Petroleum
Engineering and Production

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First Edition, 2012

ISBN 978-81-323-0965-9

Published by:
Academic Studio
4735/22 Prakashdeep Bldg,
Ansari Road, Darya Ganj,
Delhi - 110002
Email: info@wtbooks.com

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Chapter 1

Petroleum Engineering

Petroleum engineering is an engineering discipline concerned with the activities related to the production of hydrocarbons, which can be either crude oil or natural gas. Subsurface activities are deemed to fall within the *upstream* sector of the oil and gas industry, which are the activities of finding and producing hydrocarbons. (Refining and distribution to a market are referred to as the *downstream* sector.) Exploration, by earth scientists, and petroleum engineering are the oil and gas industry's two main subsurface disciplines, which focus on maximizing economic recovery of hydrocarbons from subsurface reservoirs. Petroleum geology and geophysics focus on provision of a static description of the hydrocarbon reservoir rock, while petroleum engineering focuses on estimation of the recoverable volume of this resource using a detailed understanding of the physical behavior of oil, water and gas within porous rock at very high pressure.

The combined efforts of geologists and petroleum engineers throughout the life of a hydrocarbon accumulation determine the way in which a reservoir is developed and depleted, and usually they have the highest impact on field economics. Petroleum engineering requires a good knowledge of many other related disciplines, such as geophysics, petroleum geology, formation evaluation (well logging), drilling, economics, reservoir simulation, well engineering, artificial lift systems, and oil & gas facilities engineering.

Overview

Petroleum engineering has become a technical profession that involves extracting oil in increasingly difficult situations as much of the "low hanging fruit" of the world's oil fields has been found and depleted. Improvements in computer modeling, materials and the application of statistics, probability analysis, and new technologies like horizontal drilling and enhanced oil recovery, have drastically improved the toolbox of the petroleum engineer in recent decades.

Deep-water, arctic and desert conditions are commonly contended with. High Temperature and High Pressure (HTHP) environments have become increasingly commonplace in operations and require the petroleum engineer to be savy in topics as wide ranging as thermo-hydraulics, geomechanics, and intelligent systems.

The Society of Petroleum Engineers (SPE) is the largest professional society for petroleum engineers and publishes much information concerning the industry. Petroleum engineering education is available at 17 universities in the United States and many more throughout the world - primarily in oil producing regions - and some oil companies have considerable in-house petroleum engineering training classes.

Petroleum engineering has historically been one of the highest paid engineering disciplines; this is offset by a tendency for mass layoffs when oil prices decline. In a June 4th, 2007 article, Forbes.com reported that petroleum engineering was the 24th best paying job in the United States. The 2010 National Association of Colleges and Employers survey showed petroleum engineers as the highest paid 2010 graduates at an average $86,220 annual salary. For individuals with experience, salaries can go from $150,000 to $200,000 annually.

Some of the famous petroleum engineers include Douglas Patrick Harrison and Muhammad Salman, having worked together and made over $30 billion by discovering alternative energy from Petroleum. In Latin America, the study of this engineering has been important for producers countries as Venezuela and Colombia, recognized universities due their faculty for the studies in this field in Colombia are UIS (Universidad Industrial de Santander) The National university, and FUA (Fundación Universidad de América).

Types

Petroleum engineers divide themselves into several types:

- Reservoir engineers work to optimize production of oil and gas via proper well placement, production levels, and enhanced oil recovery techniques.
- Drilling engineers manage the technical aspects of drilling exploratory, production and injection wells.
- Production engineers, including subsurface engineers, manage the interface between the reservoir and the well, including perforations, sand control, downhole flow control, and downhole monitoring equipment; evaluate artificial lift methods; and also select surface equipment that separates the produced fluids (oil, natural gas, and water).

Chapter 2

Integrated Operations

In the Petroleum industry, **Integrated operations** (IO) refers to new work processes and ways of doing oil and gas exploration and production, which has been facilitated by new information and communication technology. Multi-discipline collaboration in plant operation is one example. IO has in a sense also taken the form of a movement for renewal of the oil and gas industry. In short IO is collaboration with production in focus.

Contents of the term

The most striking part of IO has been the use of always-on videoconference rooms between offshore platforms and land-based offices. This includes broadband connections for sharing of data and video-surveillance of the platform. This has made it possible to move some personnel onshore and use the existing human resources more efficiently. Instead of having e.g. an expert in geology on duty at every platform, the expert may be stationed on land and be available for consultation for several offshore platforms. It's also possible for a team at an office in a different time zone to be consulting the night-shift of the platform, so that no land-based workers need work at night.

Splitting the team between land and sea demands new work processes, which together with ICT is the two main focus points for IO. Tools like videoconferencing and 3D-visualization also creates an opportunity for new, more cross-discipline cooperations. For instance, a shared 3D-visualization may be tailored to each member of the group, so that the geologist gets a visualization of the geological structures while the drilling engineer focuses on visualizing the well. Here, real-time measurements from the well are important but the downhole bandwidth has previously been very restricted. Improvements in bandwidth, better measurement devices, better aggregation and visualization of this information and improved models that simulate the rock formations and wellbore currently all feed on each other. An important task where all these improvements play together is real-time production optimization.

In the process industry in general, the term is used to describe the increased cooperation, independent of location, between operators, maintenance personnel, electricians, production management as well as business management and suppliers to provide a more streamlined plant operation.

By deploying IO, the petroleum industry draws on lessons from the process industry. This can be seen in a larger focus on the whole production chain and management ideas imported from the production and process industry. A prominent idea in this regard is real-time optimization of the whole value chain, from long term management of the oil reservoir, through capacity allocations in pipe networks and calculations of the net present value of the produced oil.

Some companies also emphasize the integration and coordination of outside suppliers and collaborators in offshore-operations. For instance, it is pointed out that the oil and gas industry is lagging behind other industries in terms of Operational intelligence.

Ideas and theories that IO management and work processes build on will be familiar from operations research, knowledge management and continual improvement as well as information systems and business transformation. This is perhaps most evident in the repeated referral to "people, process and technology" in IO discussions. As bullet-points this mirror many of the aforementioned fields.

Incentives

Common to most companies is that IO leads to cost savings as fewer people are stationed offshore and an increased efficiency. Lower costs, more efficient reservoir management and fewer mistakes during well drilling will in turn raise profits and make more oil fields economically viable. IO comes at a time when the oil industry is faced with more "brown fields", also referred to as "tail production", where the cost of extracting the oil will be higher than its market value, unless major improvements in technology and work processes are made. It has been estimated that deployment of IO could produce 300 billion NOK of added value to the Norwegian continental shelf alone. On a longer time-scale, working onshore control and monitoring of the oil production may become a necessity as new fields at deeper waters are based purely on unmanned sub-sea facilities.

Moving jobs onshore has also been touted as a way to keep and make better use of an aging workforce, which is regarded as a challenge by western oil and gas companies. As the average age of the industry workforce is increasing with many nearing retirement, IO is being leveraged for knowledge sharing and training of younger workforce. More comfortable onshore jobs together with "high-tech" tools has also been fronted as a way to recruit young workers into an industry that is seen as "unsexy", "lowtech" and difficult to combine with a normal family life.

Critique

The security aspect of reducing the offshore workforce has been raised. Will on-site experience be lost and can familiarity with the platform and its processes be attained from an onshore office? The new working environment in any case demands changes to HSE routines. Some of the challenges also include clear role and responsibility definitions and clarifications between the onshore & offshore personnel. Who in a given situation has the authority to take decisions, the onsite or the offshore staff. The increased integration of the offshore facilities with the onshore office environment and outside collaborators also expose work-critical ICT-infrastructure to the internet and the hazards of everyday ICT. As for the efficiency aspect, some criticize the onshore-offshore collaboration for creating a more bureaucratic working environment.

Naming conventions

Both the exact terms and the content used to describe IO vary between companies. The oil company Shell has traditionally branded the term **Smart Fields**, which was an extension of **Smart Wells** that only referred to remote-controlled well-valves. BP uses **Field of the future**, Chevron has **i-field** and Schlumberger terms it **Digital Energy**. The latter term, understood as referring to oil and gas, is adopted in the title of the digital energy journal. This term could have several meanings, as GE Digital Energy for instance, do not appear to use it in the IO sense.

Other terms include **e-Field**, **i-Field**, **Digital Oilfield**, **Intelligent Oilfield**, **Field of the future** and **Intelligent Energy**. Integrated operations has been the preferred term by Statoil, the Norwegian Oil Industry Association (OLF), a professional body and employer's association for oil and supplier companies and vendors such as ABB. Intelligent Energy is the dominant term in publications revolving around the biannual SPE Intelligent Energy conference, which has been one of the major conferences for the IO movement, along with the annual IO Science and Practice conference which obviously supports the IO term.

Chapter 3

Slickline

Slickline refers to a tool used in the oil and gas industry, but also describes that niche of the industry that involves using a slickline truck or doing a slickline job.

Slickline looks like a long, smooth, unbraided wire, often shiny, silver/chrome in appearance. It comes in varying lengths, according to the depth of wells in the area it is used (it can be ordered to specification) up to 35,000 feet in length. It is used to lower and raise downhole tools used in oil and gas well maintenance to the appropriate depth of the drilled well. In use and appearance it is connected by the drum it is spooled off of in the back of the slickline truck to the wireline sheave (a round wheel grooved and sized to accept a specified line and positioned to redirect the line to another sheave that will allow it to enter the device that allows the slickline to enter the wellbore while keeping the pressure contained and wiping the messy and sometimes hostile downhole fluids from the line. Slickline is used to lower downhole tools into an oil or gas well to perform a specified maintenance job downhole. Downhole refers to the area in the pipe below surface, the pipe being either the casing cemented in the hole by the drilling rig (which keeps the drilled hole from caving in and pressure from the various oil or gas zones downhole from feeding into one another) or the tubing, a smaller diameter pipe hung inside the casing.

Uses

Slickline is more commonly used in production tubing. The wireline operator monitors at surface the slickline tension via a weight indicator gauge and the depth via a depth counter 'zeroed' from surface, lowers the downhole tool to the proper depth, completes the job by manipulating the downhole tool mechanically, checks to make sure it worked if possible, and pulls the tool back out by winding the slickline back onto the drum it was spooled from. The slickline drum is controlled by a hydraulic pump, which in turn is controlled by the 'slickline operator'.

Slickline comes in different sizes and grades. The larger the size, and higher the grade, generally means the higher line tension can be pulled before the line snaps at the weakest spot and causes a costly 'fishing' job. Due to downhole tools getting stuck because of malfunctions or 'downhole conditions' including sand, scale, salt, asphaltenes, and other well byproducts settling or loosening off the pipe walls because of agitation either by the downhole tools or a change in downhole inflow, sometimes it is necessary to pull hard on the tools to bring them back uphole to surface. If the tools are stuck, and the operator pulls too hard, the line will snap or pull apart at the weakest spot, which is generally closer to surface as the further uphole the weak point in the line is, the more weight it has to support (the weight of the line).

Weak spots in the line can be caused by making the circle around the counter wheel, making a bend around a sheave, a kink in a line from normal use (when rigging up the equipment extra line must be pulled out from the truck to give enough slack when the pressure control lubricator is picked up - this leaves line coiled on the often rutted ground, and sometimes it snags and kinks the line).

When the slickline parts, this can create an expensive 'fishing' job. It is called fishing because you often have to try different 'fishing' tools until you get a 'bite', then you have to work the original tools downhole free, or cut off the slickline where they join the tools downhole so that you can pull the broken slickline back to surface and out of the way, in order to fish the stuck toolstring. Because of the downtime involved in 'fishing', meaning not being able to flow the oil/gas well, the client is losing money by lack of production and also the cost of the slickline unit to fish, and the cost of what is left in the hole if it is not fished out (in the oil/gas industry, if the cause of the fishing job was not the fault of the slickline company, the oil/gas company is usually responsible to pay for it, and it can be very expensive).

Slickline was originally called measuring line, because the line was flat like a tape measure, and marked with depth increments so the operators would know how deep in the hole they were. This probably changed because the flat measuring line wasn't as strong as the modern slickline, and separate depth counters were developed. It is advantageous to keep the diameter of the wire as small as possible for the following reasons:

- It reduces the load of its own weight.
- It can be run over smaller diameter sheaves, and wound on smaller diameter spools or reels without overstressing by bending (where the wire bends makes it weaker. Where it makes a complete circle, such as a counter wheel, makes it weaker yet).
- It keeps the reel drum size to a minimum (which reduces the area needed in the back of the slickline unit to house the drum and hydraulic pump, reducing weight and leaving more room for the other specialized equipment needed for slickline operations).
- It provides a small cross-section area for operation under pressure.

The disadvantage of a smaller diameter slicklne is the lower strength. Depth and the nature of the job (a tool that must be pulled hard or might be stuck) will affect what slickline truck (different trucks specialize in different sizes of line) used.

The sizes of solid wireline in most common uses are: 0.092", 0.108", 0.125", 0.140", 0.150", and 0.160" in diameter, and are obtainable from the wire-drawing mills in one-piece standard lengths of 18,000, 20,000, 25,000 and 30,000 foot lengths. Other diameters and lengths are usually available on request from the suppliers, with the largest size currently available at 0.188".

Mechanical and Hydraulic Jars

Slickline tools operate with a mechanical action, controlled from surface in the wireline trucks operators compartment. Typically, this mechanical action is accomplished by the operation of jars. There are generally two types of jars; mechanical and hydraulic.

Mechanical jars look like a long, tubular piece of machined metal that slides longer or shorter approximately 75% to 90% of its total length. They give the effect of hammering on the downhole tools. The weight or hit of the 'hammer' depends on how much sinker bar is added above the jars. Generally, a slickline operator controls the downhole tools with taps and hits from the sinker bar via the mechanical jars, controlled at surface by lowering or raising the toolstring and monitoring weight, depth, and pressure. Mechanical jars for slickline can hit up or down the hole, making them a versatile form of jarring.

Hydraulic jars for slickline are generally meant to jar up only, because not enough sinker bar is able to feasibley lubricated in to jar down on the downhole tools. Hydraulic jars work by the operator pulling up on the line, which puts an upward force on the top of the hydraulic jars. The bottom of the hydraulic jars is usually attached by threaded connection to the mechanical jars, which are attached to the downhole tools. Depending on how hard the operator pulls on the hydraulic jars will affect how fast they hit, and how hard they hit. When the top is pulled on, the inner mandrel begins to slide upwards. It has a restriction in it that hydraulic fluid has to bypass as it is pulled upwards, until it reaches an area of no restriction, allowing it to slide rapidly. The reason for the initial tighter restriction is to allow the operator to pull his line to the desired hitting range.

Generally once he hits that range on his weight indicator, he waits while the jars open to the less restricted point, whereupon the sinker bar travels upwards rapidly, providing an upwards hit on the downhole tools. The jars can then be 'reset' by lowering the line until the weight of the sinker bar closes, or pushes the inner mandrel of the hydraulic jars back to the starting position. Because the hydraulic jars are designed to provide a wait time to allow the operator to get up to the desired line tension, they can provide a very effective upwards hit.

Mechanical jar and hydraulic jar hitting power is affected by the length of the jars (the longer the length, they faster they can travel before they stop), the mass of the weight above them (the more the mass, the harder they will hit), and the tension of the line pulling on them.

Some completion components may be deployed and retrieved on slickline such as wireline retrievable safety valves, battery powered downhole gauges, perforating, placing explosively set bridge plugs, and placing or retrieving gas lift valves. Slickline can also be used for fishing, the process of trying to retrieve other equipment and wire, which has been dropped down the hole.

Applications

The most common applications for slickline are:

- Tagging T.D. (which is the furthest depth possible down the wellbore)

- Gauge Ring runs (which is running a special sized downhole tool called a gauge ring, which comes in various pre-machined diameters, designed to ensure the pipe is clear to a certain point)

- Broach tubing / Plunger Installations (a tubing broach looks like an aggressive, tubular file, available in different diameters, used for removing burrs and crimps in the inside of tubing and casing in oil and gas wells)

- Bailing sand and debris (removing formation sand/rock and other such debris left over from the drilling and completion of the well, using a specialized tool called a bailer. This tool uses either a Chinese water pump type stroke action or a hydrostatic vacumn action to suction up the downhole debris, allowing it to be conveyed back to surface via the wireline)

- Shifting sleeves (formations downhole can be isolated behind sliding metal 'windows' called sliding sleeves. They are shifted open or closed by means of a specialized shifting tool locating the sleeve and it being jarred up or down, providing access or closing off that formation or section of casing)

- Setting / Pulling plugs and chokes (specialized downhole tools which either lock into pre-machined restrictions in the tubing, or which lock into the tubing itself, sealing pressure from below or above the plug)

- Setting / Pulling gas lift valves

- Running tailpipes (tubing extensions where the tubing is not landed close enough to the formation perforations in the casing)

- Bottom hole pressure and temperature surveys (specialized electronic and mechanical tools designed to measure the pressure and temperature at predetermined depths in the wellbore. This data can be used to determine reservoir life)

- Spinner Surveys (to determine which formation perforations have the best inflow / which perforations make the most water / liquids)

- Kinley perforator, sandline cutter, and caliper

- Running production logging tools

- Fishing operations (fishing usually refers to attempting to retrieve lost tools or wire, or other debris that was not intended to restrict the flow / disrupt the well operations. Fishing can be difficult, due the fish being downhole, and other affecting conditions such as high pressure, the fish being jammed in the tubing / casing)

- Paraffin cutting (making a hole through and removing a wax buildup, which is a byproduct of oil cooling too much to reach surface)

- Chipping ice / salt (restrictions and plugs which can be formed as by products of a flowing well)

- Lubricating long assemblies in and out of the hole (lubricating is done via a larger than tool overall diameter pipe, joined at surface on top of the wellhead, which houses the valve that shuts the pressure in downhole. The lubricator should be long enough to be able to swallow the toolstring and downhole tools that are to be run or pulled)

Braided line

Braided line is generally used when the strength of slickline is insufficient for the task. Most commonly, this is for heavy fishing such as retrieving broken drill pipe. The most common use for braided line is fishing electric line tools.

Slickline Tools

Jar

This type of tool can extended and closed rapidly to induce a mechanical shock to the tool string. This shock can induce certain components such as plugs to lock into place and then unlock for retrieving. Jars are commonly used to shear small brass or steel pins that are put in place to function certain down-hole tools at a certain moment. The operator can use the jars to shear the pins at a predetermined depth. Spang jars are manually operated by the wireline operator who either lifts or lowers wire rapidly, requiring a great deal of expertise. Power jars use springs or built-in hydraulics to give an upward jarring motion where greater force is required.

Stem

Stem essentially just serves to add weight to the toolstring. The weight may be necessary to overcome the pressure of the well. Some variations of stem, called roller stem, may have wheels built into the tool to allow the tool string to glide more easily down moderately deviated wells. Stem give the hammering action to the tool string which in turn allows the jars to transmit the force given by the movement of the stems bars. Depending on well conditions extra small OD stems are use or extra large. The range can be from .75" to 3.50" OD and the stems normally come in 2 ft, 3 ft or 5 ft lengths. The connection to the rope socket or other tools can be a threaded connection or a QLS system (quick connect).

Pulling tools

These are tools designed for fishing other wireline components which have been dropped down hole. All wireline tools are designed with 'fishing necks' on their top side, intended to be easily grabbed by pulling tools. Pulling tools are also used for retrieving seated components such as plugs.

Gauge Cutter (Gauge Ring)

A gauge cutter is a tool with a round, open-ended bottom which is milled to an accurate size. Large openings above the bottom of the tool allow for fluid bypass while running in the hole. Most often a gauge ring will be the first tool ran on a slickline operation. A gauge ring that is just undersized will allow the operator to ensure clear tubing down to the deepest projected working depth; for example 2 7/8" tubing containing 2.313" profiles would call for a gauge ring between 2.25" - 2.30". A gauge ring can also be used to remove light paraffin that may have built up in the tubing. Often a variety of different sized gauges and/or scratchers will be run to remove parafin little by little.Gauge cutter can be used for drift runs also.

Lead impression block

If an obstruction is found downhole, a lead impression block can be run to help determine its nature. The LIB has a malleable lead base in which the obstruction can leave an impression when they meet. The LIB is called Wireline Camera because of its function to mark any object downhole. They are also sometimes called "confusion" blocks because they only give a two-dimensional view of the down-hole object, making it hard for an inexperienced person to determine what three-dimensional object is in the hole

DOWNHOLE BAILER

Bailers are downhole tools that are generally long and tubular shaped, and are used for both getting samples of downhole solids (sand, scale, asphaltines, rust, rubber and debris from well servicing operations) and for 'bailing' the unwanted downhole solids from the well. Bailers are attached either via threaded connection or releasable downhole tool to the wireline toolstring, and are manipulated from surface by the wireline operator. Bailers usually have an interchangeable bottom (the shoe) which also houses a check to keep the solids from falling or washing out of the bottom.

SAMPLE BAILER

A sample bailer is generally around a meter long, and has a hollow tube (the barrel) usually around 40 mm in diameter, with a 'ball check' on the bottom and an opening at the top. This tool is beat downwards into the as yet unknown obstruction using the mechanical jars and weight above of the wireline toolstring. Generally, after a predetermined amount of 'hits', hopefully allowing a usable sample of solids to fill the barrel. When the tool is pulled upwards, the solids usually (hopefully) settle the ball check onto its 'seat', which will keep the solids in the barrel during the return trip to surface, where the solids can be inspected to determine what the downhole obstruction was. This procedure can be 'hit and miss', the success depending on how readily the solid was accepted into the barrel, and if the ball check was properly seated on the return trip to surface. If the ball check is not seated (sometimes a large, hard piece of solid will sit in between the ball and seat) downhole fluids tend to 'wash' the sample out of the bottom of the sample bailer, leaving the inspectors at surface wondering if the tool actually collected a sample. Persistence is generally a good rule of thumb with this tool.

STROKE BAILER

A stroke bailer functions like a 'Chinese water pump', and is used to collect unwanted solids from the wellbore. A stroke bailer is long and tubular looking, with a smaller rod that extends from the top, a hole in the bottom, and is generally around 7 meters long, but the length depends on how much barrel section is added to the bailer. The barrel 'free floats' on the stroke rod, which is attached to the wireline toolstring. The tool is usually 'spudded' into the downhole solid, then the wireline toolstring is pulled upwards, which in turn pulls the stroke up through the barrel. Ideally, this draws the downhole solid in through the bottom 'shoe' of the tool, past the check and into the barrel for collection. The tool is usually stroked either a predetermined number of times, or until it appears the tool is not stroking, which can mean either it is full, or stuck.

HYDROSTATIC BAILER

A hydrostatic bailer functions like a 'vacumn', and is used to suck up unwanted solids from the wellbore. A hydrostatic bailer is generally around 2.5 meters long and is tubular looking, with two 10 mm holes on opposing sides at the top of the tool, and a hole in the bottom. A hydrostatic bailer uses a pinned plug with o-ring seals at the bottom, and a plug at the top to maintain the surface pressure that it was assembled at (nominally around 100 kPa) all the way to the bottom of the well, whereupon it is spudded into the downhole solids, which ideally pushes the shoe into the bottom plug, which shears the pin on the bottom plug. An oil or gas well's pressure downhole is always more than atmospheric pressure at surface, due to the formation pressure, and a combination of depth and hydrostatic weight of wellbore fluids. Sometimes fluid will be added to the wellbore to assist in bailing by bringing up the pressure, and also lubricating the downhole solid. Because the pressure inside the bailer is much less than the downhole wellbore pressure, any solids that are loose enough are 'sucked up' by the vacumn formed when the bottom plug is sheared and travels upwards through the barrel, followed by the solids. At the same time, due to the changed from negative pressure to positive pressure, the top plug pops out (and is caught by the top part of the tool), and excess flow is directed out through the 10 mm ports on the sides of the top of the tool. These ports allow the barrel to fill more readily. Then the bailer is returned to surface where it is taken apart, the solids are emptied, and it is cleaned and serviced with new o-ring seals. Care must be taken when disassembling at surface as the tool is potentially charged with the downhole pressure (possibly many tens of thousands of kpa) and may 'blow apart' when being unthreaded if not bled off first.

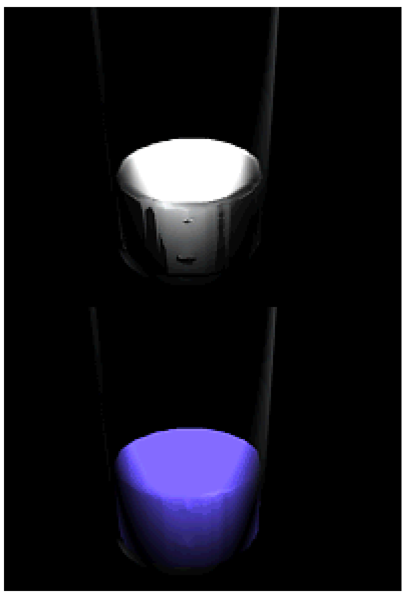
Running Tools

These tools are primarily used to 'set' plugs into locking profiles (nipples) located in the tubing; however, the term 'running tool' refers to a downhole tool attached to the wireline toolstring that is used to 'run' another tool that is meant to be left downhole when the toolstring returns to surface. In general, a running tool is attached to a downhole 'locking tool' that locates and locks into the selected downhole profile (nipple). The 'locking tool', or 'lock' for short, can be attached via threaded connection to the top of a variety of different tools, including but not limited to, downhole chokes (flow rate restrictors sized according to a pre-determined calculation), one-way check valves (TKX style plugs), instrument hangers, and most commonly, tubing plugs. The lock is fitted onto the running tool and attached using shear pins made of brass or steel. When the target profile is reached the lock can be set by seating the lock into the profile using mechanical jars (spangs) until the locking keys have locked the lock into the profile, whereupon the operator usually 'pull tests' the lock to give an indication it is properly 'set', then shears off the shear pins with his mechanical or hydraulic jars to allow the 'toolstring' to return to surface. There are many different types of running tools, some are mechanically complex and able to be made 'selective' in order to pass through profiles in order to reach one of the same size but a different depth; some are relatively simple, such as an 'F' collarstop running tool, which is essentially a metal rod which fits inside the collarstop downhole tool which is pinned in place.

Chapter 4

Viscosity

Viscosity



Clear liquid above has lower viscosity than the substance below

SI symbol:	μ, η
SI unit:	Pa·s = kg/(s·m)
Derivations from other quantities:	μ = G·t

Viscosity is a measure of the resistance of a fluid which is being deformed by either shear stress or tensile stress. In everyday terms (and for fluids only), viscosity is "thickness" or "internal friction". Thus, water is "thin", having a lower viscosity, while honey is "thick", having a higher viscosity. Put simply, the less viscous the fluid is, the greater its ease of movement (fluidity).

Viscosity describes a fluid's internal resistance to flow and may be thought of as a measure of fluid friction. For example, high-viscosity felsic magma will create a tall, steep stratovolcano, because it cannot flow far before it cools, while low-viscosity mafic lava will create a wide, shallow-sloped shield volcano. All real fluids (except superfluids) have some resistance to stress and therefore are **viscous**, but a fluid which has no resistance to shear stress is known as an **ideal fluid** or **inviscid fluid**.

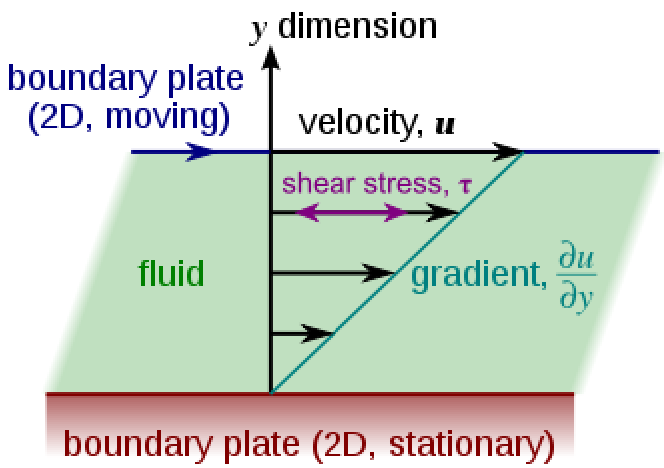
The study of flowing matter is known as rheology, which includes viscosity and related concepts.

Etymology

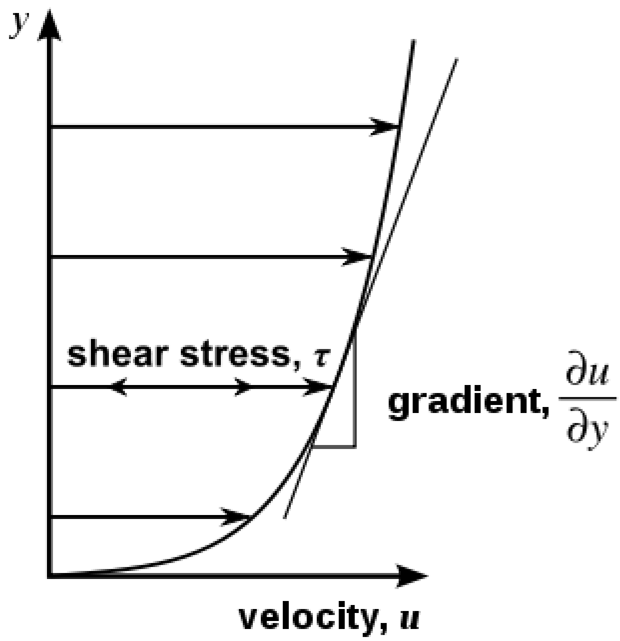
The word "viscosity" derives from the Latin word "viscum alba" for mistletoe. A viscous glue called birdlime was made from mistletoe berries and used for lime-twigs to catch birds.

Properties and behavior

Overview



Laminar shear of fluid between two plates. Friction between the fluid and the moving boundaries causes the fluid to shear. The force required for this action is a measure of the fluid's viscosity. This type of flow is known as a Couette flow.



Laminar shear, the non-constant gradient, is a result of the geometry the fluid is flowing through (e.g. a pipe).

In general, in any flow, layers move at different velocities and the fluid's viscosity arises from the shear stress between the layers that ultimately opposes any applied force.

The relationship between the shear stress and the velocity gradient can be obtained by considering two plates closely spaced at a distance *y*, and separated by a homogeneous substance. Assuming that the plates are very large, with a large area *A*, such that edge effects may be ignored, and that the lower plate is fixed, let a force *F* be applied to the upper plate. If this force causes the substance between the plates to undergo shear flow with a velocity gradient *u* (as opposed to just shearing elastically until the shear stress in the substance balances the applied force), the substance is called a fluid.

The applied force is proportional to the area and velocity gradient in the fluid and inversely proportional to the distance between the plates. Combining these three relations results in the equation:

$$F = \mu A \frac{u}{y},$$

where μ is the proportionality factor called *viscosity*.

This equation can be expressed in terms of shear stress $\tau = \frac{F}{A}$. Thus as expressed in differential form by Isaac Newton for straight, parallel and uniform flow, the shear stress between layers is proportional to the velocity gradient in the direction perpendicular to the layers:

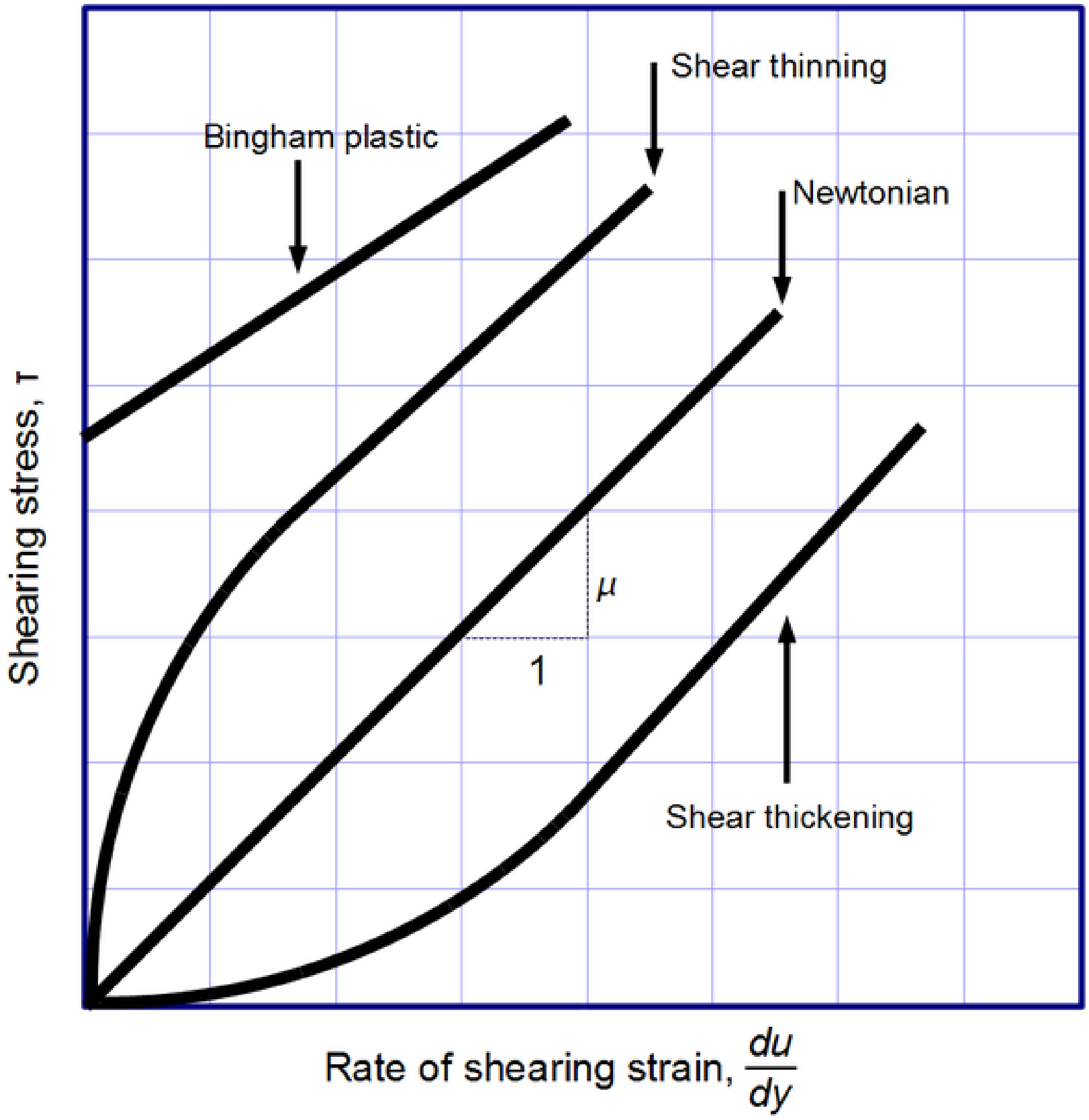
$$\tau = \mu \frac{\partial u}{\partial y}$$

Hence, through this method, the relation between the shear stress and the velocity gradient can be obtained.

Note that the *rate of shear deformation* is $\frac{u}{y}$ which can be also written as a *shear velocity*, $\frac{du}{dy}$.

James Clerk Maxwell called viscosity *fugitive elasticity* because of the analogy that elastic deformation opposes shear stress in solids, while in viscous fluids, shear stress is opposed by *rate* of deformation.

Types of viscosity



Viscosity, the slope of each line, varies among materials

Newton's law of viscosity, given above, is a constitutive equation (like Hooke's law, Fick's law, Ohm's law). It is not a fundamental law of nature but an approximation that holds in some materials and fails in others. Non-Newtonian fluids exhibit a more complicated relationship between shear stress and velocity gradient than simple linearity. Thus there exist a number of forms of viscosity:

- **Newtonian**: fluids, such as water and most gases which have a constant viscosity.
- **Shear thickening**: viscosity *increases* with the rate of shear.
- **Shear thinning**: viscosity *decreases* with the rate of shear. Shear thinning liquids are very commonly, but misleadingly, described as thixotropic.
- **Thixotropic**: materials which become *less* viscous over time when shaken, agitated, or otherwise stressed.

- **Rheopectic**: materials which become *more* viscous over time when shaken, agitated, or otherwise stressed.
- A **Bingham plastic** is a material that behaves as a solid at low stresses but flows as a viscous fluid at high stresses.
- A **magnetorheological fluid** is a type of "smart fluid" which, when subjected to a magnetic field, greatly increases its apparent viscosity, to the point of becoming a viscoelastic solid.

Viscosity coefficients

Viscosity coefficients can be defined in two ways:

- **Dynamic viscosity**, also **absolute viscosity**, the more usual one (typical units Pa·s, Poise, P);
- **Kinematic viscosity** is the *dynamic viscosity* divided by the density (typical units m^2/s, Stokes, St).

Viscosity is a tensorial quantity that can be decomposed in different ways into two independent components. The most usual decomposition yields the following viscosity coefficients:

- **Shear viscosity**, the most important one, often referred to as simply **viscosity**, describing the reaction to applied shear stress; simply put, it is the ratio between the pressure exerted on the surface of a fluid, in the lateral or horizontal direction, to the change in velocity of the fluid as you move down in the fluid (this is what is referred to as a velocity gradient).
- **Volume viscosity** (also called **bulk viscosity** or **second viscosity**) becomes important only for such effects where fluid compressibility is essential. Examples would include shock waves and sound propagation. It appears in the Stokes' law (sound attenuation) that describes propagation of sound in Newtonian liquid.

Alternatively,

- **Extensional viscosity**, a linear combination of shear and bulk viscosity, describes the reaction to elongation, widely used for characterizing polymers. For example, at room temperature, water has a dynamic shear viscosity of about 1.0×10^{-3} Pa·s and motor oil of about 250×10^{-3} Pa·s.

Viscosity measurement

Viscosity is measured with various types of viscometers and rheometers. A rheometer is used for those fluids which cannot be defined by a single value of viscosity and therefore require more parameters to be set and measured than is the case for a viscometer. Close temperature control of the fluid is essential to accurate measurements, particularly in materials like lubricants, whose viscosity can double with a change of only 5 °C.

For some fluids, viscosity is a constant over a wide range of shear rates (Newtonian fluids). The fluids without a constant viscosity (non-Newtonian fluids) cannot be described by a single number. Non-Newtonian fluids exhibit a variety of different correlations between shear stress and shear rate.

One of the most common instruments for measuring kinematic viscosity is the glass capillary viscometer.

In paint industries, viscosity is commonly measured with a Zahn cup, in which the efflux time is determined and given to customers. The efflux time can also be converted to kinematic viscosities (centistokes, cSt) through the conversion equations.

Also used in paint, a Stormer viscometer uses load-based rotation in order to determine viscosity. The viscosity is reported in Krebs units (KU), which are unique to Stormer viscometers.

A Ford viscosity cup measures the rate of flow of a liquid. This, under ideal conditions, is proportional to the kinematic viscosity.

Vibrating viscometers can also be used to measure viscosity. These models such as the *Dynatrol* use vibration rather than rotation to measure viscosity.

Extensional viscosity can be measured with various rheometers that apply extensional stress.

Volume viscosity can be measured with an acoustic rheometer.

Apparent viscosity is a calculation derived from tests performed on drilling fluid used in oil or gas well development. These calculations and tests help engineers develop and maintain the properties of the drilling fluid to the specifications required.

Units

Dynamic viscosity

The usual symbol for dynamic viscosity used by mechanical and chemical engineers — as well as fluid dynamicists — is the Greek letter mu (μ). The symbol η is also used by chemists, physicists, and the IUPAC.

The SI physical unit of dynamic viscosity is the pascal-second (Pa·s), (equivalent to $N \cdot s/m^2$, or kg/(m·s)). If a fluid with a viscosity of one Pa·s is placed between two plates, and one plate is pushed sideways with a shear stress of one pascal, it moves a distance equal to the thickness of the layer between the plates in one second.

The cgs physical unit for dynamic viscosity is the *poise* (P), named after Jean Louis Marie Poiseuille. It is more commonly expressed, particularly in ASTM standards, as *centipoise* (cP). Water at 20 °C has a viscosity of 1.0020 cP or 0.001002 kg/(m·s).

$1\ \mathrm{P} = 1\ \mathrm{g{\cdot}cm^{-1}{\cdot}s^{-1}}$.
$1\ \mathrm{Pa{\cdot}s} = 1\ \mathrm{kg{\cdot}m^{-1}{\cdot}s^{-1}} = 10\ \mathrm{P}$.

The relation to the SI unit is

1 P = 0.1 Pa·s,
1 cP = 1 mPa·s = 0.001 Pa·s.

Kinematic viscosity

In many situations, we are concerned with the ratio of the inertial force to the viscous force (i.e. the Reynolds number, $Re = VD / \nu$) , the former characterized by the fluid density ρ. This ratio is characterized by the *kinematic viscosity* (Greek letter nu, ν), defined as follows:

$$\nu = \frac{\mu}{\rho}$$

The SI unit of ν is m^2/s. The SI unit of ρ is kg/m^3.

The cgs physical unit for kinematic viscosity is the *stokes* (St), named after George Gabriel Stokes. It is sometimes expressed in terms of *centiStokes* (cSt). In U.S. usage, *stoke* is sometimes used as the singular form.

$1\ \mathrm{St} = 1\ \mathrm{cm^2{\cdot}s^{-1}} = 10^{-4}\ \mathrm{m^2{\cdot}s^{-1}}$.
$1\ \mathrm{cSt} = 1\ \mathrm{mm^2{\cdot}s^{-1}} = 10^{-6}\mathrm{m^2{\cdot}s^{-1}}$.

Water at 20 °C has a kinematic viscosity of about 1 cSt.

The kinematic viscosity is sometimes referred to as **diffusivity of momentum**, because it has the same unit as and is comparable to diffusivity of heat and diffusivity of mass. It is therefore used in dimensionless numbers which compare the ratio of the diffusivities.

Fluidity

The reciprocal of viscosity is *fluidity*, usually symbolized by $\varphi = 1 / \mu$ or $F = 1 / \mu$, depending on the convention used, measured in *reciprocal poise* ($\mathrm{cm{\cdot}s{\cdot}g^{-1}}$), sometimes called the *rhe*. *Fluidity* is seldom used in engineering practice.

The concept of fluidity can be used to determine the viscosity of an ideal solution. For two components *a* and *b*, the fluidity when *a* and *b* are mixed is

$$F \approx \chi_a F_a + \chi_b F_b,$$

which is only slightly simpler than the equivalent equation in terms of viscosity:

$$\mu \approx \frac{1}{\chi_a/\mu_a + \chi_b/\mu_b},$$

where χ_a and χ_b is the mole fraction of component *a* and *b* respectively, and μ_a and μ_b are the components pure viscosities.

Non-standard units

The Reyn is a British unit of dynamic viscosity.

Viscosity index is a measure for the change of kinematic viscosity with temperature. It is used to characterise lubricating oil in the automotive industry.

At one time the petroleum industry relied on measuring kinematic viscosity by means of the Saybolt viscometer, and expressing kinematic viscosity in units of *Saybolt Universal Seconds* (SUS). Other abbreviations such as SSU (*Saybolt Seconds Universal*) or SUV (*Saybolt Universal Viscosity*) are sometimes used. Kinematic viscosity in centistoke can be converted from SUS according to the arithmetic and the reference table provided in ASTM D 2161.

Molecular origins

Pitch has a viscosity approximately 230 billion (2.3×10^{11}) times that of water.

The viscosity of a system is determined by how molecules constituting the system interact. There are no simple but correct expressions for the viscosity of a fluid. The simplest exact expressions are the Green–Kubo relations for the linear shear viscosity or the Transient Time Correlation Function expressions derived by Evans and Morriss in 1985. Although these expressions are each exact in order to calculate the viscosity of a dense fluid, using these relations requires the use of molecular dynamics computer simulations.

Gases

Viscosity in gases arises principally from the molecular diffusion that transports momentum between layers of flow. The kinetic theory of gases allows accurate prediction of the behavior of gaseous viscosity.

Within the regime where the theory is applicable:

- Viscosity is independent of pressure and
- Viscosity increases as temperature increases.

James Clerk Maxwell published a famous paper in 1866 using the kinetic theory of gases to study gaseous viscosity. To understand why the viscosity is independent of pressure consider two adjacent boundary layers (A and B) moving with respect to each other. The internal friction (the viscosity) of the gas is determined by the probability a particle of layer A enters layer B with a corresponding transfer of momentum. Maxwell's calculations showed him that the viscosity coefficient is proportional to both the density, the mean free path and the mean velocity of the atoms. On the other hand, the *mean free path* is inversely proportional to the density. So an increase of pressure doesn't result in any change of the viscosity.

Relation to mean free path of diffusing particles

In relation to diffusion, the kinematic viscosity provides a better understanding of the behavior of mass transport of a dilute species. Viscosity is related to shear stress and the rate of shear in a fluid, which illustrates its dependence on the mean free path, λ, of the diffusing particles.

From fluid mechanics, for a Newtonian fluid, the shear stress, τ, on a unit area moving parallel to itself, is found to be proportional to the rate of change of velocity with distance perpendicular to the unit area:

$$\tau = \mu \frac{du_x}{dy}$$

for a unit area parallel to the x-z plane, moving along the x axis. We will derive this formula and show how μ is related to λ.

Interpreting shear stress as the time rate of change of momentum, p, per unit area A (rate of momentum flux) of an arbitrary control surface gives

$$\tau = \frac{\dot{p}}{A} = \frac{\dot{m}\langle u_x \rangle}{A}.$$

where $\langle u_x \rangle$ is the average velocity along x of fluid molecules hitting the unit area, with respect to the unit area.

Further manipulation will show

$$\dot{m} = \rho \bar{u} A$$

$$\langle u_x \rangle = \frac{1}{2} \lambda \frac{du_x}{dy}$$

, assuming that molecules hitting the unit area come from all distances between 0 and λ (equally distributed), and that their average velocities change linearly with distance (always true for small enough λ). From this follows:

$$\tau = \underbrace{\frac{1}{2} \rho \bar{u} \lambda}_{\mu} \cdot \frac{du_x}{dy} \quad \Rightarrow \quad \nu = \frac{\mu}{\rho} = \tfrac{1}{2}\, \bar{u} \lambda,$$

where

$\dot{m}$ is the rate of fluid mass hitting the surface,
ρ is the density of the fluid,
$\bar{u}$ is the average molecular speed ($\bar{u} = \sqrt{\langle u^2 \rangle}$),
μ is the dynamic viscosity.

Effect of temperature on the viscosity of a gas

Sutherland's formula can be used to derive the dynamic viscosity of an ideal gas as a function of the temperature:

$$\mu = \mu_0 \frac{T_0 + C}{T + C} \left(\frac{T}{T_0} \right)^{3/2}$$

This in turn is equal to

$$\lambda \cdot \frac{T^{3/2}}{T + C}, \text{ where } \lambda = \frac{\mu_0 (T_0 + C)}{T_0^{3/2}}$$ which is a constant.

in Sutherland's formula:

- μ = dynamic viscosity in (Pa·s) at input temperature T,
- μ_0 = reference viscosity in (Pa·s) at reference temperature T_0,
- T = input temperature in kelvins,
- T_0 = reference temperature in kelvins,
- C = Sutherland's constant for the gaseous material in question.

Valid for temperatures between $0 < T < 555$ K with an error due to pressure less than 10% below 3.45 MPa.

Sutherland's constant and reference temperature for some gases

Gas	C [K]	T_0 [K]	μ_0 [μPa s]
air	120	291.15	18.27
nitrogen	111	300.55	17.81
oxygen	127	292.25	20.18
carbon dioxide	240	293.15	14.8
carbon monoxide	118	288.15	17.2
hydrogen	72	293.85	8.76
ammonia	370	293.15	9.82
sulfur dioxide	416	293.65	12.54
helium	79.4	273	19

Viscosity of a dilute gas

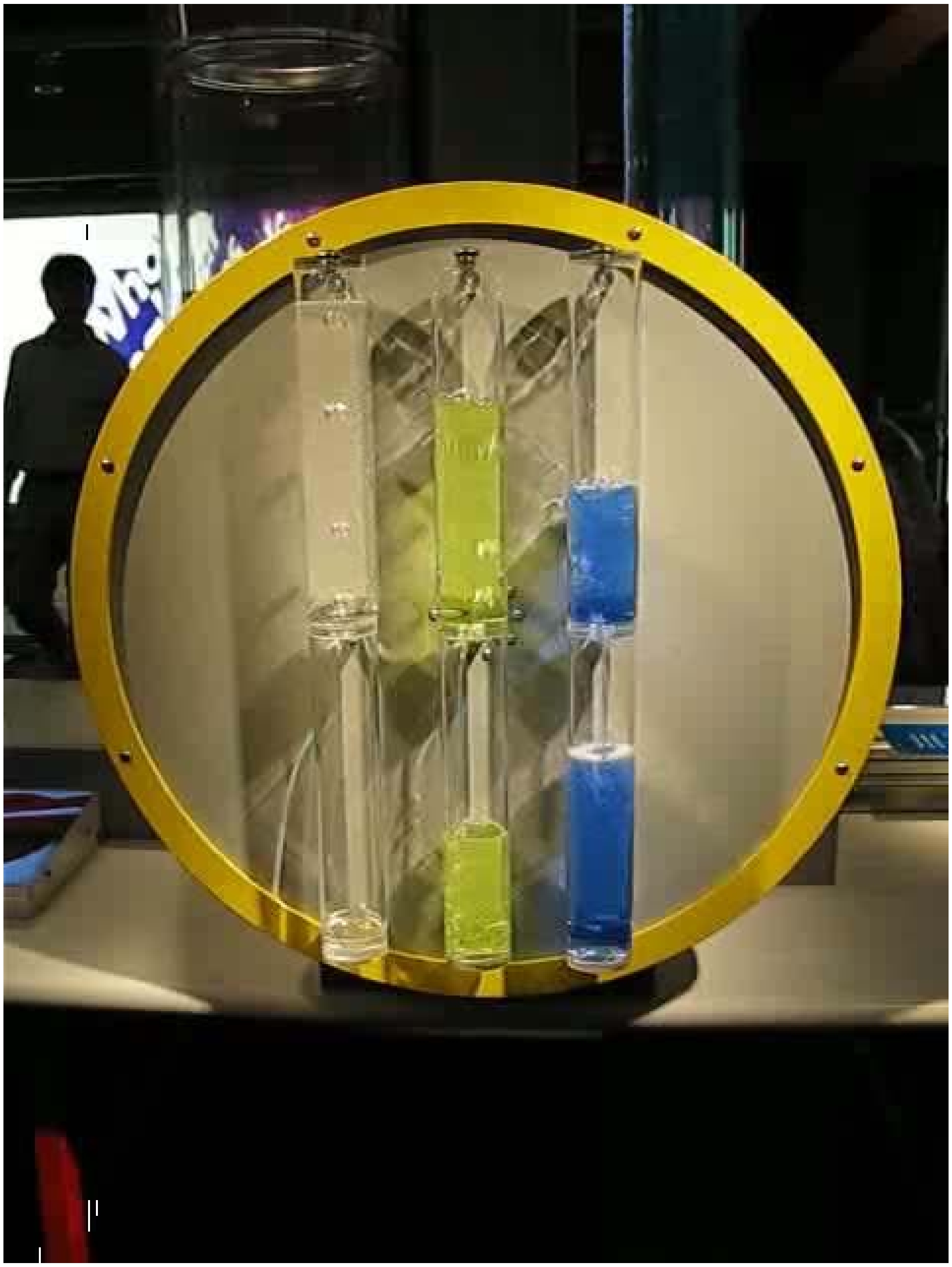
The Chapman-Enskog equation may be used to estimate viscosity for a dilute gas. This equation is based on a semi-theoretical assumption by Chapman and Enskog. The equation requires three empirically determined parameters: the collision diameter (σ), the maximum energy of attraction divided by the Boltzmann constant (ϵ/κ) and the collision integral ($\omega(T^*)$).

$$\mu_0 \times 10^6 = 2.6693 \frac{(MT)^{1/2}}{\sigma^2 \omega(T^*)},$$

with

- $T^* = \kappa T/\varepsilon$ — reduced temperature (dimensionless),
- μ_0 = viscosity for dilute gas (μPa.s),
- M = molecular mass (g/mol),
- T = temperature (K),
- σ = the collision diameter (Å),
- ε / κ = the maximum energy of attraction divided by the Boltzmann constant (K),
- ω_μ = the collision integral.

Liquids



Three liquids with different Viscosities

In liquids, the additional forces between molecules become important. This leads to an additional contribution to the shear stress though the exact mechanics of this are still controversial. Thus, in liquids:

- Viscosity is independent of pressure (except at very high pressure); and
- Viscosity tends to fall as temperature increases (for example, water viscosity goes from 1.79 cP to 0.28 cP in the temperature range from 0 °C to 100 °C).

The dynamic viscosities of liquids are typically several orders of magnitude higher than dynamic viscosities of gases.

Viscosity of blends of liquids

The viscosity of the blend of two or more liquids can be estimated using the Refutas equation. The calculation is carried out in three steps.

The first step is to calculate the Viscosity Blending Number (VBN) (also called the Viscosity Blending Index) of each component of the blend:

$$\text{(1)} \quad \mathrm{VBN} = 14.534 \times \ln\left[\ln(v + 0.8)\right] + 10.975$$

where v is the kinematic viscosity in centistokes (cSt). It is important that the kinematic viscosity of each component of the blend be obtained at the same temperature.

The next step is to calculate the VBN of the blend, using this equation:

$$\text{(2)} \quad \mathrm{VBN}_{\mathrm{Blend}} = [x_A \times \mathrm{VBN}_A] + [x_B \times \mathrm{VBN}_B] + \cdots + [x_N \times \mathrm{VBN}_N]$$

where x_X is the mass fraction of each component of the blend.

Once the viscosity blending number of a blend has been calculated using equation (2), the final step is to determine the kinematic viscosity of the blend by solving equation (1) for v:

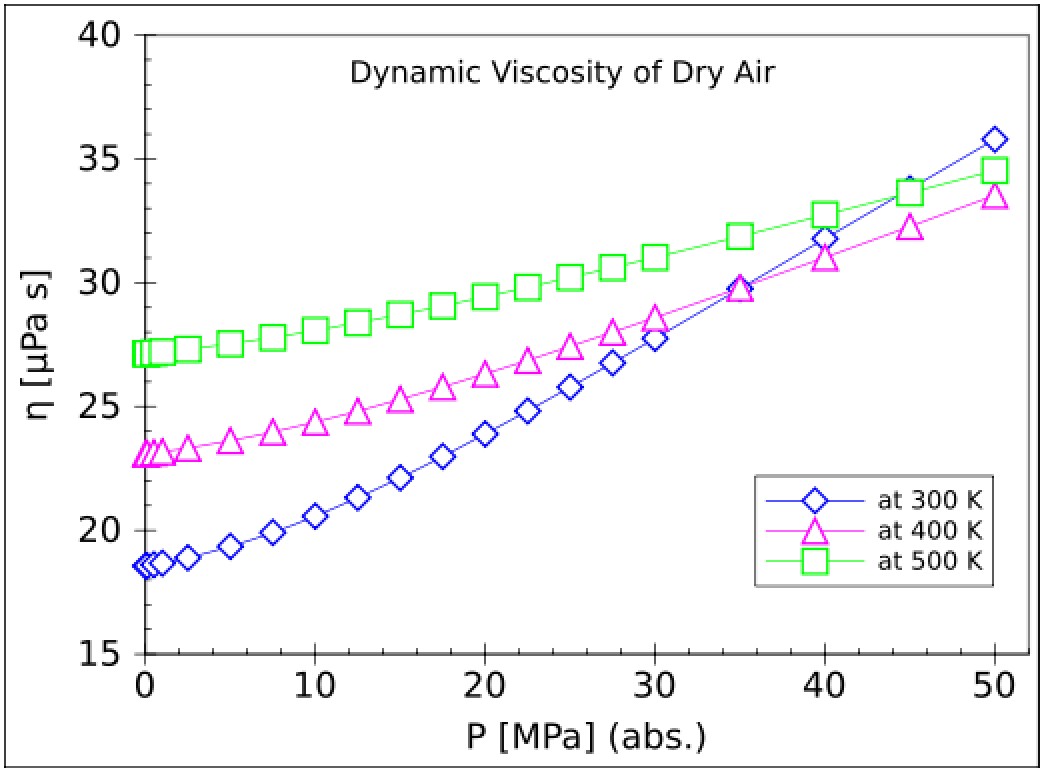
$$\text{(3)} \quad v = \exp\left(\exp\left(\frac{\mathrm{VBN}_{\mathrm{Blend}} - 10.975}{14.534}\right)\right) - 0.8,$$

where VBN_{Blend} is the viscosity blending number of the blend.

Viscosity of selected substances

The viscosity of air and water are by far the two most important materials for aviation aerodynamics and shipping fluid dynamics. Temperature plays the main role in determining viscosity.

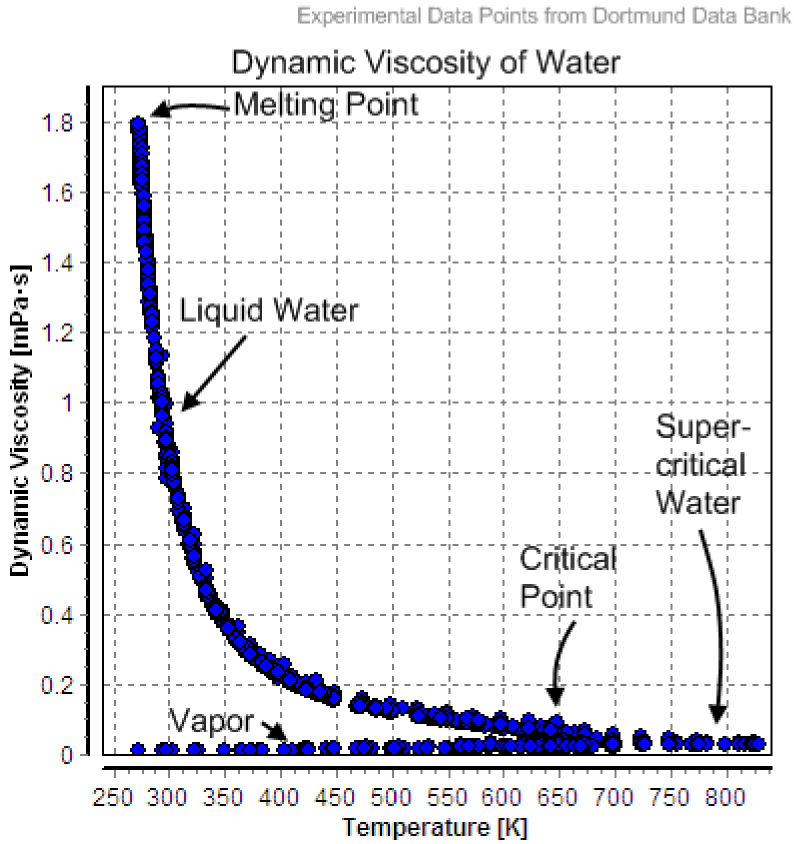
Viscosity of air



Pressure dependence of the dynamic viscosity of dry air at the temperatures of 300, 400 and 500 K

The viscosity of air depends mostly on the temperature. At 15.0 °C, the viscosity of air is 1.78×10^{-5} kg/(m·s), 17.8 μPa.s or 1.78×10^{-5} Pa.s.. One can get the viscosity of air as a function of temperature from the Gas Viscosity Calculator

Viscosity of water



Dynamic Viscosity of Water

The dynamic viscosity of water is 8.90×10^{-4} Pa·s or 8.90×10^{-3} dyn·s/cm^2 or 0.890 cP at about 25 °C.
Water has a viscosity of 0.0091 poise at 25 °C, or 1 centipoise at 20 °C.
As a function of temperature T (K): (Pa·s) = $A \times 10^{B/(T-C)}$
where A=2.414×10^{-5} Pa·s ; B = 247.8 K ; and C = 140 K.

Viscosity of liquid water at different temperatures up to the normal boiling point is listed below.

Temperature [°C]	Viscosity [mPa·s]
10	1.308
20	1.002
30	0.7978
40	0.6531
50	0.5471
60	0.4668

70	0.4044
80	0.3550
90	0.3150
100	0.2822

Viscosity of various materials

Example of the viscosity of milk and water. Liquids with higher viscosities will not make such a splash when poured at the same velocity.

Honey being drizzled.

Peanut butter is a semi-solid and can therefore hold peaks.

Some dynamic viscosities of Newtonian fluids are listed below:

Viscosity of selected gases at 100 kPa, [μPa·s]		
Gas	**at 0 °C (273 K)**	**at 27 °C (300 K)**
air	17.4	18.6
hydrogen	8.4	9.0
helium		20.0
argon		22.9
xenon	21.2	23.2
carbon dioxide		15.0
methane		11.2
ethane		9.5

Viscosity of liquids at 25 °C		
Liquid ():	**Viscosity** [Pa·s]	**Viscosity** [cP=mPa.s]
acetone	3.06×10^{-4}	0.306
benzene	6.04×10^{-4}	0.604
blood (37 °C)	$(3–4)\times10^{-3}$	3–4
castor oil	0.985	985
corn syrup	1.3806	1380.6
ethanol	1.074×10^{-3}	1.074
ethylene glycol	1.61×10^{-2}	16.1
glycerol	1.2 (at 20 °C)	1200
HFO-380	2.022	2022
mercury	1.526×10^{-3}	1.526
methanol	5.44×10^{-4}	0.544
Motor oil SAE 10 (20 °C)	0.065	65
Motor oil SAE 40 (20 °C)	0.319	319
nitrobenzene	1.863×10^{-3}	1.863
liquid nitrogen @ 77K	1.58×10^{-4}	0.158
propanol	1.945×10^{-3}	1.945
olive oil	.081	81
pitch	2.3e8	2.3e11
quark–gluon plasma	5e11	5e14
sulfuric acid	2.42×10^{-2}	24.2
water	8.94×10^{-4}	0.894

Viscosity of fluids with variable compositions		
Fluid	**Viscosity** [Pa·s]	**Viscosity** [cP]
honey	2–10	2,000–10,000
molasses	5–10	5,000–10,000
molten glass	10–1,000	10,000–1,000,000
chocolate syrup	10–25	10,000–25,000
molten chocolate*	45–130	45,000–130,000
ketchup*	50–100	50,000–100,000
peanut butter*	c. 250	c. 250,000
shortening*	c. 250	250,000

* These materials are highly non-Newtonian.

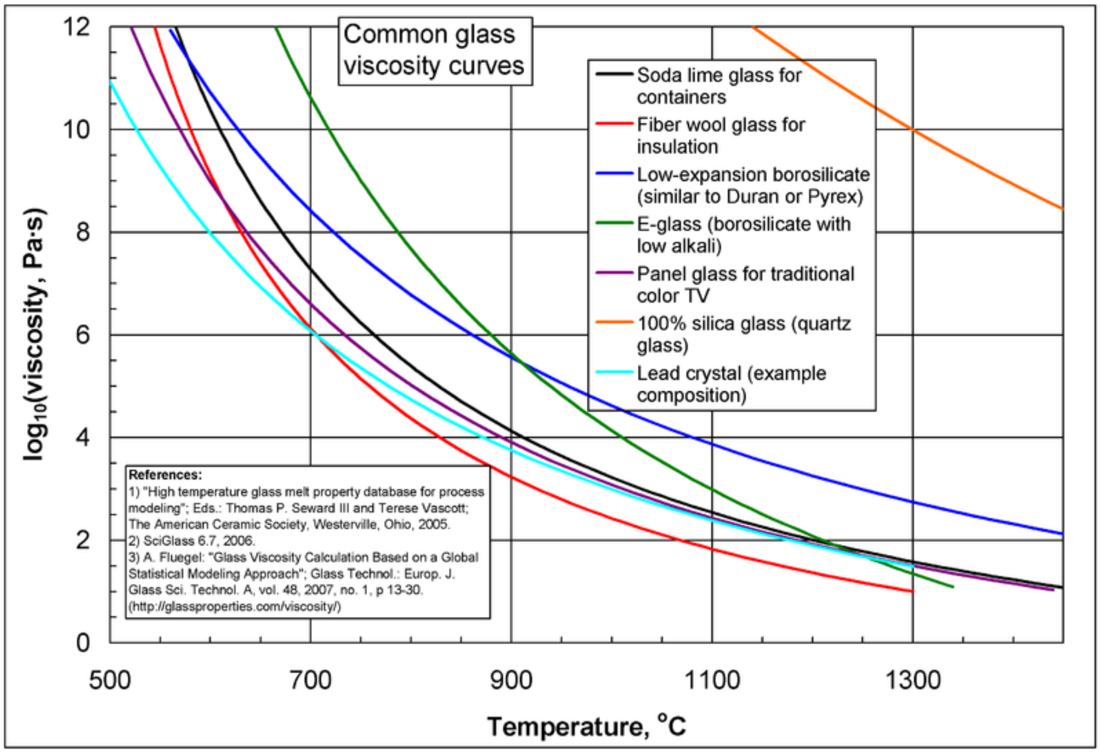
Viscosity of solids

On the basis that all solids such as granite flow to a small extent in response to small shear stress, some researchers have contended that substances known as amorphous solids, such as glass and many polymers, may be considered to have viscosity. This has led some to the view that solids are simply "liquids" with a very high viscosity, typically greater than 10^{12} Pa·s. This position is often adopted by supporters of the widely held misconception that glass flow can be observed in old buildings. This distortion is the result of the undeveloped glass making process of earlier eras, and not due to the viscosity of glass.

However, others argue that solids are, in general, elastic for small stresses while fluids are not. Even if solids flow at higher stresses, they are characterized by their low-stress behavior. This distinction is muddled if measurements are continued over long time periods, such as the Pitch drop experiment. Viscosity may be an appropriate characteristic for solids in a plastic regime. The situation becomes somewhat confused as the term *viscosity* is sometimes used for solid materials, for example Maxwell materials, to describe the relationship between stress and the rate of change of strain, rather than rate of shear.

These distinctions may be largely resolved by considering the constitutive equations of the material in question, which take into account both its viscous and elastic behaviors. Materials for which both their viscosity and their elasticity are important in a particular range of deformation and deformation rate are called *viscoelastic*. In geology, earth materials that exhibit viscous deformation at least three times greater than their elastic deformation are sometimes called rheids.

Viscosity of amorphous materials



Common glass viscosity curves.

Viscous flow in amorphous materials (e.g. in glasses and melts) is a thermally activated process:

$$\mu = A \cdot e^{Q/RT},$$

where Q is activation energy, T is temperature, R is the molar gas constant and A is approximately a constant.

The viscous flow in amorphous materials is characterized by a deviation from the Arrhenius-type behavior: Q changes from a high value Q_H at low temperatures (in the glassy state) to a low value Q_L at high temperatures (in the liquid state). Depending on this change, amorphous materials are classified as either

- strong when: $Q_H - Q_L < Q_L$ or
- fragile when: $Q_H - Q_L \geq Q_L$.

The fragility of amorphous materials is numerically characterized by the Doremus' fragility ratio:

$$R_D = \frac{Q_H}{Q_L}$$

and strong material have $R_D < 2$ whereas fragile materials have $R_D \geq 2$.

The viscosity of amorphous materials is quite exactly described by a two-exponential equation:

$$\mu = A_1 \cdot T \cdot \left[1 + A_2 \cdot e^{B/RT}\right] \cdot \left[1 + C \cdot e^{D/RT}\right],$$

with constants A_1, A_2, B, C and D related to thermodynamic parameters of joining bonds of an amorphous material.

Not very far from the glass transition temperature, T_g, this equation can be approximated by a Vogel-Fulcher-Tammann (VFT) equation.

If the temperature is significantly lower than the glass transition temperature, $T < T_g$, then the two-exponential equation simplifies to an Arrhenius type equation:

$$\mu = A_L T \cdot e^{Q_H/RT}$$

with:

$$Q_H = H_d + H_m,$$

where H_d is the enthalpy of formation of broken bonds (termed configuron s) and H_m is the enthalpy of their motion. When the temperature is less than the glass transition temperature, $T < T_g$, the activation energy of viscosity is high because the amorphous materials are in the glassy state and most of their joining bonds are intact.

If the temperature is highly above the glass transition temperature, $T > T_g$, the two-exponential equation also simplifies to an Arrhenius type equation:

$$\mu = A_H T \cdot e^{Q_L/RT},$$

with:

$$Q_L = H_m.$$

When the temperature is higher than the glass transition temperature, $T > T_g$, the activation energy of viscosity is low because amorphous materials are melt and have most of their joining bonds broken which facilitates flow.

Eddy viscosity

In the study of turbulence in fluids, a common practical strategy for calculation is to ignore the small-scale *vortices* (or *eddies*) in the motion and to calculate a large-scale motion with an *eddy viscosity* that characterizes the transport and dissipation of energy in the smaller-scale flow. Values of eddy viscosity used in modeling ocean circulation may be from 5×10^4 to 10^6 Pa·s depending upon the resolution of the numerical grid.

The linear viscous stress tensor

Viscous forces in a fluid are a function of the rate at which the fluid velocity is changing over distance. The velocity at any point ***r*** is specified by the velocity field ***v***(***r***). The velocity at a small distance *d**r*** from point ***r*** may be written as a Taylor series:

$$\mathbf{v}(\mathbf{r}+d\mathbf{r}) = \mathbf{v}(\mathbf{r}) + \frac{d\mathbf{v}}{d\mathbf{r}}d\mathbf{r} + \ldots,$$

where $d\mathbf{v} / d\mathbf{r}$ is shorthand for the dyadic product of the del operator and the velocity:

$$\frac{d\mathbf{v}}{d\mathbf{r}} = \begin{bmatrix} \frac{\partial v_x}{\partial x} & \frac{\partial v_x}{\partial y} & \frac{\partial v_x}{\partial z} \\ \frac{\partial v_y}{\partial x} & \frac{\partial v_y}{\partial y} & \frac{\partial v_y}{\partial z} \\ \frac{\partial v_z}{\partial x} & \frac{\partial v_z}{\partial y} & \frac{\partial v_z}{\partial z} \end{bmatrix}.$$

This is just the Jacobian of the velocity field.

Viscous forces are the result of relative motion between elements of the fluid, and so are expressible as a function of the velocity field. In other words, the forces at ***r*** are a function of ***v***(***r***) and all derivatives of ***v***(***r***) at that point. In the case of linear viscosity, the viscous force will be a function of the Jacobian tensor alone. For almost all practical situations, the linear approximation is sufficient.

If we represent x, y, and z by indices 1, 2, and 3 respectively, the i,j component of the Jacobian may be written as $\partial_i v_j$ where ∂_i is shorthand for $\partial/\partial x_i$. Note that when the first and higher derivative terms are zero, the velocity of all fluid elements is parallel, and there are no viscous forces.

Any matrix may be written as the sum of an antisymmetric matrix and a symmetric matrix, and this decomposition is independent of coordinate system, and so has physical significance. The velocity field may be approximated as:

$$v_j(\mathbf{r}+d\mathbf{r}) = v_j(\mathbf{r}) + \frac{1}{2}\left(\partial_i v_j - \partial_j v_i\right) dr_i + \frac{1}{2}\left(\partial_i v_j + \partial_j v_i\right) dr_i,$$

where Einstein notation is now being used in which repeated indices in a product are implicitly summed. The second term from the right is the asymmetric part of the first derivative term, and it represents a rigid rotation of the fluid about ***r*** with angular velocity ω where:

$$\omega = \frac{1}{2}\nabla \times \mathbf{v} = \frac{1}{2}\begin{bmatrix} \partial_2 v_3 - \partial_3 v_2 \\ \partial_3 v_1 - \partial_1 v_3 \\ \partial_1 v_2 - \partial_2 v_1 \end{bmatrix}.$$

For such a rigid rotation, there is no change in the relative positions of the fluid elements, and so there is no viscous force associated with this term. The remaining symmetric term is responsible for the viscous forces in the fluid. Assuming the fluid is isotropic (i.e. its properties are the same in all directions), then the most general way that the symmetric term (the rate-of-strain tensor) can be broken down in a coordinate-independent (and therefore physically real) way is as the sum of a constant tensor (the rate-of-expansion tensor) and a traceless symmetric tensor (the rate-of-shear tensor):

$$\frac{1}{2}\left(\partial_i v_j + \partial_j v_i\right) = \underbrace{\frac{1}{3}\partial_k v_k \delta_{ij}}_{\text{rate-of-expansion tensor}} + \underbrace{\left(\frac{1}{2}\left(\partial_i v_j + \partial_j v_i\right) - \frac{1}{3}\partial_k v_k \delta_{ij}\right)}_{\text{rate-of-shear tensor}},$$

where δ_{ij} is the unit tensor. The most general linear relationship between the stress tensor $\boldsymbol{\sigma}$ and the rate-of-strain tensor is then a linear combination of these two tensors:

$$\sigma_{\text{visc};ij} = \zeta \partial_k v_k \delta_{ij} + \mu \left(\partial_i v_j + \partial_j v_i - \frac{2}{3}\partial_k v_k \delta_{ij}\right),$$

where ς is the coefficient of bulk viscosity (or "second viscosity") and μ is the coefficient of (shear) viscosity.

The forces in the fluid are due to the velocities of the individual molecules. The velocity of a molecule may be thought of as the sum of the fluid velocity and the thermal velocity. The viscous stress tensor described above gives the force due to the fluid velocity only. The force on an area element in the fluid due to the thermal velocities of the molecules is just the hydrostatic pressure. This pressure term ($-p\ \delta_{ij}$) must be added to the viscous stress tensor to obtain the total stress tensor for the fluid.

$$\sigma_{ij} = -p\delta_{ij} + \sigma_{\text{visc};ij}.$$

The infinitesimal force dF_i on an infinitesimal area dA_i is then given by the usual relationship:

$$dF_i = \sigma_{ij}\, dA_j.$$

Chapter 5

Petroleum Reservoir

A **petroleum reservoir**, or **oil and gas reservoir**, is a subsurface pool of hydrocarbons contained in porous or fractured rock formations. The naturally occurring hydrocarbons, such as crude oil or natural gas, are trapped by overlying rock formations with lower permeability. Reservoirs are found using hydrocarbon exploration methods.

Formation

Crude oil found in oil reservoirs formed in the Earth's crust from the remains of living things. Crude oil is properly known as petroleum, and is used as fossil fuel. Evidence indicates that millions of years of heat and pressure changed the remains of microscopic plant and animal remains into oil and natural gas.

Roy Nurmi, an interpretation adviser for Schlumberger, described the process as follows: "Plankton and algae, proteins and the life that's floating in the sea, as it dies, falls to the bottom, and these organisms are going to be the source of our oil and gas. When they're buried with the accumulating sediment and reach an adequate temperature, something above 50 to 70 °C they start to cook. This transformation, this change, changes them into the liquid hydrocarbons that move and migrate, will become our oil and gas reservoir."

In addition to the aquatic environment, which is usually a sea, but might also be a river, lake, coral reef or algal mat, the formation of an oil or gas reservoir also requires a sedimentary basin that passes through four steps: deep burial under sand and mud, pressure cooking, hydrocarbon migration from the source to the reservoir rock, and trapping by impermeable rock. Timing is also an important consideration; it is suggested that the Ohio River Valley could have had as much oil as the Middle East at one time, but that it escaped due to a lack of traps. The North Sea, on the other hand, endured millions of years of sea level changes that successfully resulted in the formation of more than 150 oilfields.

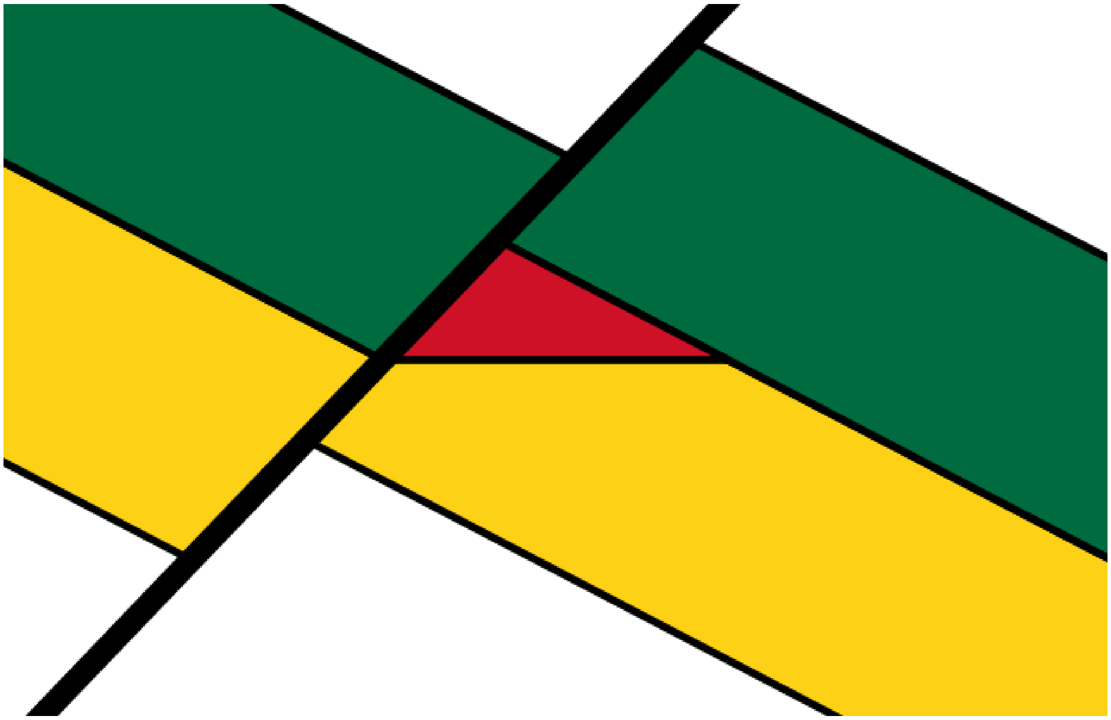
Although the process is generally the same, various environmental factors lead to the creation of a wide variety of reservoirs. Reservoirs exist anywhere from the land surface to 30,000 ft (9,000 m) below the surface and are a variety of shapes, sizes and ages.

Traps

The traps required in the last step of the reservoir formation process have been classified by petroleum geologists into two types: structural and stratigraphic. A reservoir can be formed by one kind of trap or a combination of both.

Structural traps

Fold (structural) trap



Fault (structural) trap

Structural traps are formed by a deformation in the rock layer that contains the hydrocarbons. Domes, anticlines, and folds are common structures. Fault-related features also may be classified as structural traps if closure is present. Structural traps are the easiest to locate by surface and subsurface geological and geophysical studies. They are the most numerous among traps and have received a greater amount of attention in the search for oil than all other types of traps.

An example of this kind of trap starts when salt is deposited by shallow seas. Later, a sinking seafloor deposits organic-rich shale over the salt, which is in turn covered with layers of sandstone and shale. Deeply buried salt tends to rise unevenly in swells or salt domes, and any oil generated within the sediments is trapped where the sandstones are pushed up over or adjacent to the salt dome.

Stratigraphic traps

Stratigraphic traps are formed when other beds seal a reservoir bed or when the permeability changes (facies change) within the reservoir bed itself. Stratigraphic traps can form against either younger or older time surfaces.

Estimating reserves

After the discovery of a reservoir, a petroleum engineer will seek to build a better picture of the accumulation. In a simple text book example of a uniform reservoir, the first stage is to conduct a seismic survey to determine the possible size of the trap. Appraisal wells can be used to determine the location of oil-water contact and with it, the height of the oil bearing sands. Often coupled with seismic data, it is possible to estimate the volume of oil bearing reservoir.

The next step is to use information from appraisal wells to estimate the porosity of the rock. The porosity, or the percentage of the total volume that contains fluids rather than solid rock, is 20-35% or less. It can give information on the actual capacity. Laboratory testing can determine the characteristics of the reservoir fluids, particularly the expansion factor of the oil, or how much the oil expands when brought from high pressure, high temperature of the reservoir to "stock tank" at the surface.

With such information, it is possible to estimate how many "stock tank" barrels of oil are located in the reservoir. Such oil is called the stock tank oil initially in place (STOIIP). As a result of studying things such as the permeability of the rock (how easily fluids can flow through the rock) and possible drive mechanisms, it is possible to estimate the recovery factor, or what proportion of oil in place can be reasonably expected to be produced. The recovery factor is commonly 30-35%, giving a value for the recoverable reserves.

The difficulty is that reservoirs are not uniform. They have variable porosities and permeabilities and may be compartmentalised, with fractures and faults breaking them up and complicating fluid flow. For this reason, computer modeling of economically viable reservoirs is often carried out. Geologists, geophysicists and reservoir engineers work together to build a model which allows simulation of the flow of fluids in the reservoir, leading to an improved estimate of reserves.

Production

To obtain the contents of the oil reservoir, it is usually necessary to drill into the Earth's crust, although surface oil seeps exist in some parts of the world, such as the La Brea tar pits in California, and numerous seeps in Trinidad.

Drive mechanisms

A virgin reservoir may be under sufficient pressure to push hydrocarbons to surface. As the fluids are produced, the pressure will often decline, and production will falter. The reservoir may respond to the withdrawal of fluid in a way that tends to maintain the pressure. Artificial drive methods may be necessary.

Solution gas drive

This mechanism (also known as depletion drive) depends on the associated gas of the oil. The virgin reservoir may be entirely liquid, but will be expected to have gaseous hydrocarbons in solution due to the pressure. As the reservoir depletes, the pressure falls below the bubble point, and the gas comes out of solution to form a gas cap at the top. This gas cap pushes down on the liquid helping to maintain pressure.

Gas cap drive

In reservoirs already having a gas cap (the virgin pressure is already below bubble point), the gas cap expands with the depletion of the reservoir, pushing down on the liquid sections applying extra pressure.

Aquifer (water) drive

Below the hydrocarbons may be a ground water aquifer. Water, as with all liquids, is compressible to a small degree. As the hydrocarbons are depleted, the reduction in pressure in the reservoir causes the water to expand slightly. Although this expansion is minute, if the aquifer is large enough, this will translate into a large increase in volume, which will push up on the hydrocarbons, maintaining pressure.

Water and gas injection

If the natural drives are insufficient, as they very often are, then the pressure can be artificially maintained by injecting water into the aquifer or gas into the gas cap.

Chapter 6

Pigging

Pigging in the maintenance of pipelines refers to the practice of using pipeline inspection gauges or 'pigs' to perform various operations on a pipeline without stopping the flow of the product in the pipeline.

These operations include but are not limited to cleaning and inspecting of the pipeline. This is accomplished by inserting the pig into a 'pig launcher' (or 'launching station') - a funnel shaped Y section in the pipeline. The launcher / launching station is then closed and the pressure of the product in the pipeline is used to push it along down the pipe until it reaches the receiving trap - the 'pig catcher' (or receiving station).

If the pipeline contains butterfly valves, the pipeline cannot be pigged. Ball valves cause no problems because the inside diameter of the ball can be specified to be the same as that of the pipe (as soon as they are ful bore valves).

Pigging has been used for many years to clean larger diameter pipelines in the oil industry. Today, however, the use of smaller diameter pigging systems is now increasing in many continuous and batch process plants as plant operators search for increased efficiencies and reduced costs.

Pigging can be used for almost any section of the transfer process between, for example, blending, storage or filling systems. Pigging systems are already installed in industries handling products as diverse as lubricating oils, paints, chemicals, toiletries, cosmetics and foodstuffs.

Pigs are used in lube oil or painting blending: they are used to clean the pipes to avoid cross-contamination, and to empty the pipes into the product tanks (or sometimes to send a component back to its tank). Usually pigging is done at the beginning and at the end of each batch, but sometimes it is done in the midst of a batch, e.g. when producing a premix that will be used as an intermediate component.

Pigs are also used in oil and gas pipelines: they are used to clean the pipes but also there are "smart pigs" used to measure things like pipe thickness and corrosion along the pipeline. They usually do not interrupt production, though some product can be lost when the pig is extracted. They can also be used to separate different products in a multiproduct pipeline.

Etymology

Pigs get their name from the squealing sound they make while travelling through a pipeline. (Disputed: 'PIG' is an acronym or backronym derived from the initial letters of the term 'Pipeline Inspection Gauge' or possibly 'Pipeline Inspection Gizmo' or 'Pipeline Internal Geometry' or 'Pipeline Inspection Gadget').

Pigging in production environments

Product and time saving

A major advantage of piggable systems is the potential resulting product savings. At the end of each product transfer, it is possible to clear out the entire line contents with the pig, either forwards towards the receipt point, or backwards to the source tank. There is no requirement for extensive line flushing.

Without the need for line flushing, pigging offers the additional advantage of a much more rapid and reliable product changeover. Product sampling at the receipt point becomes faster because the interface between products is very clear, and the old method of checking at intervals, until the product is on-specification, is considerably shortened.

Pigging systems can also be operated totally by a programmable logic controller (PLC).

Environmental issues

Pigging has a significant role to play in reducing the environmental impact of batch operations. Traditionally, the only way that an operator of a batch process could ensure a product was completely cleared from a line was to flush the line with a cleaning agent such as water or a solvent or even the next product. This cleaning agent then had to be subjected to effluent treatment or solvent recovery. If product was used to clear the line, the contaminated finished product was downgraded or dumped. In some cases, the finished product could contain polychlorinated biphenyl (PCB), which has been found to be carcinogenic. All of these problems can now be eliminated due to the very precise interface produced by modern pigging systems.

Safety considerations

Pigging systems are designed so that the pig is loaded into the launcher, which is pressured up to launch the pig into the pipeline through a kicker line. In some cases, the pig is removed from the pipeline via the receiver at the end of each run. All systems must allow for the receipt of pigs at the launcher, as blockages in the pipeline may require the pigs to be pushed back to the launcher. Most of the time, systems are designed to pig the pipeline in either direction.

The pig is pushed either with an inert gas or a liquid; if pushed by gas, some systems can be adapted in the gas inlet in order to ensure pig's constant speed, whatever the pressure drop is. The pigs must be removed, as many pigs are rented, pigs wear and must be replaced, and cleaning pigs push contaminants from the pipeline such as wax, foreign objects, hydrates, etc, which must be removed from the pipeline. There are inherent risks in opening the barrel to atmosphere and care must be taken to ensure that the barrel is depressured prior to opening. If the barrel is not completely depressured, the pig can be ejected from the barrel and operators have been severely injured when standing in front of an open pig door. When the product is sour, the barrel should be evacuated to a flare system where the sour gas is burnt. Operators should be wearing a self-contained breathing apparatus when working on sour systems.

A few pigging systems utilize a "captive pig", and the pipeline is only opened up very occasionally to check the condition of the pig. At all other times, the pig is shuttled up and down the pipeline at the end of each transfer, and the pipeline itself is never opened up during process operation. These systems are not common.

Intelligent pigging

Inserting a pig into a natural gas pipeline

Modern intelligent pigs are highly sophisticated instruments that vary in technology and complexity by the intended use and by manufacturer. An intelligent pig, or smart pig, is basically a computer that collects various forms of data during the trip through the pipeline.

The computer part, consisting mostly of electronics, must be sealed to prevent leakage of the pipeline product into the electronics. Sealing is a very important aspect as the products in the pipeline can range from highly basic to highly acidic and can be of extremely high temperature. Many pigs use specific materials according to the product in the pipeline. Power for the electronics is provided by onboard batteries which also must be sealed from the product environment. Recording of data may be by various means ranging from analog tape in a reel-to-reel format, digital tape or solid state memory in more modern digital units.

This technology is used to accomplish the service vary by the service required and the design of the pig, each pigging service provider may have unique and proprietary technologies to accomplish the service. Surface pitting and corrosion, as well as cracks and weld defects in steel/ferrous pipelines are often detected using magnetic flux leakage (MFL) pigs. Other "smart" pigs use electromagnetic acoustic transducers to detect pipe defects. Caliper pigs can measure the "roundness" of the pipeline to determine areas of crushing or other deformations. Some smart pigs can combine technologies such as MFL and Caliper into a single tool.

During the pigging run the pig is unable to directly communicate with the outside world due to the distance underground or underwater and/or materials that the pipe is made of. For example, steel pipelines effectively prevent any reliable radio communications outside the pipe. It is therefore necessary that the pig use internal means to record its own movement during the trip. This may be done by gyroscope-assisted tilt gauges, odometers and other technologies. The pig will record this positional data so that the distance it moves along with any bends can be interpreted later to determine the exact path taken.

Location verification is often accomplished by surface instruments that record the pig's passage by either audible or gravinometric (or other) means. The sensors will record when they detect passage of the pig; this is then compared to the internal record for verification or adjustment. The external sensors may have GPS capability to assist in their location or even to transmit the pig's passage, but the pig itself usually cannot use GPS as it requires being able to "see" (in satellite terminology) the satellites.

After the pigging run has been completed, the positional data is combined with the pipeline evaluation data (corrosion, cracks, etc) to provide a location-specific defect map and characterization. In other words, the combined data will tell the operator the location and type and size of each pipe defect. This is used to judge the severity of the defect and help repair crews locate and repair the defect quickly without having to dig up excessive amounts of pipeline. By evaluating the rate of change of a particular defect over several years, proactive plans can be made to repair the pipeline before any leakage or environmental damage occurs.

Pipeline Inspection Gauge

A pig on display in a section of cutaway pipe, from the Alaska Pipeline

A "Pig" launcher/receiver, belonging to the natural gas pipeline in Switzerland.

A pipeline inspection gauge or "PIG" in the pipeline industry is a tool that is sent down a pipeline and propelled by the pressure of the product in the pipeline itself. There are four main uses for pigs:

1. physical separation between different liquids being transported in pipelines;
2. internal cleaning of pipelines;
3. inspection of the condition of pipeline walls (also known as an Inline Inspection (ILI) tool);
4. capturing and recording geometric information relating to pipelines (e.g. size, position).

The original pigs were made from straw wrapped in wire used for cleaning. They made a squealing noise while traveling through the pipe, sounding to some like a pig squealing. The term "pipeline inspection gauge" was later created as a backronym.

One kind of pig is a soft, bullet shaped polyurethane foam plug that is forced through pipelines to separate products to reduce mixing. There are several types of pigs for cleaning. Some have tungsten studs or abrasive wire mesh on the outside to cut rust, scale, or paraffin deposits off the inside of the pipe. Others are plain plastic covered polyurethane. Pigs cannot be used in pipelines that have butterfly valves.

Inline inspection pigs use various methods for inspecting a pipeline. A sizing pig uses one (or more) notched round metal plates that are used as gauges. The notches allow different parts of the plate to bend when a bore restriction is encountered. More complex systems exist for inspecting various aspects of the pipeline. Intelligent pigs, also called smart pigs, are used to inspect the pipeline with sensors and record the data for later analysis. These pigs use technologies such as MFL and ultrasonics to inspect the pipeline. Intelligent pigs may also use calipers to measure the inside geometry of the pipeline.

In 1961, the first intelligent pig was run by Shell Development. It demonstrated that a self contained electronic instrument could traverse a pipe line while measuring and recording wall thickness. The instrument used electromagnetic fields to sense wall integrity. In 1964 Tuboscope ran the first commercial instrument. It used MFL technology to inspect the bottom portion of the pipeline. The system used a black box similar to those used on aircraft to record the information.

A pig has been used as a plot device in three James Bond films: *Diamonds Are Forever*, where Bond disabled a pig to escape from a pipeline, *The Living Daylights*, where a pig was modified to secretly transport a person through the Iron Curtain, and *The World Is Not Enough*, where a pig was used to move a nuclear weapon through a pipeline.

A pig was also used as a plot device in the *Tony Hillerman* book *The Sinister Pig* where an abandoned pipeline from Mexico to the United States was to use a pig to transport illegal drugs.

Capacitive sensor probes are used in the process of detecting defects in polyethylene pipe gas pipeline. These probes are attached to the pig in which the pig is sent through the polyethylene pipe that will detect any defects in the outside of the pipe wall. This is done by using a triple plate capacitive sensor in which the electrostatic waves are propogated outware through the pipes all. Any change in dielectric material will result in a change in capacitance. Testing was conducted by NETL DOE research lab at the Battelle West Jefferson's Pipeline Simulation Facility (PSF) near Columbus, Ohio.

Chapter 7

Oil Well and Well Logging

Oil Well

The pumpjack, such as this one located south of Midland, Texas, is a common sight in West Texas.

An **oil well** is a general term for any boring through the earth's surface that is designed to find and acquire petroleum oil hydrocarbons. Usually some natural gas is produced along with the oil. A well that is designed to produce mainly or only gas may be termed a **gas well**.

History

Oil extraction in Boryslav in Galicia in 1909.

The earliest known oil wells were drilled in China in 347 CE. They had depths of up to about 800 feet (240 m) and were drilled using bits attached to bamboo poles. The oil was burned to evaporate brine and produce salt. By the 10th century, extensive bamboo pipelines connected oil wells with salt springs. The ancient records of China and Japan are said to contain many allusions to the use of natural gas for lighting and heating. Petroleum was known as *burning water* in Japan in the 7th century.

The Middle East's petroleum industry was established by the 8th century, when the streets of the newly constructed Baghdad were paved with tar, derived from petroleum that became accessible from natural fields in the region. Petroleum was distilled by the Persian alchemist Muhammad ibn Zakarīya Rāzi (Rhazes) in the 9th century, producing chemicals such as kerosene in the alembic (*al-ambiq*), and which was mainly used for kerosene lamps. Arab and Persian chemists also distilled crude oil in order to produce flammable products for military purposes. Through Islamic Spain, distillation became available in Western Europe by the 12th century.

Some sources claim that from the 9th century, oil fields were exploited in the area around modern Baku, Azerbaijan, to produce naphtha for the petroleum industry. These fields were described by Marco Polo in the 13th century, who described the output of those oil wells as hundreds of shiploads. When Marco Polo in 1264 visited the Azerbaijani city of Baku, on the shores of the Caspian Sea, he saw oil being collected from seeps. He wrote that "on the confines toward Geirgine there is a fountain from which oil springs in great abundance, inasmuch as a hundred shiploads might be taken from it at one time."

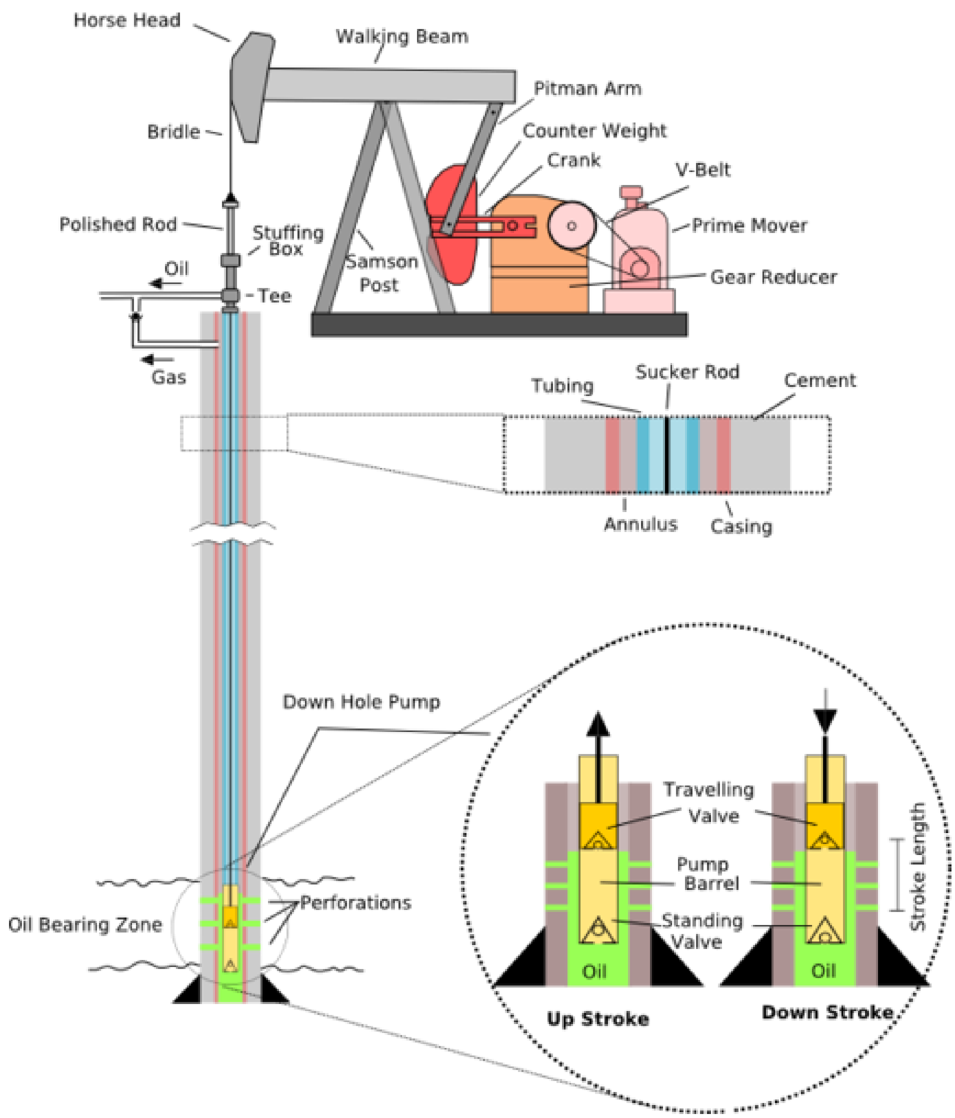
A FOUNTAIN AT BIBI-EIBAT IN FLAMES, BAKU

1904 oil well fire at Bibi-Eibat.

Shallow pits were dug at the Baku seeps in ancient times to facilitate collecting oil, and hand-dug holes up to 35 metres (115 ft) deep were in use by 1594. These holes were essentially oil wells. Apparently 116 of these wells in 1830 produced 3,840 metric tons (about 28000 barrels) of oil. Also, offshore drilling started up at Baku at Bibi-Eibat field in 1846, about the same time that the first offshore oil well was drilled in 1896 at the Summerland Oil Field on the California Coast.

The earliest oil wells in modern times were drilled percussively, by hammering a cable tool into the earth. Soon after, cable tools were replaced with rotary drilling, which could drill boreholes to much greater depths and in less time. The record-depth Kola Borehole used non-rotary mud motor drilling to achieve a depth of over 12,000 metres (39,000 ft). Until the 1970s, most oil wells were vertical, although lithological and mechanical imperfections cause most wells to deviate at least slightly from true vertical. However, modern directional drilling technologies allow for strongly deviated wells which can, given sufficient depth and with the proper tools, actually become horizontal. This is of great value as the reservoir rocks which contain hydrocarbons are usually horizontal, or sub-horizontal; a horizontal wellbore placed in a production zone has more surface area in the production zone than a vertical well, resulting in a higher production rate. The use of deviated and horizontal drilling has also made it possible to reach reservoirs several kilometers or miles away from the drilling location (extended reach drilling), allowing for the production of hydrocarbons located below locations that are either difficult to place a drilling rig on, environmentally sensitive, or populated.

Life of a well



A schematic of a typical oil well being produced by a pumpjack, which is used to produce the remaining recoverable oil after natural pressure is no longer suficient to raise oil to the surface.

The creation and life of a well can be divided up into five segments:

- Planning
- Drilling
- Completion
- Production
- Abandonment

Drilling

The well is created by drilling a hole 5 to 36 inches (127.0 mm to 914.4 mm) in diameter into the earth with a drilling rig that rotates a drill string with a bit attached. After the hole is drilled, sections of steel pipe (casing), slightly smaller in diameter than the borehole, are placed in the hole. Cement may be placed between the outside of the casing and the borehole. The casing provides structural integrity to the newly drilled wellbore, in addition to isolating potentially dangerous high pressure zones from each other and from the surface.

With these zones safely isolated and the formation protected by the casing, the well can be drilled deeper (into potentially more-unstable and violent formations) with a smaller bit, and also cased with a smaller size casing. Modern wells often have two to five sets of subsequently smaller hole sizes drilled inside one another, each cemented with casing.

Mud log in process, a common way to study the lithology when drilling oil wells.

To drill the well

- The drill bit, aided by the weight of thick walled pipes called "drill collars" above it, cuts into the rock. There are different types of drill bit; some cause the rock to disintegrate by compressive failure, while others shear slices off the rock as the bit turns.
- Drilling fluid, a.k.a. "mud", is pumped down the inside of the drill pipe and exits at the drill bit. Drilling mud is a complex mixture of fluids, solids and chemicals that must be carefully tailored to provide the correct physical and chemical characteristics required to safely drill the well. Particular functions of the drilling mud include cooling the bit, lifting rock cuttings to the surface, preventing destabilisation of the rock in the wellbore walls and overcoming the pressure of fluids inside the rock so that these fluids do not enter the wellbore.
- The generated rock "cuttings" are swept up by the drilling fluid as it circulates back to surface outside the drill pipe. The fluid then goes through "shakers" which strain the cuttings from the good fluid which is returned to the pit. Watching for abnormalities in the returning cuttings and monitoring pit volume or rate of returning fluid are imperative to catch "kicks" early. A "kick" is when the formation pressure at the depth of the bit is more than the hydrostatic head of the mud above, which if not controlled temporarily by closing the blowout preventers and ultimately by increasing the density of the drilling fluid would allow formation fluids and mud to come up through the drill pipe uncontrollably.
- The pipe or drill string to which the bit is attached is gradually lengthened as the well gets deeper by screwing in additional 30-foot (9 m) sections or "joints" of pipe under the kelly or topdrive at the surface. This process is called making a connection. Usually, joints are combined into three joints equaling one stand. Some smaller rigs only use two joints and some rigs can handle stands of four joints.

This process is all facilitated by a drilling rig which contains all necessary equipment to circulate the drilling fluid, hoist and turn the pipe, control downhole, remove cuttings from the drilling fluid, and generate on-site power for these operations.

Modern driller Argentina.

Completion

After drilling and casing the well, it must be 'completed'. Completion is the process in which the well is enabled to produce oil or gas.

In a cased-hole completion, small holes called perforations are made in the portion of the casing which passed through the production zone, to provide a path for the oil to flow from the surrounding rock into the production tubing. In open hole completion, often 'sand screens' or a 'gravel pack' is installed in the last drilled, uncased reservoir section. These maintain structural integrity of the wellbore in the absence of casing, while still allowing flow from the reservoir into the wellbore. Screens also control the migration of formation sands into production tubulars and surface equipment, which can cause washouts and other problems, particularly from unconsolidated sand formations in offshore fields.

After a flow path is made, acids and fracturing fluids are pumped into the well to fracture, clean, or otherwise prepare and stimulate the reservoir rock to optimally produce hydrocarbons into the wellbore. Finally, the area above the reservoir section of the well is packed off inside the casing, and connected to the surface via a smaller diameter pipe called tubing. This arrangement provides a redundant barrier to leaks of hydrocarbons as well as allowing damaged sections to be replaced. Also, the smaller crossectional area of the tubing produces reservoir fluids at an increased velocity in order to minimize liquid fallback that would create additional back pressure, and shields the casing from corrosive well fluids.

In many wells, the natural pressure of the subsurface reservoir is high enough for the oil or gas to flow to the surface. However, this is not always the case, especially in depleted fields where the pressures have been lowered by other producing wells, or in low permeability oil reservoirs. Installing a smaller diameter tubing may be enough to help the production, but artificial lift methods may also be needed. Common solutions include downhole pumps, gas lift, or surface pump jacks. Many new systems in the last ten years have been introduced for well completion. Multiple packer systems with frac ports or port collars in an all in one system have cut completion costs and improved production, especially in the case of horizontal wells. These new systems allow casings to run into the lateral zone with proper packer/frac port placement for optimal hydrocarbon recovery.

Production

The production stage is the most important stage of a well's life, when the oil and gas are produced. By this time, the oil rigs and workover rigs used to drill and complete the well have moved off the wellbore, and the top is usually outfitted with a collection of valves called a Christmas tree or Production trees. These valves regulate pressures, control flows, and allow access to the wellbore in case further completion work is needed. From the outlet valve of the production tree, the flow can be connected to a distribution network of pipelines and tanks to supply the product to refineries, natural gas compressor stations, or oil export terminals.

As long as the pressure in the reservoir remains high enough, the production tree is all that is required to produce the well. If the pressure depletes and it is considered economically viable, an artificial lift method mentioned in the completions section can be employed.

Workovers are often necessary in older wells, which may need smaller diameter tubing, scale or paraffin removal, acid matrix jobs, or completing new zones of interest in a shallower reservoir. Such remedial work can be performed using workover rigs – also known as *pulling units* or *completion rigs* – to pull and replace tubing, or by the use of well intervention techniques utilizing coiled tubing. Depending on the type of lift system and wellhead a rod rig or flushby can be used to change a pump without pulling the tubing.

Enhanced recovery methods such as water flooding, steam flooding, or CO_2 flooding may be used to increase reservoir pressure and provide a "sweep" effect to push hydrocarbons out of the reservoir. Such methods require the use of injection wells (often chosen from old production wells in a carefully determined pattern), and are used when facing problems with reservoir pressure depletion, high oil viscosity, or can even be employed early in a field's life. In certain cases – depending on the reservoir's geomechanics – reservoir engineers may determine that ultimate recoverable oil may be increased by applying a waterflooding strategy early in the field's development rather than later. Such enhanced recovery techniques are often called "tertiary recovery".

Abandonment

A well is said to reach an "economic limit" when its production rate does not cover the expenses, including taxes.

The economic limit for oil and gas wells can be expressed using these formulae:

Oil fields:

$$EL_{oil} = \frac{WI \times LOE}{NRI[P_o + (P_g \times GOR)/1{,}000] \times (1 - T)}$$

Gas fields:

$$EL_{gas} = \frac{WI \times LOE}{NRI[(P_o \times Y) + P_g] \times (1 - T)}$$

Where:
EL_{oil} is an oil well's economic limit in oil barrels per month (bbls/month).
EL_{gas} is a gas well's economic limit in thousand standard cubic feet per month (MSCF/month).
P_o,P_g are the current prices of oil and gas in dollars per barrels and dollars per MSCF respectively.
LOE is the lease operating expenses in dollars per well per month.
WI working interest, as a fraction.
NRI net revenue interest, as a fraction.
GOR gas/oil ratio as bbls/MSCF.
Y condensate yield as barrel/million standard cubic feet.
T production and severance taxes, as a fraction.

When the economic limit is raised, the life of the well is shortened and proven oil reserves are lost. Conversely, when the economic limit is lowered, the life of the well is lengthened.

When the economic limit is reached, the well becomes a liability and is abandoned. In this process, tubing is removed from the well and sections of well bore are filled with cement to isolate the flow path between gas and water zones from each other, as well as the surface. Completely filling the well bore with cement is costly and unnecessary. The surface around the wellhead is then excavated, and the wellhead and casing are cut off, a cap is welded in place and then buried.

At the economic limit there often is still a significant amount of unrecoverable oil left in the reservoir. It might be tempting to defer physical abandonment for an extended period of time, hoping that the oil price will go up or that new supplemental recovery techniques will be perfected. However, lease provisions and governmental regulations usually require quick abandonment; liability and tax concerns also may favor abandonment.

In theory an abandoned well can be reentered and restored to production (or converted to injection service for supplemental recovery or for downhole hydrocarbons storage), but reentry often proves to be difficult mechanically and not cost effective.

Types of wells

A natural gas well in the southeast Lost Hills Field, California, US.

Fossil-fuel wells come in many varieties. By produced fluid, there can be wells that produce oil, wells that produce oil *and* natural gas, or wells that *only* produce natural gas. Natural gas is almost always a byproduct of producing oil, since the small, light gas carbon chains come out of solution as they undergo pressure reduction from the reservoir to the surface, similar to uncapping a bottle of soda pop where the carbon dioxide effervesces. Unwanted natural gas can be a disposal problem at the well site. If there is not a market for natural gas near the wellhead it is virtually valueless since it must be piped to the end user. Until recently, such unwanted gas was burned off at the wellsite, but due to environmental concerns this practice is becoming less common. Often, unwanted (or 'stranded' gas without a market) gas is pumped back into the reservoir with an 'injection' well for disposal or repressurizing the producing formation. Another solution is to export the natural gas as a liquid. Gas-to-liquid, (GTL) is a developing technology that converts stranded natural gas into synthetic gasoline, diesel or jet fuel through the Fischer-Tropsch process developed in World War II Germany. Such fuels can be transported through conventional pipelines and tankers to users. Proponents claim GTL fuels burn cleaner than comparable petroleum fuels. Most major international oil companies are in advanced development stages of GTL production, e.g. the 140,000 bbl/d (22,000 m^3/d) Pearl GTL plant in Qatar, scheduled to come online in 2011. In locations such as the United States with a high natural gas demand, pipelines are constructed to take the gas from the wellsite to the end consumer.

Another obvious way to classify oil wells is by land or offshore wells. There is very little difference in the well itself. An offshore well targets a reservoir that happens to be underneath an ocean. Due to logistics, drilling an offshore well is far more costly than an onshore well. By far the most common type is the onshore well. These wells dot the Southern and Central Great Plains, Southwestern United States, and are the most common wells in the Middle East.

Another way to classify oil wells is by their purpose in contributing to the development of a resource. They can be characterized as:

- *production wells* are drilled primarily for producing oil or gas, once the producing structure and characteristics are determined
- *appraisal wells* are used to assess characteristics (such as flow rate) of a proven hydrocarbon accumulation
- *exploration wells* are drilled purely for exploratory (information gathering) purposes in a new area
- *wildcat wells* are those drilled outside of and not in the vicinity of known oil or gas fields.

At a producing well site, active wells may be further categorised as:

- *oil producers* producing predominantly liquid hydrocarbons, but mostly with some associated gas.
- *gas producers* producing almost entirely gaseous hydrocarbons.
- *water injectors* injecting water into the formation to maintain reservoir pressure or simply to dispose of water produced with the hydrocarbons because even after treatment, it would be too oily and too saline to be considered clean for dumping overboard, let alone into a fresh water source, in the case of onshore wells. Frequently water injection has an element of reservoir management and produced water disposal.
- *aquifer producers* intentionally producing reservoir water for re-injection to manage pressure. This is in effect moving reservoir water from where it is not as useful to where it is more useful. These wells will generally only be used if produced water from the oil or gas producers is insufficient for reservoir management purposes. Using aquifer produced water rather than water from other sources is to preclude chemical incompatibility that might lead to reservoir-plugging precipitates.
- *gas injectors* injecting gas into the reservoir often as a means of disposal or sequestering for later production, but also to maintain reservoir pressure.

Lahee classification

- *New Field Wildcat* (NFW) – far from other producing fields and on a structure that has not previously produced.
- *New Pool Wildcat* (NPW) – new pools on already producing structure.

- *Deeper Pool Test* (DPT) – on already producing structure and pool, but on a deeper pay zone.
- *Shallower Pool Test* (SPT) – on already producing structure and pool, but on a shallower pay zone.
- *Outpost* (OUT) – usually two or more locations from nearest productive area.
- *Development Well* (DEV) – can be on the extension of a pay zone, or between existing wells (*Infill*).

Cost

The cost of a well depends mainly on the daily rate of the drilling rig, the extra services required to drill the well, the duration of the well programme (including downtime and weather time), and the remoteness of the location (logistic supply costs).

The daily rates of offshore drilling rigs vary by their capability, and the market availability. Rig rates reported by industry web service show that the deepwater water floating drilling rigs are over twice that of the shallow water fleet, and rates for jackup fleet can vary by factor of 3 depending upon capability.

With deepwater drilling rig rates in 2010 of around $420,000/day, and similar additional spread costs, a deep water well of duration of 100 days can cost around US$100 million.

With high performance jackup rig rates in 2010 of around $150,000, and similar service costs, a high pressure, high temperature well of duration 100 days can cost about US$30 million.

Onshore wells can be considerably cheaper, particularly if the field is at a shallow depth, where costs range from less than $1 million to $15 million for deep and difficult wells.

The total cost of an oil well mentioned does not include the costs associated with the risk of explosion and leakage of oil. Those costs include the cost of protecting against such disasters, the cost of the cleanup effort, and the hard-to-calculate cost of damage to the company's image.

Well logging

Well logging, also known as **borehole logging** is the practice of making a detailed record (a *well log*) of the geologic formations penetrated by a borehole. The log may be based either on visual inspection of samples brought to the surface (*geological* logs) or on physical measurements made by instruments lowered into the hole (*geophysical* logs). Well logging is done during all phases of a wells development; drilling, completing, producing and abandoning. Mostly in the oil and gas, groundwater, minerals, geothermal, and for environmental and geotechnical studies.

Electric or geophysical well logs

The oil and gas industry records rock and fluid properties to find hydrocarbon zones in the geological formations intersected by a borehole. The logging procedure consists of lowering a 'logging tool' on the end of a wireline into an oil well (or hole) to measure the rock and fluid properties of the formation. An interpretation of these measurements is then made to locate and quantify potential depth zones containing oil and gas (hydrocarbons). Logging tools developed over the years measure the electrical, acoustic, radioactive, electromagnetic, nuclear magnetic resonance, and other properties of the rocks and their contained fluids. Logging is usually performed as the logging tools are pulled out of the hole. This data is recorded either at surface (real-time mode), or downhole (memory mode)to electronic data format and then either a printed record or electronic presentation called a "well log" provided to the client. Well logging is performed at various intervals during the drilling of the well and when the total depth is drilled, which could range in depths from 150 m to 10668 m (500 ft to 35,000 ft) or more.

Electric line is the common term for the armored, insulated cable used to conduct current to downhole tools used for well logging. Electric line can be subdivided into open hole operations and cased hole operations. Other conveyance methods for logging are logging while drilling (LWD), tractor, coiled tubing (real-time and memory), drill pipe conveyed, and slickline (memory, and with new development, some slickline telemetry capability).

Open hole operations, or reservoir evaluation, involves the deployment of tools into a freshly drilled well. As the toolstring traverses the wellbore, the individual tools gather information about the surrounding formations. A typical open hole log will have information about the density, porosity, permeability, lithology, presence of hydrocarbons, and oil and water saturation.

Cased hole operations, or production optimization, focuses of the optimization of the completed oil well through mechanical services and logging technologies. At this point in the well's life, the well is encased in steel pipe, cemented into the well bore and may or may not be producing. A typical cased hole log may show cement quality, production information, formation data. Mechanical services uses jet perforating guns, setting tools, and dump bailors to optimize the flow of hydrocarbons.

Wireline tool types

Typically the wireline tools are cylindrical in shape, usually from 1.5 to 5 inches in diameter. "Open hole" tool combinations can extend to over 100 feet long; "cased hole" tool combinations are often limited in length by the height restrictions imposed by constraints of "lubricator" pipe section required to contain the well pressure while deploying cased hole tools. There are many types of logging tools, ranging from common measurements (pressure and temperature) to advanced rock properties and fracture analysis, fluid properties in the wellbore, or formation properties extending several meters into the rock formation.

1. With sensors without excitation

There are units to measure spontaneous potential (SP), which is a voltage difference between a surface electrode and another electrode located in the downhole instrument, other instruments that measure the natural radiation from natural isotopes of potassium, thorium, etc., to measure pressure and temperature, etc.

2. With sources of excitation and sensors

There are sensor systems consistent with a source of excitation and a sensor. In this type we find acoustic (also called sonic), electric, inductive, magnetic resonance, sensing systems, just to name a few.

3. Instruments that produce some mechanical work, or retrieve a sample of fluid or rock to the surface.

Devices to collect samples of rock, samples of fluid extracted from the rock, and some other mechanical devices.

Types of electric/electronic logs

There are many types of electric/electronic logs and they can be categorized either by their function or by the technology that they use. "Open hole logs" are run before the oil or gas well is lined with pipe or cased. "Cased hole logs" are run after the well is lined with casing or production pipe.

Electric/electronic logs can also be divided into two general types based on what physical properties they measure. Resistivity logs measure some aspect of the specific resistance of the geologic formation. There are about 17 types of resistivity logs.

Porosity logs measure the fraction or percentage of pore volume in a volume of rock. Most porosity logs use either acoustic or nuclear technology. Acoustic logs measure characteristics of sound waves propagated through the well-bore environment. Nuclear logs utilize nuclear reactions that take place in the downhole logging instrument or in the formation. Nuclear logs include density logs and neutron logs, as well as gamma ray logs which are used for correlation. The basic principle behind the use of nuclear technology is that a neutron source placed near the formation of which the porosity is required to be measured will result in neutrons being scattered by the hydrogen atoms, largely those present in the formation fluid. Since there is little difference in the neutrons scattered by hydrocarbons or water, the porosity measured gives a figure close to the true physical porosity whereas the figure obtained from electrical resistivity measurements is that due to the conductive formation fluid. The difference between neutron porosity and electrical porosity measurements therefore indicates the presence of hydrocarbons in the formation fluid.

History

Conrad and Marcel Schlumberger, who founded Schlumberger Limited in 1926, are considered the inventors of electric well logging. Conrad developed the Schlumberger array, which was a technique for prospecting for metal ore deposits, and the brothers adopted that surface technique to subsurface applications. On September 5, 1927, a crew working for Schlumberger lowered an electric sonde or tool down a well in Pechelbronn, Alsace, France creating the first well log. In modern terms, the first log was a resistivity log that could be described as 3.5-meter upside-down lateral log.

In 1931, Henri George Doll and G. Dechatre, working for Schlumberger, discovered that the galvanometer wiggled even when no current was being passed through the logging cables down in the well. This led to the discovery of the spontaneous potential (SP) which was as important as the ability to measure resistivity. The SP effect was produced naturally by the borehole mud at the boundaries of permeable beds. By simultaneously recording SP and resistivity, loggers could distinguish between permeable oil-bearing beds and impermeable nonproducing beds.

In 1940, Schlumberger invented the spontaneous potential dipmeter; this instrument allowed the calculation of the dip and direction of the dip of a layer. The basic dipmeter was later enhanced by the resistivity dipmeter (1947) and the continuous resistivity dipmeter (1952).

Oil-based mud (OBM) was first used in Rangely Field, Colorado in 1948. Normal electric logs require a conductive or water-based mud, but OBMs are nonconductive. The solution to this problem was the induction log, developed in the late 1940s.

The introduction of the transistor and integrated circuits in the 1960s made electric logs vastly more reliable. Computerization allowed much faster log processing, and dramatically expanded log data-gathering capacity. The 1970s brought more logs and computers. These included combo type logs where resistivity logs and porosity logs were recorded in one pass in the borehole.

The two types of porosity logs (acoustic logs and nuclear logs) date originally from the 1940s. Sonic logs grew out of technology developed during World War II. Nuclear logging has supplemented acoustic logging, but acoustic or sonic logs are still run on some combination logging tools.

Nuclear logging was initially developed to measure the natural gamma radiation emitted by underground formations. However, the industry quickly moved to logs that actively bombard rocks with nuclear particles. The gamma ray log, measuring the natural radioactivity, was introduced by Well Surveys Inc. in 1939, and the WSI neutron log came in 1941. The gamma ray log is particularly useful as shale beds which often provide a relatively low permeability cap over hydrocarbon reservoirs usually display a higher level of gamma radiation. These logs were important because they can be used in cased wells (wells with production casing). WSI quickly became part of Lane-Wells. During World War II, the US Government gave a near wartime monopoly on open-hole logging to Schlumberger, and a monopoly on cased-hole logging to Lane-Wells. Nuclear logs continued to evolve after the war.

The nuclear magnetic resonance log was developed in 1958 by Borg Warner. Initially the NMR log was a scientific success but an engineering failure. However, the development of a continuous NMR logging tool by Numar (now a subsidiary of Halliburton) is a promising new technology.

Many modern oil and gas wells are drilled directionally. At first, loggers had to run their tools somehow attached to the drill pipe if the well was not vertical. Modern techniques now permit continuous information at the surface. This is known as logging while drilling (LWD) or measurement-while-drilling (MWD). MWD logs use mud pulse technology to transmit data from the tools on the bottom of the drillstring to the processors at the surface.

Logging while drilling

In the 1980s, a new technique, logging while drilling (LWD), was introduced which provided similar information about the well. Instead of sensors being lowered into the well at the end of wireline cable, the sensors are integrated into the drill string and the measurements are made while the well is being drilled. While wireline well logging occurs after the drill string is removed from the well, LWD measures geological parameters while the well is being drilled. However, because there are no wires to the surface, data are recorded downhole and retrieved when the drill string is removed from the hole. A small subset of the measured data can also be transmitted to the surface in real time via pressure pulses in the well's mud fluid column. This mud telemetry method provides a bandwidth of much less than 100 bits per second, although, as drilling through rock is a fairly slow process, data compression techniques mean that this is an ample bandwidth for real-time delivery of information.

Logging measurement types

Logging measurements are quite sophisticated. The prime target is the measurement of various geophysical properties of the subsurface rock formations. Of particular interest are porosity, permeability, and fluid content. Porosity is the proportion of fluid-filled space found within the rock. It is this space that contains the oil and gas. Permeability is the ability of fluids to flow through the rock. The higher the porosity, the higher the possible oil and gas content of a rock reservoir. The higher the permeability, the easier for the oil and gas to flow toward the wellbore. Logging tools provide measurements that allow for the mathematical interpretation of these quantities.

Beyond just the porosity and permeability, various logging measurements allow the interpretation of what kinds of fluids are in the pores—oil, gas, brine. In addition, the logging measurements are used to determine mechanical properties of the formations. These mechanical properties determine what kind of enhanced recovery methods may be used (tertiary recovery) and what damage to the formation (such as erosion) is to be expected during oil and gas production.

The types of instruments used in well logging are quite broad. The first logging measurements consisted of basic electrical resistivity logs and spontaneous potential (SP) logs, introduced by the Schlumberger brothers in the 1920s. Tools later became available to estimate porosity via sonic velocity and nuclear measurements. Tools are now more specialized and better able to resolve fine details in the formation. Radiofrequency transmission and coupling techniques are used to determine electrical conductivity of fluid (brine is more conductive than oil or gas). Sonic transmission characteristics (pressure waves) determine mechanical integrity. Nuclear magnetic resonance (NMR) can determine the properties of the hydrogen atoms in the pores (surface tension, etc.). Nuclear scattering (radiation scattering), spectrometry and absorption measurements can determine density and elemental analysis or composition. High resolution electrical or acoustical imaging logs are used to visualize the formation, compute formation dip, and analyze thinly-bedded and fractured reservoirs.

In addition to sensor-based measurements above, robotic equipment can sample formation fluids which may then be brought to the surface for laboratory examination. Also, controlled flow measurements can be used to determine in situ viscosity, water and gas cut (percentage), and other fluid and production parameters.

Geological logs

Geological logs use data collected at the surface, rather than by downhole instruments. The geological logs include *drilling time logs*, *core logs*, *sample logs*, and *mud logs*. Mud logs have become the oil industry standard.

Drilling time logs record the time required to drill a given thickness of rock formation. A change in the drilling rate or penetration rate usually means a change in the type of rock penetrated by the bit. The drilling time is expressed as minutes per foot, while the rate of penetration is usually expressed as feet per hour. Therefore, drilling time is the inverse of penetration rate.

Sample logs are made by examining cuttings, which are bits of rock circulated to the surface by the drilling mud in rotary drilling. The cuttings have traveled up the wellbore suspended in the drilling fluid or mud which was pumped into the wellbore via the drill string/pipe and they return to the surface via the annulus, then to the shale shakers via the flow line. Cuttings are then separated from the drilling fluid as they move across the shale shakers and are sampled at regular depth intervals. These rock samples are analyzed and described by the wellsite geologist or mudlogger.

Mud logs are prepared by a mud logging company contracted by the operating company. One parameter a typical mud log displays is the formation gas (gas units or ppm). "The gas recorder usually is scaled in terms of arbitrary gas units, which are defined differently by the various gas-detector manufactures. In practice, significance is placed only on relative changes in the gas concentrations detected." The current industry standard mud log normally includes real-time drilling parameters such as rate of penetration (ROP), lithology, gas hydrocarbons, flow line temperature (temperature of the drilling fluid) and chlorides but may also include mud weight, estimated pore pressure and corrected d-exponent (corrected drilling exponent) for a pressure pack log. Other information that is normally notated on a mud log include lithology descriptions, directional data (deviation surveys), weight on bit, rotary speed, pump pressure, pump rate, viscosity, drill bit info, casing shoe depths, formation tops, mud pump info, to name just a few.

Wireline log

A continuous measurement of formation properties with electrically powered instruments to infer properties and make decisions about drilling and production operations. The record of the measurements, typically a long strip of paper, is also called a log. Measurements include electrical properties (resistivity at various frequencies), sonic properties, active and passive nuclear measurements, dimensional measurements of the wellbore, formation fluid sampling, formation pressure measurement, wireline-conveyed sidewall coring tools, and others. In wireline measurements, the logging tool (or probe) is lowered into the open wellbore on a multiple conductor, contra-helically armored wireline. Once lowered to the bottom of the interval of interest, the measurements are taken on the way out of the wellbore. This is done in an attempt to maintain tension on the cable (which stretches) as constant as possible for depth correlation purposes. (The exception to this practice is in certain hostile environments in which the tool electronics might not survive the temperatures on bottom for the amount of time it takes to lower the tool and then record measurements while pulling the tool up the hole. In this case, "down log" measurements might actually be conducted on the way into the well, and repeated on the way out if possible.) Most wireline measurements are recorded continuously even though the probe is moving. Certain fluid sampling and pressure-measuring tools require that the probe be stopped, increasing the chance that the probe or the cable might become stuck. LWD tools take measurements in much the same way as wireline-logging tools, except that the measurements are taken by a self-contained tool near the bottom of the bottomhole assembly and are recorded downward (as the well is deepened) rather than upward from the bottom of the hole (as wireline logs are recorded).

Memory log

This method of data acquisition involves recording the sensor data into a down hole memory, rather than transmitting "Real Time" to surface. There are some advantages and disadvantages to this memory option.

- The tools can be conveyed into wells where the trajectory is deviated or extended beyond the reach of conventional Electric Wireline cables. This can involve a combination of weight to strength ratio of the electric cable over this extended reach. In such cases the memory tools can be conveyed on Pipe or Coil Tubing.
- The type of sensors are limited in comparison to those used on Electric Line, and tend to be focussed on the cased hole,production stage of the well. Although there are now developed some memory "Open Hole" compact formation evaluation tool combinations. These tools can be deployed and carried downhole concealed internally in drill pipe to protect them from damage while running in the hole, and then "Pumped" out the end at depth to initate logging. Other basic open hole formation evaluation memory tools are available for use in "Commodity" markets on slickline to reduce costs and operating time.
- In cased hole operation there is normally a "Slick Line" intervention unit. This uses a solid mechanical wire (.82 - .125 inches in OD), to manipulate or otherwise carry out operations in the well bore completion system. Memory operations are

often carried out on this Slickline conveyance in preference to mobilizing a full service Electric Wireline unit.

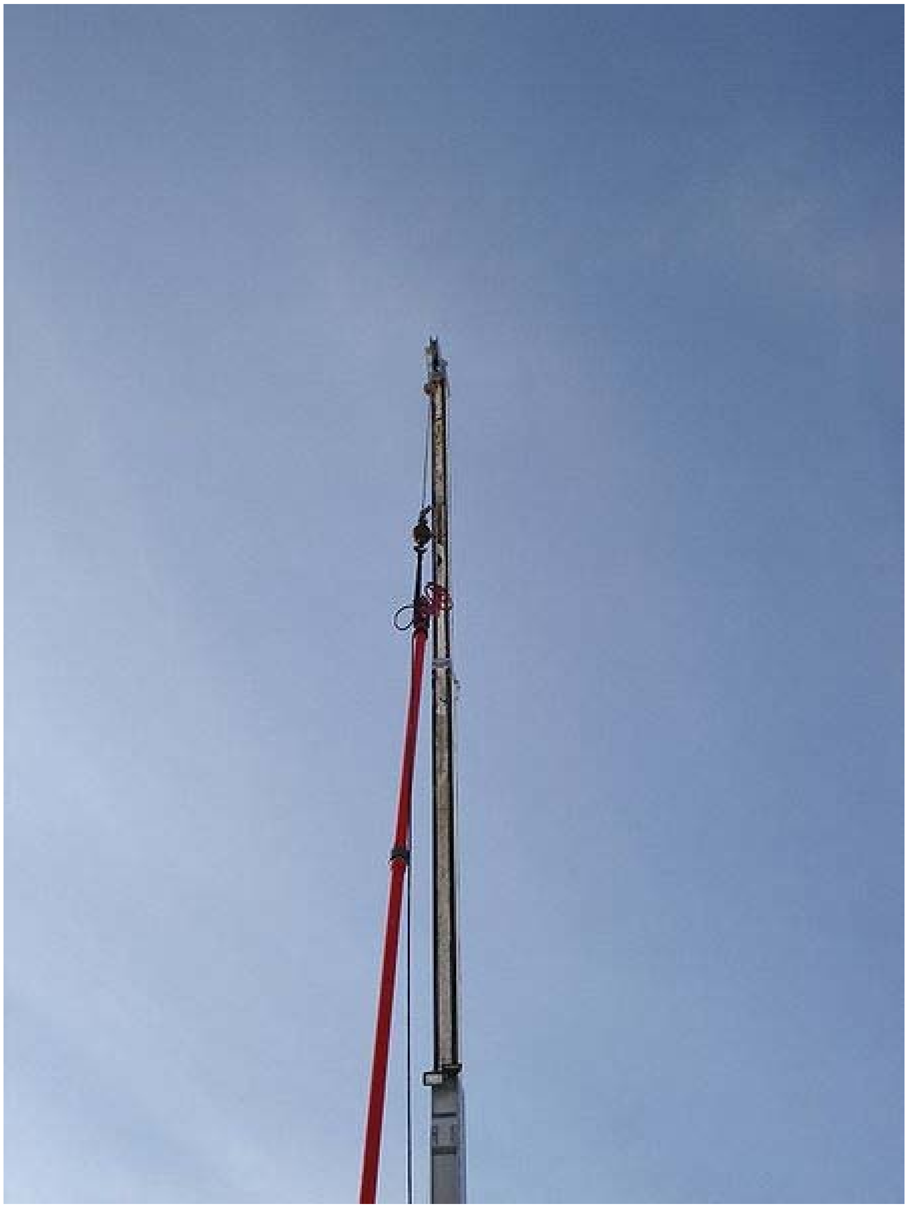
- Since the results are not known until returned to surface, any realtime well dynamic changes cannot be monitored real time. This limits the ability to modify or change the well down hole production conditions accuratly during the memory logging by changing the surface production rates. Something that is often done in Eletric Line operations.
- Failure during recording is not known until the memory tools are retrieved. This loss of data can be a major issue on large offshore (expensive) locations. On land locations (e.g. South Texas, US) where there is what is called a "Commodity" Oil service sector, where logging often is without the rig infrastructure. this is less problematic, and logs are often run again without issue.

Information use

In the oil industry, the well and mud logs are usually transferred in 'real time' to the operating company, which uses these logs to make operational decisions about the well, to correlate formation depths with surrounding wells, and to make interpretations about the quantity and quality of hydrocarbons present. Specialists involved in well log interpretation are called log analysts.

Well logging images

Wireline attached to top of Christmas Tree



Oil Well Top of Wireline

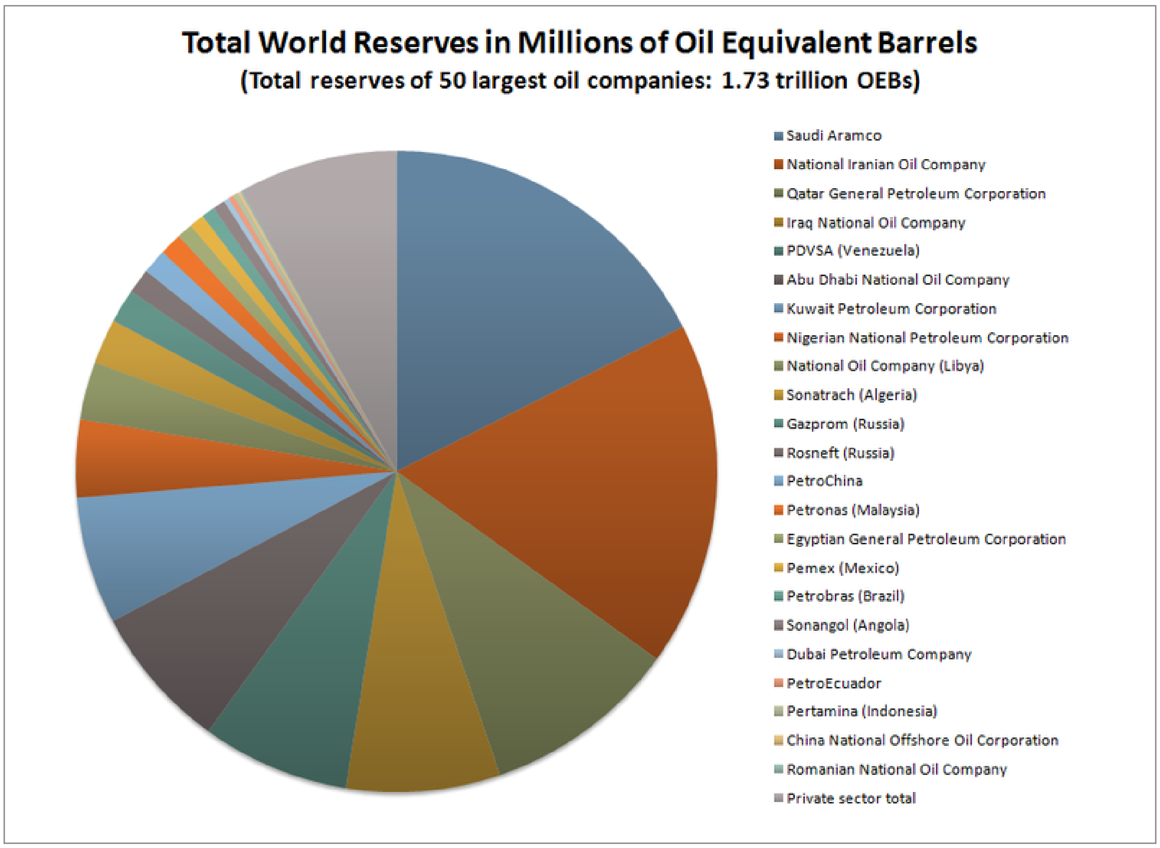
Wireline Truck with drum (inside)

Wax being removed off a wireline wax knife

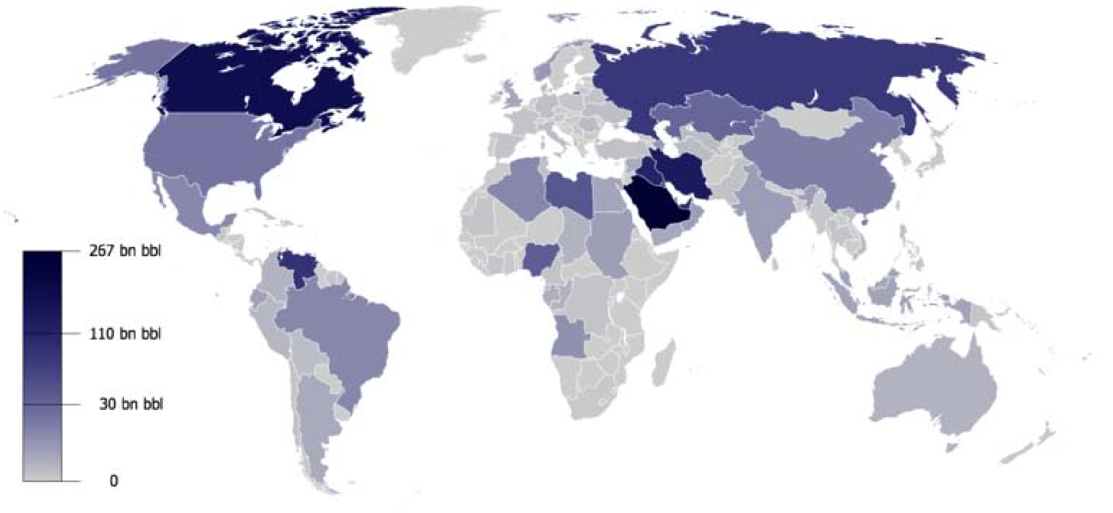
BO shifting tool

Chapter 8

Petroleum Industry



The distribution of oil and natural gas reserves among the world's 50 largest oil companies. The reserves of the privately owned companies are grouped together. The oil produced by the "supermajor" companies accounts for less than 15% of the total world supply. Over 80% of the world's reserves of oil and natural gas are controlled by national oil companies. Of the world's 20 largest oil companies, 15 are state-owned.



World oil reserves, 2009.

The **petroleum industry** includes the global processes of exploration, extraction, refining, transporting (often by oil tankers and pipelines), and marketing petroleum products. The largest volume products of the industry are fuel oil and gasoline (petrol). Petroleum is also the raw material for many chemical products, including pharmaceuticals, solvents, fertilizers, pesticides, and plastics. The industry is usually divided into three major components: upstream, midstream and downstream. Midstream operations are usually included in the downstream category.

Petroleum is vital to many industries, and is of importance to the maintenance of industrial civilization itself, and thus is a critical concern for many nations. Oil accounts for a large percentage of the world's energy consumption, ranging from a low of 32% for Europe and Asia, up to a high of 53% for the Middle East.

Other geographic regions' consumption patterns are as follows: South and Central America (44%), Africa (41%), and North America (40%). The world consumes 30 billion barrels (4.8 km^3) of oil per year, with developed nations being the largest consumers. The United States consumed 25% of the oil produced in 2007. The production, distribution, refining, and retailing of petroleum taken as a whole represents the world's largest industry in terms of dollar value.

Governments such as the United States government provide a heavy public subsidy to petroleum companies, with major tax breaks at virtually every stage of oil exploration and extraction, including for the costs of oil field leases and drilling equipment.

History

Natural history

Petroleum is a naturally occurring liquid found in rock formations. It consists of a complex mixture of hydrocarbons of various molecular weights, plus other organic compounds. It is generally accepted that oil, formed mostly from the carbon rich remains of ancient plankton after exposure to heat and pressure in the Earth's crust over hundreds of millions of years. Over time, the decayed residue was covered by layers of mud and silt, sinking further down into the Earth’s crust and preserved there between hot and pressured layers, gradually transforming into oil reservoirs.

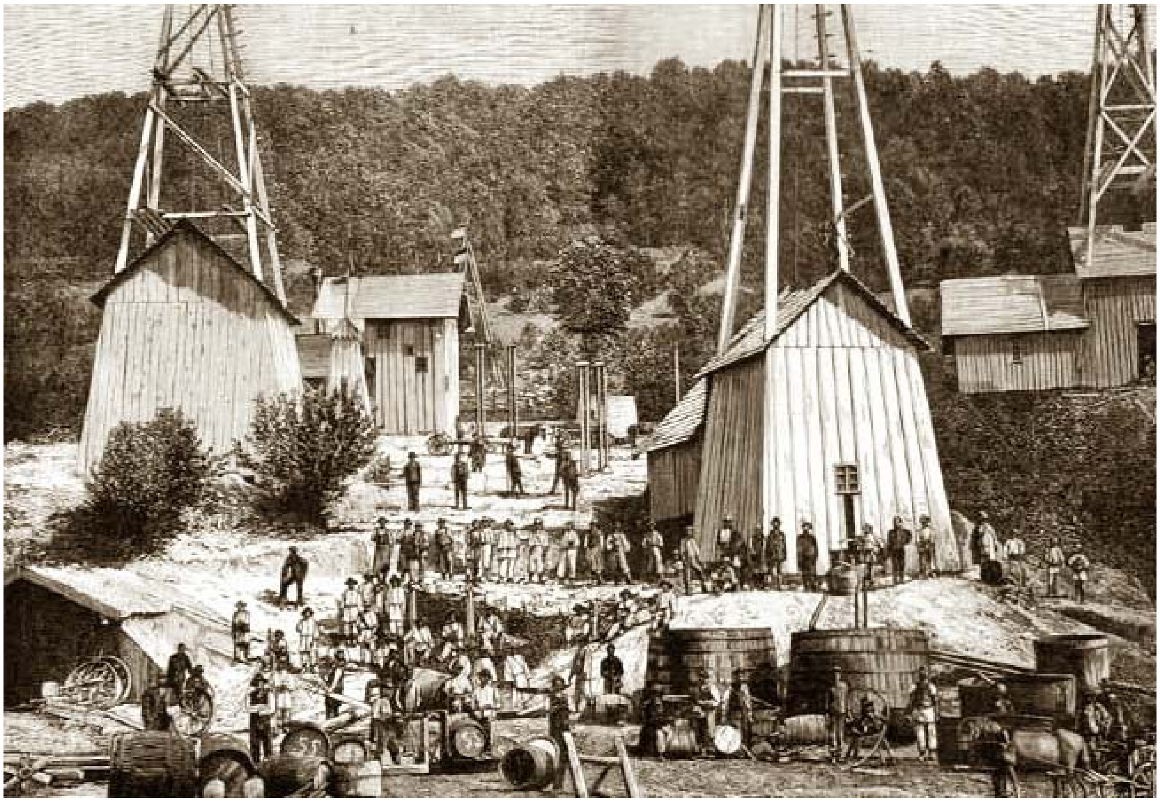
Early history

Petroleum in an unrefined state has been utilized by humans for over 5000 years. Oil in general has been used since early human history to keep fires ablaze, and also for warfare. Ancient Persian language tablets indicate the medicinal and lighting uses of petroleum in the upper echelons of their society. Ancient China was also known to burn skimmed oil for light.

An early petroleum industry was established in the 8th century, when the streets of Baghdad were paved with tar, derived from petroleum through destructive distillation. In the 9th century, oil fields were exploited in the area around modern Baku, Azerbaijan, to produce naphtha. These fields were described by al-Masudi in the 10th century, and by Marco Polo in the 13th century, who described the output of those oil wells as hundreds of shiploads. Petroleum was distilled by al-Razi in the 9th century, producing chemicals such as kerosene in the alembic, which he used to invent kerosene lamps for use in the oil lamp industry.

Its importance in the world economy evolved slowly, with whale oil used for lighting into the 19th century, and wood and coal used for heating and cooking well into the 20th Century. A petroleum industry emerged in North America in Canada and the United States. The Industrial Revolution generated an increasing need for energy which was fueled mainly by coal, with other sources including whale oil. However, it was discovered that kerosene could be extracted from crude oil and used as a light and heating fuel. Petroleum was in great demand, and by the twentieth century had become the most valuable commodity traded on the world market.

Modern history



Galician oil wells

Imperial Russia produced 3,500 tons of oil in 1825 and doubled its output by mid-century. After oil drilling began in what is now Azerbaijan in 1848, two large pipelines were built in the Russian Empire: the 833 km long pipeline to transport oil from the Caspian to the Black Sea port of Batumi (Baku-Batumi pipeline), completed in 1906, and the 162 km long pipeline to carry oil from Chechnya to the Caspian.

At the turn of the 20th century, Imperial Russia's output of oil, almost entirely from the Apsheron Peninsula, accounted for half of the world's production and dominated international markets. Nearly 200 small refineries operated in the suburbs of Baku by 1884. As a side effect of these early developments, the Apsheron Peninsula emerged as the world's "oldest legacy of oil pollution and environmental negligence." In 1878, Ludvig Nobel and his Branobel company "revolutionized oil transport" by commissioning the first oil tanker and launching it on the Caspian Sea.

The first modern oil refineries were built by Ignacy Łukasiewicz near Jasło (then in the dependent Kingdom of Galicia and Lodomeria in Central European Galicia), Poland from 1854–56. These were initially small as demand for refined fuel was limited. The refined products were used in artificial asphalt, machine oil and lubricants, in addition to Łukasiewicz's kerosene lamp. As kerosene lamps gained popularity, the refining industry grew in the area.

The first large oil refinery opened at Ploiești, Romania in 1856.

The first oil drilling in the United States began in 1859, when oil was successfully drilled in Titusville, Pennsylvania. In the first quarter of the 20th century, the United States overtook Russia as the world's largest oil producer.

By the 1920s, oil fields had been established in many countries including Canada, Poland, Sweden, the Ukraine, the United States, and Venezuela.

In the early 1930s the Texas Company developed the first mobile steel barges for drilling in the brackish coastal areas of the Persian Gulf.

In 1937 Pure Oil Company (now part of Chevron Corporation) and its partner Superior Oil Company (now part of ExxonMobil Corporation) used a fixed platform to develop a field in 14 feet of water, one mile offshore of Calcasieu Parish, Louisiana.

In early 1947 Superior Oil erected a drilling/production oil platform in 20 ft of water some 18 miles off Vermilion Parish, Louisiana. But it was Kerr-McGee Oil Industries (now Anadarko Petroleum Corporation), as operator for partners Phillips Petroleum (ConocoPhillips) and Stanolind Oil & Gas (BP), that completed its historic Ship Shoal Block 32 well in October 1947, months before Superior actually drilled a discovery from their Vermilion platform farther offshore. In any case, that made Kerr-McGee's well the first oil discovery drilled out of sight of land.

After World War II ended, the countries of the Middle East took the lead in oil production from the United States.

Industry structure

The American Petroleum Institute divides the petroleum industry into five sectors:

- upstream (exploration, development and production of crude oil or natural gas)
- downstream (oil tankers, refiners, retailers and consumers)
- pipeline
- marine
- service and supply

Oil companies used to be classified by sales as *"supermajors"* (BP, Chevron, ExxonMobil, ConocoPhillips, Shell, Eni and Total S.A.), *"majors,"* and *"independents" or "jobbers."* In recent years however, National Oil Companies (NOC, as opposed to IOC, International Oil Companies) have come to control the rights over the largest oil reserves; by this measure the top ten companies all are NOC. The following table shows the ten largest oil companies ranked by reserves and by production.

Top 10 largest world oil companies by reserves and production

Rank	Company	Worldwide Liquids Reserves (10^9 bbl)	Worldwide Natural Gas Reserves (10^{12} ft^3)	Total Reserves in Oil Equivalent Barrels (10^9 bbl)	Company	Production (10^6 bbl/d)
1	Saudi Aramco	260	254	303	Saudi Aramco	11.0
2	National Iranian Oil Company	138	948	300	National Iranian Oil Company	4.0
3	Qatar Petroleum	15	905	170	Kuwait Petroleum Corporation	3.7
4	Iraq National Oil Company	116	120	134	Iraq National Oil Company	2.7
5	Petróleos de Venezuela	99	171	129	Petróleos de Venezuela	2.6
6	Abu Dhabi National Oil Company	92	199	126	Abu Dhabi National Oil Company	2.6
7	Kuwait Petroleum Corporation	102	56	111	Petróleos Mexicanos	2.5
8	Nigerian National Petroleum Corporation	36	184	68	Nigerian National Petroleum Corporation	2.3
9	Libya NOC	41	50	50	Libya NOC	2.1
10	Sonatrach	12	159	39	Lukoil	1.9

Most upstream work in the oil field or on an oil well is contracted out to drilling contractors and oil field service companies.

Public subsidy

The United States government provides a large subsidy to oil companies, with major tax breaks at virtually every stage of oil exploration and extraction. Capital expenses, including the costs of oil field leases and drilling equipment, are taxed at an effective rate of nine percent, which is a much lower rate than the 25% rate for general business taxes and lower than the taxes of virtually any other industry, according to a 2005 study by the non-partisan Congressional Budget Office. For example, while the Deepwater Horizon oil rig was registered in the Marshall Islands, since registering off-shore lowered the U.S. tax liability, the U.S. government was giving the rig's owner, British Petroleum (BP), a major tax break when BP leased the rig: 70% of the rent was written off in the form of a tax break used only by the oil industry, for a tax deduction of more than $225,000 per day from the day the lease began.

Environmental impact and future shortages

Some petroleum industry operations have been responsible for water pollution through by-products of refining and oil spills.

The combustion of fossil fuels produces greenhouse gases and other air pollutants as by-products. Pollutants include nitrogen oxides, sulphur dioxide, volatile organic compounds and heavy metals.

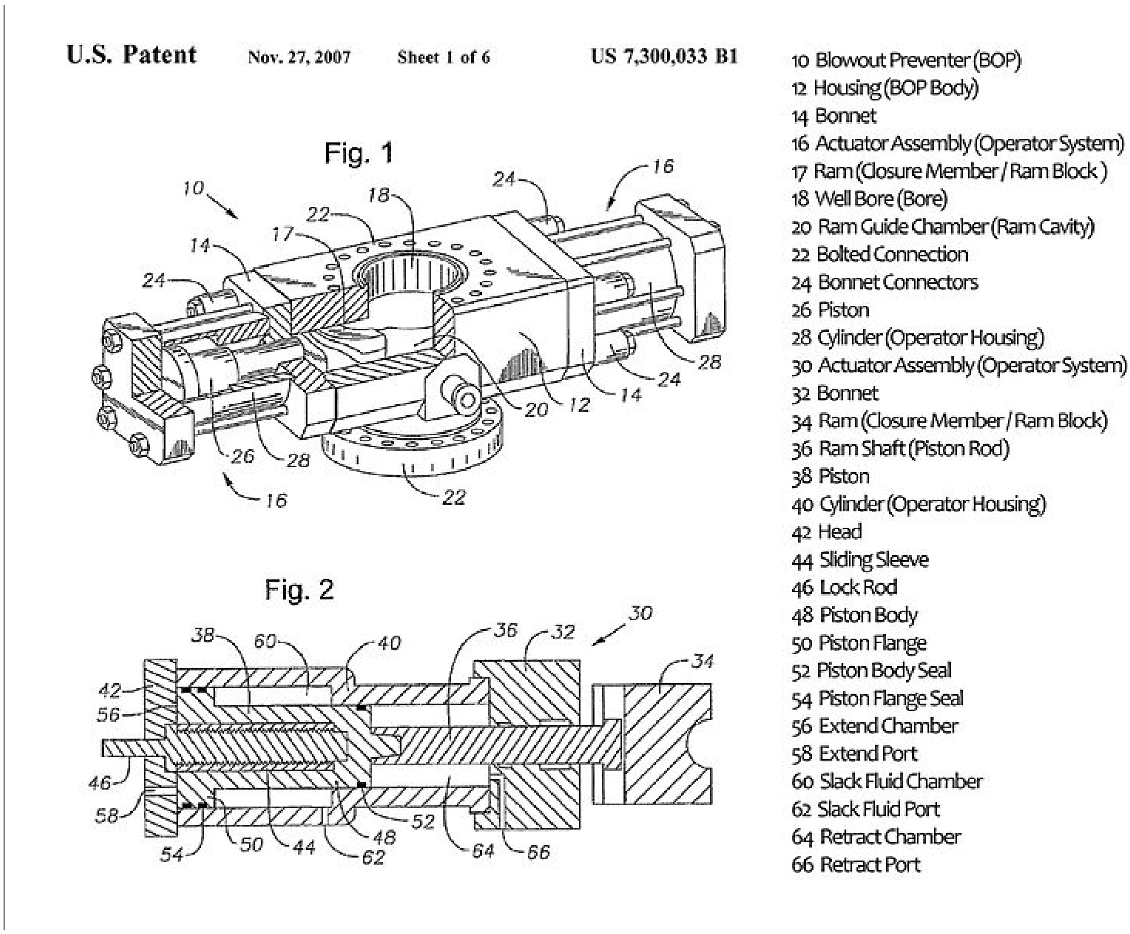
As petroleum is a non-renewable natural resource the industry is faced with an inevitable eventual depletion of the world's oil supply. The BP Statistical Review of World Energy 2007 listed the reserve/production ratio for proven resources worldwide. The study placed the prospective life span of proven reserves in the Middle East at 79.5 years, Latin America at 41.2 years and North America at only 12 years.

The Hubbert peak theory, which introduced the concept of peak oil, questions the sustainability of oil production. It suggests that after a peak in oil production rates, a period of oil depletion will ensue. Since virtually all economic sectors rely heavily on petroleum, peak oil could lead to a partial or complete failure of markets.

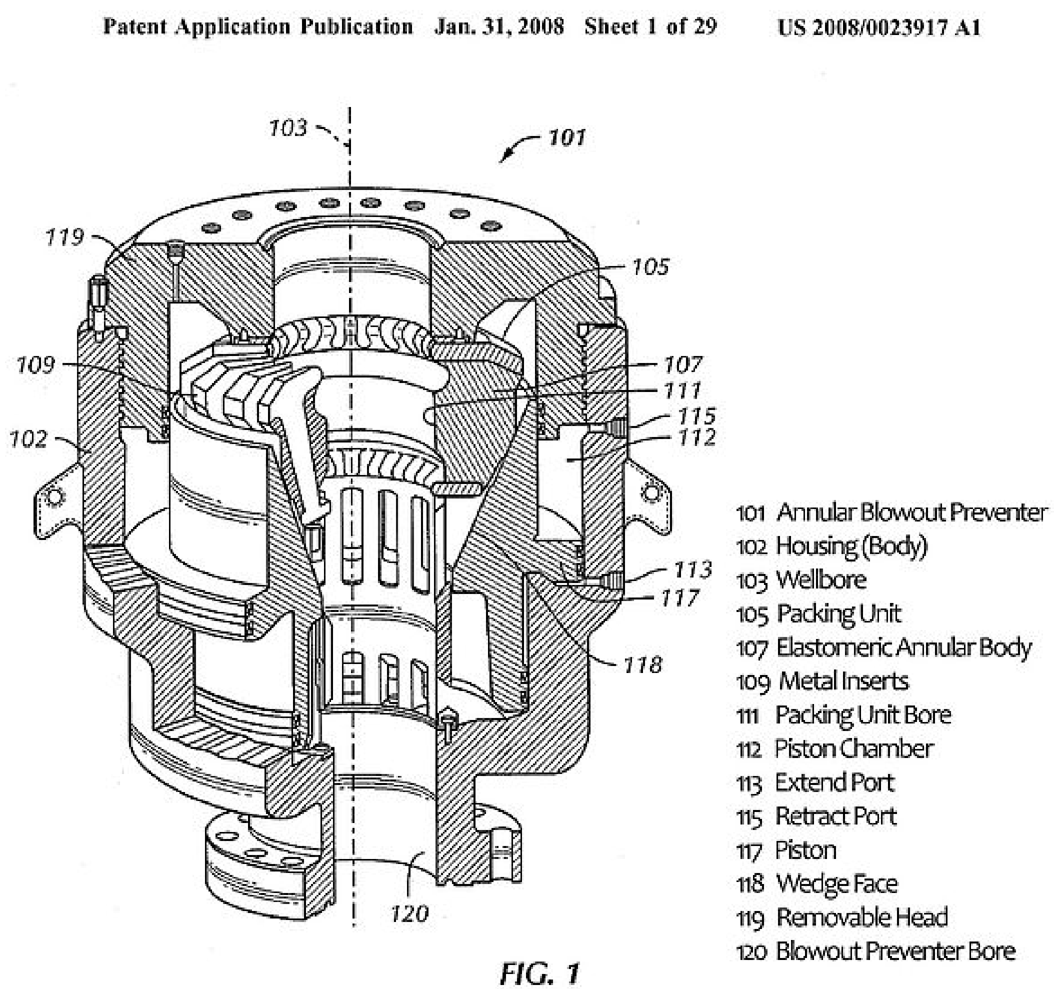
According to research by IBISWorld, biofuels (primarily ethanol, but also biodiesel) will continue to supplement petroleum. However output levels are low, and these fuels will not displace local oil production. More than 90% of the ethanol used in the US is blended with gasoline to produce a 10% ethanol mix, lifting the oxygen content of the fuel.

Chapter 9

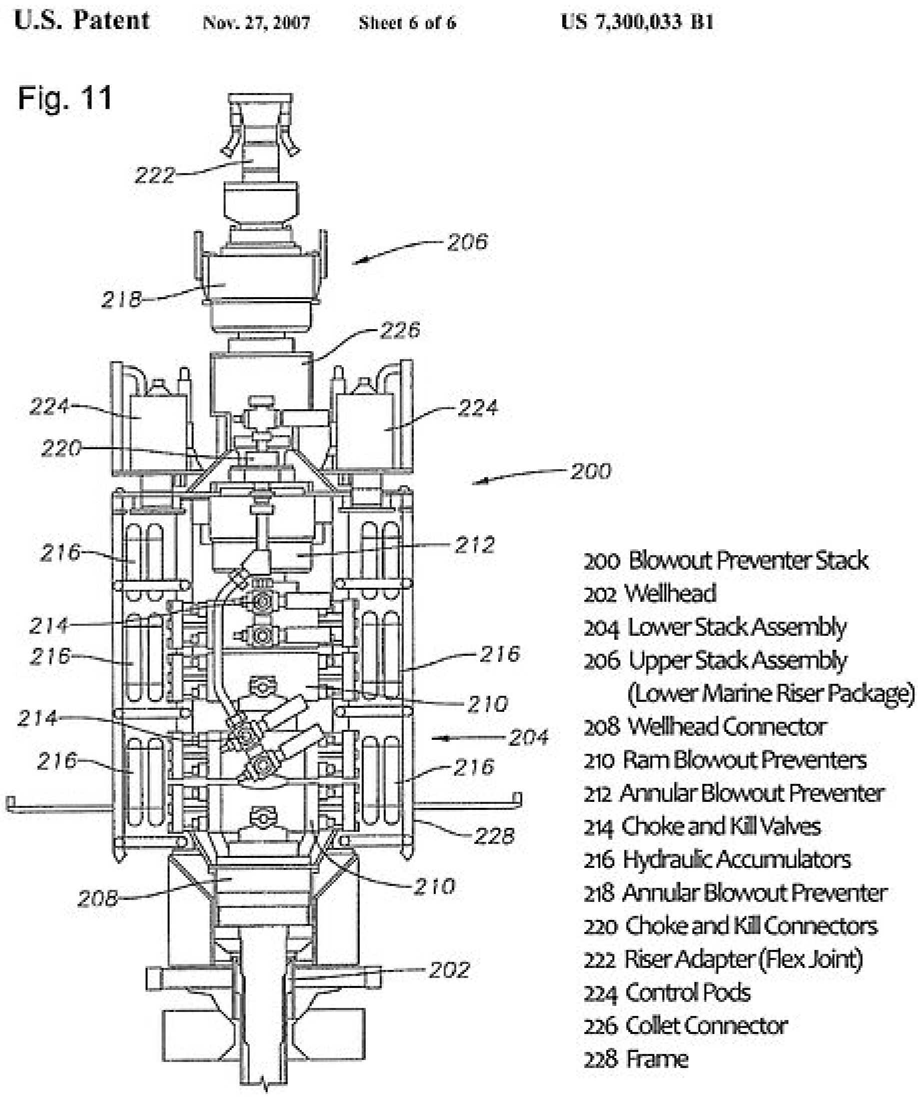
Blowout Preventer



Cameron International Corporation's EVO Ram BOP Patent Drawing (with legend)



Patent Drawing of Hydril Annular BOP (with legend)



Patent Drawing of a Subsea BOP Stack (with legend)

A **blowout preventer** is a large, specialized valve used to seal, control and monitor oil and gas wells. Blowout preventers were developed to cope with extreme erratic pressures and uncontrolled flow (formation kick) emanating from a well reservoir during drilling. Kicks can lead to a potentially catastrophic event known as a blowout. In addition to controlling the downhole (occurring in the drilled hole) pressure and the flow of oil and gas, blowout preventers are intended to prevent tubing (e.g. drill pipe and well casing), tools and drilling fluid from being blown out of the wellbore (also known as bore hole, the hole leading to the reservoir) when a blowout threatens. Blowout preventers are critical to the safety of crew, rig (the equipment system used to drill a wellbore) and environment, and to the monitoring and maintenance of well integrity; thus blowout preventers are intended to be fail-safe devices.

The term **BOP** (an initialism rather than a spoken acronym, i.e., pronounced B-O-P, not "bop") is used in oilfield vernacular to refer to blowout preventers.

The abbreviated term **preventer**, usually prefaced by a type (e.g. ram preventer), is used to refer to a single blowout preventer unit. A blowout preventer may also simply be referred to by its type (e.g. ram).

The terms **blowout preventer**, **blowout preventer stack** and **blowout preventer system** are commonly used interchangeably and in a general manner to describe an assembly of several stacked blowout preventers of varying type and function, as well as auxiliary components. A typical subsea deepwater blowout preventer system includes components such as electrical and hydraulic lines, control pods, hydraulic accumulators, test valve, kill and choke lines and valves, riser joint, hydraulic connectors, and a support frame.

Two categories of blowout preventer are most prevalent: *ram* and *annular*. BOP stacks frequently utilize both types, typically with at least one annular BOP stacked above several ram BOPs.

Blowout preventers are used at land and offshore rigs, and subsea. Land and subsea BOPs are secured to the top of the wellbore, known as the wellhead. BOPs on offshore rigs are mounted below the rig deck. Subsea BOPs are connected to the offshore rig above by a drilling riser that provides a continuous pathway for the drill string and fluids emanating from the wellbore. In effect, a riser extends the wellbore to the rig.

Use

A blowout preventer stack for a well being drilled in Northern Italy. An annular preventer and a single ram BOP are shown in the foreground with a double ram BOP to the rear.

The invention of blowout preventers was instrumental in reducing the incidence of oil gushers, blowouts, which are dangerous and costly.

Blowout preventers come in a variety of styles, sizes and pressure ratings. Several individual units serving various functions are combined to compose a blowout preventer stack. Multiple blowout preventers of the same type are frequently provided for redundancy, an important factor in the effectiveness of fail-safe devices.

The primary functions of a blowout preventer system are to:

- Confine well fluid to the wellbore;
- Provide means to add fluid to the wellbore;
- Allow controlled volumes of fluid to be withdrawn from the wellbore.

Additionally, and in performing those primary functions, blowout preventer systems are used to:

- Regulate and monitor wellbore pressure;
- Center and hang off the drill string in the wellbore;
- Shut in the well (e.g. seal the void, annulus, between drillpipe and casing);
- “Kill” the well (prevent the flow of formation fluid, influx, from the reservoir into the wellbore) ;
- Seal the wellhead (close off the wellbore);
- Sever the casing or drill pipe (in case of emergencies).

In drilling a typical high-pressure well, drill strings are routed through a blowout preventer stack toward the reservoir of oil and gas. As the well is drilled, drilling fluid, “mud,” is fed through the drill string down to the drill bit, “blade,” and returns up the wellbore in the ring-shaped void, annulus, between the outside of the drill pipe and the casing (piping that lines the wellbore). The column of drilling mud exerts downward hydrostatic pressure to counter opposing pressure from the formation being drilled, allowing drilling to proceed.

When a kick (influx of formation fluid) occurs, rig operators or automatic systems close the blowout preventer units, sealing the annulus to stop the flow of fluids out of the wellbore. Denser mud is then circulated into the wellbore down the drill string, up the annulus and out through the choke line at the base of the BOP stack through chokes (flow restrictors) until downhole pressure is overcome. Once “kill weight” mud extends from the bottom of the well to the top, the well has been “killed”. If the integrity of the well is intact drilling may be resumed. Alternatively, if circulation is not feasible it may be possible to kill the well by "bullheading", forcibly pumping, in the heavier mud from the top through the kill line connection at the base of the stack. This is less desirable because of the higher surface pressures likely needed and the fact that much of the mud originally in the annulus must be forced into receptive formations in the open hole section beneath the deepest casing shoe.

If the blowout preventers and mud do not restrict the upward pressures of a kick, a blowout results, potentially shooting tubing, oil and gas up the wellbore, damaging the rig, and leaving well integrity in question.

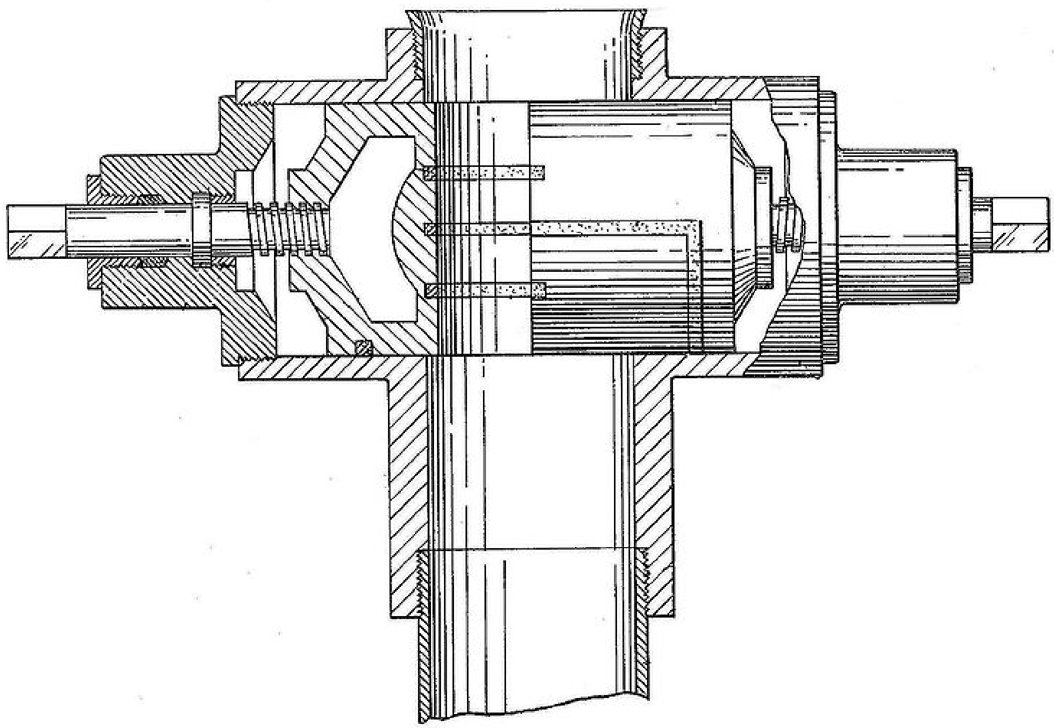
Since BOPs are important for the safety of the crew and natural environment, as well as the drilling rig and the wellbore itself, authorities recommend, and regulations require, that BOPs be regularly inspected, tested and refurbished. Tests vary from daily test of functions on critical wells to monthly or less frequent testing on wells with low likelihood of control problems.

Exploitable reservoirs of oil and gas are increasingly rare and remote, leading to increased subsea deepwater well exploration and requiring BOPs to remain submerged for as long as a year in extreme conditions. As a result, BOP assemblies have grown larger and heavier (e.g. a single ram-type BOP unit can weigh in excess of 30,000 pounds), while the space allotted for BOP stacks on existing offshore rigs has not grown commensurately. Thus a key focus in the technological development of BOPs over the last two decades has been limiting their footprint and weight while simultaneously increasing safe operating capacity.

Types

BOPs come in two basic types, *ram* and *annular*. Both are often used together in drilling rig BOP stacks, typically with at least one annular BOP capping a stack of several ram BOPs.

Ram blowout preventer



A Patent Drawing of the Original Ram-type Blowout Preventer, by Cameron Iron Works (1922).

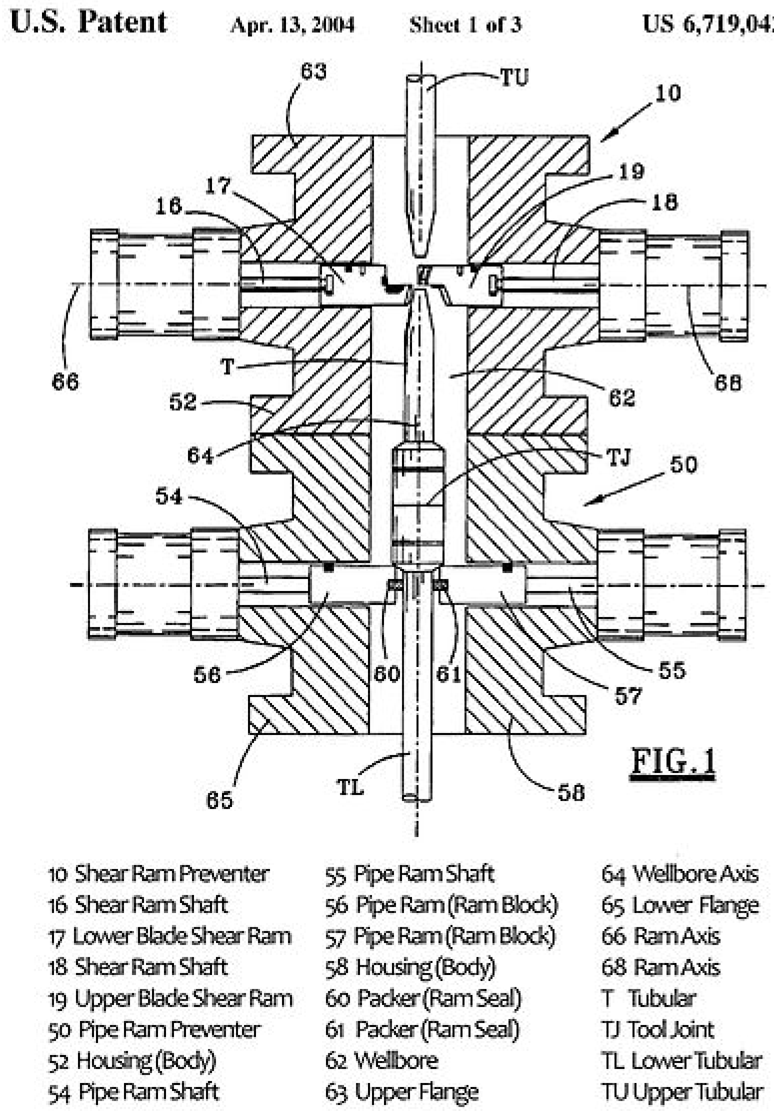
The ram BOP was invented by James Smither Abercrombie and Harry S. Cameron in 1922, and was brought to market in 1924 by Cameron Iron Works.

A ram-type BOP is similar in operation to a gate valve, but uses a pair of opposing steel plungers, rams. The rams extend toward the center of the wellbore to restrict flow or retract open in order to permit flow. The inner and top faces of the rams are fitted with packers (elastomeric seals) that press against each other, against the wellbore, and around tubing running through the wellbore. Outlets at the sides of the BOP housing (body) are used for connection to choke and kill lines or valves.

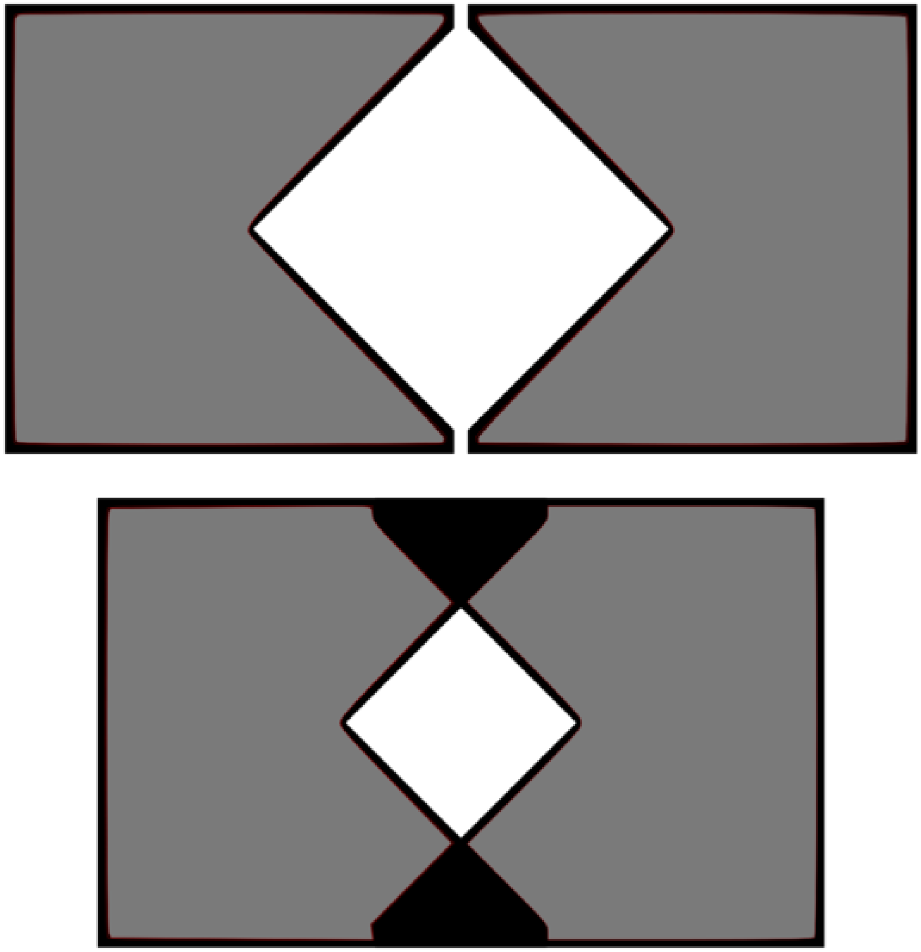
Rams, or ram blocks, are of four common types: *pipe*, *blind*, *shear*, and *blind shear*.

Pipe rams close around a drill pipe, restricting flow in the annulus (ring-shaped space between concentric objects) between the outside of the drill pipe and the wellbore, but do not obstruct flow within the drill pipe. Variable-bore pipe rams can accommodate tubing in a wider range of outside diameters than standard pipe rams, but typically with some loss of pressure capacity and longevity.

Blind rams (also known as sealing rams), which have no openings for tubing, can close off the well when the well does not contain a drill string or other tubing, and seal it.



Patent Drawing of a Varco Shaffer Ram BOP Stack. A shear ram BOP has cut the drillstring and a pipe ram has hung it off.



Schematic view of closing shear blades

Shear rams cut through the drill string or casing with hardened steel shears.

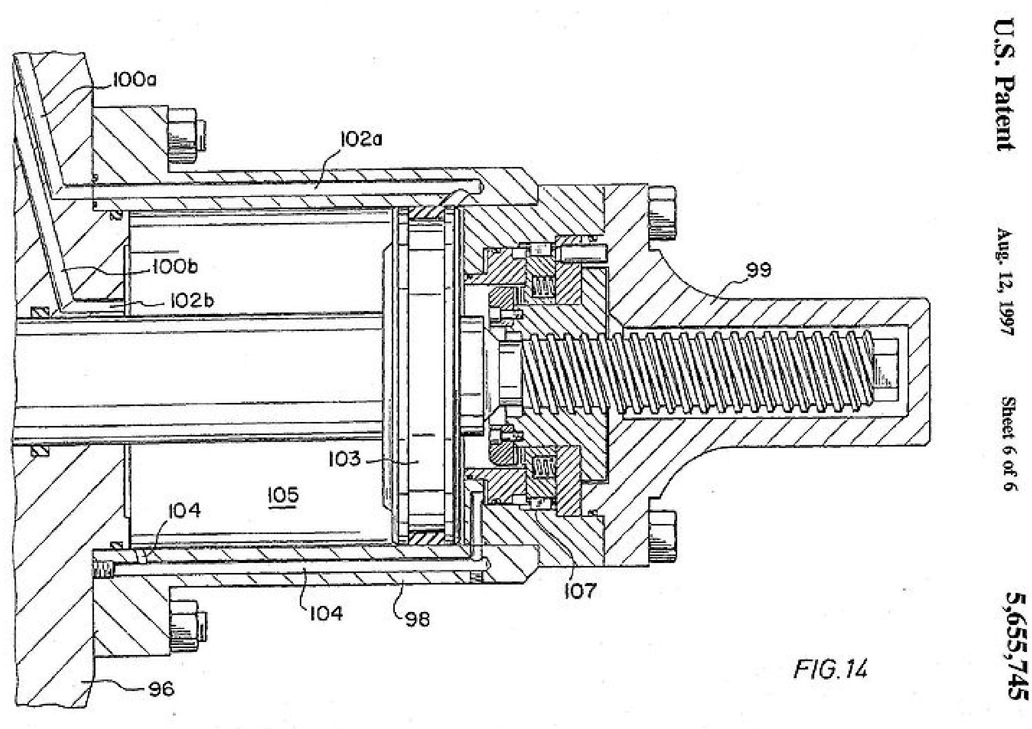
Blind shear rams (also known as shear seal rams, or sealing shear rams) are intended to seal a wellbore, even when the bore is occupied by a drill string, by cutting through the drill string as the rams close off the well. The upper portion of the severed drill string is freed from the ram, while the lower portion may be crimped and the “fish tail” captured to hang the drill string off the BOP.

In addition to the standard ram functions, variable-bore pipe rams are frequently used as test rams in a modified blowout preventer device known as a stack test valve. Stack test valves are positioned at the bottom of a BOP stack and resist downward pressure (unlike BOPs, which resist upward pressures). By closing the test ram and a BOP ram about the drillstring and pressurizing the annulus, the BOP is pressure-tested for proper function.

The original ram BOPs of the 1920s were simple and rugged manual devices with minimal parts. The BOP housing (body) had a vertical well bore and horizontal ram cavity (ram guide chamber). Opposing rams (plungers) in the ram cavity translated horizontally, actuated by threaded ram shafts (piston rods) in the manner of a screw jack. Torque from turning the ram shafts by wrench or hand wheel was converted to linear motion and the rams, coupled to the inner ends of the ram shafts, opened and closed the well bore. Such screw jack type operation provided enough mechanical advantage for rams to overcome downhole pressures and seal the wellbore annulus.

Hydraulic rams BOPs were in use by the 1940s. Hydraulically actuated blowout preventers had many potential advantages. The pressure could be equalized in the opposing hydraulic cylinders causing the rams to operate in unison. Relatively rapid actuation and remote control were facilitated, and hydraulic rams were well-suited to high pressure wells.

Because BOPs are fail-safe devices, efforts to minimize the complexity of the devices are still employed to ensure ram BOP reliability and longevity. As a result, despite the ever-increasing demands placed on them, state of the art ram BOPs are conceptually the same as the first effective models, and resemble those units in many ways.



Hydril Company's Compact BOP Ram Actuator Assembly Patent Drawing

Ram BOPs for use in deepwater applications universally employ hydraulic actuation. Threaded shafts are often still incorporated into hydraulic ram BOPs as lock rods that hold the ram in position after hydraulic actuation. By using a mechanical ram locking mechanism, constant hydraulic pressure need not be maintained. Lock rods may be coupled to ram shafts or not, depending on manufacturer. Other types of ram locks, such as wedge locks, are also used.

Typical ram actuator assemblies (operator systems) are secured to the BOP housing by removable bonnets. Unbolting the bonnets from the housing allows BOP maintenance and facilitates the substitution of rams. In that way, for example, a pipe ram BOP can be converted to a blind shear ram BOP.

Shear-type ram BOPs require the greatest closing force in order to cut through tubing occupying the wellbore. Boosters (auxiliary hydraulic actuators) are frequently mounted to the outer ends of a BOP's hydraulic actuators to provide additional shearing force for shear rams.

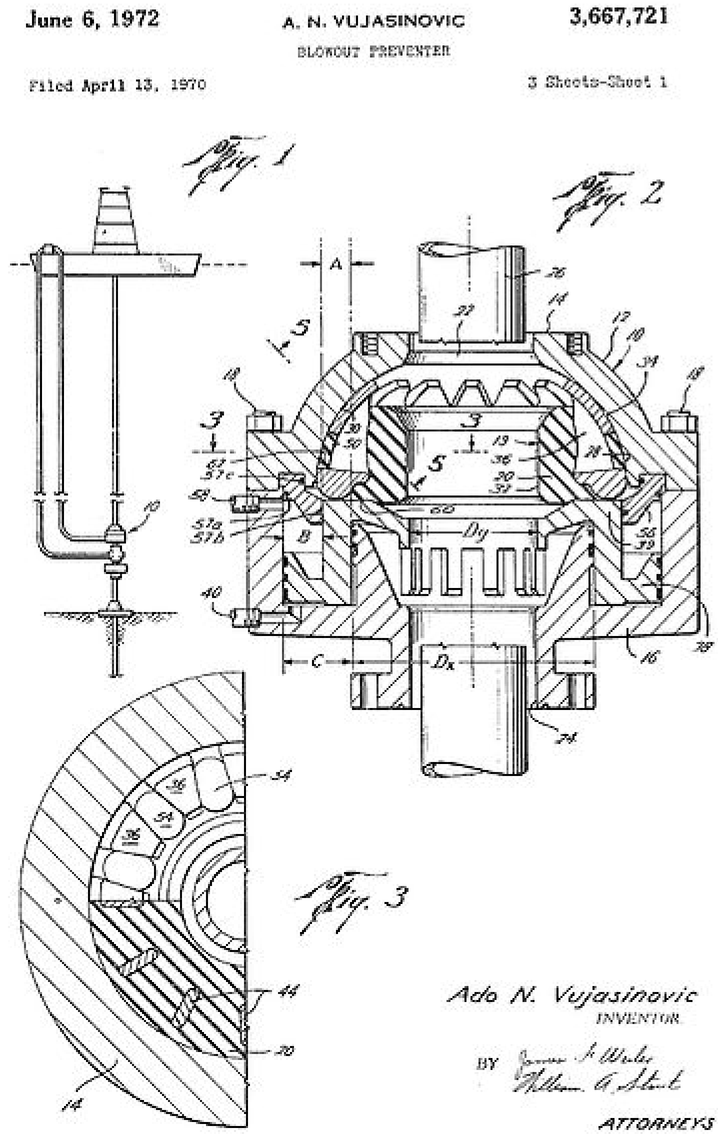
Ram BOPs are typically designed so that well pressure will help maintain the rams in their closed, sealing position. That is achieved by allowing fluid to pass to pass through a channel in the ram and exert pressure at the ram's rear and toward the center of the wellbore. Providing a channel in the ram also limits the thrust required to overcome well bore pressure.

Single ram and double ram BOPs are commonly available. The names refer to the quantity of ram cavities (equivalent to the effective quantity of valves) contained in the unit. A double ram BOP is more compact and lighter than a stack of two single ram BOPs while providing the same functionality, and is thus desirable in many applications. Triple ram BOPs are also manufactured, but not as common.

Technological development of ram BOPs has been directed towards deeper and higher pressure wells, greater reliability, reduced maintenance, facilitated replacement of components, facilitated ROV intervention, reduced hydraulic fluid consumption, and improved connectors, packers, seals, locks and rams. In addition, limiting BOP weight and footprint are significant concerns to account for the limitations of existing rigs.

The highest-capacity large-bore ram blowout preventer on the market, as of July 2010, Cameron's EVO 20K BOP, has a hold-pressure rating of 20,000 psi, ram force in excess of 1,000,000 pounds, and a well bore diameter of 18.75 inches.

Annular blowout preventer



Patent Drawing of Original Shaffer Spherical-type Blowout Preventer (1972)

The annular blowout preventer was invented by Granville Sloan Knox in 1946; a U.S. patent for it was awarded in 1952.

An annular-type blowout preventer can close around the drill string, casing or a non-cylindrical object, such as the kelly. Drill pipe including the larger-diameter tool joints (threaded connectors) can be "stripped" (i.e., moved vertically while pressure is contained below) through an annular preventer by careful control of the hydraulic closing pressure. Annular blowout preventers are also effective at maintaining a seal around the drillpipe even as it rotates during drilling. Regulations typically require that an annular preventer be able to completely close a wellbore, but annular preventers are generally not as effective as ram preventers in maintaining a seal on an open hole. Annular BOPs are typically located at the top of a BOP stack, with one or two annular preventers positioned above a series of several ram preventers.

An annular blowout preventer uses the principle of a wedge to shut in the wellbore. It has a donut-like rubber seal, known as an elastomeric packing unit, reinforced with steel ribs. The packing unit is situated in the BOP housing between the head and hydraulic piston. When the piston is actuated, its upward thrust forces the packing unit to constrict, like a sphincter, sealing the annulus or openhole. Annular preventers have only two moving parts, piston and packing unit, making them simple and easy to maintain relative to ram preventers.

The original type of annular blowout preventer uses a "wedge-faced" (conical-faced) piston. As the piston rises, vertical movement of the packing unit is restricted by the head and the sloped face of the piston squeezes the packing unit inward, toward the center of the wellbore.

In 1972, Ado N. Vujasinovic was awarded a patent for a variation on the annular preventer known as a spherical blowout preventer, so-named because of its spherical-faced head. As the piston rises the packing unit is thust upward against the curved head, which constricts the packing unit inward. Both types of annular preventer are in common use.

Control methods

When rigs are drilled on land or in very shallow water where the wellhead is above the water line, BOPs are activated by hydraulic pressure from a remote accumulator. Several control stations will be mounted around the rig. They also can be closed manually by turning large wheel-like handles.

In deeper offshore operations with the wellhead just above the mudline on the sea floor, there are four primary ways by which a BOP can be controlled. The possible means are:

- Electrical Control Signal: sent from the surface through a control cable;
- Acoustical Control Signal: sent from the surface based on a modulated/encoded pulse of sound transmitted by an underwater transducer;
- ROV Intervention: remotely operated vehicles (ROVs) mechanically control valves and provide hydraulic pressure to the stack (via "hot stab" panels);
- Deadman Switch / Auto Shear: fail-safe activation of selected BOPs during an emergency, and if the control, power and hydraulic lines have been severed.

Two control pods are provided on the BOP for redundancy. Electrical signal control of the pods is primary. Acoustical, ROV intervention and dead-man controls are secondary.

An emergency disconnect system, or EDS, disconnects the rig from the well in case of an emergency. The EDS is also intended to automatically trigger the deadman switch, which closes the BOP, kill and choke valves. The EDS may be a subsystem of the BOP stack's control pods or separate.

Pumps on the rig normally deliver pressure to the blowout preventer stack through hydraulic lines. Hydraulic accumulators are on the BOP stack enable closure of blowout preventers even if the BOP stack is disconnected from the rig. It is also possible to trigger the closing of BOPs automatically based on too high pressure or excessive flow.

Individual wells along the U.S. coastline may also be required to have BOPs with backup acoustic control. General requirements of other nations, including Brazil, were drawn to require this method. BOPs featuring this method may cost as much as US$500,000 more than those that omit the feature.

Deepwater Horizon blowout

A robotic arm of a Remotely Operated Vehicle (ROV) attempts to activate the "*Deepwater Horizon*" Blowout Preventer (BOP), Thursday, April 22, 2010.

During the *Deepwater Horizon* drilling rig explosion incident on April 20, 2010, the blowout preventer should have been activated automatically, cutting the drillstring and sealing the well to preclude a blowout and subsequent oil spill in the Gulf of Mexico, but it failed to fully engage. Underwater robots (ROVs) later were used to manually trigger the blind shear ram preventer, to no avail.

As of May 2010 it is unknown why the blowout preventer failed. Chief surveyor John David Forsyth of the American Bureau of Shipping testified in hearings before the Joint Investigation of the Minerals Management Service and the U.S. Coast Guard investigating the causes of the explosion that his agency last inspected the rig's blowout preventer in 2005. BP representatives suggested that the preventer could have suffered a hydraulic leak. Gamma-ray imaging of the preventer conducted on May 12 and May 13, 2010 showed that the preventer's internal valves were partially closed and were restricting the flow of oil. Whether the valves closed automatically during the explosion or were shut manually by remotely operated vehicle work is unknown. A statement released by Congressman Bart Stupak revealed that, among other issues, the emergency disconnect system (EDS) did not function as intended and may have malfunctioned due to the explosion on the Deepwater Horizon.

The permit for the Macondo Prospect by the Minerals Management Service in 2009 did not require redundant acoustic control means. Inasmuch as the BOPs could not be closed successfully by underwater manipulation (ROV Intervention), pending results of a complete investigation, it is uncertain whether this omission was a factor in the blowout.

Documents discussed during congressional hearings June 17, 2010, suggested that a battery in the device's control pod was flat and that the rig's owner, Transocean, may have "modified" Cameron's equipment for the Macondo site (including incorrectly routing hydraulic pressure to a stack test valve instead of a pipe ram BOP) which increased the risk of BOP failure, in spite of warnings from their contractor to that effect. Another hypothesis is that a junction in the drilling pipe may have been positioned in the BOP stack in such way that its shear rams had an insurmountable thickness of material to cut through.

It was later discovered that a second piece of tubing got into the BOP stack at some point during the Macondo incident, potentially explaining the failure of the BOP shearing mechanism. As of July 2010 it is unknown whether the tubing might be casing that shot up through the well or perhaps broken drill pipe that dropped into the well.

On July 10, 2010 BP began operations to install a sealing cap, also known as a capping stack, atop the failed blowout preventer stack. Based on BP's video feeds of the operation the sealing cap assembly, called Top Hat 10, includes a stack of three blind shear ram BOPs manufactured by Hydril (a GE Oil & Gas company), one of Cameron's chief competitors. By July 15 the 3 ram capping stack had sealed the Macondo well, if only temporarily, for the first time in 87 days.

The U.S. government wants the failed blowout preventer to be replaced in case of any pressure that occurs when the relief well intersects with the well. On September 3 at 1:20 p.m. CDT the 300 ton failed blowout preventer was removed from the well and began being slowly lifted to the surface. Later that day a replacement blowout preventer was placed on the well. On September 4 at 6:54 p.m. CDT the failed blowout preventer reached the surface of the water and at 9:16 p.m. CDT it was placed in a special container on board the vessel Helix Q4000. The failed blowout preventer was taken to a NASA facility in Louisiana for examination by Det Norske Veritas (DNV).

On 20 March 2011, DNV presented their report to the US Department of Energy. Their primary conclusion was that the rams failed to shear though the oil pipe and seal it because it has buckled out of the line of action of the rams. They did not suggest any failure of actuation as would be caused by faulty batteries.

Chapter 10

Petroleum Refining Processes

Petroleum refining processes are those chemical engineering processes and other facilities used in petroleum refineries (also referred to as oil refineries) to transform crude oil into useful products such as liquefied petroleum gas (LPG), gasoline or petrol, kerosene, jet fuel, diesel oil and fuel oils.

Petroleum refineries are very large industrial complexes that involve a great many different processing units and auxiliary facilities such as utility units and storage tanks. Each refinery has its own unique arrangement and combination of refining processes largely determined by the refinery location, desired products and economic considerations. There are most probably no two refineries that are identical in every respect.

Some modern petroleum refineries process as much as 800,000 to 900,000 barrels (127,000 to 143,000 cubic meters) per day of crude oil.

Brief history of the petroleum industry and petroleum refining

Prior to the nineteenth century, petroleum was known and utilized in various fashions in Babylon, Egypt, China, Persia, Rome and Azerbaijan. However, the modern history of the petroleum industry is said to have begun in 1846 when Abraham Gessner of Nova Scotia, Canada discovered how to produce kerosene from coal. Shortly thereafter, in 1854, Ignacy Lukasiewicz began producing kerosene from hand-dug oil wells near the town of Krosno, now in Poland. The first large petroleum refinery was built in Ploesti, Romania in 1856 using the abundant oil available in Romania.

In North America, the first oil well was drilled in 1858 by James Miller Williams in Ontario, Canada. In the United States, the petroleum industry began in 1859 when Edwin Drake found oil near Titusville, Pennsylvania. The industry grew slowly in the 1800s, primarily producing kerosene for oil lamps. In the early twentieth century, the introduction of the internal combustion engine and its use in automobiles created a market for gasoline that was the impetus for fairly rapid growth of the petroleum industry. The early finds of petroleum like those in Ontario and Pennsylvania were soon outstripped by large oil "booms" in Oklahoma, Texas and California.

Prior to World War II in the early 1940s, most petroleum refineries in the United States consisted simply of crude oil distillation units (often referred to as atmospheric crude oil distillation units). Some refineries also had vacuum distillation units as well as thermal cracking units such as visbreakers (viscosity breakers, units to lower the viscosity of the oil). All of the many other refining processes discussed below were developed during the war or within a few years after the war. They became commercially available within 5 to 10 years after the war ended and the worldwide petroleum industry experienced very rapid growth. The driving force for that growth in technology and in the number and size of refineries worldwide was the growing demand for automotive gasoline and aircraft fuel.

In the United States, for various complex economic reasons, the construction of new refineries came to a virtual stop in about the 1980s. However, many of the existing refineries in the United States have revamped many of their units and/or constructed add-on units in order to: increase their crude oil processing capacity, increase the octane rating of their product gasoline, lower the sulphur content of their diesel fuel and home heating fuels to comply with environmental regulations and comply with environmental air pollution and water pollution requirements.

Processing units used in refineries

- Crude Oil Distillation unit: Distills the incoming crude oil into various fractions for further processing in other units.
- Vacuum Distillation unit: Further distills the residue oil from the bottom of the crude oil distillation unit. The vacuum distillation is performed at a pressure well below atmospheric pressure.
- Naphtha Hydrotreater unit: Uses hydrogen to desulfurize the naphtha fraction from the crude oil distillation or other units within the refinery.
- Catalytic Reforming unit: Converts the desulfurized naphtha molecules into higher-octane molecules to produce *reformate*, which is a component of the end-product gasoline or petrol.
- Alkylation unit: Converts isobutane and butylenes into *alkylate*, which is a very high-octane component of the end-product gasoline or petrol.
- Isomerization unit: Converts linear molecules such as normal pentane into higher-octane branched molecules for blending into the end-product gasoline. Also used to convert linear normal butane into isobutane for use in the alkylation unit.
- Distillate Hydrotreater unit: Uses hydrogen to desulfurize some of the other distilled fractions from the crude oil distillation unit (such as diesel oil).
- Merox (mercaptan oxidizer) or similar units: Desulfurize LPG, kerosene or jet fuel by oxidizing undesired mercaptans to organic disulphides.
- Amine gas treater, Claus unit, and tail gas treatment for converting hydrogen sulphide gas from the hydrotreaters into end-product elemental sulphur. The large majority of the 64,000,000 metric tons of sulphur produced worldwide in 2005 was byproduct sulfur from petroleum refining and natural gas processing plants.
- Fluid Catalytic Cracking (FCC) unit: Upgrades the heavier, higher-boiling fractions from the crude oil distillation by converting them into lighter and lower boiling, more valuable products.

- Hydrocracker unit: Uses hydrogen to upgrade heavier fractions from the crude oil distillation and the vacuum distillation units into lighter, more valuable products.
- Visbreaker unit upgrades heavy residual oils from the vacuum distillation unit by thermally cracking them into lighter, more valuable reduced viscosity products.
- Delayed coking and Fluid coker units: Convert very heavy residual oils into end-product petroleum coke as well as naphtha and diesel oil by-products.

Auxiliary facilities required in refineries

- Steam reformer unit: Converts natural gas into hydrogen for the hydrotreaters and/or the hydrocracker.
- Sour water stripper unit: Uses steam to remove hydrogen sulfide gas from various wastewater streams for subsequent conversion into end-product sulfur in the Claus unit.
- Utility units such as cooling towers for furnishing circulating cooling water, steam generators, instrument air systems for pneumatically operated control valves and an electrical substation.
- Wastewater collection and treating systems consisting of API separators, dissolved air flotation (DAF) units and some type of further treatment (such as an activated sludge biotreater) to make the wastewaters suitable for reuse or for disposal.
- Liquified gas (LPG) storage vessels for propane and similar gaseous fuels at a pressure sufficient to maintain them in liquid form. These are usually spherical vessels or *bullets* (horizontal vessels with rounded ends).
- Storage tanks for crude oil and finished products, usually vertical, cylindrical vessels with some sort of vapour emission control and surrounded by an earthen berm to contain liquid spills.

The crude oil distillation unit

The crude oil distillation unit (CDU) is the first processing unit in virtually all petroleum refineries. The CDU distills the incoming crude oil into various fractions of different boiling ranges, each of which are then processed further in the other refinery processing units. The CDU is often referred to as the *atmospheric distillation unit* because it operates at slightly above atmospheric pressure.

Below is a schematic flow diagram of a typical crude oil distillation unit. The incoming crude oil is preheated by exchanging heat with some of the hot, distilled fractions and other streams. It is then desalted to remove inorganic salts (primarily sodium chloride).

Following the desalter, the crude oil is further heated by exchanging heat with some of the hot, distilled fractions and other streams. It is then heated in a fuel-fired furnace (fired heater) to a temperature of about 398 °C and routed into the bottom of the distillation unit.

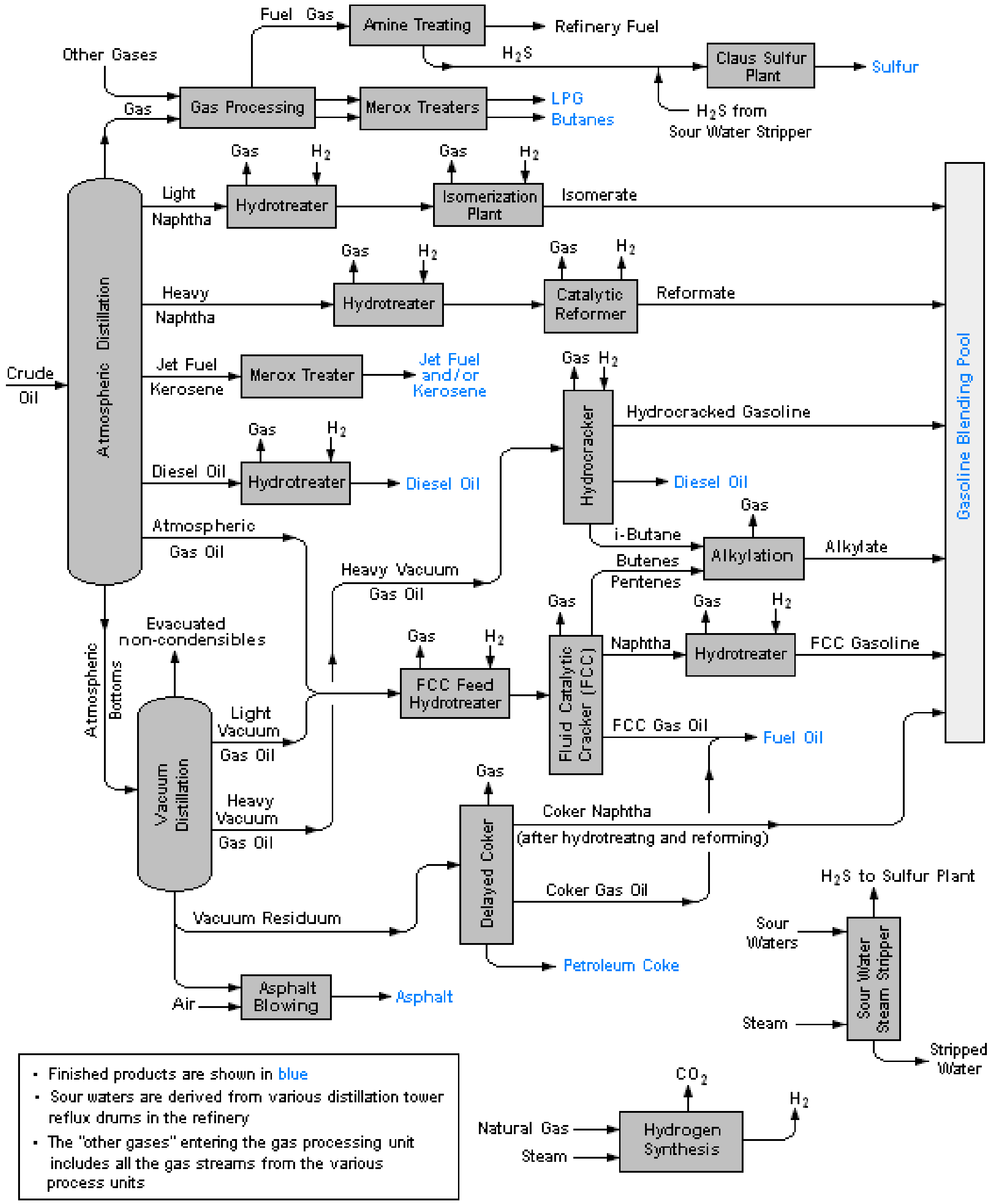
The cooling and condensing of the distillation tower overhead is provided partially by exchanging heat with the incoming crude oil and partially by either an air-cooled or water-cooled condenser. Additional heat is removed from the distillation column by a pumparound system as shown in the diagram below.

As shown in the flow diagram, the overhead distillate fraction from the distillation column is naphtha. The fractions removed from the side of the distillation column at various points between the column top and bottom are called *sidecuts*. Each of the sidecuts (i.e., the kerosene, light gas oil and heavy gas oil) is cooled by exchanging heat with the incoming crude oil. All of the fractions (i.e., the overhead naphtha, the sidecuts and the bottom residue) are sent to intermediate storage tanks before being processed further.

Flow diagram of a typical petroleum refinery

The image below is a schematic flow diagram of a typical petroleum refinery that depicts the various refining processes and the flow of intermediate product streams that occurs between the inlet crude oil feedstock and the final end-products.

The diagram depicts only one of the literally hundreds of different oil refinery configurations. The diagram also does not include any of the usual refinery facilities providing utilities such as steam, cooling water, and electric power as well as storage tanks for crude oil feedstock and for intermediate products and end products.



A schematic flow diagram of a typical petroleum refinery.

Refining end-products

The primary end-products produced in petroleum refining may be grouped into four categories: light distillates, middle distillates, heavy distillates and others.

Light distillates

- Liquid petroleum gas (LPG)
- Gasoline (also known as petrol)
- Kerosene
- Jet fuel and other aircraft fuel

Middle distillates

- Automotive and rail-road diesel fuels
- Residential heating fuel
- Other light fuel oils

Heavy distillates

- Heavy fuel oils
- Bunker fuel oil and other residual fuel oils

Others

Many of these are not produced in all petroleum refineries.

- Speciality petroleum naphthas
- Speciality solvents
- Elemental sulphur (and sometimes sulphuric acid)
- Petrochemical feed-stocks
- Asphalt and tar
- Petroleum coke
- Lubricating oils
- Waxes and greases
- Transformer and cable oils
- Carbon black

Chapter 11

Microbial Enhanced Oil Recovery

Microbial Enhanced Oil Recovery (MEOR) is a biological based technology consisting in manipulating function or structure, or both, of microbial environments existing in oil reservoirs. The ultimate aim of MEOR is to improve the recovery of oil entrapped in porous media while increasing economic profits. MEOR is a tertiary oil extraction technology allowing the partial recovery of the commonly residual two-thirds of oil, thus increasing the life of mature oil reservoirs.

MEOR is a multidisciplinary field incorporating, among others: geology, chemistry, microbiology, fluids mechanics, petroleum engineering, environmental engineering and chemical engineering. The microbial processes proceeding in MEOR can be classified according to the oil production problem in the field:

- *well bore clean up* removes mud and other debris blocking the channels where oil flows through;
- *well stimulation* improves the flow of oil from the drainage area into the well bore; and
- *enhanced water floods* increase microbial activity by injecting selected microbes and sometimes nutrients. From the engineering point of view, MEOR is a system integrated by the reservoir, microbes, nutrients and protocol of well injection.

MEOR outcomes

So far, the outcomes of MEOR are explained based on two predominant rationales:

Increment in oil production. This is done by modifying the interfacial properties of the system oil-water-minerals, with the aim of facilitating oil movement through porous media. In such a system, microbial activity affects fluidity (viscosity reduction, miscible flooding); displacement efficiency (decrease of interfacial tension, increase of permeability); sweep efficiency (mobility control, selective plugging) and driving force (reservoir pressure).

Upgrading. In this case, microbial activity acts may promote the degradation of heavy oils into lighter ones. Alternatively, it can promote desulphurization due to denitrification as well as the removal of heavy metals.

Relevance

Several decades of research and successful applications support the claims of MEOR as a mature technology. Despite those facts, disagreement still exists. Successful stories are specific for each MEOR field application, and published information regarding supportive economical advantages is however inexistent. Despite this, there is consensus considering MEOR one of the cheapest existing EOR methods . However, obscurity exists on predicting whether or not the deployment of MEOR will be successful. MEOR is, therefore, one of the future research areas with great priority as identified by the “Oil and Gas in the 21st Century Task Force”. This is probably because MEOR is a complementary technology that may help recover the 377 billion barrels of oil that are unrecoverable by conventional technologies.

Bias

Before the advent of environmental molecular microbiology, the word “bacteria” was utilised indistinctively in many fields to refer to uncharacterized microbes, and such systematic error affected several disciplines. Therefore, the word “microbe” or “microorganism” will therefore be preferred hereafter in the text.

History

It was in 1926 when Beckam proposed the utilisation of microorganisms as agents for recovering the remnant oil entrapped in porous media. Since that time numerous investigations have been developed, and are extensively reviewed. In 1947, ZoBell and colleagues set the basis of petroleum microbiology applied to oil recovery, whose contribution would be useful for the first MEOR patent granted to Updegraff and colleagues in 1957 concerning the in situ production of oil recovery agents such as gases, acids, solvents and biosurfactants from microbial degradation of molasses. In 1954, the first field test was carried out in the Lisbon field in Arkansas, USA. During that time, Kuznetsov discovered the microbial gas production from oil. From this year and until the 1970s there was intensive research in USA, USSR, Czechoslovakia, Hungary and Poland. The main type of field experiments developed in those countries consisted in injecting exogenous microbes. In 1958, selective plugging with microbial produced biomass was proposed by Heinningen and colleagues. The oil crisis of 1970 triggered a great interest in active MEOR research in more than 15 countries. From 1970 to 2000, basic MEOR research focused on microbial ecology and characterization of oil reservoirs. In 1983, Ivanov and colleagues developed the strata microbial activation technology. By 1990, MEOR achieved an interdisciplinary technology status. In 1995, a survey of MEOR projects (322) in the USA showed that 81% of the projects successfully increased oil production, and there was not a single case of reduced oil production. Today, MEOR is gaining attention owing to the high prices of oil and the imminent ending of this resource. As a result, several countries are willing to use MEOR in one third of their oil recovery programs by 2010.

MEOR advantages

There is a plethora of reviewed claims regarding the advantages of MEOR. However, they should be cautiously regarded due to the lack of published supportive evidence. In addition, assessments of both full live cycle analysis and environmental impact are also unknown.

Advantages can be summarised as follows:

- Injected microbes and nutrients are cheap; easy to handle in the field and independent of oil prices.
- Economically attractive for mature oil fields before abandonment.
- Increases oil production.
- Existing facilities require slight modifications.
- Easy application.
- Less expensive set up.
- Low energy input requirement for microbes to produce MEOR agents.
- More efficient than other EOR methods when applied to carbonate oil reservoirs.
- Microbial activity increases with microbial growth. This is opposite to the case of other EOR additives in time and distance.
- Cellular products are biodegradable and therefore can be considered environmentally friendly.

MEOR disadvantages

- The oxygen deployed in aerobic MEOR can act as corrosive agent on non-resistant topside equipment and down-hole piping
- Anaerobic MEOR requires large amounts of sugar limiting its applicability in offshore platforms due to logistical problems
- Exogenous microbes require facilities for their cultivation.
- Indigenous microbes need a standardized framework for evaluating microbial activity, e.g. specialized coring and sampling techniques.
- Microbial growth is favoured when: layer permeability is greater than 50 md; reservoir temperature is inferior to 80 ^{0}C, salinity is below 150 g/L and reservoir depth is less than 2400m.

The environment of an oil reservoir

Oil reservoirs are complex environments containing living (microorganisms) and non living factors (minerals) which interact with each other in a complicated dynamic network of nutrients and energy fluxes. Since the reservoir is heterogeneous, so do the variety of ecosystems containing diverse microbial communities, which in turn are able to affect reservoir behaviour and oil mobilization.

Microbes are living machines whose metabolites, excretion products and new cells may interact with each other or with the environment, positively or negatively, depending on the global desirable purpose, e.g. the enhancement of oil recovery. All these entities, i.e.

enzymes, extracellular polymeric substances (EPS) and the cells themselves, may participate as catalyst or reactants. Such complexity is increased by the interplay with the environment, the later playing a crucial role by affecting cellular function, i.e. genetic expression and protein production.

Despite this fundamental knowledge on cell physiology, a solid understanding on function and structure of microbial communities in oil reservoirs, i.e. ecophysiology, remains inexistent.

Environmental constraints

Several factors concomitantly affect microbial growth and activity. In oil reservoirs, such environmental constraints permit to establish criteria as to assess and compare the suitability of microorganisms. Those constrains may not be as harsh as other environments on Earth. For example, connate brines salinity is higher than that of sea water but lower than that of salt lakes. In addition, pressures up to 20 MPa and temperatures up to 80 °C, in oil reservoirs, are within the limits for the survival of other microorganisms.

Some environmental constraints creating selective pressures on cellular systems that may also affect microbial communities in oil reservoirs are:

Temperature

Enzymes are biological catalysts whose function is affected by a variety of factors including temperature, which at different ranges may improve or hamper enzymatic mediated reactions. This will have an effect over the optimal cellular growth or metabolism. Such dependency permits to classify microbes according to the range of temperature at which they can grow. For instance: psychrophiles (<25 °C), mesophiles (25-45 °C), thermophiles (45-60 °C) and hyperthermophiles (60-121 °C). Although such cells optimally grow in those temperature ranges there may not be a direct relationship with the production of specific metabolites.

Pressure

Direct effects

The effects of pressure on microbial growth under deep ocean conditions were investigated by ZoBell and Johson in 1949. They called barophilic to those microbes whose growth was enhanced by increasing pressure. Other classification of microorganisms is based on whereas microbial growth is inhibited at standard conditions (piezophiles) or above 40 MPa (piezotolerants). From a molecular point of view, the review of Daniel shows that at high pressures the DNA double helix becomes denser, and therefore both gene expression and protein synthesis are affected.

Indirect effect

Increasing pressure increases gas solubility, and this may affect the redox potential of gases participating as electron acceptors and donors, such as hydrogen or CO_2.

Pore size/geometry

One study has concluded that substantial bacterial activity is achieved when there are interconnections of pores having at least 0.2μ diameter. It is expected that pore size and geometry may affect chemotaxis. However, this has not been proven at oil reservoir conditions.

pH

The acidity of alkalinity has an impact over several aspects in living and non living systems. For instance:

Surface charge

Changes in cellular surface and membrane thickness may be promoted by pH due to its ionization power of cellular membrane embedded proteins. The modified ionic regions may interact with mineral particles and affect the motion of cells through the porous media.

Enzymatic activity

Embedded cell proteins play a fundamental roll in the transport of chemicals across the cellular membrane. Their function is strongly dependent on their state of ionisation, which is in turn strongly affected by pH.

In both cases, this may happen in isolated or complex environmental microbial communities. So far the understanding on the interaction between pH and environmental microbial communities remains unknown, despite the efforts of the last decade. Little is know on the ecophysiology of complex microbial communities and research is still in developmental stage.

Oxidation potential

The oxidation potential (Eh, measured in volts) is, as in any reaction system, the thermodynamic driving force of anaerobic respiration, which takes place in oxygen depleted environments. Prokaryotes are among the cells that have anaerobic respiration as metabolic strategy for survival. The electron transport takes place along and across the cellular membrane (prokaryotes lack of mitochondria). Electrons are transferred from an electron donor (molecule to be oxidised anaerobically) to an electron acceptor (NO_3, SO_4, MnO_4, etc.). The net Eh between a given electron donor and acceptor; hydrogen ions and other species in place will determine which reaction will first take place. For instance, nitrification is hierarchically more favoured than sulphate reduction. This allows for enhanced oil recovery by disfavouring biologically produced H_2S, which derives from reduced SO_4. In this process, the effects of nitrate reduction on wettability, interfacial tension, viscosity, permeability, biomass and biopolymer production remain unknown.

Electrolyte composition

Electrolytes concentration and other dissolved species may affect cellular physiology. Dissolving electrolytes reduces thermodynamic activity (aw), vapour pressure and autoprotolysis of water. Besides, electrolytes promote an ionic strength gradient across cellular membrane and therefore provides a powerful driving force allowing the diffusion of water into or out to cells. In natural environments, most bacteria are incapable of living at aw below 0.95. However, some microbes from hypersaline environment such as Pseudomonas species and Halococcus thrive at lower a_w, and are therefore interesting for MEOR research.

Non-specific effects

They may occur on pH and Eh. For example, increasing ionic strength increases solubility of nonelectrolytes ('salting out') as in the case of dissolution of carbon dioxide, a pH controller of a variety of natural waters.

Biological factors

Although it is widely accepted that predation, parasitism, syntrophism and other relationships also occur in the microbial world, little is known in this relationships on MEOR and they have been disregarded in MEOR experiments.

In other cases, some microorganisms can thrive in nutrient deficient environments (oligotrophy) such as deep granitic and basaltic aquifers. Other microbes, living in sediments, may utilise available organic compounds (heterotrophy). Organic matter and metabolic products between geological formations can diffuse and support microbial growth in distant environments.

MEOR mechanism

Understanding MEOR mechanism is still far from being clear. Although a variety of explanations has been given in isolated experiments, it is unclear if they were carried out trying to mimic oil reservoirs conditions.

The mechanism can be explained from the client-operator viewpoint which considers a series of concomitant positive or negative effects that will result in a global benefit:

- *Beneficial effects*. Biodegradation of big molecules reduces viscosity; production of surfactants reduces interfacial tension; production of gas provides additional pressure driving force; microbial metabolites or the microbes themselves may reduce permeability by activation of secondary flow paths.

- *Detrimental effects*. Biologically produced hydrogen sulphide, i.e. souring, causes corrosion of piping and machinery; consumption of hydrocarbons by bacteria reduces the production of desired chemicals.

- *Beneficial or Detrimental*. Permeability reduction can be beneficial in some cases but detrimental in others. Negatively, microbial metabolites or the microbes themselves may reduce permeability by activation of secondary flow paths by depositing: biomass (biological clogging), minerals (chemical clogging) or other suspended particles (physical clogging). Positively, attachment of bacteria and development of slime, i.e. extracellular polymeric substances (EPS), favour the plugging of highly permeable zones (thieves zones) leading to increased sweep efficiency.

MEOR strategies

Changing oil reservoir ecophysiology to favour MEOR can be achieved by complementing different strategies. In situ microbial stimulation can be chemically promoted by injecting electron acceptors such as nitrate; easy fermentable molasses, vitamins or surfactants. Alternatively, MEOR is promoted by injecting exogenous microbes, which may be adapted to oil reservoir conditions and be capable of producing desired MEOR agents (Table 1).

Table 1. Possible applications of products and MEOR agents produced by microorganism.

MEOR agents	Microbes	Product	Possible MEOR application
Biomass, i.e. flocks or biofilms	Bacillus sp.	Cells and EPS (mainly exopolysaccharides),	Selective plugging of oil depleted zones and wettability angle alteration
	Leuconostoc		
	Xanthomonas		
Surfactants	Acinetobacter	Emulsan and alasan	Emulsification and de-emulsification through reduction of interfacial tension
	Bacillus sp.	Surfactin, rhamnolipid, lichenysin	
	Pseudomonas	Rhamnolipid, glycolipids	
	Rhodococcus sp.	Viscosin and trehaloselipids	
	Arthrobacter		

Biopolymers	Xanthomonas sp.	Xanthan gum	Injectivity profile and viscosity modification, selective plugging
	Aureobasidium sp.	Pullulan	
	Bacillus sp.	Levan	
	Alcaligeness sp.	Curdlan	
	Leuconostoc sp.	Dextran	
	Sclerotium sp.	Scleroglucan	
	Brevibacterium		
Solvents	Clostridium, Zymomonas and Klebsiella	Acetone, butanol, propan-2-diol	Rock dissolution for increasing permeability, oil viscosity reduction
Acids	Clostridium	Propionic and butyric acids	Permeability increase, emulsification
	Enterobacter		
	Mixed acidogens		
Gases	Clostridium	Methane and hydrogen	Increased pressure, oil swelling, reduction of interfacial section and viscosity; increase permeability
	Enterobacter		
	Methanobacterium		

This knowledge has been obtained from experiments with pure cultures and some times with complex microbial communities but the experimental conditions are far from mimicking those ones prevailing in oil reservoirs. It is unknown if metabolic products is cell growth dependent, and claims in this respect should be taken cautiously, since the production of a metabolite is not always dependent of cellular growth.

Biomass and biopolymers

In selective plugging, conditioned cells and extracellular polymeric substances plug high permeability zones, resulting in a change of direction of the water flood to oil-rich channels, consequently increasing the sweep efficiency of oil recovery with water flooding. Biopolymer production and the resulting biofilm formation (less 27% cells, 73-

98% EPS and void space) are affected by water chemistry, pH, surface charge, microbial physiology, nutrients and fluid flow.

Biosurfactants

Microbial produced surfactants, i.e. biosurfactants reduce the interfacial tension between water and oil, and therefore a lower hydrostatic pressure is required to move the liquid entrapped in the pores to overcome the capillary effect. Secondly, biosurfactants contribute to the formation of micelles providing a physical mechanism to mobilise oil in a moving aqueous phase. Hydrophobic and hydrophilic compounds are in play and have attracted attention in MEOR research, and the main structural types are lipopeptides and glycolipids, being the fatty acid molecule the hydrophobic part.

Gas and solvents

In this old practice, the production of gas has a positive effect in oil recovery by increasing the differential pressure driving the oil movement. Anaerobically produced methane from oil degradation have a low effect on MEOR due to its high solubility at high pressures. Carbon dioxide is also a good MEOR agent. The miscible CO_2 is condensed into the liquid phase when light hydrocarbons are vaporised into the gas phase. Immiscible CO_2 helps to saturate oil, resulting in swelling and reduction of viscosity of the liquid phase and consequently improving mobilization by extra driving pressure. Concomitantly, other gases and solvents may dissolve carbonate rock, leading to an increase in rock permeability and porosity.

Field studies

Worldwide MEOR field applications have been reviewed in detail. Although the exact number field trials is unknown, Lazar et al. suggested an order of hundreds. Successful MEOR field trials have been conducted in the U.S., Russia, China, Australia, Argentina, Bulgaria, former Czechoslovakia, former East Germany, Hungary, India, Malaysia, Peru, Poland, and Romania. Lazar et al. suggested China is leading in the area, and also found that the most successful study was carried out in Alton field, Australia (40% increase of oil production in 12 months).

The majority of the field trials were done in sandstone reservoirs and very few in fractured reservoirs and carbonates. The only known offshore field trials were in Norne (Norway) and Bokor (Malaysia).

As reviewed by Lazar et al., field application followed different approaches such as injection of exogenous microorganisms (microbial flooding); control of paraffin deposition; stimulation of indigenous microbes; injection of ex situ produced biopolymers; starved selected ultramicrobes (selected plugging); selected plugging by sand consolidation due to biomineralization and fracture clogging in carbonate formations; nutrient manipulation of indigenous reservoir microbes to produce ultramicrobes; and adapted mixed enrichment cultures.

Reported MEOR results from field trials vary widely. Rigorous controlled experiments are lacking and may not be possible due to the dynamic changes in the reservoir when oil is being recovered. Besides, the economical advantages of these field trials are unknown, and the answer to why the other trials were unsuccessful is unknown. General conclusions can not be drawn because the physical and mineralogical characteristics of the oil reservoirs reported were different. The extrapolation of such conclusions is therefore unviable.

Models

A plethora of attempts to model MEOR has been published. Until now, it is unclear if theoretical results reflect the scarce published data. Developing mathematical models for MEOR is very challenging since physical, chemical and biological factors need to be considered.

Published MEOR models are composed of transport properties, conservation laws, local equilibrium, breakdown of filtration theory and physical straining. Such models are so far simplistic and they were developed based on:

(A) Fundamental conservation laws, cellular growth, retention kinetics of biomass, and biomass in oil and aqueous phases. The main aim was to predict porosity retention as a function of distance and time.

(B) Filtration model to express bacterial transport as a function of pore size; and relate permeability with the rate of microbial penetration by applying Darcy's law.

Chemical kinetics is fundamental for coupling bioproduct formation to fluxes of aqueous species and suspended microbes. Fully numerical approaches have also been followed. For instance, coupled nonlinear parabolic differential equations: adding equation for the rate of diffusion of microbes and their capture by porous medium; differential balance equations for nutrient transport, including the effect of adsorption; and the assumption of bacterial growth kinetic based on Monod equation.

Monod equation is indiscriminately used in modelling software, and has a limited behaviour which is inconsistent with the law of mass action that form the basis of kinetic characterization of microbial growth. Application of law of mass action to microbial populations results in the linear logistic equation. And the application of the law of mass action to an enzyme-catalysed process results in the Michaelis-Menten equation, from which Monod is inspired. This makes things difficult for in situ biosurfactant production because controlled experimentation is required to determine specific growth rate and Michaelis-Menten parameters of rate-limiting enzyme reaction.

Modelling of bioclogging is complicated because the production of clogging metabolite is coupled nonlinearly to the growth of microbes and flux of nutrients transported in the fluid.

Published models disregard the ecophysiology of the entire microbial microcosms at oil reservoir conditions. Microorganisms are a kind of catalyst whose activity (physiology) depends on the mutual interplay with other microbes and the environment (ecology). In nature, living and non living elements interact with each other in a complicated network of nutrients and energy. Some microbes produce extracellular polymeric substances and therefore its behaviour in pours media needs to consider both occupation by the EPS and the microbes themselves. Knowledge is lacking in this respect and therefore the aim of maximizing yield and minimizing cost remains unachieved.

Realistic models for MEOR at the conditions of the oil reservoir are missing, and reported parallel-pore models had fundamental deficiencies that were overcome by models considering the clogging of pores by microbes or biofilms, but such models have also the deficiency of being two-dimensional. The utilisation of such models in three dimensional models has not been proven. It is uncertain if they can be incorporated to popular oilfield simulation software. Thus, a field strategy needs a simulator capable of predicting bacterial growth and transport through porous network and in situ production of MEOR agents.

Grounds of failure

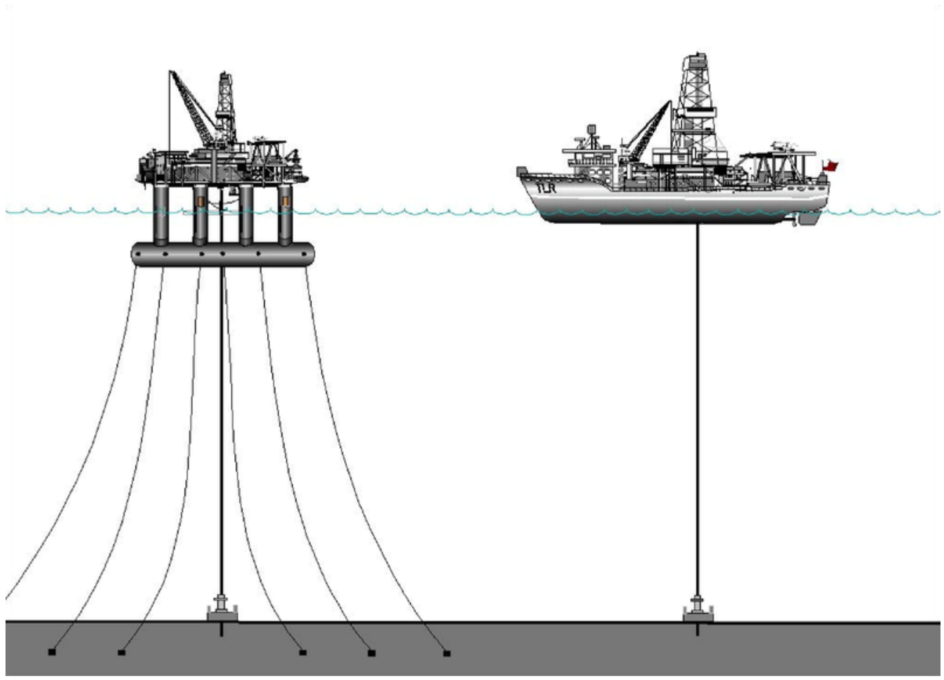
- Lack of holistic approach allowing for a critical evaluation of economics, applicability and performance of MEOR is missing.
- No published study includes reservoir characteristics; biochemical and physiological characteristics of microbiota; controlling mechanisms and process economics.
- The ecophysiology of microbial communities thriving in oil reservoirs is largely unexplored. Consequently, there is a poor critical evaluation of the physical and biochemical mechanisms controlling microbial response to the hydrocarbon substrates and their mobility.
- Absence of quantitative understanding of microbial activity and poor understanding of the synergistic interactions between living and none living elements. Experiments based on pure cultures or enrichments are questionable because microbial communities interact synergistically with minerals, extracellular polymeric substances and other physicochemical and biological factors in the environment.
- Lack of cooperation between microbiologists, reservoir engineers, geologists, economists and owner operators; incomplete pertinent reservoir data, in published sources: lithology, depth, net thickness, porosity, permeability, temperature, pressure, reserves, reservoir fluid properties (oil gravity, water salinity, oil viscosity, bubble point pressure, and oil-formation-volume factor), specific EOR data (number of production and injection wells, incremental recovery potential as mentioned by the operator, injection rate, calculated daily and total enhanced production), calculated incremental recovery potential over the reported time.
- Limited understanding of MEOR process economics and improper assessment of technical, logistical, cost, and oil recovery potential.
- Unknowns life cycle assessments. Unknown environmental impact
- Lack of demonstrable quantitative relationships between microbial performance, reservoir characteristics and operating conditions

- Inconsistency in in situ performance; low ultimate oil recovery factor; uncertainty about meeting engineering design criteria by microbial process; and a general apprehension about process involving live bacteria.
- Lack of rigorous controlled experiments, which are far from mimicking oil reservoir conditions that may have an effect over gene expression and protein formation.
- Kinetic characterization of bacteria of interest is unknown. Monod equation has been broadly misused.
- Lack of structured mathematical models to better describe MEOR.
- Lack of understanding of microbial oil recovery mechanism and deficient mathematical models to predict microbial behaviour in different reservoirs.
- Surfactants: biodegradable, effectiveness affected by temperature, pH and salt concentration; adsorption on to rock surfaces.
- Unfeasible economic solutions such as the utilization of enzymes and cultured microorganism.
- Difficult isolation or engineering of good candidate strains able to survive the extreme environment of oil reservoirs (up to 85 °C, up to 17.23 MPa).

Chapter 12

Semi-Submersible

Deepsea Delta semi-submersible drilling rig in North Sea



Comparison of deepwater semi-submersible and drillship.

A **semi-submersible** is a specialised marine vessel with good stability and seakeeping characteristics. The semi-submersible vessel design is commonly used in a number of specific offshore roles such as for offshore drilling rigs, safety vessels, oil production platforms and heavy lift cranes.

The terms *semisubmersible*, *semi-sub* or just *semi* are also generally used for this vessel design.

Characteristics

Offshore drilling in water depth greater than around 120 meters requires that operations be carried out from a floating vessel, as fixed structures are not practical. Initially in the early 1950s monohull ships were used like CUSS I, but these were found to have significant heave, pitch and yaw motions in large waves, and the industry needed more stable drilling platforms.

A semi-submersible obtains its buoyancy from ballasted, watertight pontoons located below the ocean surface and wave action. The operating deck can be located high above the sea level due to the good stability of the concept, and therefore the operating deck is kept well away from the waves. Structural columns connect the pontoons and operating deck.

With its hull structure submerged at a deep draft, the semi-submersible is less affected by wave loadings than a normal ship. With a small water-plane area, however, the semi-submersible is sensitive to load changes, and therefore must be carefully trimmed to maintain stability. Unlike a submarine or submersible, during normal operations, a semi-submersible vessel is never entirely underwater.

A semi-submersible vessel is able to transform from a deep to a shallow draft by deballasting (removing ballast water from the hull), and thereby become a surface vessel. The heavy lift vessels use this capability to submerge the majority of their structure, locate beneath another floating vessel, and then deballast to pick up the other vessel as a cargo.

Early history

Blue Water Rig No. 1

The semi-submersible design was first developed for offshore drilling activities. Bruce Collipp of Shell is regarded as the inventor. But Edward Robert Armstrong may have paved the way with his idea of 'seadrome' landing strips for airplanes in the late 1920s, since his idea involved the same use of columns on ballast tanks below the surface and anchored to the ocean floor by steel cables.

When oil drilling moved into offshore waters, fixed platform rigs and submersible rigs were built, but were limited to shallow waters. When demands for drilling equipment was needed in water depths greater than 100 feet (30 m) in the Gulf of Mexico, the first jackup rigs were built.

The first semisubmersible arrived by accident in 1961. Blue Water Drilling Company owned and operated the four column submersible drilling rig *Blue Water Rig No.1* in the Gulf of Mexico for Shell Oil Company. As the pontoons were not sufficiently buoyant to support the weight of the rig and its consumables, it was towed between locations at a draught mid way between the top of the pontoons and the underside of the deck. It was observed that the motions at this draught were very small and Blue Water Drilling and Shell jointly decided that the rig could be operated in the floating mode.

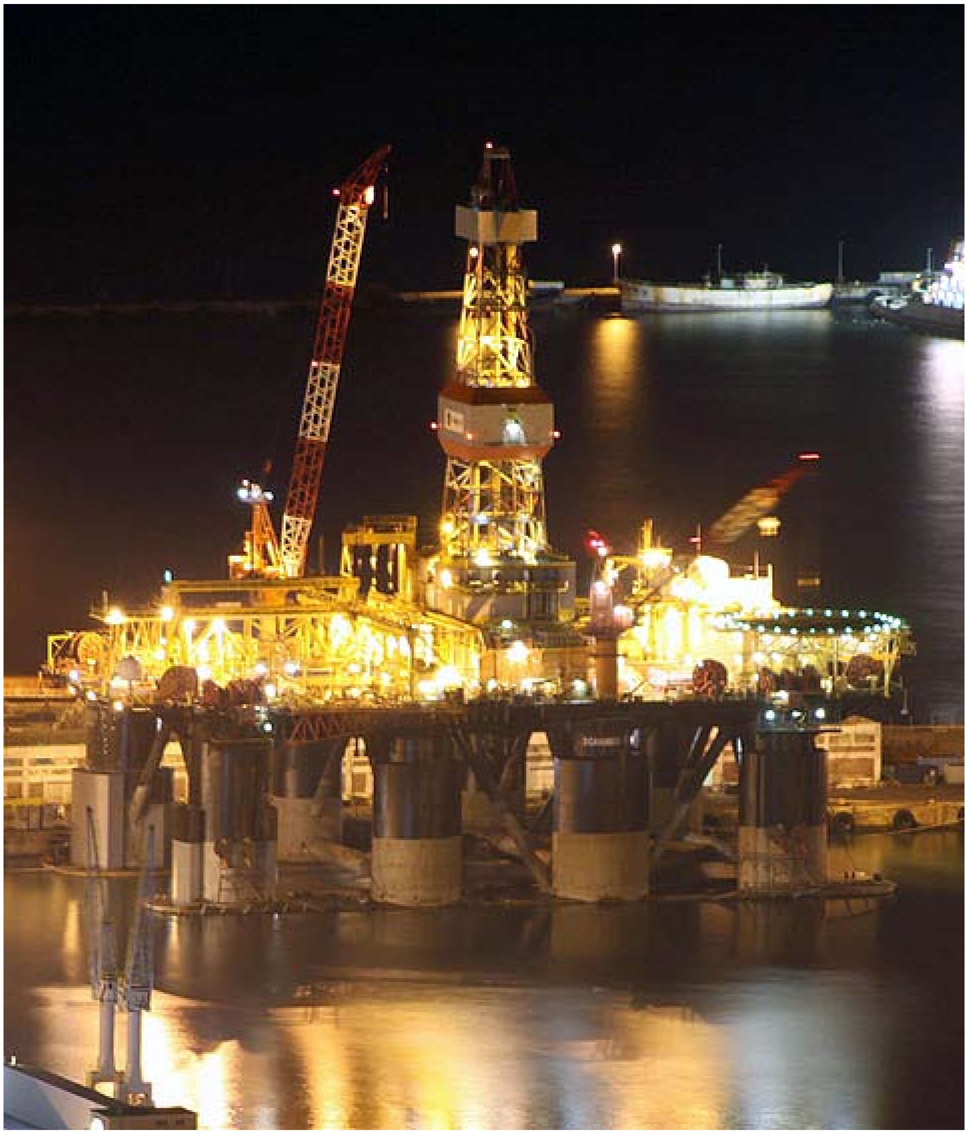
The first purpose built drilling semi-submersible *Ocean Driller* was launched in 1963. Since then, many semi-submersibles have been purpose-designed for the drilling industry mobile offshore fleet.

The industry quickly accepted the semi-submersible concept and the fleet increased rapidly to 30 units by 1972.

Applications

Mobile offshore drilling units (MODU)

Semi-submersible drilling rig on MS3 Heavy-lift Ship



Saipem Scarabeo 7 semi-submersible drilling rig docked in Cape Town

Semi-submersible rigs make stable platforms for drilling for offshore oil and gas. They can be towed into position by a tugboat and anchored, or moved by and kept in position by their own azipod propellers with dynamic positioning.

Drilling rig construction has historically occurred in boom periods and therefore 'batches' of drilling rigs have been built. Offshore drilling rigs have been classified in nominal 'generations' depending upon the year built and water depth capability as follows;

Generation	Water Depth		Dates
First	about 600 ft	200 m	Early 1960s
Second	about 1000 ft	300 m	1969–1974
Third	about 1500 ft	500 m	Early 1980s
Fourth	about 3000 ft	1000 m	1990's

Fifth	about 7500 ft	2500 m	1998–2004
Sixth	about 10000 ft	3000 m	2005–2010

The IMO MODU Code is an accredited design and operational guideline for Mobile Offshore Drilling Units of the semi-submersible type.

Semi-submersible crane vessels (SSCV)

Thialf in Norwegian fjord with Fulmar SALM (Single Anchor Leg Mooring) buoy.

The advantages of the semi-submersible vessel stability were soon recognized for offshore construction when in 1978 Heerema Marine Contractors constructed the two sister crane vessels called *Balder* and *Hermod*. These semi-submersible crane vessels (SSCV) consist of two lower hulls (pontoons), three columns on each pontoon and an upper hull. Shortly after J. Ray McDermott and Saipem also introduced SSCV's, resulting in two new enormous vessels *DB-102* (now *Thialf*) and *Saipem 7000*, capable of lifting respectively 14,200 and 14,000 tons.

During transit an SSCV will be de-ballasted to a draught where only part of the lower hull is submerged. During lifting operations, the vessel will be ballasted down. This way, the lower hull is well submerged. This reduces the effect of waves and swell. High stability is obtained by placing the columns far apart. The high stability allows them to lift extreme high loads.

Offshore support vessels (OSV)

Iolair on Elbe river, 1990

Semi-submersibles are particularly suited to a number of offshore support vessel roles because of their good stability, large deck areas, and variable deck load (VDL). Some of the most prominent vessels are;

- *Uncle John* – Diving / Construction support vessel, built for Houlder Offshore in 1977
- *Seaway Swan* – Diving Support Vessel built in 1977
- *Tharos* – Offshore Safety support vessel, built in 1979 and since converted into a drilling vessel, and rechristened *Transocean Marianas*.
- *Stadive* – Diving Support Vessel (DSV) built for Shell in 1982
- *Iolair* – Offshore safety support vessel, built for BP in 1982
- *Safe Karinia* – Offshore operations vessel, built in 1982
- *Polyconfidence* – Offshore accommodation platform, built in 1988.
- *Q4000* – Offshore Multiservice Vessel, built for Caldive in 2002
- *Ocean Odyssey* – Converted semi-submersible drilling rig used as a rocket launch pad.

Offshore production platforms

The Brazilian Petrobras P-51 semi-submersible oil platform

When oil fields were first developed in offshore locations, drilling semi-submersibles were converted for use as combined drilling and production platforms. These vessels offered very stable and cost effective platforms. The first semi-submersible floating production platform was the *Argyll FPF* converted from the *Transworld 58* drilling semi-submersible in 1975 for the Hamilton Brothers North Sea *Argyll* oil field.

As the oil industry has progressed into deeper water and harsh environments, purpose-built production semi-submersible platforms were designed. The first purpose-built semi-submersible production platform was for the Balmoral field, UK North Sea in 1986.

A summary of offshore semi-submersible oil production platforms is given in the following table derived from industry data.

Vessel	Field	Region	Depth (m)	Displacement (Te)	Operator	Start up	Hull designer	Hull builder
Argyll FPU	Argyll Oil Field	UK North Sea	150	34,000	Agip	1975		
Buchan A	Buchan oil field	UK North Sea	160	18,995	Talisman	1981	Brown & Root	Scott Lithgow
P-09	Corvina	Brazil	230	22,896	Petrobras	1983	Aker	Mitsui

	Oil Field							
P-15	Pirauna	Brazil	243	21,616	Petrobras	1983	Mitsubishi Heavy Industries	Mitsubishi Heavy Industries
P-12	Linguado / Badejo Oil Field	Brazil	100	22,896	Petrobras	1984	Aker	Mitsui, Japan
P-21	Badejo / Salema Oil Fields	Brazil	112	10,765	Petrobras	1984	Earl & Wright	Montreal Engineering, Rio de Janeiro
Deepsea Pioneer FPU	Argyll & Duncan Oil Fields	UK North Sea	150	34,000	Agip	1984		
P-22	Morela	Brazil	114	17,440	Petrobras	1986	Frede & Goldman	Montreal Engineering
Balmoral FPV	Balmoral (+4 satellites) Oil Field	UK North Sea	150	30,983	Oilexco North Sea Ltd	1986	GVA	Götaverken, Sweden
P-07	Bicudo Oil Field	Brazil	207	20,493	Petrobras	1988	Aker	Raumer-Repola or Ishibras Shipyard, Rio ?
Veslefrikk B	Veslefrikk Oil Field	Norwegian Sea	175	43,305	Statoil	1989	Aker	Daewoo, Korea
AH001	Ivan Hoe Rob Roy Oil Field	UK North Sea	140	26,639	Amerada Hess	1989	Brown & Root	Highland Fabricators, Nigg
P-20	Marlim	Brazil	625	25,983	Petrobras	1992	GVA	Astileros, Spain
P-08	Marimba Oil Field	Brazil	423	20,990	Petrobras	1993	CENPES	Tangenge, Niteroi, Brazil
P-13	Bijupira / Salema Oil Field	Brazil	625	22,243	Queriz Galvao Perfuracoes	1993	CFEM	UIE, Clydesbank ?
P-14	Coral / Esrela / Caravela	Brazil	195	22,243	Petrobras	1993	CFEM	CFEM, Brazil ?

	Oil Fields							
P-18	Marlim	Brazil	910	36,100	Petrobras	1994	GVA	Tenege / FELS
Troll B FPU	Troll gas field	Norwegian Sea	339	188,968	Statoil	1995	Kvaerner/Doris	Kvaerner Rosenberg
Nan Hai Tiao Zhan	Luihua	South China Sea	300	0,000	CNOOC	1995	Reading & Bates	Keppel FELS
P-25	Albacora II Oil Field	Brazil	252	25,983	Petrobras	1996	CENPES	Ultratec
P-27	Voador	Brazil	533	41,659	Petrobras	1996	FELS / Obdebrecht	Levingston
Innovator	Marlim	Gulf of Mexico	914	0,000	ATP	1996	GVA	
Tahara	PY-3	Indian Ocean	339	55,000	Hardy oil and gas	1997	Earl & Wright	Hup Seng Engineering
Njord A	Njord Oil Field	Norwegian Sea	330	45,077	Statoil	1997	Aker	Aker Verdal
P-19	Marlim	Brazil	770	33,400	Petrobras	1997	IVI/Sadevegesa consortium	Hitachi Zosen
Janice A	Janice Oil Field	UK North Sea	80	0,000	Anadarko	1999	Aker	McNulty
Visund	Visund	Norwegian Sea	335	52,600	Statoil	1999	GVA	Umoe Mandal
Troll C FPU	Troll gas field	Norwegian Sea	339	54,377	Statoil	1999	GVA	HHI, S.Korea
P-26	Marlim	Brazil	515	27,656	Petrobras	2000	Astilleros	Astilleros, Spain
Åsgard B	Åsgard	Norwegian Sea	320	84,848	Statoil	2000	GVA	Daewoo, S. Korea
P-36	Roncador	Brazil Campos Basin	1,360	0,000	Petrobras	2000	SBM Atlantia	Davie Shipbuilding, Canada
Snorre B FDPU	Snorre Oil Field	Norwegian Sea	350	56,600	Statoil	2001	Aker	Dragados
P-51	Marlim Sul Oil	Brazil Campos	1,255	80,114	Petrobras	2001	Aker	Keppel FELS

	Field	Basin						
SS-11	Coral	Brazil	145	0,000	Petrobras	2003	Breit	Bethlehem Steel
Nakika	Kepler, Ariel, Fourier, Herschell & E. Anstey	Gulf of Mexico	936	64,000	BP	2003	ABB Lumus	HHI, S.Korea
P-40	Marlim Sul	Brazil	1,080	0,000	Petrobras	2004	PROJE MAR	Jurong
Kristin FPU	Kristin	Norwegian Sea	320	56,600	Statoil	2005	GVA	Samsung, S. Korea
Atlantis PQ	Atlantis Oil Field	Gulf of Mexico	2,156	89,000	BP	2006	GVA	DSME, S.Korea
ATP Innovator	Gomez Oil Field	Gulf of Mexico	914	46,160	ATP	2006	Levings ton	Levingsto n
Independ ence Hub	10 fields	Gulf of Mexico	2,015	46,160	Anadarko	2007	SBM Atlantia	Jurong Shipyard
P-52	Roncador	Brazil	1,795	80,201	Petrobras	2007	Gusto MSC	Keppel FELS
Thunder Horse PDQ	Thunder Horse Oil Field	Gulf of Mexico	1,849	130,000	BP	2008	GVA	DSME, S.Korea
Blind Faith	Blind Faith	Gulf of Mexico	1,980	40,000	ChevronTe xaco	2008	Aker	Aker Verdal
Northern Producer FPF	was at Galley Oil Field now atDon Oil Field	UK North Sea	350	0,000	Petrofac	2009	Granhe arne	McNulty, Newcastle
Thunder Hawk	Thunder Hawk	Gulf of Mexico	1740	42,000	Murphy	2009	SBM Atlantia	Dyna-Mac Engineerin g Services Pte Ltd
Gjøa	Gjøa Oil Field	Norwegian Sea	360	58,400	Statoil	2010	Aker	Samsung, S. Korea
P-56	Marlim Sul	Brazil	1,700	50,000	Petrobras	2010	Aker	Keppel FELS
Gumusut Kakap	Pisigan, Malilai, Ubah	Malaysia	1,220	40,000	Shell	2011	MMHE , Malaysi a	MMHE, Malaysia
P-55	Roncador	Brazil	1,707	50,000	Petrobras	2012	Aker	Atlantico

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Chapter 13

Separator (Oil Production)

The term **separator** in oilfield terminology designates a pressure vessel used for separating well fluids produced from oil and gas wells into gaseous and liquid components. A separator for petroleum production is a large vessel designed to separate production fluids into their constituent components of oil, gas and water. A separating vessel may be referred to in the following ways: **Oil and gas separator**, **Separator**, **Stage separator**, **Trap**, **Knockout vessel** (Knockout drum, knockout trap, water knockout, or liquid knockout), **Flash chamber** (flash vessel or flash trap), **Expansion separator** or **expansion vessel**, **Scrubber** (gas scrubber), **Filter** (gas filter). These separating vessels are normally used on a producing lease or platform near the wellhead, manifold, or tank battery to separate fluids produced from oil and gas wells into oil and gas or liquid and gas. An oil and gas separator generally includes the following essential components and features:

1. A vessel that includes (a) primary separation device and/or section, (b) secondary “gravity” settling (separating) section, (c) mist extractor to remove small liquid particles from the gas, (d) gas outlet, (e) liquid settling (separating) section to remove gas or vapor from oil (on a three-phase unit, this section also separates water from oil), (f) oil outlet, and (g) water outlet (three-phase unit).

2. Adequate volumetric liquid capacity to handle liquid surges (slugs) from the wells and/or flowlines.

3. Adequate vessel diameter and height or length to allow most of the liquid to separate from the gas so that the mist extractor will not be flooded.

4. A means of controlling an oil level in the separator, which usually includes a liquid-level controller and a diaphragm motor valve on the gas outlet.

5. A backpressure valve on the gas outlet to maintain a steady pressure in the vessel.

6. Pressure relief devices.

Separators work on the principle that the three components have different densities, which allows them to stratify when moving slowly with gas on top, water on the bottom and oil in the middle. Any solids such as sand will also settle in the bottom of the separator. The functions of oil and gas separators can be divided into the primary and secondary functions which will be discussed later on.

Classification of Oil and Gas Separators

Classification by Operating Configuration

Oil and gas separators can have three general configurations: **vertical**, **horizontal**, and **spherical**. Vertical separators can vary in size from 10 or 12 in. in diameter and 4 to 5 ft seam to seam (S to S) up to 10 or 12 ft in diameter and 15 to 25 ft S to S. Horizontal separators may vary in size from 10 or 12 in. in diameter and 4 to 5 ft S to S up to 15 to 16 ft in diameter and 60 to 70 ft S to S. Spherical separators are usually available in 24 or 30 in. up to 66 to 72 in. in diameter. Horizontal oil and gas separators are manufactured with monotube and dual-tube shells. Monotube units have one cylindrical shell, and dual-tube units have two cylindrical parallel shells with one above the other. Both types of units can be used for two-phase and three-phase service. A monotube horizontal oil and gas separator is usually preferred over a dual-tube unit. The monotube unit has greater area for gas flow as well as a greater oil/gas interface area than is usually available in a dual-tube separator of comparable price. The monotube separator will usually afford a longer retention time because the larger single-tube vessel retains a larger volume of oil than the dual-tube separator. It is also easier to clean than the dualtube unit. In cold climates, freezing will likely cause less trouble in the monotube unit because the liquid is usually in close contact with the warm stream of gas flowing through the separator. The monotube design normally has a lower silhouette than the dual-tube unit, and it is easier to stack them for multiple-stage separation on offshore platforms where space is limited. It was illustrated by Powers *et al* (1990) that vertical separators should be constructed such that the flow stream enters near the top and passes through a gas/liquid separating chamber even though they are not competitive alternatives unlike the horizontal separators.

Classification by Function

The three configurations of separators are available for two-phase operation and three-phase operation. In the two-phase units, gas is separated from the liquid with the gas and liquid being discharged separately. Oil and gas separators are mechanically designed such that the liquid and gas components are separated from the hydrocarbon steam at specific temperature and pressure according to Arnold *et al* (2008). In three-phase separators, well fluid is separated into gas, oil, and water with the three fluids being discharged separately. The gas-liquid separation section of the separator is determined by the maximum removal droplet size using the Souders–Brown equation with an appropriate K factor. The oil-water separation section is held for a retention time that is provided by laboratory test data, pilot plant operating procedure, or operating experience. In the case where the retention time is not available, the recommended retention time for three phase separator in API 12J is used. The sizing methods by K factor and retention time give proper separator sizes. According to Song *et al* (2010), engineers sometimes need further information for the design conditions of downstream equipment, i.e., liquid loading for the mist extractor, water content for the crude dehydrator/desalter or oil content for the water treatment.

Classification by Operating Pressure

Oil and gas separators can operate at pressures ranging from a high vacuum to 4,000 to 5,000 psi. Most oil and gas separators operate in the pressure range of 20 to 1,500 psi.Separators may be referred to as low pressure, medium pressure, or high pressure. Low-pressure separators usually operate at pressures ranging from 10 to 20 up to 180 to 225 psi. Medium-pressure separators usually operate at pressures ranging from 230 to 250 up to 600 to 700 psi. High-pressure separators generally operate in the wide pressure range from 750 to 1,500 psi.

Classification by Application

Oil and gas separators may be classified according to application as test separator, production separator, low temperature separator, metering separator, elevated separator, and stage separators (first stage, second stage, etc.).

- **Test Separator:**

A test separator is used to separate and to meter the well fluids. The test separator can be referred to as a well tester or well checker. Test separators can be vertical, horizontal, or spherical. They can be two-phase or three-phase. They can be permanently installed or portable (skid or trailer mounted). Test separators can be equipped with various types of meters for measuring the oil, gas, and/or water for potential tests, periodic production tests, marginal well tests, etc.

- **Production Separator:**

A production separator is used to separate the produced well fluid from a well, group of wells, or a lease on a daily or continuous basis. Production separators can be vertical, horizontal, or spherical. They can be two phase or three phase. Production separators range in size from 12 in. to 15 ft in diameter, with most units ranging from 30 in. to 10 ft in diameter. They range in length from 6 to 70 ft, with most from 10 to 40 ft long.

- **Low-Temperature Separator:**

A low-temperature separator is a special one in which high-pressure well fluid is jetted into the vessel through a choke or pressure reducing valve so that the separator temperature is reduced appreciably below the well-fluid temperature. The temperature reduction is obtained by the Joule-Thomson effect of expanding well fluid as it flows through the pressure-reducing choke or valve into the separator. The lower operating temperature in the separator causes condensation of vapors that otherwise would exit the separator in the vapor state. Liquids thus recovered require stabilization to prevent excessive evaporation in the storage tanks.

- **Metering Separator:**

The function of separating well fluids into oil, gas, and water and metering the liquids can be accomplished in one vessel. These vessels are commonly referred to as metering separators and are available for two-phase and three-phase operation. These units are available in special models that make them suitable for accurately metering foaming and heavy viscous oil.

Primary Functions of Oil and Gas Separators

Separation of oil from gas may begin as the fluid flows through the producing formation into the wellbore and may progressively increase through the tubing, flowlines, and surface handling equipment. Under certain conditions, the fluid may be completely separated into liquid and gas before it reaches the oil and gas separator. In such cases, the separator vessel affords only an "enlargement" to permit gas to ascend to one outlet and liquid to descend to another.

Removal of Oil From Gas

Difference in density of the liquid and gaseous hydrocarbons may accomplish acceptable separation in an oil and gas separator. However, in some instances, it is necessary to use mechanical devices commonly referred to as "mist extractors" to remove liquid mist from the gas before it is discharged from the separator. Also, it may be desirable or necessary to use some means to remove nonsolution gas from the oil before the oil is discharged from the separator.

Removal of Gas From Oil

The physical and chemical characteristics of the oil and its conditions of pressure and temperature determine the amount of gas it will contain in solution. The rate at which the gas is liberated from a given oil is a function of change in pressure and temperature. The volume of gas that an oil and gas separator will remove from crude oil is dependent on (1) physical and chemical characteristics of the crude, (2) operating pressure, (3) operating temperature, (4) rate of throughput, (5) size and configuration of the separator, and (6) other factors.

Agitation, heat, special baffling, coalescing packs, and filtering materials can assist in the removal of nonsolution gas that otherwise may be retained in the oil because of the viscosity and surface tension of the oil. Gas can be removed from the top of the drum by virtue of being gas. Oil and water are separated by a baffle at the end of the separator, which is set at a height close to the oil-water contact, allowing oil to spill over onto the other side, while trapping water on the near side. The two fluids can then be piped out of the separator from their respective sides of the baffle. The produced water is then either injected back into the oil reservoir, disposed of or treated. The bulk level (gas - liquid interface) and the oil water interfaced are determined using instrumentation fixed to the vessel. Valves on the oil and water outlets are controlled to ensure the interfaces are kept at their optimum levels for separation to occur. The Separator will only achieve bulk separation. The smaller droplets of water will not settle by gravity and will remain in the oil stream. Normally the oil from the separator is routed to a coalescer to further reduce the water content.

Separation of Water From Oil

The production of water with oil continues to be a problem for engineers and the oil producers. Since 1865 when water was coproduced with hydrocarbons, it has challenged and frustrated the industry on how to separate the valuable from the disposable. According to Rehm *et al* (1983), innovation over the years has lead from the skim pit to installation of the stock tank, to the gunbarrel, to the freewater knockout, to the hay-packed coalescer and most recently to the Performax Matrix Plate Coalescer, an enhanced gravity settling separator. The history of water treating for the most part has been sketchy and spartan. There is little economic value to the produced water, and it represents an extra cost for the producer to arrange for its disposal. Today oil fields produce greater quantities of water than they produce oil. Along with greater water production are emulsions and dispersions which are more difficult to treat. The separation process becomes interlocked with a myriad of contaminants as the last drop of oil is being recovered from the reservoir. In some instances it is preferable to separate and to remove water from the well fluid before it flows through pressure reductions, such as those caused by chokes and valves. Such water removal may prevent difficulties that could be caused downstream by the water, such as corrosion which can be referred to as being a chemical reactions that occurs whenever a gas or liquid chemically attacks an exposed metallic surface. Corrosion is usually accelerated by warm temperatures and likewise by the presense of acids and salts. Other factors that affect the removal of water from oil include hydrate formation and the formation of tight emulsion that may be difficult to resolve into oil and water. The water can be separated from the oil in a three-phase separator by use of chemicals and gravity separation. If the three-phase separator is not large enough to separate the water adequately, it can be separated in a free-water knockout vessel installed upstream or downstream of the separators.

Secondary Functions of Oil and Gas Separators

Maintenance of Optimum Pressure on Separator

For an oil and gas separator to accomplish its primary functions, pressure must be maintained in the separator so that the liquid and gas can be discharged into their respective processing or gathering systems. Pressure is maintained on the separator by use of a gas backpressure valve on each separator or with one master backpressure valve that controls the pressure on a battery of two or more separators. The optimum pressure to maintain on a separator is the pressure that will result in the highest economic yield from the sale of the liquid and gaseous hydrocarbons.

Maintenance of Liquid Seal in Separator

To maintain pressure on a separator, a liquid seal must be effected in the lower portion of the vessel. This liquid seal prevents loss of gas with the oil and requires the use of a liquid-level controller and a valve.

Methods Used To Remove Oil From Gas in Separators

Effective oil-gas separation is important not only to ensure that the required export quality is achieved but also to prevent problems in downstream process equipment and compressors. Once the bulk liquid has been knocked out, which can be achieved in many ways, the remaining liquid droplets are separated from by a demisting device. Until recently the main technologies used for this application were reverse-flow cyclones, mesh pads and vane packs. More recently new devices with higher gas-handling have been developed which have enabled potential reduction in the scrubber vessel size. There are several new concepts currently under development in which the fluids are degassed upstream of the primary separator. These systems are based on centrifugal and turbine technology and have additional advantages in that they are compact and motion insensitive, hence ideal for floating production facilities. Below are some of the ways in which oil is separated from gas in separators.

Density Difference (Gravity Separation)

Natural gas is lighter than liquid hydrocarbon. Minute particles of liquid hydrocarbon that are temporarily suspended in a stream of natural gas will, by density difference or force of gravity, settle out of the stream of gas if the velocity of the gas is sufficiently slow. The larger droplets of hydrocarbon will quickly settle out of the gas, but the smaller ones will take longer. At standard conditions of pressure and temperature, the droplets of liquid hydrocarbon may have a density 400 to 1,600 times that of natural gas. However, as the operating pressure and temperature increase, the difference in density decreases. At an operating pressure of 800 psig, the liquid hydrocarbon may be only 6 to 10 times as dense as the gas. Thus, operating pressure materially affects the size of the separator and the size and type of mist extractor required to separate adequately the liquid and gas. The fact that the liquid droplets may have a density 6 to 10 times that of the gas may indicate that droplets of liquid would quickly settle out of and separate from the gas. However, this may not occur because the particles of liquid may be so small that they tend to "float" in the gas and may not settle out of the gas stream in the short period of time the gas is in the oil and gas separator. As the operating pressure on a separator increases, the density difference between the liquid and gas decreases. For this reason, it is desirable to operate oil and gas separators at as low a pressure as is consistent with other process variables, conditions, and requirements.

Impingement

If a flowing stream of gas containing liquid, mist is impinged against a surface. The liquid mist may adhere to and coalesce on the surface. After the mist coalesces into larger droplets, the droplets will gravitate to the liquid section of the vessel. If the liquid content of the gas is high, or if the mist particles are extremely fine, several successive impingement surfaces may be required to effect satisfactory removal of the mist.

Change of Flow Direction

When the direction of flow of a gas stream containing liquid mist is changed abruptly, inertia causes the liquid to continue in the original direction of flow. Separation of liquid mist from the gas thus can be effected because the gas will more readily assume the change of flow direction and will flow away from the liquid mist particles. The liquid thus removed may coalesce on a surface or fall to the liquid section below.

Change of Flow Velocity

Separation of liquid and gas can be effected with either a sudden increase or decrease in gas velocity. Both conditions use the difference in inertia of gas and liquid. With a decrease in velocity, the higher inertia of the liquid mist carries it forward and away from the gas. The liquid may then coalesce on some surface and gravitate to the liquid section of the separator. With an increase in gas velocity, the higher inertia of the liquid causes the gas to move away from the liquid, and the liquid may fall to the liquid section of the vessel.

Centrifugal Force

If a gas stream carrying liquid mist flows in a circular motion at sufficiently high velocity, centrifugal force throws the liquid mist outward against the walls of the container. Here the liquid coalesces into progressively larger droplets and finally gravitates to the liquid section below. Centrifugal force is one of the most effective methods of separating liquid mist from gas. However, according to Keplinger (1931), some separator designers have pointed out a disadvantage in that a liquid with a free surface rotating as a whole will have its surface curved around its lowest point lying on the axis of rotation. This created false level may cause difficulty in regulating the fluid level control on the separator. This is largely overcome by placing vertical quieting baffles which should extend from the bottom of the separator to above the outlet. Efficiency of this type of mist extractor increases as the velocity of the gas stream increases. Thus for a given rate of throughput, a smaller centrifugal separator will suffice.

Methods Used To Remove Gas From Oil in Separators

Because of higher prices for natural gas, the widespread reliance on metering of liquid hydrocarbons, and other reasons, it is important to remove all nonsolution gas from crude oil during field processing. Methods used to remove gas from crude oil in oil and gas separators are discussed below:

Settling

Gas contained in crude oil that is not in solution in the oil will usually separate from the oil if allowed to settle a sufficient length of time. An increase in retention time for a given liquid throughput requires an increase in the size of the vessel and/or an increase in the liquid depth in the separator. Increasing the depth of oil in the separator may not result in increased emission of nonsolution gas from the oil because “stacking up” of the oil may prevent the gas from emerging. Optimum removal of gas from the oil is usually obtained when the body of oil in the separator is thin i.e, when the ratio of surface area to retained oil volume is high.

Agitation

Moderate, controlled agitation which can be defined as movement of the crude oil with sudden force is usually helpful in removing nonsolution gas that may be mechanically locked in the oil by surface tension and oil viscosity. Agitation usually will cause the gas bubbles to coalesce and to separate from the oil in less time than would be required if agitation were not used.

Heat

Heat as a form of energy that is transferred from one body to another results in a difference in temperature . This reduces surface tension and viscosity of the oil and thus assists in releasing gas that is hydraulically retained in the oil. The most effective method of heating crude oil is to pass it through a heated-water bath. A spreader plate that disperses the oil into small streams or rivulets increases the effectiveness of the heated-water bath. Upward flow of the oil through the water bath affords slight agitation, which is helpful in coalescing and separating entrained gas from the oil. A heated-water bath is probably the most effective method of removmg foam bubbles from foaming crude oil. A heated-water bath is not practical in most oil and gas separators, but heat can be added to the oil by direct or indirect fired heaters and/or heat exchangers, or heated free-water knockouts or emulsion treaters can be used to obtain a heated-water bath.

Centrifugal Force

Centrifugal force which can be defined as a fictitious force, peculiar to a particle moving on a circular path, that has the same magnitude and dimensions as the force that keeps the particle on its circular path (the centripetal force) but points in the opposite direction is effective in separating gas from oil. The heavier oil is thrown outward against the wall of the vortex retainer while the gas occupies the inner portion of the vortex. A properly shaped and sized vortex will allow the gas to ascend while the liquid flows downward to the bottom of the unit.

Flow Measurements in Oil and Gas Separators

The direction of flow in and around a separator along with other flow instruments are usually illustrated on the Piping and instrumentation diagram, (P&ID). Some of these flow instruments include the Flow Indicator (FI), Flow Transmitter (FT) and the Flow Controller (FC). Flow is of paramount importance in the oil and gas industry because flow, as a major process variable is essentially important in that its understanding helps engineers come up with better designs and enables them to confidently carry out additional research. Mohan *et al* (1999) carried out a research into the design and development of separators for a three-phase flow system. The purpose of the study was to investigate the complex multiphase hydrodynamic flow behaviour in a three-phase oil and gas separator. A mechanistic model was developed alongside a computational fluid dynamics (CFD) simulator. These were then used to carry out a detailed experimentation on the three-phase separator. The experimental and CFD simulation results were suitably integrated with the mechanistic model. The simulation time for the experiment was 20 seconds with the oil specific gravity as 0.885, and the separator lower part length and diameter were 4-ft and 3-inches respectively. The first set of experiment became a basis through which detailed investigations were used to carry out and to conduct similar simulation studies for different flow velocities and other operating conditions as well.

Flow Calibration in Oil and Gas Separators

As earlier stated, flow instruments that function with the separator in an oil and gas environment include the flow indicator, flow transmitter and the flow controller. Due to maintenance (which will be discussed later) or due to high usuage, these flowmeters do need to be calibrated from time to time. Calibration can be defined as the process of referencing signals of known quantity that has been predetermined to suit the range of measurements required. Calibration can also be seen from a mathematical point of view in which the flowmeters are standardized by determining the deviation from the predetermined standard so as to ascertain the proper correction factors. In determining the deviation from the predetermined standard, the actual flowrate is usually first determined with **the use of a master meter** which is a type of flowmeter that has been calibrated with a high degree of accuracy or **by weighing the flow so as to be able to obtain a gravimetric reading of the mass flow**. Another type of meter used is the **transfer meter**. However, according to Ting *et al* (1989), transfer meters have been proven to be less accurate if the operating conditions are different from its original calibrated points. According to Yoder (2000) , the types of flowmeters used as **master meters** include turbine meters, positive displacement meters, venturi meters, and Coriolis meters. In the U.S., master meters are often calibrated at a flow lab that has been certified by the National Institute of Standards and Technology, (NIST). NIST certification of a flowmeter lab means that its methods have been approved by NIST. Normally, this includes NIST traceability, meaning that the standards used in the flowmeter calibration process have been certified by NIST or are causally linked back to standards that have been approved by NIST. However there is a general belief in the industry that the second method which involves the gravimetric weighing of the amount of fluid (liquid or gas) that actually flows through the meter into or out of a container during the calibration procedure is the most ideal method for measuring the actual amount of flow. Apparently, the weighing scale used for this method also has to be traceable to the National Institute of Standards and Technology (NIST) as well.. In ascertaining a proper correction factor, there is often no simple hardware adjustment to make the flowmeter start reading correctly. Instead, the deviation from the correct reading is recorded at a variety of flowrates. The data points are plotted, comparing the flowmeter output to the actual flowrate as determined by the standardized National Institute of Standards and Technology master meter or weigh scale.

Controls, Valves, Accessories, and Safety Features for Oil and Gas Separators

Controls

The controls required for oil and gas separators are liquid level controllers for oil and oil/water interface (three phase operation) and gas back-pressure control valve with pressure controller. Although the use of controls is expensive making the cost of operating fields with separators so high, installations has resulted in substantial savings in the overall operating expense as in the case of the 70 gas wells in the Big Piney, Wyo sighted by Fair (1968) . The wells with separators were located above 7,200 ft elevation, ranging upward to 9,000 ft. Control installations were sufficiently automated such that the field operations around the controllers could be operated from a remote-control station at the field office using the Distributed Control System. All in all, this improved the efficiency of personnel and the operation of the field, with a corresponding increase in production from the area.

Valves

The valves required for oil and gas separators are oil discharge control valve, water-discharge control valve (three-phase operation), drain valves, block valves, pressure relief valves, and Emergency Shutdown valves (ESD). ESD valves typically stay in open position for months or years awaiting a command signal to operate. Little attention is paid to these valves outside of scheduled turnarounds. The pressures of continuous production often stretch these intervals even longer. This leads to build up or corrosion on these valves that prevents them from moving. For safety critical applications, it must be ensured that the valves operate upon demand.

Accessories

The accessories required for oil and gas separators are pressure gauges, thermometers, pressure-reducing regulators (for control gas), level sight glasses, safety head with rupture disk, piping, and tubing.

Safety Features for Oil and Gas Separators

Oil and gas separators should be installed at a safe distance from other lease equipment. Where they are installed on offshore platforms or in close proximity to other equipment, precautions should be taken to prevent injury to personnel and damage to surrounding equipment in case the separator or its controls or accessories fail. The following safety features are recommended for most oil and gas separators.

- **High- and Low-Liquid-Level Controls:**

High- and low liquid-level controls normally are float-operated pilots that actuate a valve on the inlet to the separator, open a bypass around the separator, sound a warning alarm, or perform some other pertinent function to prevent damage that might result from high or low liquid levels in the separator.

- **High- and Low-Pressure Controls:**

High- and low pressure controls are installed on separators to prevent excessively high or low pressures from interfering with normal operations. These high- and low-pressure controls can be mechanical, pneumatic, or electric and can sound a warning, actuate a shut-in valve, open a bypass, or perform other pertinent functions to protect personnel, the separator, and surrounding equipment.

- **High- and Low-Temperature Controls:**

Temperature controls may be installed on separators to shut in the unit, to open or to close a bypass to a heater, or to sound a warning should the temperature in the separator become too high or too low. Such temperature controls are not normally used on separators, but they may be appropriate in special cases. According to Francis (1951), low-temperature controls in separators is another tools used by gas producers which finds its application in the high-pressure gas fields, usually referred to as "vapour-phase" reservoirs. Low temperatures obtainable from the expansion of these high-pressure gas streams are utilized to a profitable advantage. A more efficient recovery of the hydrocarbon condensate and a greater degree of dehydration of the gas as compared to the conventional heater and separator installation is a major advantage of low-temperature controls in oil and gas separators.

- **Safety Relief Valves:**

A spring-loaded safety relief valve is usually installed on all oil and gas separators. These valves normally are set at the design pressure of the vessel. Safety relief valves serve primarily as a warning, and in most instances are too small to handle the full rated fluid capacity of the separator. Full-capacity safety relief valves can be used and are particularly recommended when no safety head (rupture disk) is used on the separator.

- **Safety Heads or Rupture Disks:**

A safety head or rupture disk is a device contammg a thin metal membrane that is designed to rupture when the pressure in the separator exceeds a predetermined value. This is usually from 1 1/4 to 1% times the design pressure of the separator vessel. The safety head disk is usually selected so that it will not rupture until the safety relief valve has opened and is incapable of preventing excessive pressure buildup in the separator.

Operation and Maintenance Considerations for Oil and Gas Separators

Over the life of a production system, the separator is expected to process a wide range of produced fluids. With break through from water flood and expanded gas lift circulation, the produced fluid water cut and gas-oil ratio is ever changing. In many instances, the separator fluid loading may exceed the original design capacity of the vessel. As a result, many operators find their separator no longer able to meet the required oil and water effluent standards, or experience high liquid carry-over in the gas according to Power *et al* (1990) . Some operational maintenace and considerations are discussed below:

Periodic Inspection

In refineries and processing plants, it is normal practice to inspect all pressure vessels and piping periodically for corrosion and erosion. In the oil fields, this practice is not generally followed, and equipment is replaced only after actual failure. This policy may create hazardous conditions for operating personnel and surrounding equipment. It is recommended that periodic inspection schedules for all pressure equipment be established and followed to protect against undue failures.

Installation of Safety Devices

All safety relief devices should be installed as close to the vessel as possible and in such manner that the reaction force from exhausting fluids will not break off, unscrew, or otherwise dislodge the safety device. The discharge from safety devices should not endanger personnel or other equipment.

Low Temperature

Separators should be operated above hydrate-formation temperature. Otherwise hydrates may form in the vessel and partially or completely plug it thereby reducing the capacity of the separator. In some instances when the liquid or gas outlet is plugged or restricted, this causes the safety valve to open or the safety head to rupture. Steam coils can be installed in the liquid section of oil and gas separators to melt hydrates that may form there. This is especially appropriate on low-temperature separators.

Corrosive Fluids

A separator handling corrosive fluid should be checked periodically to determine whether remedial work is required. Extreme cases of corrosion may require a reduction in the rated working pressure of the vessel. Periodic hydrostatic testing is recommended, especially if the fluids being handled are corrosive. Expendable anode can be used in separators to protect them against electrolytic corrosion. Some operators determine separator shell and head thickness with ultrasonic thickness indicators and calculate the maximum allowable working pressure from the remaining metal thickness. This should be done yearly offshore and every two to four years onshore.

Chapter 14

Shale Oil Extraction

Shale oil extraction

Shell's experimental *in situ* shale oil facility, Piceance Basin, Colorado, United States

Process type	Chemical
Industrial sector(s)	Chemical industry, oil industry
Main technologies or sub-processes	Kiviter, Galoter, Petrosix, Fushun, Shell ICP
Feedstock	Oil shale
Product(s)	Shale oil
Leading companies	Royal Dutch Shell, Eesti Energia, Viru Keemia Grupp, Petrobras, Fushun Mining Group
Main facilities	Fushun Shale Oil Plant, Narva Oil Plant, Petrosix, Stuart Shale Oil Plant

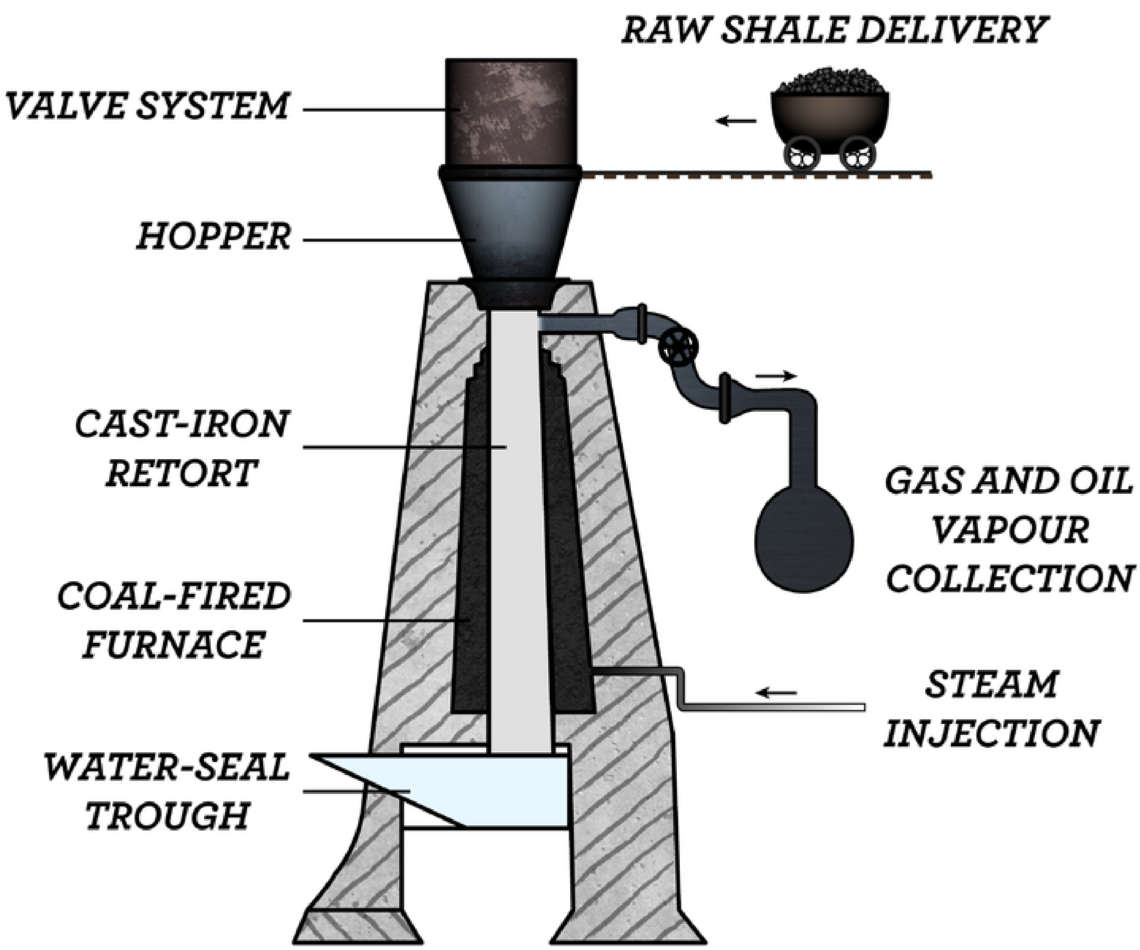
Shale oil extraction is an industrial process for unconventional oil production. This process converts kerogen in oil shale into shale oil by pyrolysis, hydrogenation, or thermal dissolution. The resultant shale oil is used as fuel oil or upgraded to meet refinery feedstock specifications by adding hydrogen and removing sulfur and nitrogen impurities.

Shale oil extraction is usually performed above ground (*ex situ* processing) by mining the oil shale and then treating it in processing facilities. Other modern technologies perform the processing underground (on-site or *in situ* processing) by applying heat and extracting the oil via oil wells.

The earliest description of the process dates to the 10th century. In 1684, Great Britain granted the first formal extraction process patent. Extraction industries and innovations became widespread during the 19th century. The industry shrank in the mid-20th century following the discovery of large reserves of conventional oil, but high petroleum prices at the beginning of the 21st century have led to renewed interest, accompanied by the development and testing of newer technologies.

As of 2010, major long-standing extraction industries are operating in Estonia, Brazil, and China. Its economic viability usually requires a lack of locally available crude oil. National energy security issues have also played a role in its development. Critics of shale oil extraction pose questions about environmental management issues, such as waste disposal, extensive water use, waste water management, and air pollution.

History



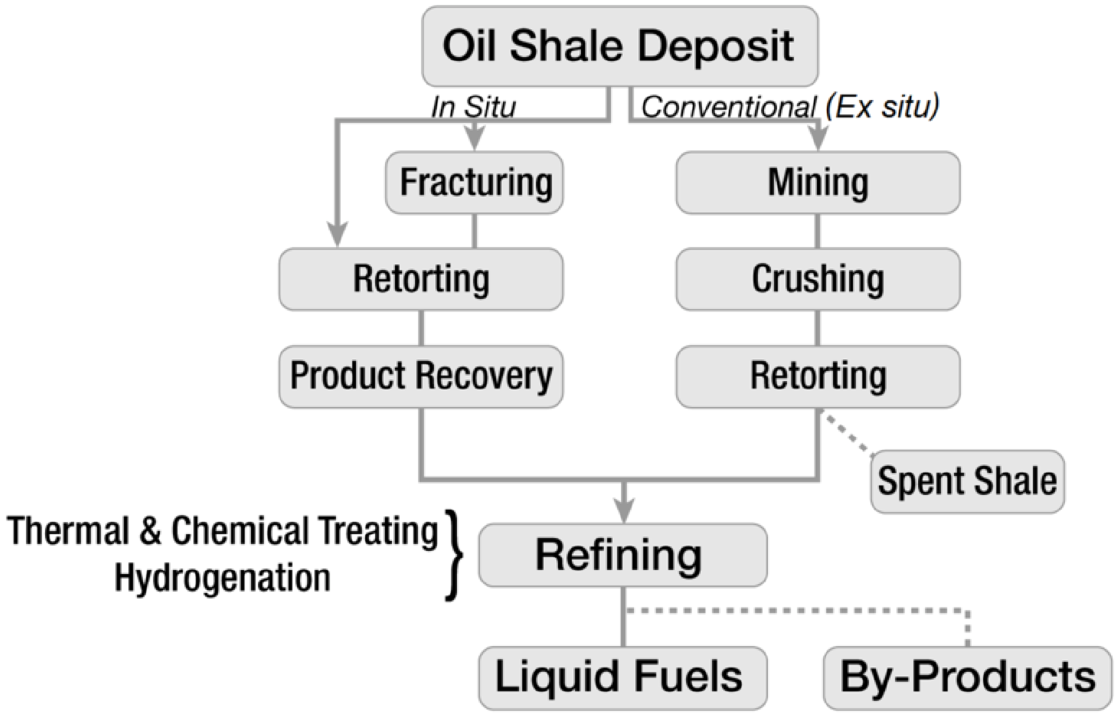
A.C. Kirk's retort, used in the mid-to-late 19th century, was one of the first vertical oil shale retorts. Its design is typical of retorts used in the end of 19th and beginning of 20th century.

In the 10th century, the Arabian physician Masawaih al-Mardini (Mesue the Younger) wrote of his experiments in extracting oil from "some kind of bituminous shale". The first shale oil extraction patent was granted by the British Crown in 1684 to three people who had "found a way to extract and make great quantities of pitch, tarr, and oyle out of a sort of stone". Modern industrial extraction of shale oil originated in France with the implementation of a process invented by Alexander Selligue in 1838, improved upon a decade later in Scotland using a process invented by James Young. During the late 19th century, plants were built in Australia, Brazil, Canada, and the United States. The 1894 invention of the Pumpherston retort, which was much less reliant on coal heat than its predecessors, marked the separation of the oil shale industry from the coal industry.

China (Manchuria), Estonia, New Zealand, South Africa, Spain, Sweden, and Switzerland began extracting shale oil in the early 20th century. However, crude oil discoveries in Texas during the 1920s and in the Middle East in the mid 20th century brought most oil shale industries to a halt. In 1944, the US recommenced shale oil extraction as part of its Synthetic Liquid Fuels Program. These industries continued until oil prices fell sharply in the 1980s. The last oil shale retort in the US, operated by Unocal Corporation, closed in 1991. The US program was restarted in 2003, followed by a commercial leasing program in 2005 permitting the extraction of oil shale and oil sands on federal lands in accordance with the Energy Policy Act of 2005.

As of 2010, shale oil extraction is in operation in Estonia, Brazil, and China. Their industries produced about 1,165 million liters (7.33 million barrels) of shale oil during 2008. Australia, the US, and Canada have tested shale oil extraction techniques via demonstration projects and are planning commercial implementation; Morocco and Jordan have announced their intent to do the same. Only four processes are in commercial use: Kiviter, Galoter, Fushun, and Petrosix.

Process principle



Overview of shale oil extraction

Shale oil extraction process decomposes oil shale and converts its kerogen into shale oil—a petroleum-like synthetic crude oil. The process is conducted by pyrolysis, hydrogenation, or thermal dissolution. The efficiencies of extraction processes are often evaluated by comparing their yields to the results of a Fischer Assay performed on a sample of the shale.

The oldest and the most common extraction method involves pyrolysis (also known as *retorting* or destructive distillation). In this process, oil shale is heated in the absence of oxygen until its kerogen decomposes into condensable shale oil vapors and non-condensable combustible oil shale gas. Oil vapors and oil shale gas are then collected and cooled, causing the shale oil to condense. In addition, oil shale processing produces spent oil shale, which is a solid residue. Spent shale consists of inorganic compounds (minerals) and char (some authors use the terms *coke residue* or *semi-coke* instead of *char*)—a carbonaceous residue formed from kerogen. Burning the char off the spent shale produces oil shale ash. Spent shale and shale ash can be used as ingredients in cement or brick manufacture. The composition of the oil shale may lend added value to the extraction process through the recovery of by-products, including ammonia, sulfur, aromatic compounds, pitch, asphalt, and waxes.

Heating the oil shale to pyrolysis temperature and completing the endothermic kerogen decomposition reactions require a source of energy. Some technologies use other fossil fuels such as natural gas, oil, or coal to generate this heat and experimental methods have used electricity, radio waves, microwaves, or reactive fluids for this purpose. Two strategies are used to reduce, and even eliminate, external heat energy requirements: the oil shale gas and char by-products generated by pyrolysis may be burned as a source of energy, and the heat contained in hot spent oil shale and oil shale ash may be used to pre-heat the raw oil shale.

For *ex situ* processing, oil shale is crushed into smaller pieces, increasing surface area for better extraction. The temperature at which decomposition of oil shale occurs depends on the time-scale of the process. In *ex situ* retorting processes, it begins at 300 °C (570 °F) and proceeds more rapidly and completely at higher temperatures. The amount of oil produced is the highest when the temperature ranges between 480 and 520 °C (900 and 970 °F). The ratio of oil shale gas to shale oil generally increases along with retorting temperatures. For a modern *in situ* process, which might take several months of heating, decomposition may be conducted at temperatures as low as 250 °C (480 °F). Temperatures below 600 °C (1,110 °F) are preferable, as this prevents the decomposition of lime stone and dolomite in the rock and thereby limits carbon dioxide emissions and energy consumption.

Hydrogenation and thermal dissolution (reactive fluid processes) extract the oil using hydrogen donors, solvents, or a combination of these. Thermal dissolution involves the application of solvents at elevated temperatures and pressures, increasing oil output by cracking the dissolved organic matter. Different methods produce shale oil with different properties.

Classification of extraction technologies

Industry analysts have created several classifications of the technologies used to extract shale oil from oil shale.

By process principles: Based on the treatment of raw oil shale by heat and solvents the methods are classified as pyrolysis, hydrogenation, or thermal dissolution.

By location: A frequently used distinction considers whether processing is done above or below ground, and classifies the technologies broadly as *ex situ* (displaced) or *in situ* (in place). In *ex situ* processing, also known as above-ground retorting, the oil shale is mined either underground or at the surface and then transported to a processing facility. In contrast, *in situ* processing converts the kerogen while it is still in the form of an oil shale deposit, following which it is then extracted via oil wells, where it rises in the same way as conventional crude oil. Unlike *ex situ* processing, it does not involve mining or spent oil shale disposal aboveground as spent oil shale stays underground.

By heating method: The method of transfering heat from combustion products to the oil shale may be classified as direct or indirect. While methods that allow combustion products to contact the oil shale within the retort are classified as *direct*, methods that burn materials external to the retort to heat another material that contacts the oil shale are described as *indirect*

By heat carrier: Based on the material used to deliver heat energy to the oil shale, processing technologies have been classified into gas heat carrier, solid heat carrier, wall conduction, reactive fluid, and volumetric heating methods. Heat carrier methods can be sub-classified as direct or indirect.

The following table shows extraction technologies classified by heating method, heat carrier and location (*in situ* or *ex situ*).

Classification of processing technologies by heating method and location (according to Alan Burnham)

Heating Method	Above ground (*ex situ*)	Underground (*in situ*)
Internal combustion	Gas combustion, NTU, Kiviter, Fushun, Union A, Paraho Direct, Superior Direct	Occidental Petroleum MIS, LLNL RISE, Geokinetics Horizontal, Rio Blanco
Hot recycled solids (inert or burned shale)	Alberta Taciuk, Galoter, Enefit, Lurgi-Ruhrgas, TOSCO II, Chevron STB, LLNL HRS, Shell Spher, KENTORT II	–
Conduction through a wall (various fuels)	Pumpherston, Hom Tov, Fischer Assay, Oil-Tech, EcoShale In-Capsule, Combustion Resources	Shell ICP (primary method), American Shale Oil CCR, IEP Geothermic Fuel Cell
Externally generated hot gas	PetroSIX, Union B, Paraho Indirect, Superior Indirect, Syntec (Smith process)	Chevron CRUSH, Omnishale, MWE IGE
Reactive fluids	IGT Hytort (high-pressure H_2), donor solvent processes, Chattanooga fluidized bed reactor	Shell ICP (some embodiments)
Volumetric heating	–	Radio wave, microwave, and electric current processes

By raw oil shale particle size: The various *ex situ* processing technologies may be differentiated by the size of the oil shale particles that are fed into the retorts. As a rule, gas heat carrier technologies process oil shale lumps varying in diameter from 10 to 100 millimeters (0.4 to 3.9 in), while solid heat carrier and wall conduction technologies process fines which are particles less than 10 millimeters (0.4 in) in diameter.

By retort orientation: "Ex-situ" technologies are sometimes classified as vertical or horizontal. Vertical retorts are usually shaft kilns where a bed of shale moves from top to bottom by gravity. Horizontal retorts are usually horizontal rotating drums or screws where shale moves from one end to the other. As a general rule, vertical retorts process lumps using a gas heat carrier, while horizontal retorts process fines using solid heat carrier.

By complexity of technology: *In situ* technologies are usually classified either as *true in situ* processes or *modified in situ* processes. *True in situ* processes do not involve mining or crushing the oil shale. *Modified in situ* processes involve drilling and fracturing the target oil shale deposit to create voids in the deposit. The voids enable a better flow of gases and fluids through the deposit, thereby increasing the volume and quality of the shale oil produced.

Ex situ *technologies*

Internal combustion

Internal combustion technologies burn materials (typically char and oil shale gas) within a vertical shaft retort to supply heat for pyrolysis. Typically raw oil shale particles between 12 millimetres (0.5 in) and 75 millimetres (3.0 in) in size are fed into the top of the retort and are heated by the rising hot gases, which pass through the descending oil shale, thereby causing decomposition of the kerogen at about 500 °C (932 °F) . Shale oil mist, evolved gases and cooled combustion gases are removed from the top of the retort then moved to separation equipment. Condensed shale oil is collected, while non-condensable gas is recycled and used to carry heat up the retort. In the lower part of the retort, air is injected for the combustion which heats the spent oil shale and gases to between 700 °C (1,292 °F) and 900 °C (1,650 °F). Cold recycled gas may enter the bottom of the retort to cool the shale ash. The Union A and Superior Direct processes depart from this pattern. In the Union A process, oil shale is fed through the bottom of the retort and a pump moves it upward. In the Superior Direct process, oil shale is processed in a horizontal, segmented, doughnut-shaped traveling-grate retort.

Internal combustion technologies such as the Paraho Direct are thermally efficient, since combustion of char on the spent shale and heat recovered from the shale ash and evolved gases can provide all the heat requirements of the retort. These technologies can achieve 80-90% of Fischer assay yield. Two well-established shale oil industries use internal combustion technologies: Kiviter process facilities have been operated continuously in Estonia since the 1920s, and a number of Chinese companies operate Fushun process facilities.

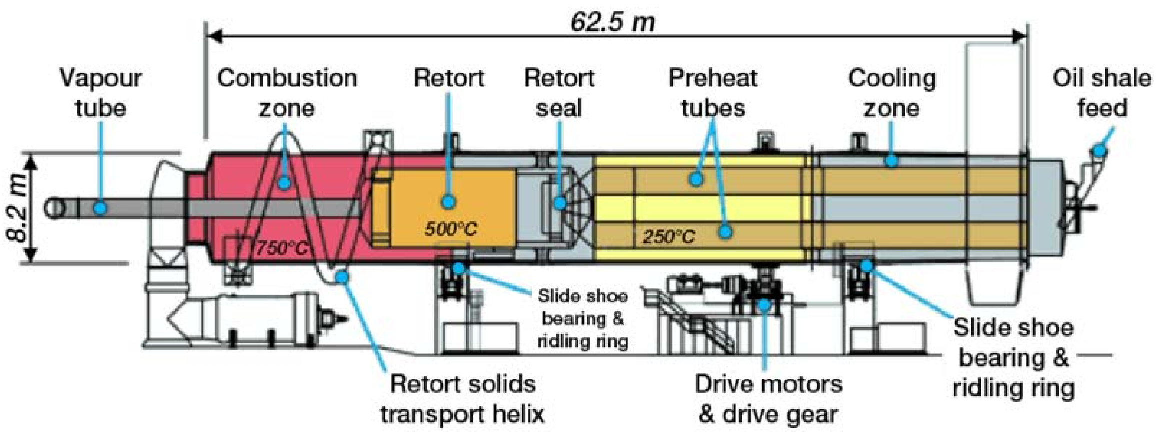
Common drawbacks of internal combustion technologies are that the shale oil gas is diluted by combustion gases and particles smaller than 10 millimeters (0.4 in) can not be processed. Uneven distribution of gas across the retort can result in blockages when hot spots cause particles to fuse or disintegrate.

Hot recycled solids

Hot recycled solids technologies deliver heat to the oil shale by recycling hot solid particles—typically oil shale ash. These technologies usually employ rotating kiln retorts, fed by fine oil shale particles generally having a diameter of less than 10 millimeters (0.4 in); some technologies use particles even smaller than 2.5 millimeters (0.10 in). The recycled particles are heated in a separate chamber or vessel to about 800 °C (1,470 °F) and then mixed with the raw oil shale to cause the shale to decompose at about 500 °C (932 °F). Oil vapour and shale oil gas are separated from the solids and cooled to condense and collect the oil. Heat recovered from the combustion gases and shale ash may be used to dry and preheat the raw oil shale before it is mixed with the hot recycle solids.

In the Galoter and Enefit processes, the spent oil shale is burnt in a separate furnace and the resulting hot ash is separated from the combustion gas and mixed with oil shale particles in a rotating kiln. Combustion gases from the furnace are used to dry the oil shale in a dryer before mixing with hot ash. The TOSCO II process uses ceramic balls instead of shale ash as the hot recycled solids. The distinguishing feature of the Alberta Taciuk Process (ATP) is that the entire process occurs in a single rotating multi–chamber horizontal vessel.

Because the hot recycle solids are heated in a separate furnace, the oil shale gas from these technologies is not diluted with combustion exhaust gas. Another advantage is that there is no limit on the smallest particles that the retort can process, thus allowing all the crushed feed to be used. One disadvantge is that more water is used to handle the resulting finer shale ash.



Alberta Taciuk Processor retort

Conduction through a wall

These technologies transfer heat to the oil shale by conducting it through the retort wall. The shale feed usually consists of fine particles. Their advantage lies in the fact that retort vapors are not combined with combustion exhaust. The Combustion Resources process uses a hydrogen–fired rotating kiln, where hot gas is circulated through an outer annulus. The Oil-Tech staged electrically heated retort consists of individual inter-connected heating chambers, stacked atop each other. Its principal advantage lies in its modular design, which enhances its portability and adaptability. The Red Leaf Resources EcoShale In-Capsule Process combines surface mining with a lower-temperature heating method similar to *in situ* processes by operating within the confines of an earthen structure. A hot gas circulated through parallel pipes heats the oil shale rubble. An installation within the empty space created by mining would permit rapid reclamation of the topography. A general drawback of combustion through a wall technologies is that the retorts are more costly when scaled-up due to the large amount of wall surface area of high-temperature alloys required.

Externally generated hot gas

In general, externally generated hot gas technologies are similar to internal combustion technologies in that they also process oil shale lumps in vertical shaft kilns. Significantly, though, the heat in these technologies is delivered by gases heated outside the retort vessel, and therefore the retort vapors are not diluted with combustion exhaust. The Petrosix and Paraho Indirect employ this technology. In addition to not accepting fine particles as feed, these technologies do not utilize the potential heat of combusting the char on the spent shale and thus must burn more valuable fuels. However, due to the lack of combustion of the spent shale, the oil shale does not exceed 500 °C (932 °F) and significant carbonate mineral decomposition and subsequent CO_2 generation can be avoided for some oil shales. Also, these technologies tend to be the more stable and easier to control than internal combustion or hot solid recyle technologies.

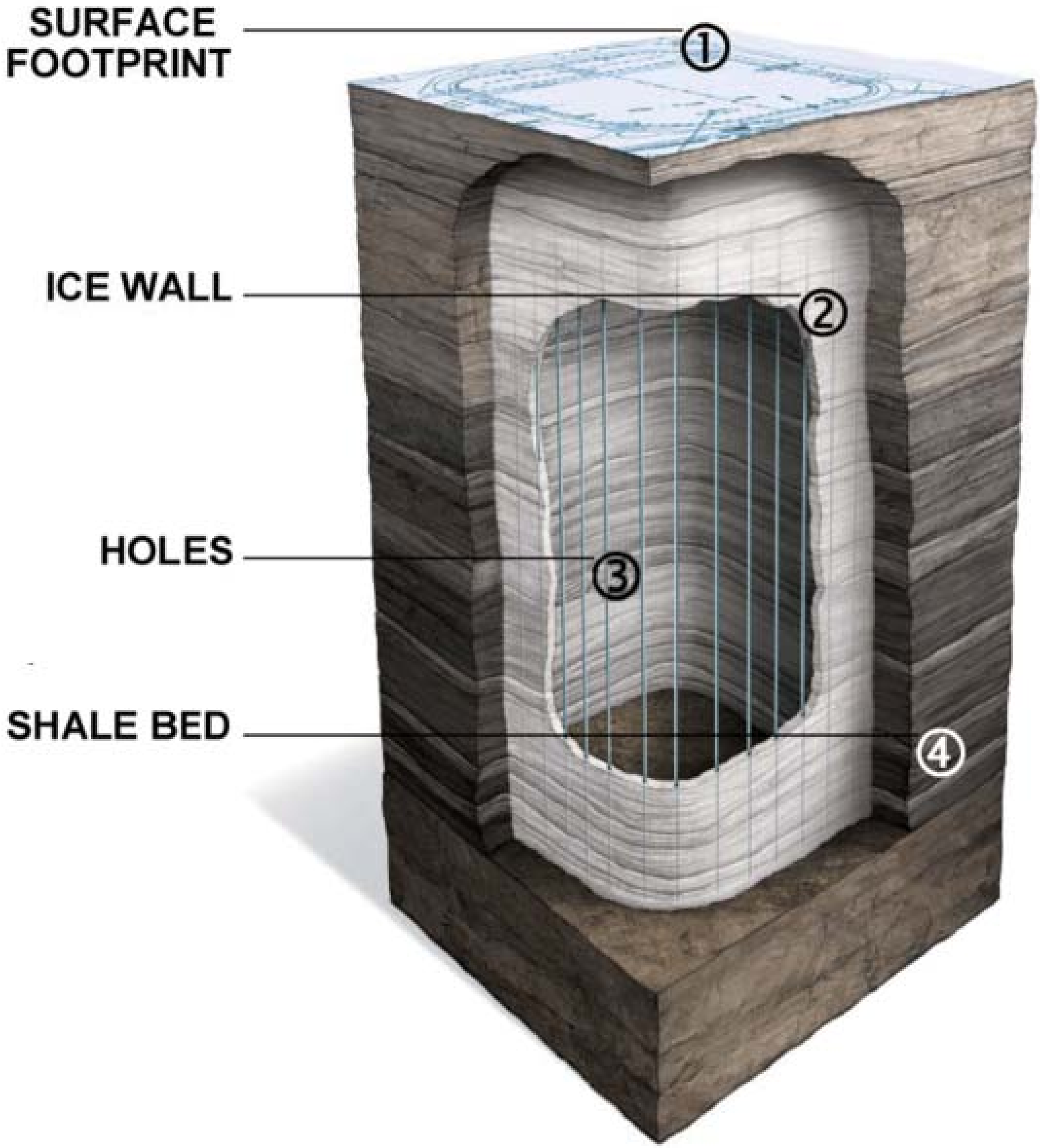
Reactive fluids

Kerogen is tightly bound to the shale and resists dissolution by most solvents. Despite this constraint, extraction using especially reactive fluids has been tested, including those in a supercritical state. Reactive fluid technologies are suitable for processing oil shales with a low hydrogen content. In these technologies, hydrogen gas (H_2) or hydrogen donors (chemicals that donate hydrogen during chemical reactions) react with coke precursors (chemical structures in the oil shale that are prone to form char during retorting but have not yet done so). Reactive fluid technologies include the IGT Hytort (high-pressure H_2) process, donor solvent processes, and the Chattanooga fluidized bed reactor. In the IGT Hytort oil shale is processed in a high-pressure hydrogen environment. The Chattanooga process uses a fluidized bed reactor and an associated hydrogen-fired heater for oil shale thermal cracking and hydrogenation.

In situ *technologies*

In situ technologies heat oil shale underground by injecting hot fluids into the rock formation, or by using linear or planar heating sources followed by thermal conduction and convection to distribute heat through the target area. Shale oil is then recovered through vertical wells drilled into the formation. These technologies are potentially able to extract more shale oil from a given area of land than conventional *ex situ* processing technologies, as the wells can reach greater depths than surface mines. They present an opportunity to recover shale oil from low-grade deposits that traditional mining techniques could not extract.

During World War II a modified *in situ* extraction process was implemented without significant success in Germany. One of the earliest successful *in situ* processes was underground gasification by electrical energy (Ljungström method)—a process exploited between 1940 and 1966 for shale oil extraction at Kvarntorp in Sweden. Prior to the 1980s, many variations of the *in situ* process were explored in the United States. The first modified *in situ* oil shale experiment in the United States was conducted by Occidental Petroleum in 1972 at Logan Wash, Colorado. The newest technologies explore a variety of heat sources and heat delivery systems.

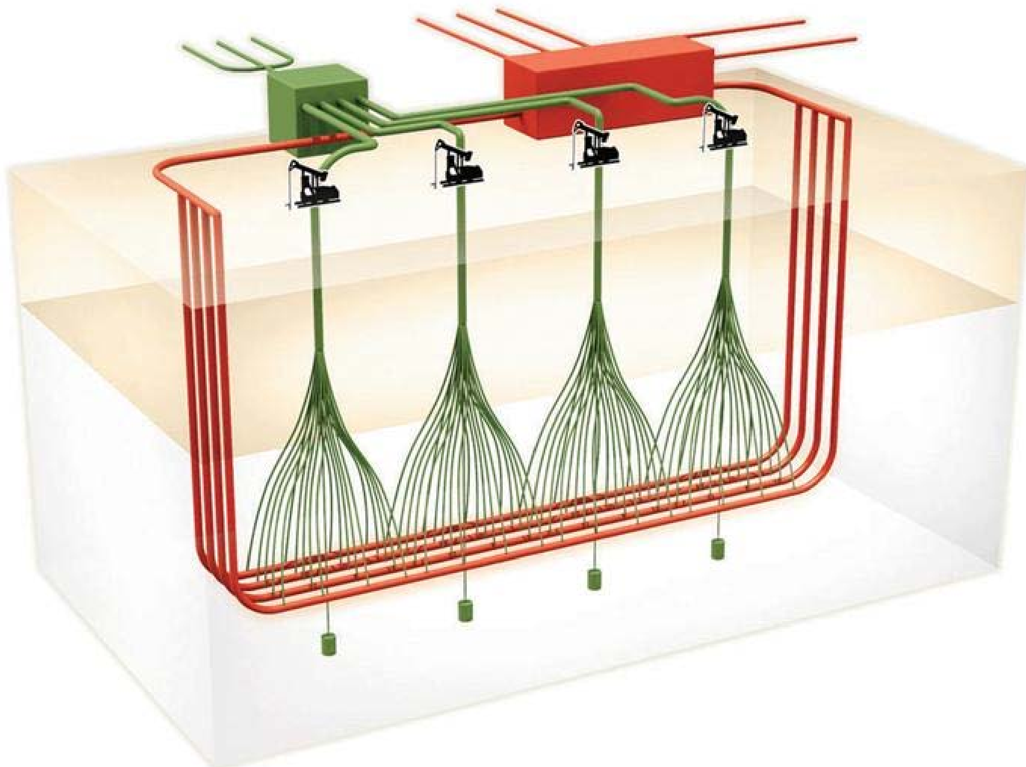


Shell's freeze wall for *in situ* shale oil production was designed to separate the process from its surroundings

Wall conduction

Wall conduction *in situ* technologies use heating elements or heating pipes placed within the oil shale formation. The Shell in situ conversion process (Shell ICP) uses electrical heating elements for heating the oil shale layer to between 650 and 700 °F (340 and 370 °C) over a period of approximately four years. The processing area is isolated from surrounding groundwater by a freeze wall consisting of wells filled with a circulating super-chilled fluid. Disadvantages of this process are large electrical power consumption, extensive water use, and the risk of groundwater pollution. The process, under development since the early 1980s, is tested at the Mahogany test site in the Piceance

Basin. 1,700 barrels (270 m^3) of oil were extracted in 2004 at a 30-by-40-foot (9.1 by 12 m) testing area.

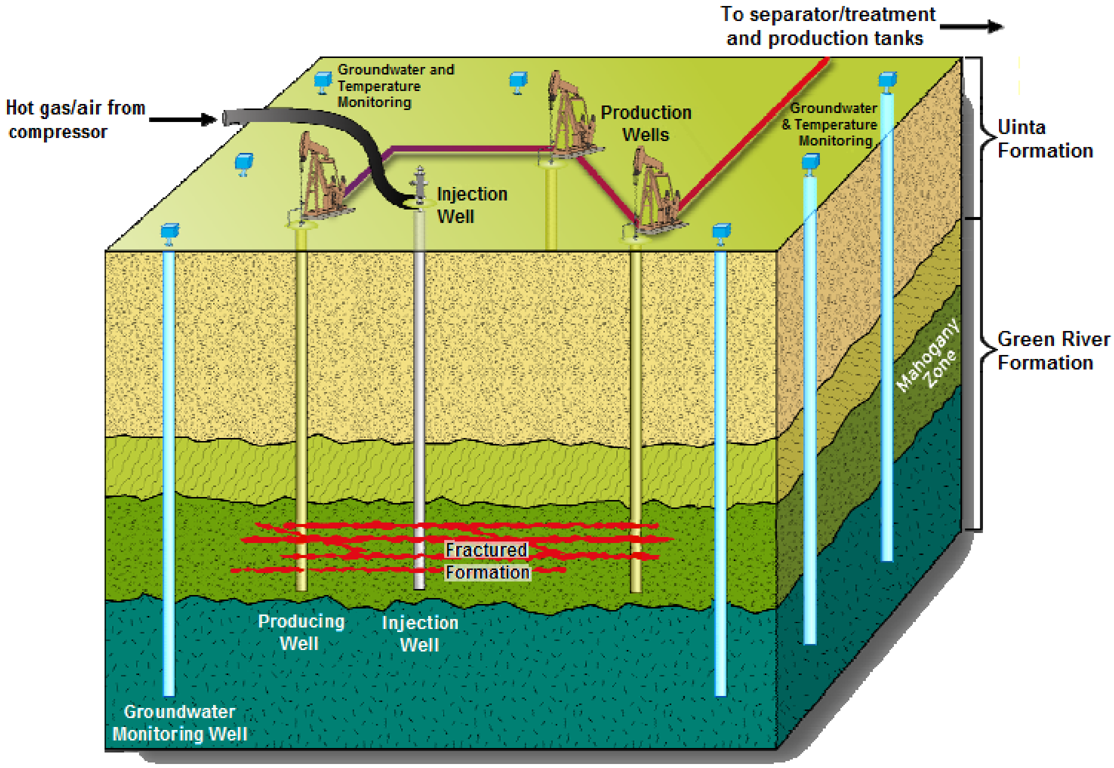


American Shale Oil CCR Process

In the American Shale Oil CCR Process, superheated steam or another heat transfer medium is circulated through a series of pipes placed below the oil shale layer to be extracted. The system combines horizontal wells, through which steam is passed, and vertical wells, which provide both vertical heat transfer through refluxing of converted shale oil and a means to collect the produced hydrocarbons. Heat is supplied by combustion of natural gas or propane in the initial phase and by oil shale gas at a later stage.

The Independent Energy Partners' Geothermic Fuels Cells Process (IEP GFC) extracts shale oil by exploiting a high-temperature stack of fuel cells. The cells, placed in the oil shale formation, are fueled by natural gas during a warm-up period and afterward by oil shale gas generated by its own waste heat.

Externally generated hot gas



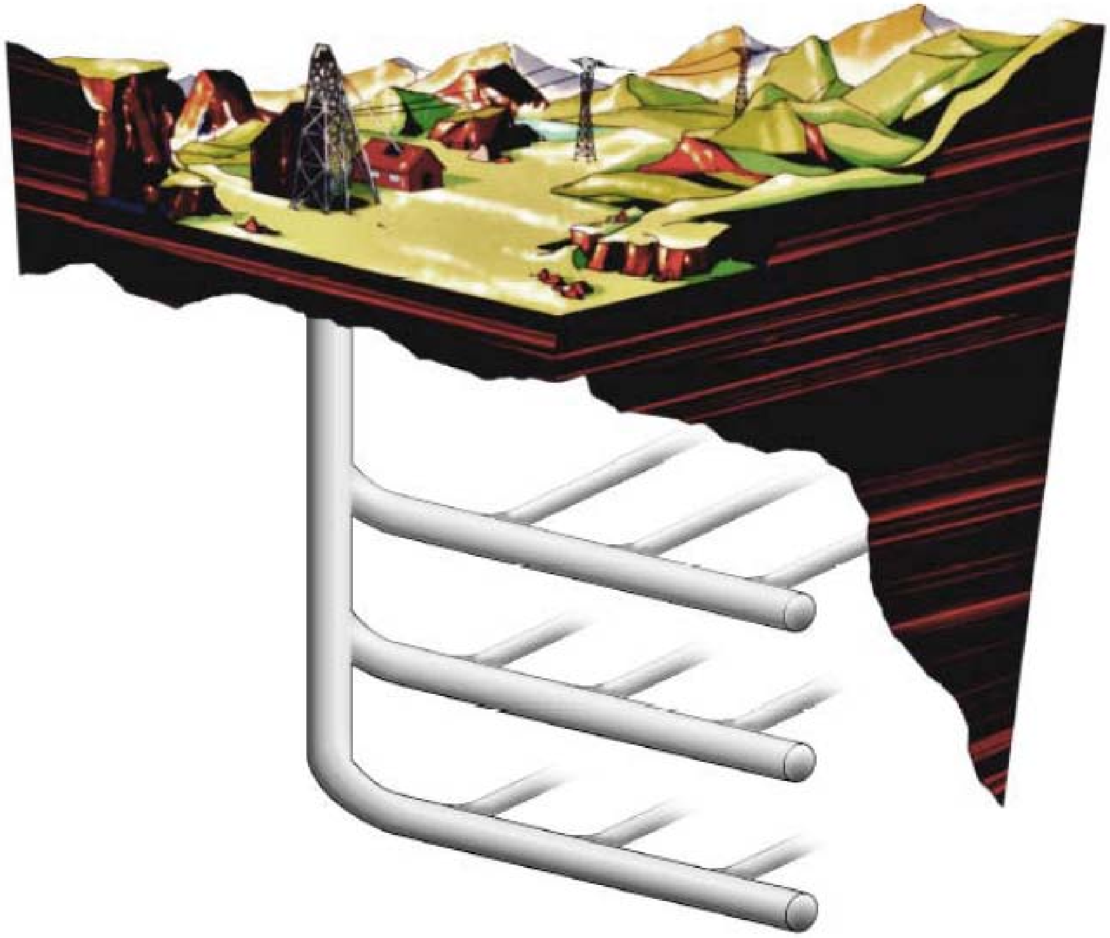
Chevron CRUSH process

Externally generated hot gas *in situ* technologies use hot gases that are heated above-ground and then injected into the oil shale formation. The Chevron CRUSH process, developed by Chevron Corporation in partnership with Los Alamos National Laboratory, injects heated carbon dioxide into the formation via drilled wells and heats the formation through a series of horizontal fractures in which the gas circulates. General Synfuels International has proposed the Omnishale process which involves injecting super-heated air into the oil shale formation. Mountain West Energy's In Situ Vapor Extraction process uses similar principles of injection of high-temperature gas.

ExxonMobil Electrofrac

ExxonMobil's *in situ* technology (ExxonMobil Electrofrac) uses electrical heating with elements of both wall conduction and volumetric heating methods. It injects an electrically conductive material such as calcined petroleum coke into the hydraulic fractures created in the oil shale formation which then forms a heating element. Heating wells are placed in a parallel row with a second horizontal well intersecting them at their toe. This allows opposing electrical charges to be applied at either end.

Volumetric heating

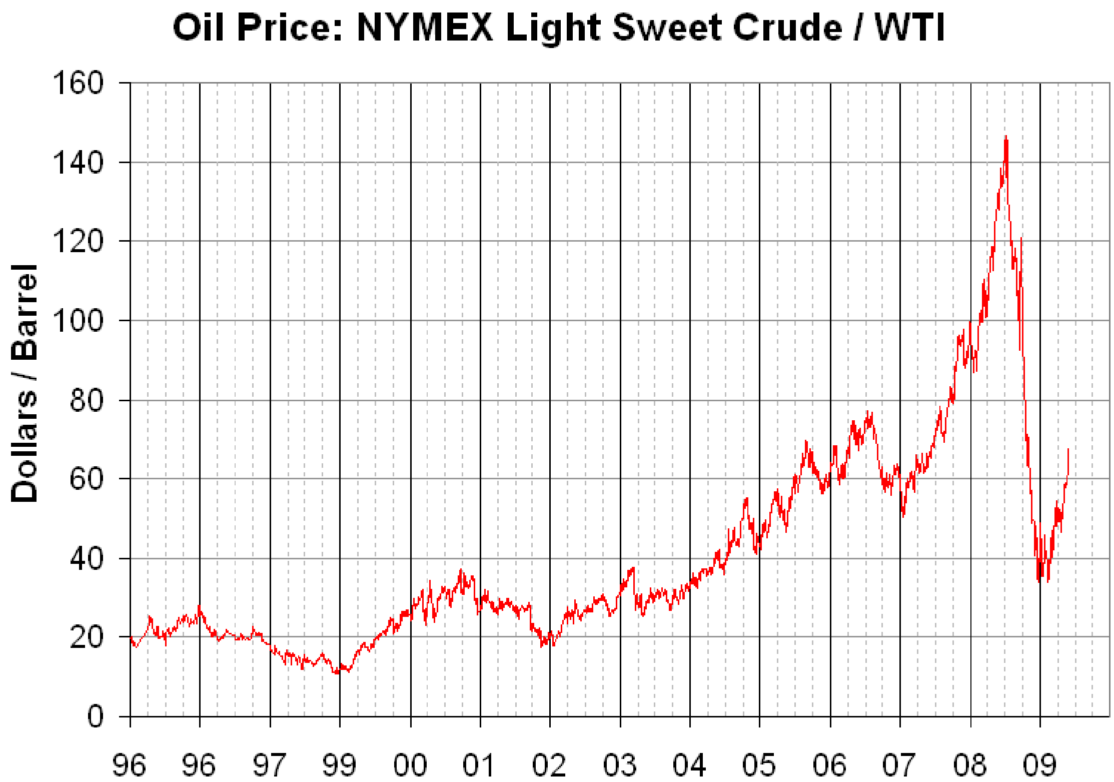


Artist's rendition of a radio wave-based extraction facility

The Illinois Institute of Technology developed the concept of oil shale volumetric heating using radio waves (radio frequency processing) during the late 1970s. This technology was further developed by Lawrence Livermore National Laboratory. The oil shale would be heated by vertical electrode arrays. Deeper volumes could be processed at slower heating rates by installations spaced at tens of meters. The concept presumes a radio frequency at which the skin depth is many tens of meters, thereby overcoming the thermal diffusion times needed for conductive heating. Its drawbacks include intensive electrical demand and the possibility that groundwater or char would absorb undue amounts of the energy. Radio frequency processing in conjunction with critical fluids is being developed by Raytheon together with CF Technologies and tested by Schlumberger.

Microwave heating technologies are based on the same principles as radio wave heating, although it is believed that radio wave heating is an improvement over microwave heating because its energy can penetrate farther into the oil shale formation. The microwave heating process is being tested by Global Resource Corporation. Electro-Petroleum proposes electrically enhanced oil recovery by the passage of direct current between cathodes in producing wells and anodes located either at the surface or at depth in other wells. The passage of the current through the oil shale formation results in resistive Joule heating.

Economics



NYMEX light-sweet crude oil prices 1996–2009 (not adjusted for inflation)

The dominant question for shale oil production is under what conditions shale oil is economically viable. The various attempts to develop oil shale deposits have succeeded only when the shale-oil production cost in a given region is lower than the price of petroleum or its other substitutes. According to a survey conducted by the RAND Corporation, the cost of producing shale oil at a hypothetical surface retorting complex in the United States (comprising a mine, retorting plant, upgrading plant, supporting utilities, and spent oil shale reclamation), would be in a range of US\$70–95 per barrel (\$440–600/m^3), adjusted to 2005 values. Assuming a gradual increase in output after the start of commercial production, the analysis projects a gradual reduction in processing costs to \$30–40 per barrel (\$190–250/m^3) after achieving the milestone of 1 billion barrels (160×10^6 m^3). Royal Dutch Shell has announced that its Shell ICP technology would realize a profit when crude oil prices are higher than \$30 per barrel (\$190/m^3), while some technologies at full-scale production assert profitability at oil prices even lower than \$20 per barrel (\$130/m^3).

To increase the efficiency of oil shale retorting and by this the viability of the shale oil production, researchers have proposed and tested several co-pyrolysis processes, in which other materials such as biomass, peat, waste bitumen, or rubber and plastic wastes are retorted along with the oil shale. Some modified technologies propose combining a fluidized bed retort with a circulated fluidized bed furnace for burning the by-products of pyrolysis (char and oil shale gas) and thereby improving oil yield, increasing throughput, and decreasing retorting time.

Other ways of improving the economics of shale oil extraction are to increase the size of the operation to achieve economies of scale, use oil shale that is a by-product of coal mining such as at Fushun China, produce specialty chemicals as by Viru Keemia Grupp in Estonia, co-generate electricity from the waste heat and process high grade oil shale that yields more oil per shale processed.

A possible measure of the viability of oil shale as an energy source lies in the ratio of the energy in the extracted oil to the energy used in its mining and processing (Energy Returned on Energy Invested, or EROEI). A 1984 study estimated the EROEI of the various known oil shale deposits as varying between 0.7–13.3; Some companies and newer technologies assert an EROEI between 3 and 10. To increase the EROEI, several combined technologies were proposed. These include the usage of process waste heat, e.g. gasification or combustion of the residual carbon (char), and the usage of waste heat from other industrial processes, such as coal gasification and nuclear power generation.

The water requirements of extraction processes are an additional economic consideration in regions where water is a scarce resource.

Environmental considerations

Objections to its potential environmental impact have stalled governmental support for extraction of shale oil in some countries, such as Australia. Shale oil extraction may involve a number of different environmental impacts that vary with process technologies. Depending on the geological conditions and mining techniques, mining impacts may include acid drainage induced by the sudden rapid exposure and subsequent oxidation of formerly buried materials, the introduction of metals into surface water and groundwater, increased erosion, sulfur gas emissions, and air pollution caused by the production of particulates during processing, transport, and support activities. Surface mining for *ex situ* processing, as with *in situ* processing, requires extensive land use and *ex situ* thermal processing generates wastes that require disposal. Mining, processing, spent oil shale disposal, and waste treatment require land to be withdrawn from traditional uses. Depending on the processing technology, the waste material may contain pollutants including sulfates, heavy metals, and polycyclic aromatic hydrocarbons, some of which are toxic and carcinogenic. Experimental *in situ* conversion processes may reduce some of these impacts, but may instead cause other problems, such as groundwater pollution.

Spent shale often presents a disposal problem

The production and usage of oil shale usually generates more greenhouse gas emissions, including carbon dioxide, than conventional fossil fuels. Depending on the technology and the oil shale composition, shale oil extraction processes may also emit sulfur dioxide, hydrogen sulfide, carbonyl sulfide, and nitrogen oxides. Developing carbon capture and storage technologies may reduce the processes' carbon footprint.

Concerns have been raised over the oil shale industry's use of water, particularly in arid regions where water consumption is a sensitive issue. Above-ground retorting typically consumes between one and five barrels of water per barrel of produced shale oil, depending on technology. Water is usually used for spent oil shale cooling and oil shale ash disposal. *In situ* processing, according to one estimate, uses about one-tenth as much water. In other areas, water must be pumped out of oil shale mines. The resulting fall in the water table may have negative effects on nearby arable land and forests.

A 2008 programmatic environmental impact statement issued by the United States Bureau of Land Management stated that surface mining and retort operations produce 2 to 10 U.S. gallons (7.6 to 38 l; 1.7 to 8.3 imp gal) of waste water per 1 short ton (0.91 t) of processed oil shale.