. What follows is a selection of logging tools, systems and acronyms from Baker Atlas

16.10.1 List of Logging Tool Mnemonics – from only ONE company

```
TOOL DESCRIPTION
---- -----------
3VSP 3-AXIS GEOPHONE
4CAL 4 ARM CALIPER
AC   ACOUSTIC LOG
AGN  AIRGUN
AP   AUTOMATIC DIFF PRSSR VALVE
BAL  BOND ATTENUATION LOG
BPS  FMT BYPASS SUB
BRDL CABLEHEAD WITH 85 FEET OF BRIDLE MATERIAL AND SP ELECTRODE
CAL  CALIPER
CBIL CIRCUMFERENTIAL BOREHOLE IMAGING LOG
CBL  CEMENT BOND LOG
CCL  CASING COLLAR LOCATOR
CDB  DUMP BAILER
CDL  COMPENSATED DENSITY LOG
CENT CENTRALIZER
CH   CABLEHEAD WITH SP ELECTRODE BUTTON
CHL  CHLORINE LOGGING TOOL
CHTS CABLEHEAD TENSION MEASUREMENT
CMI  COMPACTION MONITORING INSTRUMENT
CN   COMPENSATED NEUTRON LOG
CO   CARBON/OXYGEN LOG
DAC  DIGITAL ARRAY ACOUSTILOG LOG
DAL  DIGITAL ACOUSTIC LOG
DCEN DE-CENTRALIZER
DEL2 200MHz DIELECTRIC LOG
DEL4 47MHz DIELECTRIC LOG
DEN  NON-COMPENSATED DENSITY LOG
DFS  DISPLACEMENT FLUID SAMPLER
DHPA DOWNHOLE POWER ADAPTOR
DIFL DUAL INDUCTION FOCUS LOG
DIP  DIPLOG
DLL  DUAL LATEROLOG
DMAG DIGITAL MAGNELOG
DPIL DUAL PHASE INDUCTION LOG
DSL  DIGITAL SPECTRALOG
DVRT DIGITAL VERTILOG
FCON WELLBORE FLUID CONDUCTIVITY (SALINITY) LOG
FDDP FLUID DENSITY FROM DIFFERENTIAL PRESSURE LOG
FDN  FLUID DENSITY LOG
FMCS FLOWMETER - CONTINUOUS SPINNER
FMFI FLOWMETER - FOLDING IMPELLER
FMT  FORMATION MULTI-TESTER
FPI  FREE POINT INDICATOR (PIPE RECOVERY)
FS   BOREHOLE FLUID SAMPLER
GP   GRAVEL PACK (SHAKER)
GR   GAMMA RAY LOG
GRC  PRESSURE (GRC STRAIN GAUGE)
GRN  GAMMA RAY/NEUTRON COMBINATION
HDIL HIGH DEFINITION INDUCTION LOG
HDIP 6-ARM (HEX) DIPLOG
HDLL HIGH DEFINITION LATEROLOG
HP   PRESSURE (HP QUARTZ GAUGE)
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HOIS SURFACE SYSTEM PANEL (HOIST/DEPTH)
HTD HIGH TEMPERATURE DENSITY LOG
HYDL HYDROLOG
IEL INDUCTION ELECTROLOG
ISSB MASS-ISOLATION JOINT
JBSK JUNK BASKET
KNJT KNUCKLE JOINT
LL3 LATERALOG (3 ELECTRODE)
M5M7 CROSSOVER POINT FOR M5 TO M7 OR M7 TO M5
MAC MULTIPLE ARRAY ACOUSTIC LOG
MAC2 MULTIPLE ARRAY ACOUSTIC LOG
MAG MAGNELOG (ANALOG)
MCFM MULTI-CAPACITANCE FLOW METER
MFC MULTI-FINGER CALIPER
MFP CONTINUOUS MAGNETIC FREE POINT SENSOR
ML MINILOG
MLL MICRLATEROLOG
MRIL MAGNETIC RESONANCE IMAGING LOG
MSI MULTIPARAMETER SPECROSCOPY INSTRUMENT
MSL MICRO SPHERICAL LATEROLOG WITH CALIPER
MST HEAVY-WALLED DRILL PIPE SEVERING WITH SYNCHRONIZED DETONATION
NEU SINGLE DETECTOR NEUTRON
NFL TRACER/FLO-LOG
NIR NEAR INFARED INSTRUMENT
NLL NEUTRON LIFETIME LOG
NO NUCLEAR ORIENTATOR
ORIT ORIENTATION LOG
PDK PULSE/DECAY PULSED NEUTRON LOG
PFC PERFORATING FORMATION CORRELATION LOG
PHT PHOTON LOG
PNHI PULSED NEUTRON HOLDUP INDICATOR
POS POWERED ORIENTAION SWIVEL
PROX PROXIMITY LOG
PRSM PRISM LOG (MULTIPLE ISOTOPE TRACING)
RCI RESERVOIR CHARACTERIZATION INSTRUMENT
RCOR ROTARY SIDEWALL CORING TOOL
ROLR ROLLER BODY
RPL PANEX PRESSURE GAUGE
RPM MULTI-PURPOSE SMALL DIAMETER PULSED NEUTRON LOGGING INSTRUMENT
SBT SEGMENTED BOND TOOL
SG STRAIN GAUGE
SGEO SURFACE GEOPHONE
SJ SILVER JET PERFORATOR
SK SELECTKONE PERFORATOR
SL SPECTRALOG
SLAP SIMULTANEOUS LOGGING AND PERFORATING
SLKP SLIMKONE PERFORATOR
SNKB SINKER BAR
SON SONAN (NOISE LOG)
SPCR SPACER BAR
SPDK SPECTRAL PULSE/DECAY PULSED NEUTRON LOG
SPSB SP (SPONTANEOUS POTENTIAL) SUB
SRPL SURFACE RECORDED PRESSURE LOG
SSP SEMI-SELECT PERFORATOR
STAR SIMULTANEOUS ACOUSTIC-RESISTIVITY IMAGING LOG
STFP PIPE FREE POINT INDICATOR
SUB GYRO DATA INTERCONNECT
SUB AC/DC SWITCHING CIRCUIT TO RUN PHOTON & GRAVEL PACK IN COMBO.
SWC SIDEWALL CORGUN

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SWN  SIDEWALL NEUTRON
SWVL SWIVEL
TBFS THROUGH TUBING FLUID SAMPLER
TBRT THIN-BED RESISTIVITY LOG
TCAL THROUGH TUBING CALIPER
TCP  TUBING-CONVEYED PERFORATING
TCR  THROUGH CASING RESISTIVITY
TEMP TEMPERATURE LOG
TILT TRANSVERSE INDUCTION LOG
TMFP MAGNA-TECTOR FREE POINT INDICATOR
TPFM THERMAL PULSE FLOWMETER
TTRM TEMPERATURE, TENSION AND MUD RESISTIVITY SUB
VRT  VERTILOG
VSP  VERTICAL SEISMIC PROFILE
VTLN VERTILINE
WCAL BOWSPRING 6-ARM CALIPER
WESB SIDE ENTRY SUB FOR PIPE CONVEYED LOGGING
WHI  WATER HOLD-UP INDICATOR
WTS  WIRELINE TRANSMISSION SYSTEM DOWNHOLE TELEMETRY REPEATER
WTSP WIRELINE TRANSMISSION SYSTEM SURFACE PANEL
WTSS WIRELINE TRANSMISSION SYSTEM SWITCHING SUB
XMAC CROSS MULTIPOLE ARRAY ACOUSTILOG
ZDL  Z-DENSITY LOG
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16.10.2 Further Reading

Please refer to *'Staying Ahead of the Curve'*, a roundtable discussion, printed in Harts E&P magazine, for an overview of where well log analysts think logging technology is today and where the future lies.

16.11 Through Tubing Production Logging

Through-tubing Production Logging refers to logs run after the production string casing has been cemented and the well placed on production. Measurements are made under dynamic as well as static conditions.

Surface liquid measurements are usually not adequate to determine the efficiency of the downhole production or injection system. In many wells downhole malfunctions, related to mechanical problems or communication problems, may reduce the ultimate recovery from the reservoir.

Production logs have application in three major areas:

1. diagnosis of mechanical problems
2. analysis of individual well performance in relation to the reservoir (perhaps most important from the standpoint of recovery)
3. Management of reservoir fluids.

Major questions which can be addressed to Production Logs are:

- Mechanical Condition of the Well.
- Are there casing, tubing or packer leaks?
- Is there internal or external corrosion damage?

- Anomalous Fluid in Movements between Zones.
- Is there flow behind casing through inadequate primary cementing?
- Is flow from inside casing moving into thief zones?
- Evaluation of Completion Efficiency (Producing Well).
- Are some zones not contributing?
- Are some zones only contributing gas – or only water?
- Are contributing zones producing up to the potential shown by other data sources?
- Evaluation of Completion Efficiency (Injection Well).
- Where is injected fluid going?
- How much into each zone?
- Design and Evaluation of Stimulation Treatment.
- Which zones need to be stimulated?
- Where did stimulation fluids go?
- Did stimulation achieve the desired result?
- Reservoir Management
- What are initial fluid saturations in each zone?
- What fluid saturation changes have occurred, due to production or extraneous fluid movement?
- Is the reservoir being depleted in the desired manner?

Confident answers to these questions require careful design and application of Production Logging techniques. Usually more than one logging device or measurement is required. For producing wells, the combination of radioactive devices to evaluated fluid type and saturations behind casing, flow devices and fluid differentiation devices to evaluate fluids and fluid movements inside casing, can provide most of the clues needed to effectively deplete all hydrocarbons zones penetrated by the well. For flow behind the casing, the combination of temperature and noise measurements usually provides optimum definition. Data from all available sources must be considered to provide most effective diagnosis – correlated logs.

16.11.1 Downhole Measurements

There is no lack of measurements that can be made downhole, each providing clues aiding problem diagnosis. These measurements are outlined as follows.

Temperature is a simple economic measurement and is affected by many factors associated with problems both inside and outside casing. Measurements can be recorded in various manners:

- Temperature at a particular level
- Temperature at various points around casing circumference at a particular level
- Temperature change with time at a particular level
- Temperature change with depth
- Rate of temperature change with depth

Temperature inside the tubing or casing is relative to the temperature and characteristics of the flowing hydrocarbon and the way heat travels around in fluids.

Pressure measurements are simple and can also be recorded in several manners. With the well flowing, pressure change with time at a particular level indicates stability of flow conditions. Pressure change with depth (pressure gradient) indicates *'fluid density'.*

Fluid Density can also be measured by a radioactive device through gamma ray absorption. Density can distinguish between the amount of water, oil and gas at a particular level in the well-bore at a given instance.

Fluid Velocity within the well-bore is often an interesting measurement related to flow entering or leaving the casing. Velocity can be measured with a **spinner** – there are many physical properties and occurrences which may effect the accuracy of a spinner; but nevertheless it is a useful device.

Fluid velocity can also be measured by injecting a radioactive tracer in the flow stream and recording the time to move a particular distance. Problems involve knowing when the tracer actually passes the detector and that it actually moves with the fluid. However, at low flow rates, tracer measurements of velocity may be better than spinner measurements.

Increased radioactivity at a particular depth compared with a base log indicates movement of radioactive fluid or solids into the zone. Radioactive cement or sand grains can show the position of the cement or frac sand after a treatment.

Audible noise level and frequency patterns in the wellbore caused by movement of fluid inside or outside the casing can be used to establish the presence of flow, the path of the flow, what fluid phases are involved and to a degree, the flow rate.

Sound transmission characteristics form a wellbore transmitter to a nearby receiver provides information as to acoustic coupling between the cement and the casing, and the cement and the formation. Under favourable conditions, these characteristics may be related to the possibility of fluid movement between zones outside the casing.

Electrical properties (i.e. conductivity or dielectric constant) usually differ significantly between hydrocarbons and water. Thus they may be used to determine relative amounts of these fluids at a particular level in the wellbore. These measurements are more definitive as low water percentages, and where the fluids are intimately mixed. Again the relative amounts of fluids residing at a particular level are not necessarily the same as the relative amounts of the fluids passing that level.

Logging Devices

Most through-tubing logging devices operate on an electric line and record at the surface.

Most significant through-tubing tools are:

- Temperature devices
- Spinner flow meters
- Gradio-manometer or radioactive density devices
- Noise device
- Pulsed neutron devices
- Gamma ray-neutron devices
- Bottom-hole pressure device

Invariably production logging devices are measuring parameters that do not give concrete answers to specific questions – but give clues indirectly related to these questions –thus, the problem of the production logger is to put enough clues together from every source available to develop answers having an acceptable confidence level. Experience with specific devices in specific areas is an important factor in effective analysis.

Production logging interpretation many times depends on measurement of small differences; thus tool operational characteristics and limitations must be known and must be a constant consideration during the logging and interpretation process. The following brief discussions of typical tools are intended primarily to provide background.

16.12 Coring

This method consists of taking much larger samples of formation material (cores) from the bottom of the hole and/or the sidewalls of the hole. The samples are brought to the surface and particles of the material are extracted from the cores, treated and tested under laboratory conditions to determine porosity, permeability and the amount of water or oil in the core. This process can take a few days to carry out and may increase costs if drilling is suspended pending the results

16.13 Fluid Sampling

It is extremely helpful if fluid samples can be obtained from the formation of interest but again to be useful, they must be representative of the fluid at reservoir conditions. Many types of down hole sampling tools have been developed to trap an oil sample above the reservoir. This means that the oil will contain the correct percentage of molecules which exist in the oil producing rock.

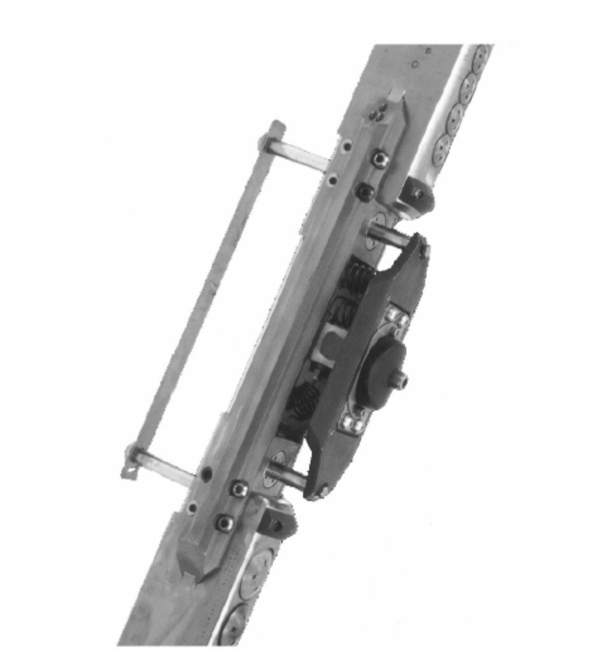


Figure 75 Typical Repeat Formation Sample Tool

These are just a few of the logging operations that can be found in the drilling industry today.

16.14 LWD / MWD

Not all logging has to be done via the wire line method – an operation that interrupts the drilling operation and costs time and money. **Logging While Drilling** and **Measuring While Drilling - LWD** and **MWD are** now very successful and technically advanced. These tools are placed in the **drill string and** pass information back to the surface via the mud. How? Pressure devices which react relative to the measurements taken give out pulses, which travel through the mud as waves of energy. Although small, these pulses can be coded to give readings at the surface which ay relate to any collected data at the drill bit.

The data is collected and processed to give real time data without interrupting the drilling program. The MWD tool is an in-line drill collar that records at-the-bit drilling parameters and transmits the drilling data (as well as data from other LWD tools) to the surface in real-time. MWD measurements include **Weight On Bit (WOB)**, **Rate Of Penetration (ROP)**, torque, and pressure. The measurement of down hole weight and torque on the bit to help the driller maintain optimal weight on bit or torque and improve the penetration rate. Of course one of the real benefits of MWD is in directional drilling so that accurate data about drill bit location and orientation can be fed back to the driller – real time.

Logging While Drilling tools use the same transmission technology to transmit all manner of logging information.

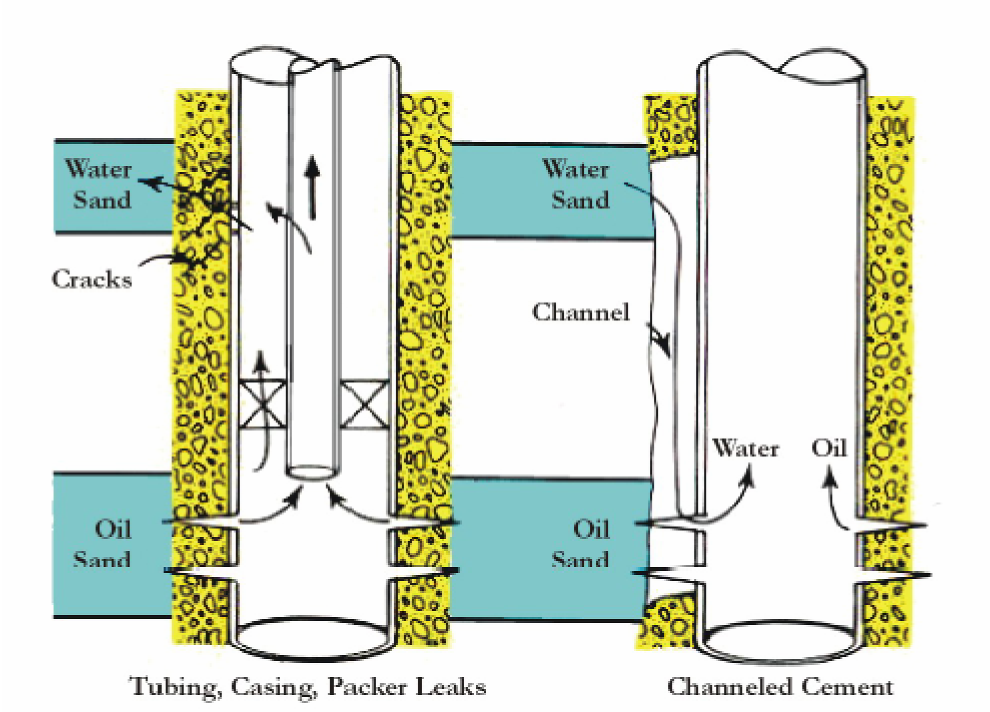


Figure 76 Well problems found with logging

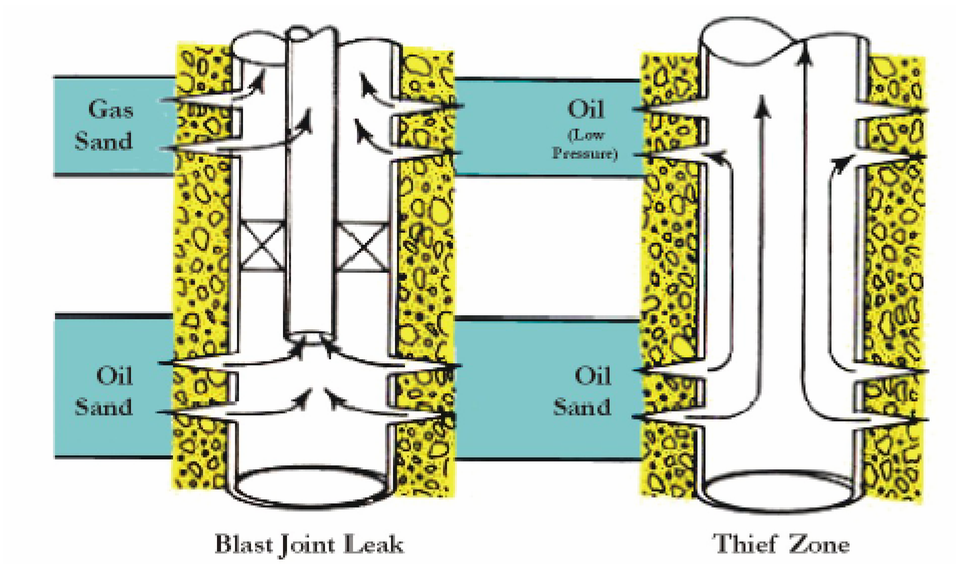


Figure 77 more problems found by logging

16.15 Camera Images

Technology is available today to allow us to view live pictures of the inside of the wellbore; in fact we have been doing this for some time. Getting good quality pictures back to the surface has been difficult in the past due to signal transmission, however technology is developing fast.

Figure 78 Subsea well head sea area

'DHV' now owned by Expro, provides the *'Hawkeye'* camera system which provides B&W pictures to surface.

EV Offshore, can provide shallow well colour images of equipment down to about SSSV depth.

One major limitation on all camera systems is the fluid in the well – if it is dirty brine or heavy mud, then it may be impossible for the camera to view the subject. The well must be cleaned up in order to provide good images.

17 Well Production

In an oil reservoir, primary production results from the utilization of existing pressure. Basically, there are three drive mechanisms: dissolved gas, gas cap and water drive; however, as a practical matter most reservoirs produce through some combination of each mechanism.

The effect of the reservoir drive mechanism on producing well characteristics must be taken into account in making well completions initially, and later in re-completing wells to systematically recover reservoir hydrocarbons.

17.1 Dissolved Gas Drive

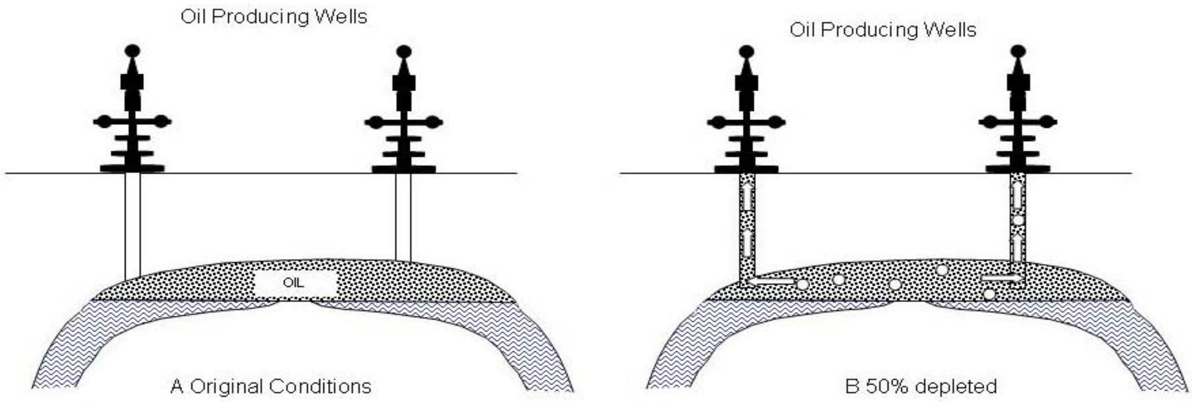


Figure 79 Dissolved Gas Drive Reservoir

In a **dissolved gas drive** reservoir, the source of pressure is principally the liberation and expansion of gas from the oil as pressure is reduced.

In a dissolved gas drive reservoir, (with no attempt to maintain pressure by fluid injection) pressure declines rapidly; the gas comes out of solution and pushes the oil up the tubing to surface. The gas-oil ratio peaks rapidly, and then declines rapidly. Therefore primary oil recovery is relatively low.

Primary recovery is where nothing is done to boost production by other means, such as gas or water injection. The **primary** force to drive out the hydrocarbon is from within the reservoir itself.

17.2 Gas Cap Drive

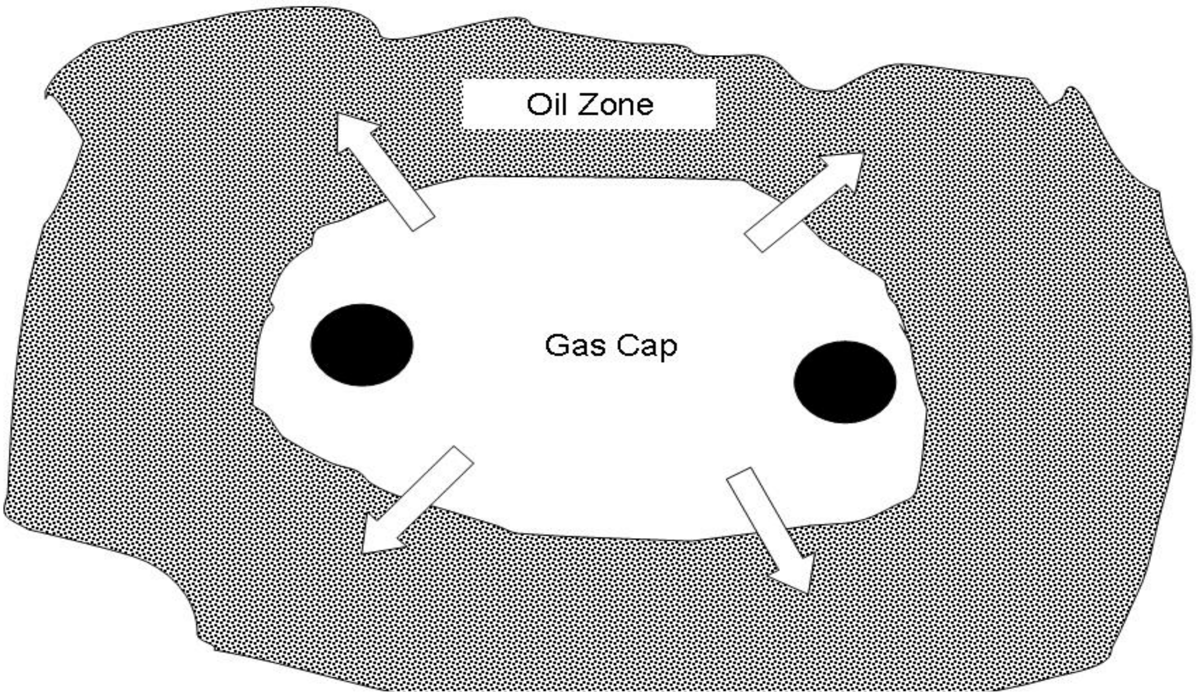


Figure 80 Gas Cap Drive Reservoir

A **gas-drive** reservoir uses principally the expansion of a cap of free gas over the oil zone.

In a gas-cap drive reservoir, pressure declines less rapidly, generally there is a larger volume of gas available than in a dissolved gas reservoir.

17.3 Water Drive

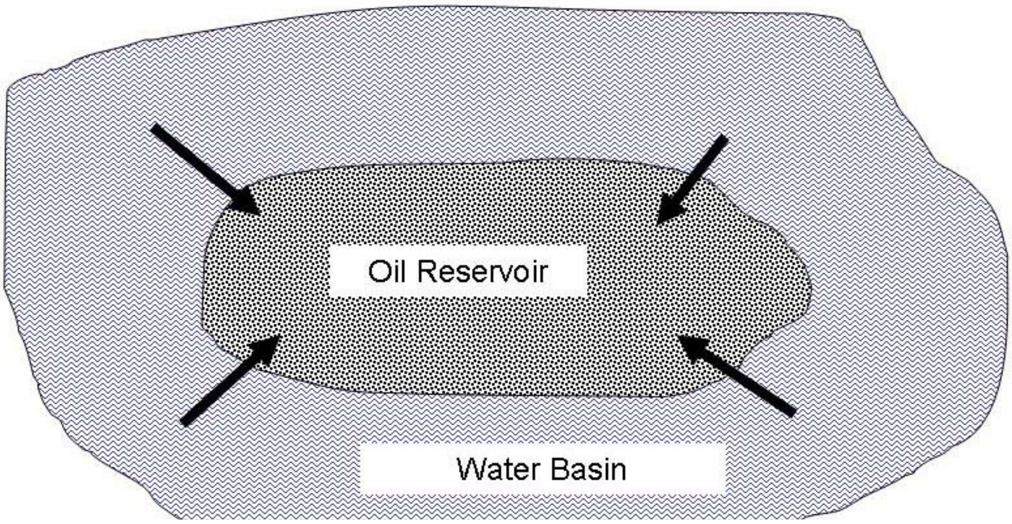


Figure 81 Water Drive Reservoir

A **water drive** uses principally expansion or influx of water form outside and below the reservoir.

In a water drive reservoir, pressure **remains** relatively high. Gas-oil ratios are low; but wells which reach further down the reservoir soon begin to produce water. This must be controlled be re-completion or shutting in of these wells. Re-completion is where the design of the well bore tubing and devices is altered so that water is not produced – generally this involves re-perforating further up the well bore, possibly the use of packers, perhaps running a new liner. Eventually with water drive reservoirs even wells which produce from higher up the formation must produce significant amounts of water in order to maximise oil recovery; because the two liquids are mixed.

17.4 Well Location

Obviously many factors must be considered in developing a reservoir, however, the main factors deal with the reservoir itself and the procedures used in exploitation. Well spacing, or better, well location, is one important factor. Money, time, labour, and materials consumed in drilling wells are largely non-recoverable. Therefore, if development drilling proceeds before the drive mechanism is correctly identified the investment may be wasted. For example, wells could produce water earlier than expected. Down hole pump systems may be required which hadn't previously been considered in well design.

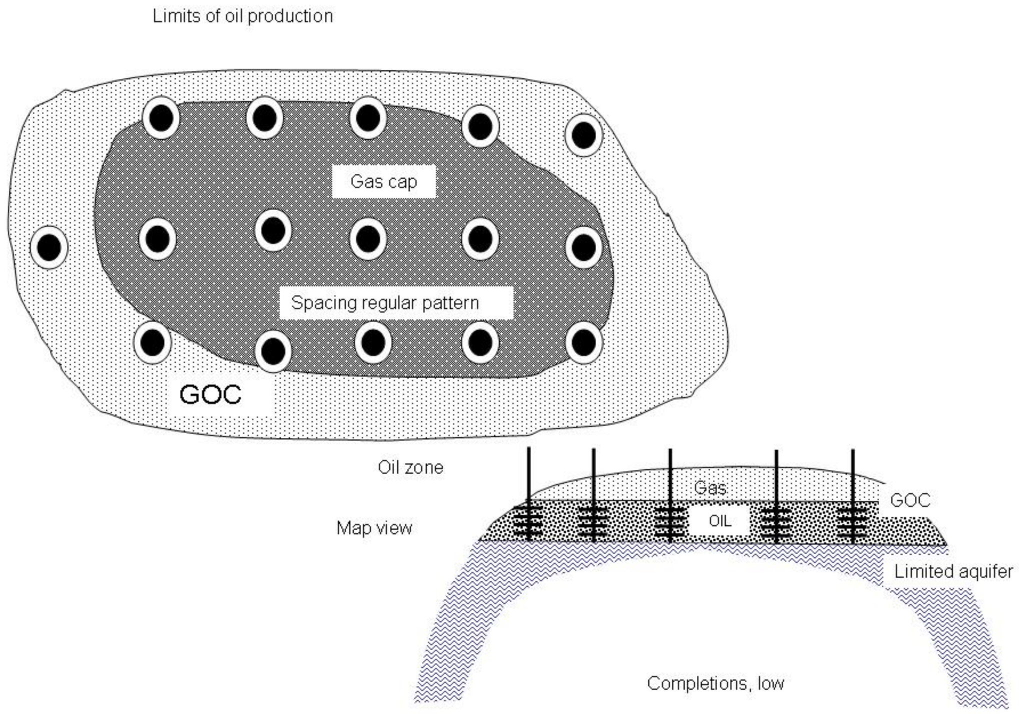


Figure 82 Gas Cap Drive, Low Dip Angle

This does not present an impossible problem, even when the predominant drive cannot be determined early in development. A certain number of wells must be drilled in any event if the field is of an appreciable size. Enough wells are needed to define the reservoir – that is, to establish the detailed geophysical picture regarding zone continuity and to locate oil-water and gas-oil contacts. Beyond this minimum, the number of infill wells and the well spacing can be varied in many instances.

The development programme should be based on reservoir considerations and conditions, rather than on surface conditions or on some arbitrary grid pattern. The development programme can be outlined schematically with subsurface stratigraphic cross-sections and a surface plan for well locations on the structure map. Detailed knowledge of the geology of the reservoir and its depositional environment is the key to an effective development plan.

Many case histories are available to show the problems resulting from reservoir development without sufficient consideration of the stratigraphy of the reservoir.

17.4.1 Dissolved Gas Well Location

Well completions in a dissolved-gas drive reservoir with low structural relief can be made in a regularly spaced pattern throughout the reservoir.

A regular spacing pattern could also be used for a dissolved-gas drive reservoir with a high angle of dip.

Again the completion intervals should be structurally low because of the angle of structural dip, and exact subsurface location would vary with well location on the structure. Here it is expected that the oil will drain down-structure in time so that higher than usual oil recovery will be realized with minimum investment in wells. The operator must recognise the reservoir situation soon enough to eliminate drilling the structurally high wells.

Due to low recovery by the primary mechanism, some means of secondary recovery will almost certainly be required at some point in the life of the reservoir. Initial well completions need to be designed with this in mind.

17.4.2 Gas Cap Well Location

Wells may be spaced on a regular pattern in a gas-cap drive reservoir where sand is thick, dip angle is low, and the gas-cap is completely underlain by oil.

Again, completions should be made low in the section to permit the gas cap to expand and drive oil down to the completion intervals for maximum recovery with minimum gas production.

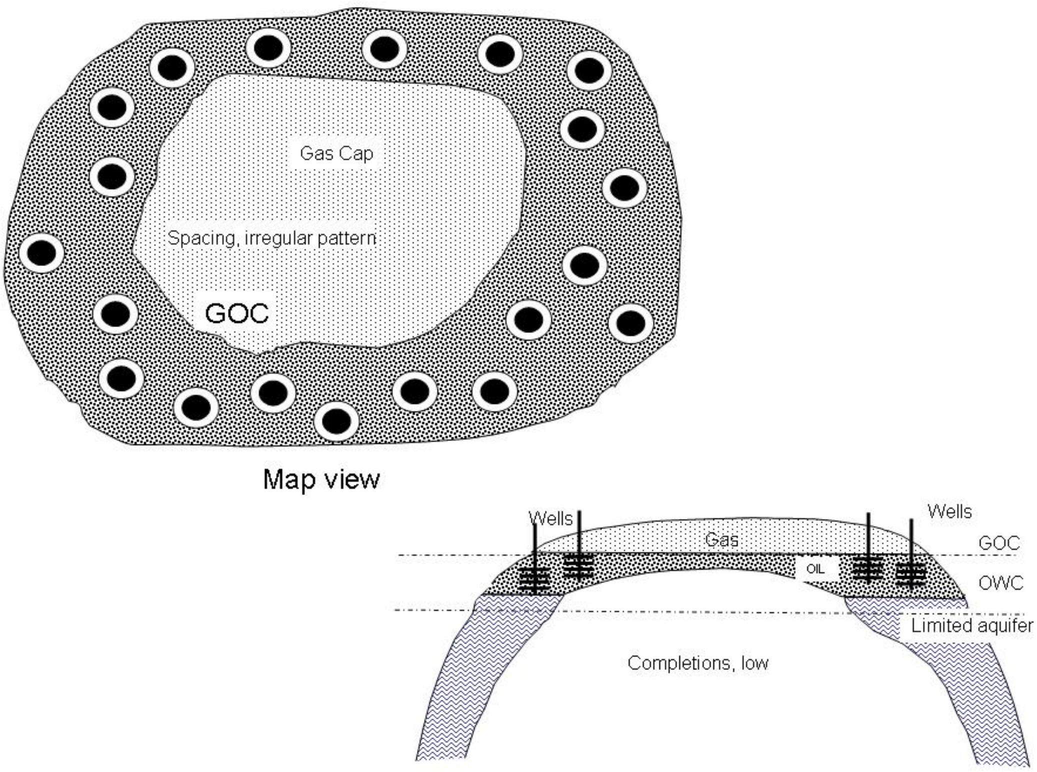


Figure 83 Gas Cap Drive, High Dip Angle

A gas-cap drive reservoir in thin sand with a high angle of dip is likely to be more efficiently controlled by having completion spaced irregularly but low on the structure to conform to the shape of the reservoir.

17.4.3 Water-Drive Well Location

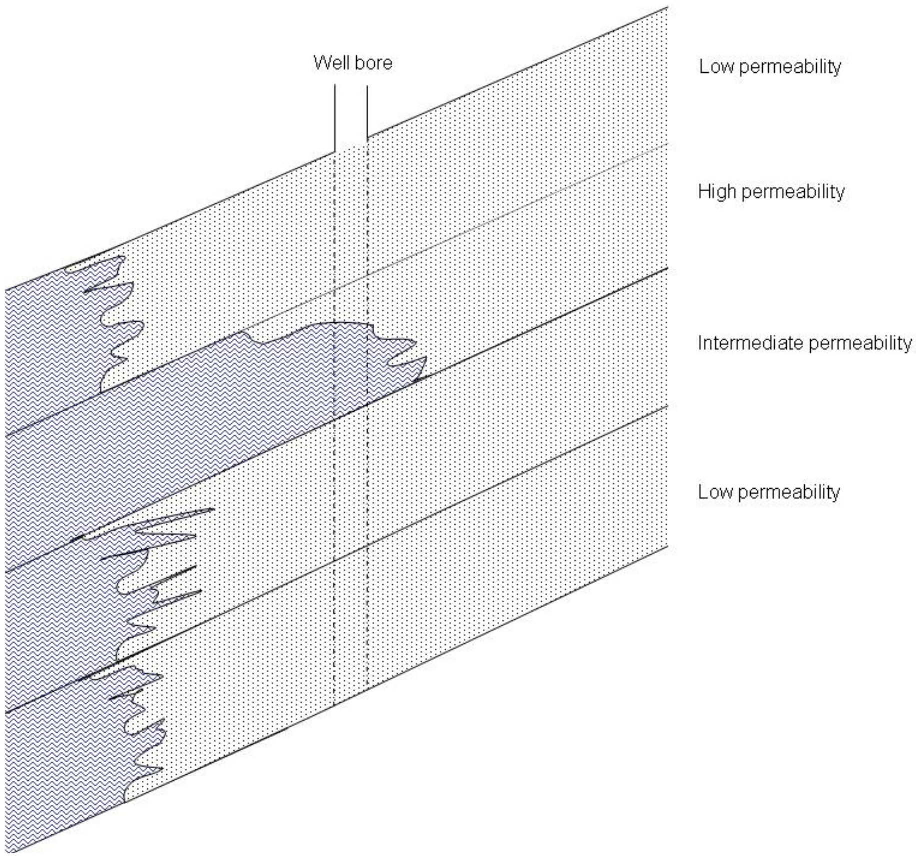


Figure 84 Water Breakthrough in High Permeability Rock

Completion intervals should be selected high on the structure to permit long producing life while oil is displaced up to the completion intervals by invading water from below.

The completions, should be made high on the structure to delay encroachment of water into the producing wells. Spotting the wells on a regular spacing pattern not only may cause a number of wells to produce water early in the life of the reservoir and result in their early abandonment, but also may reduce the effectiveness of the water-drive through excessive early water production. Fewer wells would then remain to produce the remainder of the oil, thus lengthening unnecessarily the length of time required to deplete the reservoir.

Significant amounts of water must be produced in the later life of the field in order to maximise recovery.

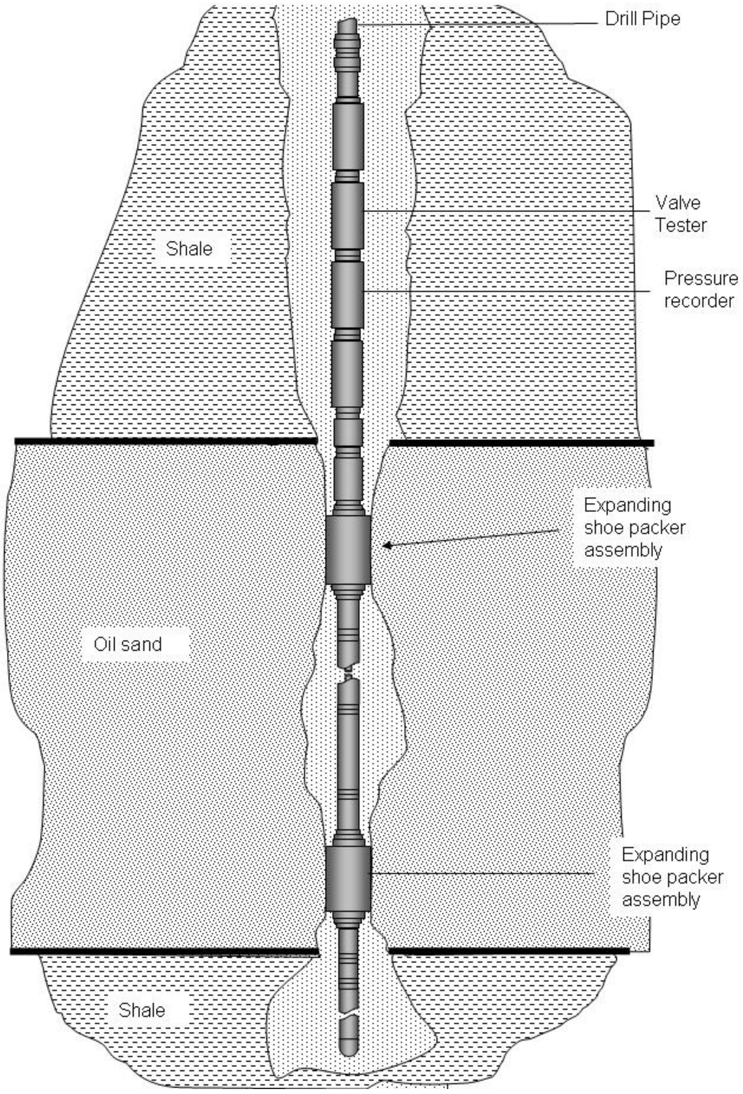
18 Well Testing

Well Testing is an important early analysis tool for newly drilled (Drill Stem Testing) or completed (Well Production Testing) wells.

Production tests help to determine flow rate and how much a well will produce; accuracy is very important as the data from these tests forms part of the case history of a well.

18.1 Drill Stem Testing

Drill stem testing (DST) provides a way of completing a well, temporarily, in order to obtain a clearer picture of the producing characteristics of a particular zone.



This tester is run on drill pipe in an open hole situation. A packer(s) is used to seal off the formation being tested from the mud column in the annulus – the drill pipe is usually run partly or completely empty to avoid contamination of the test sample and to encourage flow to begin (by reducing / removing the weight of fluid above the producing zone.

The DST assembly includes a valve which prevents mud entering the drill pipe while it is being lowered into the hole. Once the packers have been set, the control valve is opened from the surface and fluid can then flow from the isolated formation through the tester into the empty drill pipe.

The control valve may be opened and shut several times during a test in order to record how the pressure varies from flowing to shut-in conditions.

On some wells, the fluids may flow to surface and this may be down for several days in order to build up a clear picture of the conditions under which the well will flow and what effect these flowing conditions have on the reservoir (see Production Testing below).

18.2 Production Testing

Modern techniques and equipment for production testing can provide a wide range of information about the reservoir and its contents. For example:

- Reservoir pressures
- Effective permeability in the reservoir (in contrast to measurements on a core sample in the laboratory)
- Depletion effects – estimates of how the reservoir pressure will change with sustained production
- Indications of damage to the producing formation next to the wellbore and the resulting reduction in flow rate
- Detailed analytical information on reservoir fluids.

This is the most comprehensive way of establishing the production characteristics of a reservoir.

A production test is carried out after casing is set. Contact with the zone of interest is established by perforating the casing and the zone is then produced through a completion assembly and tubing. A production test may last for days or weeks.

18.3 Surface Test Equipment

For this operation, large amounts of surface equipment are required to flow the well through to clean up, test and measure, such things as well pressure, temperature, rates of flow and oil, water and gas content.

Once drilled a well is often tested, because despite the millions of pounds already spent finding, evaluating and drilling a well – it may not flow and certainly it may not flow at the rate projected.

On a drilling rig, surface test equipment is set up to monitor and control the flow of oil, gas and water from a particular well. Oil, gas and water have to be separated out and their respective flow rates measured and samples of each collected for analysis. The surface equipment which is required on the drilling vessel to carry out these various functions is discussed below.

It is important to note that on an exploration well, the amount of flow of each fluid will be unknown and every contingency has to be catered for if the test is to go ahead uninterrupted. E.g. there could be large amounts of water which flow unexpectedly, in this case water treatment equipment will need to be large enough to cope with this amount, or the production rate will have to be slowed or perhaps even the well shut in.

The following equipment will satisfy most requirements:

- Surface test tree with master valve, swab valve, two wing valves,
- Choke manifold with fixed and adjustable chokes and choke
- Data header with sufficient ports for pressure and temperature gauges, chemical injection, fluid sampling, ESD sensing.
- Temporary flow line to connect surface tree to choke manifold.
- Heater.
- Test separator. 3-phase (oil, gas and water).
- Chemical injection pumps for methanol or glycol.
- Gauge tank, atmospheric.
- Transfer pumps explosion proof motor.
- Temporary low pressure flow line.
- Oil manifold, gas manifold.
- Two burners with 60 ft flare booms.
- Air compressor.
- Emergency shut-down system (ESD) control manifold for wing valve actuator.

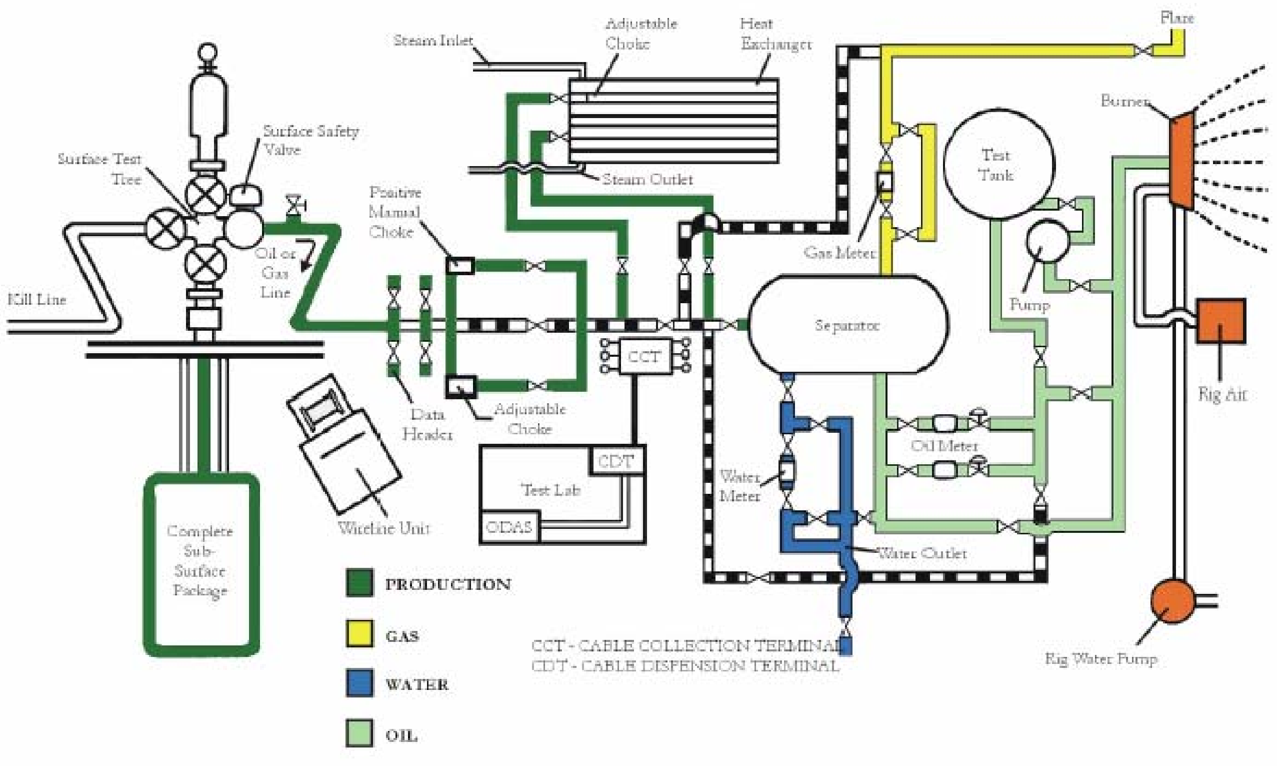


Figure 85 Typical Test Equipment

18.4 Potential Test

This is one of the most frequent tests done and measures the largest amount of oil and gas a well can produce over a 24hour period under certain fixed conditions. This is basically a test that involves allowing the well to flow over a given period of time, measuring and recording the production.

18.5 Bottom Hole Pressure Test

The build-up pressure of a well that has been shut in for a period of 24 to 48 hrs will reveal information about the decline or depletion of the producing zone and allow the reservoir engineer to calculate the most effective rate of flow for that well. This will prevent such things as formation damage, collapse or sanding up, for example.

18.6 Productivity Test

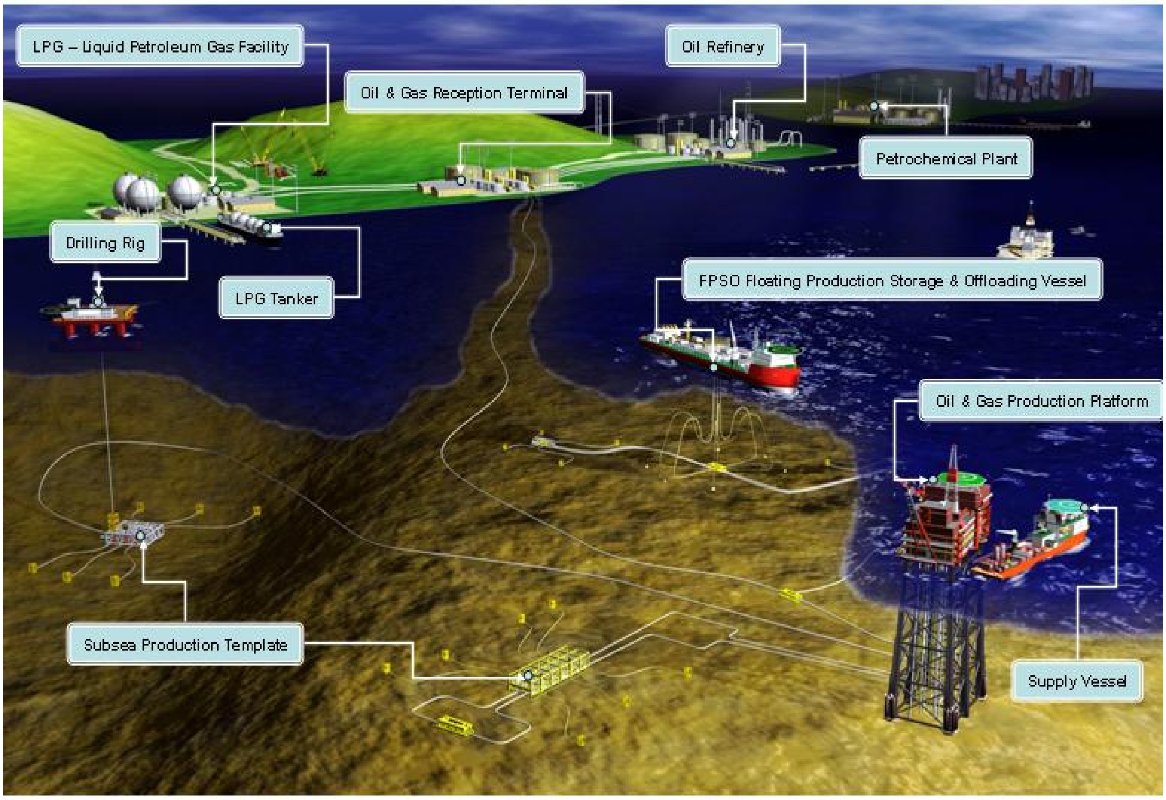
A productivity test is the combination of a potential test and bottom hole pressure test. Using different flow rates and assessing the effect on the pressure of the well can indicate the best production to use without damaging the life of the well.

Knowing the closed in well bottom hole pressure the well is then subjected to stepped inclines of flowing bottom hole rates. This is the most widely accepted method of determining the capacity of gas wells and can be used on both oil and gas production wells.

19 Basic Process Systems

Production varies from facility to facility. Some simple onshore wells are serviced only with a pipeline; some major offshore installations include gas dehydration, oil storage, gas re-compression, water injection and more. The production rate and total extractable volume of a well or a field, it's geographic location, the market, other transportation systems nearby, the produced quality of the hydrocarbon; all this and more will have an economic effect on the on-site production process facilities.

Some highly complex processing plant comprise miles of interconnecting pipe work, dozens of process vessels and a vast array of modern equipment instrumentation, and machinery. In addition, the site must have safety systems and might require utility systems such as heating and ventilation, fresh water and power to provide a safe and suitable habitat for personnel.



The following is a typical list of systems you might find onshore or offshore:

- Gathering system
- Separation system
- Oil treatment system
- Gas treatment system

- Oily water treatment and disposal system
- Water injection system
- Safety systems
- Utility systems

19.1 Gathering System

Both onshore and offshore fields require gathering systems these days. Prior to subsea completions being utilised, offshore fields contained all of the production wells onboard; but now subsea wells are utilised to extend the reach of new developments and maintain the economics of fields with declining production rates.

As the reservoir fluids reach the surface, having flowed up the tubing of the individual wells, the total production must be gathered together prior to being processed. In order to do this, each well must flow through a choke device which effectively controls the well pressure and effectively equalises all the well pressures as they flow into the production headers. Where artificial lift is employed, pressure control is less onerous because the pressures are generally quite low.

On offshore fields, the wellheads and Xmas Trees are located on the sea bed generally in groups on a template, and are known as Subsea Completions. The templates may be spaced some considerable distance apart. Onshore fields, depending on the country and area of location may have pipelines criss-crossing the ground in a seemingly un-controlled fashion, or may have pipelines buried and marked running from well to well. Whatever the law allows, these pipelines end up at a gathering system plant.

- At the gathering system plant (on High Pressure (HP) well systems):
- High pressure (HP) wells are routed to the high pressure header which directs the flow to the HP (first stage) separator.
- The medium pressure wells are directed into the medium pressure (MP) header and then to the second stage separator where the oil from these wells joins the outlet oil from the first stage separator.
- Any very low pressure (LP) wells will be directed into the atmospheric, (LP) separator together with the outlet oil from the HP and MP separators.

The interconnected pipe work of flow lines and headers is called the inlet manifold and it allows groups of wells or individual wells to be directed to the appropriate separation system. On offshore platforms, most of the wellheads will be grouped together on a particular deck level; if subsea wells are included in the flow, their production will come through a pipeline and riser to the same area.

19.2 Overview of the Oil, Gas, Water Processes

When the oil is produced, it comes out of the well usually with other fluids commingled – water and gas are the most common. The process system needs to separate these fluids to deliver high specification gas and oil for sale and clean water for disposal or re-injection into the formation. In order to do this a number of different process vessels (usually vertical or horizontal drums) will be required. In addition, some heat exchangers, pumps and valves will be needed to alter temperatures and pressures. The following diagram gives an overview of a typical process system for an oil, gas and water production system.

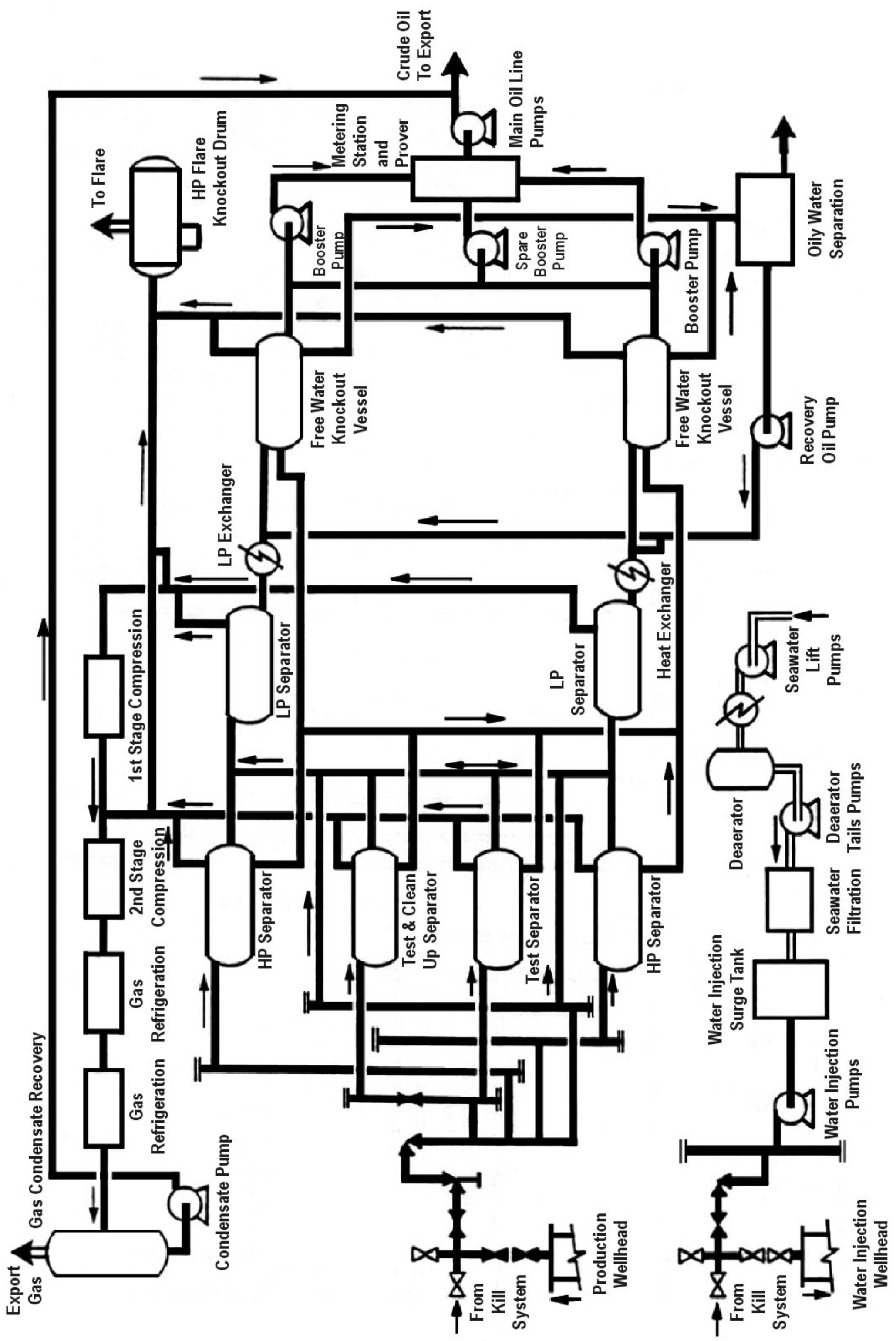


Figure 86 Typical Process System Overview

19.2.1 Heat

In order to aid separation, the crude oil stream is often directed through heaters to lower the viscosity of the oil and prevent freezing due to gas expansion. The heater exchangers often use steam or a heated fluid circulated around turbine exhausts to provide the heat source. A process system must be as energy efficient as possible and any waste heat from turbines or other sources will be put to good use.

19.2.2 Principles of Separation

The principle of separation relies on the fact that the oil, water and gas simply have different densities. Hence, if a sample of just produced crude oil was allowed to stand in a sealed beaker, the water, being the heaviest, would fall to the bottom; the oil would float on top of the water, and the gas, being the lightest, would occupy the space on top of the oil. Separation also requires a drop in pressure on the fluid to liberate the dissolved gas (in the same way that gas is liberated from a lemonade bottle when the top is removed) and that takes place over the HP, MP and LP separators where the pressure in each subsequent vessel is less. This is known as **stage separation** where the overall flow of fluid is from high pressure to low pressure under controlled conditions, and it is this action of reducing pressure on the oil over two or more stages which leads to efficient release of dissolved gas from the oil.

If complete separation was attempted in one stage (pressure drop) only, say from 30 bar (435 psi) to atmospheric pressure, with high flow rates, foaming would be uncontrollable due to the instantaneous release of gas and much liquid would carry over into the gas line (try shaking a bottle of lemonade before opening and see what happens); the separation would be very ineffective.

19.2.3 Separators

Separators are vessels in which the oil, water and gas are segregated from each other. They can be classified in two ways:

• According to the shape of the vessel, horizontal, vertical or spherical.

• According to the number of phases which are separated, that is, in a 2-phase separator the gas would be liberated from the liquid. In a 3-phase separator, gas would be liberated from liquid and the liquid separated into oil and water.

The separator provides the necessary space for liquid and gas phases to separate out and for the liquid to accumulate for a long enough period of time to liberate as much gas as possible at its operating pressure. This is known as the retention time.

The pressure in the separator is kept constant by a control valve on the gas outlet line and the oil and water levels also have automatic controls on their respective outlets. The separator is protected from overpressure by relief valves and liquid level and pressure level alarms.

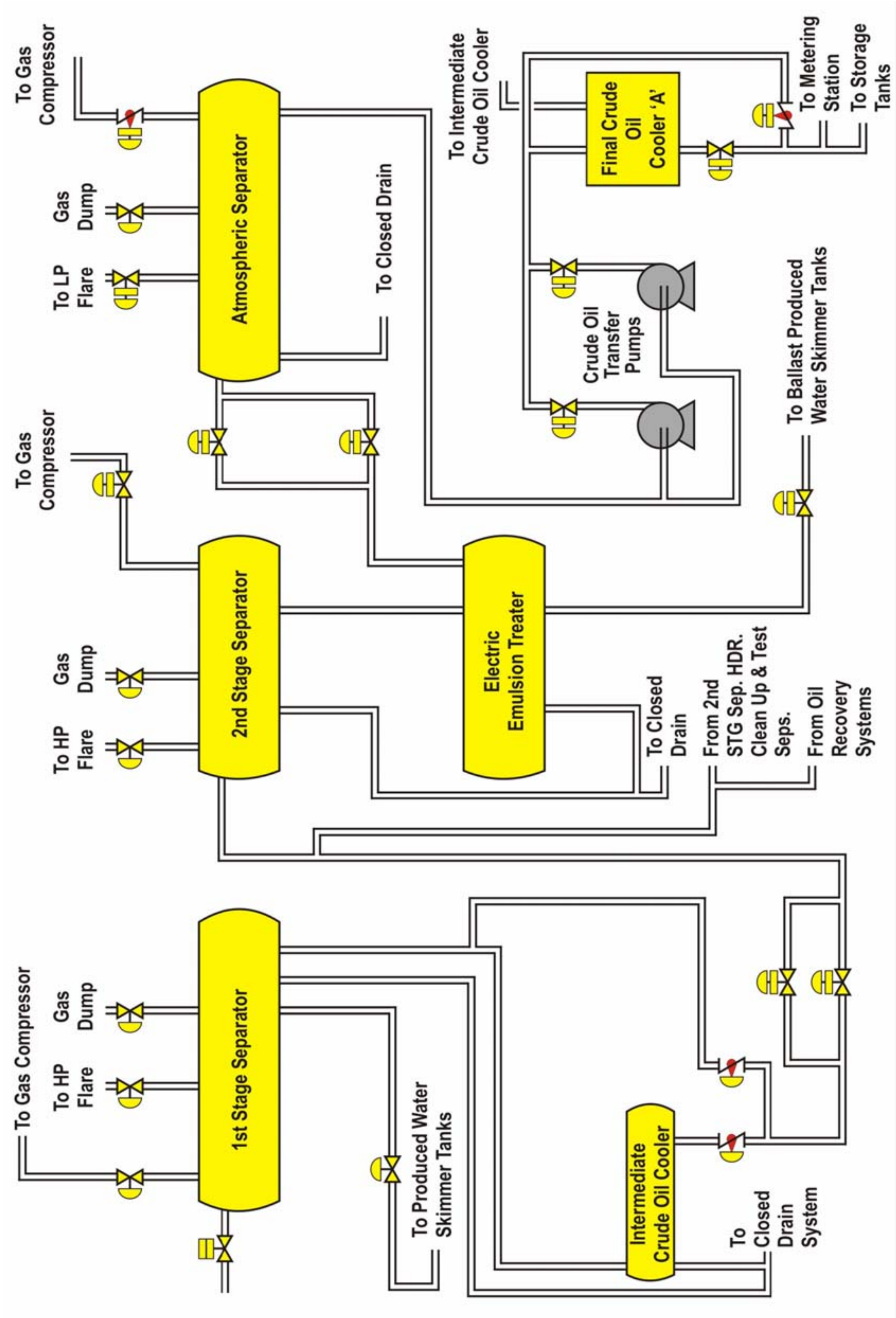


Figure 87 Typical Separation System

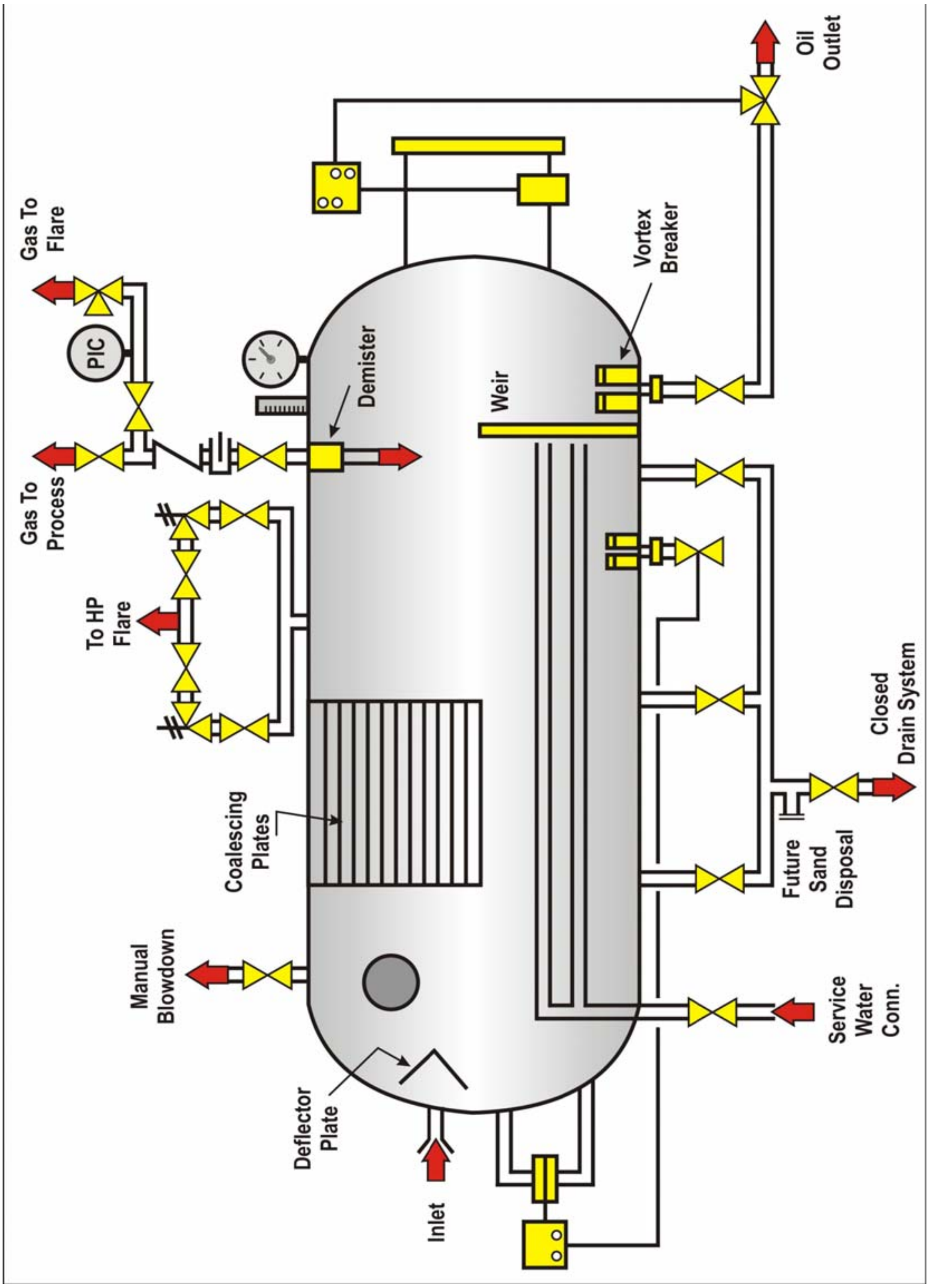


Figure 88 Typical Separator

19.3 Oil Treatment System

After separation, the oil is free from most of the dissolved gas; however, it may contain water in the form of an emulsion. This water comes from the formation and has a high salts content. If this water was left in the oil, it would reduce the efficiency of pipelines or tankers, cause corrosion and be unacceptable as feedstock in a refinery.

There are several ways of breaking down an emulsion and removing the water. Chemicals may be injected to break the emulsion by reducing the surface tension of the supporting fluid (just as washing up liquid helps to remove grease from dishes), or the oil may be passed through a treating vessel; which may use heat and a high electric potential voltage to do the job. The **electrostatic treater** polarises the water droplets which elongates them. This makes it easier for the droplets to collide, coalesce and drop out as free water.

19.4 Oil Metering

The oil is now free of water and gas and is ready for exporting to the tanker, pipeline or other system. On certain offshore platforms (principally concrete gravity structures) and FPSOs (Floating Production Storage and Offloading), the oil may be temporarily stored prior to export in large tanks.

When the time for export arrives, the volume of oil being exported must be carefully measured. The main reason for this is a legal requirement, since all Governments impose taxes on the amount of oil sold. A second reason is that operators may share export facilities, such as a pipeline, and individual operators need to know how much oil they are putting into a pipeline.

The meters themselves are either turbine meters or orifice meters and are housed in individual metering streams. The streams may be connected together with common inlet and outlet manifolds to permit large quantities of fluid to be metered. Metering is not just a measurement of flow, for it must take into account pressure, temperature and density as well.

Having been metered, the oil can now be exported. The pumps used for this can be driven either by an electric motor or by a turbine and may be reciprocating or centrifugal types. Pumps are controlled by instrumentation which senses the level in the final process vessel so that if the wells are shut in for any reason the pumps will sense a drop in liquid level and shut down or go into a recycle mode.

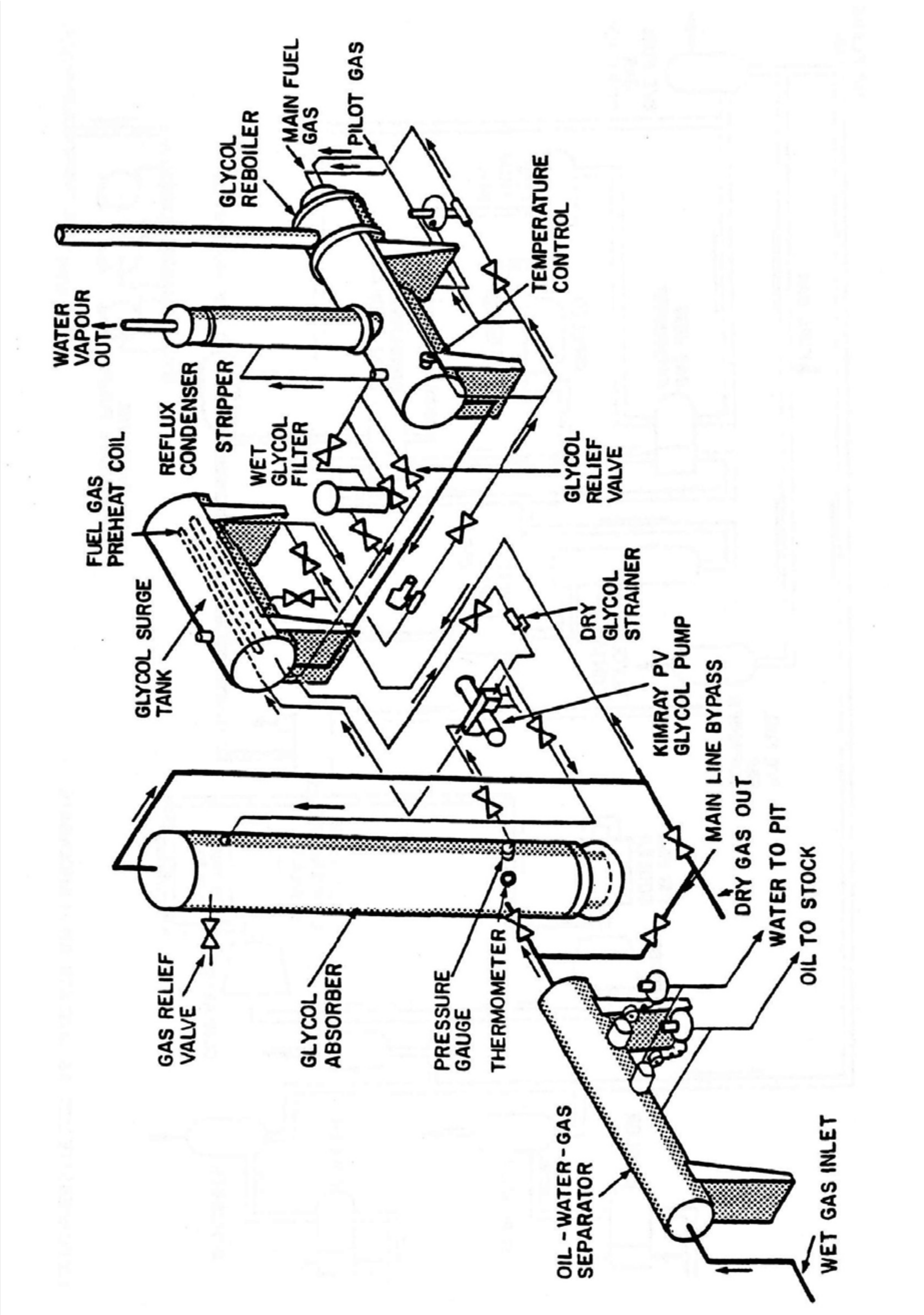


Figure 89 Typical Gas Dehydration System

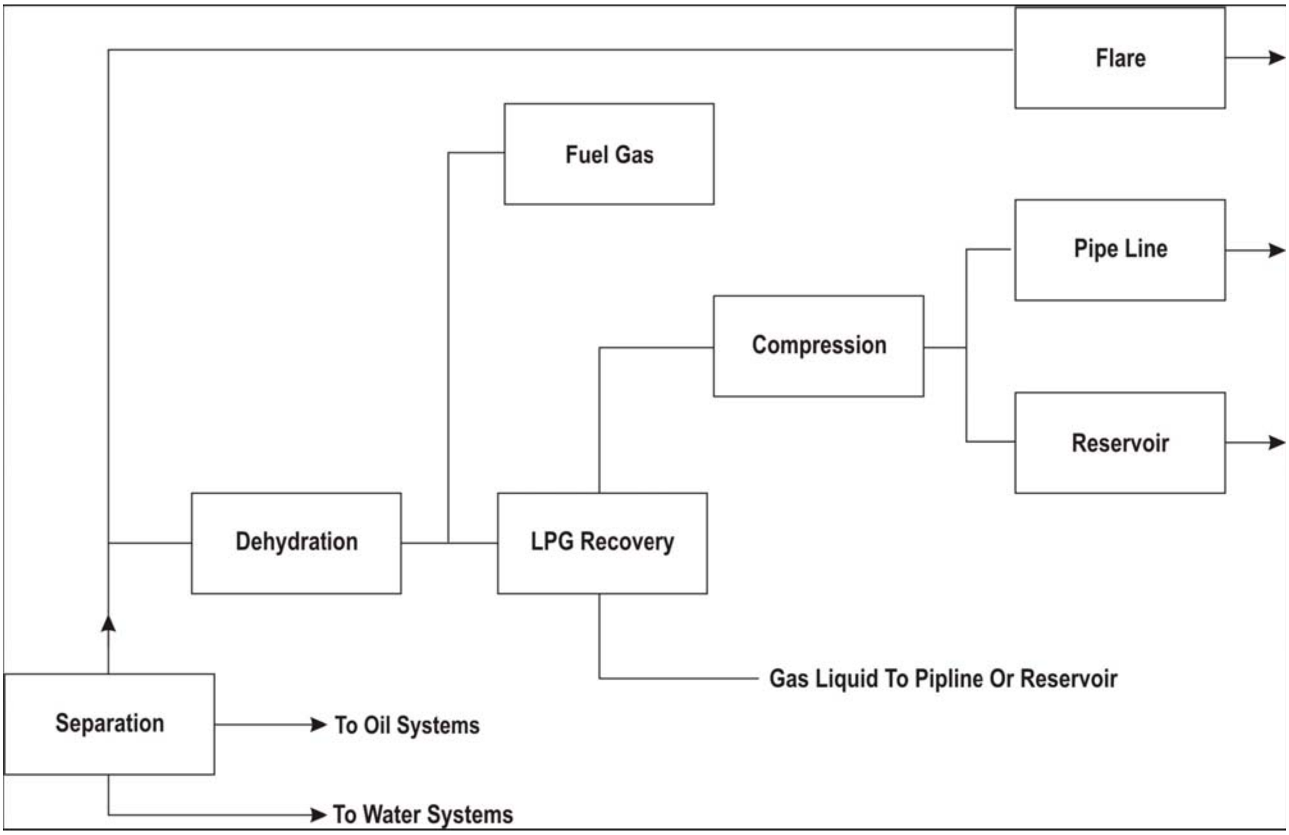


Figure 90 Typical Gas Flow Diagram

19.5 Gas Treatment

Natural gas is saturated with water vapour; the amount of water it contains depends on pressure and temperature. If this water was not removed, it would cause corrosion and slugs of water in pipelines or worst of all - hydrates.

Hydrates are ice-like substances which, if allowed to form, can build up to completely block pipelines, causing process upsets or even line rupture. They form due to a physical reaction between the water and hydrocarbons under special conditions of temperature and pressure – and unfortunately these special conditions often occur in export pipelines. They can form above the freezing temperature of water. Also since water-vapour laden gas is denser than dry gas; it takes significantly more horsepower to move it along pipelines, which would result in the need for bigger, more expensive compressors.

There are several methods of removing the water from the gas and this is called dehydration. A common process utilises a water absorbing substance such as tri-ethylene glycol (TEG) through which gas is passed in an absorption tower. As the gas is bubbled through the glycol, water is adsorbed from the gas into the glycol. The glycol is then passed to a separate regeneration unit, where it is heated to drive off the absorbed water, after which the lean (no water) glycol can be re-used.

The gas may also contain components which could be liquefied and recovered. These components, mainly propane and butane, are valuable and it is to the operator's advantage to recover them if possible in liquid form rather than exporting them as gaseous components. A method employed to effect recovery involves a refrigeration process whereby the temperature of the gas is reduced to a point where these elements condense to liquid and becomes known as Liquefied Petroleum Gas (LPG). The LPG may then be injected into the oil stream to be further processed onshore.

Once the water vapour has been removed and the gas purified it can also be used as a source of fuel for platform equipment such as the gas turbine which drive the electricity generators or export pumps. The gas may be re-injected into the reservoir to maintain the pressure in it and drive more oil to the surface.

Gas also needs to be metered just as accurately as the oil; although being a gas it is more complicated and requires more instrumentation to measure accurately.

19.6 Flare Systems

Until recently, it was common practice to burn off the produced gas. But because of the extreme waste of energy, saleable gas and the damage to the environment this practice has largely been eradicated throughout the world. Some gas must still be flared off so that the emergency flare system is constantly purged to prevent ingress of oxygen creating a potentially hazardous situation. That small amount of flared gas constitutes the flame which is normally seen at the end of a flare stack, particularly common on an offshore platform.

The flare system must also be able to safely dispose of any emergency release of gas from the separators, process vessels or compressor lines. This means it must be able to handle large quantities of gas in a very short period of time.

20 Advanced Drilling Techniques

20.1 Directional Drilling

Horizontal and directional drilling are other methods of increasing a well's productivity and reducing the environmental footprint of an oil and gas operation. New technologies enable us to drill laterally or horizontally beneath the surface, as opposed to vertically, allowing for a wider range of possible well configurations.

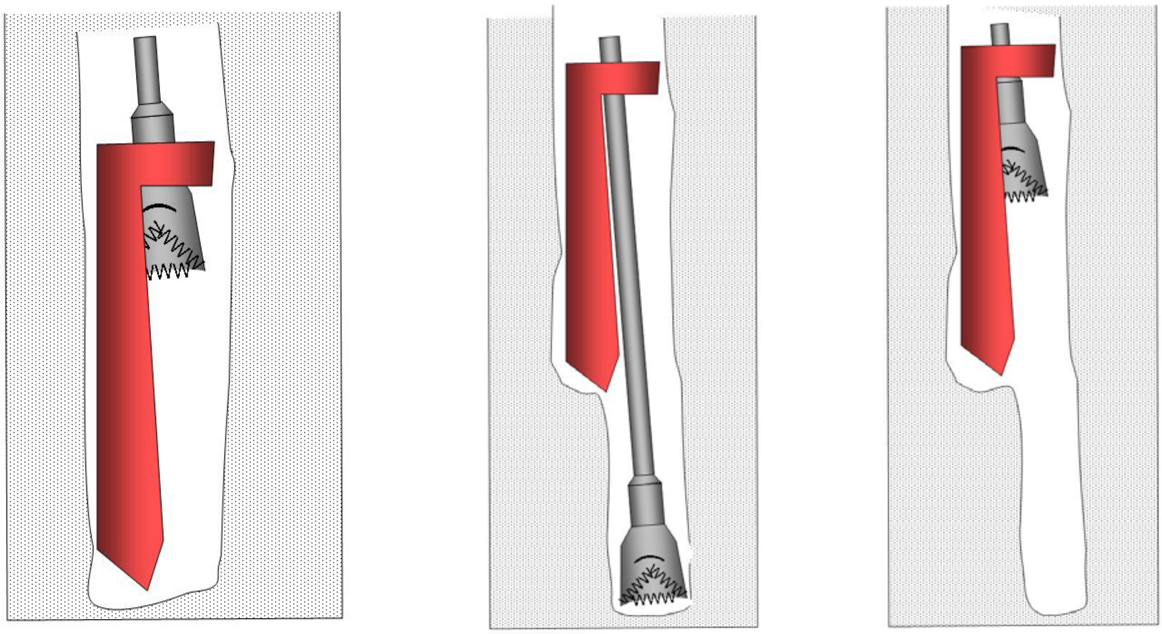


Figure 91 Whipstocks

Because horizontal and directional drilling methods often utilize existing vertical well-bores, additional wells may be drilled without additional disruption to the environment. Utilizing this technique also helps maximize recovery from existing reservoirs by penetrating a greater cross-section of the formation, allowing substantially more oil to be produced while reducing the total number of wells required.

In the early days of oil exploration and exploitation, there was no such thing as directional drilling. The drilling derricks used were cheap structures, often made of wood and, upon discovery of oil by one particular well, it was a fairly inexpensive operation to build new derricks and drill a series of vertical wells at various points round the original. Today, with an offshore installation costing millions of pounds (often in the order of £1,000 million) this is financially impossible and, indeed, offshore oil would not have been exploited at all had it not been for the development of directional drilling.

In offshore drilling from a platform, only one well will be vertical: all the other wells will be directional, so that the reservoir can be fully exploited.

20.2 Directional Drilling Equipment

To achieve a deviation while drilling, various devices can be employed:

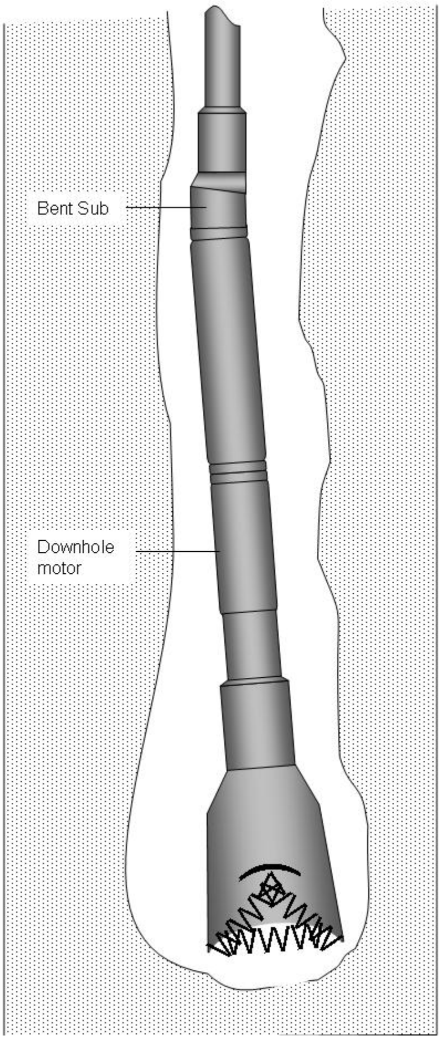


Figure 92 Downhole Motor & Bent Sub

- **Whipstock**: The first and oldest device is the Whipstock. This is a long, inverted steel wedge which literally forces the drill bit off in the required direction. This tool is not common today.
- **Knuckle Joint**: Another device is the knuckle joint, but it too is falling out of favour because it is not possible to set the angle of deviation accurately; therefore its use is limited to non-directional (that is, no specific direction) or ‘blind’ sidetracking to drill round an obstruction in the hole where the actual direction of deviation is not important. The knuckle joint comprises a spring-loaded, ball-type, universal joint which is connected to the drill pipe to allow the drill bit to drill at an angle to the axis of the drill string.
- **Jet Bit**: The jet bit is a modified two or three cone bit with three jet openings; two small and one large. The drill bit must be correctly orientated in the hole with the large jet pointing in the required direction of deviation. The drill is frequently lifted off the bottom of the hole and re-spudded (repositioned for drilling) and this alternating jetting and drilling continues until initial curvature has been established.
- **Downhole Motor**: This is probably today's most widely used deflection tool. The drill bit is driven by mud flowing down the drill string to drive a turbine or motor connected to the bit. The motor is used in conjunction with a bent sub which is used to impart a constant deflection to the tool. This deflection may only be in the order of 1 to 3°, but is sufficient to set the tool off in the required direction.

20.3 Applications of Directional Drilling

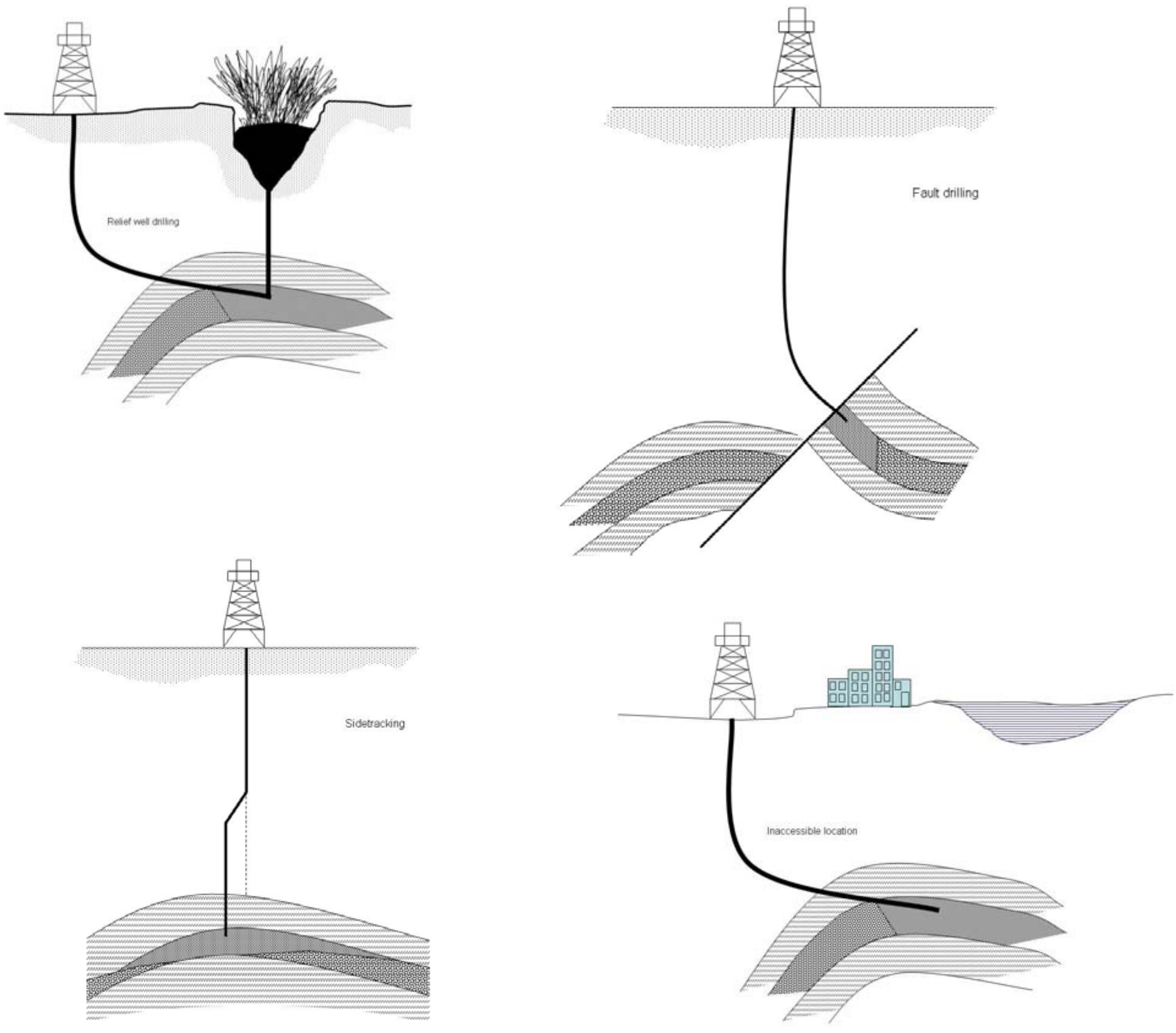


Figure 93 Applications of Directional Drilling

Directional drilling is used for various purposes, for example:

- To drill to a specific reservoir section so that a reservoir may be fully exploited from one drilling platform, saving money and time.
- To by-pass junk in the hole which cannot be fished.
- To deviate when the well has been wrongly sited on the surface.
- To reach the bottom of a hole that has blown and is on fire, to kill the well, when there is no other way of dealing with the fire.

20.4 Measuring the Deviation

Again, the driller must be aware of all the factors affecting the movement of the drill bit many thousands of feet beneath him. Watching the surface pipe will give no indication of lateral movement downhole. Consequently, special equipment must be used to gain this information and specialists used to interpret it.

The orientation and deviation of the hole can be measured with a photographic type recorder; this has a compass and a plumb-bob so that the orientation and the degree of deviation are measured. Inclination can also be measured after the hole has been drilled by using an electronic wireline device.

20.5 Measurement While Drilling

While tools which are lowered downhole in the absence of the drill string provide accurate data on hole deviation and orientation, they have the obvious disadvantage that the drill string has to be pulled from the hole for data to be recovered. To overcome this, ***Measurement Whilst Drilling*** (MWD) tools have been developed. These sophisticated, electronic tools take the usual downhole measurements, but transmit the data to surface by binary coded pulses in the mud.

The tools operate either by slightly increasing mud pressure to create a pulse or slightly decreasing mud pressure through a downhole dump valve, which also creates pulses. The pulses are in the form of a code which is interpreted by equipment on the surface. The surface equipment produces a print out or display for use by the driller showing drift azimuth and Tool Face Orientation (TFO). Other MWD tools can also be used for normal logging purposes such as gamma ray and resistivity logs and these operate on similar principles.

One of the big dangers in directional drilling is the risk of a new well drilling into an existing, possibly a producing well. For this reason, great care must be taken to determine the position of the drill bit at frequent intervals.

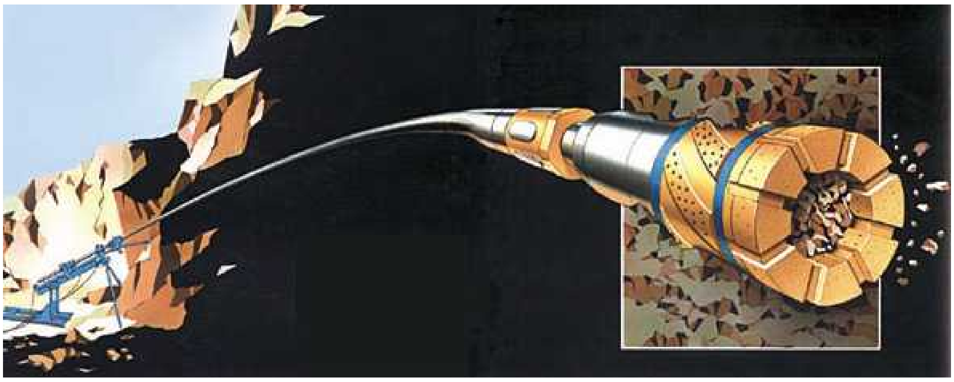
In order to achieve the desired angle of deviation in the shallow waters of Morecambe Bay, installations in the Morecambe Bay Field are equipped with slanted drilling facilities. These enable the entire drilling derrick to be canted at angles up to 30° to the vertical, thus providing an initial deviation angle. This technique was pioneered in British waters by the operators of the Morecambe Bay Field. Because the forces associated with slant drilling are not purely vertical, the drilling derrick must be a more sophisticated piece of equipment, designed to support and control the additional, horizontal force elements.

As technology developed, improvements in directional drilling allowed for the drilling of horizontal wells……

20.6 Horizontal Drilling

A horizontal well is drilled laterally at an angle between 70 to 110 degrees. In addition to reducing the environmental impact of the drilling process, horizontal drilling is more cost-effective, uses less produced water and creates less drilling waste. Horizontal drilling may also provide access to oil and gas in thin, tight reservoirs that may be inaccessible by vertical drilling.

A horizontal well can access far more of the reservoir which is capable of producing hydrocarbon, so especially in tight formations, horizontal wells can make the difference between a well being economic or not.



21 Under-balanced Drilling (UBD)

For an understanding of what overbalanced and under-balanced mean please refer to section 13.1 Over-balance v Under-balance.

21.1 What is Under-balanced Drilling?

"Under-balanced drilling operations reduce the hydrostatic pressure of the drilling fluid column so that the pressure in the well bore is less than the formation pressure".

Conventional drilling practice calls for maintaining the hydrostatic pressure of the drilling fluid between the formation's pore pressure and its fracture pressure; this means that no hydrocarbon will flow out into the well bore and that the driller can control the formation pressures safely. This is an **overbalanced** situation. If the hydrostatic pressure is allowed to fall below the pore pressure then the well could start to flow. In order to maintain this stability, the drilling fluid is continuously circulated within the well bore to control the formation fluids and transport cuttings to the surface. It also works as a stabilizing agent within the well bore, and lubricates and cools the drill bit. The fluid is either a water-based or oil-based liquid that varies from 7.8 to 19 pounds per gallon, and contains a variety of solid and liquid products to impart density, fluid loss characteristics and rheological properties.

The conventional practice described above has long been recognized as the safest method for drilling a well. It does, however, have drawbacks. Since the drilling fluid pressure is higher than the natural formation pressure, fluid invasion frequently occurs, causing permeability damage to the formation. This damage is mainly caused by washout or physical blockage by the intrusion of fluids and/or solids into the formation structure.

Drilling in an underbalanced situation permits the well to flow while drilling proceeds.

Besides minimizing lost circulation and increasing the penetration rate, this technique has a widely recognized benefit of minimizing the damage caused by invasion of drilling fluid into the formation. In many UBD applications, additional benefits are seen due to reduction in drilling time, increased bit life, and early detection and dynamic testing of productive intervals while drilling. It is critical to keep the well under-balanced at all times, if formation damage is to be minimized.

Because many hydrocarbons today are found in existing fields with depleting pressures, or in complex and low quality reservoirs, the economical use of UBD becomes more and more popular, because of this ability to prevent formation damage.

Most of the under-balanced drilling applications today are conducted through the use of coiled tubing systems.

In under-balanced drilling the fluids from the well are returned to a closed system at surface to assist well control as opposed to conventional drilling where fluids are returned to an open system with the well open to atmosphere.

Current activities worldwide involve UBD projects both onshore and offshore, on mobile rigs and production platforms, with jointed pipe and coiled tubing.

21.2 Effect of Drilling Under-balanced.

The primary value of under-balanced drilling is to minimize formation damage. Negative differential pressure between the formation and the well bore also stimulates the production of formation fluids and gasses. Increased penetration rates are also often observed in wells drilled under-balanced. Under-balanced drilling does not build a filter cake in the well bore. During conventional drilling, this filter cake can act as a protective barrier, reducing damage to formation permeability from drill cuttings. But when drilling horizontal well-bores, drill cuttings are ground into fine powder. In conventional drilling, if the well bore does not have a filter cake and is overbalanced, this powder is carried into the formation, greatly reducing near-well bore permeability. Which is why underbalanced drilling is very popular for horizontal wells.

21.3 Techniques to Achieve Under-balanced Conditions

Four techniques are currently available to achieve under-balanced conditions while drilling. These include using lightweight drilling fluids, injecting gas down the drill pipe, injecting gas into a parasite string, and use of foam.

21.3.1 Lightweight Drilling Fluids.

The simplest mechanism to reduce hydrostatic pressure in the well bore is the use of lightweight drilling fluids, such as fresh water, diesel or lease crude. The primary problem with this approach is that hydrostatic pressure can not be reduced enough to remain under-balanced in many reservoirs.

21.3.2 Gas Injection Down Drill pipe.

With this technique, air or nitrogen is added to the drilling fluid and is pumped directly down the drill pipe.

Advantages of this technique include:

- Hydrostatic advantage gained over entire vertical depth,
- Well bore does not have to be specifically designed for under-balanced condition,
- Less gas is required to achieve given pressure compared to parasite injection, and
- Penetration rate may be improved.

Disadvantages of this technique include:

- An overbalanced condition may occur if the well is shut down and
- Exotic MWD systems are required.

21.3.3 Gas Injection via Parasite String.

With this technique, a second pipe is run outside of the intermediate casing.

Advantages of this technique include:

- No operational differences.
- Constant bottom hole pressure is achieved, and
- Standard MWD equipment can be used.

Disadvantages of this technique include:

- Additional costs are incurred.
- Additional time is required.
- Larger diameter surface casing is required.

21.3.3.1 Choice of Gas.

In order to lighten the drilling fluids a gas needs to be introduced which mixes with the fluid and reduces its density.

Air, nitrogen and natural gas have been used as the gas phase in under-balanced drilling. When natural gas is available and can be recovered and re-injected into the supply/sales line, it can be the most cost-effective method to achieve an under-balanced condition. However, this is not typically an option. Drilling with air injection is common, but there are significant corrosion problems and the potential for down hole fires always exists. For these reasons, nitrogen has become the gas of choice for under-balanced drilling.

Cryogenic nitrogen of high purity (99.9%) can be purchased, but price and logistics are unfavourable. Generally the best source is nitrogen that is generated onsite using a membrane unit.

Membrane units typically produce 95% purity nitrogen. Purity is such that corrosion can usually be managed and down hole fires are not possible. Membrane units are available in a range of capacities.

21.3.4 Foam Versus Two Phase Flow.

A nitrogen foam system is less damaging to water sensitive formations and has been used on a limited basis. However, the additional nitrogen requirements to generate stable foam have made this cost prohibitive in most cases.

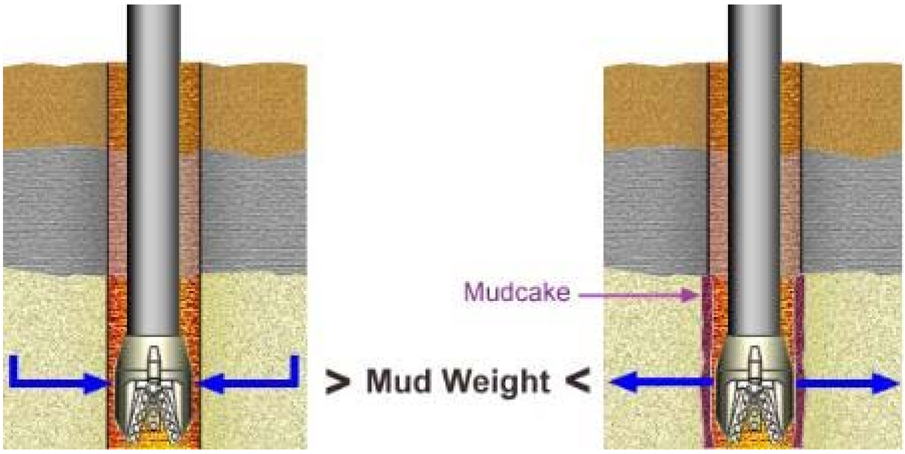


Figure 94 Underbalanced (left) V. Overbalanced (right)

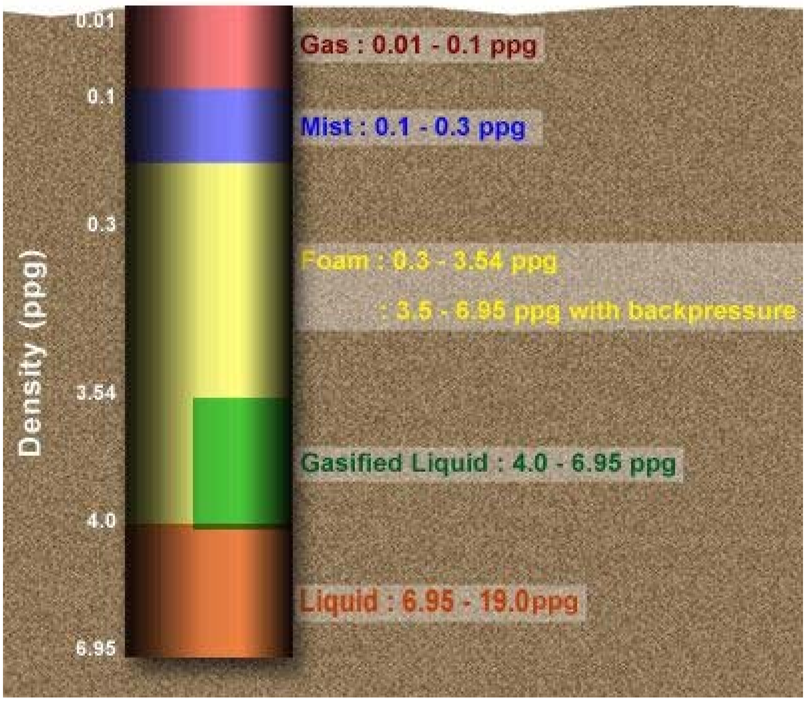


Figure 95 Densities of various drilling fluids

21.4 Benefits & Limitations of Under-balanced Drilling

21.4.1 Advantages

Maintaining well bore pressure below the reservoir pressure allows reservoir fluids to enter the well bore, thus avoiding formation damage. Since significant formation damage is avoided, the stimulation requirements during well completion are also reduced, leading to considerable savings.

- During under-balanced drilling there is no physical mechanism to force drilling fluid into the formation drilled. Therefore, lost circulation is kept to a minimum when fractured or high permeability zones are encountered.
- Drilling under-balanced can help in detecting potential hydrocarbon zones, even identifying zones that would have been bypassed with conventional drilling methods.
- Due to the decreased pressure at the bit head, UBD operations demonstrate superior penetration rates compared to conventional drilling techniques. Along with reduced drilling times, an increase in bit life is typically reported.
- Since there is no filter cake around the well bore wall, the chances of differential sticking are also reduced.

A combination of all these factors can significantly improve the economics of drilling a well. UBD is often preferred if it reduces formation damage and hole problems, and reduces the cost of stimulation in fractured or moderate/high permeability formations. Moreover, with good mud logging and drilling records, UBD can provide valuable Formation Evaluation data.

21.4.2 Disadvantages

Under-balanced drilling also has disadvantages that can prove detrimental to the outcome of the drilling process:

- There is potentially a higher risk of blowout, fire or explosion (although some would argue against this).
- Under-balanced drilling is still an expensive technology. Depending on the drilling fluid used, the cost can be significant, particularly for extended reach horizontal wells.
- It is not always possible to maintain a continuously under-balanced condition. And since there is not a filter cake around the well bore, any instantaneous pulse of overbalance might cause severe damage to the unprotected formation.
- UBD has its own unique damage mechanisms, such as surface damage of the formation due the lack of heat conduction capacity of under-balanced drilling fluids.
- It is more complicated to model and predict the behaviour of compressible drilling fluids.

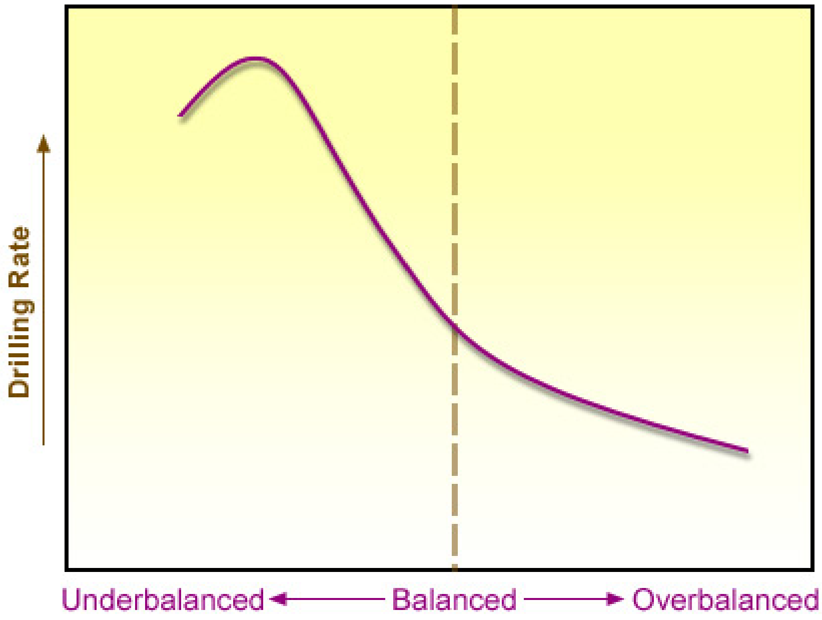


Figure 96 Rate of Penetration of Drill Bit

Even though the cost of drilling under-balanced could be more expensive than conventional overbalanced drilling, due to the increased ROP and reduced formation damage, it often turns out to be the more cost-effective drilling technique.

Figure 97 Typical UBD Spread

22 Coiled Tubing

22.1 What is CT?

Coiled Tubing (CT) has been defined as any continuously-milled tubular product manufactured in lengths that require spooling onto a take-up reel, during the primary milling or manufacturing process.

In simple terms, it is a long length of continuous steel pipe. It is stored on a reel, spooled off, straightened and pushed into a well.

Tubing diameter normally ranges from 0.75in. to 4in., with single reels of tubing in excess of 30,000 ft. long having been commercially manufactured. Common coiled tubing steels have yield strengths ranging from 55,000 PSI to 120,000 PSI.

Figure 98 CTU Control Cabin

22.2 Key Elements of a CT Unit

Figure 99 CTU Power Pack

The coiled tubing unit is comprised of the complete set of equipment necessary to perform standard continuous-length tubing operations in the field. The unit consists of four basic elements:

- Control Cabin - from which the equipment operator monitors and controls the coiled tubing
- Power Pack - to generate hydraulic and pneumatic power required to operate the coiled tubing unit
- Reel - for storage and transport of the coiled tubing
- Injector Head - to provide the surface drive force to run and retrieve the coiled tubing

Figure 100 CTU Reel

Figure 101 CTU Injector & Goose Neck

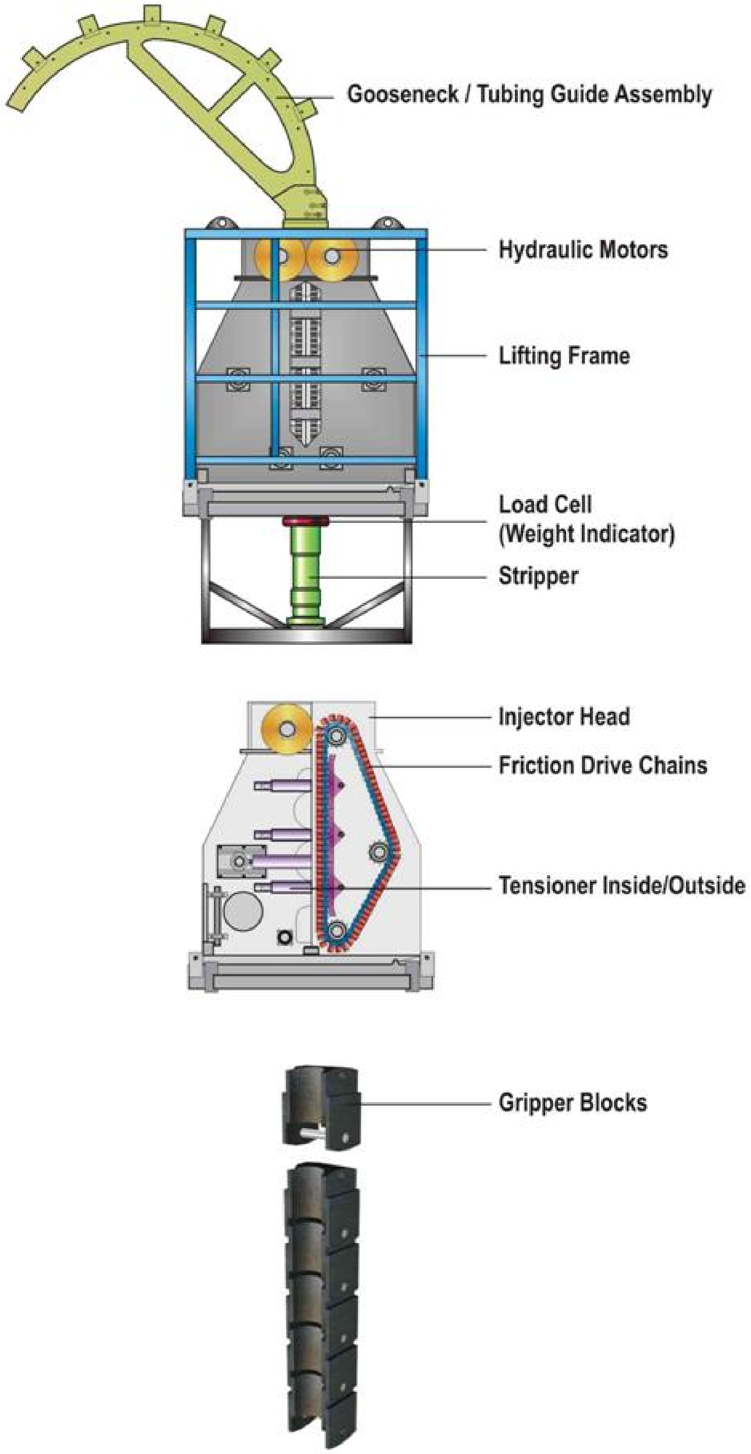


Figure 102 The Injector Head

22.3 Well Control Equipment

Proper well control equipment is another key component of CT operations, given that a majority of these operations are performed in the presence of surface wellhead pressure. Typical CT well control equipment consists of a BOP topped with a stripper (high pressure CT units have two strippers and additional BOP components). All components must be rated for the maximum wellhead pressure and temperature possible for the planned field operation.

The stripper (sometimes referred to as a pack-off or stuffing box) provides the primary operational seal between pressurised wellbore fluids and the surface environment. It is physically located between the BOP and the injector head. The stripper provides a dynamic seal around the CT during tripping and a static seal around the CT when there is no movement. The latest style of stripper devices are designed with a side door that permits easy access and replacement of the sealing elements, with the CT in place.

Figure 103 BOP

The BOP is situated beneath the stripper, and can also be used to contain wellbore pressure. A CT BOP is designed specifically for CT operations. It consists of several pairs of rams, with each ram designed to perform a specific function. The number and type of ram pairs in a BOP are determined by the BOP configuration: single, double or quad. A quad system is commonly used in most operations.

The four BOP rams, from top to bottom and their associated functions are:

- Blind ram - seals the wellbore when the CT is out of the BOP
- Shear ram - used to cut the CT
- Slip ram - supports the CT weight hanging below it (some are bi-directional and prevent the CT from moving upward)
- Pipe ram - seals around the hanging CT

22.4 CT Benefits

While the initial development of coiled tubing was spurred by the desire to work on live well-bores, speed and economy have emerged as key advantages for application of CT. In addition, the relatively small footprint and short rig-up time make CT even more attractive for drilling and workover applications.

Some of the key benefits associated with the use of CT technology are as follows:

- Safe and efficient live well intervention
- Rapid mobilisation and rig-up
- Ability to circulate while RIH/POOH
- Reduced trip time, resulting in less production downtime.

- Reduced crew/personnel requirements
- Cost may be significantly reduced

Coiled tubing can also be fitted with internal electrical conductors or hydraulic conduits, which enables downhole communication and power functions to be established between the BHA and surface. This means that logging operations in horizontal wells are much easier as the CT can push the logging tools to location; whereas on wireline, downhole tractor units have to be used to pull the tools along the horizontal section.

22.5 CT Field Applications

CT was originally used for operations such as cleaning out wells; where the CT string could be run into the well, fluids pumped down and then dirt and debris removed through the annular space around the CT inside the tubing or casing. Gas lifting was another common operation, where nitrogen was pumped down CT which then mixed with the well bore fluid as it exited the CT and therefore lightened the liquid phase. Pumping acid down CT to an exact place in the formation was also a typical operation in the 1980s.

Whilst these types of operations still continue, the use of CT has continued to grow beyond these typical well cleanout, lifting and acid stimulation application. This growth can be attributed to a multitude of factors, including advances in CT technology and materials as well as the increased emphasis on well-bores containing a horizontal and/or highly-deviated sections.

22.6 Operations where CT could be of benefit in field work.

Growth Applications

- CT Drilling
- Fracturing
- Subsea
- Deeper Wells
- Pipeline/Flowline

Traditional Applications

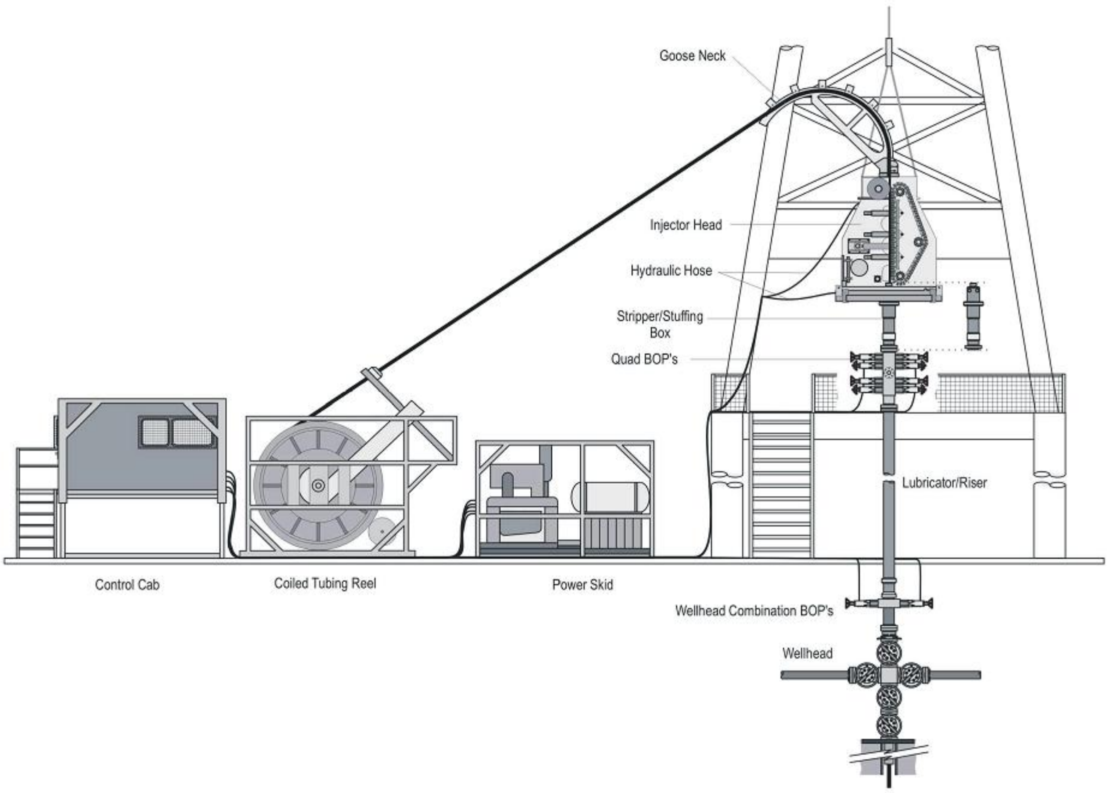
- Well unloading
- Cleanouts
- Acidizing/Stimulation
- Velocity Strings
- Fishing
- Tool Conveyance
- Well Logging (real time & memory
- Setting/Retrieving Plugs

22.7 History

The development of coiled tubing as we know it today dates back to the early 1960's, and it has become an integral component of many well service and workover applications. While well service/workover applications still account for more than 75% of CT use, technical advancements have increased the utilization of CT in both drilling and completion applications.

The ability to perform remedial work on a live well was the key driver associated with the development of CT. To accomplish this feat, three technical challenges had to be overcome:

- A continuous conduit capable of being inserted into the wellbore (CT string).
- A means of running and retrieving the CT string into or out of the wellbore while under pressure (injector head).
- A device capable of providing a dynamic seal around the tubing string (stripper or pack-off device).



22.7.1 CT Origin

Prior to the Allied invasion in 1944, British engineers developed and produced very long, continuous pipelines for transporting fuel from England to the European Continent to supply the Allied armies. The project was named operation "PLUTO", an acronym for "Pipe Lines Under The Ocean", and involved the fabrication and laying of several pipelines across the English Channel. The successful fabrication and spooling of continuous flexible pipeline provided the foundation for additional technical developments that eventually led to the tubing strings used today by the CT industry.

In 1962, the California Oil Company and Bowen Tools developed the first fully functional CT unit, for the purpose of washing out sand bridges in wells.

22.7.2 Early CT Equipment

The first injector heads operated on the principle of two vertical, contra-rotating chains. This design is still used in the majority of CT units today. The stripper was a simple, annular-type sealing device that could be hydraulically activated to seal around the tubing at relatively low wellhead pressures. The tubing string used for the initial trials was fabricated by butt-welding 50 ft. sections of 1 3/8 in. OD pipe into a 15,000 ft. string and spooling it onto a reel with a 9 ft. diameter core.

Figure 104 Inside a Control Cabin

22.7.3 Evolution of CT Equipment

Throughout the late 1960's and into the 1970's, both Bowen Tools and Brown Oil Tools continued to improve their designs to accommodate CT up to 1” OD. By the mid-1970's, more than 200 of the original-design CT units were in service. By the late 1970's, several new equipment manufacturing companies (Uni-Flex Inc., Otis Engineering, and Hydra Rig Inc.) also started influencing improved injector head design.

CT strings were also undergoing significant improvements during this period. Through the late 1960's, CT services were dominated by tubing sizes of 1 in. and less, and relatively short string lengths. Tubing diameter and length were limited by the tubing mechanical properties and currently available manufacturing processes.

Early CT operations suffered many failures due to the inconsistent quality of the tubing and the numerous butt welds required to produce a suitable string length. However, by the late 1960's, tubing strings were being milled in much longer lengths with fewer butt welds per string. During this time, steel properties also improved. These changes and the associated improvement in CT string reliability contributed greatly to the continued growth of the CT industry.

Today it's common for CT strings to be constructed from continuously milled tubing that can be manufactured with no butt welds. In addition, CT diameters have continued to grow to keep pace with the strength requirements associated with new market applications. It's not unusual for CT diameters of up to 2 7/8 in. to be readily available for routine use.

22.8 The CT Business

The coiled tubing industry continues to be one of the fastest growing segments of the oilfield services sector, and for good reason. CT growth has been driven by attractive economics, continual advances in technology, and utilization of CT to perform an ever-growing list of field operations. Coiled tubing today is a global, multi billion dollar industry in the mainstream of energy extraction technology.

The potential advantages associated with CT are typically driven by the fact that a workover rig (and associated cost) is not required, the rapid CT trip speed in and out of the well, and that CT operations are designed to be performed with pressure on the well. Eliminating the requirement to kill the well can be a significant factor in the decision to utilize CT for a particular field operation, as it reduces the risk of formation damage.

22.9 Growth of the CT Service Fleet

In January 2004, slightly more than 1,050 CT units were estimated to be available on a worldwide basis. The total number of working CT units is up sharply from the roughly 850 units reported in February 2001. At present, the International market accounts for the bulk of the currently available CT fleet with more than 425 units. Canada and the U.S. are estimated to contribute an additional 239 and 253 units, respectively.

Figure 105 Truck Mounted CT Unit

22.10 New CT Markets / Field Applications

CT first established it's niche in the marketplace as a cost-effective well cleanout tool. In recent years, these conventional wellbore cleanouts and acid stimulation jobs accounted for more than three quarters of total CT revenue. However, CT use has continued to expand as it is adopted for use in additional field operations. Most recently, CT fracturing and drilling applications have emerged as two of the fastest growth areas. Revenue from these two CT applications has grown from almost zero 10 years ago, to approximately 15 percent in more recent times.

22.10.1 Workover & Completion Applications

CT is routinely used as cost-effective solution for numerous workover applications. A key advantage of CT in this application is the ability to continuously circulate through the CT while utilizing CT pressure control equipment to treat a live well. This avoids potential formation damage associated with well killing operations. The ability to circulate with CT also enables the use of flow-activated or hydraulic tools.

Other key features of CT for workover applications include the inherent stiffness of the CT string. This rigidity allows access to highly deviated/horizontal well-bores, and the ability to apply significant tensile or compression forces downhole. In addition, CT permits much faster trip times as compared to jointed pipe operations.

22.10.2 Common CT Workover Applications

Some of the more common CT applications for workover operations are listed below.

Pumping Applications

- Removing sand or fill from a wellbore
- Fracturing/acidizing a formation
- Unloading a well with nitrogen
- Gravel packing
- Cutting tubulars with fluid
- Pumping slurry plugs
- Zone isolation (to control flow profiles)
- Scale removal (hydraulic)
- Removal of wax, hydrocarbon, or hydrate plugs

Mechanical Applications

- Setting a plug or packer
- Fishing
- Perforating
- Logging
- Scale removal (mechanical)
- Cutting tubulars (mechanical)
- Sliding sleeve operation
- Running a completion
- Straddles for zonal isolation
- Drilling

Figure 106 Zone II Control Cabin

22.10.3 Removing Sand or Fill from a Wellbore

The removal of sand or fill from a wellbore is the most common CT operation performed in the field. The process has several names, including sand washing, sand jetting, sand cleanout, and fill removal. The objective of this process is to remove an accumulation of solid particles in the wellbore. These materials will act to impede fluid flow and reduce well productivity. In many cases CT is the only viable means of removing fill from a wellbore. Fill includes materials such as formation sand or fines, proppant flowback or fracture operation screen-out, and gravel-pack failures.

The typical procedure involved in this application is to circulate a fluid through the CT while slowly penetrating the fill with an appropriate jetting nozzle attached to the end of the CT string. This action causes the fill material to become entrained in the circulating fluid flow, and is subsequently transported out of the wellbore through the CT/production tubing annulus. Where consolidated fill is present, the procedure may require the assistance of a downhole motor and bit or impact drill.

An alternative fill removal approach is to pump down the CT/production tubing annulus and allow the returns to be transported to surface within the CT string. This procedure, called reverse circulation, can be very useful for removing large quantities of particulate, such as frac sand, from the wellbore. It may also be applied when a particular wellbore configuration precludes annular velocities sufficient to lift the fill material. Reverse circulation is suitable only for dead wells.

22.10.4 Unloading a Well with Nitrogen

The process of using CT to unload a well with nitrogen is a quick and cost-effective method used to regain sustained production. A typical field scenario consists of a wellbore that has developed a fluid column with sufficient hydrostatic pressure to prevent the reservoir fluid from flowing into the wellbore. Displacement of some of this wellbore fluid with nitrogen reduces the hydrostatic head, and this reduction of BHP allows the reservoir fluid to again flow naturally into the wellbore. If the wellbore conditions are suitable (pressure, fluid phase mixture and flow rate), production will continue after nitrogen pumping ceases.

There are numerous benefits associated with the use of CT for a nitrogen kick-off operation. The rate and depth of the nitrogen injection can be adjusted to fit a wide range of field conditions. The procedure also provides a ready source of uncontaminated production fluid samples (oil, formation water). And, the procedure is extremely simple from an operational standpoint, as only a small amount of equipment and a limited number of field personnel are necessary.

22.10.5 Fracturing / Acidizing a Formation

This CT application has experienced significant growth in recent years, and provides several advantages versus conventional formation treatment techniques. In particular, CT provides the ability to quickly move in and out of the hole (or be quickly repositioned) when fracturing multiple zones in a single well. CT also provides the ability to facture or accurately spot the treatment fluid to ensure complete coverage of the zone of interest. When used in conjunction with an appropriate diversion technique, more uniform treating of long target zones can be achieved. This is particularly important in horizontal well-bores. At the end of the formation treating operation, CT can be used to remove any sand plugs used in the treating process, and to lift the well to be placed on production.

One of the earlier concerns with CT fracturing was the erosion effects that occur when proppant is pumped during the fracturing operation and the resulting impact on CT string life. An ultrasonic thickness (UT) gauge is now used on location to measure CT thickness during the job. Data from these UT measurements can be used to adjust the CT fatigue models, and to accurately monitor remaining CT string life.

22.10.6 Drilling Applications.

Coiled tubing drilling (CTD) has been utilized on a commercial basis for many years, and can provide significant economic benefits when applied in the proper field setting. In addition to potential cost advantages, CTD can provide the following additional benefits:

- Safe and efficient pressure control
- Faster tripping time (150+ ft/min)
- Smaller footprint and weight
- Faster rig-up/rig-down

- Reduced environment impact
- Less personnel
- High speed telemetry (optional)

In general, CTD can be divided into two main categories consisting of directional and non-directional wells. Non-directional wells use a fairly conventional drilling assembly in conjunction with a downhole motor. Directional drilling requires the use of an orienting device to steer the well trajectory, per the well plan. CTD can then be further segmented into over-balance and under-balanced drilling applications.

Figure 107 CTU Drilling Operation

Bit design and selection for CTD follows the same theory as is used in conventional rotary drilling. However, CTD generally uses higher bit speeds at lower weight on bit as a result of the structural differences in CT versus jointed pipe.

22.10.7 Non-Directional Wells

Non-directional wells represent the largest CTD application, and these are defined as a well that lacks downhole tools to control direction, inclination and/or azimuth. Much of the CTD work performed to date involved shallow gas well development in Canada, but it has also been used for shallow water injection wells and for "finishing" operations. A primary advantage that CTD provides in this application is the speed of the rig up/down operation, and the continuous rate of penetration (no delays to add stands of jointed pipe).

The majority of this CTD work has been performed with hole sizes less than 7 in., but hole sizes up to 13 3/4 in. have been successfully drilled. Much the same as in conventional drilling, drill collars can be used in low angle wells to control inclination build-up and apply weight on bit for CTD applications.

22.10.8 Directional Wells

This type of CTD application utilizes an orienting device in the bottomhole assembly (BHA) to control the wellbore trajectory as desired. CTD for this application can include new wells, extensions, side-tracks through existing completions, horizontal drain holes, or side-tracks where the completions are pulled. However, the primary use of CTD for directional wells is to directionally drill into new reservoir targets from existing well-bores.

Directional drilling with CT has some fundamental differences compared to conventional rotary drilling techniques. One of the basic differences is the need for an orienting device to control the well trajectory, since CT cannot rotate. Orienting devices control hole direction by rotating a bent housing to a particular orientation (tool face) or controls the side loading at the bit to push the assembly in a particular direction. This control over the BHA provides directional control for CTD applications.

A steering tool is used to measure inclination, azimuth, and tool face orientation. Two basic types of steering tools are used for directional drilling with CT. Electric steering tools are used in conjunction with a cable inside the CT to transmit data to surface. Mud pulse tools comprise the second type of steering device for CTD applications. Mud pulse steering tools transmit data to the surface by generating pressure pulses in the mud.

In addition to orientation and steering devices, some BHAs utilized for CTD are equipped with additional measurement tools, including gamma ray, casing collar locator, accelerometers (shock load measurements), pressure (internal and annulus) and weight on bit.

22.10.9 Wellbore Hydraulics and Wellbore Fluids

There are some key fluid design parameters to keep in mind for CTD applications versus traditional rotary drilling. For example, all CTD operations require the fluid to travel through the entire tubing string regardless of the current drilling depth. In addition, the frictional pressure loss for CT on the reel is considerably larger than for straight tubing. Thus, for optimum hydraulic performance, the drilling fluid must behave as a low viscosity fluid while inside the CT, and as a high viscosity fluid in the annulus (for efficient cuttings removal).

Another key difference associated with CTD is the absence of tubing rotation while drilling. Jointed pipe is rotated during conventional drilling operations, and this movement helps keep the drill cuttings suspended in the drilling fluid, so they can be lifted to surface. Since the tube doesn't rotate in CTD applications, hole cleaning can be more challenging in heavily deviated/horizontal applications. This effect is partially offset by the smaller cuttings produced with CTD (higher RPM, lower weight on bit). In addition, special visco-elastic fluids have been developed for CTD, that change their rheology according to the local shear rate, i.e., become more viscous in the annulus (lower shear rate) to improve cutting suspension.

22.10.10 Overbalanced CTD

As with conventional well drilling operations, the drilling fluid is used for controlling subsurface pressure and the CTD drilling fluid systems are typically smaller versions of conventional systems. Conventional well control principles apply except that the CT string limits the fluid flow rate and the frictional pressure loss varies with the ratio of tubing on/off the reel.

22.10.11 Underbalanced CTD

To date, most underbalanced CTD activity has been for re-entry operations, but new wells could also benefit from this approach. CTD is ideal for this underbalanced applications because of it's inherent well control system. In addition, underbalanced "finishing" is a variation of underbalanced drilling used extensively in Canada and gaining acceptance in other areas. For finishing operations, a conventional rig is used to drill to the top of the reservoir and casing is run. From this point, CTD is utilized to drill into the reservoir with underbalanced drilling techniques. This technique attempts to leverage the respective strengths of both drilling approaches. Conventional drilling can be faster (less expensive) in the large diameter, unproductive uphole drilling intervals, while underbalanced CTD is faster (less expensive) in the producing interval. CTD is also better suited to deal with the pressure/produced hydrocarbons from the productive interval.

23 Fishing Operations

A *'fish'* is a piece of equipment, a tool or a part of the drill string that the crew loses in the hole. Other small pieces of debris or tools in the hole are called '*Junk'.* The 'fish' or 'junk' has to be removed or '*fished'* out, otherwise the drilling cannot continue. Over the years many ingenious tools and techniques have been developed to retrieve fish. One of these tools is the *'overshot'.* This is made up onto the drill pipe and lowered over the fish. Grapples in the overshot latch onto the fish firmly and the overshot is then pulled out of the hole, hopefully with the fish attached.

When well servicing crews recover stuck pipe, packers, and loose equipment from a well, they call it *'fishing'*. A fish is part of a string of pipe or any other sizable piece of metal in a well. Put another way, a fish is anything crews have to remove before they can continue operations. A fish can occur because of mechanical failure, corrosion, abrasion, and so forth. Regardless of the source of the fish, however, fishing requires knowledge of many special procedures and techniques. Almost every fishing job presents special problems that require careful analysis and good judgement.

One of the more common fishing jobs well service crews handle is fishing for sucker rods. Usually, they use a **mousetrap** or other rod fishing tool and attempt to pull the rods. If they cannot quickly catch and recover the rods, they pull the tubing and recover the rods along with the tubing.

In the case of parted tubing, crews can recover it. Sometimes, however, the job is more difficult. Perhaps the top of the tubing is damaged, making it difficult to latch onto. Or perhaps a frozen packer or packed sand has stuck the tubing. In such cases, a specialist – a fishing tool operator – may bring special tools to the job and may direct the work.

In some cases, operators may have to move in a larger rig to handle drill pipe instead of tubing. In still other cases, they may have to move in a rig with a rotary to turn the work string, which may be tubing or drill pipe. In any case, fishing may be difficult or easy and the workover crew may work alone or it may work under the direction of a specialist.

23.1 Fishing tools

Over the years, manufacturers have developed many fishing tools, including tools to retrieve a fish in an open hole. In some instances, a crew can use the same tools to fish in both open and cased hole.

Taper taps and die collars, spears and overshots, internal and external cutters, milling tools, wash-over pipe, junk retrievers, and jars and safety joints are common fishing tools. Perforating companies also offer several wireline services to augment fishing, including free-point detection, string-shot backoff, and jet and chemical cut-off. Crews use these wireline services to locate the point at which tubing or pipe is stuck and to back off (unscrew) or cut tubing or pipe above the stuck point. Once they back off or cut off the tubing or pipe above the stuck point, they can fish for the stuck portion of string.

A Lead Impression Block – LIB – is often used to assess the shape of the top of the fish.

23.2 Taper Taps and Die Collars

Taper taps and die collars are amongst the oldest of fishing tools. Nevertheless, they are still in use. These tools of case-hardened steel permit the rig fisherman to connect a work string to fish and retrieve it.

A taper tap has special threads machined into it. Crew members make up the tap on the end of the work string and lower it to the top of the fish. The fish is usually part of the tubing string or the drill string lost in the hole. Then they rotate the work string and the attached taper tap. If rotating the work string does not also rotate the fish, then the tap will cut, or thread, its way into the open end of the tubing or pipe. With the tap engaged, drew members pull the work string, tap, and attached fish.

If the fish rotates with the work string as crew members try to engage the tap, then the tap cannot thread into the fish. In such a case, they select another fishing tool. What is more, even if they can successfully attach the tap to the fish, the fish may be stuck and they may not be able to pull it out? As a result, they will have to resort to other fishing tools and methods to free the stuck fish.

A die collar works much like a tap. The tap, however, threads inside the open end of the tubing or pipe. A die collar cuts threads outside of the tubing or pipe. A specialist may, therefore, select a die collar if debris has plugged the end of the fish and prevents insertion of the taper tap.

To use a die collar, crew members first make it up on the end of the work string. Then they lower the die collar and string. When the die collars tags, or touches, the fish, they rotate the work string to attach the die collar to it. As is the case of the taper tap, the fish must remain stationary for the die collar to attach. If the die collar successfully attaches, and if the fish is not stuck, then crew members pull the fish, the collar and the working string.

Unfortunately, once the fishing crew members firmly attach a taper tap or die collar, they cannot easily release it from the fish. Therefore, if the fish sticks and they cannot pull it from the well, they probably will not be able to free the work string from the fish. As a result, the work string also becomes a fish and further complicates the fishing job.

Safety joints can be installed which will part at a pre-determined tension.

23.3 Spears and Overshots

A spear grips inside a hollow fish like tubing or drill pipe. An overshot grips outside the fish. Manufacturers design spears and overshots so that fishing crews can circulate fluid down the work string, through the spear or overshot, and through the fish. Being able to circulate through the fish is an advantage, because fluid circulation may assist the removal and prevent the fish from getting stuck again as the crew pulls it from the well.

Another advantage of a spear or overshot is that crews can place it in or on the fish without rotating the work string. They set gripping devices by pulling on the work string after the spear or overshot engages the fish. By the same token, however, they can release a spear and overshot from a fish by letting down on the work string and rotating it.

23.4 Milling Tools

Crews use milling tools for many purposes. For example, mills smooth off the top of a fish or enlarge an opening in it. Smoothing or enlarging an opening lets crews run other devices inside or outside a fish. Other mills, such as flat-bottomed or bladed types, grind up or cut through solid metal objects in a well.

Manufacturers made the first milling tools of case-hardened steel. Few of these mills lasted very long. During the 1950s, manufacturers found that pieces of tungsten carbide embedded in a mill's cutting edges made mills last indefinitely. Tungsten carbide is extremely hard and resists abrasion. Thus, fragmented tungsten carbide has completely replaced other materials for the cutting edges of downhole milling tools.

23.5 Junk Retrievers

Fishing specialists often use junk retrievers to re-cover small metallic objects dropped or left in a well. One popular type of retriever is a junk basket. Crew members make it up on the end of a work string and lower it to the bottom of the well. Then they start the mud pump and circulate fluid to the junk basket. A special valve in the basket diverts the flow of fluid outside the tool, which causes an area of reduced pressure inside the basket. This reduced pressure, combined with the flow of fluid, lifts small pieces of junk into the basket. The crew then pulls the junk-filled basket to the surface.

Crews also use fishing magnets to retrieve junk. These are very strong magnets that can be placed in a junk basket or run by themselves on wireline. If the junk is an iron-based metal, such as steel, magnets are very effective,

23.6 Jars and Safety Joints

When pipe or tubing sticks in a well, crews can sometimes free it by using a bumper jar. When made up in the stuck string and actuated by the crew, the jar delivers a light upward blow and a heavy downward blow. This blow may free the stuck fish. A bumper jar has a hollow body that moves and a mandrel that joins the jar to the fish. Raising the jar's body to the limit of travel generates a slight upward jar. When the crew drops the string quickly, the jar produces a sharp downward blow on the mandrel. This heavy blow goes into the tubing or pipe made up below the jar. If downward blows can free a fish, a bumper jar can be very effective.

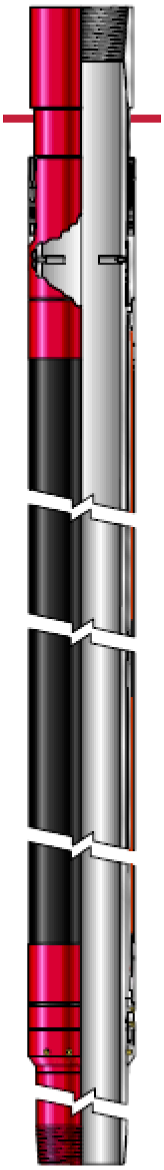
Most fish stuck in a well require a powerful upward jar to free them. Fishing jars create upward impact by the sudden release of tripping devices inside the tools. Jars use two types of tripping device:

1. Mechanical
2. Hydraulic

In a mechanical fishing jar, the blow's force depends on the amount of torque the crew turns against the trip mechanism. The greater the torque, the harder the jarring blow. In a hydraulic fishing jar, blow intensity depends on the pull the crew takes on the tool before it trips; the more pull, the heavier the blow. Drill collars increase the intensity of the blow of mechanical or hydraulic jars. With hydraulic jars, the fisherman may also use a jar accelerator. It intensifies the effect of drill collars used above a hydraulic jar.

Fishing operators almost always make up a safety joint in the fishing string. A safety joint allows release from a fish at any time. Releasing from a fish may be necessary if the fish gets stuck or if the crew needs to run a different type of fishing tool during the procedure. The crew disengages a safety joint by rotating the work string to the left.

23.7 Abandonment



Abandonment will be considered for a well, usually after either logs determine there is insufficient hydrocarbon potential to complete the well, or after production operations have drained the reservoir. Abandonment will entail that particular well being closed permanently.

Different regulatory bodies have their own requirements for plugging operations. Most require that cement plugs be placed and tested across any open hydrocarbon-bearing formations, across all casing shoes, across freshwater aquifers, and perhaps several other areas near the surface, including the top 20 to 50 ft [6 to 15 m] of the wellbore. The well designer may choose to set bridge plugs in conjunction with cement slurries to ensure that higher density cement does not fall in the wellbore. In that case, the bridge plug would be set and cement pumped on top of the plug through drillpipe, and then the drillpipe withdrawn before the slurry thickened.

The tubing will be pulled prior to abandoning, casing can also be removed and Weatherford have a range of tools for cutting and pulling casing and tubing.

Current UK rules governed by the Health and Safety Executive state that five barriers should close off an abandoned well.

24 Well Stimulation

24.1 Acidizing

Acid may be used to reduce damage near the wellbore in all types of formations. Inorganic, organic and combinations of these acids, along with surfactants, are used in a variety of well stimulation treatments. In carbonate formations, acid may be used to create linear flow systems by acid fracturing. Acid fracturing is not applicable to sandstone wells.

The two basic types of acidizing are characterised through injection rates and pressures. Injection rates **below** fracture pressure are termed *'matrix acidizing'* , while those **above** fracture pressure are termed *'fracture acidizing'.*

Matrix Acidizing is applied primarily to remove skin damage caused by drilling, completion, workover or well-killing fluids, and by precipitation of deposits from produced water. Due to the extremely large surface area contacted by acid in a matrix treatment, spending time is very short. Therefore, it is difficult to affect formation more than a few feet from the wellbore.

Removal of severe plugging in sandstone, limestone or dolomite can result in very large increases in well productivity. If there is no skin damage, a matrix treatment in limestone or dolomite could stimulate natural production no more than one and one half times. Matrix treatments tend to leave zone barriers intact if pressures are maintained below frac pressures.

Acids Used in Well Stimulation

The basic types of acid used are:

- Hydrochloric
- Hydrochloric-Hydrofluoric
- Acetic
- Formic
- Sulfamic

Also, various combinations of these acids are employed in specific applications.

Hydrochloric acid (HCl) used in the field is normally 15% by weight HCl; however, acid concentration may vary between 5% and about 35%. The freezing point of 15% acid is -27^{o}F, less than -70^{o}F for 20% – 29% acid, and -36^{o}F for 35% acid. HCl will dissolve limestone, dolomite and other carbonates.

A thousand gallons of 15% HCl will dissolve 1.840 lb or 10.5 cu ft of zero porosity limestone ($CaCO_3$). This reaction will produce 2.050 lb of calcium chloride ($CaCl_2$), 812 lb of carbon dioxide (CO_2) or 6,600 cu ft of CO_2 gas at standard conditions of temperature and pressure, and 333 lb of water, in addition to the 7,600 lb of water injected as a carrier for HCl acid. In practice, after spending in limestone, 1,000 gal of 15% HCl becomes 1,020 gal of 20.5% solution of calcium chloride, weighing 9.79 lb/gal.

Acetic Acid (HAc) is weakly-ionized, slow reacting organic acid. A thousand gallons of 10% acetic acid will dissolve about 704 lb of limestone. The cost of dissolving a given weight of limestone is greater with acetic acid than with HCl.

Acetic acid is relatively easy to inhibit against corrosion and can usually be left in contact with tubing or casing for days without danger of serious corrosion. Because of this characteristic, acetic acid is frequently used as a perforating fluid in limestone wells.

Other advantages of acetic acid in comparison to HCl are:

1. Acetic acid is naturally sequestered against iron precipitation.
2. It does not cause embrittlement or stress cracking of high strength steels.
3. It will not corrode aluminium.
4. It will not attack chrome plating up to 200^{o}F.

Therefore, acetic acid should be considered when acidizing a well with an alloy pump in the hole.

Hydrofluoric Acid use in oil, gas or service wells is normally 3% HF plus 12% HCl. It is employed exclusively in sandstone matrix acidizing to dissolve formation clays or clays which have migrated into the formation. One thousand gal of 4.2% HF acid will dissolve 700 lb of clay. Fast reaction time and precipitants make HF acid undesirable in carbonate-containing sands having more than 20% solubility in HCl. HF acid should never be used in carbonate formations.

24.2 Hydraulic Fracturing

Since hydraulic fracture well stimulation was introduced in the early 1950s, technology has increased tremendously. Frac job costs in certain situations may range upward to perhaps 100% of well drilling cost. Numerous factors must be considered to optimize a particular treatment.

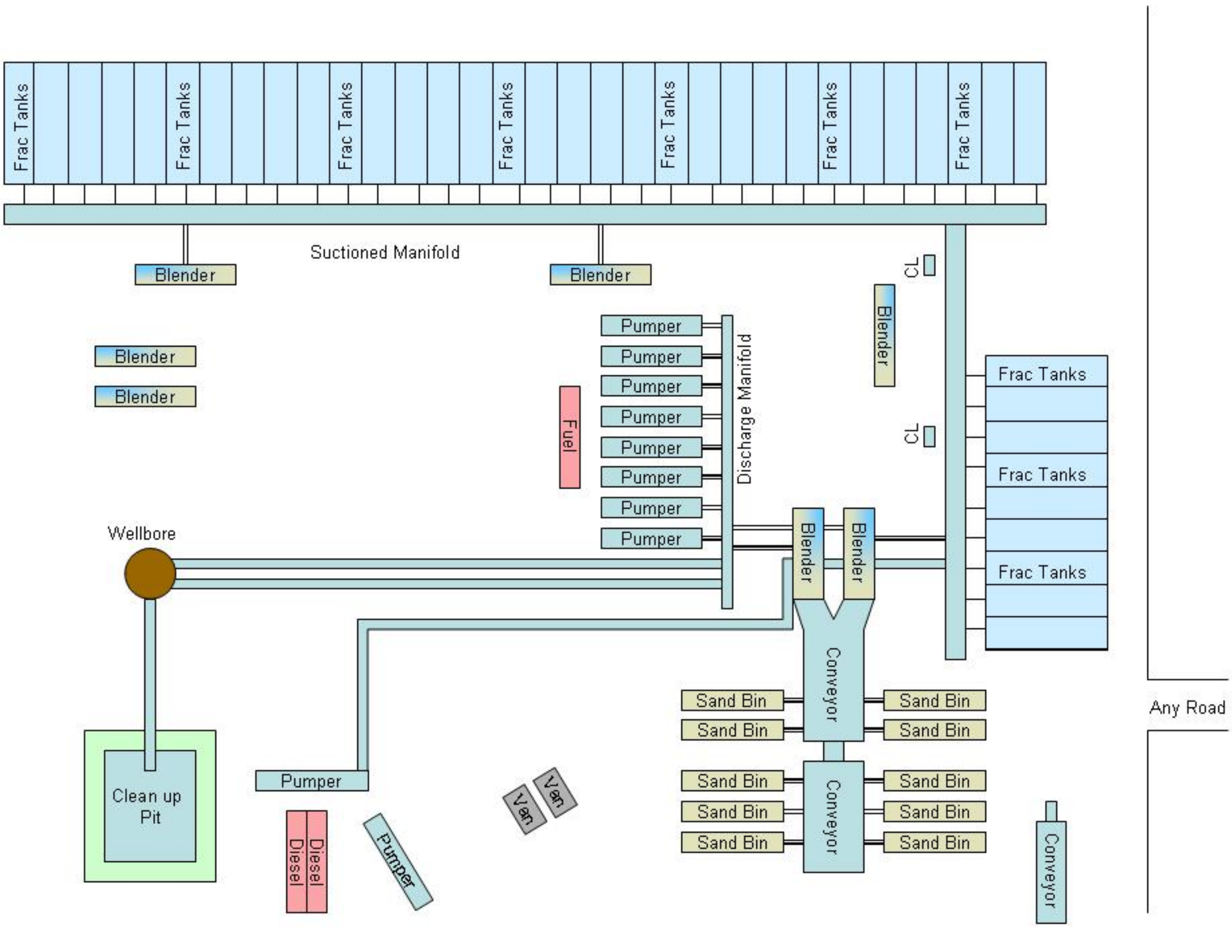


Figure 108 Equipment for a Massive Frac Job

24.2.1 Objective

The objective of hydraulic fracturing for well stimulation is to increase well productivity by creating a highly conductive path (compared to reservoir permeability) some distance away from the wellbore into the formation. Usually the conductivity is maintained by propping with sand to hold the fracture faces apart. Acid fracturing involves most of the same considerations as hydraulic fracturing except that conductivity is generated by removing portions of the fracture face with acid, leaving etched channels after the fracture closes.

Fracture Initiation – A hydraulic fracture treatment is accomplished by pumping a suitable fluid into the formation at a rate faster than the fluid can leak off into the rock. Fluid pressure or (stress) is built up sufficient to overcome the earth compressive stress holding the rock material together. The rock then parts or fractures along a plane perpendicular to the minimum compressive stress in the formation matrix.

Fracture Extension – As injection of frac fluid continues, the fracture tends to grow in width as fluid pressure in the fracture, exerted on the fracture face, works against the elasticity of the rock material. After sufficient frac fluid *'pad'* has been injected to open the fracture wide enough to accept proppant, sand is added to the frac fluid and is carried into the fracture to hold it open after the job.

A vertical fracture grows in length upward, downward and outward. The growth upward and downward may be stopped by a barrier formation, downward growth may also be stopped by fallout of sand to the bottom of the fracture. The growth outward away from the wellbore, (as well as upward or downward) will be stopped when the rate of frac fluid leak off through the face of the fracture into the formation equals the rate of fluid injection into the fracture at the wellbore.

When sufficient sand has been injected, the pumps are shut down, the pressure in the fracture drops, and the earth compressive stress closes the fracture on the proppant.

Sedimentary Rock Not a Piece of Glass –As applied to a sedimentary formation, the word fracture is sometimes thought to be an 'irreparable occurrence' somewhat the same as breaking a piece of glass. This is not true. In creating a fracture, the formation matrix stress is temporarily overcome using fluid pressure.

As soon as the fluid pressure is relaxed, the fracture closes back with little if any increase in conductivity along the fracture, unless propped open by sand, or other permeable material.

Propping the Fracture

The objective of propping is to maintain desired fracture conductivity economically. Fracture conductivity depends upon a number of interrelated factors: type, size, and uniformity of the proppant; degree of embedment, crushing and/or deformation; and amount of proppant and the manner of placement.

Commonly used proppant types and size ranges are:

Sand	
Mesh	Range, inch
70/140	.0083 x .0041
40/70*	.0165 x .0083
30/50	.0234 x .0117
20/40*	.0331 x .0165
16/30	.0469 x .0234
12/20*	.0661 x .0331
8/16	.0937 x .0469
6/12/	.132 x .0661

* *Primary sizes*

Sintered Bauxite	
Mesh	Range, inch
40/60	.0165 x .0078
20/40	.0331 x .0165
12/20	.0661 x .0331

Desirable Properties for Propping Agents

Size and Uniformity

Decreasing size range increases the load that can be supported, and also the permeability of a fracture.

Significant quantity of fines can seriously reduce fracture permeability. For example, 20% material finer than 40 mesh will reduce the permeability of 20/40 sand by factor of 5. Sand graded 10/16 has permeability about 50% greater than 10/20 sand.

24.2.2 Frac Fluids

Basically oil or water fluids are used to create, extend and replace proppant in the fracture. Our ability to tailor the properties of fluids to achieve desired results has improved tremendously with recent advances aimed at providing much higher fluid viscosity, better high temperature stability and minimising formation damage effects. Usual modifications include:

- Fluid loss control
- Gelling or thickening
- Cross-linking of gelling agents
- Emulsification
- Foaming

Generally these comparative statements can be made:

1. Crude oil fluids are cheap and have inherent viscosity which makes them advantageous for relatively low injection rate, shallow to medium depth fracturing. Pressure loss down the casing and safety consideration are often limiting factors.

2. Gelled water fluids (linear aqueous gels) have special advantages due to their higher density and lower friction loss in deeper wells and where higher injection rates are needed. Where high temperatures are involved reasonable viscosity can be maintained up to 250^{o}F

3. Cross-linked aqueous gels have high viscosity to create fracture width, and to provide the proppant carrying capacity for producing highly conductive fractures needed in stimulating higher permeability zones or in propping the long fractures needed in stimulating low permeability zones.

   Compared to linear aqueous gels, cross-linked gels can provide similar viscosity with lower polymer concentration, thereby reducing cost and formation damage. With high temperature cross-linkers and stabilizers, they can maintain relatively high viscosities for extended pumping time at high temperatures.

4. Emulsion fluids provide good viscosity and proppant carrying capacity and very good fluid loss and clean up at reasonable cost.

5. Gelled-oil fluids have primary application in water-sensitive sand zones.

6. Foamed liquids have primary application in low permeability gas zones. Usually, sufficient nitrogen is added to produce 65 -75% quality foam. A primary advantage of foam is excellent cleanup because of the small amount of liquid and the large quantity of energy represented by the high pressure nitrogen. Use of foamed fluids is relatively new; however, application is increasing. Initial problems of low sand concentration and short foam half-life are being overcome by centrifugal sand concentrators and by use of polymers for foam stabilization.

7. Alcohol fluids have primary application in low permeability dry gas zones where, due to relative permeability, oil should not be used.

Weak acid gels have application in dirty sands where clay stabilization may be important.

24.3 Enhanced Production Methods

With the 3 dimensional information from the reservoir engineers, backed up by the geologists, using information from drilling cuttings and coring and logging; we can quite accurately lay out a 3D model of the reservoir. Knowing the drive mechanism also we can work out how production will naturally change over time and what that time-scale might be.

Initially the wells are planned to cope with the particular flow of fluids and what those fluids are; but with careful planning the reservoir engineers and completions engineers can collaborate on a plan to exploit as much oil and gas from the reservoir as cost-effectively as possible.

24.3.1 Water Injection

In a water drive reservoir, additional water can be pumped down a well to add water and pressure to the formation forcing more oil out. This water may come from the sea, being filtered and treated correctly, or it may be produced water which has been filtered and treated being pumped back down the well.

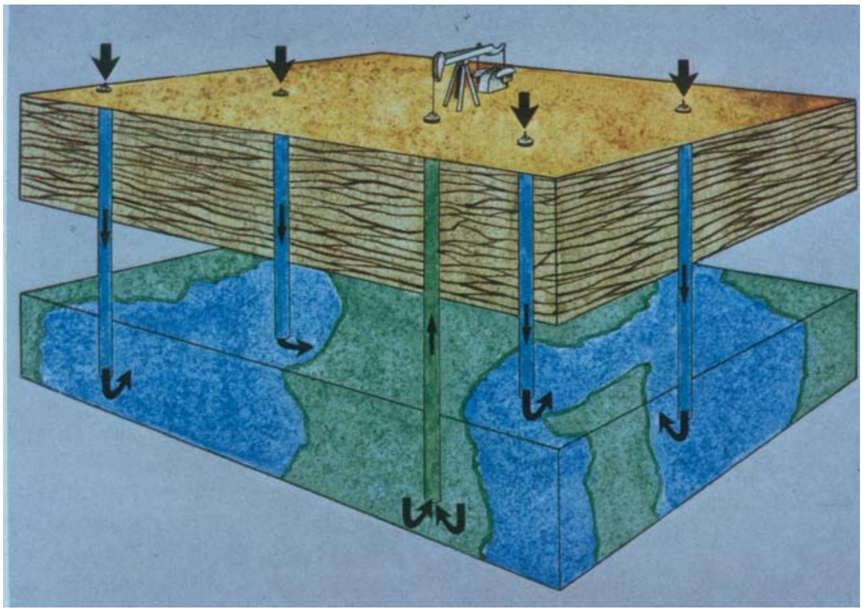


Figure 109 Water Injection

A cost efficient method of water injection would be to utilise produced water and with the pumps being driven by gas fired motors, with the gas also having been produced from the reservoir.

In a planned water injection project a purpose built well may be used for water injection, but in an un-planned situation – where water drive pressure has lowered far more quickly than expected, an existing oil well may be changed slightly and used for water injection.

24.3.2 Gas Injection

There are two types of gas injection: miscible and immiscible.

With miscible gas injection CO2 or Natural Gas is injected into the well under conditions such that the gas mixes with the oil, liberates hydrocarbons and enables oil to flow more freely.

With immiscible gas injection natural gas or Nitrogen is injected which doesn't mix with the oil but simply maintains the reservoir pressure.

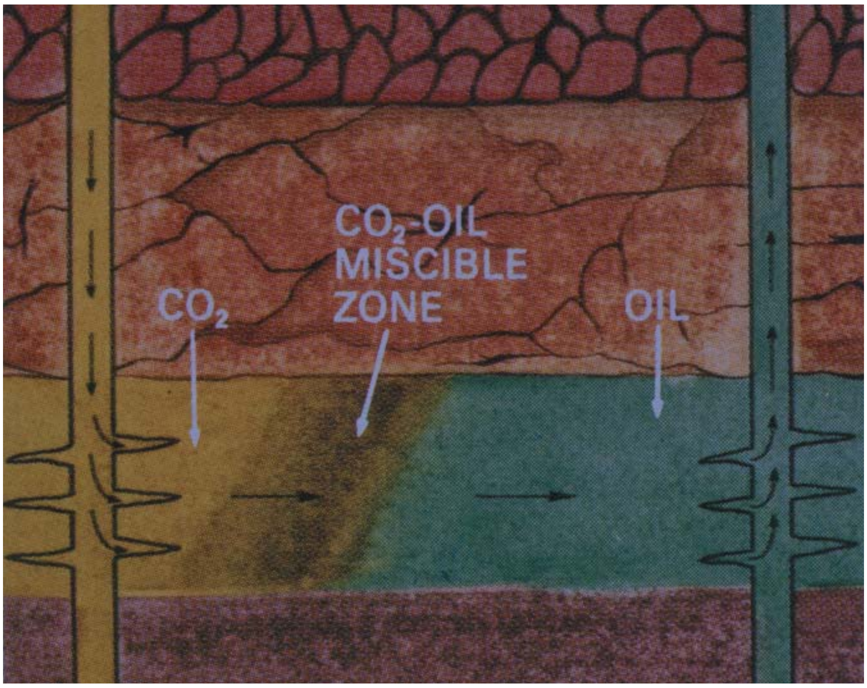


Figure 110 CO2 Injection

24.3.3 Other improved recovery methods

Chemicals can be injected into wells to enhance water injection or simply to enhance oil production.

Steam can be injected where the heat and pressure helps more viscous oil to flow.

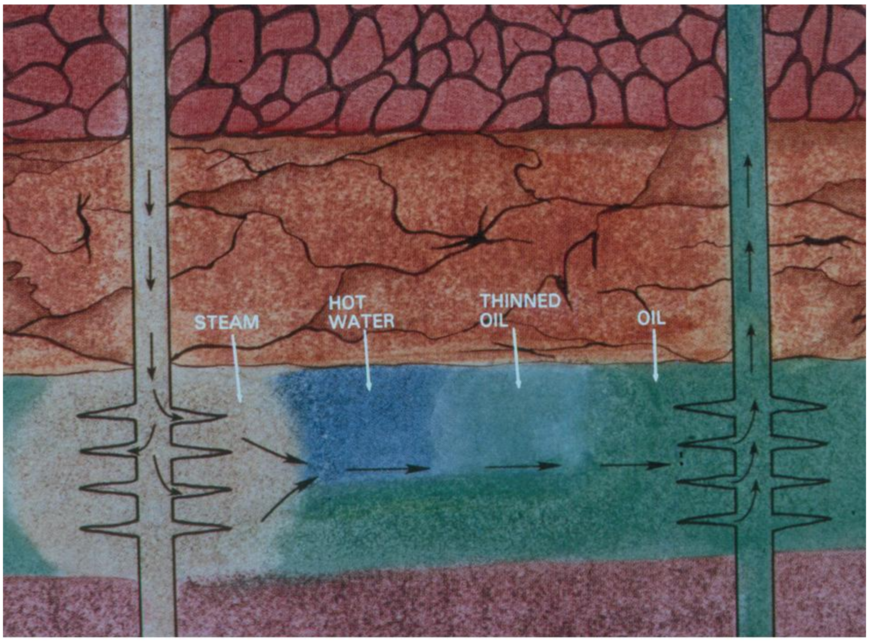


Figure 111 Steam Injection

In some cases the reservoir can be ignited and kept alight by injecting compressed air; gases and heat advance through the formation pushing out the oil ahead.

24.4 Artificial Lift – Pumping

Another of Weatherford's specialities!

Beam Pumps ('Nodding Donkeys') are a common sight in many parts of the world. These are electrically driven reciprocating pumping units which lift oil from the reservoir where there is not good flow or pressure conditions.

Submersible pumping systems are common these days; these units are also electrically driven are placed downhole and used to push the oil out of the well.

Figure 112 Beam Pump

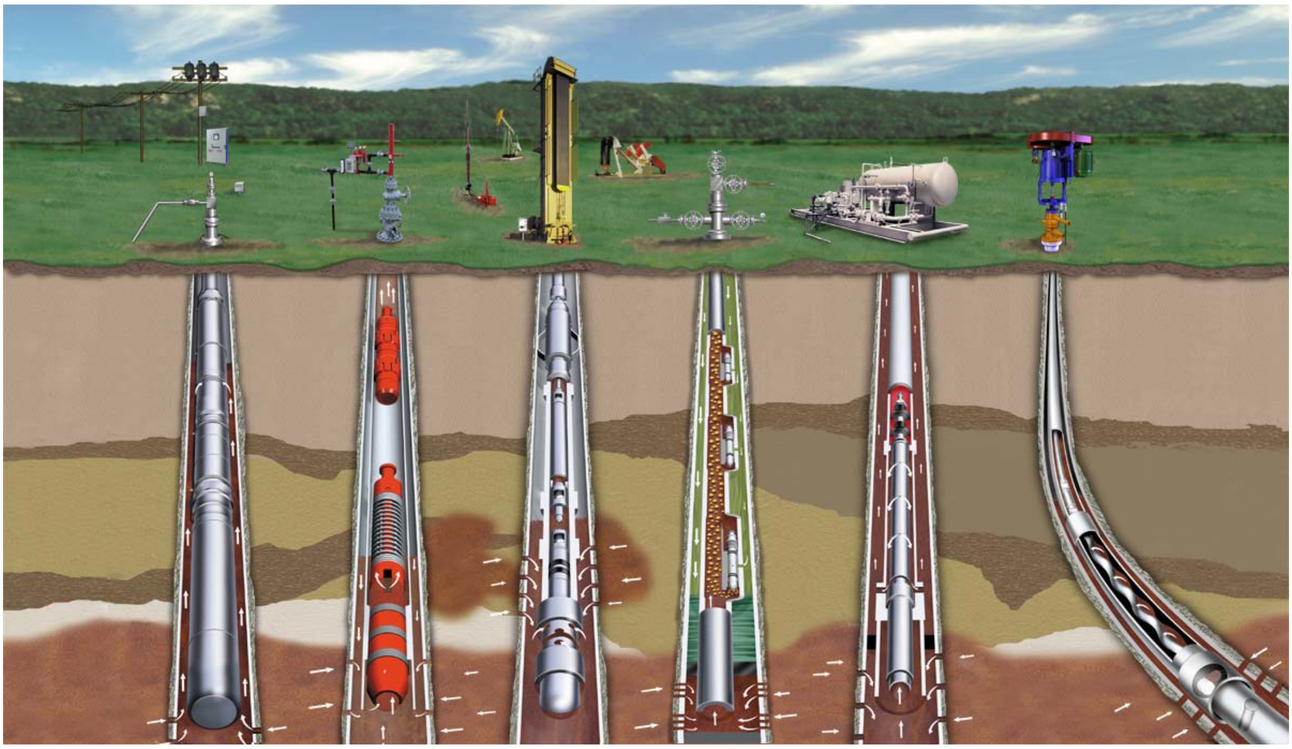
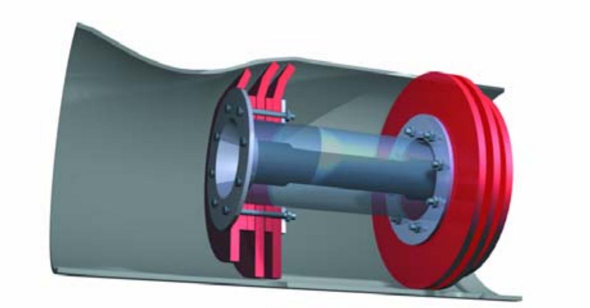


Figure 113 Weatherford Downhole Pump Systems

25 Transportation systems



Hydrocarbons are fluids, some liquids and some gases; they are all flammable and therefore relatively hazardous. So transporting them is no easy matter. That said, most of us drive in or have been driven in a petrol or diesel powered vehicle, which do carry around their own fuel supply with little hazard, unless the vehicle is involved in an accident.

From the earliest developments, hydrocarbons needed to be transported away from where they were produced to treating facilities such as refineries, where the raw material was turned into something more useful and valuable.

Originally oil was transported in wooden and then steel drums known as **barrels**, the common term since then for the unit of measurement of crude oil – the **barrel.** Even today, when hardly any of the stuff is transported in barrels, the price is calculated in barrels, the rate of production of a well is calculated in barrels; even the volume of a well is calculated in barrels – it is THE standard.

25.1 A brief history of pipelines.

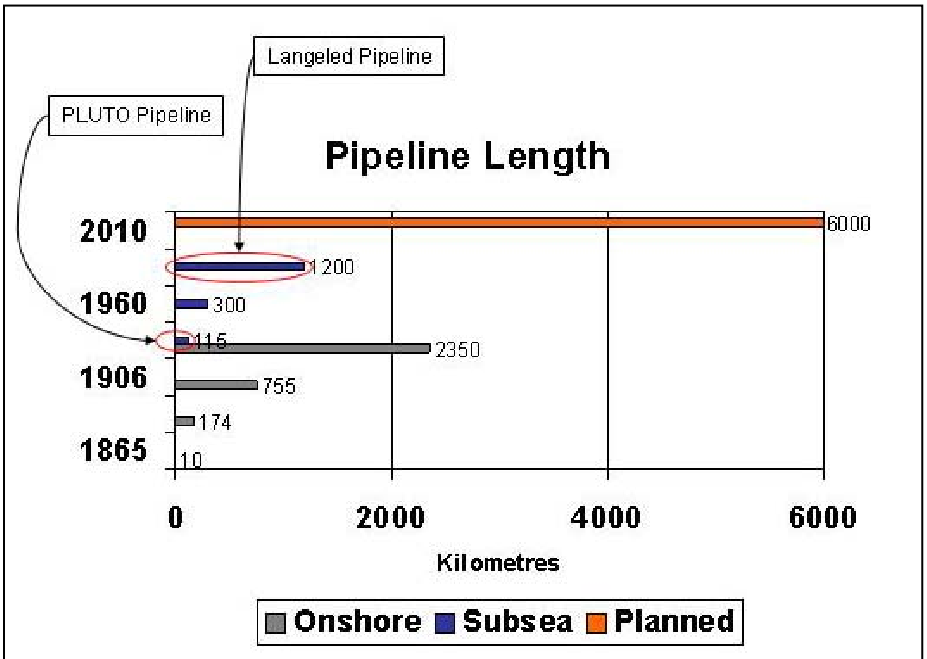


Figure 114 The Growth of Pipeline Length

The transport of fluid by pipeline was known to early civilisations. The ancient water aqueducts which may still be seen today are one of several examples of this.

Pipelines have been used for transporting oil since the first years of commercial crude-oil production. A six mile long, two inch diameter line was built in Pennsylvania in 1865. In the late nineteenth century the Russians built pipelines from their Caucasian oilfield to the Caspian Sea, one of them over 400 miles long. In 1911 BP, then the Anglo-Persian Oil Company, commissioned its first crude-oil pipeline 130 miles long from Masjid-i-Sulaiman to Abidjan, Iran.

In the oil producing countries of the Middle East there were no practical alternatives to the pipeline for the movement of large volumes of crude oil to the coast and so here the development of pipelines continued. In Europe, however, with widely distributed areas of consumption fed by traditional means of transport from coastal refineries, development was slow. It was in the USA with its own crude-producing wells and rapidly expanding centres of production that the modern pipeline industry developed.

25.1.1 What are pipelines used for?

The products carried by pipelines include oil, hydrocarbon gas, water, bitumen, cement, Ethylene (used for plastic manufacture), jam, steam, foam, and other products such as nitrogen, fuel oil and many more. Obviously here we are just interested in hydrocarbon products.

Pipelines are the simplest logistical solution to the transportation of any hydrocarbon and are used whenever production capacity and longevity, economics and environmental conditions allow. Distance is often not a restriction in terms of pipeline use; they have been installed over 100's and even 1000's of kilometres. See Figure 114 The Growth of Pipeline Length.

Figure 116 The 48" diameter Alyaska Pipeline delivers 1 million barrels per day of crude oil. That would fill a Very Large Crude Carrier (VLCC) in 2 days.

For gas, a pipeline is often the only solution, in fact for a long time gas was flared from many oil producing installations as this was the most economical option and there wasn't for a long time a huge market for gas. As gas is now utilized more, economic conditions are more improved and environmental awareness is more of a concern, gas pipelines are installed more often. In fact gas usage has grown dramatically over the past 20 years and is now a feedstock for petrochemical plants; it is used for power stations, for domestic heating and cooking. It is so valuable in fact, that operators are prepared to spend millions on the process of cooling t until it liquefies, shipping it halfway around the world and then heating it up again to provide high pressure, dry gas in another country.

Pipelines have been installed over some of the harshest terrain in the world and once installed; pipelines have to be constantly checked to ensure that the ground they are on or in does not move so much as to cause damage to the pipeline. The Alyaska Pipeline is one with enormous potential for movement, due in part to the extreme changes in temperature from winter to spring and autumn to winter.

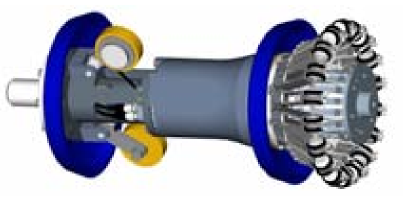


Figure 115 Weatherford Inspection Pig

Many 1000s of kilometres of pipeline have been installed subsea and Weatherford have successfully worked on some in very deep water.

Did you know?

The Temporary Air Compression Station (TACS) was installed in Sicily, Italy, for wet buckle contingency during pipe-lay of a 32" diameter gas export pipeline. Wet buckle is something which happens to pipelines occasionally when being laid from the back of a pipelay vessel; something goes wrong and the pipeline has to be cut and dropped to the sea floor. In this instance the pipeline immediately fills with water and is therefore too heavy to be lifted back onto the vessel. The air compressors are then used to remove the water, making the pipeline light enough to be lifted again.

The 520 km trans-Mediterranean pipeline, known as the Libya Gas Transmission System (LGTS) or GreenStream, runs from Mellitah, Libya, to Gela, Sicily, in water depths exceeding 1,100 m. In this depth of water, the pressure required to de-water the pipeline is over 110 bar (1,650 psi).

The Weatherford's TACS is the largest fleet of purpose-built air compression equipment in the world. The majority of the compressors (58) are built with the unique "combination" design, incorporating a rotary screw and reciprocating "booster" compressor in a single 20-ft skid frame. The fully stand-alone TACS includes 4 feed compressors, 16 air dryers capable of dew points in excess of -60°C, 8 high-pressure boosters, 18 coalescing and carbon bed oil removal filters, flowmeters, centralized remote monitoring system, fuel pumping and distribution system and all support facilities (electrical generation, lighting, etc.).

The TACS delivers 53,000 horsepower and produces more than 1,800 nm3/min (63,600 scfm) of compressed air at pressures up to 250 barg (3,625 psig). It also incorporates the facility for high-pressure nitrogen generation with the addition of Weatherford's membrane units.

The station was mobilized directly to Sicily from Russia, where it was successfully used to provide similar services to Saipem on the Blue Stream development project in the Black Sea. The entire Weatherford-GreenStream project work scope has had a contract value of €26m and a duration of two years.

25.2 Tankers

Some fixed oil producing platforms have storage facilities in their legs; other fields have tankers moored permanently on site in which they can store the produced oil. Floating Production Storage and Off-loading (FPSO) vessels usually have large storage tanks. Any of these offshore production and storage facilities require the regular attendance of a tanker to unload their cargo into. The tankers then transport the crude to refineries. Many fixed installations are serviced by pipelines, which transport the crude directly to a refinery without the need for a tanker. Some pipelines, don't take the crude all the way to a refinery however, they may terminate at an oil terminal from which tankers have to be used to transport the crude to a refinery.

Countries such as the USA and the UK have an import requirement for crude, as their own supplies are dwindling and cannot keep pace with increased demand; other countries such as China and India are developing so fast that their oil production cannot keep pace with demand. They all need tankers to deliver vast quantities of oil to them. Whilst there are many national and cross-border pipelines around the world, there are none for example across the Atlantic from Europe to the USA; and whilst there are some long crude pipelines, some of the longest pipelines these days are being constructed for gas supply. So the need for tankers will remain for some time.

Figure 117 - Super Tanker Jahre Viking. This tanker can carry 564,700 tonnes crude oil; it would take the Alyaska pipeline 4 days to fill this tanker. It has been converted to an FSO (Floating Storage and Offloading) vessel.

26 Refining and processing

Refineries take the base products – oil and gas and produce **base chemicals** and some refined products such as petrol, diesel, bitumen and jet fuel. The base chemicals – the **aromatics** and the **lower olefins** are then used by the petrochemical industry to produce **second stage** or **intermediate chemicals**.

26.1 Crude Oil Refining

Crude oil is the term for "unprocessed" oil, the stuff that comes out of the ground.

There are three main steps from raw material to finished product: refining the crude oil, then producing the base chemicals, and finally transforming these into plastics, paints, adhesives etc.

Crude oils vary in colour, from clear to tar-black, and in viscosity, from water to almost solid.

Crude oils are such a useful starting point for so many different substances because they contain **hydrocarbons**. As you will remember from earlier sections; hydrocarbons are chains of molecules that contain hydrogen and carbon in various proportions and structures.

There are two things that make hydrocarbons exciting to chemists:

- Hydrocarbons contain a lot of **energy**.
    - Many of the things derived from crude oil like gasoline, diesel fuel, paraffin wax and so on take advantage of this energy.
- Hydrocarbons can take on many different forms.
    - The smallest hydrocarbon is **methane** (CH_4), which is a gas that is a lighter than air. Longer chains with 5 or more carbons are liquids. Very long chains are solids like wax or tar. By chemically **cross-linking** hydrocarbon chains you can get everything from soft, synthetic rubber to hard nylon. Hydrocarbon chains are very versatile!

The oldest and most common method of refining crude oil is to distil it. **Fractional distillation** is the normal way of doing this, as follows:

1. **Heat** the crude to a high temperature. Heating is usually done with high pressure steam to temperatures of about 1112 degrees Fahrenheit / 600 degrees Celsius.
2. The mixture **boils**, forming vapour (gases); most substances go into the vapour phase.

3. The **vapour** enters the bottom of a long column (**fractional distillation column**) that is filled with trays or plates.
    - The trays have many holes or bubble caps (like a loosened cap on a soda bottle) in them to allow the vapour to pass through.
    - The trays increase the contact time between the vapour and the liquids in the column.
    - The trays help to collect liquids that form at various heights in the column.
    - There is a temperature difference across the column (hot at the bottom, cool at the top).
4. The **vapour rises** in the column.
5. As the vapour rises through the trays in the column, it **cools**.
6. When a substance in the vapour reaches a height where the temperature of the column is equal to that substance's boiling point, it will **condense** to form a liquid. (The substance with the lowest boiling point will condense at the highest point in the column; substances with higher boiling points will condense lower in the column.).
7. The trays **collect** the various liquid fractions.
8. The collected liquid fractions may:
    - pass to condensers, which cool them further, and then go to storage tanks
    - go to other areas for further chemical processing

The lighter products -- liquid petroleum gases (LPG), naphtha, and so-called "straight run" gasoline -- are recovered at the lowest temperatures. Middle distillates -- jet fuel, kerosene, distillates (such as home heating oil and diesel fuel) -- come next. Finally, the heaviest products (residuum or residual fuel oil) are recovered, sometimes at temperatures over 500^{o}C.

Very few of the components come out of the fractional distillation column ready for market. Many of them must be chemically processed to make other fractions. For example, only 40% of distilled crude oil is gasoline; however, gasoline is one of the major products made by oil companies. Rather than continually distilling large quantities of crude oil, oil companies chemically process some other fractions from the distillation column to make gasoline; this processing increases the yield of gasoline from each barrel of crude oil.

Refineries also treat the various fractions to remove any impurities.

Refineries **combine** the various fractions into mixtures to make desired products. For example, different mixtures of chains can create gasolines with different octane ratings.

26.2 Cracking

Neither fractional distillation of oil, nor liquefaction of natural gas, produces the chemicals that are most useful for the industry. This is achieved by **’cracking’** which can be done in two ways: either by heating a hydrocarbon to high temperatures with steam, or by using slightly lower temperatures and a catalyst, a process commonly known as **’cat cracking’**. **Cracking** is a further refining process, which breaks up some of the fractions from the distillation tower.

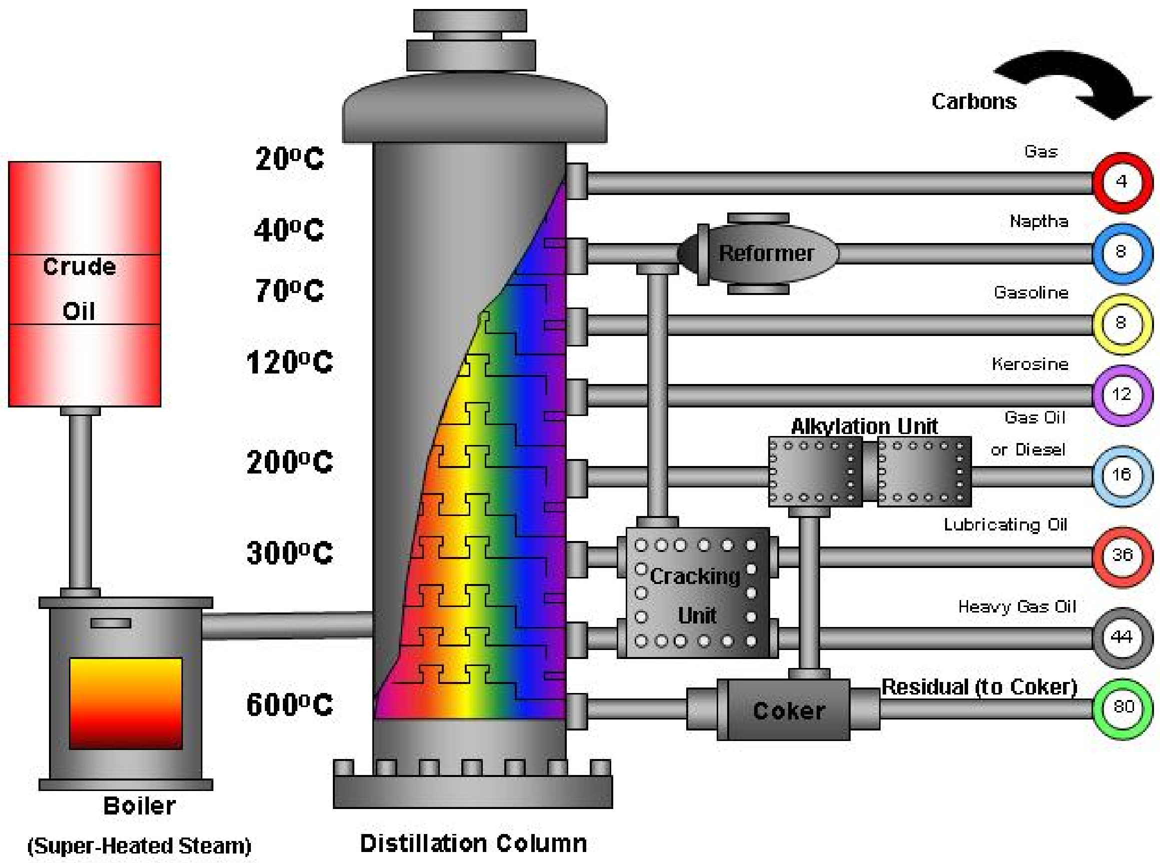


Figure 118 Fractional Distillation of Crude Oil

There are several types of cracking:

- **Thermal** - you heat large hydrocarbons at high temperatures (sometimes high pressures as well) until they break apart.
- **Steam** - high temperature steam (1500 degrees Fahrenheit / 816 degrees Celsius) is used to break ethane, butane and naphtha into ethylene and benzene, which are used to manufacture chemicals.
- **Visbreaking** - residual from the distillation tower is heated (900 degrees Fahrenheit / 482 degrees Celsius), cooled with gas oil and rapidly burned (flashed) in a distillation tower. This process reduces the viscosity of heavy weight oils and produces tar.
- **Coking** - residual from the distillation tower is heated to temperatures above 900 degrees Fahrenheit / 482 degrees Celsius until it cracks into heavy oil, gasoline and naphtha. When the process is done, a heavy, almost pure carbon residue is left (**coke**); the coke is cleaned from the cokers and sold.
- **Catalytic** - uses a catalyst to speed up the cracking reaction. Catalysts include zeolite, aluminium hydro-silicate, bauxite and silica-alumina.

- **Fluid catalytic cracking** - a hot, fluid catalyst (1000 degrees Fahrenheit / 538 degrees Celsius) cracks heavy gas oil into diesel oils and gasoline.
- **Hydrocracking** - similar to fluid catalytic cracking, but uses a different catalyst, lower temperatures, higher pressure, and hydrogen gas. It takes heavy oil and cracks it into gasoline and kerosene (jet fuel).

After various hydrocarbons are cracked into smaller hydrocarbons, the products go through another fractional distillation column to separate them.

DID YOU KNOW? :

Between eight and ten per cent of the world's output of oil and gas go to create the basic chemicals (such as ethylene, propylene, butylene, benzene, toluene, xylene) from which most chemicals products derive.

26.3 Natural Gas

Refinery gas and that from natural gas wells also offers an attractive resource. Natural gas is predominantly methane (C_1) but there are significant amounts of ethane (C_2) and propane (C_3) as well as natural gas liquids (NGL) these can be separated into their components by lowering the temperature until they liquefy.

26.3.1 To base chemicals

Almost any hydrocarbon fraction can be cracked to give a range of other hydrocarbons such as the gases, ethylene and propylene, which are the main raw ingredients for the chemicals industry.

The petrochemicals industry is mainly interested in maximising two types of product: the aromatics, and the lower olefins such as ethylene and propylene, that play a major role in the industry.

In the USA most ethylene comes from the ethane and liquefied petroleum gases extracted from natural gas.

In Europe and Japan, where there is less natural gas, the supply of olefins comes mainly from the naphtha fraction of refined oil.

DID YOU KNOW? :

Michael Faraday discovered benzene in 1825, when he investigated the oil that separated out from gas cylinders produced by the Portable Gas Company of London, which made its gas by heating whale oil. A vial of his benzene, which he called carburet of hydrogen, still exists and when it was analysed a few years ago it was discovered to be 99% pure.

27 The History of Offshore Technology

The following chronology, details some of the amazing technological events associated with offshore hydrocarbon exploration and production; it is linked with world events.

1940 – 1949
KEY EVENTS
· 1945 - World War II ends.
· 1946 - First independent platform offshore (Magnolia - Creole, Louisiana).
· 1947 - Platform built nine miles offshore (Ship Shoal - Kerr-McGee).
· 1947 - First use of tender platform support (Kerr McGee - Ship Shoal).
· 1949 - 11 fields found in Gulf of Mexico with 44 exploratory wells.

KEY TECHNOLOGIES
· 1940 - Steel/concrete caissons used to support rig (Lake Maracaibo).
· 1941 - First neutron log.
· 1943 - First subsea completion (Lake Erie).
· 1945 - Power tongs and slips introduced.
· 1945 - Piston corer for ocean bottom developed (Kullenberg).
· 1947 - Oceanographer predicts 32-ft wave maximums for US Gulf.
· 1946 - First US use of steel platform pilings (Eugene Island - Magnolia).
· 1947 - First tender-supported platform (Ship Shoal - Kerr-McGee).
· 1948 - Humble Oil buys 19 Navy LSTs for tender conversion.
· 1949 - First offshore heavy lift barge (150 tons - McDermott).
· 1949 - First offshore submersible barge (Breton Sound 20 - Hayward).

1950 - 1959
KEY EVENTS
· 1950 - First application of wave force studies (Morrison).
· 1953 - Texas holds first offshore lease sale.
· 1955 - George Bush becomes president of Zapata.
· 1955 - Platform installation depth reaches 100 ft.
· 1955 - Five mobile drilling units in operation.
· 1957 - First discovery off Texas (High Island - Stanolind).
· 1957 - First US Gulf gas flows ashore (Shell).
· 1958 - Subsea completions proposed (McEvoy).
· 1958 - Last year that production depth equalled drilling depth (135 ft).
· 1958 - First commercial helicopter service (US Gulf - PHI).
· 1959 - Jacket installation depths reach 200 ft

KEY TECHNOLOGIES
· 1953 - First platform jacked into position
· 1954 - First hydraulic rotary rig developed.
· 1954 - First platform for 100 ft water depths (McDermott).
· 1954 - First jackup drilling unit built (Barge No. 1 - Delong design).
· 1954 - First mat-supported jackup driller (Mr. Gus - Bethlehem design).
· 1954 - First offshore pipeline laid (Gulf of Mexico - Brown & Root).
· 1954 - First directional control bottom-hole assembly.
· 1954 - First purpose-build submersible (Mr. Charlie - Odeco).
· 1955 - First three-leg jack-up driller (Scorpion - LeTourneau design).
· 1955 - Analog computers used to study ocean wave data.
· 1955 - Modern supply vessel designed (Laborde - Tidewater).
· 1956 - First deepwater bottle submersible (Rig 46 - Kerr-McGee).
· 1956 - First drill ship launched (CUSS I - California).
· 1956 - First jacket launched from a barge in US Gulf (McDermott)
· 1958 - First purpose-built pipe layer (BAR 207 - Brown & Root).
· 1958 - Through-tubing workover begin offshore.
· 1958 - First wireline retrievable subsurface safety valve (Camco).
· 1959 - High temperature cement developed (Halliburton).
· 1959 - Flexible flowline installed (US Gulf - Shell).
· 1959 - Offshore rotating hoists lift 800 tons.
· 1959 - Sealed bearing drill bit developed.
· 1959 - First offshore gas compression platform (US Gulf/Shell).

1960 – 1969 KEY EVENTS

· 1960 - First multi-platform complex in US Gulf (Freeport).
· 1960 - OPEC founded.
· 1962 - Fixed platform depth reaches 200 ft (US Gulf - Gulf Oil).
· 1963 - Oil strike in Cook Inlet, Alaska (Shell).
· 1963 - Pipelay water depth reaches 264 ft (California - Shell).
· 1965 - JOIDES deepwater coring begins (Florida - Glomar Challenger).
· 1965 - Mobile drilling fleet reaches 75 units.
· 1965 - Offshore Company becomes largest rig owner (16 units).
· 1966 - Two jack-up drilling units sink (Gulf of Mexico).
· 1967 - Diving depths reach 600 ft.
· 1967 - Oil struck at Prudhoe Bay, Alaska.
· 1968 - First Offshore Technology Conference held.
· 1969 - Santa Barbara (California) blowout and pipeline leak.

KEY TECHNOLOGIES

· 1960 - Towed fish locates underwater pipelines (Shell).
· 1960 - Cement bond log developed (Schlumberger).
· 1961 - Dynamically positioned CUSS I drills first MOHO well (La Jolla, California).
· 1961 - First use of dynamic-positioning (Eureka - H. Shatto).
· 1961 - Spool pipelaying developed (Aquatic Contractors).
· 1961 - Seafloor blowout preventer developed.
· 1961 - First remote control unmanned production platforms (Gulf Oil).
· 1961 - First moving seismic collection method (Socony Mobil).
· 1961 - First underwater pipeline trencher (Orinoco/Phillips).
· 1961 - First computer program for fracture/acidizing (Dowell).
· 1961 - First subsea well completed (Gulf of Mexico - Shell).
· 1962 - Divers reach 285 ft. depth (US Gulf - Ketchman).
· 1962 - Robotic forerunner of ROV begins operation (Shell).
· 1962 - Catamaran drill ship (C.P. Baker - Reading & Bates).
· 1962 - First converted semi-submersible (Blue Water No. 1 - B. Collipp).
· 1963 - First newbuilt semi-submersible (Ocean Driller - Laborde/Graham).
· 1962 - First commercial reel pipelay vessel launched (U-303).
· 1963 - Custom-built drilling fluid transport vessel developed (Baroid).
· 1964 - Twin derricks mounted on platform (US Gulf - Humble).
· 1964 - Microwave data transmission begins in US Gulf (Shell).
· 1964 - Second generation semi-submersible (Blue Water No. 2).
· 1965 - Single buoy mooring system tested (Qatar - Shell).
· 1965 - First 500-ton derrick barge introduced.
· 1965 - Common depth point seismic technique employed.
· 1965 - Low temperature steels introduced.
· 1966 - Second generation pipelay barge (North Sea - Brown & Root).
· 1966 - Gas source seismic profiling introduced (Shell).
· 1967 - Stinger and tensioner used on pipelaying operation.
· 1967 - One-mile offset wellbore achieved (Whitley Bay - Safari).
· 1967 - Pipeline hot-tap developed (Ocean Systems - Union Carbide).
· 1967 - Computerized well data monitoring developed (Humble).
· 1967 - Diverless subsea completion (Brown Oil Tools).
· 1967 - First barge launch of platform jacket.
· 1968 - US satellite transit navigation system set up.
· 1968 - Bright Spot seismic technology developed.
· 1968 - First oil trans-shipment takes place (Shell).
· 1969 - Doppler sonar improves marine seismic accuracy.
· 1969 - First coiled tubing rig job (Bowen - Itco).

1970-1979

KEY EVENTS

· 1970 - US requires environmental impact statements.
· 1973 - Investment in US Gulf rises to $16 billion.
· 1973 - Middle East embargo of crude oil.
· 1974 - Glomar Explorer lifts Soviet submarine from 11,000 ft depths.
· 1974 - First strike in Canadian Arctic (Adgo/Imperial).
· 1974 - 800 platforms installed to date in US Gulf.
· 1976 - OPEC producing two-thirds of free world's oil.
· 1978 - 140 subsea completions installed worldwide.
· 1979 - Iranian embargo of oil.
· 1979 - Three Mile Island nuclear accident.
· 1979 - Ixtoc I well blows out off Mexico.
· 1979 - Fixed platform depth exceeds 1,000 ft.

KEY TECHNOLOGIES

· 1970 - Habitat, alignment frame developed for pipeline repair.
· 1970 - First deepwater re-entry (Glomar Challenger -13,000 ft).
· 1970 - Offshore survival capsules deployed.
· 1970 - Tanker transits Northwest Passage in winter (Manhattan).
· 1971 - PDC bits tested (Christensen/Shell).
· 1972 - Landsat becomes available for remote sensing.
· 1973 - Portable satellite rig positioning system developed
· 1973 - Small scale tension-leg platform concept tested (California).
· 1973 - Gravity/magnetic data added to seismic picture.
· 1974 - 3-D seismic data acquisition tested (Gulf)
· 1974 - Pipelay exceeds 1,000 ft water depth (Castoro V - Saipem).
· 1974 - First one-atmosphere diving suit used (North Sea - Oceaneering).
· 1974 - Drilling water depth hits 2,150 ft (Gabon - Shell).
· 1975 - Reel pipelay exceeds 1,000 ft water depth (Chickasaw).
· 1975 - First floating production system begins work (Argyll - Hamilton).
· 1976 - Seismic data streamer tracking introduced.
· 1976 - Exxon's Hondo platform installed in 850 ft water depth.
· 1976 - Pipelay barges with 1,000 ft capability (Viking Piper, ETPM 1601).
· 1976 - First subsea alignment/welding frame developed.
· 1977 - Comex simulates dives to 2,000 ft.
· 1977 - Bottom-tow pipeline installation tested.
· 1977 - First tanker production system installed (Castellon - Shell).
· 1977 - First manipulator arm developed for underwater vehicles
· 1978 - First measurement-while-drilling system introduced (Teleco).
· 1978 - Deepwater welding (300 meters) certified.
· 1978 - Shell's Cognac platform installed in 1,022 ft water depths.
· 1978 - Radio telemetry used on towed seismic receivers.
· 1978 - First bottom-towed pipeline (Statfjord).
· 1978 - Computers convert velocity data into geological information.
· 1979 - Pipelay exceeds 2,000 ft water depths (Castoro VI - Sicily).
· 1979 - First semi-submersible construction vessel (Uncle John).

1980 - 1989

KEY EVENTS

· 1980 - Iraq invades Iran.
· 1980 - Global economic recession reduces oil demand.
· 1982 - Ocean Ranger semi-submersible driller sinks (Hibernia - Odeco).
· 1982 - First artificial drilling island built off Alaska.
· 1982 - 108 mobile new drilling units delivered (total - 574).
· 1983 - NYMEX oil trading begins.
· 1983 - Demand for oil continues decline, inventories rising.
· 1983 - Transworld Rig 46 completes 18-year contract (Nigeria - Gulf).
· 1984 - Offshore production surpasses 14 million b/d (26% of total world).
· 1984 - Saudi Arabia reduces large oil output to support prices.
· 1984 - Buyouts and takeovers of US oil companies escalate.
· 1985 - Support vessel fleet peaks at 5,000 worldwide.
· 1984 - Mobile drilling unit fleet peaks at 603 units.
· 1984 - Production water depth exceeds 2,000 ft.
· 1985 - Demand for mobile drilling units peaks at 530.
· 1985 - Oil prices drop to $10/bbl.
· 1986 - Chernobyl nuclear disaster.
· 1987 - Demand for mobile drilling units drops to 275.
· 1988 - Oil prices remain below $18/bbl.
· 1988 - Kerr McGee leases tract in 10,942 ft water depth.
· 1989 - Exxon Valdez tanker accident (Valdez, Alaska).
· 1989 - Platform removals outpace installations in US Gulf.

KEY TECHNOLOGIES

· 1981 - First long single piece jacket launched (Union - Cerveza -968 ft)
· 1981 - First offshore horizontal well drilled (Rospo Mare- Elf).
· 1982 - Mechanical tie-in executed in 650 ft depths (Big Inch).
· 1983 - First guyed tower installed (Lena - Exxon).
· 1984 - First steerable drilling system (Norton Christensen).
· 1984 - First tension-leg platform in operation (Hutton - Conoco).
· 1985 - First floater installed in US Gulf (1,400 ft - Placid Oil).
· 1986 - Deepest US offshore well drilled (25,000 ft - Apache).
· 1986 - Derrick barge lift capacity reaches 13,200 tons (McDermott)
· 1987 - Alaska's first arctic offshore field on-stream (Endicott).
· 1988 - Drilling water depth reaches 7,512 ft (US Gulf - Shell).
· 1988 - Deepest fixed platform installation (1,353 ft - Bullwinkle/Shell).
· 1988 - First minimal platforms emerge in US Gulf.
· 1989 - First floater installed in US Gulf (Placid).
· 1989 - First US tension leg platform (Jolliet - 1,760 ft - Conoco).
· 1989 - 3D seismic processing begins.

1990 - 1997

KEY EVENTS

· 1990 - Iraq invades Kuwait; oil prices rise to $35/bbl.
· 1991 - Oil prices slide as Iraq/Kuwait conflict ends.
· 1991 - Collapse of USSR, opening of Eastern Europe.
· 1991 - Zero discharge drilling units mandated for some US areas.
· 1992 - US majors' international budgets exceed US allocations.
· 1992 - Russia/CIS countries provide new investment opportunities.
· 1993 - Oil prices weaken to $13-15/bbl.
· 1993 - Higher gas prices push up US Gulf of Mexico activity.
· 1993 - Low oil prices, UK tax policies reduce North Sea drilling.
· 1993 - Operators begin partnering, integrated services.
· 1994 - International Law of the Sea enacted by UN.
· 1995 - Oil demand begins edging up.
· 1995 - North Sea production escalates to meet energy demand.
· 1996 - Oil prices surpass $20/bbl mark and remain there.
· 1996 - OCS lease sale attracts largest bid volume since 1983.
· 1996 - Shortage of deepwater semi-submersibles becomes critical.
· 1997 - Rig day rates climb as shortage for all units develops.
· 1997 - Ten rig new builds, 24 rig upgrades underway.

KEY TECHNOLOGIES

· 1991 - First horizontal well drilled offshore.
· 1991 - First offshore sand control fracture/packing job.
· 1991 - Workstations begin modelling 3D seismic.
· 1992 - Sleipner A condeep sinks in Norwegian fjord.
· 1993 - Second tension leg platform installed in US Gulf (Auger - Shell).
· 1993 - Layaway tree designed for 6,000 ft water depths (Petrobras).
· 1993 - First J-lay pipelaying operation (McDermott - Shell).
·1993 - First threaded flowline installed (BP).
·1993 - Shearable completion riser joint (Petrobras).
·1994 - Spoolable gas lift completion developed (Camco).
·1994 - Shell's Auger TLP installed in 2,860 ft water depths.
·1994 - US Gulf's first successful floating producer installed (Enserch)
·1995 - 26,000 ft horizontal offset record set at Wytch Farm (BP-UK)
·1996 - First through-tubing multi-lateral intervention
·1996 - First spar production unit installed.
· 1997 - Production exceeds 5,000 ft water depth (Shell - Mensa)