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Oil and gas production handbook
An introduction to oil and gas production, transport, refining and petrochemical industry

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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. Little material was found to quickly give the reader an overview of the entire oil and gas industry, while still preserving enough detail to let the engineer have an appreciation of the main characteristics and design issues.

I have had many requests that downstream processes be included, and have restructured the book into Upstream, Midstream, Refining and Petrochemical, adding basic information on these facilities. The main focus of the book is still the upstream production process.

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 of what typical facilities or equipment look like. Non-ABB photo sources are given below pictures; other pictures and illustrations are copyrighted by ABB.

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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 the tales of eternal fires where oil and gas seeps ignited and burned. One example is the site where the famous oracle of Delphi was built around 1,000 B.C. Written sources from 500 B.C. describe how the Chinese used natural gas to boil water.

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 northwestern Pennsylvania, and sparked the international search for an industrial use for petroleum.

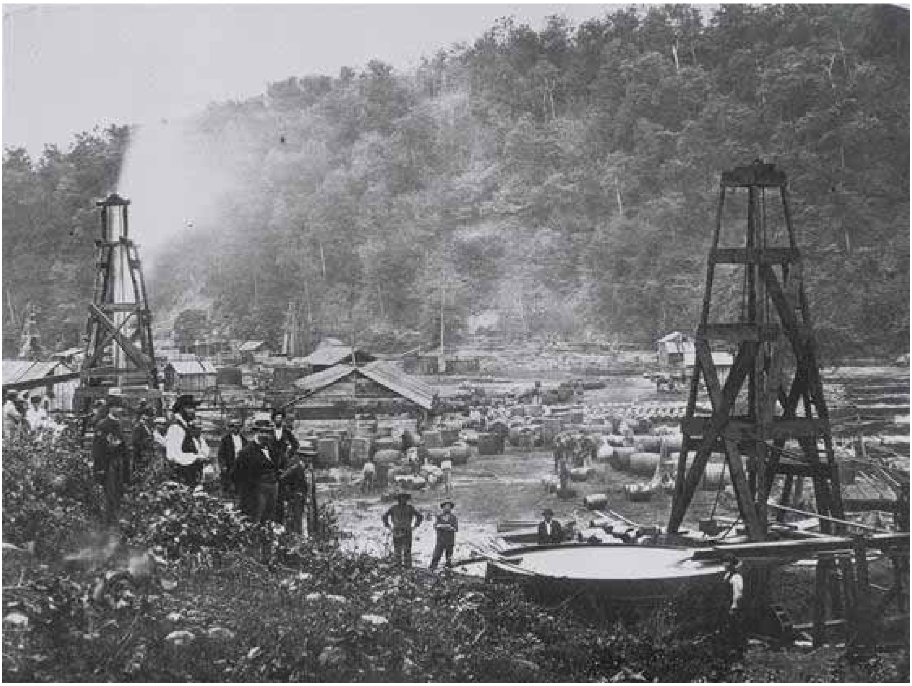


Photo: Drake Well Museum Collection, Titusville, PA

These wells were shallow by modern standards, often less than 50 meters deep, but they produced large quantities of oil. In this picture of the Tarr Farm, Oil Creek Valley, the Phillips well on the right initially produced 4,000 barrels per day in October, 1861, and the Woodford well on the left came in at 1,500 barrels per 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. At this time, barrel size had not been standardized, which made statements like "oil is selling at $5 per barrel" very confusing (today a barrel is 159 liters (see units on p. 141). But even in those days, overproduction was something to be avoided. When the "Empire well" was completed in September 1861, it produced 3,000 barrels per day, flooding the market, and the price of oil plummeted to 10 cents a barrel. In some ways, we see the same effect today. When new shale gas fields in the US are constrained by the capacity of the existing oil and gas pipeline network, it results in bottlenecks and low prices at the production site.

Soon, oil had replaced most other fuels for motorized transport. The automobile industry developed at the end of the 19^{th} 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 World War II that welding techniques, pipe rolling, and metallurgical advances allowed for the construction of reliable long distance pipelines, creating 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 liquefied natural gas (LNG) provides an economical way of transporting gas from even the remotest sites.

With the appearance of automobiles and more advanced consumers, it was necessary to improve and standardize the marketable products. Refining was necessary to divide the crude in fractions that could be blended to precise specifications. As value shifted from refining to upstream production, it became even more essential for refineries to increase high-value fuel yield from a variety of crudes. From 10-40% gasoline for crude a century ago, a modern refinery can get up to 70% gasoline from the same quality crude through a variety of advanced reforming and cracking processes.

Chemicals derived from petroleum or natural gas – petrochemicals – are an essential part of the chemical industry today. Petrochemistry is a fairly young industry; it only started to grow in the 1940s, more than 80 years after the drilling of the first commercial oil well.

During World War II, the demand for synthetic materials to replace costly and sometimes less efficient products caused the petrochemical industry to develop into a major player in modern economy and society.

Before then, it was a tentative, experimental sector, starting with basic materials:

- Synthetic rubbers in the 1900s
- Bakelite, the first petrochemical-derived plastic, in 1907
- First petrochemical solvents in the 1920s
- Polystyrene in the 1930s

And it then moved to an incredible variety of areas:

- Household goods (kitchen appliances, textiles, furniture)
- Medicine (heart pacemakers, transfusion bags)
- Leisure (running shoes, computers...)
- Highly specialized fields like archaeology and crime detection

With oil prices of $100 a barrel or more, even more difficult-to-access sources have become economically viable. Such sources include tar sands in Venezuela and Canada, shale oil and gas in the US (and developing elsewhere), coal bed methane and synthetic diesel (syndiesel) from natural gas, and biodiesel and bioethanol from biological sources have seen a dramatic increase over the last ten years. These sources may eventually more than triple the potential reserves of hydrocarbon fuels. Beyond that, there are even more exotic sources, such as methane hydrates, that some experts claim can double available resources once more.

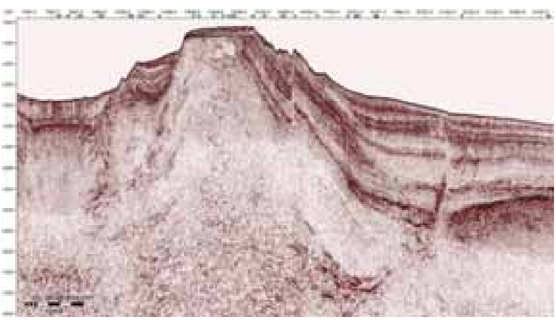
With increasing consumption and ever-increasing conventional and unconventional resources, the challenge becomes not one of availability, but of sustainable use of fossil fuels in the face of rising environmental impacts, that range from local pollution to global climate effects.

2 Facilities and processes

The oil and gas industry facilities and systems are broadly defined, according to their use in the oil and gas industry production stream:

Exploration	Includes prospecting, seismic and drilling activities that take place before the development of a field is finally decided.
Upstream	Typically refers to all facilities for production and stabilization of oil and gas. The reservoir and drilling community often uses upstream for the wellhead, well, completion and reservoir only, and downstream of the wellhead as production or processing. Exploration and upstream/production together is referred to as E&P.
Midstream	Broadly defined as gas treatment, LNG production and regasification plants, and oil and gas pipeline systems.
Refining	Where oil and condensates are processed into marketable products with defined specifications such as gasoline, diesel or feedstock for the petrochemical industry. Refinery offsites such as tank storage and distribution terminals are included in this segment, or may be part of a separate distributions operation.
Petrochemical	These products are chemical products where the main feedstock is hydrocarbons. Examples are plastics, fertilizer and a wide range of industrial chemicals.

2.1 Exploration



In the past, surface features such as tar seeps or gas pockmarks provided initial clues to the location of shallow hydrocarbon deposits. Today, a series of surveys, starting with broad geological mapping through increasingly advanced methods such as passive seismic, reflective seismic, magnetic and gravity surveys give data to sophisticated analysis tools that identify potential hydrocarbon bearing rock as “prospects.” Chart: Norwegian Petroleum Directorate (Barents Sea)

An offshore well typically costs $30 million, with most falling in the $10-$100 million range. Rig leases are typically $200,000 - $700,000 per day. The average US onshore well costs about $4 million, as many have much lower production capacity. Smaller companies exploring marginal onshore fields may drill a shallow well for as little as $100,000.

This means that oil companies spend much time on analysis models of good exploration data, and will only drill when models give a good indication of source rock and probability of finding oil or gas. The first wells in a region are called wildcats because little may be known about potential dangers, such as the downhole pressures that will be encountered, and therefore require particular care and attention to safety equipment.

If a find (strike, penetration) is made, additional reservoir characterization such as production testing, appraisal wells, etc., are needed to determine the size and production capacity of the reservoir in order to justify a development decision.

2.2 Production

This illustration gives an overview of typical oil and gas production facilities:

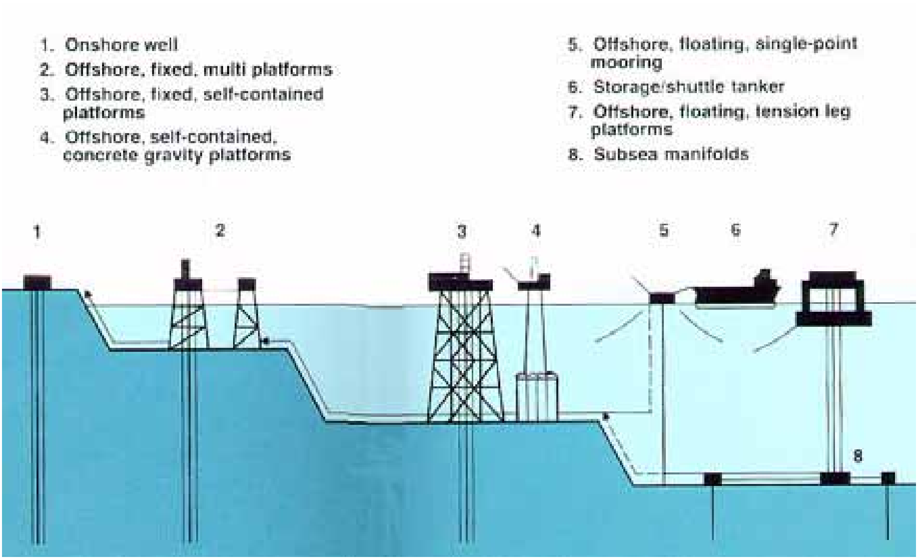


Figure 1. Oil and gas production facilities

Although there is a wide range of sizes and layouts, most production facilities have many of the same processing systems shown in this simplified overview:

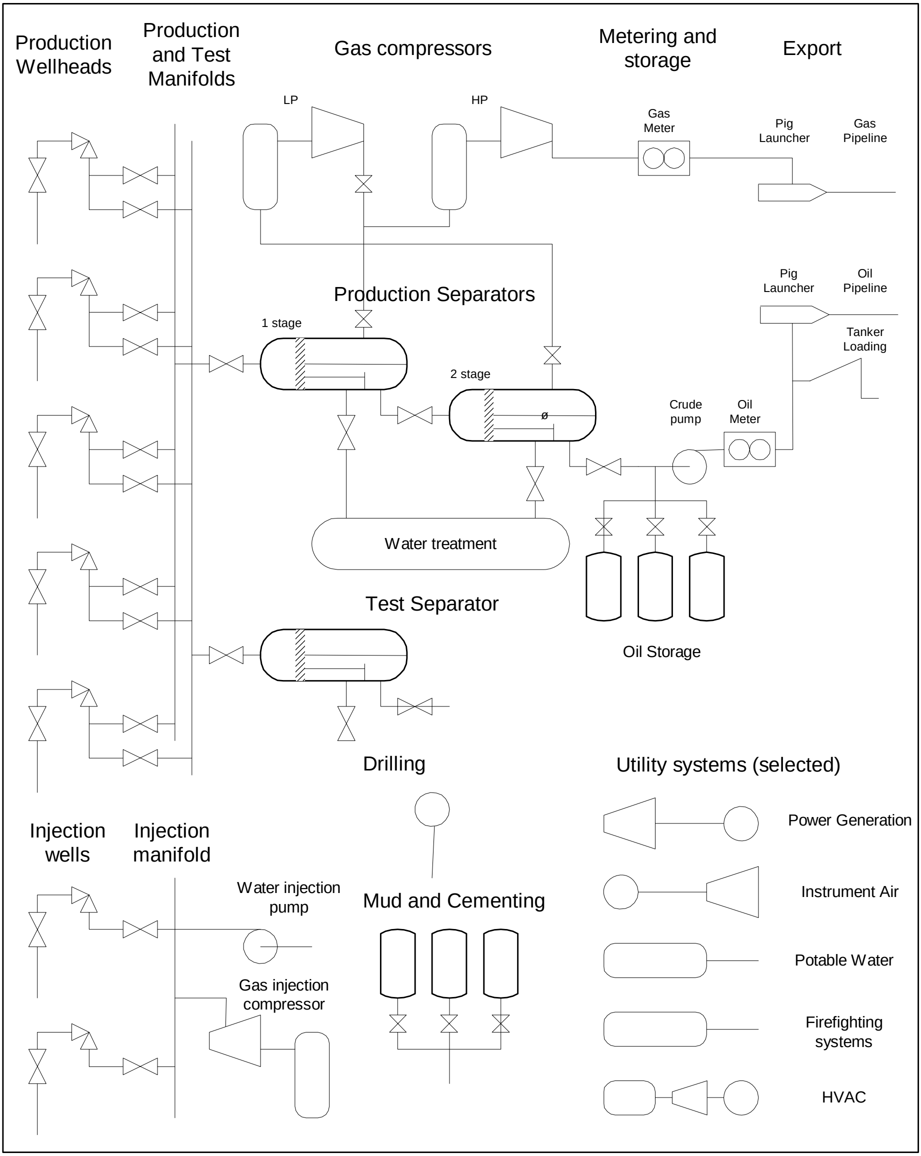


Figure 2. Oil and gas production overview

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 4,000 barrels-a-day wells; in shallow 20 meter deep reservoirs to 3,000 meter deep wells in more than 2,000 meters of water; in $100,000 onshore wells and $10 billion 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 distributed production, this is 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 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, which are not part of the actual process but provide energy, water, air or some other utility to the plant.

2.2.1 Onshore

Onshore production is economically viable from a few dozen barrels of oil a day and upward. Oil and gas is produced from several million wells worldwide. 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. This 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 to be processed at a refinery.

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

Unconventional plays target very heavy crude and tar sands that became 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. Since about 2007, drilling technology and fracturing of the reservoir have allowed shale gas and liquids to be produced in increasing volumes. This allows the US in particular to reduce dependence on hydrocarbon imports. Canada, China, Argentina, Russia, Mexico and Australia also rank among the top unconventional plays. These unconventional reserves may contain more 2-3 times the hydrocarbons found in conventional reservoirs. These pictures show the Syncrude Mildred plant at Athabasca, Canada *Photo: GDFL Jamitzky/Wikimedia* and the Marcellus Shale in Pennsylvania. *Photo: GDFL Ruhrfisch /Wikimedia*

2.2.2 Offshore

A whole range of different structures is 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:

Shallow water complex, which is characterized by several independent platforms with different parts of the process and utilities linked with gangway bridges. Individual platforms include wellhead riser, processing, accommodations and power generation platforms. (This picture shows the BP Valhall complex.) Typically found in water depths up to 100 meters.

Gravity base consists of enormous concrete fixed structures placed on the bottom, typically with oil storage cells in a "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 of water depth were typical in the 1980s and 1990s. The concrete was poured at an onshore 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 Statoil*

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. Flexibility allows it to operate in much deeper water, as it can absorb much of the pressure exerted by the wind and sea. Compliant towers are used between 500 and 1,000 meters of water depth.

Floating production, where all topside systems are located on a floating structure with dry or 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 currently 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. It 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*

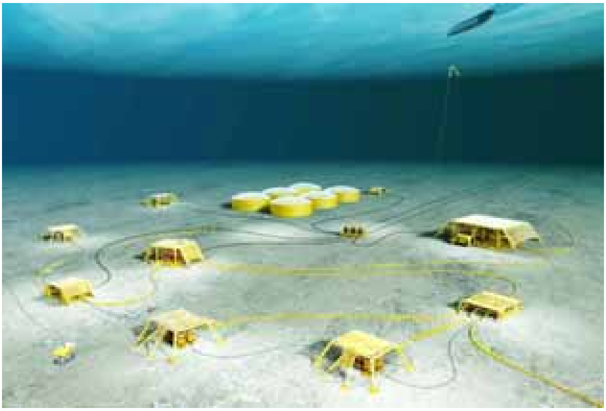
Tension Leg Platform (TLP – left side in picture) consists of a structure held in place by vertical tendons connected to the sea floor by pile-secured templates. The structure is held in a fixed position by tensioned tendons, which provide for use of the TLP in a broad water depth range up to about 2,000m. 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.

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

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. Rather, it 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 up to 3,000 meters. SPAR is not an acronym, and is named for its resemblance 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 the surface. As in a floating production system, the petroleum is extracted at the seabed, and is then “tied-back” to a pre-existing production platform or even an onshore facility, limited by horizontal distance or "offset.” The well is drilled by a movable 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 used 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. The aim of the industry is to allow fully autonomous subsea production facilities, with multiple wellpads, processing, and direct tie-back to shore. *Photo: Statoil*



2.3 Upstream process sections

We will go through each section in detail in the following chapters. The summary below is an introductory synopsis of each section. The activities up to the producing wellhead (drilling, casing, completion, wellhead) are often called “pre-completion,” while the production facility is “post-completion.” For conventional fields, they tend to be roughly the same in initial capital expenditure.

2.3.1 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 petroleum or natural gas to flow 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 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, 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.

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

Offshore, the dry completion wells on the main field center feed directly into production manifolds, while outlying wellhead towers and subsea installations feed via multiphase pipelines back to the production risers. Risers are a system that allows a pipeline to "rise" up to the topside structure. For floating 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.

2.3.3 Separation

Some wells have pure gas production which can be taken directly for gas treatment and/or compression. More often, the well produces a combination of gas, oil and water, with various contaminants that must be separated and processed. The production separators come in many forms and designs, with the classic 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 five minutes, allowing 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.

2.3.4 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, allowing 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 called custody transfer metering. It forms the basis for invoicing the sold product and also for production taxes and revenue sharing between partners. Accuracy requirements are often set by governmental authorities.

Typically, a metering installation 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.

2.3.5 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, such as electricity. Many remote installations are fully self-sustaining and must generate their own power, water, etc.

2.4 Midstream

The midstream part of the value chain is often defined as gas plants, LNG production and regasification, and oil and gas pipeline transport systems.

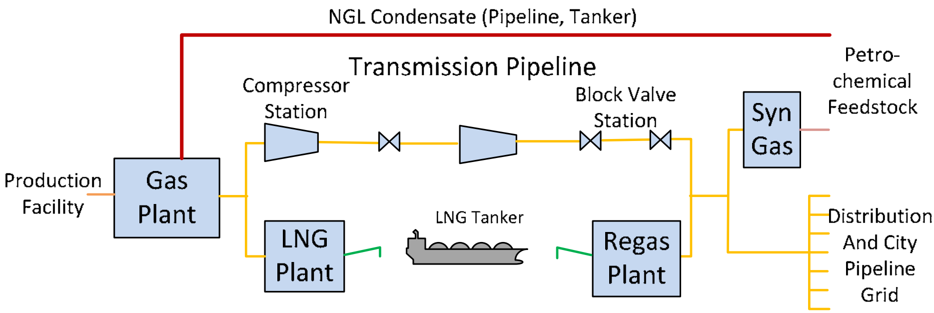


Figure 3. Midstream facilities

2.4.1 Gas Plants

Gas processing consists of separating 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 makeup of natural gas that is allowed into the pipeline. Before the natural gas can be transported it must be purified.

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 (H2S), carbon dioxide, helium, nitrogen and other compounds.

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

2.4.1 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 centrifugal compressor. This type of compression does not require the use of any 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.

2.4.2 Pipelines

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 with 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 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.

2.4.1 LNG liquefaction and regasification facilities

Natural gas that is mainly methane cannot be compressed to liquid state at normal ambient temperature. Except for special uses such as compressed natural gas (CNG), the only practical solution to long distance gas transportation when a pipeline is not available or economical is to produce LNG at -162 °C. This requires one or more cooling stages. Cooling work consumes 6-10% of the energy to be transported. Special insulated tank LNG carriers are required for transportation, and at the receiving end, a regasification terminal heats the LNG to vaporization for pipeline distribution.

Photo: Cove Point LNG Regas terminal

2.5 Refining

Refining aims to provide a defined range of products according to agreed specifications. Simple refineries use a distillation column to separate crude into fractions, and the relative quantities are directly dependent on the crude used. Therefore, it is necessary to obtain a range of crudes that can be blended to a suitable feedstock to produce the required quantity and quality of end products.

Photo: Statoil Mongstad Refinery

The economic success of a modern refinery depends on its ability to accept almost any available crude. With a variety of processes such as cracking, reforming, additives and blending, it can provide product in quantity and quality to meet market demand at premium prices.

The refinery operations often include product distribution terminals for dispensing product to bulk customers such as airports, gasoline stations, ports and industries.

2.6 Petrochemical

Chemicals derived from petroleum or natural gas – petrochemicals – are an essential part of today's chemical industry. Petrochemical plants produce thousands of chemical compounds. The main feedstock is natural gas, condensates (NGL) and other refinery byproducts such as naphtha, gasoil, and benzene. Petrochemical plants are divided into three main primary product groups according to their feedstock and primary petrochemical product:

Olefins include ethylene, propylene, and butadiene. These are the main sources of plastics (polyethylene, polyester, PVC), industrial chemicals and synthetic rubber.

Aromatics include benzene, toluene, and xylenes, which also are a source of plastics (polyurethane, polystyrene, acrylates, nylon), as well as synthetic detergents and dyes.
Synthesis gas (syngas) is formed by steam reforming between methane and steam to create a mixture of carbon monoxide and hydrogen. It is used to make ammonia, e.g., for fertilizer urea, and methanol as a solvent and chemical intermediary. Syngas is also feedstock for other processes such as the Fischer–Tropsch process that produces synthetic diesel.

Photo: DOW, Terneusen, Netherlands

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 well type, 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 may be installed, particularly as the reservoir pressure falls during years of production.

There is no distinct transition from conventional to unconventional oil and gas production. Lower porosity (tighter reservoirs) and varying maturity create a range of shale oil and gas, tight gas, heavy oil, etc., that is simply an extension of the conventional domain.

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 alkanes (single bond hydrocarbons on the form C_nH_{2n+2}) and smaller fraction aromatics (six-ring molecules such as benzene C_6H_6)

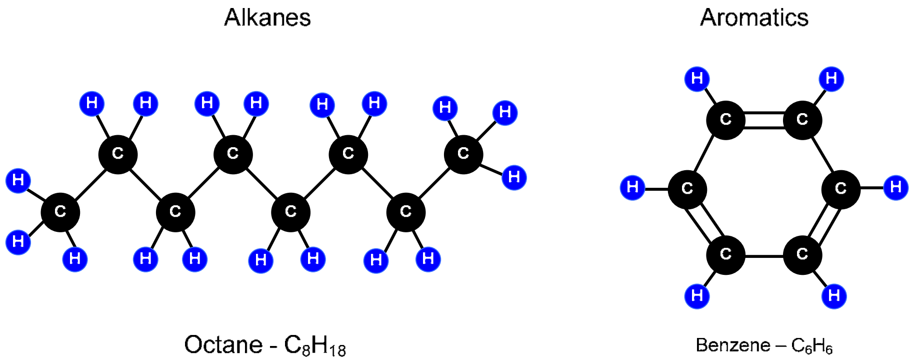


Figure 4. Basic hydrocarbons

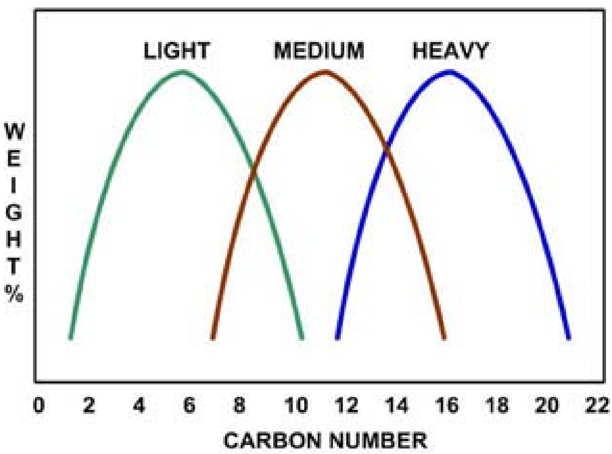
Different crude contains different combinations and concentrations of these various compounds. The API (American Petroleum Institute) gravity of a particular crude is merely a measure of its specific gravity or density. The higher the API number expressed as degrees API, the less dense (lighter, thinner)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

In addition to API grade and hydrocarbons, crude is characterized for other undesired elements like sulfur, 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 degrees 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 fluid density.

For instance, consider a barrel of tar that is dissolved in 3 barrels of naphtha (lighter fluid) to produce 4 barrels of a 40 degrees 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 degrees 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 previous figure 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, though 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 separately 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 only raw natural gas. 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.

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 byproducts 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.

3.2 The reservoir

The oil and gas bearing structure is typically porous rock, such as sandstone or washed out limestone. The sand may 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.

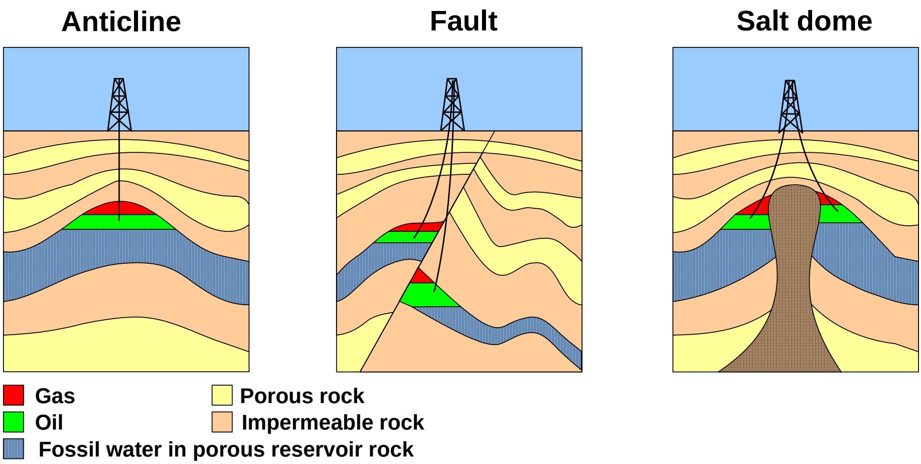
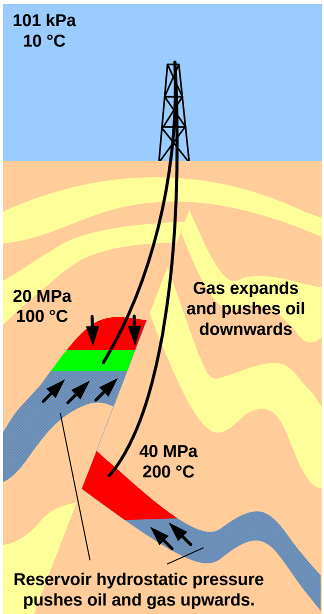


Figure 5. Reservoir formations

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 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 and oil and fossil water at the bottom. Salt is a thick fluid, and if deposited under the reservoir, it will flow up in heavier rock over millions of years. This process creates salt domes with a similar reservoir-forming effect. These are common e.g. in the Middle East.

This extraordinary process is ongoing. 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 the rock above have allowed 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 are extracted, and the levels 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% recovery. Reservoirs can be quite complex, with many folds and several layers of hydrocarbon-bearing rock above each other (in some areas more than ten). 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

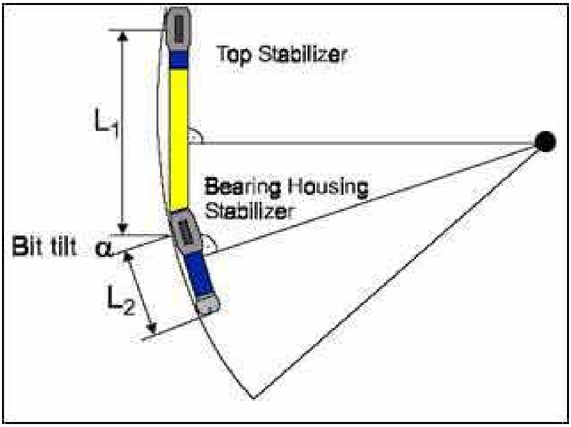
When 3D seismic investigation has been completed, it is time to drill the well. Normally, dedicated drilling rigs either on mobile onshore units or offshore floating rigs are used. Larger production platforms may also have their own production drilling equipment.

The main components of the drilling rig are the derrick, floor, drawworks, drive and mud handling. 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. *Photo: Puna Geothermal Venture*

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 above 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 3,000 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. Rate of penetration (ROP) is very dependent on depth and could be as much as 20m per hour for shallow sandstone and dolomite (chalk), and as low as 1m per 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 bends 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 that 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 km. Multiple completions allow production from several locations.

Wells can be of any depth from near the surface to a depth of more than 6,000 meters. Oil and gas are typically formed at 3,000-4,000 meters depth, but part of the overlying rock may have since eroded away. The pressure and temperature generally increase with increasing depth, so that deep wells can have more than 200 ºC 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 3,000 meter deep well with 30 MPa downhole pressure and normal crude oil at 850 kg/m^3, the wellhead static pressure will only be around 4.5 MPa. During production, the pressure will drop further due to 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 special 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*

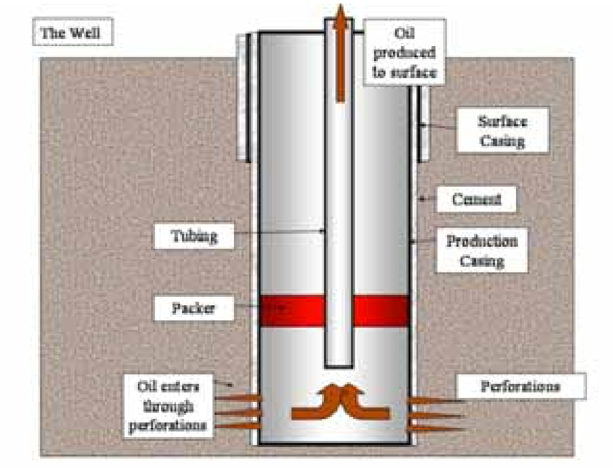
A special high-density mud called “kill fluid” is used to shut down a well for workover.

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

3.4 The well

Once 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, if 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 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 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 conical shape that must be taken into account when installing casing. The casing is normally cemented in place. *Ill: 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 m) long, is 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 contamination 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 damage 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 may be less than 100 barrels per day to several thousand barrels per day. (5,000 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 that 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 while still providing 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, while preventing 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 underwater on a special sea bed template.

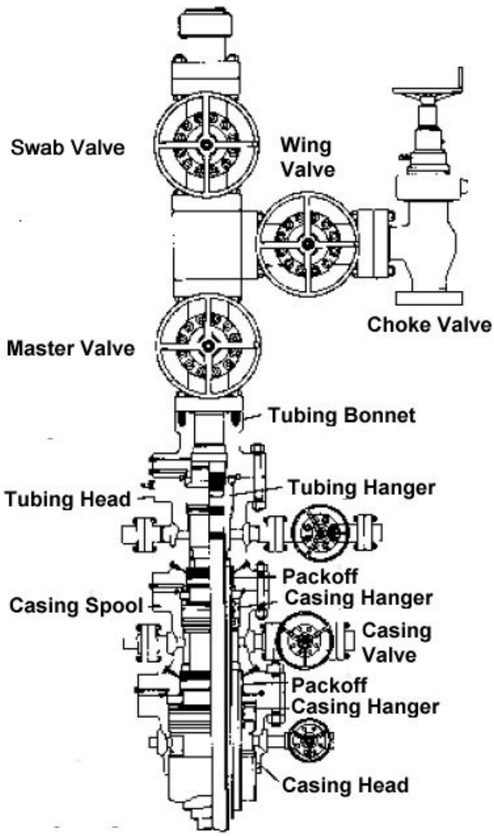
The wellhead has equipment mounted at the opening of the well to regulate and monitor the extraction of hydrocarbons from the underground formation. This also prevents oil or natural gas leaking out of the well, and prevents blow-outs due to high pressure formations. Formations that are under high pressure 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 (1,400 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 above. The Christmas tree may also have a number of check valves. The functions of these devices are explained below. *Ill: Vetco Gray*

At the bottom we find the **casing head** and **casing hangers**.
The casing is screwed, bolted or welded to the hanger. Several valves and plugs are normally fitted to give access to the casing. This permits 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 is also 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.

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 are normally fitted.

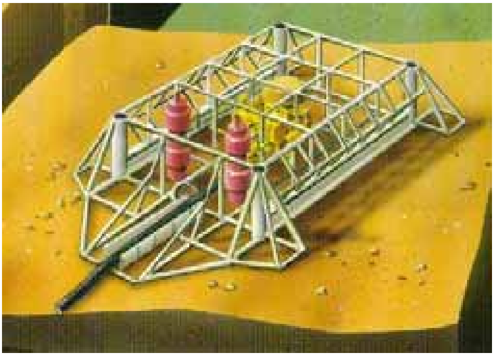
Wing valve. The wing valve can be a gate or ball valve. When shutting in the well, the wing gate or valve is normally used so that the tubing pressure can be easily read.

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 mates with a range of equipment.

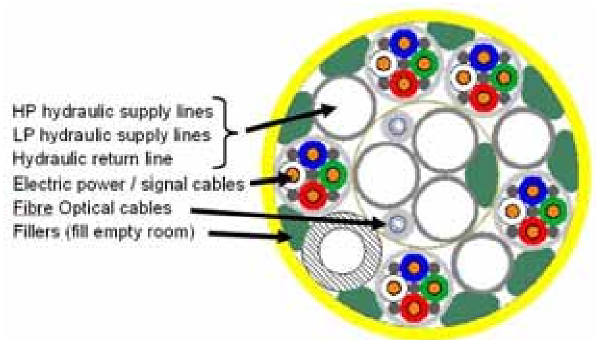
Variable flow choke valve. The variable flow choke valve is typically a large needle valve. Its calibrated opening is adjustable in 1/64 inch increments (called beans). High-quality steel is used in order to withstand the high-speed flow of abrasive materials that pass through the choke, usually over 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.

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: Statoil*



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

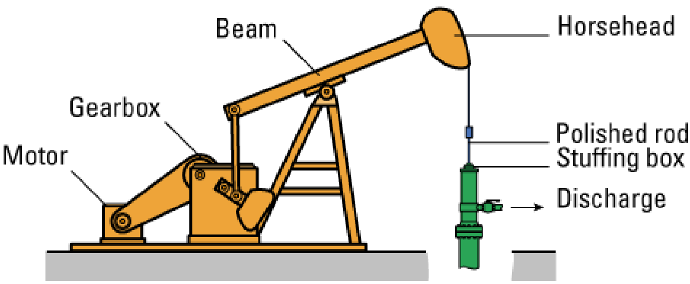
Wells are also divided into *production* and *injection wells*. The former are for production of oil and gas. Injection wells are drilled to inject gas or water into the reservoir. The purpose of injection is to maintain overall and hydrostatic reservoir pressure and force the oil toward the production 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 is 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

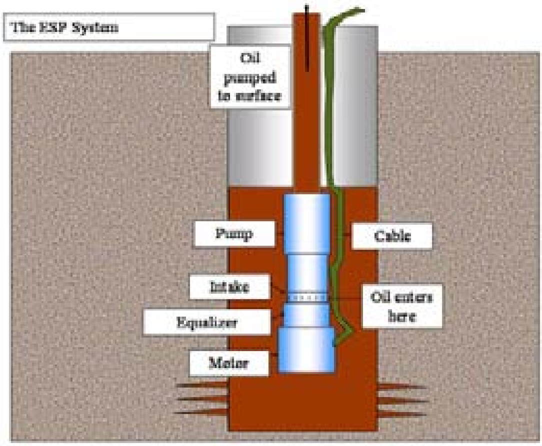


Sucker rod pumps, also called donkey or beam pumps, are the most common artificial lift system used in land-based operations. A motor drives a reciprocating beam, connected to a polished rod passing into the tubing via a stuffing box. The sucker rod continues down to the oil level and is connected to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

3.6.2 ESP

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 multiphase pump, such as a progressive cavity pump (PCP) or centrifugal pump, hangs by an electrical cable with tension members down the tubing. *Ill: Wikipedia.org*

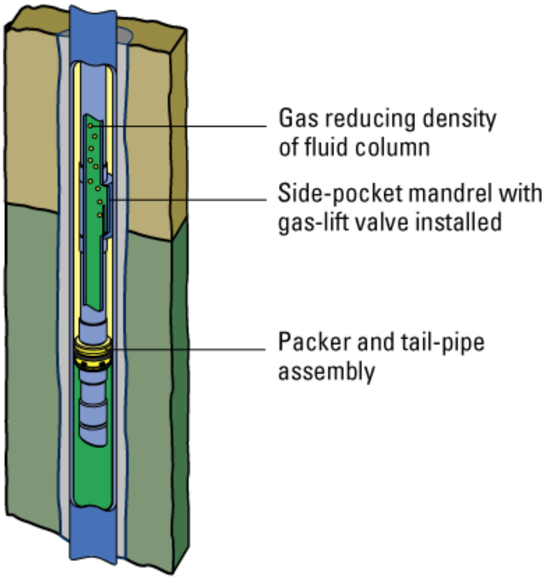


Installations down to 3.7 km with power up to 750 kW have been installed. At these depths and power ratings, medium voltage drives (up to 5kV) must be used.

ESPs work in deep reservoirs, but are sensitive to contaminants such as sand, and efficiency is sensitive to gas oil ration (GOR) (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 to the wellhead falls off, due to the counter pressure from weight of the oil column in the tubing. Thus, a 150 MPa reservoir pressure at 1,600 meters will fall to zero in the wellhead if the specific gravity is 800 kg/m^2 (0.8 times water). By injecting gas into this oil, the specific gravity is lowered and the well will start to flow. Typically, gas is injected between the casing and tubing, and a release valve on a gas lift mandrel is inserted into the tubing above the packer.



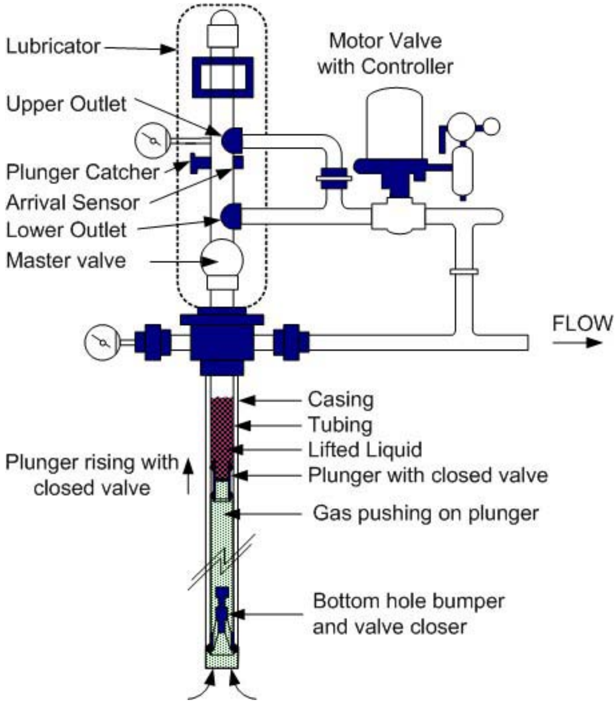
The valve will open at a set pressure to inject lift gas into the tubing. Several mandrels with valves set at different pressure ranges can be used to improve lifting and startup. *Ill: Schlumberger oilfield glossary*

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 GOR 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 closes the valve.

The cycle starts with the plunger falling into the well with its valve open. Condensed gas and oil can pass though 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 releases 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 buildup, 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 involving 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 hydrochloric acid (HCL) 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. Hydraulic fracturing is an essential technology for unconventional shale gas and liquids extraction.
- 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 upstream oil and gas process

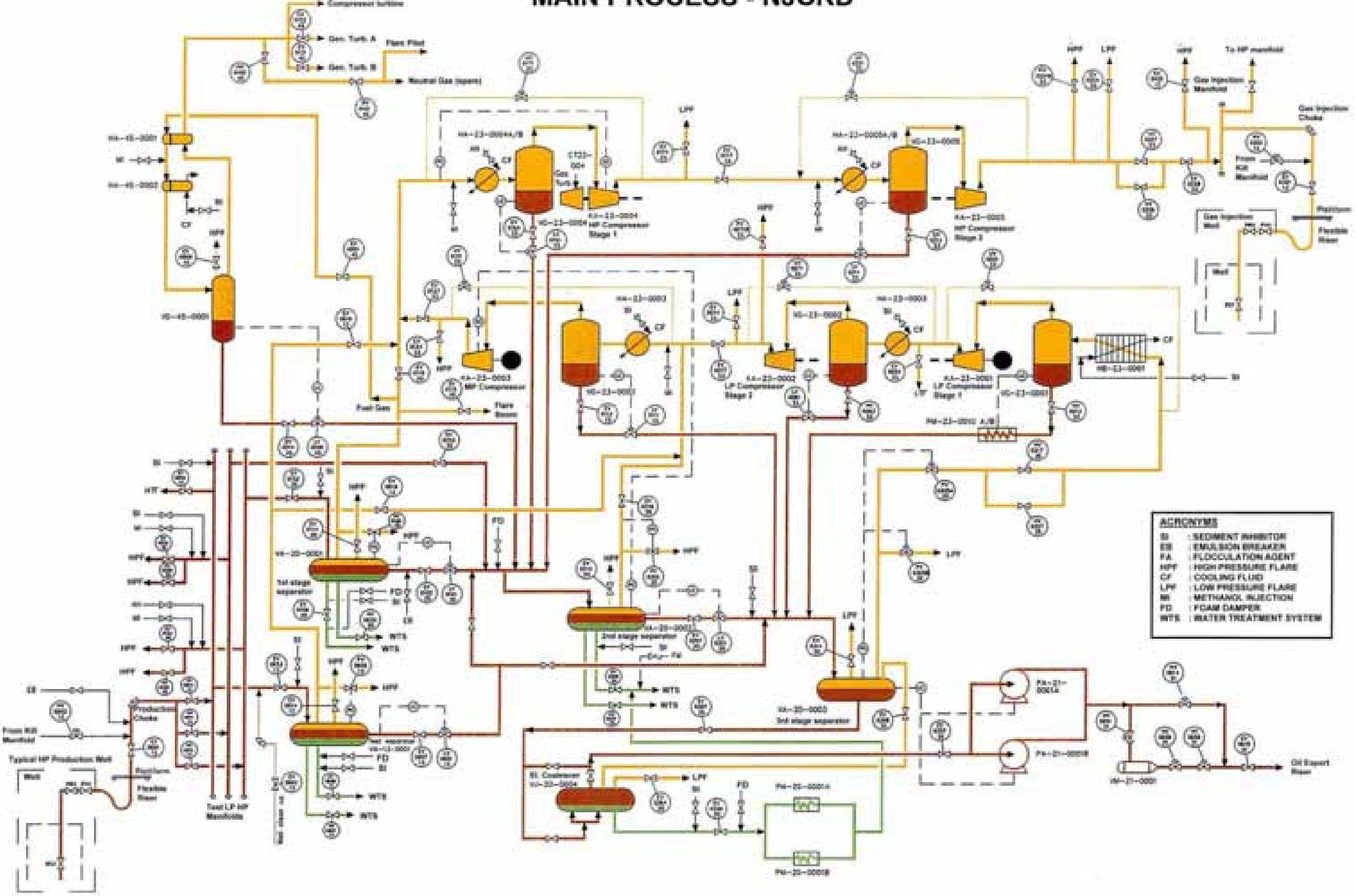
The oil and gas process is the process equipment that takes the product from the wellhead manifolds and delivers stabilized marketable products, in the form of crude oil, condensates or gas. Components of the process also exist to test products and clean waste products such as produced water.

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 bpd of 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 of 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. Currently, Njord sends the oil via a short pipeline to a nearby storage floater. On gravity base platforms, floating production and storage operations (FPSO) and onshore plants, storage a part of the main installation if the oil is not piped out directly. *Photo: Statoil ASA*

A large number of connections to chemicals, flares, etc., are also shown. These systems will be 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 may also occur in the well as described earlier. Slugging can be controlled manually by adjusting the choke, or by automatic slug controls. Additionally, areas of heavy condensate may 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 this 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 optimum production and recovery rate.

4.2 Separation

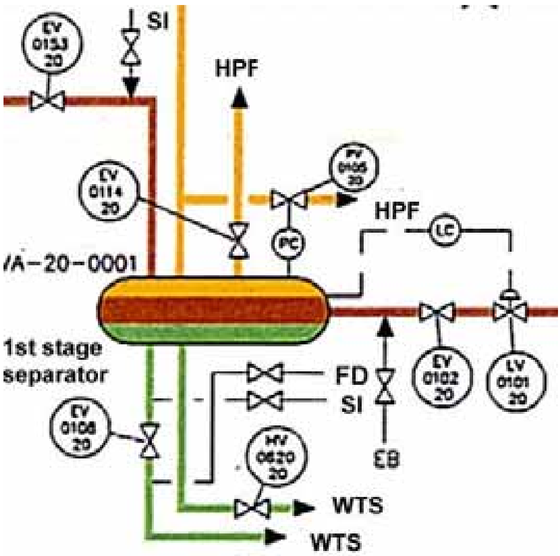
As described earlier, the well-stream may consist of crude oil, gas, condensates, water and various contaminants. The purpose of the separators is to split the flow into desirable fractions.

4.2.1 Test separators and well test

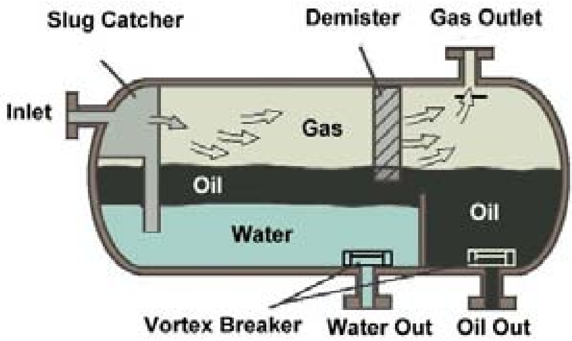
Test separators are used to separate the well flow from one or more wells for analysis and detailed flow measurement. In this way, the behavior of each well under different pressure flow conditions can be defined. This normally takes place when the well is taken into production and later at regular intervals (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 can 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 ºC. 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 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). The loops are operated by the control system. Another important function is 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 remove liquid droplets in the gas.

Emergency valves (EVs) are sectioning valves that separate the process components and blow-down valves, allowing excess hydrocarbons to burn off in the flare. These valves are operated if critical operating conditions are detected or on manual command from a dedicated emergency shutdown system. This may involve partial shutdown and shutdown sequences, since the flare may 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 3m in diameter and 14m 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 (to be discussed later).

There must also be a certain minimum pressure difference between each stage to allow satisfactory performance in the pressure and level control loops. Chemical additives will also 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 also receives production from wells connected to the low pressure manifold. The pressure is now around 1 MPa (10 atmospheres) and temperature below 100ºC. The water content will be reduced to below 2%.

An oil heater can be located between the first and second stage separator to reheat the oil/water/gas mixture. This makes 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 though tubes in a heating medium placed inside an outer shell.

4.2.4 Third stage separator

The final separator 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 can boil out. In some processes where the initial temperature is low, it might be necessary to heat the liquid again (in a heat exchanger) before the flash drum to achieve good separation of the heavy components. There are level and pressure control loops.

As an alternative, when 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, 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 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 4,000 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 Northeast Atlantic, the OSPAR convention limits oil in water discharged to sea to 40 mg/liter (ppm).

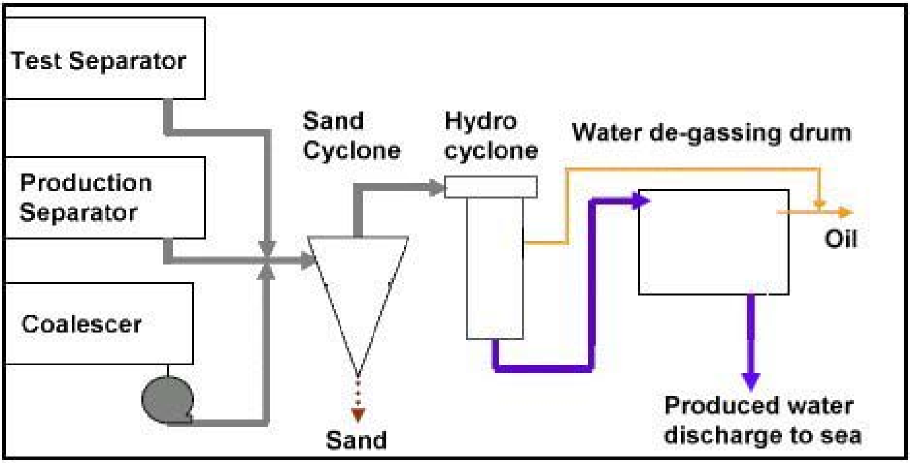


Figure 6. Produced water treatment

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, microscopic oil drops are broken down quickly 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.

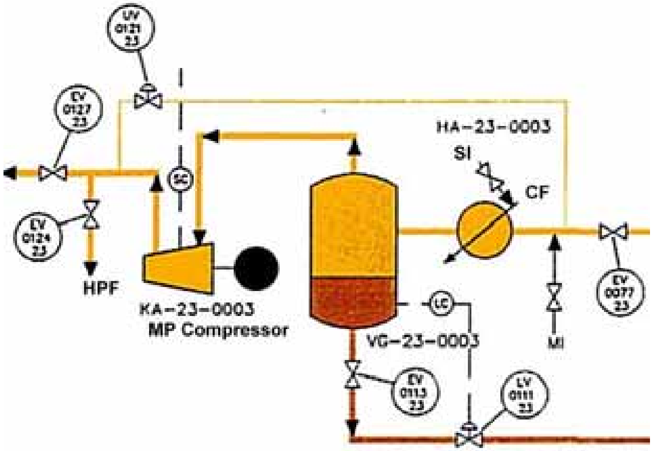
The water then goes to a **hydrocyclone**, a centrifugal separator that removes oil drops. The hydrocyclone creates a standing vortex where oil collects in the middle and water is forced to the side.

Finally the water is collected in the **water de-gassing drum**. Dispersed gas slowly rises and pulls 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

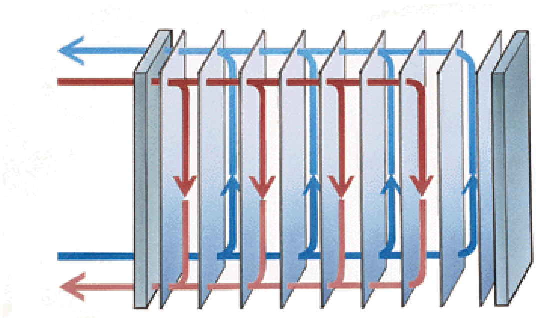
The gas train consists of several stages, each taking gas from a suitable pressure level in the production separator's gas outlet, and from the previous stage.

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.

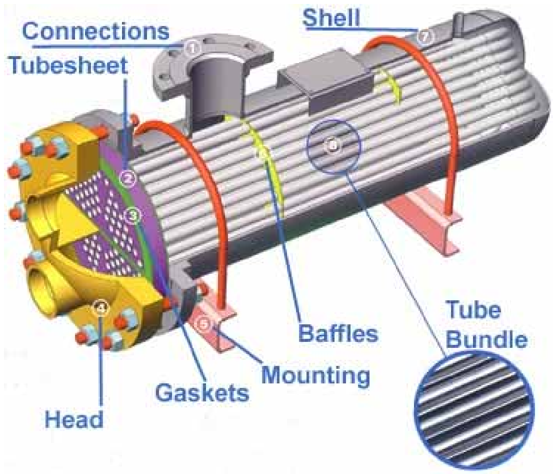


4.3.1 Heat exchangers

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 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 to the top of each section.

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 recycling the hydrocarbon liquids to the third stage separator.

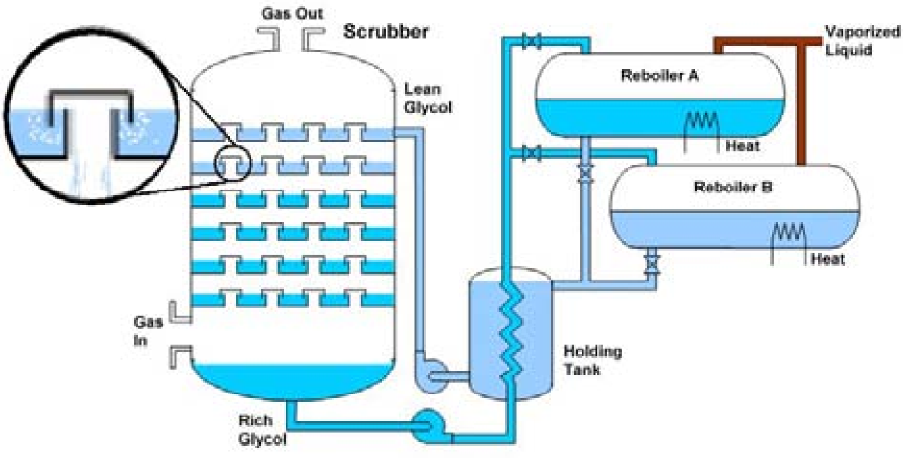


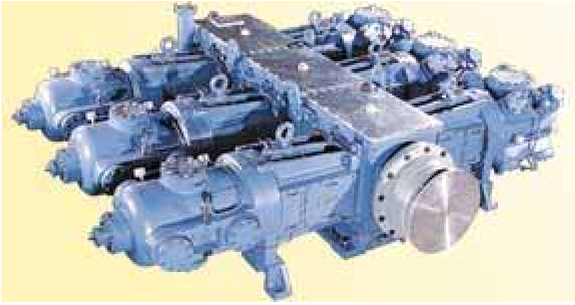
Figure 7, Glycol regeneration

4.3.3 Compressors, anti-surge and performance

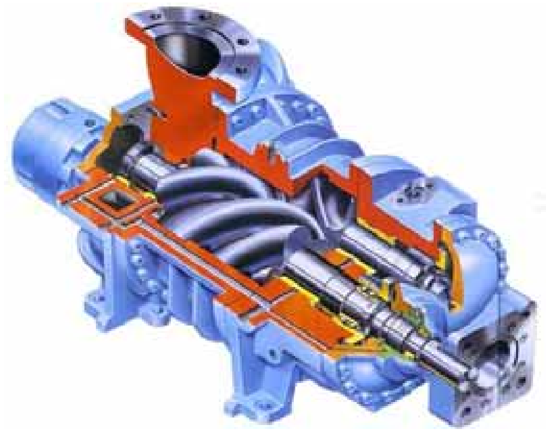
Compressors are used in many parts of the oil and gas process, from upstream production to gas plants, pipelines, LNG and petrochemical plants. The overview given here will therefore be referenced from other sections.

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

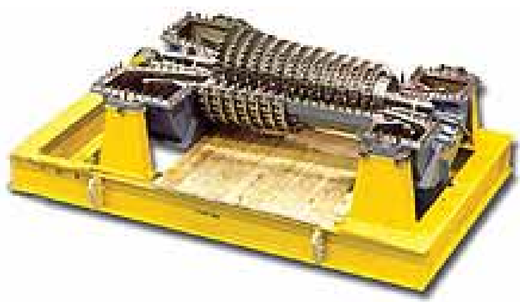
- **Reciprocating compressors**, which use a piston and cylinder design with 2-2 cylinders are built up to about 30 MW power, around 500-1,800 rpm (lower for higher power) with pressure up to 5MPa (500 bars). Used for lower capacity gas compression and high reservoir pressure gas injection. *Photo: Ariel corp.*



- **Screw compressors** are manufactured up to several MW, synchronous speed (3,000/3,600 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.*

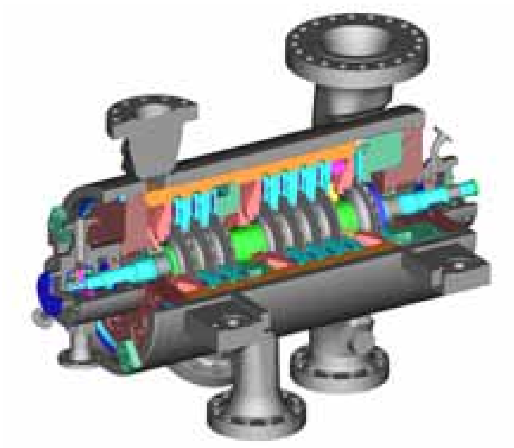


- **Axial blade and fin type compressors** with up to 15 wheels provide high volumes at a relatively low pressure differential (discharge pressure 3-5 times inlet pressure), speeds of 5,000-8,000 rpm, and inlet flows up to 200,000 m^3/hour. Applications include air compressors and cooling compression in LNG plants. *Axial rotor photo: Dresser Rand*



- Larger oil and gas installations use **centrifugal compressors** with 3-10 radial wheels, 6,000–20,000 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 m^3/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 differences between common shaft compressors 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 so as not to become overheated by circulation.

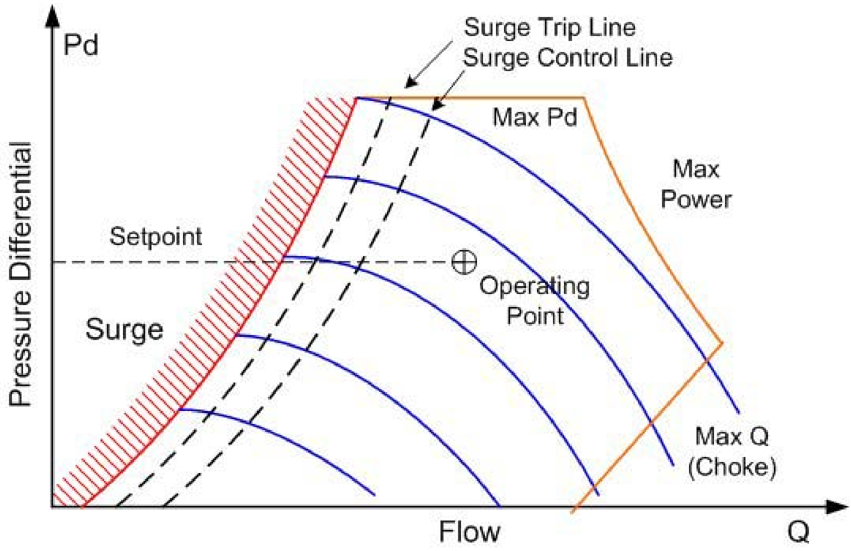


Figure 8. Compressor state diagram

The operating characteristics are defined by the manufacturer. In the diagram above, 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. It needs to be filtered and degassed. This happens in smaller reboilers, in much the same way as for the glycol reboilers described earlier.

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.

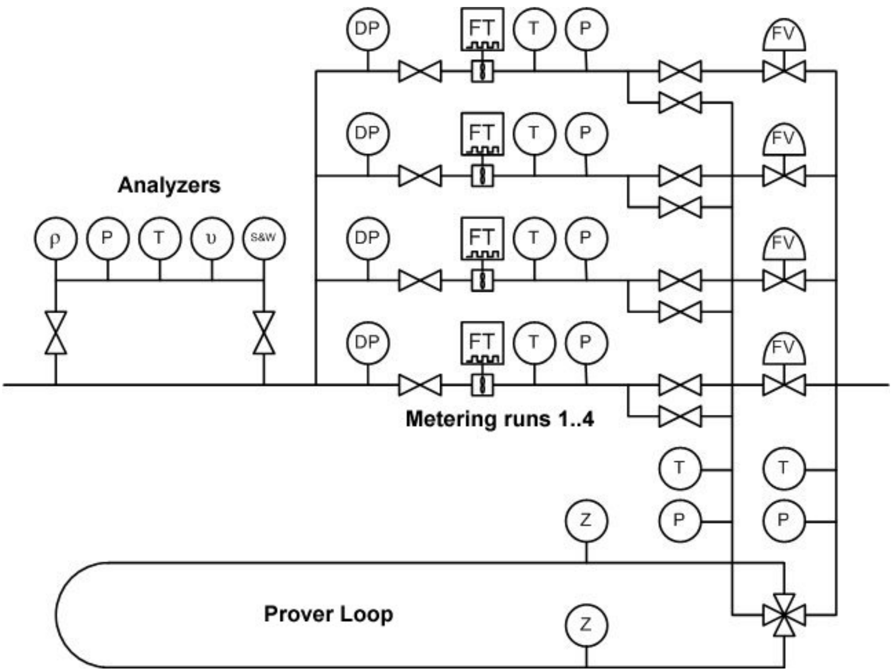
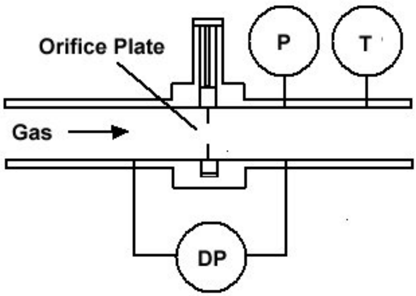


Figure 9. Metering system

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 though 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 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 ± 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 affect 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 ±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 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, oil and gas are 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 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: Statoil*

5 Midstream facilities

Raw natural gas from the well consists of methane as well as many other smaller fractions of heavier hydrocarbons, and various other components. The gas has to be separated into marketable fractions and treated to trade specifications and to protect equipment from contaminants.

5.1 Gathering

Many upstream facilities include the gathering system in the processing plant. However, for distributed gas production systems with many (often small) producers, there is little processing at each location and gas production from thousands of wells over an area instead feed into a distributed gathering system. This system in general is composed of:

- **Flowlines**: A line connecting the wellpad with a field gathering station (FGS), in general equipped with a fixed or mobile type pig launcher.
- **FGS** is a system allowing gathering of several *flowlines and permits transmission of the combined stream to the central* processing facility (CPF) and measures the oil/water/gas ratio. Each FGS is composed of:
    - Pig receiver (fixed/mobile)
    - Production header where all flowlines are connected
    - Test header where a single flow line is routed for analysis purposes (GOR Gas to oil ratio, water cut)
    - Test system (mainly test separator or multiphase flow meter)
    - Pig trap launcher
- **Trunk line** – pipeline connecting the FGS with the CPF. Equipped with a pig receiver at the end.

5.2 Gas plants

5.2.1 Gas composition

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 removing them.

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 may 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.

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	$T_{cri\ t}$−82.6 °C @ 4,6 MPa
Ethane	C_2H_6	-88.6 °C	4200 kPa
Propane	C_3H_8	-42.1 °C	890 kPa
Butane	n-C_4H_{10}	−0.5 °C	210 kPa
Higher order HC			
Alkenes	C_nH_{2n}		
Aromatics	e.g. C_6H_6		
Acid gases			
Carbon dioxide	CO_2	−78 °C	5500 kPa
Hydrogen sulfide	H_2S	-60.2 °C	
Mercaptans ex.			
Methanethiol	CH_3SH	5.95 °C	
Ethanethiol	C_2H_5SH	35 °C	
Other Gases			
Nitrogen	N_2	-195.79 °C	
Helium	He	-268.93 °C	
Water	H2O	0 °C	
Trace pollutants			
Mercury			
Chlorides			

Data source: Wikipedia, Air Liquide Gas Encyclopedia

Natural gas is characterized in several ways dependent 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 1,000 SM^3. (0.1 gallon per 1000 scf).
- **Sour gas** is raw gas with a content of more than 5.7 mg hydrogen sulfide (H_2S) 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 (CO_2) or H_2St. Pipeline natural gas specification is typically less than 2% CO_2. Acid gas fields with up to 90% CO_2 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.

5.3 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.

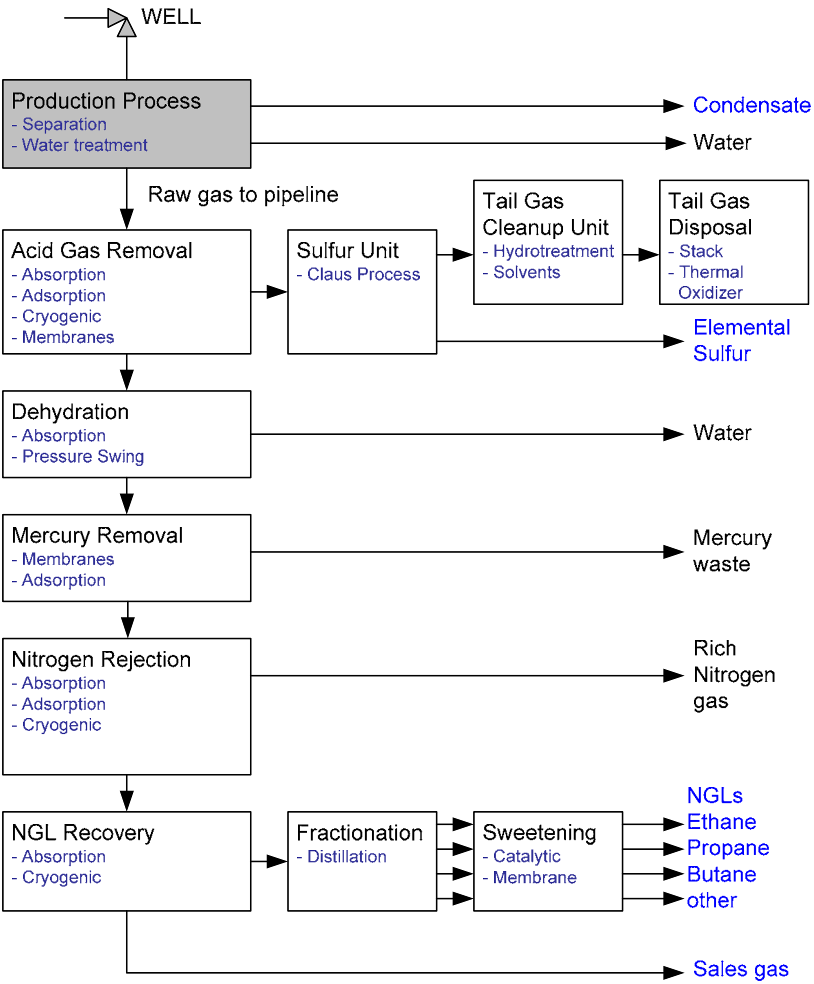


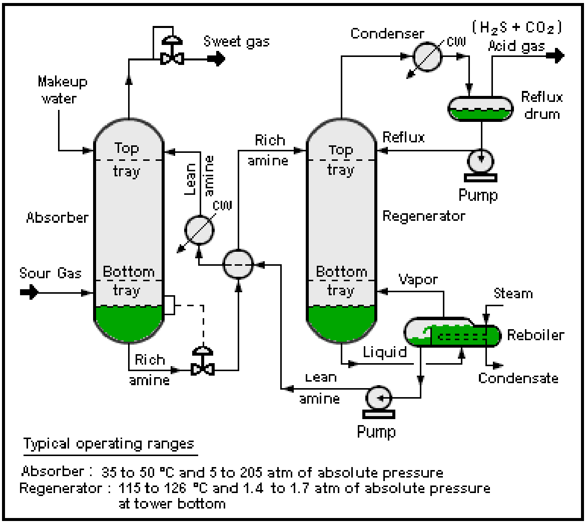
Figure 10. Typical gas plant

5.3.1 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. Monoethanolamine (MEA) dominates for CO_2 removal. Solutions with inorganic solvents based on ammonia are under development. *Ill: Wikipedia*



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 H_2S and CO_2.

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 H_2S with air or oxygen to produce SO_2 and elemental sulfur, which is released when cooled. A catalytic section allows more H_2S to react with SO_2 with alumina or titanium dioxide (TiO_2) to produce water and elemental sulfur (the Claus reaction: $2H_2S + SO_2 \rightarrow 3S + 2H_2O$). 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 SO_2 by combustion with hydrogen over catalysts to produce H_2S and water. H_2S is recycled to the Claus unit. Other solutions are the Beavon sulfur removal process (BSR), based on amine solvent and catalysts.

5.3.2 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.

5.3.3 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.

5.3.4 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 byproduct.

5.3.5 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 though 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 the type of catalyst.

5.3.6 Sales gas specifications

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

Volume is measured in standard cubic meters (scm) defined as 1 m^3 at 0 ºC 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 ºC. EU specifications are typically 38.8 MJ (10.8 kWh) ±5% per scm. In the US 1030 BTU ±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 makes aluminum and other metals brittle.

Dew point is a temperature below which some of the hydrocarbons in the gas can condense at pipeline pressure, forming liquid slugs that can 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.

5.4 Pipelines

Pipeline installations consist of driving compressors and pumps, valve stations, pig receive/launch facilities, where the pig is used for cleaning or inspecting the pipeline. A pipeline SCADA system and pipeline management system is required to control and operate the pipeline.

5.4.1 Pipeline terminal

Pipelines transport gas or liquid, and are fed from the high pressure compressors or pumps.

The pipeline terminal includes termination systems for the pipeline. A pig launcher and receiver is a minimum requirement, allowing insertion of a pipeline pigging device used to clean or inspect the pipeline on the inside. Essentially, it is 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, either directly or through a pump or turbine arrangement that also drives wheels that roll against the walls and mechanisms to rotate brushes and other scraping mechanisms. Intelligent pigs also contain instrumentation for remote control and cameras, etc.

5.4.2 Gas Pipelines, compressor and valve stations

One or more compressor stations are needed to keep the required gas flow in the pipeline. Internal friction will cause a pressure drop along the pipeline that increases with flow. Thus, the starting pressure must be high enough to maintain design capacity flow up to the final terminal. If this is not practically possible, additional compressor stations are needed along the total length. Typical starting pressure is about 150-250 bar (15-25 MPa). The final pressure can be as low as 50 bar (5 MPa) at the pipeline terminal end.

The compressors are driven in the same way as explained in the compressor chapter under production (see Chapter 4.3.3).

As an example, about 150 MW in compressor power is required to transport 70 mill scm/day though the 1166 km Langeled pipeline with a starting pressure of 250 Ormen Lange Nyhamna. The initial section is 42 in, which increases to 44 in at Sleipner, a little more than halfway (627 km from Nyhamna, 540 km from Easington, UK), where the intermediate pressure is 155 bar maximum.

The 1200 km Northstream pipeline from Russia (Portovaya, Vyborg) to Germany (by Hannover), has two parallel pipes of almost the same dimensions, pressure and compression power each as Langeled.

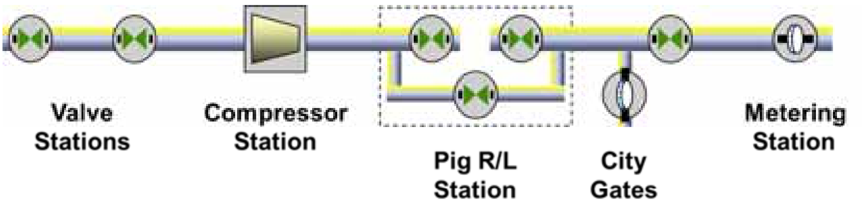


Figure 11. Gas pipeline

Block valve stations (or vine valve stations) are required to allow closure of off flow at regular intervals to limit accidental release of gas in case of pipeline rupture. This will be determined by the maximum permissible released gas volume. A valve station is normally operated by remote telemetry and in addition to the closing valve, at least contains pressure, temperature and some level of flow measurement. These will feed back into the pipeline modeling system. Even if methane (CH_4) is lighter than air and will rapidly rise, other gases such as propane (C_3H_8) are present in up to 8% by volume, and are heavier than air. They will sink, and rapidly create a large volume of combustible gas mixture.

In cases where multiple producers and pipelines feed into a larger pipeline grid, the pressure balancing to maintain required flow and observe contractual volume allocations back to individual production sites presents additional challenges for the pipeline balancing system.

5.4.3 Liquid pipelines, pump and valve stations

Liquid crude or product pipelines are handled much the same way, with pump stations and block valve stations along the pipeline. However, when the pipeline goes up or down over hills and mountains, they behave differently. Liquid, due to the much higher specific gravity, will experience much higher pressure drops uphill, and increases downhill, than gas. This often requires additional pumping capacity uphill and corresponding pressure-reducing turbines (or braking stations) downhill. In case electrical power is used, the braking power from the turbine can be fed back into the grid.

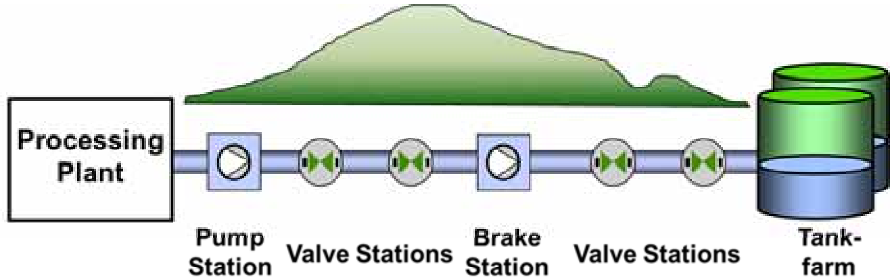


Figure 12. Liquid pipeline

Block valve stations (or line valve stations) are used with many of the same functions as gas pipelines. It is important to limit accidental spills in case of rupture of the pipeline, and placement will be determined both by maximum leak volume as well as city, river or valley crossings and wherever it is particularly important to prevent spills.

5.4.4 Pipeline management, control and safety

Pipeline management is used to maintain operation and integrity of the pipeline system. It is usually handled by a SCADA system, which interfaces with remote locations and collects data and controls valves and process setpoints. The pipeline management system may include functions such as:

Supervisory control to oversee the operation of the entire pipeline system.

Demand Forecasting to model demand for the coming days across the system based on parameters like contractual volumes, forecasts from consumers and producers and meteorology to determine necessary supply rates and corresponding pressures at various points in the network. Since the transport delay can be considerable during the off-peak season, delays can be compensated by pre-charging the line in anticipation of increases, or allowing pressure to be bled off if a reduction is expected.

Pipeline modeling models the entire pipeline system to account for pressure, temperature and flow at major checkpoints. Based on this model the management system can perform:

- Pressure balancing to make certain that pressure setpoints are correct to meet demand forecasts and avoid potential overload conditions.

- Production allocation, which ensures that producers are able to deliver their contractual volumes into the network.
- Leak detection, which compares actual measured data against dynamic data predicted by the model. A discrepancy indicates a leak (or a failing measurement). Simple liquid systems only calculate basic mass balance (in-out), while an advanced modeling system can give more precise data on size and position of the leak within a certain response time.
- Pig or scraper tracking is used to track the position of the pig within the pipeline, both from pig detection instruments and the pressure drop caused by the pig in the pipeline.

In case of liquid pipelines transporting batches of different products, a batch transfer system is needed. Based on information on when each product is injected into the pipeline, and gravity measurement at the receiving end, it is possible to sequentially transfer different products, such as gasoline and diesel in the same pipeline. Depending on product characteristics, there will be an interface section between the two products that widens as the product moves along the line. This “off spec” product must be discarded at the receiving end to avoid product degradation. It is often disposed by mixing with larger volumes of low grade fuel products. This system is often used with countrywide refined product distribution to terminals.

Safety systems are used, as for other process plants, to ensure that the systems shut down in case of malfunctions and out-of-bounds conditions. Of particular importance is the high integrity pressure protection system (**HIPPS)**. This is a highly reliable system that is needed to maintain protection against overpressures, and manage shutdowns. The strategy used by normal safety system to isolate and depressure, or simply fail to safe condition, often cannot be applied to pipelines due to the large volumes of product in the pipelines. Simply opening or closing a valve would potentially cause overpressure conditions or overload safety devices such as flares HIPPS monitors and executes these responses in a specific sequence.

5.5 LNG

LNG is a gas transport product. The gas, which is primarily methane (CH_4), is converted to liquid form for ease of storage or transport, as its volume is about 1/600th the volume of natural gas in the gaseous state. It is produced close to the production facilities in an 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.

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 0.9% per 1,000 km of transport distance for large pipeline systems.

Melkøya LNG Plant with LNG Carrier Arctic Princess Photo: Statoil

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.

5.5.1 LNG liquefaction

LNG processes are generally patented by large engineering, oil and gas companies, but are generally based on a one- two- or three-stage cooling process with pure or mixed refrigerants. The three main process types of LNG process with some examples of process licensors are:

- Cascade cycle:
  - Separate refrigerant cycles with propane, ethylene and methane (ConocoPhillips)
- Mixed refrigerant cycle:
  - Single mixed refrigerant (SMR) (PRICO)
  - Single mixed refrigerant (LIMUM®) (Linde)
  - Propane pre-cooled mixed refrigerant: C3MR (sometimes referred to as APCI: Air Products & Chemicals, Inc.)
  - Shell dual-mixed process (DMR) (Shell)

- o Dual mixed refrigerant (Liquefin Axens)
  - o Mixed fluid cascade process (MFCP) (Statoil/Linde)
- Expander cycle
  - o Kryopak EXP® process

Each process has different characteristics in scalability, investment cost and energy efficiency. For smaller installations, e.g., to handle stranded gas or isolated small gas fields, a single cycle process is preferable due to its low CAPEX (and possibly lower weight for floating LNG), even if energy efficiency is significantly lower than the best cascade or DMR processes, which cost more but also allow the largest trains typically, 7.8 million tons per annum and lowest energy consumed per energy unit LNG produced.

Most processes use a mixed refrigerant (MR) design. The reason is that the gas has a heat load to temperature (Q/T) curve that, if closely matched by the refrigerant, will improve stability, throughput and efficiency (see the figure below). The curve tends to show three distinct regions, matching the pre-cooling, liquefaction and sub-coiling 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.

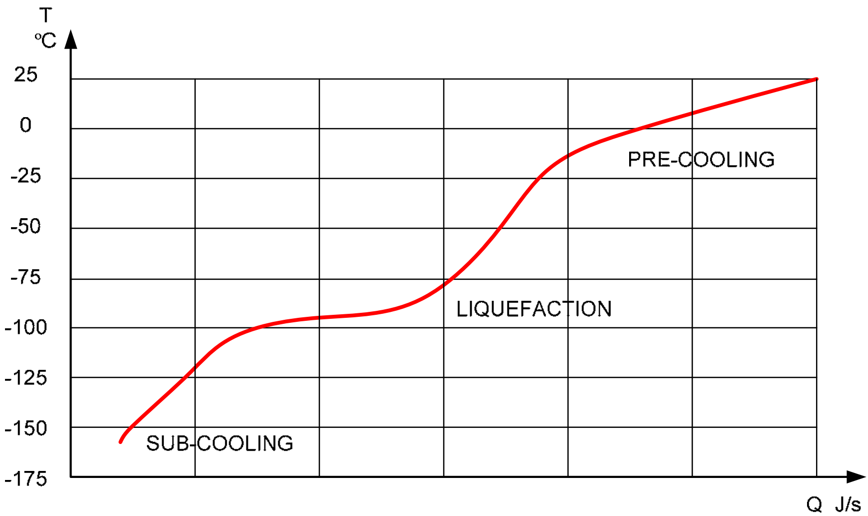


Figure 13. LNG Q/T diagram

Typical LNG train power use is about 28 MW per million tons of LNG per annum (mtpa), corresponding to typically 200 MW for a large trains of 7.2 mtpa, or 65 MW per stage for three cycles. In addition, other consumers in gas treatment and pre-compression add to total power consumption and bring it to some 35-40 MW per mtpa, and over 50 for small LNG facilities well under 1 mtpa capacity.

Some examples are given here. (Please note that these process flow diagrams are simplified to illustrate the principle and do not give a complete design.) All designs are shown with heat exchangers to the sea for comparison. This is generally needed for high capacity, but for smaller plants air fin heat exchangers are normally used.

A triple cycle mixed refrigerant cascade claims to have the highest energy efficiency. It is represented here by the Linde design, co-developed with Statoil.

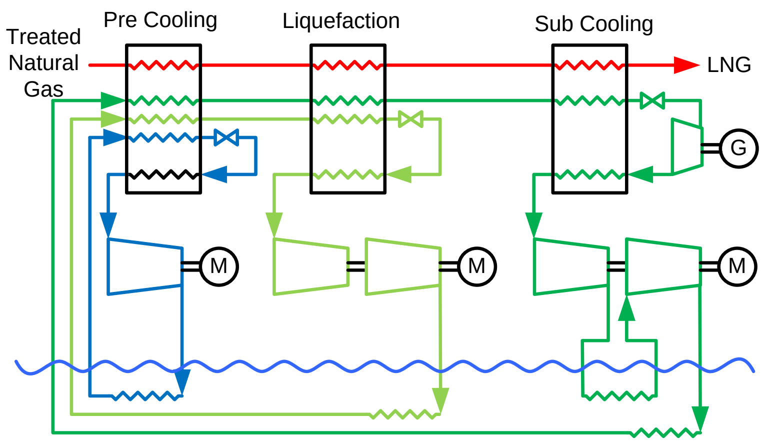


Figure 14. A triple cycle mixed refrigerant cascade

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 or three cycles may combine into one complex common heat exchanger. This particular deign uses the patented Linde coil wound heat exchanger, also called the "rocket design," due to its exterior resemblance to a classic launch vehicle.

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 (indicated by the blue wavy line). It then goes though one or more heat exchangers/cold boxes before it expands, either though 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 ºC 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 ºC to about -100-125 ºC, 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 ºC. The refrigerant is usually methane and/or nitrogen.

The ConocoPhillips optimized cascade process was developed around 1970. It has three cycles with a single refrigerant gas (propane, ethylene and methane) in each.

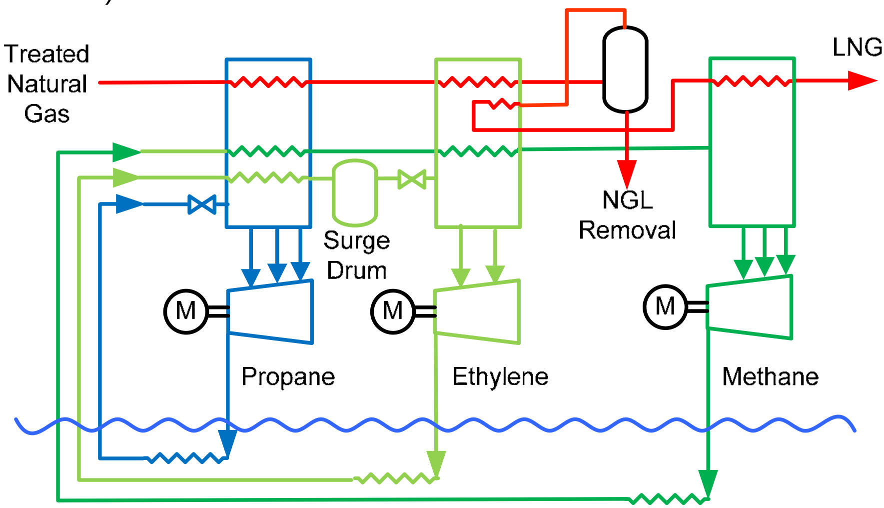


Figure 15. Optimized cascade process

The dual cycle mixed refrigerant (DMR), developed by Shell and others, may look simpler but the overall design will be similar in complexity as multistage compressors are typically needed. It is shown on the left with the C3MR on the right for comparison.

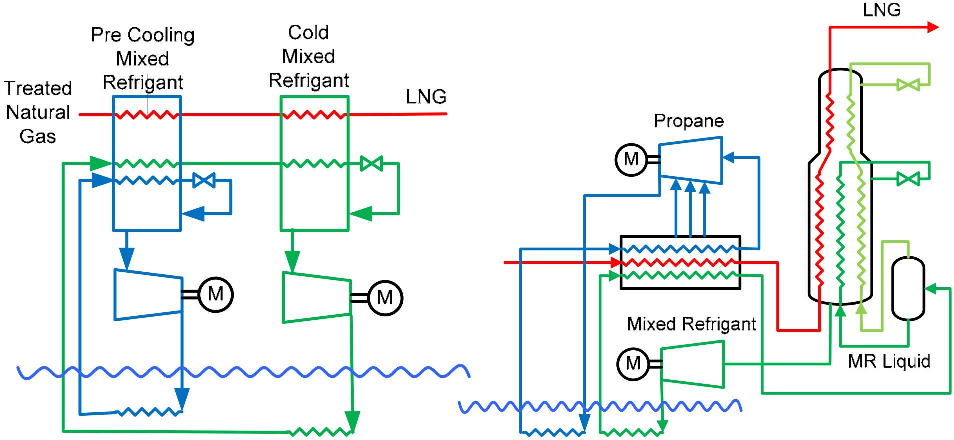


Figure 16. Shell DMR and APLI C3MR designs

For small and micro LNG, single cycle designs are often preferred. There are literally hundreds of patented solutions, but only a handful of mainline licensors, that have solved the challenge of achieving single cycle refrigeration. However, this means multiple internal stages in the process flow and the heat exchanger itself. The PRICO SMR is shown on the left and the Linde LIMUM® (on the right).

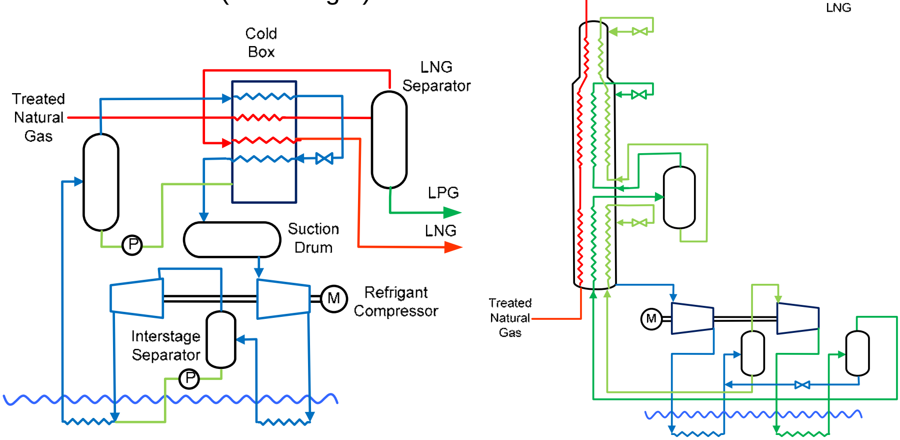


Figure 17. PRICO SMR and Linde LIMUM®

5.5.2 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 ºC. 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.

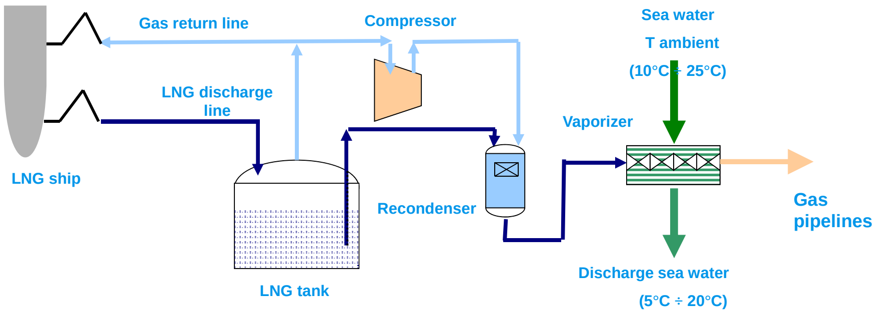


Figure 18. LNG terminal process overview

At the receiving terminal, 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 Refining

Up to the early 1970s, crude oil prices were kept reasonably stable by major international oil companies and industrialized nations. Less value was created in the upstream production operations and relatively more profits were generated in refining and distribution operations. With the 1973 oil crisis and rising crude oil prices, more of the value was created upstream.

Now, the success of a modern refinery depends more on economies of scale and the ability to process a wide range of crudes into the maximum quantity of high value fuels and feedstock. A refinery that is able to handle multiple types from heavy to light crude is said to have to have a large *swing*. Trade specifications such as ”West Texas Intermediate” (WTI) API 38.3°, “Brent Blend” API 38.3°, “Heavy Arab Crude” API 27.7° or “Grane” API 18.7° are examples of such crudes.

Medium light crudes can be used directly in early engines and burners. Modern consumers, such as gas and diesel engines, aviation turbojet engines and ship bunkers need fuels manufactured to precise specifications. This includes removing contaminants and pollutants, such as sulfur.

6.1 Fractional distillation

The basic refinery uses fractional distillation. Incoming crude is heated to its boiling point. It then enters the distillation column, which separates the different fractions. The column is of the reflux type, where colder condensed fluids running down are reheated by rising vapors that in turn condense. This produces clear thermal zones where the different products can be drained.

NOTE: The schematic on the following page is simplified. Both continuous and vacuum distillation is used in separate columns to avoid heating the raw crude to more than 370 °C. Overheating would cause thermal cracking and excessive coke that may also plug pipes and vessels. Also a *sidecut stripper* is used, in addition to the main column, to further improve separation. Sidecut is another name for the fractions emerging from the side (rather than top and bottom) of the main column, i.e., naphtha, gasoline, kerosene and diesel.

The fractions are a mix of alkanes and aromatics and other hydrocarbons, so there is not a linear and uniformly rising relationship between carbon number and boiling point and density, although there is a rough fit. Even so, this means that each fraction contains a distribution of carbon numbers and hydrocarbons.

6.2 Basic products

The basic products from fractional distillation are:

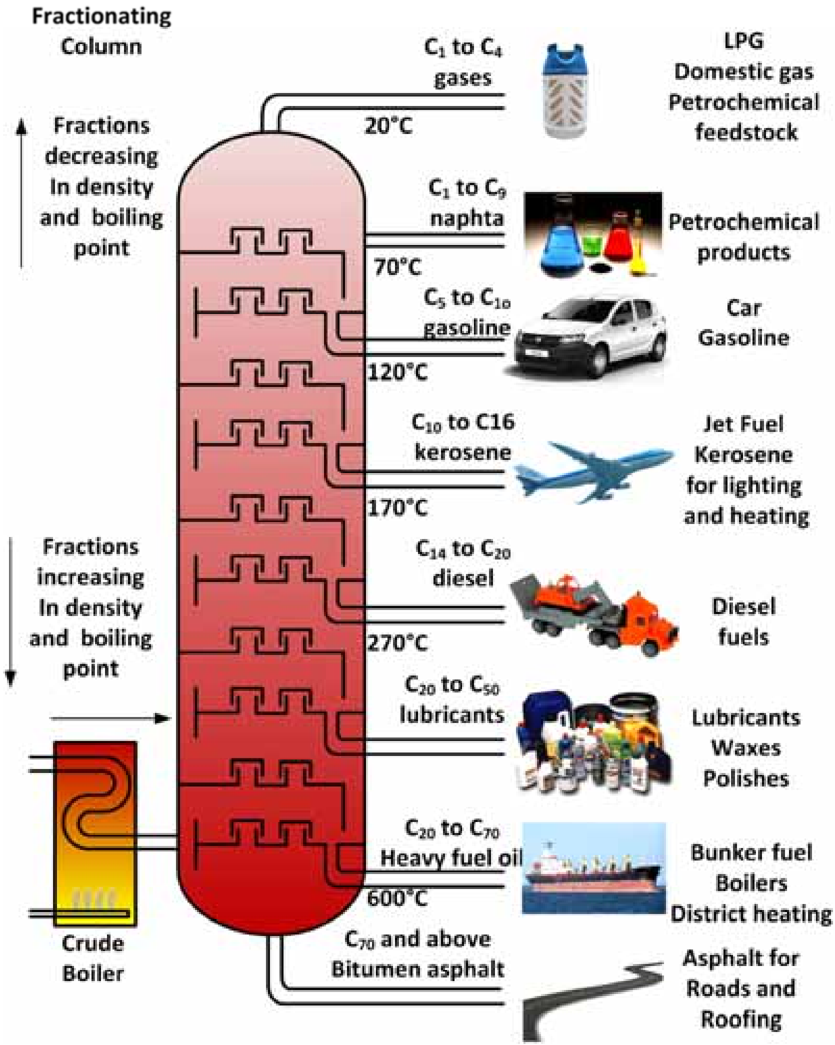


Figure 19. Fractionating continuous distillation, overview

Liquid petroleum gas (LPG) has carbon numbers of 1-5 and a boiling point up to 20 °C. Most of the LPGs are propane and butane, with carbon number

3 and 4 and boiling points -42 °C and -1 °C, respectively. Typical usage is domestic and camping gas, LPG vehicles and petrochemical feedstock.

Naphtha, or *full range naphtha,* is the fraction with boiling points between 30 °C and 200 °C and molecules generally having carbon numbers 5 to 12. The fraction is typically 15–30% of crude oil by weight. It is used mainly as a feedstock for other processes:

- In the refinery for producing additives for high octane gasoline
- A diluent for transporting very heavy crude
- Feedstock to the petrochemical olefins chain
- Feedstock for many other chemicals
- As a solvent in cleaning

Gasoline has carbon numbers mainly between 4 and 12 and boiling points up to 120 °C. Its main use is as fuel for internal combustion engines. Early on, this fraction could be sold directly as gasoline for cars, but today's engines require more precisely formulated fuel, so less than 20% of gasoline at the pump is the raw gasoline fraction. Additional sources are needed to meet the demand, and additives are required to control such parameters as octane rating and volatility. Also, other sources such as bioethanol may be added, up to about 5%.

Kerosene has main carbon numbers 10 to 16 (range 6 to 16) boiling between 150 °C and 275 °C. Its main use is as aviation fuel, where the best known blend is Jet A-1. Kerosene is also used for lighting (paraffin lamps) and heating.

Diesel oil, or *petrodiesel,* is used for diesel engines in cars, trucks, ships, trains and utility machinery. It has a carbon number range of 8 to 21 (mainly 16-20) and is the fraction that boils between 200 °C and 350 °C.

White and black oils: The above products are often called *white oils*, and the fractions are generally available from the atmospheric distillation column. The remaining fraction below are the *black oils,* which must be further separated by vacuum distillation due to the temperature restriction of heating raw crude to no more than 370-380 °C. This allows the lighter fractions to boil off at a lower temperatures than with atmospheric distillation, avoiding overheating.

Lubricating oils, or *mineral base lubricating* oil (as opposed to synthetic lubricants), form the basis for lubricating waxes and polishes. These typically contain 90% raw material with carbon numbers from 20 to 50 and a fraction boiling at 300-600 °C. 10% additives are used to control lubricant properties, such as viscosity.

Fuel oils is a common term encompassing a wide range of fuels that also includes forms of kerosene and diesel, as well as the *heavy fuel oil* and *bunker* that is produced at the low end of the column before bitumen and coke residues. Fuel oil is graded on a scale of 1 to 6 where grade 1 and 2 is similar to kerosene and diesel, 3 is rarely used anymore. 4-6 are the heavy fuels, also called Bunker A, B and C, where B and C are very high viscosity at normal ambient temperatures and requires preheating to about 100 °C and 120 °C respectively, before it flows enough to be used in an engine or burner. Fuel oil grade 4 does not require preheating and is sometimes mixed with off spec products, such as tank residue and interface liquid from multiphase pipelines or with grade 2 fuel oil to achieve low-enough viscosity at ambient temperatures. Fuel oil 6 is the lowest grade, its specification also allows 2% water and 0.5% mineral soil and is consumed almost exclusively by large ships in international waters, where pollutants such as sulfur is less regulated.

Bitumen and other residues like coke and tar has carbon numbers above 70 and boiling points above 525 °C. Low sulfur coke can be used for anodes in the metals industry (aluminum and steel) after processing (calcining). The remainder is a problem fuel, because of high sulfur content and even higher CO_2 emissions than coal (typically 15% higher). Bitumen in the form of asphalt boiling above 525 °C is used for roofing and road paving. *Asphalt concrete* pavement material is commonly composed of 5% asphalt/bitumen and 95% stone, sand, and gravel (aggregates).

6.3 Upgrading and advanced processes

The Refinery make up differs from an upstream plant, in that the overall site is divided up in to process types or 'units'. The refining plant type processes are generally licensed, and a license is required to build and operate one of these. Each license will be the same but scaled to meet the processing capacity in tons per day. A full explanation of these processes is beyond the scope of this book, but a non-exhaustive description is given below.

The following figure gives a more detailed process flow diagram of an actual modern refinery. It shows the extent of treatment that takes place after initial fractional distillation, to improve fuel yield and functional properties, and an explanation of why modern gasoline at the pump contains less than 20% raw gasoline straight from the column. Additional processes may also be included, e.g., for crude pre-treatment to be able to source lower quality crudes with less processing at the production site.

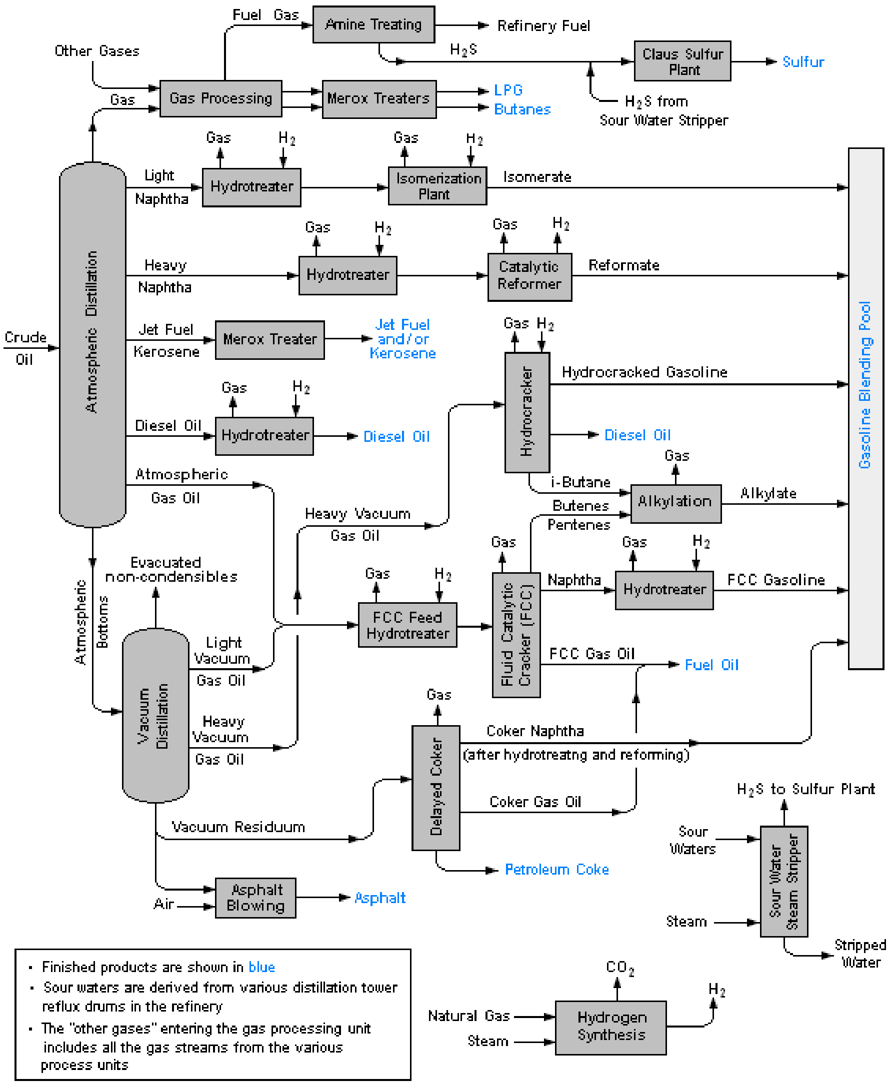


Figure 20. Refinery process flow diagram (*Source: Wikipedia*)

Most of these reactions take place at elevated temperature and pressure over a catalyst such as platinum or rhenium or sometimes iron, and need precise control for optimal throughput. A few process flow diagrams have been included to give an indication of the complexity of these processes compared to the relative simplicity of many upstream processes.

Atmospheric distillation is the fractional distillation unit already described. In actual designs, it is combined with vacuum distillation. Raw crude cannot be heated to more than 370-380 °C. It is often called the Crude Oil Distillation Unit (CDU)

Vacuum distillation unit (VDU) further distills the black oils into fuel oils and residual bitumen and coke to avoid overheating the crude and to extract additional valuable product that could be upgraded.

Naphtha hydrotreater: Various sulfur compounds are present in the hydrocarbon mixture and, if burnt with the other carbons, will cause sulfuric emissions. The hydrotreater uses hydrogen to remove some of these compounds. As an example, the hydrodesulfurization (HDS) reaction for ethanethiol can be expressed as:

ethanethiol + hydrogen → ethane + hydrogen sulfide

$C_2H_5SH + H_2 \rightarrow C_2H_6 + H_2S$

A *catalytic reformer unit* is used to convert the naphtha molecules (C5-C12) into higher octane *reformate* (reformer product). These are mixed with raw gasoline to achieve a higher octane product. The process creates more aromatics (ring formed hydrocarbons) by dehydrocyclization or more complex hydrocarbons with double bonds or side groups by *dehydrogenation*. These processes release hydrogen which is recovered and can be reused in hydrotreaters or hydrocrackers.

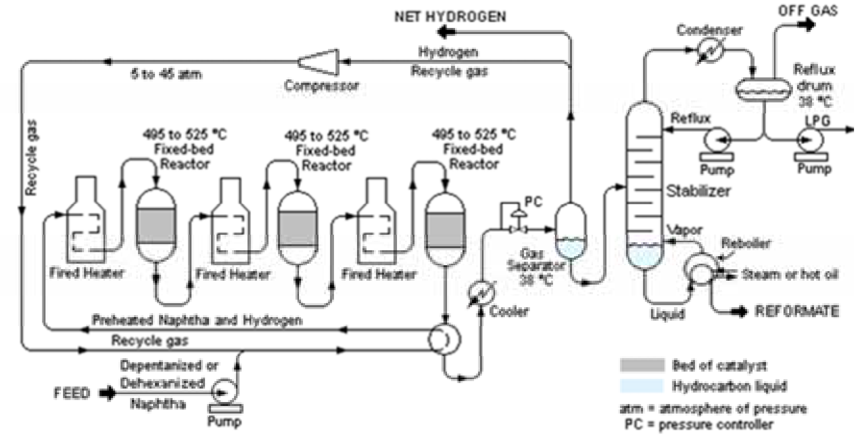


Figure 21. Catalytic reformer (*Source: Wikipedia***)**

Distillate hydrotreater units desulfurize distillates (such as diesel) after fractional distillation, in the same way as the naphtha hydrotreater.

Fluid catalytic crackers (FCC) units upgrade heavier fractions into lighter, more valuable products. Long chain molecules (high carbon numbers) are split into shorter molecules to achieve more of the high value fuel components. A typical design uses a reactor and a regenerator. A fine powdered porous catalyst with zeolite (silicate and alumina) is fluidized in the hydrocarbon vapor, where a reaction takes place at 535 °C and 0.172 MPa. The catalytic reaction takes place within a few seconds, after which the reformate and catalyst is separated in a cyclone. The spent catalyst then goes back to a regenerator that heats it to 715 °C at 0.241 MPa and releases flue gas. The catalyst powder can then be reused. The reformates go to a distillation column for separation into fractions.

A *hydrocracker unit* performs essentially the same function as the FCC when more *saturated hydrocarbons* are desirable in the product. This means alkane carbon chains with single bonds, not double bonds or cyclic rings like aromatics, or more complex molecules. For this, additional hydrogen is needed. The reaction takes place with hydrogen under pressure over a catalyst. The relative market need for diesel, kerosene and gasoline will influence the choice of FCC versus hydrocracker. In the US, with a higher relative volume of gasoline, more FCC capacity is needed, while in Europe and Asia, with higher diesel consumption, more hydrocracking is used.

Visbreaking units upgrade heavy residual oils by thermally cracking them into lower viscosity product that can be blended into lighter, more valuable products. Visbreaking is characterized by its thermal *severity,* ranging from mild cracking at 425 °C to severe cracking at 500 °C. Depending on the residual oil, as much as 15-25% lighter fractions like diesel, kerosene and gasoline could be obtained. The residue is tar and coke.

The *Merox* unit treats LPG, kerosene or jet fuel by oxidizing thiols (mercaptans) to organic disulfides. The purpose is to reduce strong odors caused by thiol presence.

Coking units (delayed coking, fluid coker, and flexicoker), like the visbreaker, uses thermal cracking of very heavy residual oils into gasoline and diesel fuel. The residue is *green coke*, and is further processed to fuel coke or, if too low in sulfur and contaminants, to anode coke for the metallurgic industries.

An *alkylation unit* produces high-octane components for gasoline blending. The main use is to convert isobutane ($C_4H_{10,}$ but arranged differently than n-butane) to *alkylates*, mainly isooctane or isoheptane by adding an alkyl group such as propene or butene over a strong acid catalyst, such as sulfuric or hydrofluoric acid.

Dimerization is similar to alkylation, but uses a dimer group instead of an alkyl group. For example, butenes can be dimerized into isooctene, which may be hydrogenated to form isooctane.

Isomerization units convert linear molecules to higher-octane branched molecules by rearranging the same atoms arranged in a different way. For example, C_4H_{10} n-butane has the carbon atoms in a chain, while isobutane has a central carbon with one hydrogen and three CH_3 groups attached. The isobutane can then be fed to the alkylation unit.

Steam reforming produces hydrogen for the hydrotreaters or hydrocracker. Typical is the steam methane reformer (SMR), where steam reacts with Methane at 425 °C with a nickel catalyst to produce syngas, which is a source for many different reactions:

$$CH_4 + H_2O \leftrightarrow CO + 3\ H_2$$

If more hydrogen is needed, followed by a gas shift reaction with CO:

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

Amine gas treater, *Claus unit*, and tail gas treatment converts hydrogen sulfide from hydrodesulfurization into elemental sulfur, which is a valuable traded product.

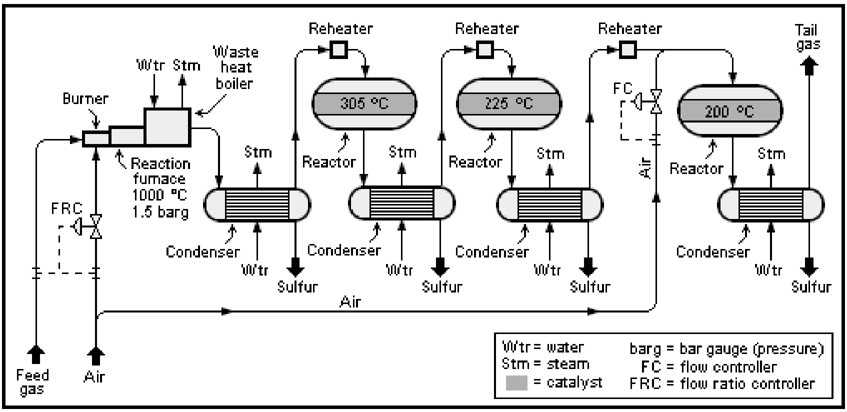


Figure 22. Claus process (*Source: Wikipedia***)**

The Claus process is the most common with the overall reaction:

$$2\ H_2S + O_2 \rightarrow S_2 + 2\ H_2O$$

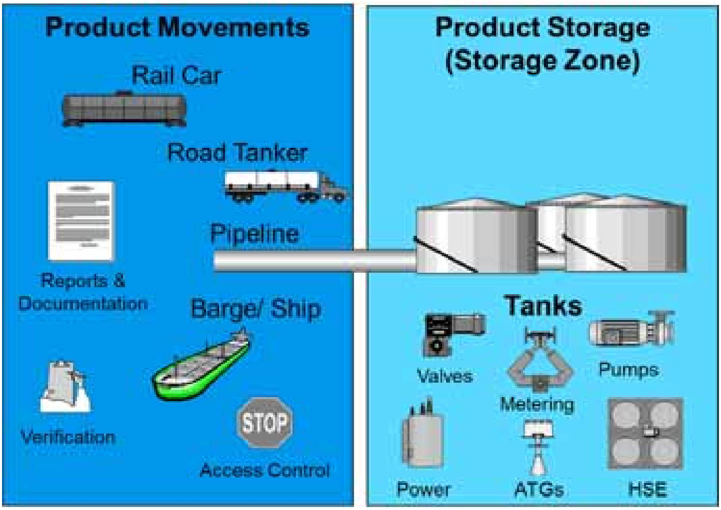
The reactor runs at 1,000° C and 0.15 MPa, with three steps: one thermal and two catalytic to improve yield.

Using these processes, a modern refinery can raise the basic gasoline yield depending on crude quality from 10-40% to around to 70%.

6.4 Blending and distribution

After the refining processes, the various fractions are stored in intermediate tanks, then blended into marketable products for loading onto railcars, trucks or ships, and distribution to gas stations or industries.

Each product is blended to a specification of up to 25 parameters such as octane rating, energy content, volatility and sulfur content. The task is to achieve the specification (and not exceed, where applicable) with the minimum amount of over-spec “giveaway.” The blending quality is managed with infrared or chromatograph type process analyzers. These can determine the precise fractions of a sample by molecule type.



The standard specification gasoline is therefore standard from company to company in the individual markets, ensuring compatibility with vehicle manufacturer requirements. Also, the terminal operator may be an independent third party or run as co-distribution, so that a terminal in one region distributes for several companies based on the same products in the same tanks.

Each company then seeks to differentiate its product by adding small quantities of unique *additives* that are marketed to increase engine performance, lifetime, clean combustion and so forth. These additives are added as the product is dispensed to trucks for delivery to that brand gasoline station.

A main task is to ensure the balance of incoming and outgoing products and consolidate with stored volumes. These have to be compensated for temperature, water content (water may be absorbed from air humidity and released at low temperatures as bottom slop in tanks) and vapor loss. Vapor or volatile organic compounds (VOCs), form above the product in fixed roof tanks and when filling up compartments in cars or vessels. VOC loss can be significant for high volatility products like gasoline, and must be recovered and/or handled to reduce emissions and explosive hazard.

The terminal management system tracks batches of product received or dispensed, as well as those eventually received by gasoline stations, airports or other consumers and consolidates with stored volumes. Each operation should be validated against orders, bills of lading and positive identification of trucks, vessels and their operators. In countries where this process is not well managed, losses of product due to theft and other factors can be as high as 15% or more in the distribution operations.

Eventually the main goal is to ensure that orders are met, and stakeholders pay or get paid in the form of VAT, taxes, product, delivery charges, etc.

7 Petrochemical

Petrochemicals are chemicals made from petroleum or natural gas. Primary petrochemicals are divided into three groups, depending on their chemical structure:

Olefins include ethylene, propylene, and butadiene. Ethylene and propylene are important sources of industrial chemicals and plastics products. Butadiene is used in making synthetic rubber. Olefins are produced by cracking.

Aromatic petrochemicals include benzene, toluene, and xylenes. Benzene is used in the manufacture of dyes and synthetic detergents. Toluene is used in making explosives. Manufacturers use xylenes in making plastics and synthetic fibers. Aromatics are produced by reforming.

Synthesis gas (SynGas) is a mixture of carbon monoxide and hydrogen, and is used to make the petrochemicals ammonia and methanol. Ammonia is used in making fertilizers and explosives, where methanol serves as a source for other chemicals.

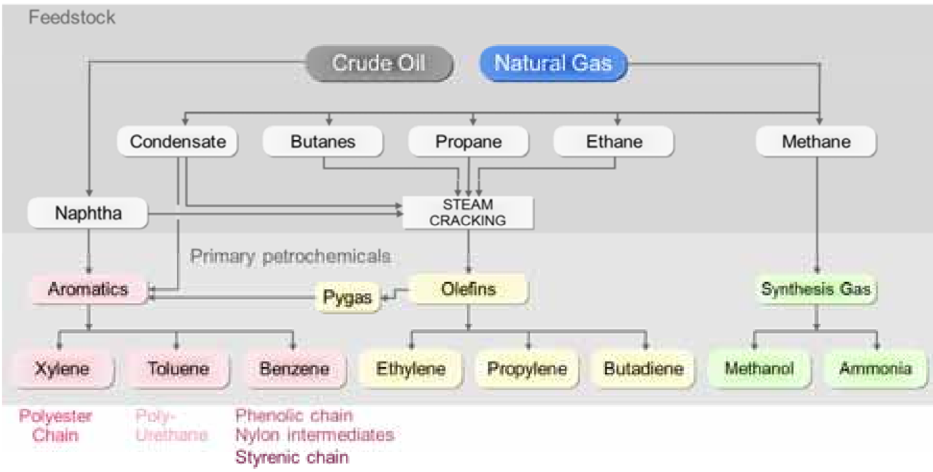


Figure 23. Petrochemical tree: feedstock and primary petrochemicals

The primary petrochemicals are not end products, but form building blocks for a wide range of materials. Therefore, each primary petrochemical gives name to a chain of reactions leading to those materials. There are almost 200 petrochemicals that can be described this way. There are more processes than end products, as each product may require multiple steps, so an exhaustive list would not fit within this book. Instead, we will focus on the main chains, properties and uses of the most important compounds and a few key processes for this overview.

Many of these processes are based on *polymerization,* which means that it is based on processes that first form monomers then let these bind together to form *polymers* as long chains or a three dimensional network. Compounds whose names start with “poly” are generally polymers, but many other trade names, such as nylon which is a generic name for a family of polyamides, are polymers.

Petrochemicals are often made in clusters of plants in the same area. These plants are often operated by separate companies, and this concept is known as *integrated manufacturing*. Groups of related materials are often used in adjacent manufacturing plants, to use common infrastructure and minimize transport.

WST - Exxon Singapore Petrochemical Complex

7.1 Aromatics

Aromatics, so called because of their distinctive perfumed smell, are a group of hydrocarbons that include benzene, toluene and the xylenes. These are basic chemicals used as starting materials for a wide range of consumer products. Almost all aromatics come from crude oil, although small quantities are made from coal.

7.1.1 Xylene and polyester chain

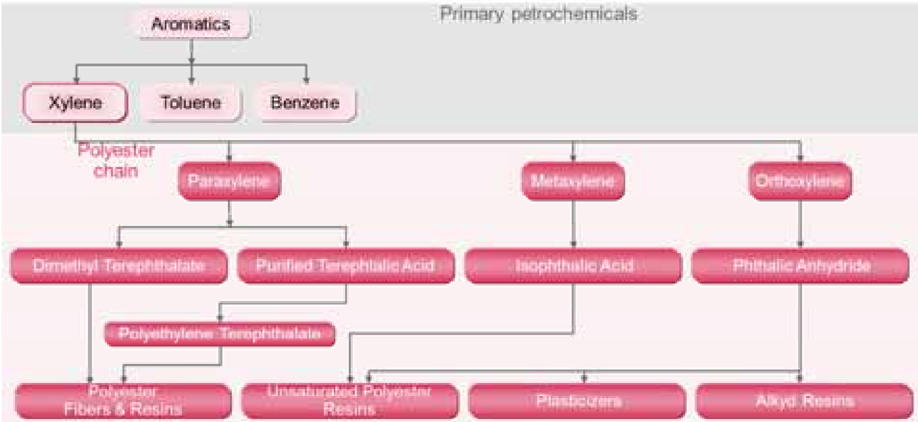


Figure 24. Aromatics – xylene and polyester chain, derivatives

One of the forms of xylene, paraxylene, is used to make polyesters which have applications in clothing, packaging and plastic bottles.

The most widely-used polyester is polyethylene terephthalate (PET), used in lightweight, recyclable soft drink bottles (30% of production), as fibers in clothing (60% of production), as a filling for anoraks and duvets, in car tire cords and conveyor belts. It can also be made into a film that is used in video and audiotapes and X-ray films. Polyester makes up about 18% of world polymer production and is the third most-produced polymer; polyethylene (PE) and polypropylene (PP) are first and second, respectively.

Metaxylene is an isomer of mixed xylene. It is used as an intermediate in the manufacture of polyesters for coatings, inks, reinforced plastics and packaging applications.

Unsaturated polyester is used over a broad spread of industries, mainly the construction, boat building, automotive and electrical industries. In most applications, they are reinforced with small glass fibers. Hence, these plastics are commonly referred to as glass reinforced plastics (GRP). Initially a liquid, the resin becomes solid by cross-linking chains. A curative or hardener creates free radicals at unsaturated bonds, which propagate in a chain reaction to adjacent molecules, linking them in the process. Styrene is often used to lower viscosity and evaporates during hardening, where the cross linking releases heat.

Orthoxylene is an isomer of mixed xylene. It is primarily used in plasticizers (primarily in flexible polyvinyl chloride (PVC) material to make it more flexible), medicines and dyes.

Alkyd resins are a group of sticky synthetic resins used in protective coatings and paints.

7.1.2 Toluene, benzene, polyurethane and phenolic chain

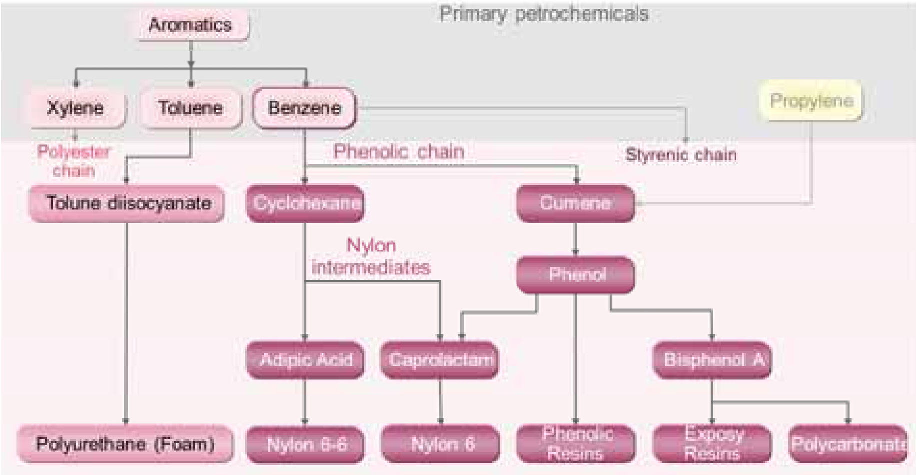


Figure 25, Aromatics – toluene and benzene, polyurethane and phenolic chain

Tolune diisocyanate (TDI) is an isocyanate used in the production of polyurethanes for flexible foam applications, ranging from furniture, bedding, and carpet underlay to transportation and packaging. TDI is also used in the manufacture of coatings, sealants, adhesives and elastomers.

Nylon is a generic designation for a family of synthetic polymers known generically as aliphatic polyamides derived from benzene, first produced in 1935 by DuPont. Nylon can be used to form fibers, filaments, bristles, or sheets to be manufactured into yarn, fabric, and cordage; and it can be formed into molded products. Nylon is tough, elastic and strong, and it has high resistance to wear, heat, and chemicals. It is generally used in the form of fine filaments in such articles as hosiery and sports equipment, e.g., parachutes; but its applications also include engineering plastics for cars, toys, healthcare products, carpets, roller-blade wheels and ship sails.

There are many varieties of nylon that have their own characteristic properties. Nylon plastics are used for making such products as combs, brushes and gears. Nylon yarns, on the other hand, are used for making nylon fabrics. When talking about nylon textile, there are two types that are mostly prevalent in the market: nylon 6-6 (also written as nylon 6,6) and nylon 6.

Phenol is an aromatic alcohol, mainly used as an intermediate in organic synthesis. Essentially, it serves as a raw material for the production of bisphenol A, phenolic resins, alkylphenols and caprolactam. It is a poisonous, acidic compound obtained from coal tar or benzene and used mainly as a disinfectant or antiseptic, carbolic acid; any hydroxyl derivative of benzene.

Phenolic resins are manufactured from phenol. They are used in wood products and molding powders applications, and also have a wide range of applications on the electrical, mechanical and decorative markets, in the automotive industry, in building and construction, in thermal insulation products and in foundry industry products.

Epoxy resin is a flexible resin made using phenols and used chiefly in coatings, adhesives, electrical laminants and composites for its excellent adhesion, strength and chemical resistance.

Polycarbonates are a particular group of thermoplastics. They are easily worked, molded, and thermoformed; as such, these plastics are very widely used in modern manufacturing. Polycarbonate is becoming more common in housewares, as well as laboratories and in industry. It is often used to create protective features, for example, in banks as well as vandal-proof windows and lighting lenses for many buildings.

7.1.3 Benzene and styrenic chain, derivatives

Polystyrene is solid plastic made from polymerized styrene. It is the second most common plastic and used in a wide variety of everyday applications, from coffee cups to CD jewel boxes. It is a thermoplastic polymer in a solid “glassy” state at room temperature, but flows if heated above about 100 °C.

It becomes solid again when cooled. This allows polystyrene to be extruded, molded and vacuum-formed in molds with fine detail and high finish.

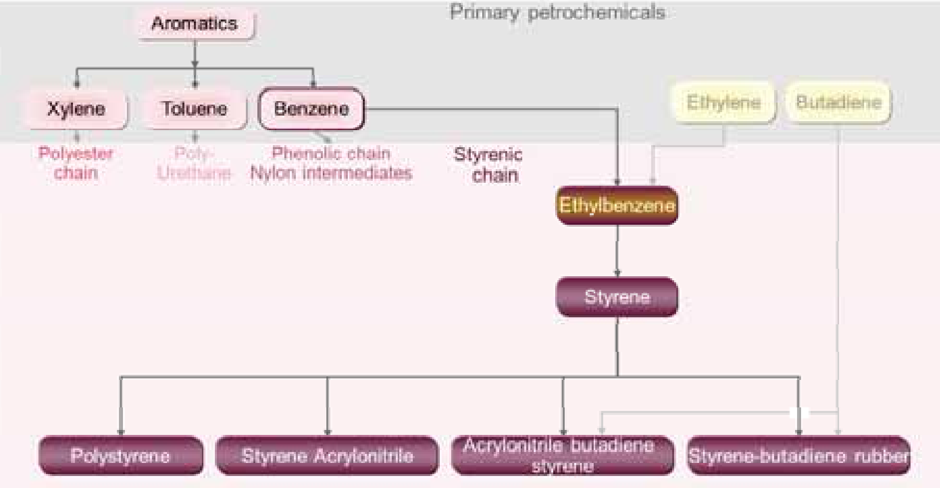


Figure 26. Aromatics – benzene and styrenic chain, derivatives

Styrene-acrylonitrile (SAN) is like polystyrene but offers higher thermal resistance and is therefore used mainly in the automotive, electrical and electronics industry, as well as in household applications and building products.

Acrylonitrile-butadiene-styrene (ABS) is a tough, heat-resistant and impact-resistant thermoplastic, with the acrylonitrile providing heat resistance and the styrene units offering rigidity. It is widely used for appliance and telephone housings, luggage, sporting helmets, pipe fittings and automotive parts.

Styrene-butadiene rubber (SBR) is a rubber manufactured from styrene. Because of its excellent abrasion resistance, it is widely used in automobile and truck tires, as well as for carpet backing and paper coating. About 50% of a car tire is made from SBR. Other applications are in belting, flooring, wire and cable insulation and footwear.

7.2 Olefins

Olefins are petrochemical derivatives produced by cracking feed stocks from raw materials such as natural gas and crude oil. Lower olefins have short chains with only two, three or four carbon atoms, and the simplest one is ethylene. The higher olefins have chains of up to twenty or more carbon atoms. The main olefin products are ethylene, propylene, butadiene and C4 derivatives. They are used to produce plastics, as chemical intermediates, and, in some cases, as industrial solvents.

7.2.1 Ethylene, derivatives

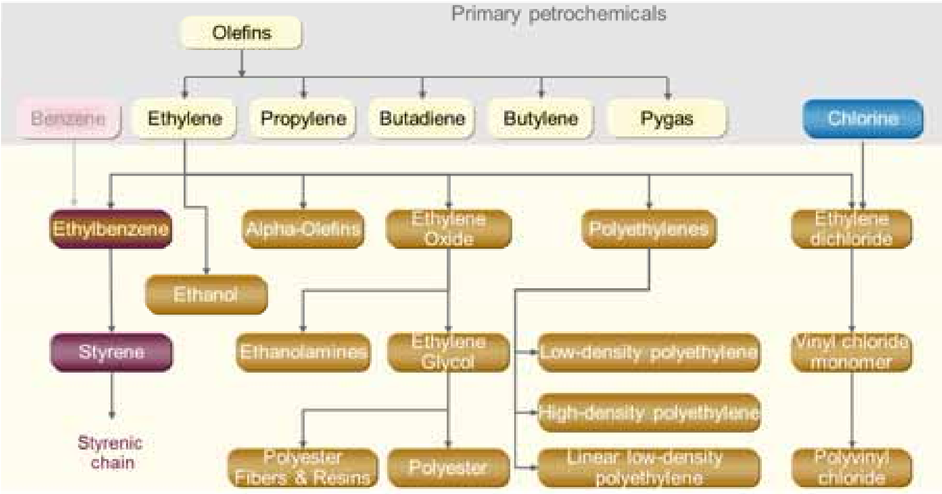


Figure 27. Olefins – ethylene, derivatives

Polyester and polyester resins is described under the Aromatics chain (Chapter 7.1.1).

Ethanol, also known as ethyl alcohol (common alcohol), is manufactured by synthesis from ethylene. It is an oxygenated hydrocarbon used in a wide variety of high performance solvent applications (toiletries and cosmetics, paints, lacquer thinners, printing inks, dyes, detergents, disinfectants and pharmaceuticals), as a chemical raw material for the production of a range of monomers and solvents, and is essential in pharmaceutical purification. In transportation, ethanol is used as a vehicle fuel by itself, blended with gasoline, or as a gasoline octane enhancer and oxygenate.

Ethanolamines are prepared by the reaction of ammonia and ethylene oxide. They include monoethanolamine (MEA), diethanolamine (DEA) and triethanolamine (TEA). The three are widely used in industry, principally as absorbents for acidic components of natural gas and of petroleum-refinery gas streams. It is also used to make detergents, metalworking fluids, and as gas sweetening. TEA is used in detergents and cosmetics applications and as a cement additive.

Polyethylene (PE), with a world production around 80 million tons, is the most common plastic (and polymer). It is a polymer of ethylene, especially any of various lightweight thermoplastics that are resistant to chemicals and moisture, and has good insulating properties. Its primary use is in packaging (plastic bags, plastic films, geomembranes, containers including bottles, etc.).

Many kinds of polyethylene are known, with most having the chemical formula $(C_2H_4)_nH_2$. It has many different trade varieties, and the most common are:

> **High-density polyethylene** (HDPE) is used predominantly in the manufacture of blow-molded bottles for milk and household cleaners and injection-molded pails, bottle caps, appliance housings and toys.
>
> **Low-density polyethylene** (LDPE) is used in film applications due to its toughness, flexibility and relative transparency. Typically, LDPE is used to manufacture flexible films such as those used for plastic retail bags. LDPE is also used to flexible lids and bottles, in wire and cable applications for its stable electrical properties and processing characteristics.
>
> **Linear low-density polyethylene** (LLDPE) is used predominantly in film applications due to its toughness, flexibility and relative transparency. LLDPE is the preferred resin for injection molding because of its superior toughness

Polyvinyl chloride (PVC). A polymer of vinyl chloride is used to make a diverse range of cost-effective products with various levels of technical performance suited to a wide range of applications. Many of these PVC products are used every day and include everything from medical devices such as medical tubing and blood bags, to footwear, electrical cables, packaging, stationery and toys.

7.2.2 Propylene, derivatives

Polypropylenes (PP) are various thermoplastic plastics or fibers that are polymers of propylene. Polypropylene can be made into fibers, where it is a major constituent in fabrics for home furnishings such as upholstery and carpets. Numerous industrial end uses include rope and cordage, disposable non-woven fabrics for diapers and medical applications. As a plastic, polypropylene is molded into bottles for foods and personal care products, appliance housings, dishwasher-proof food containers, toys, automobile battery casings and outdoor furniture.

Polyurethanes are used to make the foam in furniture, mattresses, car seats, building insulation, and coatings for floors, furniture and refrigerators. They are also used in artificial sports tracks, jogging shoes, and in roller blade wheels. (See also, Chapter 7.1.2.)

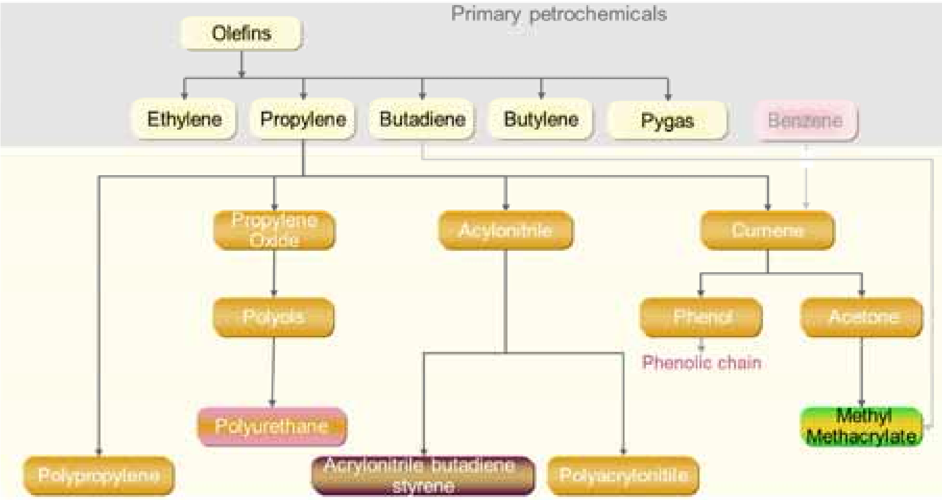


Figure 28. Olefins – propylene, derivatives

Acrylonitrile-butadiene-styrene (ABS) (see chapter 7.1.3).

Polyacrylonitrile (PAN) is a semi-crystalline polymer resin. Though it is thermoplastic, it does not melt under normal conditions. It degrades before melting. It is used to produce large variety of products including ultra-filtration membranes, hollow fibers for reverse osmosis, fibers for textiles, and PAN fibers that are the chemical precursor of carbon fiber.

Cumene is an aromatic derived from benzene and is used in turn to produce polycarbonates, phenolic resins and essential healthcare products such as aspirin and penicillin.

Methyl methacrylate (MMA). The principal application of methyl methacrylate is the production of polymethyl methacrylate (PMMA) acrylic plastics. Also, MMA is used for the production of the co-polymer methyl methacrylate butadiene-styrene (MBS), used as a modifier for PVC. MMA polymers and copolymers are used for waterborne coatings, such latex house paint.

7.2.3 Butadiene, butylenes, and pygas, derivatives

Pygas, or pyrolysis gasoline, is a naphtha-range product with a high aromatic content, used either for gasoline blending or as a feedstock for a BTX extraction unit. Pygas is produced in an ethylene plant that processes butane, naphtha or gasoil.

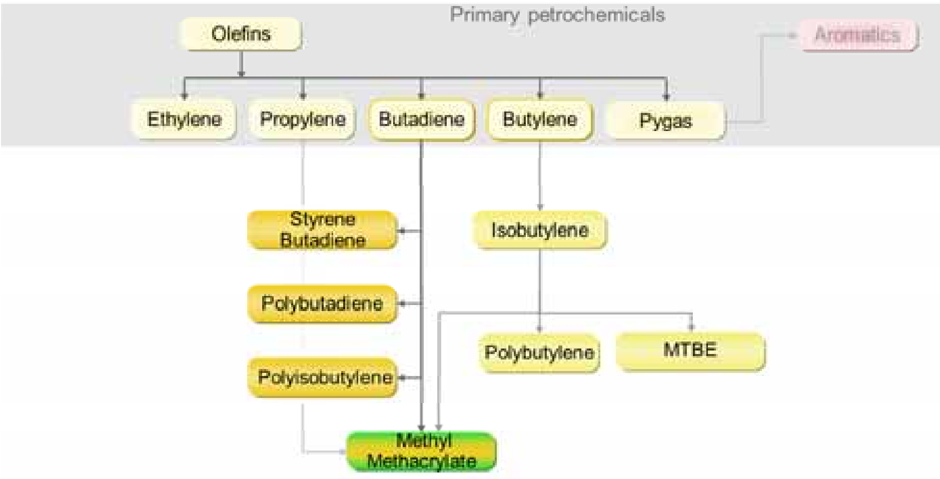


Figure 29. Olefins – butadiene, butylene, and pygas, derivatives

Styrene-butadiene (rubber) (SBR) (see Chapter 7.1.3.)

Methyl methacrylate (MMA) (see chapter 7.2.2

Polybutadiene is a synthetic rubber that is a polymer formed from the polymerization of the monomer 1,3-butadiene. It has a high resistance to wear and is used especially in the manufacture of tires. It has also been used to coat or encapsulate electronic assemblies offering extremely high electrical resistivity.

Polyisobutylene is a synthetic rubber, or elastomer. It is special because it is the only rubber that is gas impermeable; it is the only rubber which can hold air for long periods of time. Polyisobutylene, sometimes called butyl rubber is a vinyl polymer, and is very similar to polyethylene and polypropylene in structure.

Polybutylene (PB-1) is a high molecular weight, linear, isotactic, and semi-crystalline polymer. PB-1 replaces materials like metal, rubber and engineering polymers. Because of its specific properties it is mainly used in pressure piping, flexible packaging, water heaters, compounding and hot melt adhesives.

Methyl-tert-butyl-ether (MTBE) is used in gasoline to boost the octane rating and to decrease toxic emissions in the exhaust. As an octane enhancer, MTBE delivers high octane numbers at relatively low cost. A direct effect of the use of MTBE is the reduction of both "regulated" emissions (CO, unburned hydrocarbons) and "unregulated" emissions.

7.3 Synthesis gas (syngas)

Synthesis gas (syngas) is a mixture of carbon monoxide and hydrogen. It can be created from coal or methane reacting with steam at high temperatures:

From coal:	$C + H_2O \rightarrow H_2 + CO$	
Or from methane:	$CH_4 + 1/2O_2 \rightarrow CO + 2H_2$	Lean combustion
	$CH_4 + H_2O \rightarrow CO + 3H_2$	Steam reforming

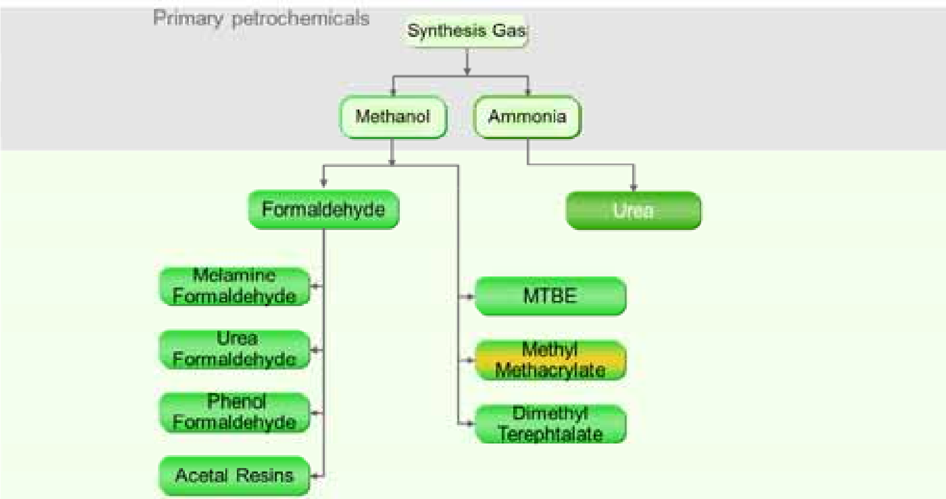


Figure 30. Synthesis gas

Syngas is used for production of methanol or ammonia. It is also used for production of synthetic fuels, both diesel (Fischer–Tropsch process) and gasoline (see Chapter 9.1.5).

7.3.1 Methanol based products

Methanol, a colorless alcohol, is a chemical used in the production of formaldehyde, acetic acid and methyl methacrylate (MMA), and is used as a solvent in many applications. It is also used to produce MTBE and other products, and can be used in fuels.

Melamine resin or melamine formaldehyde (also, incorrectly, melamine) is a hard, thermosetting plastic material made from melamine and formaldehyde by polymerization. This plastic is often used in kitchen utensils or plates and is the main constituent in high pressure laminates and laminate flooring.

Urea-formaldehyde is a non-transparent thermosetting resin or plastic, made from urea and formaldehyde. It is used in adhesives, finishes, MDF and molded objects. Its attributes include high tensile strength, heat distortion temperature, low water absorption, mold shrinkage, high surface hardness and elongation at break.

Phenol formaldehyde is a low-cost basic resin. Addition of appropriate fillers can generate high temperature-resistant grades (185 °C/370 °F). Normal phenolics are resistant to 150 °C/300 °F. Applications include moldings, bottle tops, resins, chemically resistant coatings for metals, laminates, water lubricated bearings and foams for thermal insulation.

Polyoxymethylene (POM), also known as acetal resin, polytrioxane, polyformaldehyde and paraformaldehyde, is an engineering plastic used to make gears, bushings and other mechanical parts. It is also known in variant trade names such as Delrin, Celcon and Hostaform. It is the most important polyacetal resin; a thermoplastic with good physical and processing properties.

MTBE (see Chapter 7.2.3).

Methyl methacrylate (see Chapter 7.2.2).

Dimethyl terephthalate (DMT) is an ester of terephthalic acid and methanol and is used in the production of polyesters, including polyethylene terephthalate and polytrimethylene terephthalate. It consists of benzene with methyl ester groups attached. DMT has largely been replaced by pure terephthalic acid (PTA) as the preferred industrial route to polyester production.

7.3.2 Ammonia based products

Ammonia is a pungent, colorless, gaseous alkaline compound of nitrogen and hydrogen (NH_3) that is very soluble in water and can easily be condensed to a liquid by cold and pressure. It is manufactured by the direct combination of hydrogen and nitrogen under pressure over a catalyst. The main process is still the Haber-Bosch synthesis invented in 1915, operating at 15–25 MPa and between 300 and 550 °C in four reaction chambers with catalyst. Anhydrous ammonia is mainly used for the manufacture of nitrogenous fertilizers. It is also a building block for the synthesis of many pharmaceuticals, for explosives, and is used in many commercial cleaning products.

Urea $CO(NH_2)_2$ is synthesized from ammonia and carbon dioxide. It is named for its presence in human and most land animal urine (except fish and birds). Dissolved in water, it is neither acidic nor alkaline. Urea is widely used in fertilizers as a convenient source of nitrogen. Urea is also an important raw material for the chemical industry in animal feed, plastics and resins.

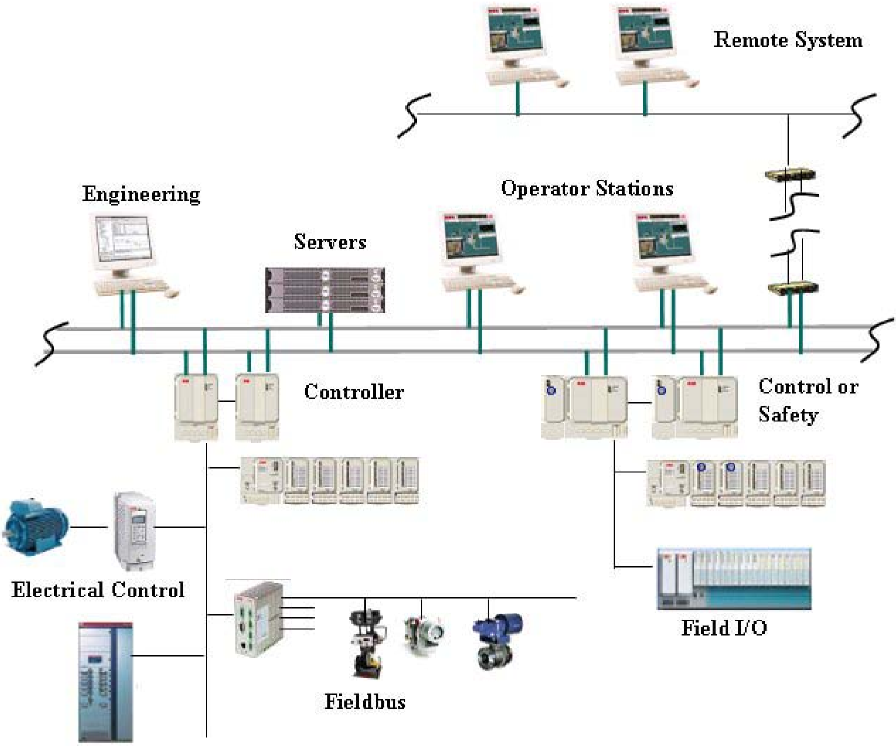
Yara Porsgrunn Ammonia Fertilizer plant

8 Utility systems

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

8.1 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 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 other similar environments.

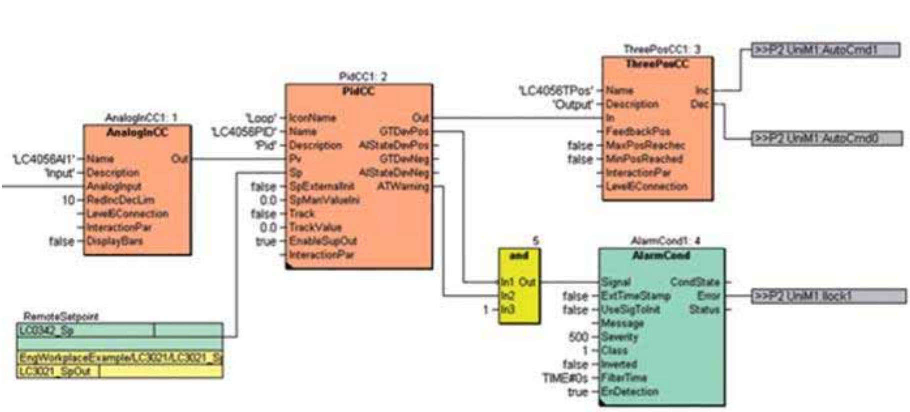


Figure 31. Function blocks define the control

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 and 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 onshore corporate operations support centers.

Field devices in most process areas must be protected to prevent them from 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 that the flow from wells and 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.

8.1.1 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 are no longer operating within 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.).

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The definition of safety is “freedom from unacceptable risk” of physical injury or of damage to the health of people, either directly or indirectly. It 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, meaning that hazards and safety functions have to be known. A process of function reviews, formal hazard identification studies (HAZID), 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 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 needs to be documented in order 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 the system be independently certified.

There is never one single action that leads to a large accident. It is often a chain 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)

An SIS is a collection of sensors, controllers and actuators that execute one or more SIFs/safety loops that are implemented for a common purpose. Each SIF has its own safety integrity level (SIL) and all sensors, controllers and final elements in one SIF must comply with the same SIL, 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 an SIS 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 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 (RFF) and probability of failure on demand (PFD):

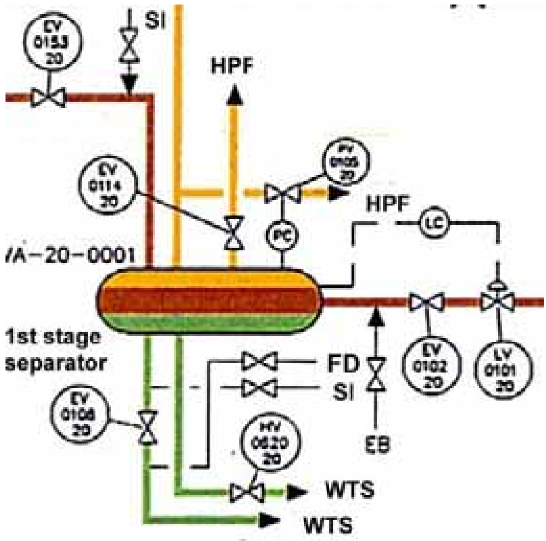
SIL	PFD	RRF
1	0.1 – 0.01	10 – 100
2	0.01 – 0.001	100 – 1000
3	0.001 – 0.0001	1000 – 10.000
4	0.0001 – 0.00001	10.000 – 100.000

The SIL for a component is given by its PFD, safe failure fraction and design to avoid influence of systematic errors.

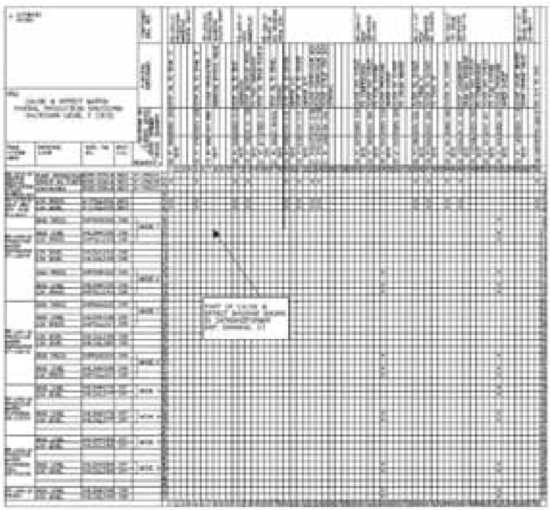
8.1.2 Emergency shutdown and process shutdown

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 LSLL (level switch LowLow) 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 causes 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-effect 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.



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 (e.g., 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 can 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 SIL 4 level, while PSD loops could be SIL 2 or SIL 3.

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

8.1.3 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 through closure of ventilation fire dampers. A fire area protection data sheet typically shows what detection exists for each fire area, and which fire protection action should be taken in case of an incident.

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

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

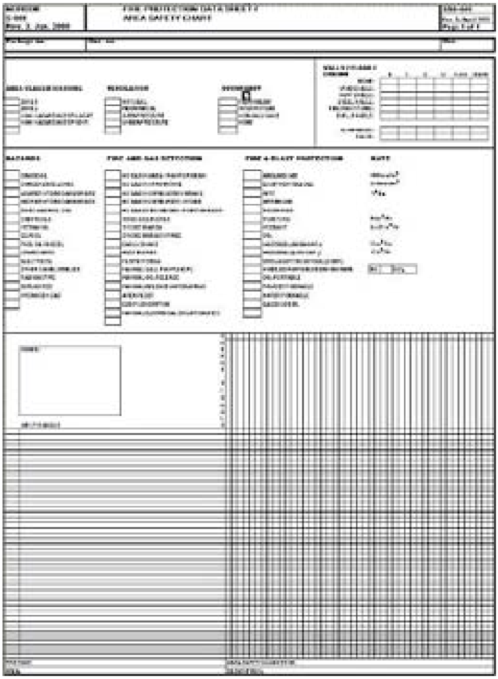
Firefighting, protection:

- Gas-based firefighting, such as CO_2
- Foam-based firefighting
- Water-based firefighting: sprinklers, mist (water spray) and deluge
- Protection: Interface to emergency shutdown and HVAC fire dampers.

* Warning and escape: PA systems, beacons/lights, fire door and damper release

A separate package related to fire and gas is the diesel- or electrically-driven fire water pumps for the sprinkler and deluge ring systems.

For fire detection, coincidence and logic are often used to identify false alarms. In such schemes, several detectors in the same area are required to detect a fire condition or gas leakage for automatic reaction. This will include different detection principles, e.g., a fire, but not welding or lightning strike.

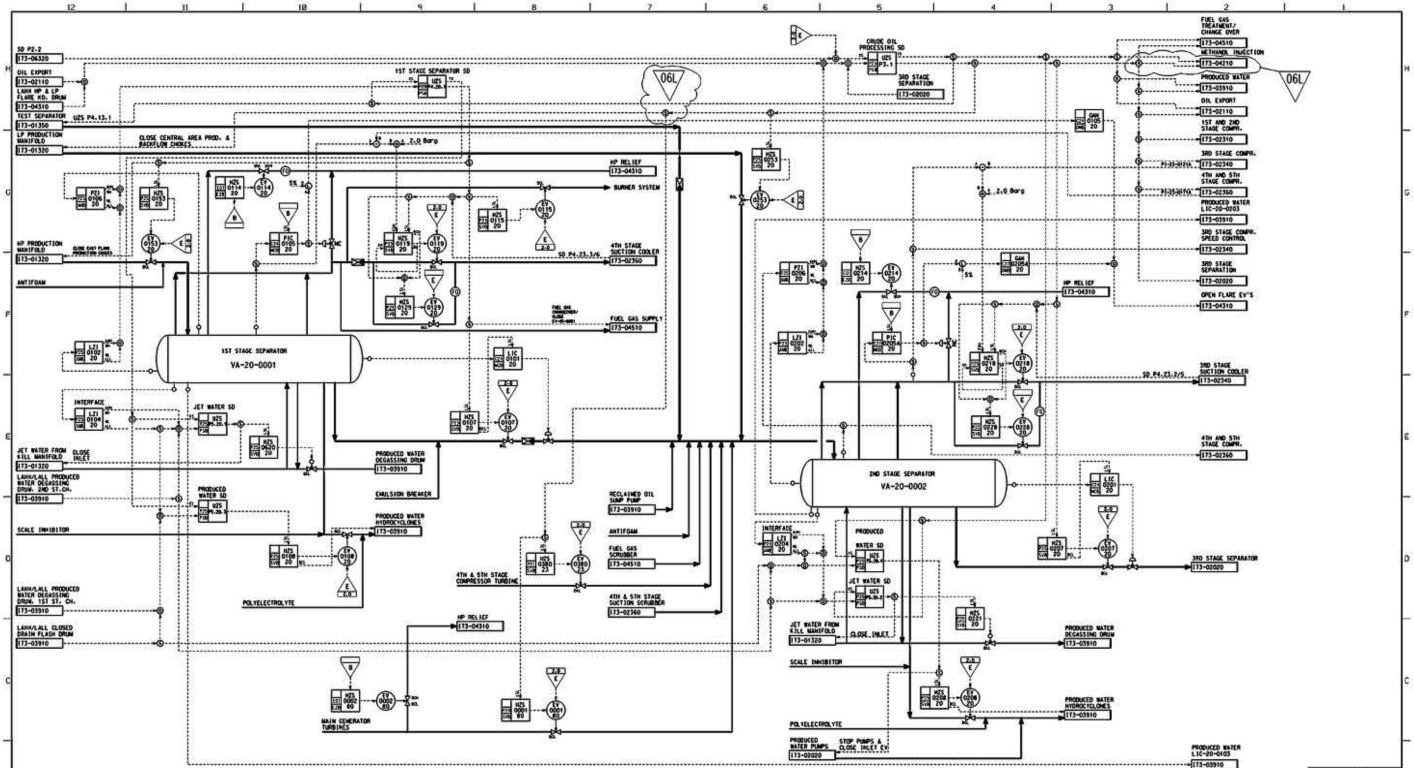


Action is controlled by a fire and gas system (F&G). Like the ESD system, F&G action is specified in a cause and action chart called the Fire Area Protection Datasheet. This chart shows all detectors and fire protection systems in a fire area and how the system will operate.

The F&G system often provides supervisory functions, either in the F&G or the information management system (IMS) to handle such tasks as maintenance, calibration or replacement and hot work permits, e.g., welding. Such actions may require that one or more fire and gas detectors or systems are overridden or bypassed. Specific work procedures should be enforced, such as a placing fire guards on duty, to make sure all devices are re-enabled when the work permit expires or work is complete.

8.1.4 Control and safety configuration

Piping and instrumentation diagrams (P&ID) show the process. Additional information is needed for the specification of the process control and safety systems design and their control logic. These include: Loop diagram, Instrument datasheet, Cable schedule and Termination list.



1. FOR PROCESS START/STOP SEQUENCES FOR 3RD STAGE COMPRESSOR, THE REFERENCE DRAWINGS ARE:
   18-1A-AS-173-02356
   18-1A-AS-173-02357
   18-1A-AS-173-02358
2. FOR PROCESS START/STOP SEQUENCES FOR 4TH AND 5TH STAGE COMPRESSORS, THE REFERENCE DRAWINGS ARE:
   18-1A-AS-173-02370
   18-1A-AS-173-02371

INCLUDED SINCE LAST REVISION:
CAN-AE-+-3019-26
CAN-AE-+-3019-27
CAN-AE-+-3019-32
CAN-AE-+-3019-33
CAN-AE-+-3019-34

ID 0657400

Rev.	Date	Description					
06L	10.11.98	AS BUILT AVROP 348404	JAH	POR	HMR		BH
05L	30.04.97	AS BUILT					
04I	15.11.96	UPDATED AFTER DISCOS FUNCTION TEST	MH		HBR		
03I	10.05.96	RE-ISSUED FOR AFC			SD		
02I	15.02.96	APPROVED FOR CONSTRUCTION			SD		
01F	01.10.95	APPROVED FOR DETAIL ENGINEERING	SP		SD		

HYDRO — Contractor: Aker — Project: NJORD

TECHNOLOGY AND PROJECTS DIVISION

Drawing title: SYSTEM CONTROL DIAGRAM, SCD
SEPARATION
1ST & 2ND STAGE

Scale: NTS — Format: A1 — Dsg.Format: 20

Drawing No: 18-1A-AS-173-02010 — Sheet: 1of1 — Rev.: 06L

The illustration shows one typical format. This is the common format for the NORSOK SCD standard. (Example for the Njord Separator 1 and 2 systems control diagram). Essentially, the P&ID mechanical information has been removed, and control loops and safety interlocks drawn in with references to typical loops.

8.1.5 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.

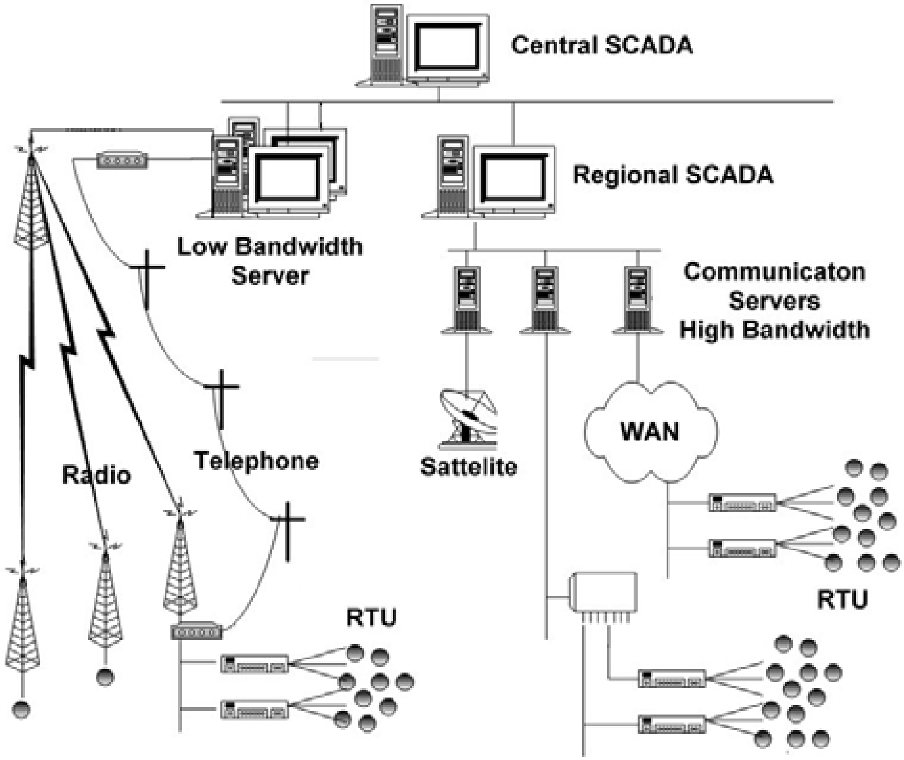


Figure 32. SCADA system topology (typical)

Remote terminal units (RTU) or local controls systems on wells, wellhead platforms, compressor and pump stations, 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 between them is mainly their data architecture and use of communications.

8.2 Digital oilfield

In the oil and gas industry digital oilfield (DOF) is a generic term for new solutions and technologies for operation, work processes and methods that are being made possible by adopting innovations in information technology. Other names such as Integrated Operations (IO), E-Field, Smart Fields, i-Field and Integrated Asset Management are used for the same concept. Intelligent Energy is a general umbrella term adopted by Society of Petroleum Engineers (SPE).

Central to this concept is collaboration between people; where data, information, knowledge shared between a number of parties in digital form. This often supported by technologies such as video conferencing and augmented reality for personnel in remote locations or in the field. In this environment we add solutions for optimal performance, security, maintenance.

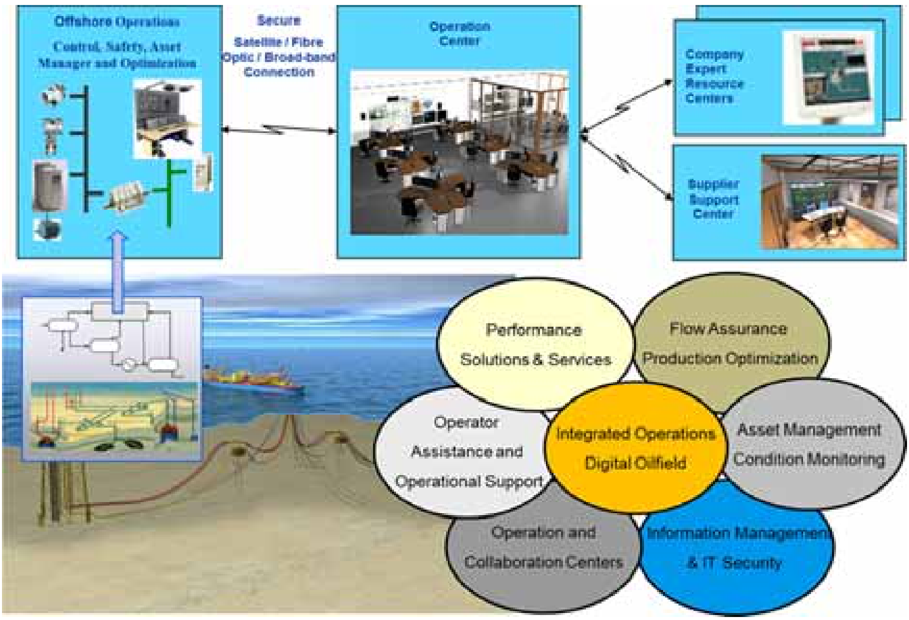


Figure 33. Digital Oilfield

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
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

8.2.1 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

8.2.2 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 helps 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 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.

8.2.3 Asset optimization and maintenance support

An asset optimization (AO) system reduces 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 as a computerized maintenance management system (CMMS).

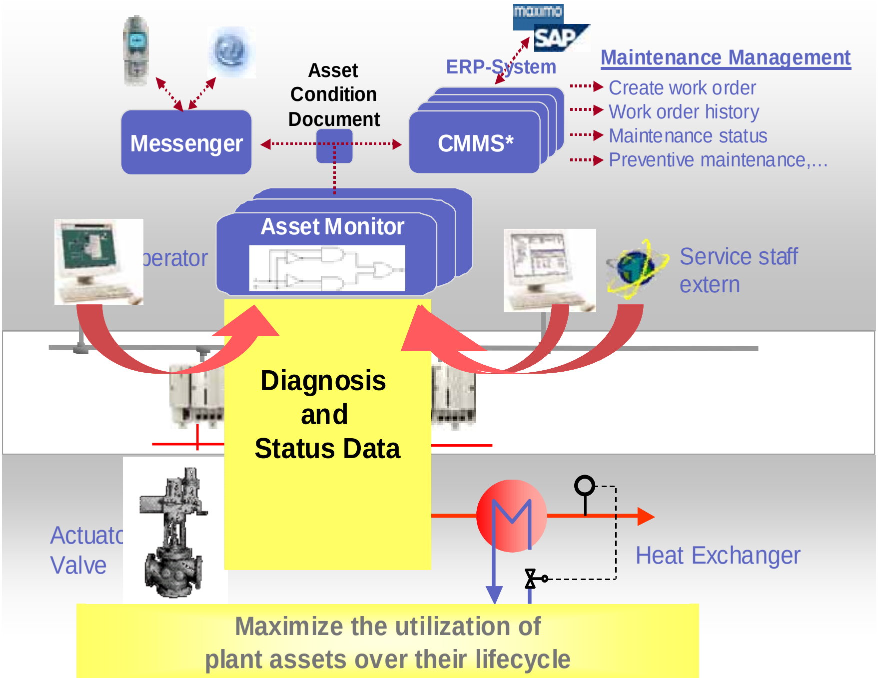


Figure 34. Computerized maintenance management system

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, so that corrosion may be metered), tension force meters and free swinging strings. These statistics are logged to a central structure condition monitoring system, to show 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 that 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 are 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.

8.2.4 Information management systems (IMS)

A specific information management system (IMS) 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.

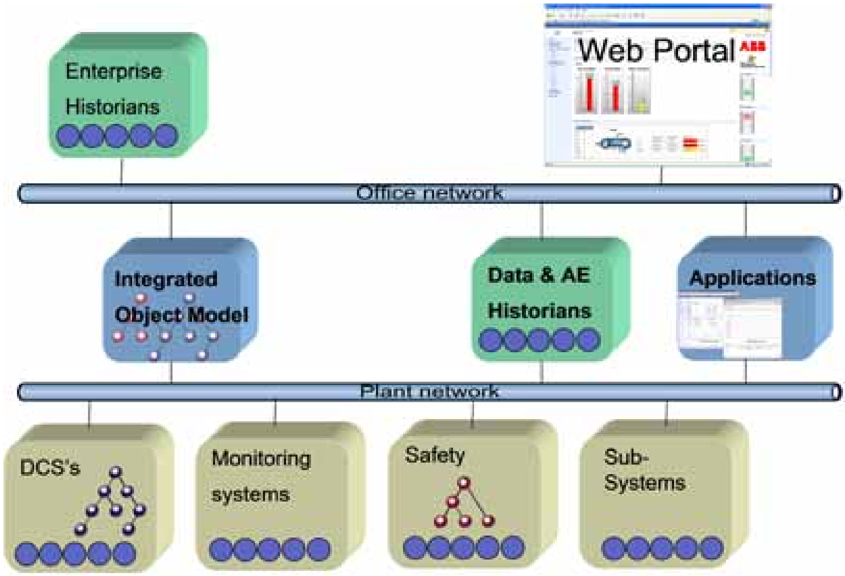


Figure 35. Information management system topology

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 and consolidation of produced stored and dispatched volumes.
- Environmental reports
- Polynomial allocation (oil/gas/water) based on well test results

8.2.5 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 provide information from the real operating situation.

8.3 Power generation, distribution and drives

Power can be provided from mains power, local gas turbines or diesel generator sets. Large facilities have high power demands, from 30 MW up 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. Exhaust heat is often needed in the main process.

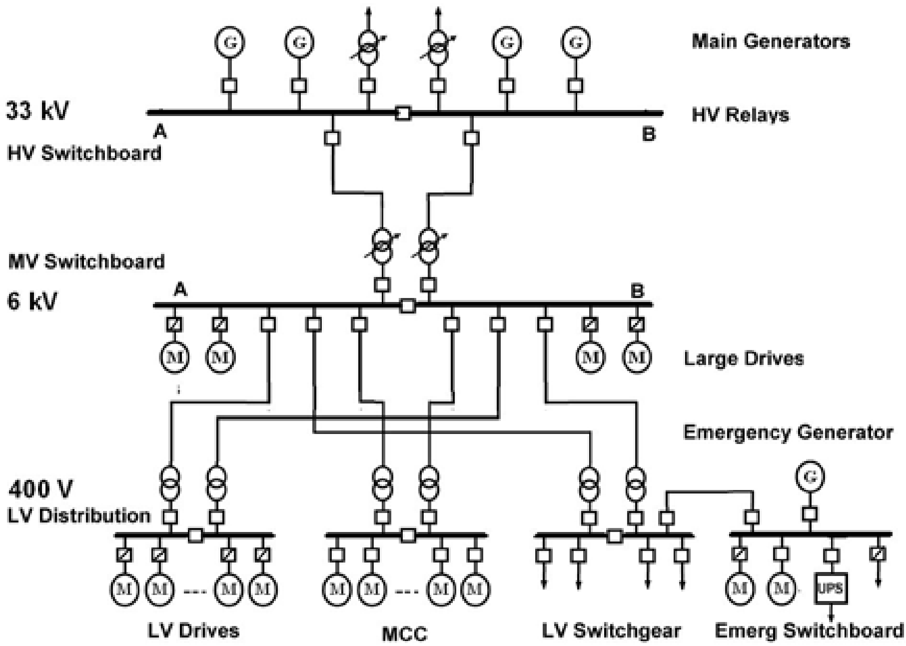


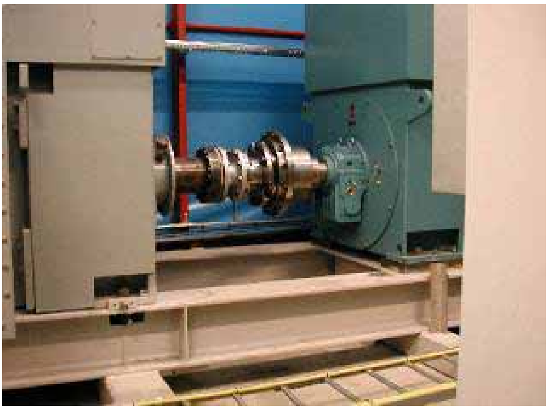
Figure 36. Electrical single line diagram

Voltage levels for high, medium and low voltage distribution boards are 13-130 kV, 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 (MCC) and variable speed drives for motors up to a few hundred KW (not necessarily separately, as shown in the figure below).

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 and plant outages (blackouts). The power management system includes HV, MV and LV low voltage switchgear plus MCCs and emergency generator sets. Functions include prioritization of loads, emergency load shedding (closing down of nonessential 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 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 avoids local power generation at each facility and contributes to low manning or remote operation.

8.4 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 slightly 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.

8.5 Instrument air

A large volume of compressed air is required for 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.

8.6 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 tropical and sub-tropical 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.

8.7 Water systems

8.7.1 Potable water

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

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

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 below ground 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.

8.7.2 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.

8.7.3 Ballast water

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

8.8 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 2,000 liters (500 gallons) of antifoam can be used. At a cost of 2 € per liter, ($10 per gallon) in bulk, antifoam alone will cost some 4,000 € or $5,000 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 change, these may precipitate and deposit in pipes, heat exchangers, valves and tanks. As a result, they may clog up or become stuck. The scale inhibitor prevents 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 true solution. However, small drops of oil can disperse in water and small water drops can disperse in oil. Such systems are called emulsions; oil-in-water (o/w) and water-in-oil (w/o), respectively. The drops are held suspended by electrostatic repulsion, and will form a distinct layer between the oil and water. Sand and particles are normally carried out by the water 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. Although the emulsion layer will eventually break down naturally, it takes time, too much time. An emulsion breaker is added to prevent formation and promote breakdown of the emulsion layer by causing the droplets to merge and grow.

Antifoam The sloshing motion inside a separator causes foaming. This foam covers the fluid surface and prevents 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 allow 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 starts 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 that 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 reducing 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 export pipelines and storage tanks. Exported oil can be highly corrosive, leading to corrosion of the inside of the pipeline or tank. The corrosion inhibitor protects 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.

8.9 Telecom

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

Some of the main systems are:

· Public address and 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 and 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 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 facility operations. 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 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 improving the working environment. They allow any type of system or operator to communicate within the facility, enabling reliable and efficient operations.

3. Safety and Security Systems

Safety and Security Systems are used for safeguarding personnel and equipment in, on and around an installation according to international rules and standards. These systems are 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 and utility systems

System and personnel well-being are supported by a number of management and utility systems that 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 of integrated operations.

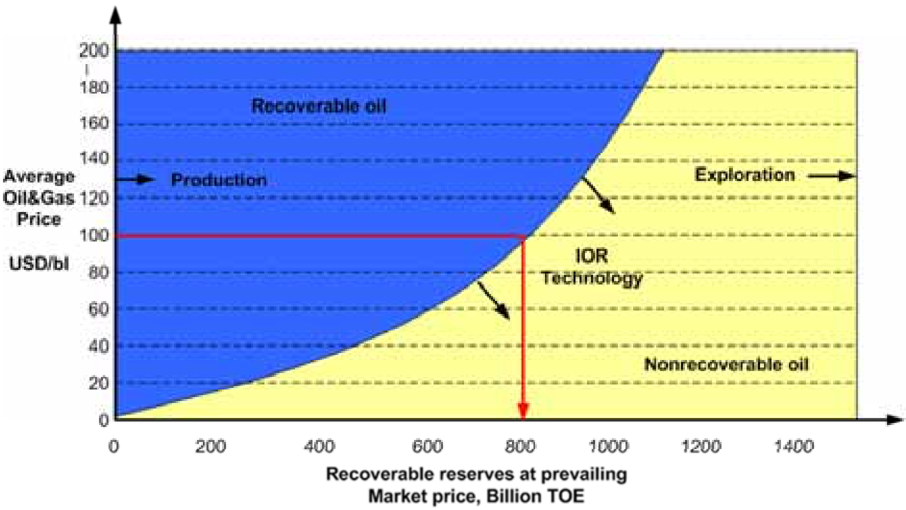
9 Unconventional and conventional resources and environmental effects

About 81.1% of the world's primary energy consumption in 2012 was fossil fuels; 27.3% was coal, oil production was 32.4% or about 4.01 billion tons, and 21.4% was gas, with 3,39 trillion scm or 3.01 billion tons oil equivalent (TOE). Thus, total oil and gas production was 6.4 billion TOE, which is about 128.5 million barrels of oil equivalent per day (IEA 2012).

Proven reserves are estimated at 201 billion TOE of oil and 6707 tcf of gas (180 trillion scm, 160 billion TOE) for a total of 361 billion TOE (converted from estimates by US Department of Energy, 2012), indicating that proven reserves will last for about 56 years.

9.1 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 becomes 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 as the oil price among different sources. The figure illustrates that if one assumes that if an oil price of $100 per barrel prevails, the estimated economically recoverable reserves with current technology will be about 800 billion tons of oil equivalent, of which 45% is proven. This is about 125 years of consumption at current rates, and is expected that up to a third of oil fuel production may come from unconventional sources within the next decade.

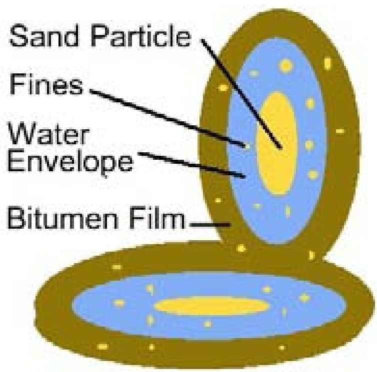
9.1.1 Extra heavy crude

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.

9.1.2 Tar sands

Tar sands can often be 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 can 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.

9.1.3 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. Significant shale “plays” have been discovered in the last decade, such as the Marcellus in the northern US and Canada, Eagle Ford on the US east coast and Bakken in south Texas.

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 prevents the breakdown of organic matter, thus allowing it to accumulate in thick layers. These layers were later covered with overlying rock, to be baked under high temperature and pressure. However, the heat and pressure were lower than in oil and gas reservoirs.

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 steam injection. Extraction cost is currently around $25-30 per barrel.

9.1.4 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 of the gas consumption in the US and Canada by 2020. Shales 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 adsorbed onto organic material. Recently, there have been strong advances 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 before. Even so, production typically requires a high number of wells with limited lifetimes, so continuous drilling of new wells is required to maintain output. Methane is a potent greenhouse gas, and emissions from leaking capped wells and fractures is a potential problem due to the large number of wells.

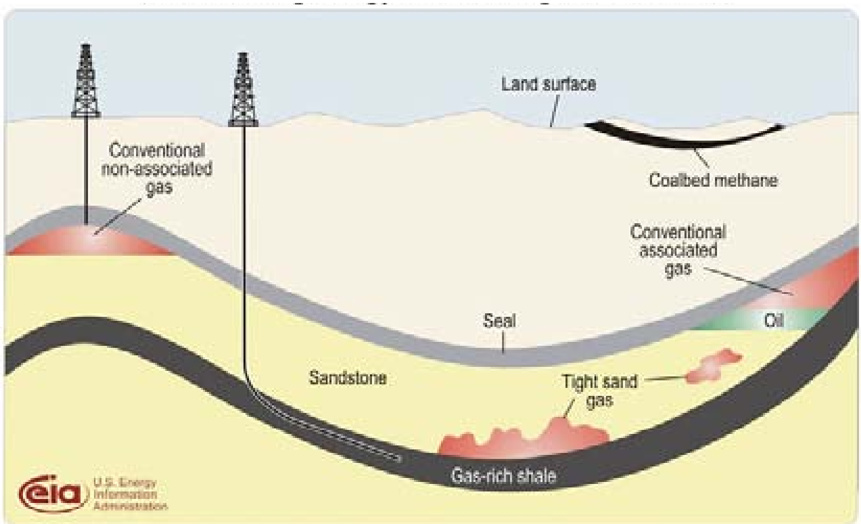


Figure 37. Schematic geology of natural gas resources

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 requires extraction techniques similar to shale gas. Often the coal bed is flooded, so after well completion and fracturing, the coal seam (layer of coal) must 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.

9.1.5 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.

(For synthesis gas, see also chapter 7.3.)
It has been known for decades that synthetic diesel could be created from coal. This is done, first by creating *water gas* as synthesis gas by passing steam over red-hot coke. The reaction is endothermic and requires heating:

$$C + H_2O \rightarrow H_2 + CO$$

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

$$CO + H_2O \rightarrow H_2 + CO_2$$

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*:

$$(2n+1)H_2 + nCO \rightarrow C_nH_{(2n+2)} + nH_2O$$

This process runs at a pressure of 2-4 MPa. With iron catalyst a high temperature process at 350 °C will yield a diesel fuel quite similar to normal diesel with an average carbon number of 12, and a certain content of unwanted aromatics. The low temperature process uses a cobalt catalyst and a temperature of 200 °C 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:

$CH_4 + 1/2O_2 \rightarrow CO + 2H_2$ Lean combustion
$CH_4 + H_2O \rightarrow CO + 3H_2$ 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 (GTL) processes.

An alternative use of the synthesis gases (CO and H_2) is production of methanol and synthetic gasoline:

$2\ H_2 + CO \rightarrow CH_3OH$ Methanol synthesis

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

$2\ CH_3OH \rightarrow CH_3OCH_3 + H_2O$ Dehydration to dimethyl ether

The second stage further dehydrates the ether with ceolite catalyst to yield a synthetic gasoline with 80% carbon number 5 and above.

9.1.6 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 first expected. Estimates range anywhere from 180 to over 5800 trillion scm.

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.

9.1.7 Biofuels

Biofuels are produced from specially-grown products such as oilseeds or sugars, and organic waste, e.g., from the forest industry. These fuels are called **carbon neutral**, because the carbon dioxide (CO_2) released during burning is offset by the CO_2 used by the plant when growing.

Ethanol alcohol (C_2H_5OH) is distilled from fermented sugars and/or starch (e.g., wood, sugar cane or beets, corn (maize) or grain) to produce ethanol that can be burned alone with retuning of the engine, or mixed with ordinary gasoline.

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):

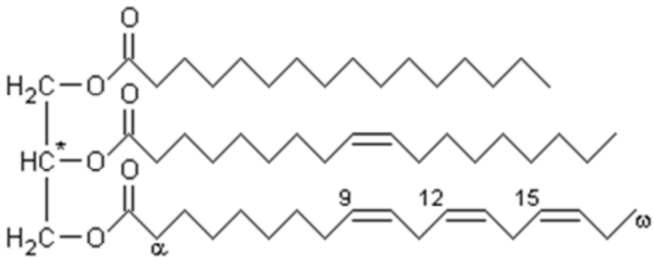


Figure 38, Vegetable Oil structure

The glycerol backbone on the left is bound (ester OH binding) to three fatty acids, shown here 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).

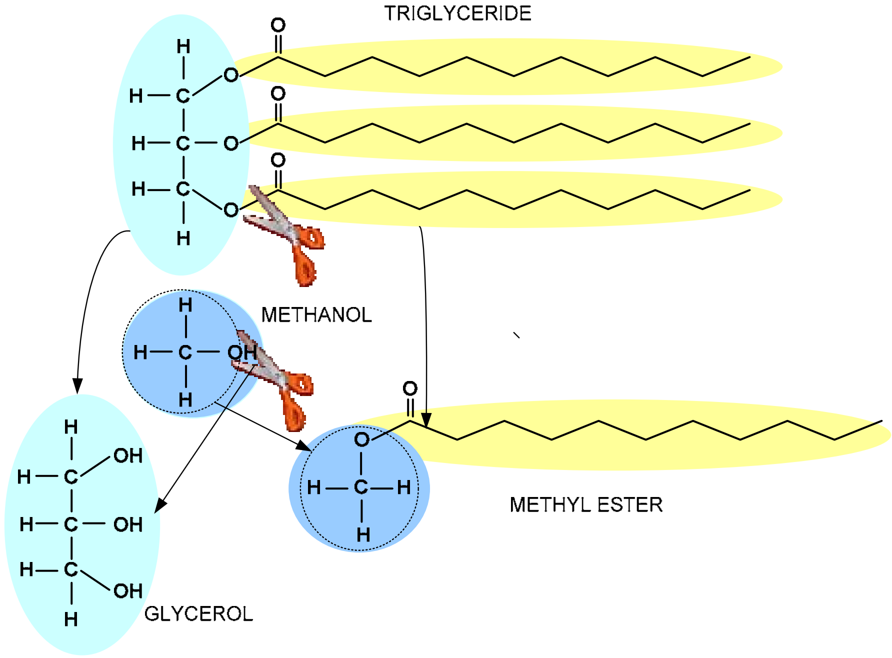


Figure 39. Transesterification

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 not otherwise be used for producing human food.

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

9.1.8 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 via syngas (see chapter 9.1.5) with up to 75-80% efficiency. Its advantage over methane gas is that carbon dioxide can be removed and handled at a central location rather than by each consumer, 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 fully 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, and 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.

9.2 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 million 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 Intergovernmental 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 ºC by the end of the 21st century, depending on models and global scenarios.

9.2.1 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:	CO_2, 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.

9.2.2 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 CO_2 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 CO_2 per kilo released to atmosphere. By order of importance to greenhouse effects, CO_2 emissions contribute 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 CO_2 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.

The annual emissions are about 1% of total atmospheric CO_2, which is in balance with about 50 times more carbon dioxide dissolved in seawater. This balance is dependent on sea temperature: Ocean CO_2 storage is reduced as temperature increases, but increases with the partial pressure of CO_2 in the atmosphere. Short term, the net effect is that about half the CO_2 emitted to air contributes to an increase of atmospheric CO_2 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 buffalos. 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 CO_2. 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.

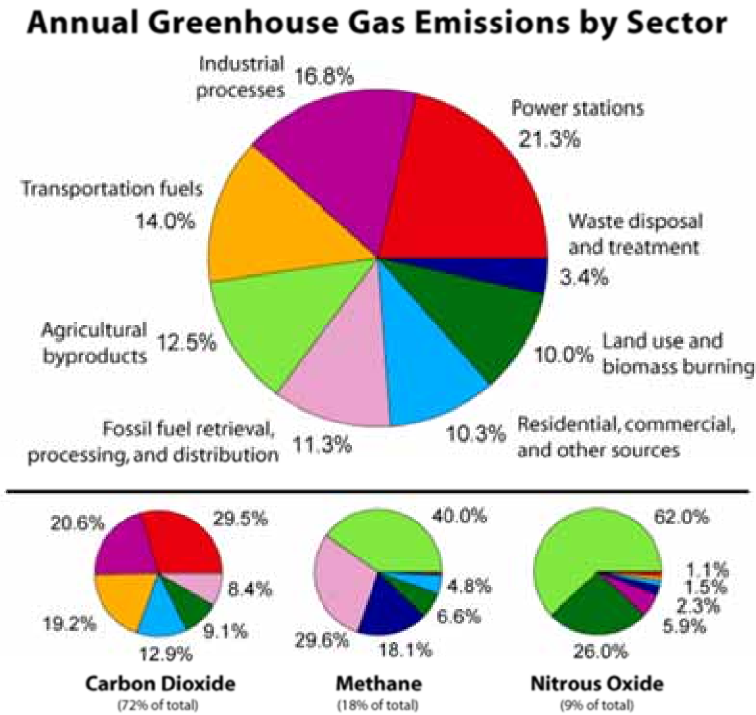


Figure 40. Greenhouse emissions Source: Wikipedia Commons

There are many mechanisms affecting the overall balance of greenhouse gases in the atmosphere. CO_2 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 ºC colder. The current data correlates well with a current global average temperature increase from a pre-industrial global average of 13.7 ºC to 14.4 ºC today. The atmosphere and seas have large heat trapping capacity, which makes their temperatures rise. These temperature rises lag behind greenhouse gas temperature increases. It is therefore predicted that the temperature will continue to rise by about 1ºC even if there were no further increase in levels of CO_2 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.

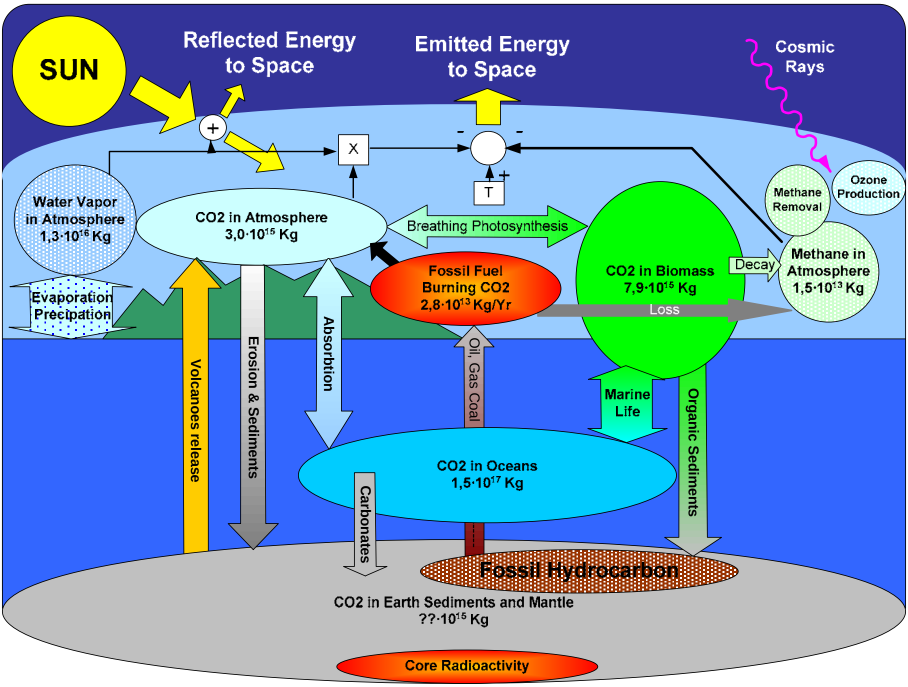


Figure 41. Carbon cycle

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 has been significantly reduced in area and thickness.

9.2.3 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 to develop more sustainable energy sources. The main problem is that as much as one third of all emissions come from planes, cars and ships, which account for about 45% of emissions from hydrocarbon fuels that are 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. For example, it can be argued that conversion to electrically-driven equipment in place of gas turbine-driven equipment could reduce CO_2 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 distributing 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 stored. Current plans call for re-injection into empty reservoirs, or reservoirs that need pressure assistance for oil extraction.

Capturing CO2 can be done at large point sites, such as large fossil fuel or biomass energy facilities, industries with major CO_2 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 burned 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 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 CO_2 at a cost of $35-90 per ton, including injection and storage in a reservoir. This is about 2-3 times the long-term expected emission quota costs.

10 Units

Some common units used in the oil and gas industry are listed here as 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 / 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 ≈ 50 tons/tons 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 ≈ 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 ≈ 0.0268 scm
Scm	Standard cubic meter (of gas, also Ncm) Defined by energy content	1 Scm = 39 MJ = 10.8 kWh 1 Scm ≈ 37.33 Scf (not a volume conv.) 1 Scm ≈ 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 Tone oil (US) 1 TOE ≈ 7.33 Barrels (at 33 API) 1 TOE ≈ 42.9 GJ =11,9 MWh 1 TOE ≈ 40.6 MMBTU 1 TOE ≈ 1.51 ton of coal 1 TOE ≈ 0.79 ton LNG 1 TOE ≈ 1,125 Scm = 42,000 Scf
kWh	Kilowatt hour = 1000 joules * 3600 S	1 kWh = 3.6 MJ = 860 kcal = 3,413 BTU

Product specific gravity, API grades

Product	Liters Per Ton (metric)
LPG	1835
Jet A-1	1254
Gasoline premium/super	1353
Gasoline regular	1418
Kerosene	1273
Gas oil	1177
Diesel fuel	1159
Fuel oil 80 CST	1065
Fuel oil 180 CST	1050
Fuel oil 230 CST	1047
Fuel oil 280 CST	1044
Bitumen	979

API Grade	Specific Gravity (kg/m3)	Barrels per Ton At 60°F
10	1000	6.29
18	934	6.73
25	904	6.98
30	876	7.19
33	860	7.33
36	845	7.46
39	830	7.60
42	816	7.73
50	780	8.06

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	

11 Glossary of terms and acronyms

ABS	Acrylonitrile-butadiene-styrene
AC	Alternating current
AGA	American Gas Association
AO	Asset optimization
API	American Petroleum Institute
BPA	Bisphenol A
BTX	Benzene, toluene and xylenes
CAPEX	Capital Expenses (Invested capital)
CCR	Central control room
CDU	Crude Oil Distillation Unit
CMMS	Computerized maintenance management system
CMS	Condition monitoring systems
CNG	Compressed natural gas
CPF	Central processing facility
CSP	Collector and separation platform
DC	Direct current
DEA	Diethanolamine
DEGBE	Diethylene glycol butyl ether
DEGBEA	Diethylene glycol butyl ether acetate
DETA	Diethylenetriamine
DPGEE	Dipropylene glycol ethyl ether.
DPGME	Dipropylene glycol methyl ether.
DYNPOS	Dynamic positioning (of rigs and ships)
E&P	Exploration and production
EDTA	Ethylenediamine tetraacetic acid
EG	Ethylene glycol
EGBE	Ethylene glycol butyl ether
EGBEA	Ethylene glycol butyl ether acetate
EO	Ethylene oxide
EOR	Enhanced oil recovery (new technology, cf IOR)
EPA	Propylene glycol ethyl ether acetate
EPS	Expanded polystyrene
ESD	Emergency shutdown system
ESP	Electric submerged pump
ETBE	Ethyl-tertiary-butyl-ether

F&G	Fire & gas system
FCC	Fluid catalytic cracking
FGS	Field gathering station
FPSO	Floating production storage and offloading
F-T	Fischer–Tropsch process
GB(S)	Gravity base structure
GE	Glycol ether
GOR	Gas oil ratio from the well
GOSP	Gas oil separation plant
GRP	Glass reinforced plastics
GTL	Gas to liquids
GTP	Gas treatment platform
HAZID	Hazard identification study
HAZOP	Hazard and operability study
HDPE	High-density polyethylene
HFC	Hydrofluorocarbons
HDS	Hydrodesulfurization (unit)
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)
IPA	Isopropyl acetate
IR	Infrared
ISO	International Standards Organization
K-Mass Flow	Coriolis type sass flow meter
LDPE	Low-density polyethylene
LLDPE	Linear low-density polyethylene
LNG	Liquid natural gas (e.g., methane)
LP	Low pressure
LPG	Liquid petroleum gas
LPG	Liquefied petroleum gas (e.g., propane)
LVOC	Large volume organic chemicals
MCC	Motor control center
MEA	Monoethanolamine

MEG	Monoethylene glycol
MEK	Methyl ethyl ketone
MMA	Methyl methacrylate
MP	Propylene glycol methyl ether
MPA	Propylene glycol methyl ether acetate
MPG / USP	Pharmaceutical grade monopropylene glycol
MSDS	Material Safety Data Sheet (international: SDS)
MTBE	Methyl-tert-butyl-ether
MTBF	Mean time between failure
NAO	Normal alpha olefins or n-olefins (See alpha olefins)
NBR	Nitrile-butadiene rubber
NGL	Natural gas liquids
NGL	Natural gas liquids, condensates (see also, LPG)
OPEX	Operational expenses
PCP	Progressive cavity pump
PD-Meter	Positive displacement meter
PES	Unsaturated polyester resins
PET	Polyethylene terephthalate
PFD	Probability of failure on demand
PG	Propylene glycol
PGEE	Propylene glycol ethyl ether
PGEEA	Propylene glycol ethyl ether acetate
PGME	Propylene glycol methyl ether
PGMEA	Propylene glycol methyl ether acetate
PGP	Power generation platform
PID	Proportional integral derivate control algorithm
PIMS	Production information management system
PMMA	Polymethyl methacrylate
PO	Propylene oxide
PoC	Pump of controller (for artificial lift)
POM	Polyoxymethylene
POSMOOR	Position mooring for a floating facility
PSD	Process shutdown system
PVC	Polyvinyl chloride
ROV	Remote operated vehicle (for subsea workover)

RRF	Risk reduction factor
RTU	Remote terminal unit
SAN	Styrene-acrylonitrile
SAS	Safety and automation system
SBR	Styrene-butadiene rubber
SCADA	Supervisory control and data acquisition
SIF	Safety instrumented function
SIL	Safety integrity level (per IEC 61508)
SIRC	
SIS	Safety instrumented system
TAED	Tetraacetylethylenediamine
TAME	Tertiary-amyl-methyl-ether
TBA	Tertiary-butyl-alcohol
TDI	Toluene di-isocyanate
TEA	Triethanolamine
TEPA	Tetraethylenepentamine
TIP	Tie-in platform
TLP	Tension leg platform
UMS	Unmanned machinery space class (marine = E0)
uPES, UPR, USPE	Unsaturated polyester resins
URF	Umbilicals, risers and flowlines
UV	Ultraviolet
VAM	Vinyl acetate monomer
VCM	Vinyl chloride monomer
VDU	Vacuum distillation unit
VOC	Volatile organic compound
WHP	Well head platform
XPS	Extruded polystyrene

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