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Oil and gas production handbook

An introduction to oil and gas production

ISBN 978-82-997886-2-5

PREFACE

This handbook has been compiled for readers with an interest in the oil and gas industry. It is an overview of the main processes and equipment. When we searched for a suitable introduction to be used for new engineers, I discovered that much of the equipment is described in standards, equipment manuals and project documentation. But little material was found to quickly give the reader an overview of the entire upstream area, whilst still preserving enough detail to let the engineer have an appreciation of the main characteristics and design issues.

This book is by no means a complete description on the detailed design of any part of this process, and many details have been omitted in order to summarize a vast subject.

The material has been compiled from various online resources as well as ABB and customer documents. I am grateful to my colleagues in the industry for providing their valuable input and comments. I have included many photos to give you, the reader an impression what typical facilities or equipment look like. Non-ABB photo sources are given below pictures, other pictures and illustrations are copyright ABB

Edition 2.3 Oslo, April 2010
Håvard Devold

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1 Introduction

Oil has been used for lighting purposes for many thousands of years. In areas where oil is found in shallow reservoirs, seeps of crude oil or gas may naturally develop, and some oil could simply be collected from seepage or tar ponds.

Historically, we know of the tales of eternal fires where oil and gas seeps would ignite and burn. One example from is the site where the famous oracle of Delphi was built around 1000 B.C. Written sources from 500 B.C. describe how the Chinese used natural gas to boil water.

But it was not until 1859 that "Colonel" Edwin Drake drilled the first successful oil well, with the sole purpose of finding oil. The Drake Well was located in the middle of quiet farm country in north-western Pennsylvania, and began the international search for an industrial use of petroleum.



Photo: Drake Well Museum Collection, Titusville, PA

These wells were shallow by modern standards, often less than 50 meters deep, but produced large quantities of oil. In the picture from the Tarr Farm,

Oil Creek Valley, The Phillips well on the right initially produced 4000 barrels a day in October 1861 and the Woodford well on the left came in at 1500 barrels a day in July, 1862.

The oil was collected in the wooden tank pictured, in the foreground. As you will no doubt notice, there are many different sized barrels in the background of the picture. At this time, barrel size had not been standardized, which made terms like "Oil is selling at \$5 per barrel" very confusing (today a barrel is 159 liters, see units at the back). But even in those days, overproduction was something to be avoided. When the "Empire well" was completed in September 1861, it gave 3,000 barrels per day, flooding the market, and the price of oil plummeted to 10 cents a barrel.

Soon, oil had replaced most other fuels for motorized transport. The automobile industry developed at the end of the 19th century, and quickly adopted oil as fuel. Gasoline engines were essential for designing successful aircraft. Ships driven by oil could move up to twice as fast as their coal powered counterparts, a vital military advantage. Gas was burned off or left in the ground.

Despite attempts at gas transportation as far back as 1821, it was not until after the World War II that welding techniques, pipe rolling, and metallurgical advances allowed for the construction of reliable long distance pipelines, resulting in a natural gas industry boom. At the same time the petrochemical industry with its new plastic materials quickly increased production. Even now gas production is gaining market share as LNG provides an economical way of transporting the gas from even the remotest sites.

With oil prices of 70 dollars a barrel or more, even more difficult to access sources have become economically viable. Such sources include tar sands in Venezuela and Canada as well as oil shales and coal bed methane,. Synthetic diesel (syndiesel) from natural gas and biological sources (biodiesel, ethanol) have seen a dramatic increase over the last 10 years. These sources may eventually more than triple the potential reserves of hydrocarbon fuels.

2 Process overview

The following illustration gives a simplified overview of the typical oil and gas production process

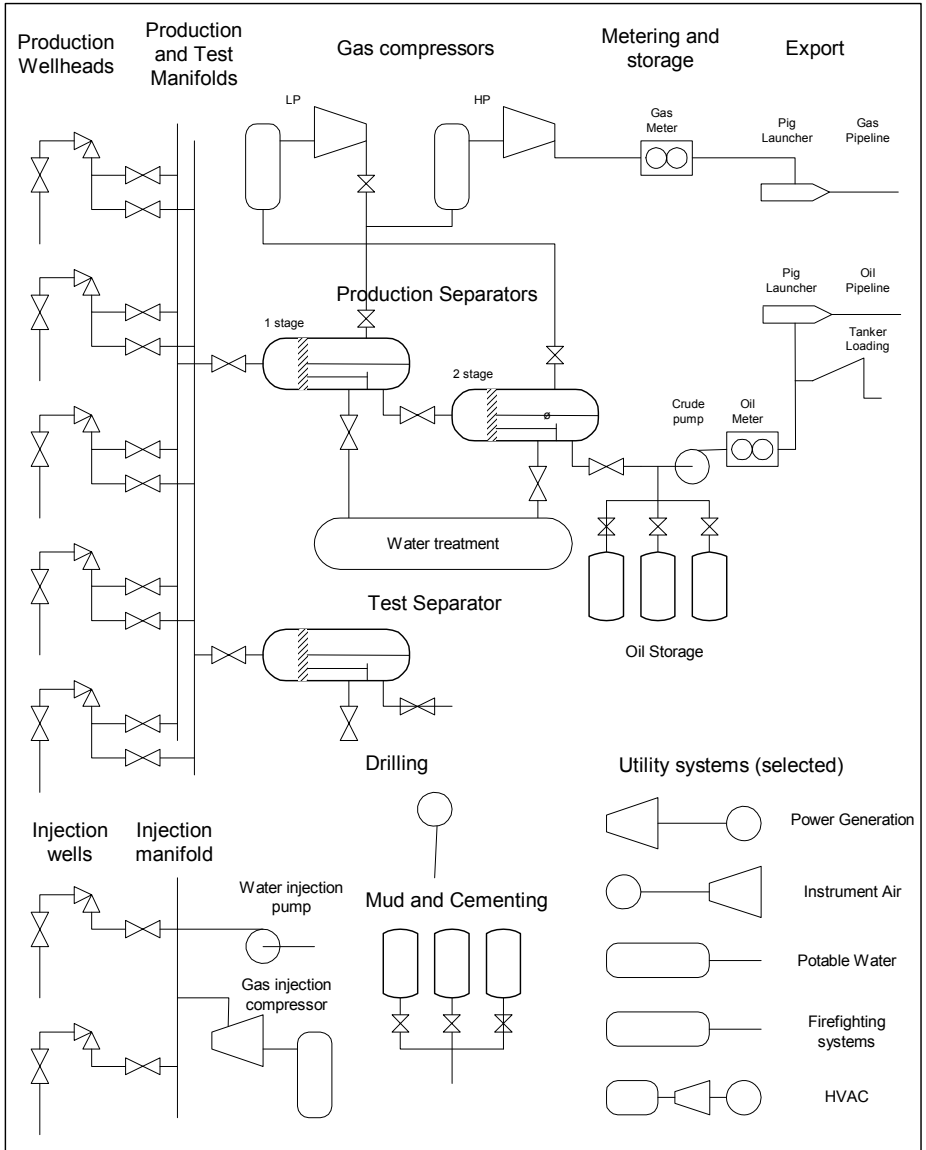


Figure 1. Oil and gas production overview

Today oil and gas is produced in almost every part of the world, from the small 100 barrels a day private wells, to the large bore 4000 barrel a day wells; in shallow 20 meter deep reservoirs to 3000 meter deep wells in more than 2000 meters of water; in 10,000 dollar onshore wells to 10 billion dollar offshore developments. Despite this range many parts of the process are quite similar in principle.

At the left side, we find the wellheads. They feed into production and test manifolds. In a distributed production system this would be called the gathering system. The remainder of the diagram is the actual process, often called the Gas Oil Separation Plant (GOSP). While there are oil or gas only installations, more often the well-stream will consist of a full range of hydrocarbons from gas (methane, butane, propane etc.), condensates (medium density hydrocarbons) to crude oil. With this well flow we will also get a variety of unwanted components such as water, carbon dioxide, salts, sulfur and sand. The purpose of the GOSP is to process the well flow into clean marketable products: oil, natural gas or condensates. Also included are a number of utility systems, not part of the actual process, but providing energy, water, air or some other utility to the plant.

2.1 Facilities

- 1. Onshore well
- 2. Offshore, fixed, multi platforms
- 3. Offshore, fixed, self-contained platforms
- 4. Offshore, self-contained, concrete gravity platforms
- 5. Offshore, floating, single-point mooring
- 6. Storage/shuttle tanker
- 7. Offshore, floating, tension leg platforms
- 8. Subsea manifolds

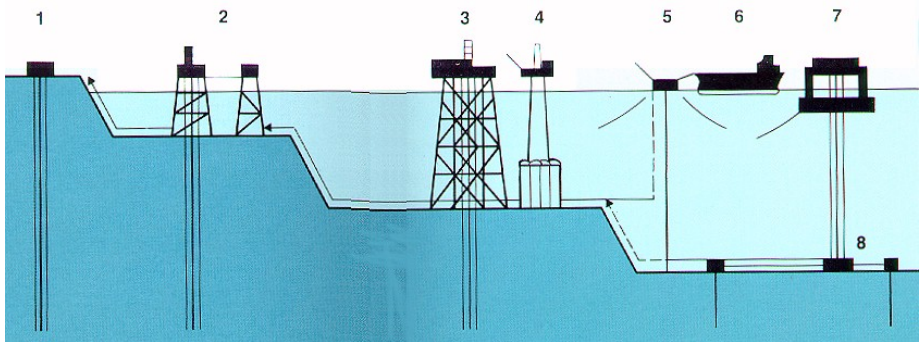


Figure 2. Oil and gas production facilities

2.1.1 Onshore

Onshore production is economically viable from a few dozen barrels of oil a day and upwards. Oil and gas is produced from several million wells world-wide. In particular, a gas gathering network can become very large, with production from thousands of wells, several hundred kilometers/miles apart, feeding through a gathering network into a processing plant. The picture shows a well equipped with a sucker rod pump (donkey pump) often associated with onshore oil production. However, as we shall see later, there are many other ways of extracting oil from a non-free flowing well



For the smallest reservoirs, oil is simply collected in a holding tank and picked up at regular intervals by tanker truck or railcar.

But onshore wells in oil rich areas are also high capacity wells with thousands of barrels per day, connected to a 1,000,000 barrel or more a day gas oil separation plant (GOSP). Product is sent from the plant by pipeline or tankers. The production may come from many different license owners, therefore metering and logging of individual well-streams into the gathering network are important tasks.

Recently, very heavy crude, tar sands and oil shale have become economically extractable with higher prices and new technology. Heavy crude may need heating and diluents to be extracted. Tar sands have lost their volatile compounds and are strip mined or can be extracted with steam. It must be further processed to separate bitumen from the sand.



These unconventional reserves may contain more than double the hydrocarbons found in conventional reservoirs. The picture shows the Syncrude Mildred plant at Athabasca, Canada *Photo: GDFL Jamitzky/Wikimedia*

2.1.2 Offshore

A whole range of different structures are used offshore, depending on size and water depth. In the last few years we have seen pure sea bottom installations with multiphase piping to shore and no offshore topside structure at all. Replacing outlying wellhead towers, deviation drilling is used to reach different parts of the reservoir from a few wellhead cluster locations. Some of the common offshore structures are:

A shallow water complex,

which is characterized by a several independent platforms with different parts of the process and utilities linked with gangway bridges. Individual platforms include Wellhead Platform, Riser Platform, Processing Platform, Accommodations Platform and Power Generation Platform. The picture shows the BP Valhall complex. Typically found in water depths up to 100 meters.



A gravity base. This consists of enormous concrete fixed structures placed on the bottom, typically with oil storage cells in the "skirt" that rests on the sea bottom. The large deck receives all parts of the process and utilities in large modules. Large fields at 100 to 500 meters water depth were typical of the 1980s and 90s. The concrete was poured at an on-shore location, with enough air in the storage cells to keep the structure floating until tow-out and lowering onto the seabed. The picture shows the world's largest GBS platform, Troll A, during construction. *Photo StatoilHydro*



Compliant towers are much like fixed platforms. They consist of a narrow tower, attached to a foundation on the seafloor and extending up to the platform. This tower is flexible, as opposed to the relatively rigid legs of a fixed platform. This flexibility allows them to operate in much deeper water, as they can 'absorb' much of the pressure exerted by the wind and sea. Compliant towers are used between 500 and 1000 meters water depth.

Floating production, where all topside systems are located on a floating structure with dry off and subsea wells. Some floaters are:

FPSO: Floating Production, Storage and Offloading. Their main advantage is that they are a standalone structure that does not need external infrastructure such as pipelines or storage. Crude oil is offloaded to a shuttle tanker at regular intervals, from days to weeks, depending on production and storage capacity. FPSOs today produce from around 10,000 to 200,000 barrels per day.

An FPSO is typically a tanker type hull or barge, often converted from an existing crude oil tanker (VLCC or ULCC). Due to the increasing sea depth for new fields, they dominate new offshore field development at more than 100 meters water depth.



The wellheads or subsea risers from the sea bottom are located on a central or bow-mounted turret so that the ship can rotate freely to point into wind, waves or current. The turret has wire rope and chain connections to several anchors (position mooring - POSMOOR), or it can be dynamically positioned using thrusters (dynamic positioning – DYNPOS). Most installations use subsea wells. The main process is placed on the deck, while the hull is used for storage and offloading to a shuttle tanker. May also be used for the transportation of pipelines.

FPSOs with additional processing and systems such as drilling and production and stranded gas LNG production are planned.

A variation of the FPSO is the Sevan Marine design. This uses a circular hull which shows the same profile to wind, waves and current regardless of direction. It shares many of the characteristics of the ship-shaped FPSO such as high storage capacity and deck load, but does not rotate and therefore does not need a rotating turret.

Photo: Sevan Marine



A Tension Leg Platform (TLP – left side in picture) consists of a structure held in place by vertical tendons connected to the sea floor by pile-secured templates. The structure is held in a fixed position by tensioned tendons, which provide for use of the TLP in a broad water depth range up to about 2000m.

Limited vertical motion. The tendons are constructed as hollow high tensile strength steel pipes that carry the spare buoyancy of the structure and ensure limited vertical motion.

Semi-submersible platforms (front of picture) have a similar design but without taut mooring. This permits more lateral and vertical motion and is generally used with flexible risers and subsea wells.

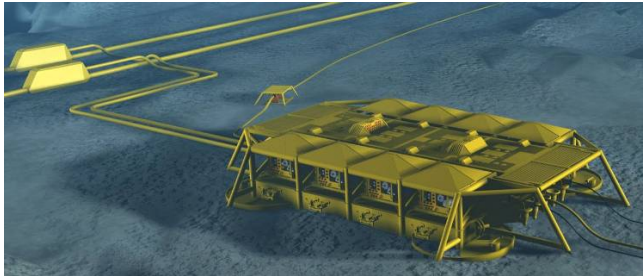
Something similar are Seastar platforms which are miniature floating tension leg platforms, much like the semi-submersible type, with tensioned tendons.



A SPAR consists of a single tall floating cylindrical hull, supporting a fixed deck. The cylinder does not however extend all the way to the seabed, but is tethered to the bottom by a series of cables and lines. The large cylinder serves to stabilize the platform in the water, and allows for movement to absorb the force of potential hurricanes. SPARs can be quite large and are used for water depths from 300 and up to 3000 meters. SPAR is not an acronym, but refers to its likeness to a ship's spar. SPARs can support dry completion wells, but are more often used with subsea wells.



Subsea production systems are wells located on the sea floor, as opposed to on the surface. As in a floating production system, the petroleum is extracted at the seabed, and can then be 'tied-back' to an already existing production platform or even an onshore facility, limited by horizontal distance or "offset". The well is drilled



by a moveable rig and the extracted oil and natural gas is transported by undersea pipeline and riser to a processing facility. This allows one strategically placed production platform to service many wells over a reasonably large area. Subsea systems are typically in use at depths of 500 meters or more, and do not have the ability to drill, only to extract and transport. Drilling and completion is performed from a surface rig. Horizontal offsets of up to 250 kilometers/150 miles are currently possible. *Photo: StatoilHydro*

2.2 Main process sections

We will go through each section in detail in the following chapters. The summary below is an introductory synopsis of each section

2.2.1 Wellheads

The wellhead sits on top of the actual oil or gas well leading down to the reservoir. A wellhead may also be an injection well, used to inject water or gas back into the reservoir to maintain pressure and levels to maximize production.

Once a natural gas or oil well is drilled, and it has been verified that commercially viable quantities of natural gas are present for extraction, the well must be 'completed' to allow for the flow of petroleum or natural gas out of the formation and up to the surface. This process includes strengthening the well hole with casing, evaluating the pressure and temperature of the formation, and then installing the proper equipment to ensure an efficient flow of natural gas from the well. The well flow is controlled with a choke.



We differentiate between, dry completion (which is either onshore or on the deck of an offshore structure) and subsea completions below the surface. The wellhead structure, which is often called a Christmas tree, must allow for a number of operations relating to production and well workover. Well workover refers to various technologies for maintaining the well and improving its production capacity.

2.2.2 Manifolds/gathering

Onshore, the individual well streams are brought into the main production facilities over a network of gathering pipelines and manifold systems. The purpose of these pipelines is to allow set up of production "well sets" so that for a given production level, the best reservoir utilization, well flow composition (gas, oil, water) etc. can be selected from the available wells.

For gas gathering systems, it is common to meter the individual gathering lines into the manifold as shown on the illustration. For multiphase

(combination of gas, oil and water) flows, the high cost of multiphase flow meters often leads to the use of software flow rate estimators that use well test data to calculate the actual flow.

Offshore, the dry completion wells on the main field centre feed directly into production manifolds, while outlying wellhead towers and subsea installations feed via multiphase pipelines back to the production risers. Risers are the system that allows a pipeline to "rise" up to the topside structure. For floating or structures, this involves a way to take up weight and movement. For heavy crude and in Arctic areas, diluents and heating may be needed to reduce viscosity and allow flow.



2.2.3 Separation

Some wells have pure gas production which can be taken directly to gas treatment and/or compression. More often, the well gives a combination of gas, oil and water and various contaminants which must be separated and processed. The production separators come in many forms and designs, with the classical variant being the gravity separator. *Photo: JL Bryan Oilfield Equipment*



In gravity separation, the well flow is fed into a horizontal vessel. The retention period is typically 5 minutes, allowing the gas to bubble out, water to settle at the bottom and oil to be taken out in the middle. The pressure is often reduced in several stages (high pressure separator, low pressure

separator etc.) to allow controlled separation of volatile components. A sudden pressure reduction might allow flash vaporization leading to instability and safety hazards.

2.2.4 Gas compression

Gas from a pure natural gas wellhead might have sufficient pressure to feed directly into a pipeline transport system. Gas from separators has generally lost so much pressure that it must be recompressed to be transported. Turbine driven compressors gain their energy by using a small proportion of the natural gas that they compress. The turbine itself serves to operate a centrifugal compressor, which contains a type of fan that compresses and pumps the natural gas through the pipeline. Some compressor stations are operated by using an electric motor to turn the same type of centrifugal compressor. This type of compression does not require the use of any of the natural gas from the pipe; however it does require a reliable source of electricity nearby. The compression includes a large section of associated equipment such as scrubbers (to remove liquid droplets) and heat exchangers, lube oil treatment etc.



Whatever the source of the natural gas, once separated from crude oil (if present) it commonly exists in mixtures with other hydrocarbons, principally ethane, propane, butane, and pentanes. In addition, raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds.

Natural gas processing consists of separating all of the various hydrocarbons and fluids from the pure natural gas, to produce what is known as 'pipeline quality' dry natural gas. Major transportation pipelines usually impose restrictions on the make-up of the natural gas that is allowed into the pipeline. That means that before the natural gas can be transported it must be purified.

Associated hydrocarbons, known as 'natural gas liquids' (NGL) are used as raw materials for oil refineries or petrochemical plants, and as sources of energy.

2.2.5 Metering, storage and export

Most plants do not allow local gas storage, but oil is often stored before loading on a vessel, such as a shuttle tanker taking oil to a larger tanker terminal, or direct to a crude carrier. Offshore production facilities without a direct pipeline connection generally rely on crude storage in the base or hull, to allow a shuttle tanker to offload about once a week. A larger production complex generally has an associated tank farm terminal allowing the storage of different grades of crude to take up changes in demand, delays in transport etc.



Metering stations allow operators to monitor and manage the natural gas and oil exported from the production installation. These employ specialized meters to measure the natural gas or oil as it flows through the pipeline, without impeding its movement.



This metered volume represents a transfer of ownership from a producer to a customer (or another division within the company) and is therefore called Custody Transfer Metering. It forms the basis for invoicing the sold product

and also for production taxes and revenue sharing between partners and accuracy requirements are often set by governmental authorities.

A metering installation typically consists of a number of meter runs so that one meter will not have to handle the full capacity range, and associated prover loops so that the meter accuracy can be tested and calibrated at regular intervals.

Pipelines can measure anywhere from 6 to 48 inches (15 – 120 cm) in diameter. In order to ensure their efficient and safe operation, operators routinely inspect their pipelines for corrosion and defects. This is done through the use of sophisticated pieces of equipment known as pigs. Pigs are intelligent



robotic devices that are propelled down pipelines to evaluate the interior of the pipe. Pigs can test pipe thickness, roundness, check for signs of corrosion, detect minute leaks, and any other defect along the interior of the pipeline that may either restrict the flow of gas, or pose a potential safety risk for the operation of the pipeline. Sending a pig down a pipeline is fittingly known as 'pigging' the pipeline. The export facility must contain equipment to safely insert and retrieve pigs from the pipeline as well as depressurization, referred to as pig launchers and pig receivers.

Loading on tankers involves loading systems, ranging from tanker jetties to sophisticated single point mooring and loading systems that allow the tanker to dock and load the product even in bad weather.

2.3 Utility systems

Utility systems are systems which do not handle the hydrocarbon process flow, but provide some service to the main process safety or residents. Depending on the location of the installation, many such functions may be available from nearby infrastructure (e.g. electricity). But many remote installations must be fully self-sustaining and must generate their own power, water etc.

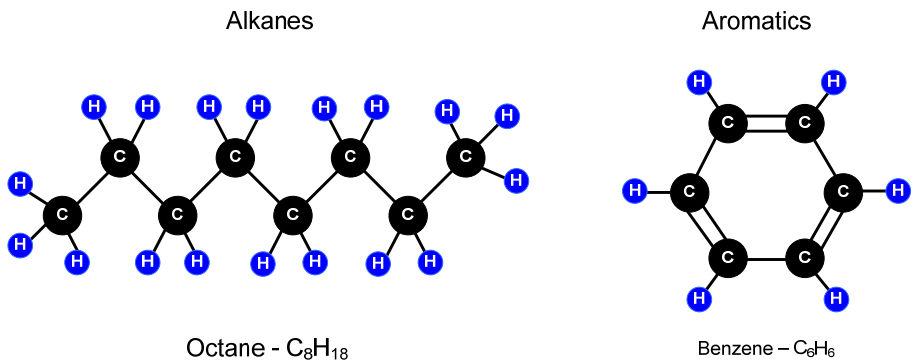
3 Reservoir and wellheads

There are three main types of conventional wells. The most common is an oil well with associated gas. Natural gas wells are drilled specifically for natural gas, and contain little or no oil. Condensate wells contain natural gas, as well as a liquid condensate. This condensate is a liquid hydrocarbon mixture that is often separated from the natural gas either at the wellhead, or during the processing of the natural gas. Depending on the type of well that is being drilled, completion may differ slightly. It is important to remember that natural gas, being lighter than air, will naturally rise to the surface of a well. Consequently, lifting equipment and well treatment are not necessary in many natural gas and condensate wells, while for oil wells many types of artificial lift might be installed, particularly as the reservoir pressure falls during years of production.

3.1 Crude oil and natural gas

3.1.1 Crude oil

Crude oil is a complex mixture consisting of 200 or more different organic compounds, mostly alkenes (single bond hydrocarbons on the form C_nH_{2n+2}) and smaller fraction aromatics (six-ring molecules such as benzene C_6H_6)



Different crude contains different combinations and concentrations of these various compounds. The API (American Petroleum Institute) gravity of a particular crude is merely a measure of its specific gravity, or density. The higher the API number expressed as degrees API, the less dense (lighter,

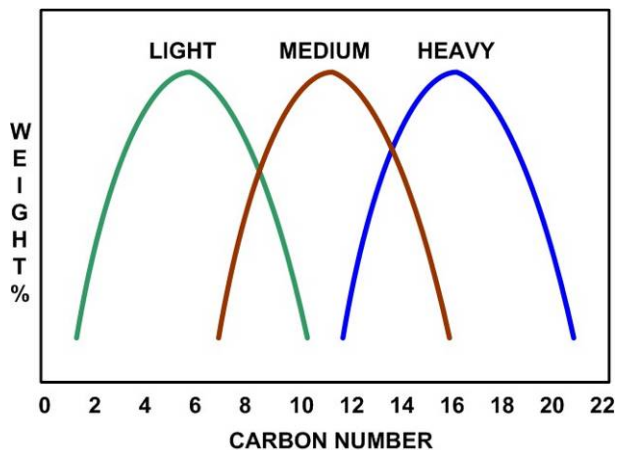
thinner) the crude. This means, put simply, that the lower the degrees API, the denser (heavier, thicker) the crude. Crude from different fields and from different formations within a field can be similar in composition or be significantly different.

In addition to API grade and hydrocarbons, crude is characterized for other undesired elements like sulfur etc, which is regulated and needs to be removed.

Crude oil API gravities typically range from 7 to 52 corresponding to about 970 kg/m^3 to 750 kg/m^3 , but most fall in the 20 to 45 API gravity range. Although light crude (i.e. 40-45 degrees API) is considered the best, lighter crude (i.e., 46 degree API and above) is generally no better for a typical refinery. As the crude gets lighter than 40-45 degrees API, it contains shorter molecules, which means a lower carbon number. This also means it contains less of the molecules useful as high octane gasoline and diesel fuel, the production of which most refiners try to maximize. If a crude is heavier than 35 degree API, it contains longer and bigger molecules that are not useful as high octane gasoline and diesel fuel without further processing.

For crude that has undergone detailed physical and chemical property analysis, the API gravity can be used as a rough index of the quality of crudes of similar composition as they naturally occur (that is, without adulteration, mixing, blending, etc.). When crudes of a different type and quality are mixed, or when different petroleum components are mixed, API gravity cannot be used meaningfully for anything other than a measure of the density of the fluid.

For instance, consider a barrel of tar that is dissolved in 3 barrels of naphtha (lighter fluid) to produce 4 barrels of a 40 degree API mixture. When this 4-barrel mixture is fed to a distillation column at the inlet to a refinery, one barrel of tar plus 3 barrels of naphtha is all that will come out of the still.



On the other hand, 4 barrels of a naturally occurring 40 degree API crude fed to the distillation column at the refinery, could come out of the still as 1.4 barrels of gasoline and naphtha (typically C_8H_{18}), 0.6 barrels of kerosene (jet fuel C_{12-15}), 0.7 barrels of diesel fuel (average $C_{12}H_{26}$), 0.5 barrels of heavy distillate (C_{20-70}), 0.3 barrels of lubricating stock, and 0.5 barrels of residue (bitumen, mainly poly-cyclic aromatics).

The figure above to the right illustrates weight percent distributions of three different hypothetical petroleum stocks that could be fed to a refinery with catalytic cracking capacity. The chemical composition is generalized by the carbon number which is the number of carbon atoms in each molecule - C_nH_{2n+2} . A medium blend is desired because it has the composition that will yield the highest output of high octane gasoline and diesel fuel in the cracking refinery. Though the heavy stock and the light stock could be mixed to produce a blend with the same API gravity as the medium stock, the composition of the blend would be very different from the medium stock, as the figure indicates. Heavy crude can be processed in a refinery by cracking and reforming that reduces the carbon number to increase the high value fuel yield.

3.1.2 Natural gas

The natural gas used by consumers is composed almost entirely of methane. However, natural gas found at the wellhead, although still composed primarily of methane, is not pure. Raw natural gas comes from three types of wells: oil wells, gas wells, and condensate wells.

Natural gas that comes from oil wells is typically termed 'associated gas'. This gas can exist separate from oil in the formation (free gas), or dissolved in the crude oil (dissolved gas). Natural gas from gas and condensate wells, in which there is little or no crude oil, is termed 'non-associated gas'.

Gas wells typically produce raw natural gas only. However condensate wells produce free natural gas along with a semi-liquid hydrocarbon condensate. Whatever the source of the natural gas, once separated from crude oil (if present) it commonly exists in mixtures with other hydrocarbons, principally ethane, propane, butane, and pentanes. In addition, raw natural gas contains water vapor, hydrogen sulfide (H_2S), carbon dioxide, helium, nitrogen, and other compounds.

Natural gas processing consists of separating all of the various hydrocarbons and fluids from the pure natural gas, to produce what is known as 'pipeline quality' dry natural gas. Major transportation pipelines usually

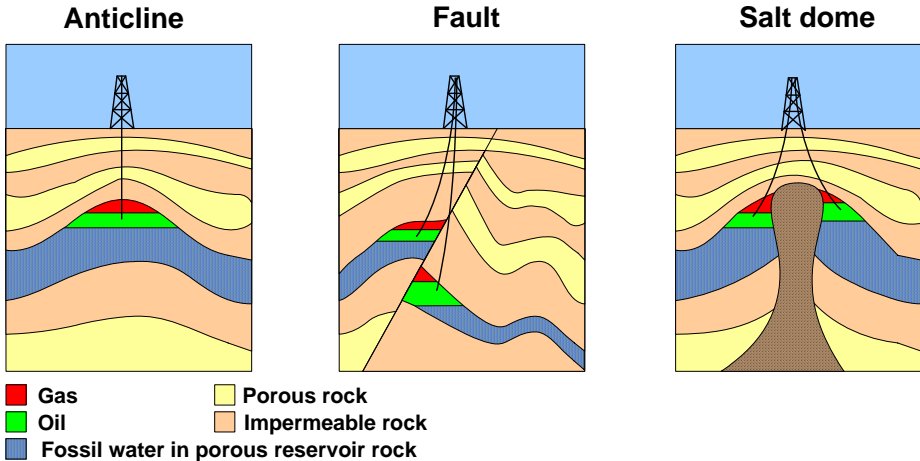
impose restrictions on the composition of the natural gas that is allowed into the pipeline and measure energy content in kJ/kg (also called calorific value or Wobbe index).

3.1.3 Condensates

While the ethane, propane, butane, and pentanes must be removed from natural gas, this does not mean that they are all 'waste products'. In fact, associated hydrocarbons, known as 'natural gas liquids' (NGL) can be very valuable by-products of natural gas processing. NGLs include ethane, propane, butane, iso-butane, and natural gasoline. These are sold separately and have a variety of different uses such as raw materials for oil refineries or petrochemical plants, as sources of energy, and for enhancing oil recovery in oil wells. Condensates are also useful as diluents for heavy crude, see below.

3.2 The reservoir

The oil and gas bearing structure is typically of porous rock such as sandstone or washed out limestone. The sand might have been laid down as desert sand dunes or seafloor. Oil and gas deposits form as organic material (tiny plants and animals) deposited in earlier geological periods, typically 100 to 200 million years ago, under, over or with the sand or silt, are transformed by high temperature and pressure into hydrocarbons.



For an oil reservoir to form, porous rock needs to be covered by a non-porous layer such as salt, shale, chalk or mud rock that can prevent the

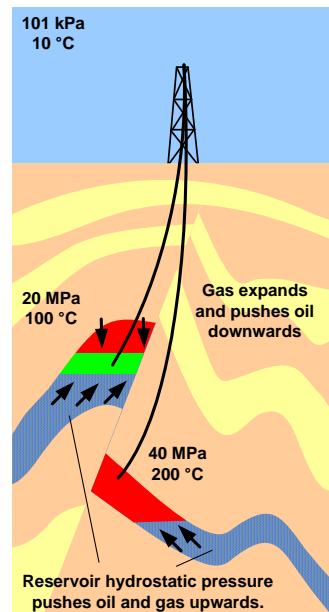
hydrocarbons from leaking out of the structure. As rock structures become folded and raised as a result of tectonic movements, the hydrocarbons migrate out of the deposits and upward in porous rock and collect in crests under the non-permeable rock, with gas at the top, then oil and fossil water at the bottom. Salt is a thick fluid and if deposited under the reservoir will flow up in heavier rock over millions of years. This creates salt domes with a similar reservoir forming effect, and are common in the Middle East for example.

This extraordinary process is still continuing. However, an oil reservoir matures in the sense that an immature formation may not yet have allowed the hydrocarbons to form and collect. A young reservoir generally has heavy crude, less than 20 API, and is often Cretaceous in origin (65-145 million years ago). Most light crude reservoirs tend to be Jurassic or Triassic (145-205/205-250 million years ago) and gas reservoirs where the organic molecules are further broken down are often Permian or Carboniferous in origin (250-290/290-350 million years ago).

In some areas, strong uplift, erosion and cracking of rock above have allowed the hydrocarbons to leak out, leaving heavy oil reservoirs or tar pools. Some of the world's largest oil deposits are tar sands, where the volatile compounds have evaporated from shallow sandy formations leaving huge volumes of bitumen-soaked sands. These are often exposed at the surface and can be strip-mined, but must be separated from the sand with hot water, steam and diluents and further processed with cracking and reforming in a refinery to improve fuel yield.

The oil and gas is pressurized in the pores of the absorbent formation rock. When a well is drilled into the reservoir structure, the hydrostatic formation pressure drives the hydrocarbons out of the rock and up into the well. When the well flows, gas, oil and water is extracted, and the levels will shift as the reservoir is depleted. The challenge is to plan drilling so that reservoir utilization can be maximized.

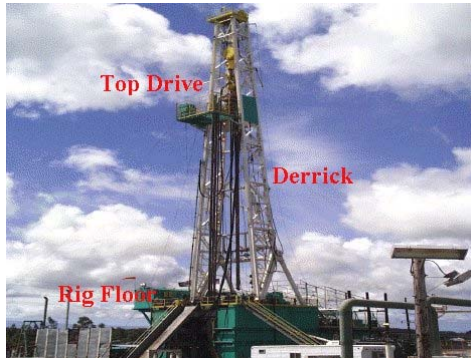
Seismic data and advanced 3D visualization models are used to plan extraction. Even so, the average recovery rate is only 40%,



leaving 60% of the hydrocarbons trapped in the reservoir. The best reservoirs with advanced Enhanced Oil Recovery (EOR) allow up to 70%. Reservoirs can be quite complex, with many folds and several layers of hydrocarbon-bearing rock above each other (in some areas more than 10). Modern wells are drilled with large horizontal offsets to reach different parts of the structure and with multiple completions so that one well can produce from several locations.

3.3 Exploration and drilling

When 3D seismic investigation has been completed, it is time to drill the well. Normally, dedicated drilling rigs either on mobile onshore units or offshore floating rigs are used. Larger production platforms may also have their own production drilling equipment. *Photo: Puna Geothermal Venture*



The main components of the drilling rig are the derrick, floor, drawworks, drive and mud handling. The control and power can be hydraulic or electric.

Earlier pictures of drillers and roughnecks working with rotary tables (bottom drives) are now replaced with top drive and semi-automated pipe handling on larger installations. The hydraulic or electric top drive hangs from the derrick crown and gives pressure and rotational torque to the drill string. The whole assembly is controlled by the drawworks.

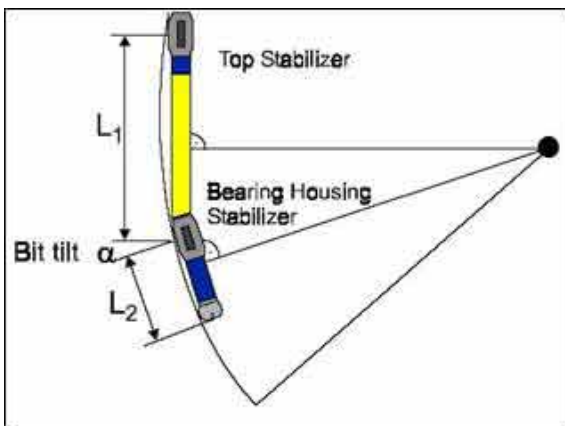
The drill string is assembled from pipe segments about 30 meters (100 feet) long normally with conical inside threads at one end and outside at the other. As each 30 meter segment is drilled, the drive is disconnected and a new pipe segment inserted in the string. A cone bit is used to dig into the rock.



Different cones are used for different types of rock and at different stages of the well. The picture shows roller cones with inserts (on the left). Other bits are PDC (polycrystalline diamond compact, on the right) and diamond impregnated. *Photo: Kingdream PLC*

As the well is sunk into the ground, the weight of the drill string increases and might reach 500 metric tons or more for a 3000 meter deep well. The drawwork and top drive must be precisely controlled so as not to overload and break the drill string or the cone. Typical values are 50kN force on the bit and a torque of 1-1.5 kNm at 40-80 RPM for an 8 inch cone. ROP (Rate of Penetration) is very dependant on depth and could be as much as 20 meters per hour for shallow sandstone and dolomite (chalk) and as low as 1 m/hour on deep shale rock and granite.

Directional drilling is intentional deviation of a well bore from the vertical. It is often necessary to drill at an angle from the vertical to reach different parts of the formation. Controlled directional drilling makes it possible to reach subsurface areas laterally remote from the point where the bit enters the earth. It often involves the use of a drill



motor driven by mud pressure mounted directly on the cone (mud motor, turbo drill, and dyna-drill), whipstocks - a steel casing that will bend between the drill pipe and cone, or other deflecting rods, also used for horizontal wells and multiple completions, where one well may split into several bores. A well which has sections of more than 80 degrees from the vertical is called a horizontal well. Modern wells are drilled with large horizontal offsets to reach different parts of the structure and achieve higher production. The world record is more than 15 kilometers. Multiple completions allow production from several locations.

Wells can be of any depth from near the surface to a depth of more than 6000 meters. Oil and gas are typically formed at 3000-4000 meters depth, but part of the overlying rock can since have eroded away. The pressure and temperature generally increase with increasing depth, so that deep wells can

have more than 200 C temperature and 90 MPa pressure (900 times atmospheric pressure), equivalent to the hydrostatic pressure set by the distance to the surface. The weight of the oil in the production string reduces wellhead pressure. Crude oil has a specific weight of 790 to 970 kg per cubic meter. For a 3000 meter deep well with 30 MPa downhole pressure and normal crude oil at 850 kg/m³, the wellhead static pressure will only be around 4.5 MPa. During production, the pressure will drop further due resistance to flow in the reservoir and well.

The mud enters though the drill pipe, passes through the cone and rises in the uncompleted well. Mud serves several purposes:

- It brings rock shales (fragments of rock) up to the surface
- It cleans and cools the cone
- It lubricates the drill pipe string and Cone
- Fibrous particles attach to the well surface to bind solids
- Mud weight should balance the downhole pressure to avoid leakage of gas and oil. Often, the well will drill though smaller pockets of hydrocarbons which may cause "a blow-out" if the mud weight cannot balance the pressure. The same might happen when drilling into the main reservoir.

To prevent an uncontrolled blow-out, a subsurface safety valve is often installed. This valve has enough closing force to seal off the well and cut the drill string in an uncontrollable blow-out situation. However, unless casing is already also in place, hydrocarbons may also leave though other cracks inside the well and rise to the surface through porous or cracked rock. In addition to fire and pollution hazards, dissolved gas in seawater rising under a floating structure significantly reduces buoyancy.

The mud mix is a specialist brew designed to match the desired flow thickness, lubrication properties and specific gravity. Mud is a common name used for all kinds of fluids used in drilling completion and workover and can be oil based, water based or synthetic, and consists



of powdered clays such as bentonite, oil, water and various additives and chemicals such as caustic soda, barite (sulfurous mineral), lignite (brown coal), polymers and emulsifiers. *Photo: OSHA.gov*

A special high density mud called Kill Fluid is used to shut down a well for workover.

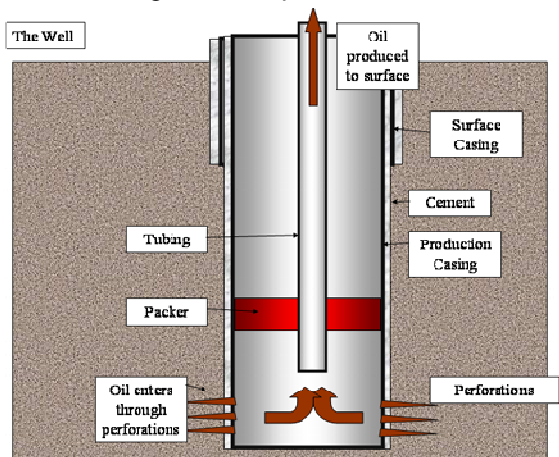
Mud is recirculated. Coarse rock shales are separated in a shale shaker before it is passed through finer filters and recalibrated with new additives before returning to the mud holding tanks

3.4 The well

When the well has been drilled, it must be completed. Completing a well consists of a number of steps, such as installing the well casing, completion, installing the wellhead, and installing lifting equipment or treating the formation should that be required.

3.4.1 Well casing

Installing the well casing is an important part of the drilling and completion process. Well casing consists of a series of metal tubes installed in the freshly drilled hole. Casing serves to strengthen the sides of the well hole, ensure that no oil or natural gas seeps out as it is brought to the surface, and to keep other fluids or gases from seeping into the formation through the well. A good deal of planning is necessary to ensure that the right casing for each well is installed. Types of casing used depend on the subsurface characteristics of the well, including the diameter of the well (which is dependent on the size of the drill bit used) and the pressures and temperatures experienced. In most wells, the diameter of the well hole decreases the deeper it is drilled, leading to a type of conical shape that must be taken into account



when installing casing. The casing is normally cemented in place. *III: wikipedia.org*

There are five different types of well casing. They include:

- Conductor casing, which is usually no more than 20 to 50 feet (7-17 meter) long, installed before main drilling to prevent the top of the well from caving in and to help in the process of circulating the drilling fluid up from the bottom of the well.
- Surface casing is the next type of casing to be installed. It can be anywhere from 100 to 400 meters long, and is smaller in diameter to fit inside the conductor casing. Its primary purpose is to protect fresh water deposits near the surface of the well from being contaminated by leaking hydrocarbons or salt water from deeper underground. It also serves as a conduit for drilling mud returning to the surface and helps protect the drill hole from being damaged during drilling.
- Intermediate casing is usually the longest section of casing found in a well. Its primary purpose is to minimize the hazards associated with subsurface formations that may affect the well. These include abnormal underground pressure zones, underground shales and formations that might otherwise contaminate the well, such as underground salt water deposits. Liner strings are sometimes used instead of intermediate casing. Liner strings are usually just attached to the previous casing with 'hangers', instead of being cemented into place and are thus less permanent.
- Production casing, alternatively called the 'oil string' or 'long string', is installed last and is the deepest section of casing in a well. This is the casing that provides a conduit from the surface of the well to the petroleum producing formation. The size of the production casing depends on a number of considerations, including the lifting equipment to be used, the number of completions required, and the possibility of deepening the well at a later date. For example, if it is expected that the well will be deepened later, then the production casing must be wide enough to allow the passage of a drill bit later on. It is also instrumental in preventing blow-outs, allowing the formation to be 'sealed' from the top should dangerous pressure levels be reached.

Once the casing is installed, **tubing** is inserted inside the casing, from the opening well at the top, to the formation at the bottom. The hydrocarbons that are extracted run up this tubing to the surface. The production casing is

typically 5 to 28 cm (2 -11 in.) with most production wells being 6 inches or more. Production depends on reservoir, bore, pressure etc. and could be less than 100 barrels a day to several thousand barrels per day. (5000 bpd is about 555 liters/minute). A **packer** is used between casing and tubing at the bottom of the well.

3.4.2 Completion

Well completion commonly refers to the process of finishing a well so that it is ready to produce oil or natural gas. In essence, completion consists of deciding on the characteristics of the intake portion of the well in the targeted hydrocarbon formation. There are a number of types of completions, including:

- Open hole completions are the most basic type and are only used in very competent formations, which are unlikely to cave in. An open hole completion consists of simply running the casing directly down into the formation, leaving the end of the piping open without any other protective filter.
- Conventional perforated completions consist of production casing run through the formation. The sides of this casing are perforated, with tiny holes along the sides facing the formation, which allows hydrocarbons to flow into the well hole but still provides a suitable amount of support and protection for the well hole. In the past, 'bullet perforators' were used. These were essentially small guns lowered into the well that sent off small bullets to penetrate the casing and cement. Today, 'jet perforating' is preferred. This consists of small, electrically-fired charges that are lowered into the well. When ignited, these charges poke tiny holes through to the formation, in the same manner as bullet perforating.
- Sand exclusion completions are designed for production in an area that contains a large amount of loose sand. These completions are designed to allow for the flow of natural gas and oil into the well, but at the same time prevent sand from entering. The most common methods of keeping sand out of the well hole are screening, or filtering systems. Both of these types of sand barriers can be used in open hole and perforated completions.
- Permanent completions are those in which the completion and wellhead are assembled and installed only once. Installing the casing, cementing, perforating, and other completion work is done with small diameter tools to ensure the permanent nature of the

completion. Completing a well in this manner can lead to significant cost savings compared to other types

- Multiple zone completion is the practice of completing a well such that hydrocarbons from two or more formations may be produced simultaneously, without mixing with each other. For example, a well may be drilled that passes through a number of formations on its way deeper underground, or it may be more desirable in a horizontal well to add multiple completions to drain the formation most effectively. When it is necessary to separate different completions, hard rubber 'packing' instruments are used to maintain separation.
- Drainhole completions are a form of horizontal or slanted drilling. This type of completion consists of drilling out horizontally into the formation from a vertical well, essentially providing a 'drain' for the hydrocarbons to run down into the well. These completions are more commonly associated with oil wells than with natural gas wells.

3.5 Wellhead

Wellheads can involve dry or subsea completion. Dry completion means that the well is onshore or on the topside structure on an offshore installation. Subsea wellheads are located under water on a special sea bed template.

The wellhead has equipment mounted at the opening of the well to regulate and monitor the extraction of hydrocarbons from the underground formation. This also prevents oil or natural gas leaking out of the well, and prevents blow-outs due to high pressure formations. Formations that are under high pressure typically require wellheads that can withstand a great deal of upward pressure from the escaping gases and liquids. These must be able to withstand pressures of up to 140 MPa (1400 Bar). The wellhead consists of three



components: the casing head, the tubing head, and the 'Christmas tree'

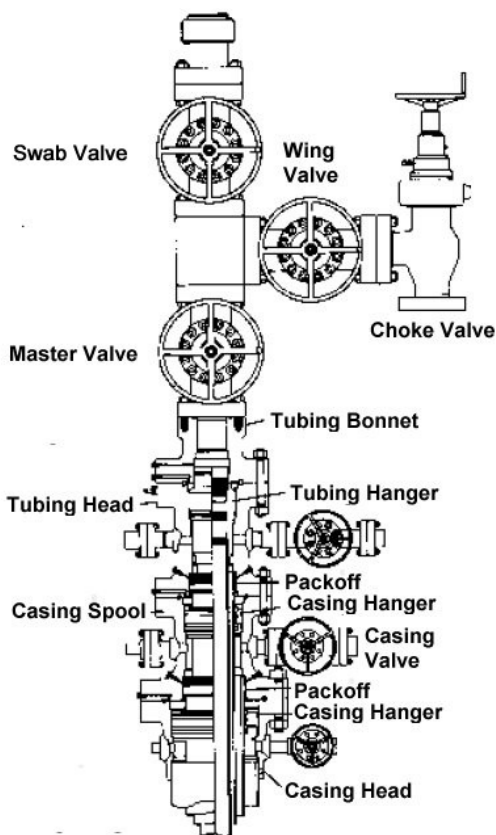
Photo: Vetco Gray

A typical Christmas tree composed of a master gate valve, a pressure gauge, a wing valve, a swab valve and a choke is shown here. The Christmas tree may also have a number of check valves. The functions of these devices are explained in the following paragraphs.

Ill: Vetco Gray

At the bottom we find the **casing head** and casing hangers.

The casing will be screwed, bolted or welded to the hanger. Several valves and plugs will normally be fitted to give access to the casing. This will permit the casing to be opened, closed, bled down, and in some cases, allow the flowing well to be produced through the casing as well as the tubing. The valve can be used to determine leaks in casing, tubing or the packer, and will also be used for lift gas injection into the casing.



The tubing hanger (also called a donut) is used to position the tubing correctly in the well. Sealing also allows Christmas tree removal with pressure in the casing.

Master gate valve. The master gate valve is a high quality valve. It provides full opening, which means that it opens to the same inside diameter as the tubing so that specialized tools may be run through it. It must be capable of holding the full pressure of the well safely for all anticipated purposes. This valve is usually left fully open and is not used to control flow.

The pressure gauge. The minimum instrumentation is a pressure gauge placed above the master gate valve before the wing valve. In addition other instruments such as a temperature gauge will normally be fitted.

The wing valve. The wing valve can be a gate or ball valve. When shutting in the well, the wing gate or valve is normally used so that the tubing pressure can be easily read.

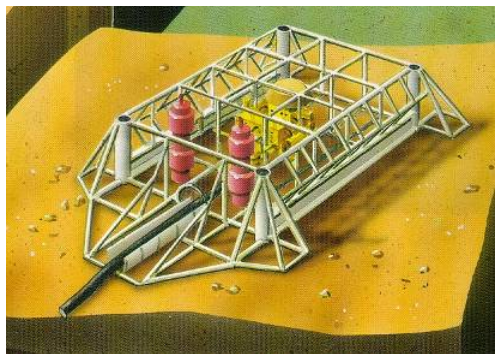
The swab valve. The swab valve is used to gain access to the well for wireline operations, intervention and other workover procedures (see below). On top of it is a tree adapter and cap that will mate with a range of equipment.

The variable flow choke valve. The variable flow choke valve is typically a large needle valve. Its calibrated opening is adjustable in 1/64 inch increments (called beans). High-quality steel is used in order to withstand the high-speed flow of abrasive materials that pass through the choke, usually over many years, with little damage except to the dart or seat. If a variable choke is not required, a less expensive positive choke is normally installed on smaller wells. This has a built-in restriction that limits flow when the wing valve is fully open.

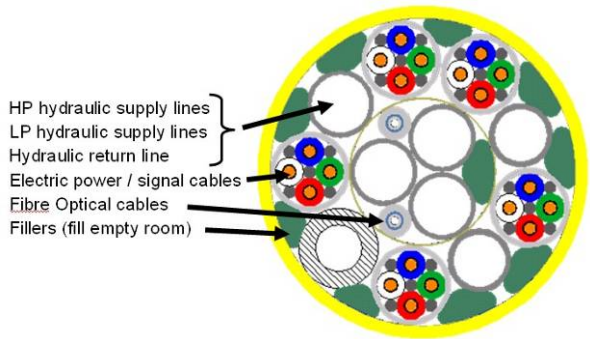
This is a **vertical tree**. Christmas trees can also be **horizontal**, where the master, wing and choke are on a horizontal axis. This reduces the height and may allow easier intervention. Horizontal trees are especially used on subsea wells.

3.5.1 Subsea wells

Subsea wells are essentially the same as dry completion wells. Mechanically however, they are placed in a subsea structure (template) that allows the wells to be drilled and serviced remotely from the surface, and protected from damage e.g. from trawlers. The wellhead is placed in a slot in the template where it mates to the outgoing pipeline as well as hydraulic and electric control signals. *Ill: StatoilHydro*



Control is from the surface where a hydraulic power unit (HPU) provides power to the subsea installation via an **umbilical**. The umbilical is a composite cable containing tension wires, hydraulic pipes, electrical power, control and communication signals. A control pod



with inert gas and/or oil protection contains control electronics, and operates most equipment via hydraulic switches. More complex subsea solutions may contain subsea separation/stabilization and electrical multiphase pumping. This may be necessary if reservoir pressure is low, offset (distance to main facility) is long or there are flow assurance problems so that the gas and liquids will not stably flow to the surface.

The product is piped back through pipelines and risers to the surface. The main choke may be located topside.

3.5.2 Injection

Wells are also divided into production and injection wells. The former are for production of oil and gas. Injection wells are drilled to inject gas or water into the reservoir. The purpose of injection is to maintain overall and hydrostatic reservoir pressure and force the oil toward the production wells. When injected water reaches the production well, it is called 'injected water breakthrough'. Special logging instruments, often based on radioactive isotopes added to injection water, are used to detect breakthrough.

Injection wells are fundamentally the same as production wellheads. The difference being their direction of flow and therefore mounting of some directional components such as the choke.

3.6 Artificial lift

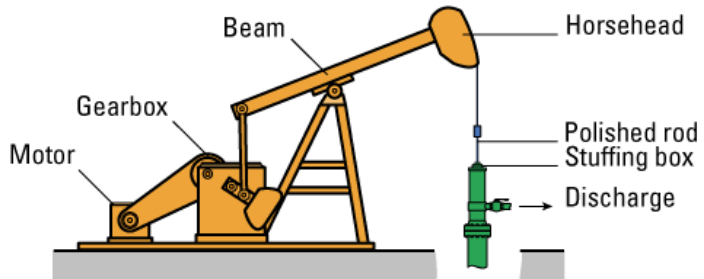
Production wells are free flowing or lifted. A free flowing oil well has enough downhole pressure to reach suitable wellhead production pressure and maintain an acceptable well-flow. If the formation pressure is too low, and

water or gas injection cannot maintain pressure or are not suitable, the well must be artificially lifted. For smaller wells, 0.7 MPa (100 PSI) wellhead pressure with a standing column of liquid in the tubing is measured, by a rule-of-thumb method, to allow the well to flow. Larger wells will be equipped with artificial lift to increase production even at much higher pressures. Some artificial lift methods are:

3.6.1 Rod pumps

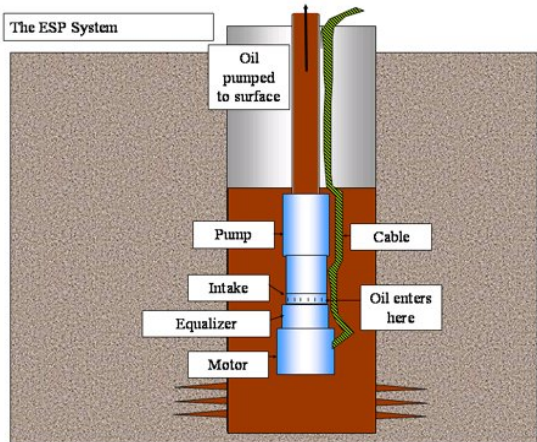
Sucker rod pumps, also called donkey or beam pumps, are the most common artificial-lift system used in land-based operations. A motor drives a reciprocating beam, connected to a polished rod passing into the tubing via a stuffing box. The sucker rod continues down to the oil level and is connected to a plunger with a valve.

On each upward stroke, the plunger lifts a volume of oil up and through the wellhead discharge. On the downward stroke it sinks (it should sink, and not be pushed) allowing oil to flow through the valve. The motor speed and torque is controlled for efficiency and minimal wear with a Pump off Controller (PoC). Use is limited to shallow reservoirs down to a few hundred meters, and flows up to about 40 liters (10 gal) per stroke.



3.6.2 Downhole pumps

A downhole pump inserts the whole pumping mechanism into the well. In



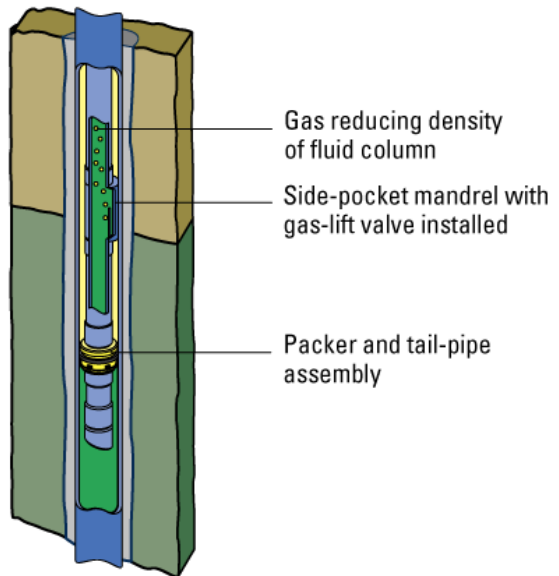
modern installations, an Electrical Submerged Pump (ESP) is inserted into the well. Here the whole assembly consisting of a long narrow motor and a multi phase pump, such as a PCP (progressive cavity pump) or centrifugal pump, hangs by an electrical cable with tension members down the tubing. *III: Wikipedia.org*

Installations down to 3.7 km with power up to 750 kW have been installed. At these depths and power ratings, medium voltage drives (up to 5kV) must be used.

ESPs work in deep reservoirs, but are sensitive to contaminants such as sand, and efficiency is sensitive to GOR (Gas Oil Ratio) where gas over 10% dramatically lowers efficiency.

3.6.3 Gas lift

A gas lift injects gas into the well flow. The downhole reservoir pressure falls off to the wellhead due to the counter pressure from weight of the oil column in the tubing. Thus a 150 MPa reservoir pressure at 1600 meters will fall to zero in the wellhead if the specific gravity is 800 kg/m². (0.8 times water). By injecting gas into this oil, the specific gravity is lowered and the well will start to flow. Typically gas injected between the casing and tubing, and a release valve on a gas lift mandrel is inserted into the tubing above the packer.



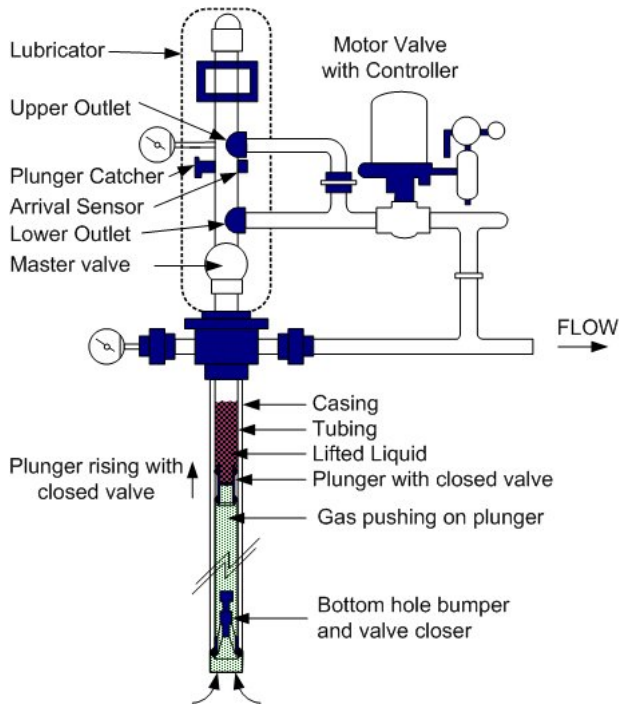
The valve will open at a set pressure to inject lift gas into the tubing. Several mandrels with valves set at different pressure ranges can be used to improve lifting and startup. *III: Schlumberger oilfield glossary*

Gas lift can be controlled for a single well to optimize production, and to reduce slugging effects where the gas droplets collect to form large bubbles that can upset production. Gas lift can also be optimized over several wells to use available gas in the most efficient way.

3.6.4 Plunger lift

The Plunger lift is normally used on low pressure gas wells with some condensate, oil or water, or high gas ratio oil wells. In this case the well flow conditions can be such that liquid starts to collect downhole and eventually blocks gas so that the well production stops. In this case a plunger with an open/close valve can be inserted in the tubing. A plunger catcher at the top opens the valve and can hold the plunger, while another mechanism downhole will close the valve.

The cycle starts with the plunger falling into the well with its valve open. Condensed gas and oil can pass through the plunger until it reaches bottom. There the valve is closed, now with a volume of oil, condensate or water on top. Gas pressure starts to accumulate under the plunger and after a time pushes the plunger upwards, with liquid on top, which eventually flows out of the wellhead discharge.



When the plunger reaches the wellhead plunger catcher, the valve opens and allows gas to flow freely for some time while new liquid collects at the bottom. After a preset time the catcher will release the plunger and the cycle repeats.

3.7 Well workover, intervention and stimulation.

After operating for some time, a well may become less productive or faulty due to residue build up, sand erosion, corrosion or reservoir clogging.

Well workover is the process of performing major maintenance on an oil or gas well. This might include replacement of the tubing, a cleanup or new completions, new perforations and various other maintenance works such as the installation of gas lift mandrels, new packing etc.

Through-tubing workover operation is work performed with special tools that do not require the time-consuming full workover procedure including replacement or removal of tubing. Well maintenance without killing the well and performing full workover is time-saving and often called **well intervention**. Various operations that are performed by lowering instruments or tools on a wire into the well are called **wireline operations**.

Work on the reservoir such as chemical injection, acid treatment, heating etc is referred to as **reservoir stimulation**. Stimulation serves to correct various forms of structure damage and improve flow. Damage is a generic term for accumulation of particles and fluids that block fractures and pores and limit reservoir permeability.

- Acids, such as HCL (Hydrochloric Acid) are used to open up calcareous reservoirs and to treat accumulation of calcium carbonates in the reservoir structure around the well. Several hundred liters of acid (typically 15% solution in water) are pumped into the well under pressure to increase permeability of the formation. When the pressure is high enough to open the fractures, the process is called fracture acidizing. If the pressure is lower, it is called matrix acidizing.
- Hydraulic fracturing is an operation in which a specially blended liquid is pumped down a well and into a formation under pressure high enough to cause the formation to crack open, forming passages through which oil can flow into the well bore. Sand grains, aluminum pellets, walnut shells, glass beads, or similar materials (propping agents) are carried in suspension by this fluid into the fractures. When the pressure is released at the surface, the fractures partially close on the propping agents, leaving channels for oil to flow through to the well. The fracture channels may be up to 100 meters long.
- Explosive fracturing uses explosives to fracture a formation. At the moment of detonation, the explosion furnishes a source of high-

pressure gas to force fluid into the formation. The rubble prevents fracture healing, making the use of propping agents unnecessary.

- Damage removal refers to other forms of removing formation damage, such as flushing out of drill fluids.

Flexible **coiled tubing** can be wound around a large diameter drum and inserted or removed much quicker than tubing installed from rigid pipe segments. Well workover equipment including coiled tubing is often mounted on well workover rigs.

4 The oil and gas process

The oil and gas process is the process equipment that takes the product from the wellhead manifolds and delivers stabilized marketable products, in the form of crude oil, condensates or gas. Components of the process also exist to test products and clean waste products such as produced water.

An example process for the Statoil Njord floater is shown on the next page. This is a medium size platform with one production train and a production of 40-45,000 barrels per day (bpd). This is actual production, after the separation of water and gas. The associated gas and water are used for onboard power generation and gas



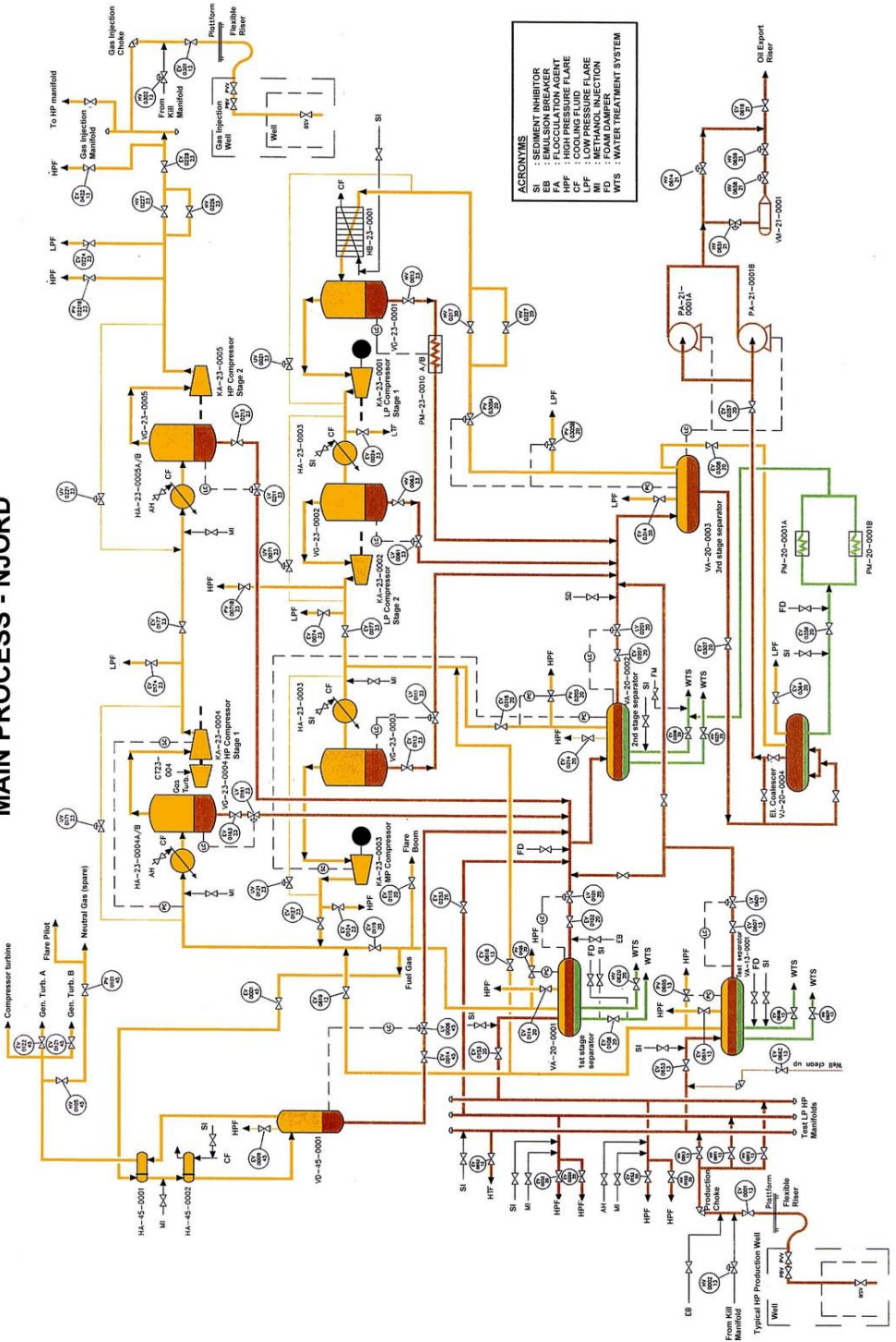
reinjection. There is only one separation and gas compression train. The water is treated and released (it could also have been reinjected). This process is quite representative for hundreds of similar sized installations, and only one more complete gas treatment train for gas export is missing to form a complete gas production facility, Njord sends the oil via a short pipeline to a nearby storage floater. On gravity base platforms, FPSO (Floating Production and Storage Operations) and onshore plants this storage will be a part of the main installation if the oil is not piped out directly.

Photo: Norsk Hydro ASA

A large number of connections to chemicals, flares etc. are shown, these systems are described separately.

Nård main process illustration (next page): Statoil

MAIN PROCESS - NJORD



4.1 Manifolds and gathering

4.1.1 Pipelines and risers

This facility uses subsea production wells. The typical High Pressure (HP) wellhead at the bottom right, with its Christmas tree and choke, is located on the sea bed. A production riser (offshore) or gathering line (onshore) brings the well flow into the manifolds. As the reservoir is produced, wells may fall in pressure and become Low Pressure (LP) wells.

This line may include several check valves. The choke, master and wing valves are relatively slow, therefore in the case of production shutdown, the pressure on the first sectioning valve closed will rise to the maximum wellhead pressure before these valves can close. The pipelines and risers are designed with this in mind.

Short pipeline distances are not a problem, but longer distances may cause a multiphase well flow to separate and form severe slugs - plugs of liquid with gas in between - traveling in the pipeline. Severe slugging may upset the separation process and cause overpressure safety shutdowns. Slugging might also occur in the well as described earlier. Slugging can be controlled manually by adjusting the choke, or by automatic slug controls. Furthermore, areas of heavy condensate might form in the pipelines. At high pressure, these plugs may freeze at normal sea temperature, e.g. if production is shut down or with long offsets. This can be prevented by injecting ethylene glycol. Glycol injection is not used at Njord.

The Njord floater has topside chokes for subsea wells. The diagram also shows that Kill Fluid, essentially high specific gravity mud, can be injected into the well before the choke.

4.1.2 Production, test and injection manifolds

Check valves allow each well to be routed into one or more of several manifold lines. There will be at least one for each process train plus additional manifolds for test and balancing purposes. In the diagram we show three: test, low pressure and high pressure manifolds. The test manifold allows one or more wells to be routed to the test separator. Since there is only one process train, the HP and LP manifolds allow groups of HP and LP wells to be taken to the first and second stage separators respectively. The chokes are set to reduce the wellhead flow and pressure to the desired HP and LP pressures respectively.

The desired setting for each well and which of the wells produce at HP and LP for various production levels are defined by reservoir specialists to ensure the optimum production and recovery rate.

4.2 Separation

As described earlier, the well-stream may consist of crude oil, gas, condensates, water and various contaminants. The purpose of the separators is to split the flow into desirable fractions.

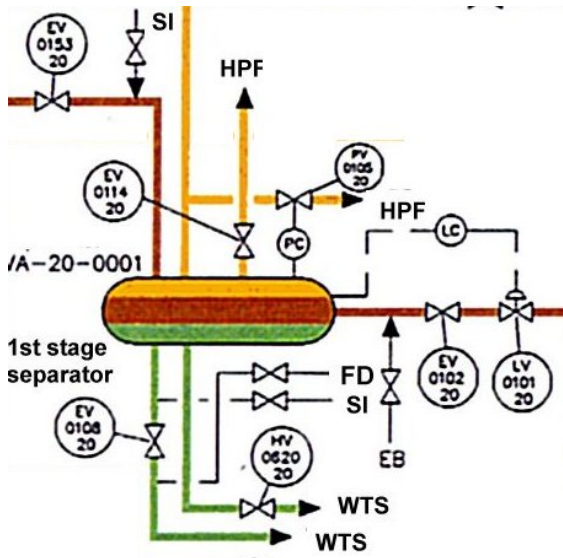
4.2.1 Test separators and well test

Test separators are used to separate the well flow from one or more wells for analysis and detailed flow measurement. In this way, the behavior of each well under different pressure flow conditions can be defined. This normally takes place when the well is taken into production and later at regular intervals, typically 1-2 months and will measure the total and component flow rates under different production conditions. Undesirable consequences such as slugging or sand can also be determined. The separated components are analyzed in the laboratory to determine hydrocarbon composition of the gas oil and condensate.

Test separators can also be used to produce fuel gas for power generation when the main process is not running. Alternatively, a three phase flow meter could be used to save weight.

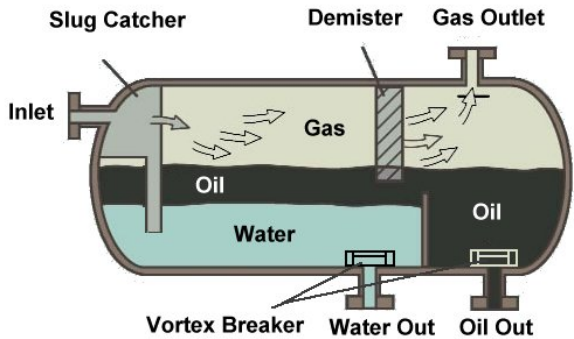
4.2.2 Production separators

The main separators shown here are gravity types. On the right you see the main components around the first stage separator. As mentioned before, the production choke reduces well pressure to the HP manifold and first stage separator to about 3-5 MPa



(30-50 times atmospheric pressure). Inlet temperature is often in the range of 100-150 degrees C. On the example platform, the well stream is colder due to subsea wells and risers.

The pressure is often reduced in several stages, in this instance three stages are used to allow the controlled separation of volatile components. The idea is to achieve maximum liquid recovery and stabilized oil and gas and to separate water. A large pressure reduction in a single separator will cause flash vaporization leading to instability and safety hazards.



The retention period is typically 5 minutes, allowing the gas to bubble out, water to settle at the bottom and oil to be taken out in the middle. In this platform the water cut (percentage water in the well flow) is almost 40% which is quite high. In the first stage separator, the water content is typically reduced to less than 5%.

At the crude entrance, there is a baffle **slug catcher** that will reduce the effect of slugs (large gas bubbles or liquid plugs). However some turbulence is desirable as this will release gas bubbles faster than a laminar flow.

At the end, there are barriers up to a certain level to keep back the separated oil and water. The main control loops are the oil level control loop (EV0101 20 above) controlling the oil flow out of the separator on the right, and the gas pressure loop at the top.(FV0105 20 above) These loops are operated by the Control System. An important function is also to prevent **gas blow-by** which happens when a low oil level causes gas to exit via the oil output causing high pressure downstream. There are generally many more instruments and control devices mounted on the separator. These will be discussed later.

The liquid outlets from the separator will be equipped with **vortex breakers** to reduce disturbance on the liquid table inside. This is basically a flange trap to break any vortex formation and ensure that only separated liquid is tapped off and not mixed with oil or water drawn in through these vortices. Similarly

the gas outlets are equipped with **demisters**, essential filters that will remove liquid droplets in the gas.

Emergency Valves (EV) are sectioning valves that will separate the process components and blow-down valves, this will allow excess hydrocarbons to be burned off in the flare. These valves are operated if critical operating conditions are detected or on manual command, by a dedicated Emergency Shutdown System. This might involve partial shutdown and shutdown sequences since the flare might not be able to handle a full blow-down of all process sections simultaneously.

A 45,000 bpd design production with gas and 40% water cut will give about 10 cubic meters from the wellheads per minute. There also needs to be enough capacity to handle normal slugging from wells and risers. This means the separator has to be about 100 cubic meters, e.g. a cylinder 3 meters in diameter and 14 meters in length at the rated operating pressure. This means a very heavy piece of equipment, typically around 50 tons for this size, which limits the practical number of stages. Other types of separators such as vertical separators or cyclones (centrifugal separation) can be used to save weight, space or improve separation (see later).

There also has to be a certain minimum pressure difference between each stage to allow satisfactory performance in the pressure and level control loops. Chemical additives will be discussed later.

4.2.3 Second stage separator

The second stage separator is quite similar to the first stage HP separator. In addition to output from the first stage, it will also receive production from wells connected to the Low Pressure manifold. The pressure is now around 1 MPa (10 atmospheres) and temperature below 100 degrees C. The water content will be reduced to below 2%.

An oil heater could be located between the first and second stage separator to reheat the oil/water/gas mixture. This will make it easier to separate out water when initial water cut is high and temperature is low. The heat exchanger is normally a tube/shell type where oil passes through tubes in a heating medium placed inside an outer shell.

4.2.4 Third stage separator

The final separator here is a two-phase separator, also called a flash drum. The pressure is now reduced to atmospheric pressure of around 100 kPa, so that the last heavy gas components will boil out. In some processes where

the initial temperature is low, it might be necessary to heat the liquid (in a heat exchanger) again before the flash drum to achieve good separation of the heavy components. There are level and pressure control loops.

As an alternative, when the production is mainly gas, and remaining liquid droplets have to be separated out, the two-phase separator can be a Knock-Out Drum (K.O. Drum).

4.2.5 Coalescer

After the third stage separator, the oil can go to a coalescer for final removal of water. In this unit the water content can be reduced to below 0.1%. The coalescer is completely filled with liquid: water at the bottom and oil on top. Internal electrodes form an electric field to break surface bonds between conductive water and isolating oil in an oil water emulsion. The coalescer field plates are generally steel, sometimes covered with dielectric material to prevent short-circuits. The critical field strength in oil is in the range of 0.2 to 2 kV/cm. Field intensity and frequency as well as the coalescer grid layout are different for different manufacturers and oil types.

4.2.6 Electrostatic desalter

If the separated oil contains unacceptable amounts of salts, they can be removed in an electrostatic desalter (not used in the Njord example) The salts, which may be sodium, calcium or magnesium

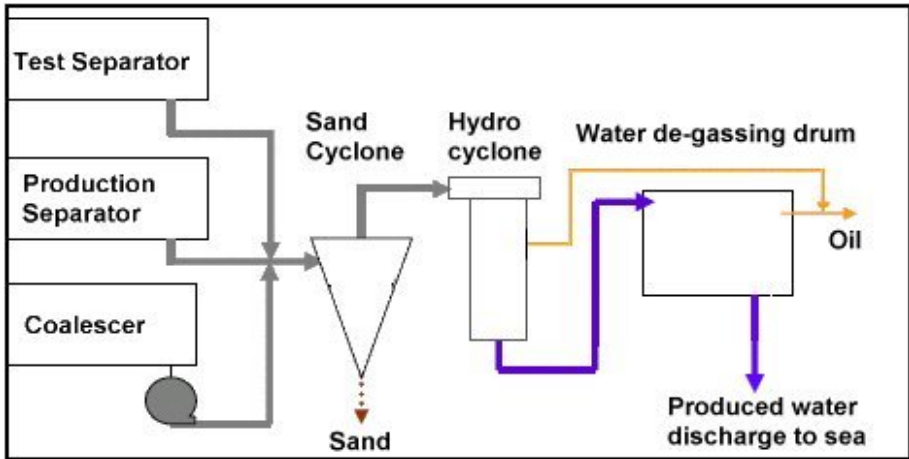


chlorides come from the reservoir water and are also dissolved in the oil. The desalters will be placed after the first or second stage separator depending on Gas Oil Ratio (GOR) and water cut. *Photo: Burgess Manning Europe PLC*

4.2.7 Water treatment

On an installation such as this, where the water cut is high, there will be a huge amount of water produced. In our example, a water cut of 40% gives water production of about 4000 cubic meters per day (4 million liters) that must be cleaned before discharge to sea. Often this water contains sand particles bound to the oil/water emulsion.

The environmental regulations in most countries are quite strict, for example, in the North-East Atlantic the OSPAR convention limits oil in water discharged to sea to 40 mg/liter (ppm).



It also places limits on other forms of contaminants. This still means that the equivalent of up to one barrel of oil per day in contaminants from the above production is discharged into the sea, but in this form, the microscopic oil drops are broken down fast by natural bacteria.

Various pieces of equipment are used. This illustration shows a typical water treatment system. Water from the separators and coalescers first goes to a **sand cyclone**, which removes most of the sand. The sand is further washed before it is discharged.

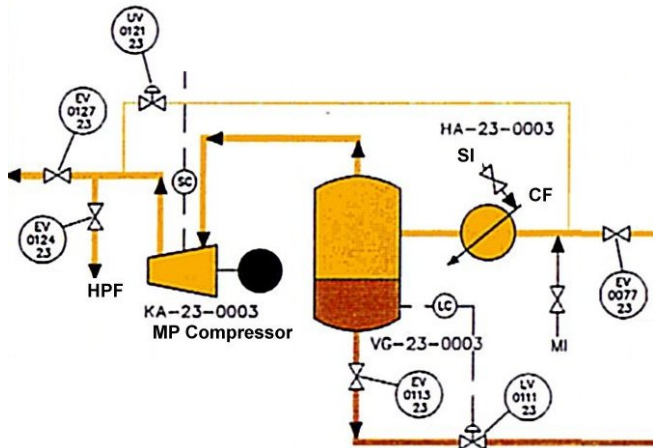
The water then goes to a **hydrocyclone**, a centrifugal separator that will remove oil drops. The hydrocyclone creates a standing vortex where oil collects in the middle and water is forced to the side.

Finally the water is collected in the **water de-gassing drum**. Dispersed gas will slowly rise to the surface and pull remaining oil droplets to the surface by flotation. The surface oil film is drained, and the produced water can be discharged to sea. Recovered oil in the water treatment system is typically recycled to the third stage separator.

4.3 Gas treatment and compression

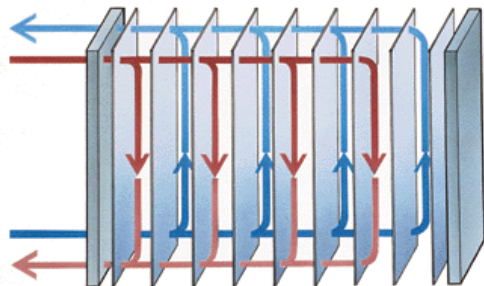
The gas train consists of several stages, each taking gas from a suitable pressure level in the production separator's gas outlet, and from the previous stage.

A typical stage is shown on the right. Incoming gas (on the right) is first cooled in a **heat exchanger**. It then passes through the **scrubber** to remove liquids and goes into the compressor. The **anti surge** loop (thin orange line) and the surge valve (UV0121 23) allow the gas to recirculate. The components are described below.



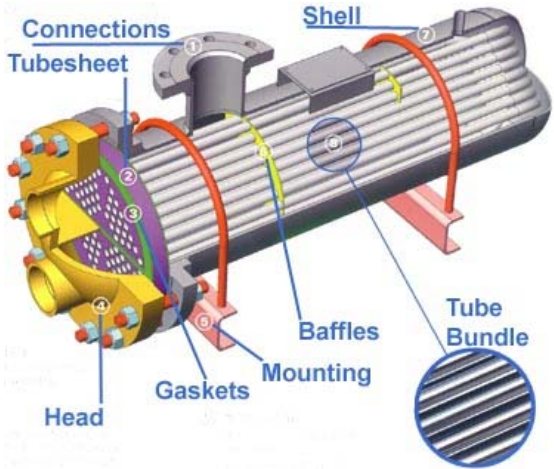
4.3.1 Heat exchangers

For the compressor to operate efficiently, gas temperature should be low. The lower the temperature, the less energy will be used to compress the gas for the given final pressure and temperature. However both gas from separators and compressed gas are relatively hot. When gas is compressed, it must remain in thermodynamic balance, which means that the gas pressure times the volume over the temperature (PV/T) must remain constant. ($PV = nkT$). This ends up as a temperature increase.



Heat exchangers of various forms are used to cool the gas. Plate heat exchangers (upper picture) consist of a number of plates where the gas and cooling medium pass between alternating plates in opposing directions. Tube and shell exchangers (next picture) place tubes inside a shell filled with of cooling fluid. The cooling fluid is often pure water with corrosion inhibitors.

When designing the process, it is important to plan the thermal energy balance. Heat should be conserved e.g. by using the cooling fluid from the gas train to reheat oil in the oil train. Excess heat is dispersed e.g. by seawater cooling. However hot seawater is extremely corrosive, so materials with high resistance to corrosion, such as titanium must be used. *Photo: SEC Shell and Tube Heat Exchanges*



4.3.2 Scrubbers and reboilers

The separated gas may contain mist and other liquid droplets. Drops of water and hydrocarbons also form when the gas is cooled in the heat exchanger, and must be removed before it reaches the compressor. If liquid droplets enter the compressor they will erode the fast rotating blades. A scrubber is designed to remove small fractions of liquid from the gas.

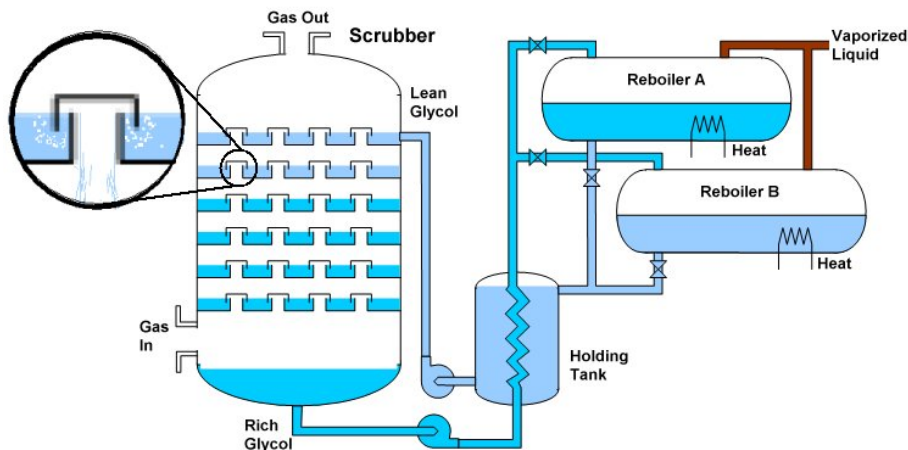
There are various types of gas-drying equipment available, but the most common suction (compressor) scrubber is based on dehydration by absorption in Triethylene Glycol (TEG). The scrubber consists of many levels of glycol layers.

A large number of gas traps (enlarged detail) force the gas to bubble up through each glycol layer as it flows from the bottom up each section to the top.

Processed glycol is pumped in at the top from the holding tank. It flows from level to level against the gas flow as it spills over the edge of each trap. During this process it absorbs liquids from the gas and comes out as rich

glycol at the bottom. The holding tank also functions as a heat exchanger for liquid to and from the reboilers.

The glycol is recycled by removing the absorbed liquid. This is done in the reboiler, which is filled with rich glycol and heated to boil out the liquids at temperature of about 130-180 °C (260-350 °F) for a number of hours.



Usually there is a distillation column on the gas vent to further improve separation of glycol and other hydrocarbons. For higher capacity, there are often two reboilers which alternate between heating rich glycol and draining recycled processed glycol.

On a standalone unit, the heat is supplied from a burner that uses the recovered vaporized hydrocarbons. In other designs, heating will be a combination of hot cooling substances from other parts of the process and electric heaters, and recycle the hydrocarbon liquids to the third stage separator

4.3.3 Compressor anti surge and performance

Several types of compressors are used for gas compression, each with different characteristics such as operating power, speed, pressure and volume:

- Reciprocating compressors, which use a piston and cylinder design with 2-2 cylinders are built up to about 30 MW power, around 500-1800 rpm (lower for higher power) with pressure up to 5MPa (500 bars).



Used for lower capacity gas compression and high reservoir pressure gas injection. *Photo: Ariel corp.*

- Screw compressors are manufactured up to several MW, synchronous speed (3000/3600 rpm) and pressure up to about 2.5 MPa (25 bar). Two counter-rotating screws with matching profiles provide positive displacement and a wide operating range. Typical use is natural gas gathering.

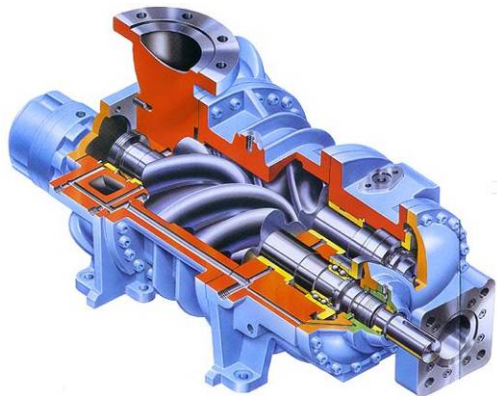
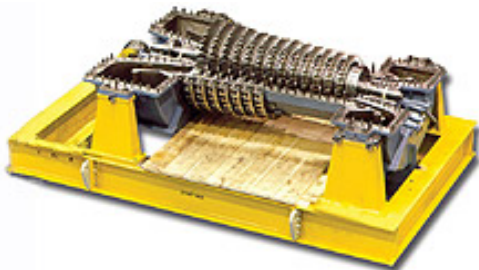


Photo: Mycom/Mayekawa mfg.

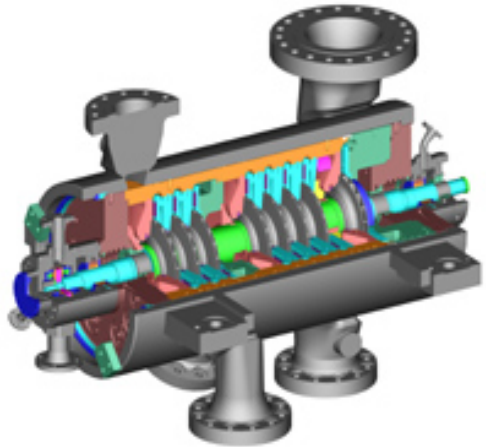
- Axial blade and fin type compressors with up to 15 wheels provide high volumes at relatively low pressure differential (discharge pressure 3-5 times inlet pressure), speeds of 5000-8000 rpm, and inlet flows up to 200,000 m³/hour.



Applications include air compressors and cooling compression in LNG plants. *Axial rotor photo: Dresser Rand*

- Larger oil and gas installations use centrifugal compressors with 3-10 radial wheels, 6000–20000 rpm (highest for small size), up to 80 MW load at discharge pressure of up to 50 bars and inlet volumes of up to 500,000 m³/hour. Pressure differential up to 10.

Photo: Dresser Rand



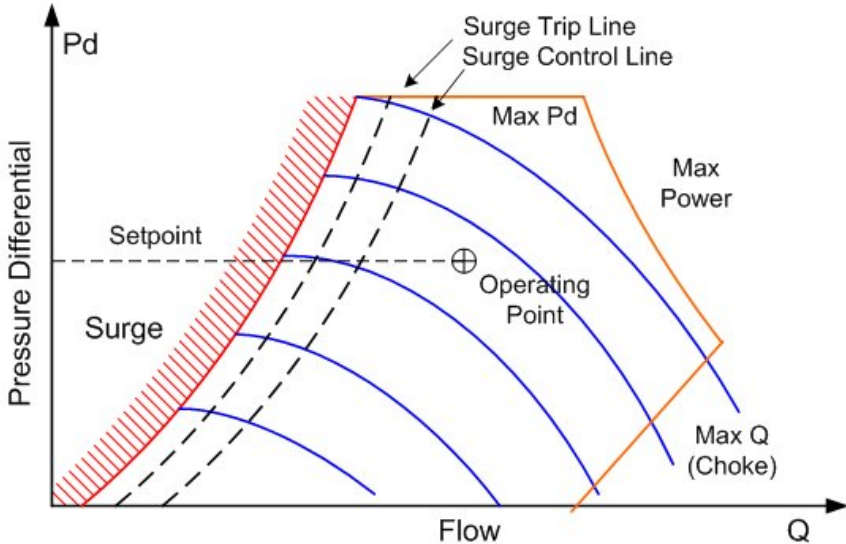
Most compressors will not cover the full pressure range efficiently. The lowest pressure is atmospheric, for gas to pipeline, some 3 to 5 MPa (30-50 bar) pressure is used, while reservoir reinjection of gas will typically require 20 MPa (200 bar) and upwards since there is no liquid in the tubing and the full reservoir pressure must be overcome. Therefore compression is divided into several stages to improve maintenance and availability.

Also due to single unit power limitations, compression is often divided in several parallel trains. This is not the case in this example since gas is not exported, and reinjection can be interrupted during maintenance periods.

Compressors are driven by gas turbines or electrical motors (for lower power also reciprocating engines, steam turbines are sometimes used if thermal energy is available). Often several stages in the same train are driven by the same motor or turbine.

The main operating parameters for a compressor are the flow and pressure differentials. The product defines the total loading, so there is a ceiling set by the maximum design power. Furthermore, there is a maximum differential pressure (Max P_d) and choke flow (Max Q), the maximum flow that can be achieved. At lower flow, there is a minimum pressure differential and flow before the compressor will "surge" if there is not enough gas to operate. If variations in flow are expected or difference between common shaft compressors will occur, the situation will be handled with recirculation. A high flow, high pressure differential surge control valve will open to let gas from the discharge side back into the suction side. Since this gas is heated it will also pass through the heat exchanger and scrubber not to become overheated by circulation.

The operating characteristics are defined by the manufacturer. In the above diagram the blue lines mark constant speed lines. The maximum operating limits are set by the orange line as described above. The surge domain is the area to the left of the red surge curve.



The objective of **compressor performance control** is to keep the operating point close to the optimal set point without violating the constraints, by means of control outputs, such as the speed setting. However, gas turbine speed control response is relatively slow and even electric motors are not fast enough, since surge response must be in the 100 ms range. **Anti surge control** will protect the compressor from going into surge by operating the surge control valve. The basic strategy is to use distance between operating point and surge line to control the valve with a slower response time starting at the surge control line. Crossing the surge trip line will cause a fast response opening of the surge valve to protect the compressor.

Operation with recirculation wastes energy (which could result in unnecessary emissions) and produces wear and tear, particularly on the surge valve. Each vendor supplies several variants of compressor control and anti surge control to optimize performance, based on various corrective and predictive algorithms. Some strategies include:

- Set point adjustment: If rapid variations in load cause surge valve action, the set point will be moved to increase the surge margin.

- Equal margin: The set point is adjusted to allow equal margin to surge between several compressors.
- Model based control: Outside the compressor itself, the main parameter for the surge margin is the total volume from the surge valve to the compressor suction inlet, and the response time for the surge valve flow. A model predictive controller could predict surge conditions and react faster to real situations while preventing unnecessary recirculation.

Since compressors require maintenance and are potentially expensive to replace, several other systems are normally included:

Load management: To balance loading among several compressors in a train and between trains, the compressor control system often includes algorithms for load sharing, load shedding and loading. Compressors are normally purged with inert gas, such as nitrogen, during longer shutdowns, e.g. for maintenance. Therefore, startup and shutdown sequences will normally include procedures to introduce and remove the purge gas.

Vibration: Vibration is a good indicator of problems in compressors, and accelerometers are mounted on various parts of the equipment to be logged and analyzed by a vibration monitoring system.

Speed governor If the compressor is turbine driven, a dedicated speed governor handles the fuel valves and other controls on the turbine to maintain efficiency and control rotational speed. For electrical motors this function is handled by a variable speed drive.

The final function around the compressor itself is **lube and seal oil** handling. Most compressors have wet seals, which are traps around shafts where oil at high pressure prevents gas from leaking out to atmosphere or other parts of the equipment. Oil is used for lubrication of the high speed bearings. This oil gradually absorbs gas under pressure and may become contaminated. So it needs to be filtered and degassed. This happens in smaller reboilers much the same way as for the glycol reboilers described earlier.

4.3.4 Gas treatment

When gas is exported, many gas trains include additional equipment for further gas processing to remove unwanted components such as hydrogen sulfide and carbon dioxide. These gases are called **acids** and **sweetening/acid removal** is the process of taking them out.

Natural gas sweetening methods include absorption processes, cryogenic processes; adsorption processes (PSA, TSA and iron sponge) and membranes. Often hybrid combinations are used, such as cryogenic and membranes.

Gas treatment could also include calibration. If the delivery specification is for a specific calorific value (BTU per scf or MJ per scm) gas with higher values can be adjusted by adding an inert gas, such as nitrogen. This is often done at a common point such as a pipeline gathering system or a pipeline onshore terminal.

4.4 Oil and gas storage, metering and export

The final stage before the oil and gas leaves the platform consists of storage, pumps and pipeline terminal equipment.

4.4.1 Fiscal metering

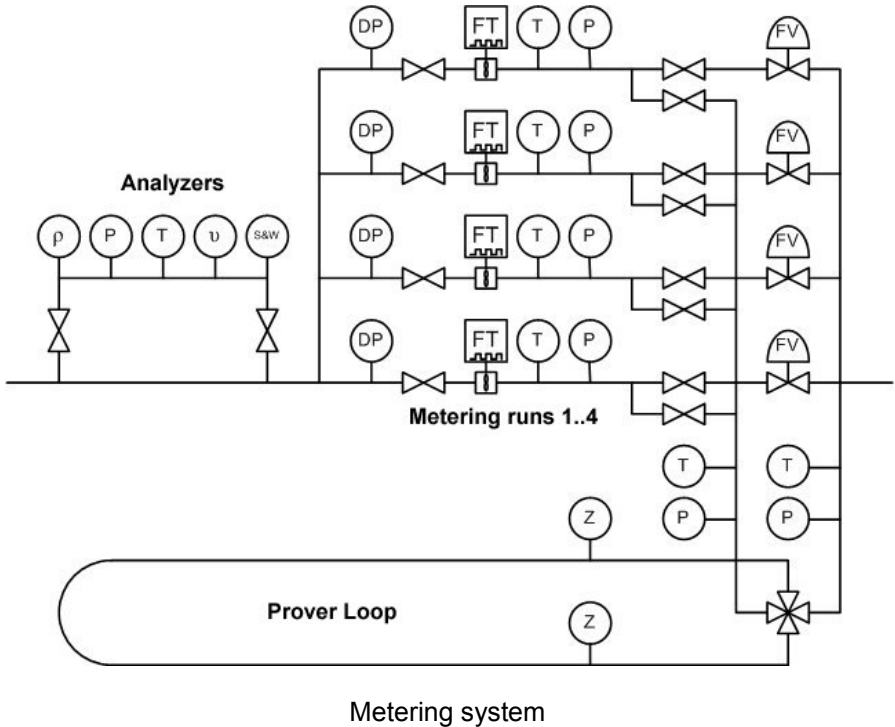
Partners, authorities and customers all calculate invoices, taxes and payments based on the actual product shipped out. Often custody transfer also takes place at this point, which means transfer of responsibility or title from the producer to a customer, shuttle tanker operator or pipeline operator.

Although some small installations are still operated with a dipstick and manual records, larger installations have analysis and metering equipment. To make sure readings are accurate, a fixed or movable prover loop for calibration is also installed.

The illustration shows a full liquid hydrocarbon (oil and condensate) metering system. The analyzer instruments on the left provide product data such as density, viscosity and water content. Pressure and temperature compensation is also included.

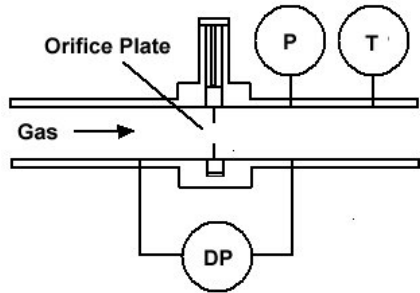
For liquids, turbine meters with dual pulse outputs are most common. Alternatives are positive displacement meters (pass a fixed volume per rotation or stroke) and coriolis mass flow meters. These instruments cannot cover the full range with sufficient accuracy. Therefore the metering is split into several runs, and the number of runs depends on the flow. Each run

employs one meter and several instruments to provide temperature and pressure correction. Open/close valves allow runs to be selected and control valves can balance the flow between runs. The instruments and actuators are monitored and controlled by a flow computer. If the interface is not digital, dual pulse trains are used to allow direction sensing and fault finding.



To obtain the required accuracy, the meters are calibrated. The most common method is a prover loop. A prover ball moves through the loop, and a calibrated volume is provided between the two detectors (Z). When a meter is to be calibrated the four way valve opens to allow oil to flow behind the ball. The number of pulses from it passes one detector Z to the other and is counted. After one loop the four way valve turns to reverse flow direction and the ball moves back providing the same volume and in reverse, again counting the pulses. From the known reference volume, number of pulses, pressure and temperature the flow computer can calculate the meter factor and provide accurate flow measurements using formulas from industry standard organizations such as API MPMS and ISO 5024. The accuracy is typically $\pm 0.3\%$ of standard volume.

Gas metering is similar, but instead, analyzers will measure hydrocarbon content and energy value (MJ/scm or BTU, Kcal/scf) as well as pressure and temperature. The meters are normally orifice meters or ultrasonic meters. Orifice plates with a diameter less than the pipe are mounted in cassettes. The pressure differential over the orifice plate as well as pressure and temperature is used in standard formulas (such as AGA 3 and ISO 5024/5167) to calculate normalized flow. Different ranges are accommodated with different size restrictions.



Orifice plates are sensitive to a buildup of residue and effect on the edges of the hole. Larger new installations therefore prefer ultrasonic gas meters that work by sending multiple ultrasonic beams across the path and measure the Doppler Effect.

Gas metering is less accurate than liquid, typically $\pm 1.0\%$ of mass. There is usually no prover loop, the instruments and orifice plates are calibrated in separate equipment instead.

LNG is often metered with mass flow meters that can operate at the required low temperature. A three run LNG g metering skid is shown above.



At various points in the movement of oil and gas, similar measurements are taken, usually in a more simplified way. Examples of different gas types are flare gas, fuel gas and injected gas where required accuracy is 2-5% percent.

4.4.2 Storage

On most production sites, the oil and gas is piped directly to a refinery or tanker terminal. Gas is difficult to store locally, but occasionally underground mines, caverns or salt deposits can be used to store gas.



On platforms without a pipeline, oil is stored in onboard storage tanks to be transported by shuttle tanker. The oil is stored in storage cells around the shafts on concrete platforms, and in tanks on floating units. On some floaters, a separate storage tanker is used. Ballast handling is very important in both cases to balance the buoyancy when the oil volume varies. For onshore, fixed roof tanks are used for crude, floating roof for condensate. Rock caves are also used for storage

Special tank gauging systems such as level radars, pressure or float are used to measure the level in storage tanks, cells and caves. The level measurement is converted to volume via tank strapping tables (depending on tank geometry) and compensated for temperature to provide standard volume. Float gauges can also calculate density, and so mass can be established.

A tank farm consists of 10-100 tanks of varying volume for a typical total capacity in the area of 1 - 50 million barrels. Storage or shuttle tankers normally store up to two weeks of production, one week for normal cycle and one extra week for delays e.g. bad weather. This can amount to several million barrels.

Accurate records of volumes and history are kept to document what is received and dispatched. For installations that serve multiple production sites, different qualities and product blending must also be handled. Another planning task is forecasting for future received and delivered products. This is for stock control and warehousing requirements. A tank farm management system keeps track of all stock movements and logs all transport operations that take place

4.4.3 Marine loading

Loading systems consist of one or more loading arms/jetties, pumps, valves and a metering system.

Tanker loading systems are complex, both because of the volume involved, and because several loading arms will normally interact with the tanker's ballast system to control the loading operation. The tanks must be filled in a certain sequence; otherwise the tanker's structure might be damaged due to uneven stresses. It is the responsibility of the tanker's ballast system to signal data to the loading system and to operate the different valves and monitor the tanks on board the ship. Photo: StatoilHydro



4.4.4 Pipeline terminal

The gas pipeline is fed from the high pressure compressors. Oil pipelines are driven by separate booster pumps. For longer pipelines, intermediate compressor stations or pump stations will be required due to distance or crossing of mountain ranges. Block valve stations are placed at regular intervals to limit the potential leakage volume in case of a pipe rupture.



The pipeline terminal includes termination systems for the pipeline. A pig launcher and receiver will be included at the least, to allow insertion of a pipeline pigging device used to clean or inspect the pipeline on the inside. This is essentially a large chamber that can be pressurized and purged to insert and remove the pig or scraper without depressurizing the pipeline. The pig is often driven by pipeline flow.

5 Gas processing and LNG

Raw natural gas from the well consists of methane as well as many other smaller fractions of heavier hydrocarbons, and various other components.

Component	Chemical Formula	Boiling Point at 101 kPa	Vapor pressure at 20 °C approx.
Methane	CH ₄	-161,6 °C	T _{crit} -82.6 °C @ 4,6 MPa
Ethane	C ₂ H ₆	-88.6 °C	4200 kPa
Propane	C ₃ H ₈	-42.1 °C	890 kPa
Butane	n-C ₄ H ₁₀	-0.5 °C	210 kPa
Higher order HC Alkenes Aromatics	C _n H _{2n} e.g. C ₆ H ₆		
Acid Gases Carbon Dioxide Hydrogen Sulfide Mercaptans ex. Methanethiol Ethanethiol	CO ₂ H ₂ S CH ₃ SH C ₂ H ₅ SH	-78 °C -60.2 °C 5.95 °C 35 °C	5500 kPa
Other Gases Nitrogen Helium	N ₂ He	-195.79 °C -268.93 °C	
Water	H ₂ O	0 °C	
Trace pollutants Mercury Clorides			

Data source: Wikipedia, Air Liquide Gas Encyclopedia

The natural gas is characterized in several ways dependant on the content of these components:

- **Wet gas** is raw gas with a methane content of less than 85%
- **Dry gas** is raw or treated natural gas that contains less than 15 liters of condensate per 1000 SM³. (0.1 gallon per 1000 scf).
- **Sour gas** is raw gas with a content of more than 5.7 mg hydrogen sulfide (H₂S) per scm (0.25 grains per 100 scf), this is about 4 ppm.
- **Acid gas** has a high content of acidic gases such as carbon dioxide (CO₂) or H₂St. Pipeline natural gas specification is typically less than

2% CO₂. Acid gas fields with up to 90% CO₂ exist, but the normal range for sour raw gas is 20-40%.

- **Condensates** are a mixture of hydrocarbons and other components in the above table. These are normally gaseous from the well but condense out as liquid during the production process (see previous chapter). This is a refinery and petrochemical feedstock.

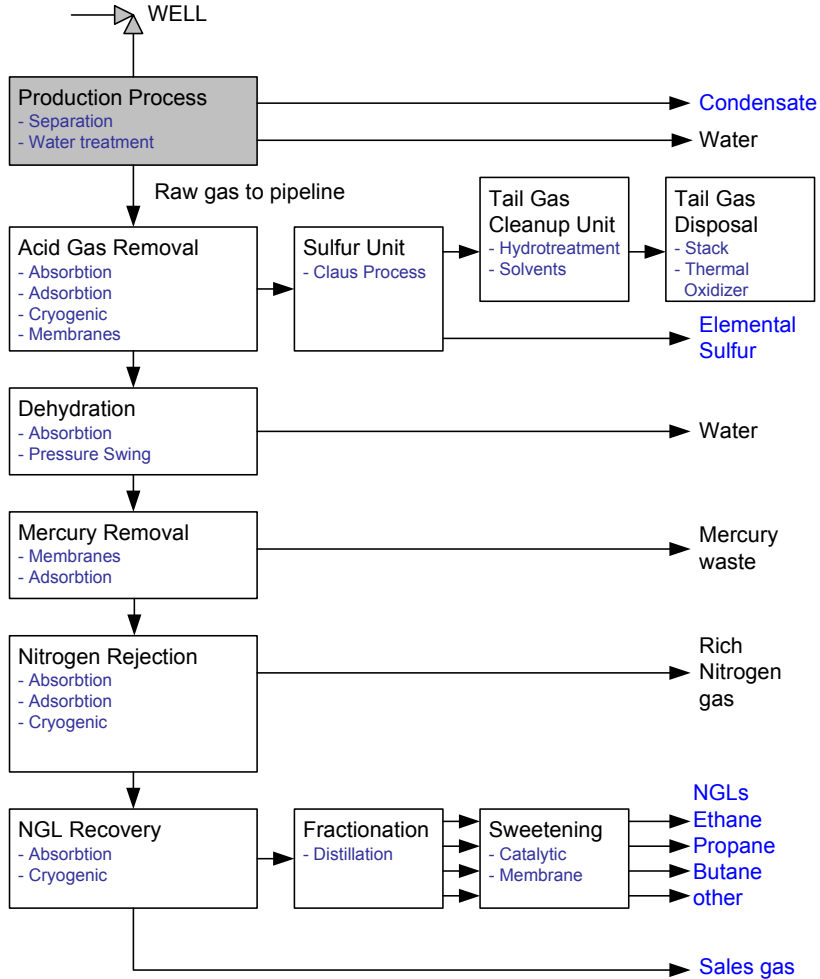
Raw gas is processed into various products or fractions:

- **Natural Gas** in its marketable form has been processed for a specific composition of hydrocarbons, sour and acid components etc. and energy content. Content is typically 90% methane, with 10% other light alkenes.
- **Natural Gas Liquids (NGL)** is a processed purified product consisting of ethane, propane, butane or some higher alkenes separately, or in a blend. It is primarily a raw material for petrochemical industry and is often processed from the condensate.
- **Liquefied Petroleum Gas (LPG)** refers to propane or butane or a mixture of these that has been compressed to liquid at room temperature (200 to 900 kPa depending on composition). LPG is filled in bottles for consumer domestic use as fuel, and is also used as aerosol propellant (in spray cans) and refrigerant (e.g. in air conditioners). Energy to volume ratio is 74% of gasoline.
- **Liquefied Natural Gas (LNG)** is natural gas that is refrigerated and liquefied at below -162 °C, for storage and transport. It is stored at close to atmospheric pressure, typically less than 125 kPa. As a liquid, LNG takes up 1/600 of the volume of the gas at room temperature. Energy to volume ratio is 66% of gasoline. After transport and storage it is reheated/vaporized and compressed for pipeline transport.
- **Compressed Natural Gas (CNG)** is natural gas that is compressed at 2-2,2 MPa to less than 1% of volume at atmospheric pressure. Unlike higher alkenes, methane cannot be kept liquid by high pressure at normal ambient temperatures because of a low critical temperature. CNG is used as a less costly alternative to LNG for lower capacity and medium distance transport. Methane for vehicle fuel is also stored as CNG. Energy to volume ratio is typically 25% of gasoline.

5.1 Gas processing

Raw natural gas must be processed to meet the trading specifications of pipeline and gas distribution companies. As part of the purification other components such as NGL is produced, and pollutants extracted.

The diagram shows an overview of a typical gas plant. Marketable products are listed in blue and the production process is shown in grey as it is not considered part of the gas plant.



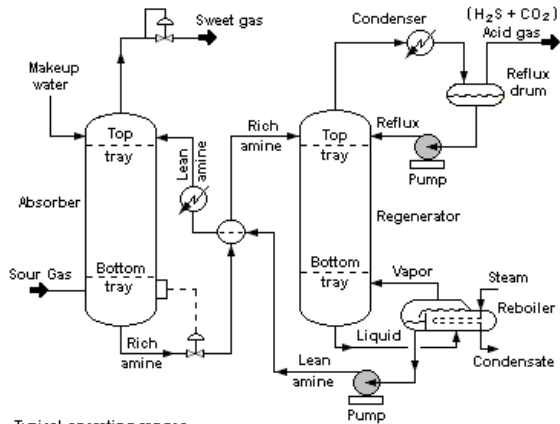
Typical gas plant

5.1.1 Acid gas removal

Acid gases such as carbon dioxide and hydrogen sulfide form acids when reacting with water, and must be removed to prevent corrosive damage to equipment and pipelines. Hydrogen sulfide is also toxic and total sulfur content is normally regulated.

The main removal process can be based on several principles:

Absorption allows acidic gases to be dissolved in a solvent, to be released by regeneration in a later stage. Amine absorption (as shown on the right) is the most common process for acid gas removal. Monoethanolamines (MEA) dominate for CO₂ removal. Solutions with inorganic solvents based on ammonia are under development. *Wikipedia*



Typical operating ranges

Absorber : 35 to 50 °C and 5 to 205 atm of absolute pressure
 Regenerator : 115 to 126 °C and 1.4 to 1.7 atm of absolute pressure
 at tower bottom

A typical amine gas treating process (as shown in the flow diagram) consists of an absorber unit, a regenerator unit and accessory equipment. In the absorber, a "lean" amine solution absorbs H₂S and CO₂ from the upflowing sour gas to produce a sweetened gas stream as a product. The "rich" amine solution contains the absorbed acid gases and is routed into the regenerator (a stripper with a reboiler). The stripped overhead gas from the regenerator is concentrated H₂S and CO₂.

Adsorption relies on the molecules to bind to the surface of certain solids. After a certain time the material must be regenerated to release the gas. Principles used include Pressure Swing Adsorption (PSA), Temperature Swing Adsorption (TSA) and Electric Swing Adsorption (ESA)

Cryogenic removal uses a turbo expander: A gas turbine is driven by the expanding gas which then cools to below the dew point for the gas to be removed.

The inlet gas to the compressor is precooled by the acid gas removed. Cryogenic removal is most often used when the content of carbon dioxide is high, typically around 50%.

Membrane based removal is based on certain materials that allow the acid gases, but not the hydrocarbons, to diffuse through the membrane. This procedure can be performed alone or in combination with absorption liquid.

Sulfur Unit. The H₂S-rich stripped gas stream is then fed to a Claus process - a multistage process with two main sections: A thermal section fires H₂S with air or oxygen to produce SO₂ and elemental sulfur which is released when cooled. A catalytic section allows more H₂S to react with SO₂ with alumina or titanium dioxide (TiO₂) to produce water and elemental sulfur (the Claus reaction: $2\text{H}_2\text{S} + \text{SO}_2 \rightarrow 3\text{S} + 2\text{H}_2\text{O}$). The Claus process can recover 95-97% of the sulfur in the feed gases.

A **Tail Gas Treatment** unit serves to reduce the sulfur content to below 250 ppm, corresponding to a total sulfur recovery of 99.9%. More complex solutions can reduce total sulfur down to 10 ppm. Some important processes include SCOT (Shell Claus Offgas Treatment) which removes SO₂ by combustion with hydrogen over catalysts to produce H₂S and water. H₂S is recycled to the Claus unit. Other solutions are the Beavon Sulfur Removal (BSR) process based on amine solvent and catalysts.

5.1.2 Dehydration

Dehydration is either glycol-based scrubbers as described in chapter 4.3.2 or based on Pressure Swing Adsorption (PSA). Newer processes also use membranes.

5.1.3 Mercury removal

Mercury removal is generally based on **molecular sieves**. A molecular sieve is a substance containing a material with tiny pores to achieve a large surface area, such as activated carbon. The surface of the material allows certain molecules to bind by surface tension. The molecules can later be extracted and the sieve material regenerated by heating, pressure and/or purging with a carrier gas.

A molecular sieve is commonly cyclic with one active unit and one (or more) units in regeneration.

5.1.4 Nitrogen rejection

Excessive nitrogen is removed by cryogenic distillation and higher concentrations are removed by absorption with lean oil or another special solvent if a smaller fraction is detected. (See acid gas removal for both principles). Cryogenic removal also permits production of helium, if present, as a valuable by-product.

5.1.5 NGL recovery and treatment

Remaining NGLs are recovered from the gas stream in most modern plants by a cryogenic turbo expander based process followed by a fractionating process. This process leads the cooled NGLs through distillation columns called de-ethanizer, de-propanizer and de-butanizer, to extract ethane, propane and butane respectively and leave a residual stream of pentane and higher hydrocarbons.

The final step is to remove mercaptans (smelly organic gases e.g. CH_3SH) if present, in a sweetening process, based on molecular sieves adsorption or catalytic oxidization such as Merox – mercaptan oxidization or Sulfrex, where the main difference is a type of catalyst.

5.1.6 Sales gas specifications

The exact sales gas specification is specified by pipeline operators and distributors. Typical standard sales gas requirements are for the following parameters:

Volume is measured in standard cubic meters (scm) defined as 1 m^3 at 0°C and 101.325 kPa or standard cubic feet (scf) as 1 ft^3 at 60°F (16°C) and 14.73 PSIA

Calorific value specifies the total amount of energy per unit generated during combustion of the gas. The value is used to calculate the amount of energy delivered. Several values are listed:

- **Gross calorific value or gross heat of combustion:** is the heat released when a specific quantity of fuel in mixture with air is ignited and the end products have returned to the initial temperature, normally 25°C . EU specifications are typically 38.8 MJ (10.8 kWh) $\pm 5\%$ per scm. In the US 1030 BTU $\pm 5\%$ per scf.

- **Net calorific value or net heat of combustion:** is the net heat generated when the water vapor in the gas does not condense (water forms during combustion) and can be 10% lower.

Wobbe index measures the heating effect that a burner is exposed to during combustion. A higher value means a greater thermal load on the burner. Different gases with the same Wobbe index will impose the same load on the burner. An excessively high value is a safety hazard as it can lead to burner overheating and to excess production of carbon monoxide during combustion.

Calorific value and Wobbe index can be adjusted by blending gas from different sources as well as by addition or removal of nitrogen (N_2)

Methane Number is a value similar to octane value for gasoline, and is important when the gas is used for internal combustion engines (as CNG).

Hydrogen Sulfide and Overall Sulfur Content both hydrogen sulfide (H_2S) and total sulfur must be reduced. H_2S is toxic as well as corrosive for the pipeline as it forms sulfuric acid (H_2SO_4) and should be kept as low as possible. Typical maximum values are 5 mg per scm. of H_2S and total sulfur at 10 mg per scm.

Mercury should be kept below 0.001 ppb (parts-per-billion) which is its detectable limit. The goal is to limit emissions and to prevent damage to equipment and pipelines by mercury amalgamation which would make aluminum and other metals brittle.

Dew point is a temperature below which some of the hydrocarbons in the gas might condense at pipeline pressure, forming liquid slugs which could damage the pipeline. The gas must also be clear of all water vapor to prevent the formation of methane hydrates within the gas processing plant or within the sales gas transmission pipeline.

Particles and other substances: must be free of particulate solids and all liquids to prevent erosion, corrosion or other damage to the pipeline and satisfy limits on carbon dioxide, nitrogen, mercaptans etc.

Additives: when the natural gas is intended for domestic use, Tetrahydrothiophene (THT) is added so that the otherwise odorless natural gas can be detected in the event of a gas leak. The sulfurous smelling substance added is equal to a sulfur content of 4-7 mg per scm.

5.2 LNG

LNG is a gas transport product. The gas, primarily methane (CH_4), is converted to liquid form for ease of storage or transport. It is produced close to the production facilities in a LNG liquefaction plant, stored, transported in cryogenic tanks on an LNG carrier and delivered to an LNG regasification terminal for storage and delivery to a pipeline system.



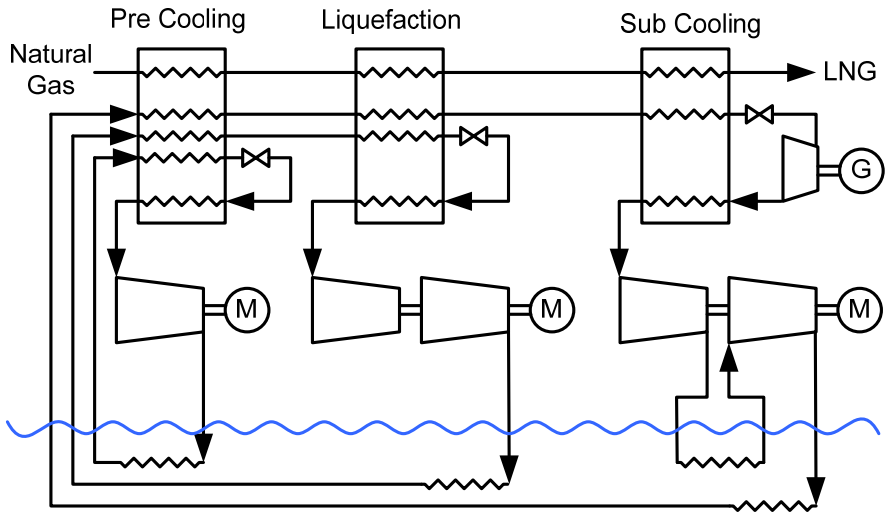
Melkøya LNG Plant with LNG Carrier Arctic Princess Photo: StatoilHydro

LNG carriers are used when the transport distance does not justify the cost of a pipeline. The main drawback is the cost of the liquefaction, calculated as how much of the total energy content of the gas is used for liquefaction. About 6% of energy content is used to produce LNG in a large modern plant, due to overall thermal efficiency. More than 10% could be consumed with smaller, gas turbine-driven trains. This compares to losses of about 0, 6-1, and 0 % per 1000 km of transport distance for large pipeline systems.

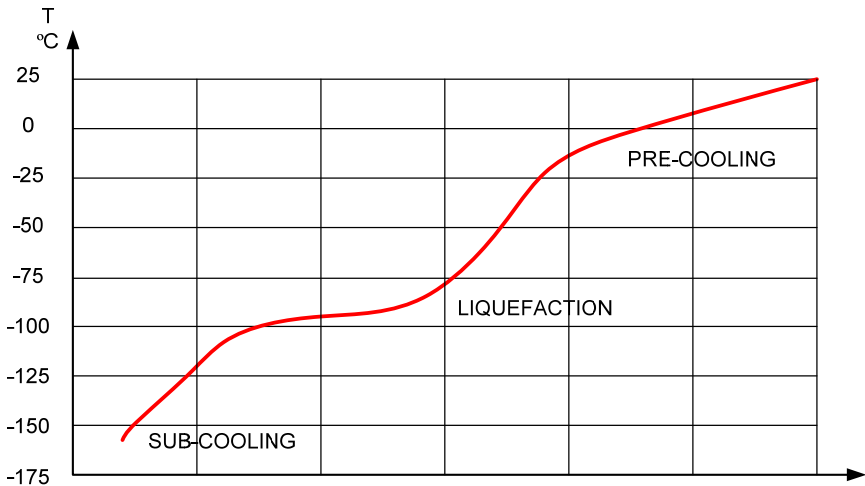
The LNG feedstock comes from a gas plant as outlined above. It must satisfy sales gas specifications. Ethane, propane and butane all have freezing points of less than -180°C and can be part of the LNG, but the concentration of methane is generally above 90%. Some NGLs are also needed as refrigerant for the cryogenic process.

5.2.1 LNG liquefaction

LNG processes are generally patented by large engineering, oil and gas companies, but are generally based on a two or three stage cooling process. A three stage liquefaction plant is shown in this simplified figure:



The actual design varies considerably with the different processes. The most critical component is the heat exchanger, also called the cold box, which is designed for optimum cooling efficiency. Designs may use separate cold boxes, or two stages may combine into one complex common heat exchanger.



Most processes use a mixed refrigerant (MR) design. The reason is that the gas has a heat load to temperature (Q/T) curve that must be closely matched to improve stability and efficiency, see the figure below. The curve tends to show three distinct regions, matching the pre-cooling, liquefaction and sub-cooling stages. The refrigerant gas composition will vary based on the individual design, as will the power requirement of each stage, and is often a patented, location-specific combination of one or two main components and several smaller, together with careful selection of the compressed pressure and expanded pressure of the refrigerant, to match the LNG gas stream.

Typical LNG train power use is about 28 MW per million tons of LNG per annum (mtpa), corresponding to typically 200 MW for the largest trains of 7.2 mtpa, or 65 MW per stage. In addition other consumers in gas treatment and pre-compression add to total energy consumption and bring it to some 35-40 MW per mtpa.

For each train, the cooling medium is first passed through its cooling compressor. Since Pressure times Volume over Temperature (PV/T) remains constant, it results in a significant temperature rise which has to be dissipated, typically in a seawater heat exchanger as shown in the figure above (as indicated by the blue wavy line). It then goes through one or more heat exchangers/cold boxes, before it expands either through a valve or a turbo-expander causing the temperature to drop significantly. It is then returned to cool its cold box before going on to the compressor.

The **pre-cooling** stage cools the gas to a temperature of about -30 to -50°C in the precooling cold box. The cooling element is generally propane or a mixture of propane and ethane and small quantities of other gases. The pre-cooling cold box also cools the cooling medium for the liquefaction and sub cooling stage.

The **liquefaction** process takes the gas down from -30°C to about -100-125°C typically based on a mixture of methane and ethane and other gases. It cools the LNG stream as well as the refrigerant for the final stage.

Sub-cooling serves to bring the gas to final stable LNG state at around 162°C. The refrigerant is usually methane and/or nitrogen.

5.2.2 Storage, transport and regasification

Storage at the terminals and on LNG carriers is done in cryogenic tanks at atmospheric pressure or slightly above, up to 125 kPa. The tanks are insulated, but will not keep LNG cold enough to avoid evaporation. Heat leakage will heat and boil off the LNG. Therefore LNG is stored as a boiling cryogen, which means that the liquid is stored at its boiling point for its storage pressure (atmospheric pressure) i.e. about -162°C . As the vapor boils off, heat of vaporization is absorbed from and cools the remaining liquid. The effect is called auto-refrigeration. With efficient insulation, only a relatively small amount of boil-off is necessary to maintain temperature. Boil-off gas from land based LNG storage tanks is compressed and fed to natural gas pipeline networks. On LNG carriers the boil-off gas can be used for fuel.

At the receiving terminal, the LNG is stored in local cryogenic tanks. It is regasified to ambient temperature on demand, commonly in a sea water heat exchanger, and then injected into the gas pipeline system.



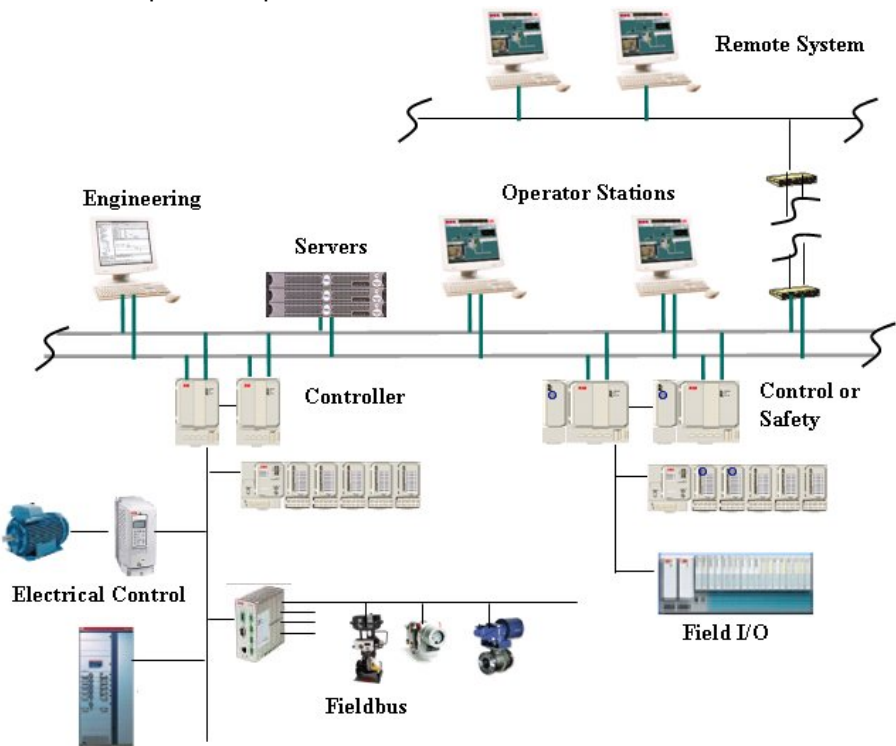
Cove point LNG terminal

6 Utility systems

This chapter contains an overview of the various systems that provides utilities or supports for the main process.

6.1 Process Control Systems

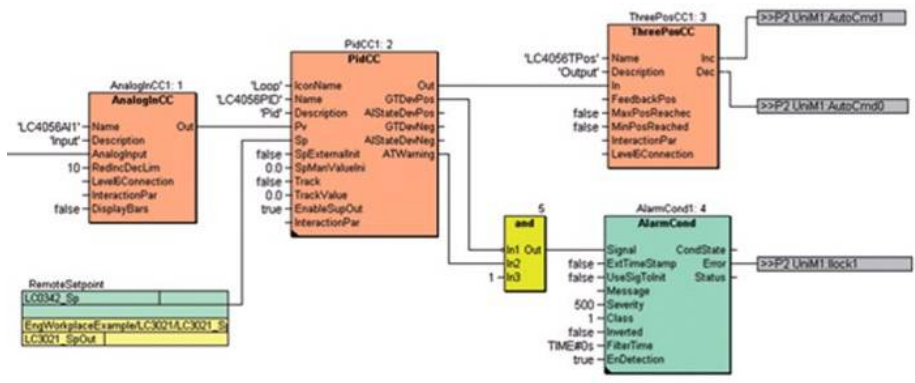
A process control system is used to monitor data and control equipment on the plant. Very small installations may use hydraulic or pneumatic control systems, but larger plants with up to 250,000 signals to and from the process require a dedicated distributed control system. The purpose of this system is to read values from a large number of sensors, run programs to monitor the process and control valves, switches etc. to control the process. Values, alarms, reports and other information are also presented to the operator and command inputs accepted.



Typical Process Control System

Process control systems consist of the following components:

- Field instrumentation: sensors and switches that sense process conditions such as temperature, pressure or flow. These are connected over single and multiple pair electrical cables (**hardwired**) or communication bus systems called **fieldbus**.
- Control devices, such as actuators for valves, electrical switchgear and drives or indicators are also hardwired or connected over fieldbus.
- Controllers execute the control algorithms so that the desired actions can be taken. The controllers will also generate events and alarms based on changes of state and alarm conditions and prepare data for operators and information systems.
- A number of servers perform the data processing required for data presentation, historical archiving, alarm processing and engineering changes.
- Clients such as operator stations and engineering stations are provided for human interfaces to the control system.
- The communication can be laid out in many different configurations, often including connections to remote facilities, remote operations support and similar.



Function blocks define the control function.

The main function of the control system is to make sure the production, processing and utility systems operate efficiently within design constraints and alarm limits. The control system is typically specified in programs as a combination of logic and control function blocks such as AND, ADD, PID. For a particular system, a library of standard solutions such as Level Control Loops and Motor Control blocks are defined. This means that the system

can be specified with combinations of typical loop templates, consisting of one or more input devices, function blocks and output devices. This allows much if not all of the application to be defined based on engineering databases and templates rather than formal programming.

The system is operated from a Central Control Room (CCR) with a combination of graphical process displays, alarm lists, reports and historical data curves. Smaller personal screens are often used in combination with large wall screens as shown on the right.



With modern systems, the same information is available to remote locations such as an onshore corporate operations support centre.

Field devices in most process areas must be protected to prevent them becoming ignition sources for potential hydrocarbon leaks. Equipment is explosive hazard classified e.g. as safe by pressurization (Ex.p), safe by explosive proof encapsulation (Ex.d) or intrinsically safe (Ex.i). All areas are mapped into explosive hazard zones from Zone 0 (inside vessels and pipes), Zone 1 (risk of hydrocarbons), Zone 2 (low risk of hydrocarbons) and Safe Area.



Beyond the basic functionality, the control system can be used for more advanced control and optimization functions. Some examples are:

- Well control may include automatic startup and shutdown of a well and/or a set of wells. Applications can include optimization and stabilization of artificial lift such as pump off control and gas lift optimization.
- Flow assurance ensures the flow from wells, in pipelines and risers is stable and maximized under varying pressure, flow and

temperatures. Unstable flow can result in slug formation, hydrates etc.

- Optimization of various processes to increase capacity or reduce energy costs.
- Pipeline management modeling, leak detection and pig tracking.
- Support for remote operations, in which facility data is available to company specialists located at a central support center.
- Support for remote operations where the entire facility is unmanned or without local operators full or part time, and is operated from a remote location.

6.2 Safety systems and Functional Safety

The function of safety systems is to take control and prevent an undesirable event when the process and the facility is no longer operating within its normal operating conditions. Functional safety is the part of the overall safety of a system that depends on the correct response of the safety system response to its inputs, including safe handling of operator errors, hardware failures and environmental changes (fires, lightning etc.)

The definition of safety is “Freedom from unacceptable risk”. of physical injury or of damage to the health of people either directly or indirectly. This requires a definition of what is acceptable risk, and who should define acceptable risk levels. This involves several concepts, including:

1. Identifying what the required safety functions are, which means that hazards and safety functions have to be known. A process of function reviews, formal Hazard Identification Studies (HAZID) and Hazard and Operability (HAZOP) studies and Accident Reviews are applied to identify the risks and failure modes.
2. Assessment of the risk-reduction required by the safety function. This will involve a Safety Integrity Level (SIL) Assessment. A Safety Integrity Level (SIL) applies to an end-to-end safety function of the safety-related system, not just to a component or part of the system.
3. Ensuring the safety function performs to the design intent, including under conditions of incorrect operator input and failure modes. Functional Safety management defines all technical and management activities during the lifecycle of the safety system. The safety lifecycle is a systematic way to ensure that all the necessary

activities to achieve functional safety are carried out and also to demonstrate that the activities have been carried out in the right order. Safety need to be documented to be able to pass information to different engineering disciplines.

For the oil and gas industry, safety standards comprise a set of corporate, national and international laws, guidelines and standards. Some of the primary international standards are:

- IEC 61508 Functional safety of electrical/electronic/programmable electronic safety-related systems
- IEC 61511 Functional safety - Safety instrumented systems for the process industry sector

A *safety integrity level* is not directly applicable to individual subsystems or components. It applies to a safety function carried out by the Safety Instrumented System (end-to-end: sensor, controller and final element).

IEC 61508 covers all components of the E/E/PE safety-related system, including field equipment and specific project application logic. All these subsystems and components, when combined to implement the safety function (or functions), are required to meet the safety integrity level target of the relevant functions. Any design using supplied subsystems and components that are all *quoted as suitable* for the required safety integrity level target of the relevant functions will not necessarily comply with the requirements for that safety integrity level target.

Suppliers of products intended for use in E/E/PE safety-related systems should provide *sufficient information* to facilitate a demonstration that the E/E/PE safety-related system complies with IEC 61508 this often requires that the functional safety for a the system should be independently certified.

There are never one single action which lead to a large accident, it is often a train of activities. There are many layers to protect against an accident, and these are grouped two different categories.

- Protection layers – to prevent an incident from happening. Example Rupture disk, relief valve, Dike.
- Mitigation layers – to minimize the consequence of an incident, example operator intervention or Safety Instrumented System (SIS)

A Safety Instrumented System (SIS) is a collection of sensors, controllers and actuators that execute one or more Safety Instrumented Functions

(SIFs/safety loops) that are implemented for a common purpose. Each SIF has its own SIL and all sensors, controllers and final element in one SIF must comply to the same SIL (Safety Integrity Level) i.e. the end-to-end safety integrity level. The SIS is typically divided into the following subsystems:

- **Emergency Shutdown System (ESD)** to handle emergency conditions (high criticality shutdown levels)
- **Process Shutdown System (PSD)** to handle non-normal but less critical shutdown levels
- **Fire and Gas Systems** to detect fire, gas leakage and initiate firefighting, shutdown and isolation of ignition sources.

The Purpose of a Safety Instrumented System is to reduce the risk that a process may become hazardous to a tolerable level. The SIS does this by decreasing the frequency of unwanted accidents:

- SIS senses hazardous conditions and takes action to move the process to a safe state, preventing an accident from occurring.
- The amount of risk reduction that an SIS can provide is represented by its Safety Integrity Level (SIL) which is a measure of the risk reduction factor provided by a safety function. IEC 61508 defines four levels SIL 1-4 and the corresponding requirements for the risk reduction factor (RRF) and Probability of Failure on Demand (PFD):

SIL	PFD	RRF
1	0.1 – 0.01	10 – 100
2	0.01 – 0.001	100 – 1000
3	0.001 – 0.0001	1000 – 10.000
4	0.0001 – 0.00001	10.000 – 100.000

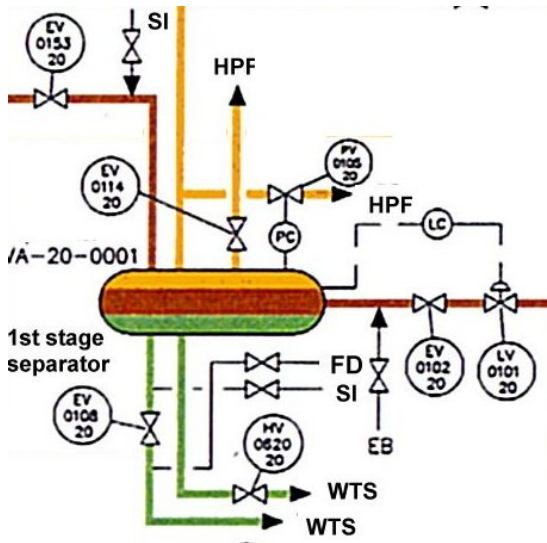
The SIL for a component is given by its PFD, Safe Failure Fraction and design to avoid influence of systematic errors.

6.2.1 Emergency Shutdown and Process Shutdown

The Emergency Shutdown (ESD) and Process Shutdown (PSD) systems will take action when the process goes into a malfunction or dangerous state. For this purpose the system maintains four sets of limits for a process value, LowLow (LL), Low (L), High (H) and HighHigh (HH). L and H are process warning limits which alert to process disturbances. LL and HH are alarm

conditions and detect that the process is operating out of range and there is a chance of undesirable events and malfunction.

Separate transmitters are provided for safety systems. One example is the LTLL (Level Transmitter LowLow) or LSL (Level Switch Low) alarm for the oil level. When this condition is triggered, there is a risk of blow-by which means gas leaks out of the oil output and gives high pressure in the next separation stage or other following process equipment such as a desalter. Transmitters are preferred over switches because of better diagnostic capabilities



Emergency shutdown actions are defined in a cause and affect chart based on a HAZOP of the process. This study identifies possible malfunctions and how they should be handled. On the left of the chart we have possible emergency scenarios, on top we find possible shutdown actions. At an oil and gas facility, the primary response is to isolate and depressurize. In this case, the typical action would be to close the inlet and outlet sectioning valves (EV 0153 20, EV 0108 20 and EV 0102 20 in the diagram), and open the blowdown valve (EV 0114 20). This will isolate the malfunctioning unit and reduce pressure by flaring of the gas.

TITLE		CAUSE & EFFECT MATRIX PARALLEL PRODUCTION SHUTDOWN SHUTDOWN LEVEL 3 (ECS)		REVISION		DATE		BY		CHECKED		APPROVED		REVISION	
NO.	DESCRIPTION	DATE	BY	NO.	DESCRIPTION	DATE	BY	NO.	DESCRIPTION	DATE	BY	NO.	DESCRIPTION	DATE	BY
1	INITIAL			1	INITIAL			1	INITIAL			1	INITIAL		
2	REVISION			2	REVISION			2	REVISION			2	REVISION		
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Events are classified on a

scale, e.-g. 0 to 5, where a full Abandon Platform/Facility Shutdown (APS – ESD 0) as the highest level means a complete shutdown and evacuation of the facility. The next levels (ESD1, ESD2) define emergency complete shutdown. The lower levels (i.e. PSD 3, PSD 4, and PSD 5), represent single equipment or process section shutdowns. A split between APS/ESD and PSD is done in large installations because most signals are PSD and could be handled with less strict requirements.

These actions are handled by the Emergency Shut Down system (ESD) and Process Shut Down system (PSD) according to Functional Safety Requirements and standards. Thus a typical ESD function might require a SIL 3 or even 4 level while PSD loops could be SIL 2 or 3.

Smaller ESD systems, e.g. on wellhead platforms, can be hydraulic or hardwired (non-programmable).

6.2.2 Fire and Gas System

The Fire and Gas System is not generally related to any particular process. Instead it divides into fire areas by geographical location. Each fire area should be designed to be self-contained, in that it should detect fire and gas by several types of sensors, and control fire protection and firefighting devices to contain and fight fire within the fire area. In the event of fire, the area will be partially shut-off by closing ventilation fire dampers. A fire area protection data sheet typically shows what detection exists for each fire area and what fire protection action should be taken in case of an incident.



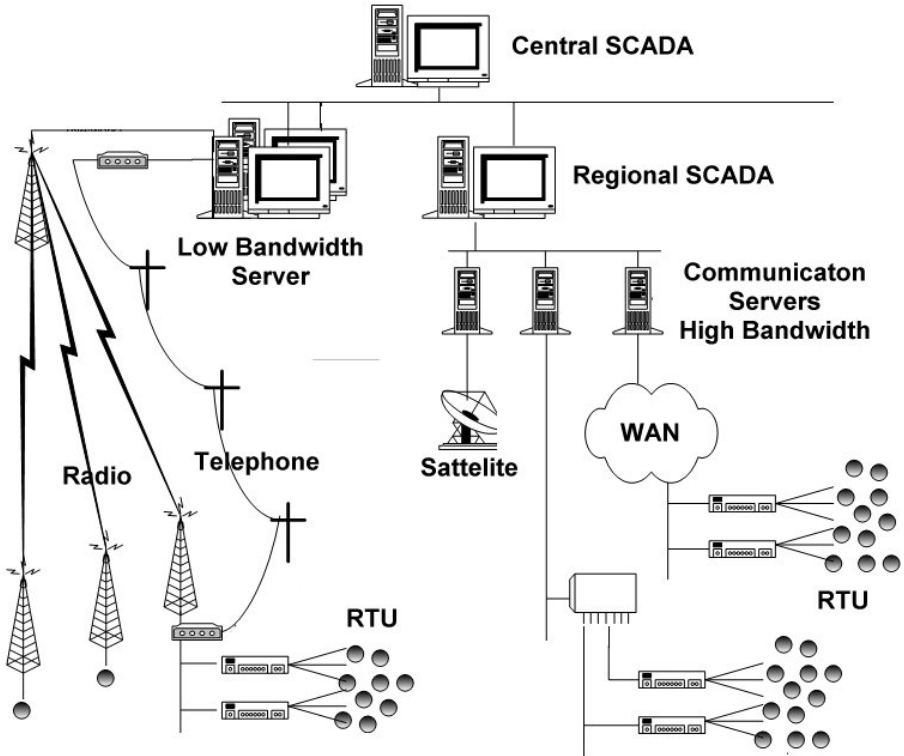
The type and number of the detection, protection and fighting devices depend on the type of equipment and size of the fire area and will vary for e.g. process areas, electrical rooms and accommodation.

Fire detection:

- Gas detection: Combustible and toxic gas, electro-catalytic or optical (IR) detector.
- Flame detection: Ultraviolet (UV) or infra red (IR) optical detectors
- Fire detection: Heat and ionic smoke detectors
- Manual pushbuttons

6.3 Telemetry/SCADA

Supervisory Control and Data Acquisition (SCADA) is normally associated with telemetry and wide area communications, for data gathering and control over large production sites, pipelines, or corporate data from multiple facilities. With telemetry, the bandwidth is often quite low and based on telephone or local radio systems. SCADA systems are often optimized for efficient use of the available bandwidth. Wide area communication operates with wideband services, such as optical fibers and broadband internet.



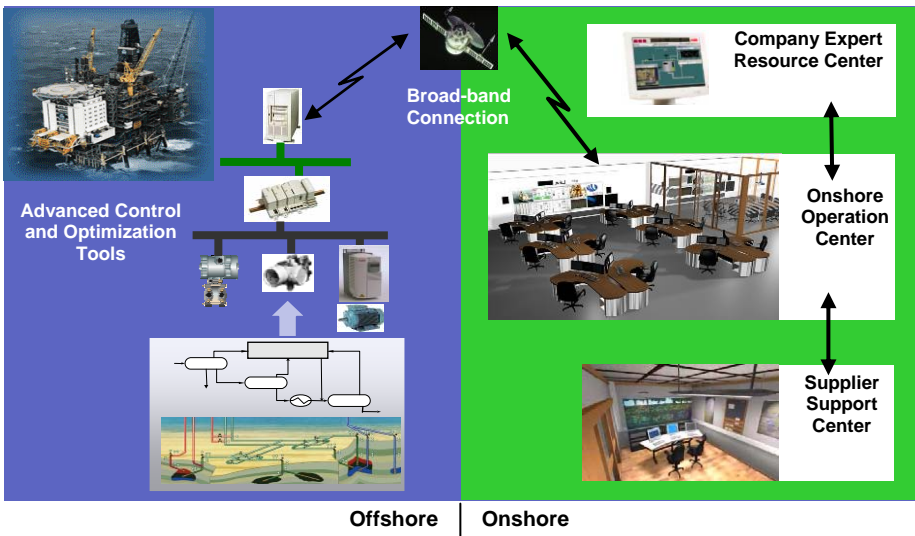
Remote Terminal Units (RTU) or local controls systems on wells, wellhead platforms, compressor and pump stations, and are connected to the SCADA system by means of the available communication media. SCADA systems have many of the same functions as the control system, and the difference mainly comes down to data architecture and use of communications.

6.4 Integrated Operations

Integrated Operations (IO) mean full integration of the organizations that work to plan, operate and maintain the oil and gas fields and their facilities. As such, it is both a business model and an infrastructure with work processes. eField, eOperations, Smart Operations and other company specific names are for all or part of this field of activities. The overall goal is:

- Increase efficiency
- Enhance recovery
- Lower operational costs through effective use of intelligent technology

Optimal production targets and maximum utilization of production resources are achieved through the use of several sources of information such as reservoir mass balance calculations and depletion strategies, well test results and use of simulation models. This is made possible by linking skills, data and tools together in real time – independent of location.



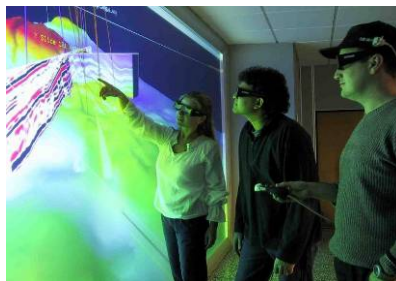
Some of the enabler technology areas are:

1. A system and communication IT infrastructure, see 5.1 and 5.2
2. Applications for remote operations and remote operations support.
3. Reservoir management and drilling operations
4. Production optimization

5. Information Management Systems
6. Operation Support and Maintenance

6.4.1 Reservoir management and drilling operations

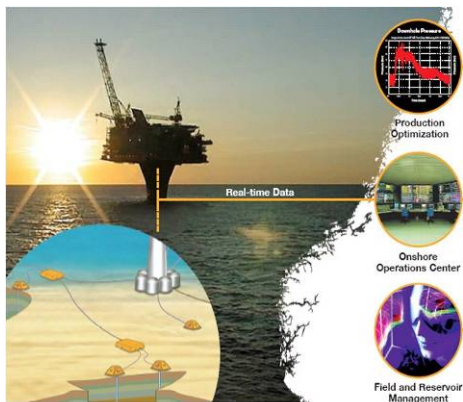
Solution for data acquisition, modeling and visualization between facility operators and central company experts to provide:



- Drilling simulation and visualization, automatic diagnostics and decision support, real-time measurements while drilling in order to locate the best targets
- Reservoir models based on real-time reservoir data, analysis of 4D seismic, in-situ measurements of changes. On-line integration with well-serviced company data
- Optimization models for increased production, based on in-reservoir properties during production, with decision support incorporated to improve productivity

6.4.2 Production optimization

Optimizing the production or improving productivity is a complex problem. In addition to the production optimization of the downhole-, subsea- and topside process, one has to consider operational costs, hardware damage, reservoir performance, environmental requirements and operational difficulties within each well and/or topside. To further complicate optimization, the individual challenges will change over time, e.g. reservoir behavior



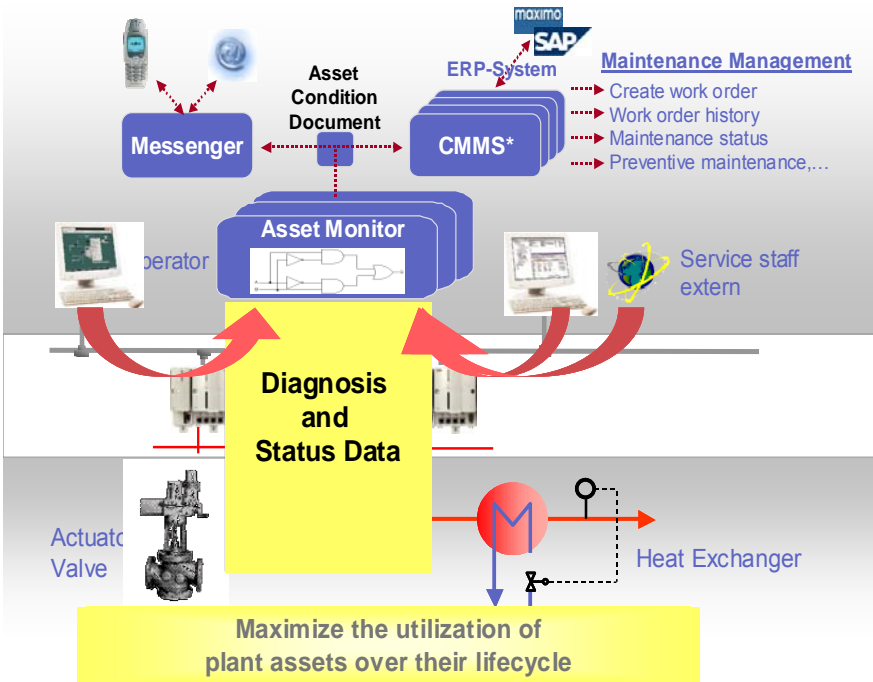
changes as an effect of depletion, shutdown of wells due to slugging, failed sensors and the change of efficiencies within the topside process system. Some of the applications included in production optimization are:

- Flowline Control to stabilize multiphase flow in gathering systems, risers and flow lines.
- Well Control that will stabilize and optimize gas lift and naturally flowing wells. This application should prevent flow and pressure surges while maintaining minimal backpressure and maintain maximum production as well as continuing production at the optimum lift gas rate.
- Gas-lift optimization is provided to ensure the best possible distribution of lift-gas between gas lifted wells.
- Slug management will help mitigate variations in inflow impact. The separation and hydrocarbon processing during startup, upset and normal operation.
- Well Monitoring Systems (WMS) are used to estimate the flow rates of oil, gas and water from all the individual wells in an oil field. The real-time evaluation is based on data from available sensors in the wells and flow lines.
- Hydrate Prediction Tools will help to avoid hydrate formation, which may occur if a subsea gathering system is allowed to cool down too much before the necessary hydrate preventive actions are performed.
- Optimal operation is defined by a set of constraints in the wells and production facilities. A Constraint Monitoring Tool monitors the closeness to all constraints. This provides decision support for corrective actions needed to move current operation closer to its true potential.
- Advanced Control and Optimization Solutions to improve the performance of product quality control, while adhering to operating constraints. This is typically done with two technologies, Model Predictive Control to drive the process closer to operating targets and Inferential Measurement to increase the frequency of product quality feedback information.
- Tuning tools are designed to optimize and properly maintain the optimal setting of control loops in the process automation system.

6.4.3 Asset Optimization and maintenance Support

An Asset Optimization (AO) system is to reduce costly production disruptions by enabling predictive maintenance. It records the maintenance history of an asset and identifies potential problems to avert unscheduled shutdowns, maximize up-time and operate closer to plant production prognoses. This functionality supports maintenance workflow as the AO system communicates with a maintenance system, often denoted CMMS (computerized maintenance management system).

Condition monitoring includes both structural monitoring and condition monitoring for process equipment such as valves and rotating machinery. For structural monitoring, the devices are corrosion meters (essentially plates that corrode, for which that corrosion may be metered), tension force meters and free swinging strings. These statistics are logged to a central structure condition monitoring system, to portray what forces are acting against the installation, and the effect those forces are having.



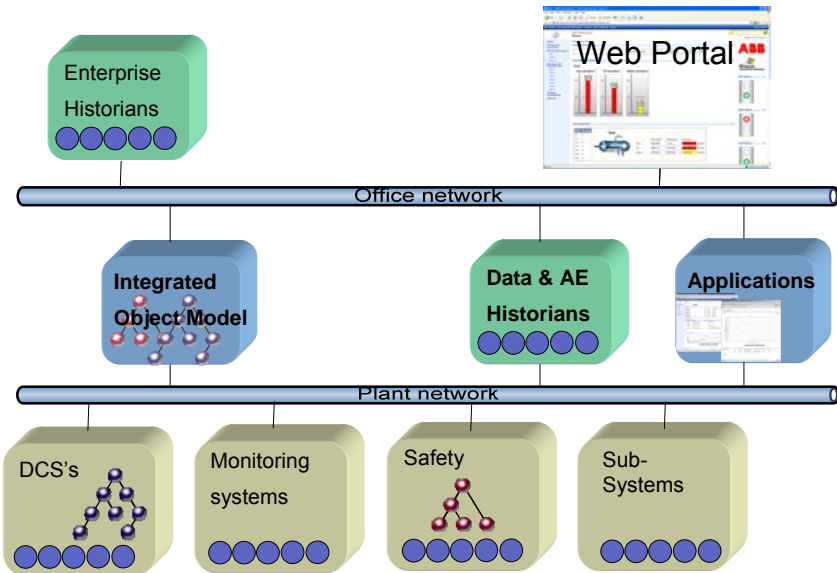
Condition monitoring of machinery is generally used for large rotating apparatus, such as turbines, compressors, generators and large pumps. Input devices are vibration meters, temperature (bearing, exhaust gases etc.) as well as the number of start/stops, running time, lubrication intervals and over-current trip-outs. For other process equipment such as valves, the system can register closing times, flow and torque. A valve which exhibits a negative trend in closing time or torque ("stiction") can be diagnosed. The maintenance trigger is the mechanism whereby field device or equipment monitor resident information, in the form of digital status signals or other numerical or computed variables interpreted to trigger a maintenance

request. A Work Order Procedure is then automatically initiated in the CMMS.

Maintenance support functionality will plan maintenance, based on input from condition monitoring systems and a periodic maintenance plan. This will allow the system to schedule personnel, for such tasks as lubrication or cleaning, and plan larger tasks such as turbine and compressor periodic maintenance.

6.4.4 Information Management Systems (IMS)

A specific Information Management System can be used to provide information about the operation and production of the facility. This can be a separate system, or an integral part of the control system or SCADA system.



For oil and gas, IMS functionality includes:

- Oil & Gas Production Reporting.
- Safety Management
- Maintenance
- Operator Support
- Overall systems integrated and external
- Historical data including post failure "flight recorder" data

Some of the applications provided by an IMS system may be:

- Drilling data acquisition and drilling data logging
- Electronic Shift Logbook
- Operator Procedures
- Chemical Injection
- Chemical Consumption
- Laboratory Analysis Registration
- Alarm and Incidents overview
- Alarm Statistics
- Valve Leakage Test
- Transmitter Surveillance
- Run Time Monitoring
- Block Log
- Production Plan
- SIL Statistics Report
- Subsea Valve Signatures
- Production Overview and Prognosis
- Valve Verification
- ESD/PSD Verification, including shutdown analysis
- Data Export
- Data Browser Tool
- Historical data and Current Trend
- Well Test
- Daily Production Report with Metering data
- Volumes in storage cells & consolidation of produced stored and dispatched volumes.
- Environmental Reports
- Polynomial allocation (oil/gas/water) based on Well Test results.

6.4.5 Training simulators

Training simulators are used to provide operator training in a realistic plant training environment. They use the actual control and safety applications of the plant, running on operator stations. Plant models simulate the feedback from the plant in real time or in fast or slow motion. Training simulator applications include functions for backup

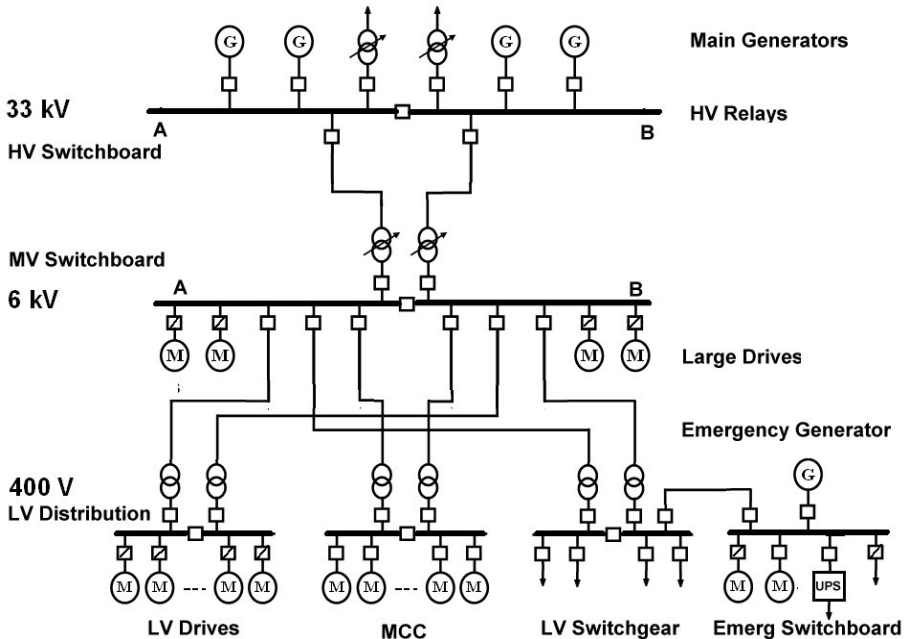


and reload including recreation of historical information and snapshots. Offsite training facilities are often connected (read only) to the live plant to give information from the real operating situation.

6.5 Power generation, distribution and drives

Power can be provided from mains power or from local gas turbines or diesel generator sets. Large facilities have high power demands, from 30 MW and upwards to several hundred MW. There is a tendency to generate electric power centrally and use electric drives for large equipment rather than multiple gas turbines, as this decreases maintenance and increases uptime.

The power generation system on a large facility is usually several gas turbines driving electric generators, 20-40 MW each. If exhaust heat is not needed in the main process, it can be used to drive exhaust steam turbines (dual cycle) for additional efficiency.



Voltage levels for high, medium and low voltage distribution boards are 13-130kV, 2-8 kV and 300-600 V respectively. Power is generated and exchanged with mains or other facilities on the HV distribution board. Relays are used for protection functions.

HV is transformed to MV switchboards to which large consumers are connected. LV switchboards feed a mix of normal consumers, Motor Control Centers and variable speed drives for motors up to a few hundred KW (Not necessarily separate as shown in the figure).



A separate emergency power switchboard provides power for critical equipment. It can be powered from a local emergency generator if main power is lost. Computer systems are fed from an Uninterruptible Power System (UPS) with batteries, connected to the main or emergency switchboard.

A power management system is used for control of electrical switchgear and equipment. Its function is to optimize electricity generation and usage and to prevent major disturbances & plant outages (blackouts). The power management system includes HV, MV and LV low voltage switchgear plus Motor Control Centers (MCC) and emergency generator sets. Functions include prioritization of loads, emergency load shedding (closing down of non-essential equipment) and prestart of generator sets (e.g. when additional power to start a big crude pump is required).

Large rotating equipment and generators are driven by gas turbines or large drives. Gas turbines for oil and gas production are generally modified aviation turbines in the 10-25 MW range. These require quite extensive maintenance and have a relatively low overall efficiency (20-27% depending on application). Also, while a turbine is relatively small and light, it



it will usually require large and heavy support equipment such as large gears, air coolers/filters, exhaust units, and sound damping and lubrication units.

Therefore use of large variable speed drives is becoming more common. For pumps on subsea facilities this is the only option. For use on remote facilities, High Voltage DC transmission and HV motors can be used, from a main facility or power from shore. This will also avoid local power generation at each facility and contribute to low manning or remote operation.

6.6 Flare and atmospheric ventilation

Flare subsystems include flare, atmospheric ventilation and blowdown. The purpose of the flare and vent systems is to provide safe discharge and disposal of gases and liquids resulting from:

- Spill-off flaring from the product stabilization system. (oil, condensate etc.).
- Production testing.
- Relief of excess pressure caused by process upset conditions and thermal expansion.
- Depressurization either in response to an emergency situation or as part of a normal procedure.
- Planned depressurization of subsea production flowlines and export pipelines.
- Venting from equipment operating close to atmospheric pressure (e.g. tanks).



The systems are typically divided into a High Pressure (HP) Flare and a Low Pressure (LP) flare system. The LP system is operated a little above atmospheric pressure to prevent atmospheric gases such as oxygen flowing back into the vent and flare system and generating a combustible mixture. With low gas flow, inert gas is injected at the flare nozzle to prevent air ingress.

Traditionally, considerable amounts of hydrocarbons have been more or less continuously flared. In these cases, a continuously burning pilot is used to ensure ignition of hydrocarbons in the flare.

Stronger environmental focus has eliminated continuous flaring and the pilot in many areas. Vapors and flare gas are normally recovered, and only in exceptional situations does flaring occur. To avoid the pilot flame, an ignition system is used to ensure safe ignition even when large volumes are discharged. One patented solution is a "ballistic ignition" system which fires burning pellets into the flare gas flow.

6.7 Instrument air

A large volume of compressed air is required for the control of pneumatic valves and actuators, tools and purging of cabinets. It is produced by electrically driven screw compressors and further treated to be free of particles, oil and water.

6.8 HVAC

The heat, ventilation and air conditioning system (HVAC) feeds conditioned air to the equipment and accommodation rooms etc. Cooling and heating is achieved by water-cooled or water/steam-heated heat exchangers. Heat may also be taken from gas turbine exhaust. In tropic and sub-tropic areas, cooling is achieved by compressor refrigeration units. In tropical areas, gas turbine inlet air must be cooled to achieve sufficient efficiency and performance. The HVAC system is usually delivered as one package, and may also include air emissions cleaning. Some HVAC subsystems include:

- Cool: cooling medium, refrigeration system, freezing system
- Heat: heat medium system, hot oil system.

One function is to provide air to equipment rooms that are secured by positive pressure. This prevents potential influx of explosive gases in case of a leak.

6.9 Water systems

6.9.1 Potable water

For smaller installations, potable water can be transported in by supply vessels or tank trucks.

For larger facilities, it is provided on site by desalination of seawater though distillation or reverse filtering. Onshore potable water is provided by purification of water from above- or underground reservoirs.

Reverse filtering or osmosis requires a membrane driving pressure of about 7000 kPa/1 PSI of pressure per 100 ppm of solids dissolved in the water. For seawater with 3.5% salt, 2.5 MPa, 350 PSI is required.

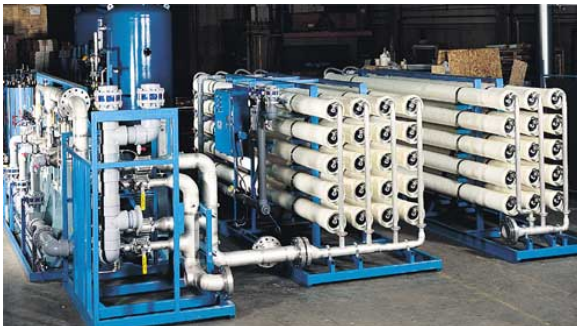


Photo: Lenntech Water treatment & air purification Holding B.V.

6.9.2 Seawater

Seawater is used extensively for cooling purposes. Cold water is provided to air compressor coolers, gas coolers, main generators and HVAC. In addition, seawater is used for the production of hypochlorite (see chemicals) and for fire water. Seawater is treated with hypochlorite to prevent microbiological growth in process equipment and piping.

Seawater is sometimes used for reservoir water injection. In this case a **deaerator** is used to reduce oxygen in the water before injection. Oxygen can cause microbiological growth in the reservoir. The deaerator is designed to use strip gas and vacuum.

6.9.3 Ballast water

Ballast systems are found on drilling rigs, floating production ships, rigs and TLP (tension leg platforms). The object is to keep the platform level and at a certain depth under varying conditions, such as mode of operation (stationary drilling, movement), climatic conditions (elevation of rig during storms), amount of produce in storage tanks, and to adjust loading on TLP tension members.

Ballasting is accomplished by means of ballast tanks, pumps and valves, which are used in combination with position measuring instruments and tension force meters (TLP) to achieve the desired ballasting.

If fresh water is produced, it can be used as ballast to avoid salt water. Additionally, if ballast water has become contaminated from oil tanks, it must be cleaned before discharged out to sea.

6.10 Chemicals and additives

A wide range of chemical additives are used in the main process. Some of these are marked in the process diagram. The cost of process chemical additives is considerable. A typical example is antifoam where a concentration of about 150 ppm is used. With a production of 40,000 bpd, about 2000 liters (500 Gallons) of antifoam could be used. At a cost of 2 € a liter, 10 \$ a gallon in bulk, antifoam alone will cost some 4000 € or 5000 USD per day.



The most common chemicals and their uses are:

- Scale inhibitor** The well flow contains several different contaminants such as salts, chalk, and traces of radioactive materials. As pressure and temperature changes, these may precipitate and deposit in pipes, heat exchangers, valves and tanks. As a result these may clog up or become stuck. The scale inhibitor will prevent the contaminants from separating out. Scale or sediment inhibitor is applied to wellheads and production equipment.
- Emulsion breaker** Water and oil cannot mix to form a solution. However small drops of oil will disperse in water and small water drops will disperse in oil. These drops are held suspended by plus and minus electrostatic forces at the molecular level. This is called an emulsion and will form a layer between the oil and water. Although the emulsion layer will eventually break down naturally, it takes time, too much time. An emulsion breaker is added to prevent formation, and breakdown of the emulsion layer by causing the droplets to merge and grow. Sand and particles will normally be carried out by the water and be extracted in water treatment. However, the emulsion can trap these particles and sink to the bottom as a sticky sludge that is difficult to remove during operation.

Antifoam

The sloshing motion inside a separator will cause foaming. This foam will cover the fluid surface and prevent gas from escaping. Foam also reduces the gas space inside the separator, and can pass the demister and escape to the gas outlet in the form of mist and liquid drops. An antifoam agent is introduced upstream of the separator to prevent or break down foam formation, by reducing liquid surface tension.

Polyelectrolyte

Polyelectrolyte is added before the hydrocyclones and causes oil droplets to merge. This works by reducing surface tension and water polarity. This is also called flocculation and polyelectrolyte flocculants and allows emissions to reach 40 ppm or less.

Methanol (MEG)

Methanol or Monoethylene Glycol (MEG) is injected in flowlines to prevent hydrate formation and prevent corrosion. Hydrates are crystalline compounds that form in water crystalline structures as a function of composition, temperature and pressure. Hydrates appear and freeze to hydrate ice that may damage equipment and pipelines.

For normal risers, hydrates form only when production stops and the temperature start to drop. Hydrate formation can be prevented by depressurization which adds to startup time or by methanol injection.

On longer flowlines in cold seawater or Arctic climates, hydrates may form under normal operating conditions and require continuous methanol injection. In this case the methanol can be separated and recycled.

Hydrate prediction model software can be used to determine when there is a risk of hydrate formation and to reduce methanol injection or delay depressurization.

TEG

Triethyleneglycol (TEG) is used to dry gas. See the chapter on scrubbers and reboilers.

Hypochlorite

Hypochlorite is added to seawater to prevent growth of algae and bacteria e.g. in seawater heat exchangers. Hypochlorite is produced by electrolysis of seawater to chlorine. In one variant, copper

electrodes are used which adds copper salts to the solution which improves effectiveness.

Biocides

Biocides are also preventive chemicals that are added to prevent microbiological activity in oil production systems such as bacteria, fungus or algae growth. Particular problems arise from the growth of sulfate bacteria that produces hydrogen sulfide and clogs filters. Typical uses include diesel tanks, produced water (after hydrocyclones), and slop and ballast tanks.

Corrosion inhibitor

Corrosion inhibitor is injected in the export pipelines and storage tanks. Exported oil can be highly corrosive and lead to corrosion of the inside of the pipeline or tank. The corrosion inhibitor will protect by forming a thin film on metal surfaces.

Drag reducers

Drag reducers improve the flow in pipelines. Fluid near the pipe tries to stay stationary while fluid in the center region of the pipe is moving quickly. This large difference in fluid causes turbulent bursts to occur in the buffer region. Turbulent bursts propagate and form turbulent eddies, which cause drag.

Drag-reducing polymers are long-chain, ultra-high molecular weight polymers from 1 to 10 million u), with higher molecular weight polymers giving better drag reduction performance. With only parts-per-million levels in the pipeline fluid, drag-reducing polymers suppress the formation of turbulent bursts in the buffer region. The net result of using a drag-reducing polymer in turbulent flow is a decrease in the frictional pressure drop in the pipeline by as much as 70%. This can be used to lower pressure or improve throughput.

6.11 Telecom

By tradition, all electronic systems that do not fall naturally under the electrical or automation bracket are grouped as telecommunication systems. And as such the telecom system consists of variety of subsystems for human and computer wired and wireless communications, monitoring, observation, messaging and entertainment.

Some of the main systems are:

- Public Address & Alarm System/F&G Integration
- Access Control
- Drillers talk back System
- UHF Radio Network System
- Closed Circuit TV System
- Mandatory Radio System
- Security Access Control
- Meteorological System/Sea Wave Radar
- Telecom Antenna Tower and Antennas
- PABX Telephone System
- Entertainment System
- Marine Radar & Vessel Movement System
- Office Data Network and Computer System
- Personnel Paging System
- Platform Personnel Registration and Tracking System
- Telecom Management and Monitoring System
- Ship Communication System/PABX Extension
- Radio Link System
- Mux and Fiber optical Terminal Equipment
- Intrusion detection
- Satellite systems

The systems are very often grouped in four main areas:

1. External communication

External communication systems interconnect installations and link them to the surrounding world - carrying voice, video, process control and safety system traffic necessary to allow uninterrupted safe operations of the facility. With today's solutions and technologies,

distance is no longer an issue and bandwidth is available as needed, either on demand or fixed. This opens up for new ideas and opportunities to reduce operational costs in the industry.



2. Internal communication

Internal telecommunication systems play a major role in supporting day-to-day operations and improve the working environment. They allow any type of system or operator to communicate within the facility, enabling reliable and efficient operations.



3. Safety & Security Systems

Safety & Security Systems are used for safeguarding personnel and equipment in, on and around an installation according to international rules and standards. These systems are very often adapted to meet local/company safety requirements. For best possible performance and flexibility, safety systems are closely integrated with each other, as well as to other internal and external systems.



4. Management & utility systems

System and personnel well-being are supported by a number of management and utility systems, which are intended to ease and simplify telecom maintenance and operations.

In today's O&G world all of these systems play an important role in laying the foundations for remote operation, diagnostics and maintenance in Integrated Operations.



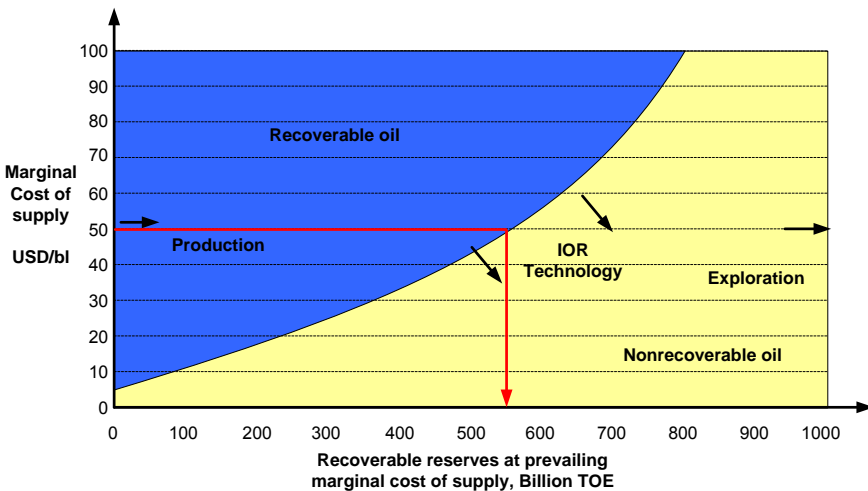
7 Unconventional and conventional resources and environmental effects

About 81% of the world primary energy consumption in 2008 was fossil fuels; 26% was coal, oil production was 34,4% or about 3,94 Billion tons, and 20,5% was gas with 3,03 trillion scm or 2,67 Billion Tons Oil Equivalent (TOE). Thus total oil and gas production was 5,71 Billion TOE, which is about 114 million barrels of oil equivalent per day (IEA 2008).

The proven reserves are estimated at 183 Billion TOE of oil and 169 Trillion scm of gas (150 Billion TOE) for a total of 333 Billion TOE (Converted from estimates by US DOE 2008), indicating that proven reserves will last for about 60 years at prevailing consumption.

7.1 Unconventional sources of oil and gas

The reservoirs described earlier are called conventional sources of oil and gas. As demand increases, prices soar and new conventional resources become economically viable. At the same time, production of oil and gas from unconventional sources become more attractive. These unconventional sources include very heavy crudes, oil sands, oil shale, gas and synthetic crude from coal, coal bed methane, methane hydrates and biofuels. At the same time improved oil recovery (IOR) can improve the percentage of the existing reservoirs that can be economically extracted. These effects are illustrated **in principle** in the following figure.



Estimates of undiscovered conventional and unconventional sources vary as widely the oil price among different sources. The figure illustrates that if one assumes that an oil price of 50 USD per barrel prevails, the estimated economically recoverable reserves with current technology will be about 550 Billion tons of oil equivalent, or 4 Trillion barrels, while an oil price of 100 USD/bl will permit about 800 Billion tons corresponding to more than 5,5 trillion barrels or about 140 years of consumption at current rates.

Economical production cost and discovery are uncertain factors. With continued high oil prices, figures of around 1-2 trillion barrels of conventional (more gas than oil) and 3 trillion barrels unconventional are often quoted, for a total remaining producible hydrocarbon reserve of about 5 trillion barrels of oil. It is expected that up to a third of oil fuel production may come from unconventional sources within the next decade.

7.1.1 Extra heavy crude

Very heavy crude are hydrocarbons with an API grade of about 15 or below. The most extreme heavy crude currently extracted is Venezuelan 8 API crude e.g. in eastern Venezuela (Orinoco basin). If the reservoir temperature is high enough, the crude will flow from the reservoir. In other areas, such as Canada, the reservoir temperature is lower, and steam injection must be used to stimulate flow from the formation.

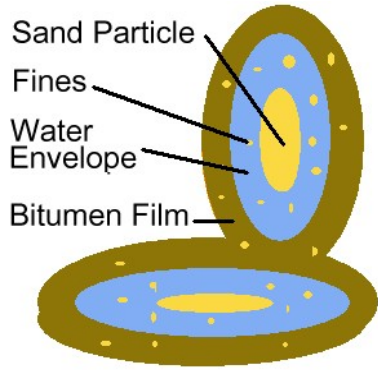
When reaching the surface, the crude must be mixed with diluents (often LPGs) to allow it to flow in pipelines. The crude must be **upgraded** in a processing plant to make lighter **SynCrude** with a higher yield of high value fuels. Typical SynCrude has an API of 26-30. The diluents are recycled by separating them out and piping them back to the wellhead site. The crude undergoes several stages of hydrocracking and coking to form lighter hydrocarbons and remove coke. It is often rich in sulfur (sour crude) which must be removed.

7.1.2 Tar sands

Tar sands can be often strip-mined. Typically two tons of tar sand will yield one barrel of oil. Typical tar sand contains sand grains with a water envelope, covered by a bitumen film that may contain 70% oil. Various fine particles can be suspended in the water and bitumen.

This type of tar sand can be processed with water extraction. Hot water is added to the sand, and the resulting slurry is piped to the extraction plant where it is agitated and the oil skimmed from the top. Provided that the water

chemistry is appropriate (the water is adjusted with chemical additives), it allows bitumen to separate from sand and clay. The combination of hot water and agitation releases bitumen from the oil sand, and allows small air bubbles to attach to the bitumen droplets. The bitumen froth floats to the top of separation vessels, and is further treated to remove residual water and fine solids. It can then be transported and processed the same way as extra heavy crude.



It is estimated that around 80% of tar sands are too far below the surface for current open-cast mining techniques. Techniques are being developed to extract the oil below the surface. This requires a massive injection of steam into a deposit, thus liberating the bitumen underground, and channeling it to extraction points where it would be liquefied before reaching the surface. The tar sands of Canada (Alberta) and Venezuela are estimated at 250 billion barrels, equivalent to the total reserves of Saudi Arabia.

7.1.3 Oil shale

Most oil shales are fine-grained sedimentary rocks containing relatively large amounts of organic matter from which significant amounts of shale oil and combustible gas can be extracted by destructive distillation. One of the largest known locations is the oil shale locked in the 40,000 km² (16,000 sq. miles) Green River Formation in Colorado, Utah, and Wyoming.

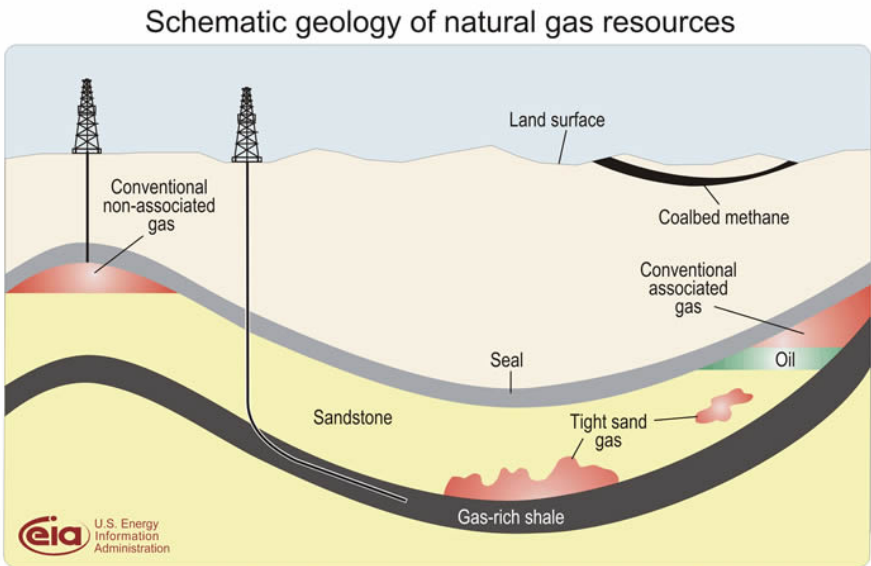
Oil shale differs from coal in that organic matter in shales has a higher atomic hydrogen to carbon ratio. Coal also has an organic to inorganic matter ratio of more than 4, i.e. 75 to 5, while oil shales have a higher content of sedimentary rock. Sources estimate the world reserves of oil shales at more than 2.5 trillion barrels.

Oil shales are thought to form when algae and sediment deposit in lakes, lagoons and swamps where an anaerobic (oxygen-free) environment prevent the breakdown of organic matter, thus allowing it to accumulate in thick layers. That is later covered with overlying rock to be baked under high temperature and pressure. However the heat and pressure was lower than in oil and gas reservoirs.

The shale can be strip-mined and processed with distillation. Extraction with fracturing and heating is still relatively unproven. Companies are experimenting with direct electrical heating rather than e.g. steam injection. Extraction cost is currently around 25-30 USD per barrel.

7.1.4 Shale gas and coal bed methane

Oil shales are also becoming an important source of shale gas, and some analysts expect that this source of natural gas can supply half the gas consumption in USA and Canada by 2020. Shale normally do not have the required matrix permeability for the gas to be produced, and in the past gas could be produced only from source rock with significant natural fracturing. The natural gas comes from decomposition of shale oil and is held in natural fractures, some in pore spaces, and some is adsorbed onto the organic material. Recently there have been strong advance in extraction technology which uses a combination of horizontal wells and hydraulic fracturing in a way that maintains fracturing (see chapter 3.7) and flow of gas much better than earlier. Even so production typically requires a high number of wells with limited lifetime, and so continuous drilling of new well is required to maintain output. Methane is a potent greenhouse gas and emissions from leaking capped wells and fractures is a potential problem die to the large



number of wells.

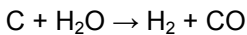
This form of production is different from *oil shale gas* which is produced by pyrolysis (heating and hydrocarbon decomposition) of mined oil shale.

Coal deposits also contain large amounts of methane, referred to as **coal bed methane**. The methane is absorbed in the coal matrix and needs extraction techniques similar to shale gas. Often the coal bed is flooded, so after well completion and fracturing, the coal seam (layer of coal) needs to be dewatered. A common solution is to extract water through the well tubing. Generally, the water needs to be pumped out and therefore control is needed to prevent the gas from entering the water in the tubing (the well becomes *gassy*) This reduces the pressure and allows methane to desorb from the matrix and be produced through the casing.

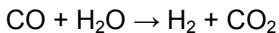
7.1.5 Coal, gas to liquids and synthetic fuel

Coal is similar in origin to oil shales, but typically formed from the anaerobic decay of peat swamps and relatively free from non organic sediment deposits, reformed by heat and pressure. To form a 1 meter thick coal layer, as much as 30 meters of peat was originally required. Coal can vary from relatively pure carbon to carbon soaked with hydrocarbons, sulfur etc.

It has been known for decades that synthetic diesel could be created from coal. This is first done by creating *water gas* as synthesis gas by passing steam over red-hot coke. The reaction is endothermic and requires heating:

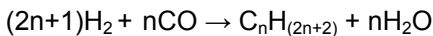


More hydrogen is produced in the *water gas shift reaction*:



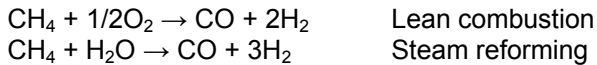
Often two stages are used: a high temperature shift (HTS) at 350 °C with catalyst iron oxide promoted with chromium oxide, and a low temperature shift (LTS) at 190–210 °C with catalyst copper on a mixed support composed of zinc oxide and aluminum oxide.

These synthesis gases are then used in the *Fischer–Tropsch process*:



This process runs at a pressure of 2-4 MPa. The high temperature process with iron catalyst runs at 350 °C and will yield a fuel similar to normal diesel with an average carbon number of 12, and a certain content of unwanted aromatics. The low temperature process runs at 200 °C with a cobalt catalyst and yields a pure synthetic diesel composed of alkanes with a carbon number of 10-15 and an average carbon number of 12.

Synthesis gas can also be created from natural gas by lean combustion or steam reforming:



This can be fed to the water shift reaction and to the F-T process. This process together with the following application are often called Gas to Liquids or GTL processes.

An alternative use of the synthesis gases (CO and H₂) is production of methanol and synthetic gasoline:



Then the methanol is converted to synthetic gasoline in the Mobil process.



The following stage further dehydrates the ether with ceolite catalyst to yield a synthetic gasoline with 80% carbon number 5 and above. It suffers from catalyst coking and currently has limited economical competitiveness.

7.1.6 Methane hydrates

Methane hydrates are the most recent form of unconventional natural gas to be discovered and researched. These formations are made up of a lattice of frozen water, which forms a sort of cage around molecules of methane. Hydrates were first discovered in permafrost regions of the Arctic and have been found in most of the deepwater continental shelves tested. The methane originates from organic decay.



At the sea bottom, under high pressure and low temperatures, the hydrate is heavier than water and cannot escape. Research has revealed that this form of methane may be much more plentiful than earlier expected. Estimates range anywhere from 180 to over 5800 trillion scm. This is also a greenhouse emission treat if released due to ocean warming.

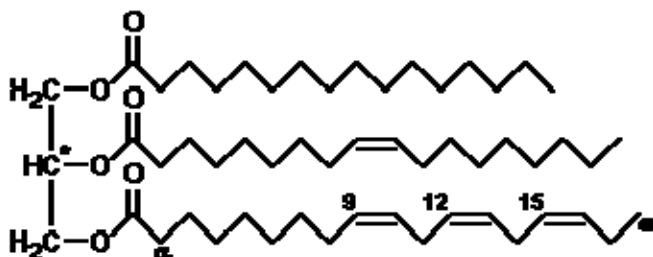
The US Geological Survey estimates that methane hydrates may contain more organic carbon than all the world's coal, oil, and conventional natural gas – combined. However, research into methane hydrates is still in its infancy.

7.1.7 Biofuels

Biofuels are produced from specially-grown products such as oil seeds or sugars, and organic waste e.g. from the forest industry. These fuels are called **carbon neutral**, because the carbon dioxide (CO₂) released during burning is offset by the CO₂ used by the plant when growing.

Ethanol alcohol (C₂H₅OH) is distilled from fermented sugars and/or starch (e.g. wood, sugar cane or beet, corn(maize) or grain) to produce ethanol that can be burnt alone with retuning of the engine, or mixed with ordinary petrol.

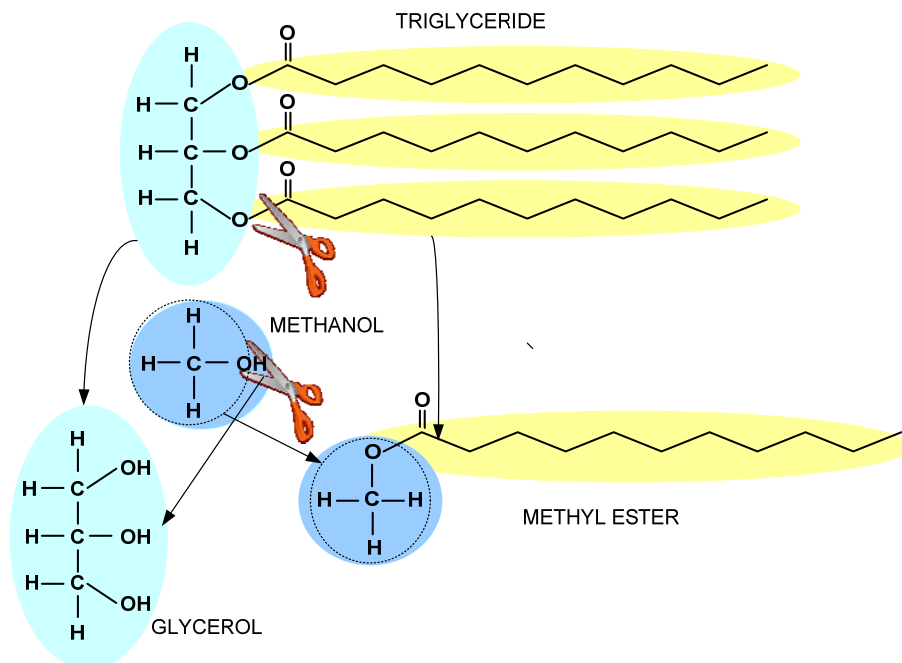
Biodiesel is made from oils from crops such as rapeseed, soy, sesame, palm or sunflower. The vegetable oil (lipid) is significantly different from mineral (crude) oil, and is composed of triglycerides. In these molecules three fatty acids are bound to a glycerol molecule shown in the following picture (The wiggly line represents the carbon chain with a carbon atom at each knee with single or double bonds and two or one hydrogen atoms respectively):



The glycerol backbone on the left is bound (ester OH binding) to three fatty acids, here shown with palmitic acid, oleic acid and alpha-linolenic acid and a total carbon number of 55.

This molecule is broken down to individual alkyl esters through a chemical process called *transesterification* whereby the glycerin is separated from the fatty acids. Methanol (CH_3OH) is added to the lipids and heated. Any strong base capable of deprotonating the alcohol, such as NaOH or KOH is used as catalyst.

The process leaves behind **methyl esters** (with a CH_3 group on the ester binding) and **glycerin** (a valuable byproduct used in soaps, explosives and other products).



Biodiesel contains no petroleum, but it can be blended at any level with petroleum diesel to create a biodiesel blend. It can be used in compression-ignition (diesel) engines with little or no modification. Biodiesel is simple to use, biodegradable, non-toxic, and essentially free of sulfur and aromatics.

Although biofuel is carbon-neutral, concern has been raised about diverting agricultural areas away from food production. Recently, research has shown potential for growing certain strains in arid regions that could otherwise not be used for producing human food.

An alternative to the above process still at the research stage is genetically modified *E. coli* bacteria that can produce enzymes to break down cellulose to sugar and then produce biodiesel. This method should allow use of general biological waste and limit competition with human food resources.

7.1.8 Hydrogen

Although not a hydrocarbon resource, hydrogen can be used in place of or as a complement to traditional hydrocarbon based fuels. As an "energy carrier". Hydrogen is clean burning, which means that when hydrogen reacts with oxygen, either in a conventional engine or a fuel cell, water vapor is the only emission. (Combustion with air at high temperatures will also form nitrous oxides).

Hydrogen can be produced either from hydrocarbons (natural gas, ethanol etc.) or by electrolysis. Production from natural gas is often done by steam reforming and water shift gas reactions ($\text{CH}_4 + \text{H}_2\text{O} \rightarrow \text{CO} + 3 \text{H}_2$, $\text{CO} + \text{H}_2\text{O} \rightarrow \text{CO}_2 + \text{H}_2$) with up to 75-80% efficiency, It has the advantage over methane gas, that carbon dioxide can be removed and handled at a central location rather than from each consumer (car, ship etc.), providing a cleaner **energy carrier**.

Hydrogen is also produced from water by electrolysis with an efficiency of about 25% at normal conditions to about 50% in high temperature, high pressure processes, or in various recycling processes in the chemical industry. (e.g. hydrochloric acid recycled in the polyurethane process). The energy supply can then come from a renewable source such as hydroelectric, solar, wind, wave, or tidal, where hydrogen acts as an **energy carrier** replacing batteries, to form a full clean, renewable energy source supply chain.

In both cases the main problem is overall economy, distribution and storage. Hydrogen cannot easily be compressed to small volumes, but requires quite bulky gas tanks for storage. Also hydrogen produced from electricity currently has an end-to-end efficiency that does not compare well with gasoline or electrical battery vehicles.

7.2 Emissions and environmental effects

The production, distribution and consumption of hydrocarbons as fuel or feedstock are globally the largest source of emissions into the environment. The total annual world energy supply of 11,000 Mill TOE is based 81% on

fossil fuels, and releases some 26,000 million tons of carbon dioxide plus other gases, e.g. methane into the atmosphere.

The most serious effect of these emissions is global climate change. **The Inter-governmental Panel on Climate Change** (often called the UN Climate Panel) predicts that these emissions will cause the global temperature to rise from between 1.4 to 6.4°C by the end of the 21st century depending on models and global scenarios.

7.2.1 Indigenous emissions

Emissions from the industry can be divided into several types.

Discharge: Mud, shale, silt, produced water with traces of hydrocarbons. Ballast water, polluted wastewater with detergent, sewage etc.

Accidental spills: Blowout, shipwreck cargo and bunker oil, pipeline leakage, other chemicals, traces of low level radioactive isotopes.

Emissions: CO₂, methane, nitrous oxides (NO_x) and sulfur from power plants and flaring

Exposure: Toxic and/or carcinogenic chemicals

Locally, these emissions are tightly controlled in most countries by national and international regulations, and during normal operations, emission targets can be reached with the systems and equipment described earlier in this document. However, there is continuing concern and research into the environmental impact of trace levels of hydrocarbons and other chemicals on the reproductive cycle and health of wildlife in the vicinity of oil and gas installations.

The major short-term environmental impact is from spills associated with accidents. These spills can have dramatic short-term effects on the local environment, with damage to marine- and wildlife. However, the effects seldom last for more than a few years outside Arctic regions.

7.2.2 Greenhouse emissions

The most effective greenhouse gas is water vapor. Water naturally evaporates from the sea and spreads out and can amplify or suppress the other effects because of its reflective and absorbing capability.

The two most potent emitted greenhouse gases emitted are CO₂ and methane. Because of its heat-trapping properties and lifespan in the atmosphere, methane's effect on global warming is 22-25 times higher than CO₂ per kilo released to atmosphere. By order of importance to greenhouse effects, CO₂ emissions contributes 72-77%, methane 14-18%, nitrous oxides 8-9% and other gases less than 1%. (Sources: Wikipedia, UNEP)

The main source of carbon dioxide emissions is burning of hydrocarbons. Out of 29 Billion Tons (many publications use Teragram Tg = Million tons) of CO₂ emitted in 2008, 18 Billion Tons or about 60% of the total comes from oil and gas, the remainder is coal, peat and renewable bioenergy such as firewood. 11% or 3,2 Billion tons comes from the oil and gas industry itself in the form of losses, local heating, power generation etc.

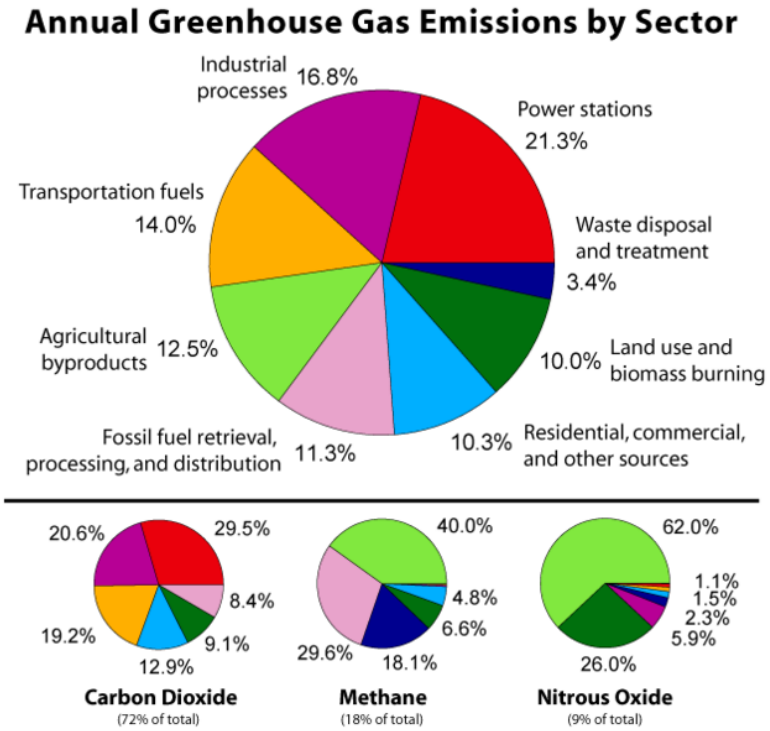


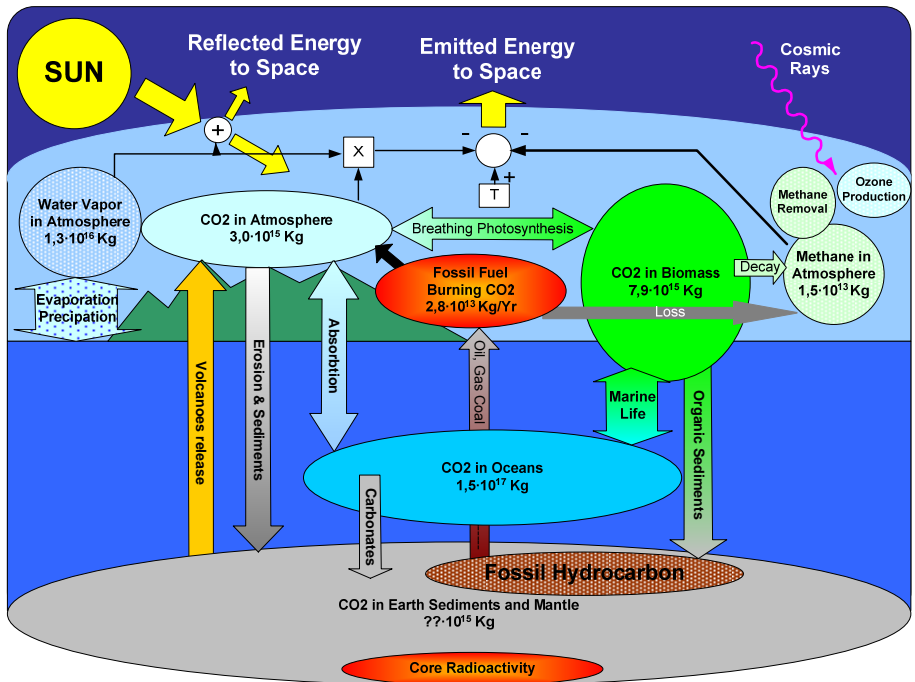
Fig. Greenhouse emissions Source: Wikipedia Commons

The annual emissions amount to about 1% of total atmospheric CO₂, which is in balance with about 50 times more carbondioxide dissolved in seawater.

This balance is dependent on sea temperature: Ocean CO₂ storage is reduced as temperature increases, but increases with the partial pressure of CO₂ in the atmosphere. Short term the net effect is that about half the CO₂ emitted to air contributes to an increase of atmospheric CO₂ by about 1,5 ppm annually.

For methane, the largest source of human activity-related methane emissions to atmosphere, is from rice paddies and enteric fermentation in ruminant animals (dung and compost) from 1.4 billion cows and buffaloes. These emissions are estimated at 78.5 Tg/year (source: FAO) out of a total of 200 Tg, which is equivalent to about 5,000 Tg of CO₂. Methane from the oil and gas industry accounts for around 30% of emissions, mainly from losses in transmission and distribution pipelines and systems for natural gas.

There are many mechanisms affecting the overall balance of greenhouse gases in the atmosphere, CO₂ has been measured both directly and in ice cores, and has increased from a pre-industrial value of around 250 ppm to 385 ppm today. Methane has increased from 1732 to 1774 ppb (parts per billion).



There is no full model that describes the net effect of these changes. It is well accepted that without CO₂, methane and water vapor, the global average temperature would be about 30°C colder. The current data correlates well with a current global average temperature increase from a pre-industrial global average of 13.7°C to 14.4°C today. The atmosphere and seas have large heat trapping capacity, which makes their temperature rise. These temperature rises lag behind greenhouse gas temperature increases. It is therefore predicted that the temperature will continue to rise by about 1°C even if there were no further increase in levels of CO₂ and methane.

The heat capacity of the atmosphere and seas also means that when the temperature increases there will be more energy stored in the atmosphere, which is expected to drive more violent weather systems.

The main contribution to sea level change in the short to medium term is thermal expansion of the oceans, currently predicted to have reached about 0.15 m over pre-industrial standards, and currently rising some 3 mm/year. Although the melting of inland ice in Greenland and Antarctica is reported, this will mainly have local effects, as this ice will possibly take 15-20,000 years to have any significant contribution to sea levels. However, polar glaciation and sea ice is an important indicator of global warming, and in particular, Arctic summer temperatures have risen and sea ice have been significantly reduced in area and thickness .

7.2.3 Carbon capture and sequestration

Due to these effects and the long-term concerns, it will be a high priority to reduce the amount of carbon dioxide and methane released into the atmosphere, and move to more sustainable energy sources. The main problem is that as much as one third of all emissions comes from planes, cars and ships, which account for about 45% of emissions from hydrocarbon fuels, not replaceable by other known energy sources at this time.

There are three main problem areas:

- There are losses in production: only about 70% of hydrocarbons extracted from the ground reach the private or industrial consumer. The rest is lost from production systems, transportation and through the refining and distribution of oil and gas.
- There are losses in consumption: much of the oil and gas is converted to work with an efficiency of 30% in cars for example to 60% in the best power plants.

- Better methods for capturing and storing emissions must also be found.

Efficiency will be improved by maintaining and operating facilities to reduce losses, and by converting to more efficient systems. As an example, it can be argued that conversion to electrically-driven equipment in place of gas turbine-driven equipment could reduce CO₂ emissions by more than 50% even if power is generated by a gas turbine and steam combined cycle unit. This also moves the emissions to a centralized unit rather than distributed to a larger number of smaller gas turbines.

To reduce overall emissions, carbon will have to be separated from other emitted gases (such as water vapor) and disposed of. Current plans call for re-injection into empty reservoirs, or reservoirs that need pressure assistance for oil extraction.

Capturing CO₂ can be used at large point sites, such as large fossil fuel or biomass energy facilities, industries with major CO₂ emissions, natural gas processing, synthetic fuel plants and fossil fuel-based hydrogen production plants:

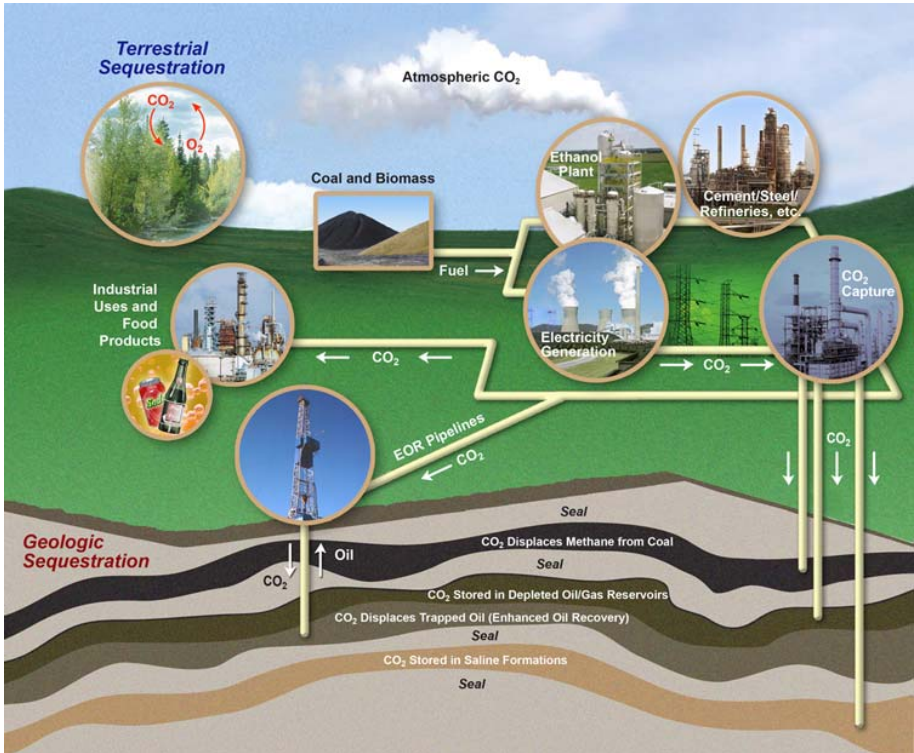
Overall there are three types of processes:

- Pre-combustion systems, where the fuel is gasified and processed before combustion and carbon dioxide can be removed from a relatively pure exhaust stream.
- Post-combustion systems where carbon dioxide is extracted from the flue gas, e.g. using an amine process.
- Oxyfuel consumption, where fuel is burnt as relatively pure oxygen, so the hydrocarbon is burned in oxygen instead of air. This produces a flue gas consisting of only carbon dioxide and water vapor, which is cooled and condensed.

For storage:

- A system to store, transport and inject gas into existing reservoirs. This is done by a pipeline, which is generally the cheapest form of transport, or may be done by ship if pipelines are not available.
- Alternatives to storage include carbonatization, deep sea deposit, and planting of photosynthetic plants in otherwise infertile areas.

Currently these processes could remove around 90% of CO₂ at a cost of 35-90 USD a ton including injection and storage in a reservoir. This is about 2-3 times the long-term expected emission quota costs.



Source: doe

8 Units

Some common units used in the oil and gas industry. I have listed a representative selection of US and metric units since both are used in different parts of the oil industry. The non-standard factors differ slightly between different sources.

API	American Petroleum Institute crude grade	$API = (141.5 / \text{Specific gravity}) + 131,5$ Spec gravity = $141.5/(API + 131,5)$ kg/l
Bl	Barrel (of oil)	1 Bl = 42 Gallons 1 Bl = 159 liters 1 Bl equiv. to 5487 scf = 147 scm gas
Bpd	Barrel per day	1 Bpd \approx 50 tons/tonnes per year
BTU	British Thermal Unit	1 BTU = 0.293 Wh = 1,055 kJ
Cal	Calorie	1 Cal = 4,187 J (Joules)
MMscf	Million Standard Cubic Feet	1 MMscf = 23.8 TOE \approx 174 barrels
psi	Pounds Per Square Inch	1 psi = 6.9 kPa = 0.069 atm
Scf	Standard Cubic Feet (of gas) Defined by energy not a normalized volume	1 scf = 1000 BTU = 252 kcal = 293 Wh = 1,055 MJ \approx 0.0268 scm
Scm	Standard Cubic metre (of gas, also Ncm) Defined by energy content	1 Scm = 39 MJ = 10.8 kWh 1 Scm \approx 37.33 Scf (not a volume conv.) 1 Scm \approx 1.122 kg
TOE	Tons oil equivalent Range 6.6 - 8 barrels at API range 8 - 52	1 TOE = 1000 kg = 1 Ton (metric) oil 1 TOE = 1 Tonne oil (US) 1 TOE \approx 7.33 Barrels (at 33 API) 1 TOE \approx 42.9 GJ = 11,9 MWh 1 TOE \approx 40.6 MMBTU 1 TOE \approx 1.51 ton of coal 1 TOE \approx 0.79 ton LNG 1 TOE \approx 1,125 Scm = 42,000 Scf
kWh	kiloWattour = 1000 Joules * 3600 S	1 kWh = 3.6 MJ = 860 kcal = 3,413 BTU

Product specific gravity, API grades

Product	Liters Per Ton (metric)	API Grade	Specific Gravity (kg/m ³)	Barrels per Ton At 60°F
LPG	1835	10	1000	6.29
Jet A-1	1254	18	934	6.73
Gasoline premium/super	1353	25	904	6.98
Gasoline regular	1418	30	876	7.19
Kerosene	1273	33	860	7.33
Gas Oil	1177	36	845	7.46
Diesel Fuel	1159	39	830	7.60
Fuel oil 80 CST	1065	42	816	7.73
Fuel oil 180 CST	1050	50	780	8.06
Fuel oil 230 CST	1047			
Fuel oil 280 CST	1044			
Bitumen	979			

CO2 Emissions from burning of coal and hydrocarbons

Product	Average Carbon No	CO ₂ kg per kg	CO ₂ kg Per kWh	Other unit
Methane	1	2,75	0,178	1,92 kg CO ₂ / scm
Gasoline	8	3,09	0,241	2,28 kg CO ₂ / liter
Diesel	12	3,11	0,249	2,68 kg CO ₂ / liter
Fuel Oil	25	3,12	0,268	3,97 kg CO ₂ / liter
Coal	1	3,67	0,325	

9 Acronyms

Acronym	Description
AC	Alternating Current
AGA	American Gas Association
API	American Petroleum Institute
AO	Asset Optimization
CAPEX	CAPital EXpenses (Invested capital)
CCR	Central Control Room
CMMS	Computerized Maintenance Management System
CMS	Condition Monitoring Systems
CNG	Compressed Natural Gas
CSP	Collector and Separation Platform
DC	Direct Current
DYNPOS	Dynamic positioning (of rigs and ships)
E&P	Exploration and Production
EOR	Enhanced Oil Recovery (new technology, cf IOR)
ESD	Emergency ShutDown system
ESP	Electric Submerged Pump
F&G	Fire & Gas System
FPSO	Floating Production Storage and Offloading
F-T	Fischer–Tropsch process
GB(S)	Gravity Base Structure
GOR	Gas Oil Ratio from the well
GOSP	Gas Oil Separation Plant
GTL	Gas To Liquids
GTP	Gas Treatment Platform
HAZID	Hazard Identification Study
HAZOP	Hazard and Operability study
HIPPS	High Integrity Pressure (or Pipeline) Protection System
HP	High Pressure
HPU	Hydraulic Power Unit (topside utility for subsea)
HVAC	Heat Ventilation and Air Conditioning
IMS	Information Management System
IO	Integrated Operations
IOR	Improved Oil Recovery (using proven technology)
IR	Infra Red
ISO	International Standards Organization
K-Mass Flow	Coriolis type Mass Flow meter
LNG	Liquid Natural Gas (e.g. Methane)
LP	Low Pressure
LPG	Liquefied Petroleum Gas (e.g. Propane)
MCC	Motor Control Centre

MTBF	Mean Time Between Failure
NGL	Natural Gas Liquids, Condensates see also LPG
OPEX	Operational Expenses
PCP	Progressive Cavity Pump
PD-Meter	Positive Displacement meter
PFD	Probability of Failure on Demand
PGP	Power Generation Platform
PID	Proportional Integral Derivate control algorithm
PIMS	Production Information Management System
PoC	Pump of controller (for artificial lift)
POSMOOR	Position mooring for a floating facility
PSD	Process Shutdown System
ROV	Remote Operated Vehicle (for subsea workover)
RRF	Risk Reduction Factor
RTU	Remote Terminal Unit
SAS	Safety and Automation System
SCADA	Supervisory Control And Data Acquisition
SIF	Safety Instrumented Function
SIL	Safety Integrity Level (per IEC 61508)
SIS	Safety Instrumented System
TIP	Tie-In Platform
TLP	Tension Leg Platform
UMS	Unmanned Machinery Space class (marine = E0)
URF	Umbilicals, Risers and Flowlines
UV	Ultra Violet
WHP	Well Head Platform

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ISBN 978-82-997886-2-5

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