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OIL AND GAS APPLICATIONS FOR CENTRIFUGAL COMPRESSORS

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Abstract
The oil and gas business requires gas compression for a number of distinctly different applications, such as transmission, storage, gas gathering and export compression, enhanced oil recovery, recycle compression and refrigeration, as well as various compression duties in refineries. This paper explains the purpose of and requirements for these applications within the context of oil and gas production, the transport of natural gas in pipelines and by LNG, and the use of hydrocarbons in downstream facilities. Typical operating requirements for the gas compressors, and typical solutions to meet these requirements are introduced. This includes discussions of process behaviors, dynamic behavior, and how to handle long and short term process changes.

EQUIPMENT

1.1 The Compressor

The duty of a gas compressor is to increase the gas pressure, thus reducing the volume of the gas. The faster a compressor runs, and the more impellers it has, the higher the pressure ratio for a given gas. At this point, we don't consider intercooled compressors. In many instances, rotordynamic considerations define the limits of speed, pressure, and number of impellers. Some applications, such as pipeline transmission, are not particular challenging from a rotordynamic perspective, since the process only requires small pressure ratios. Other applications, such as gas injection at high discharge pressures, are limited by the capability to achieve rotordynamic stability (Figures 1 and 2). Designs have to avoid critical speeds, minimize the excitation of the rotor, and seek designs that provide sufficient damping [1,2].

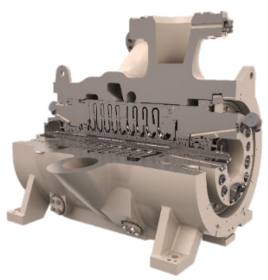


Figure 1: 2 Compartment, multistage barrel type compressor for high pressure applications

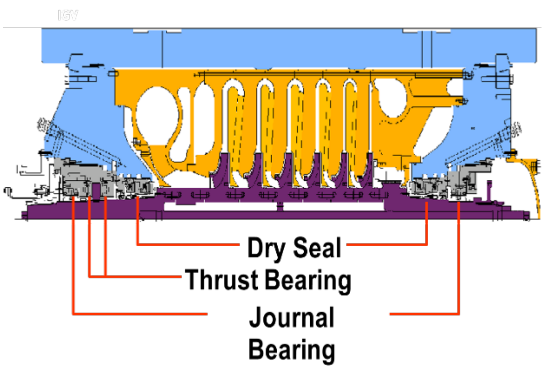


Figure 2: Cross section of a typical modern barrel type compressor with dry gas seals.

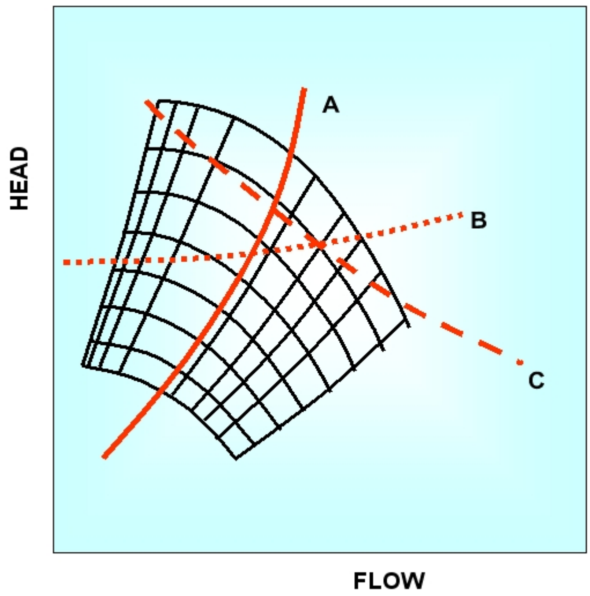


Figure 3: System characteristics and Compressor Map

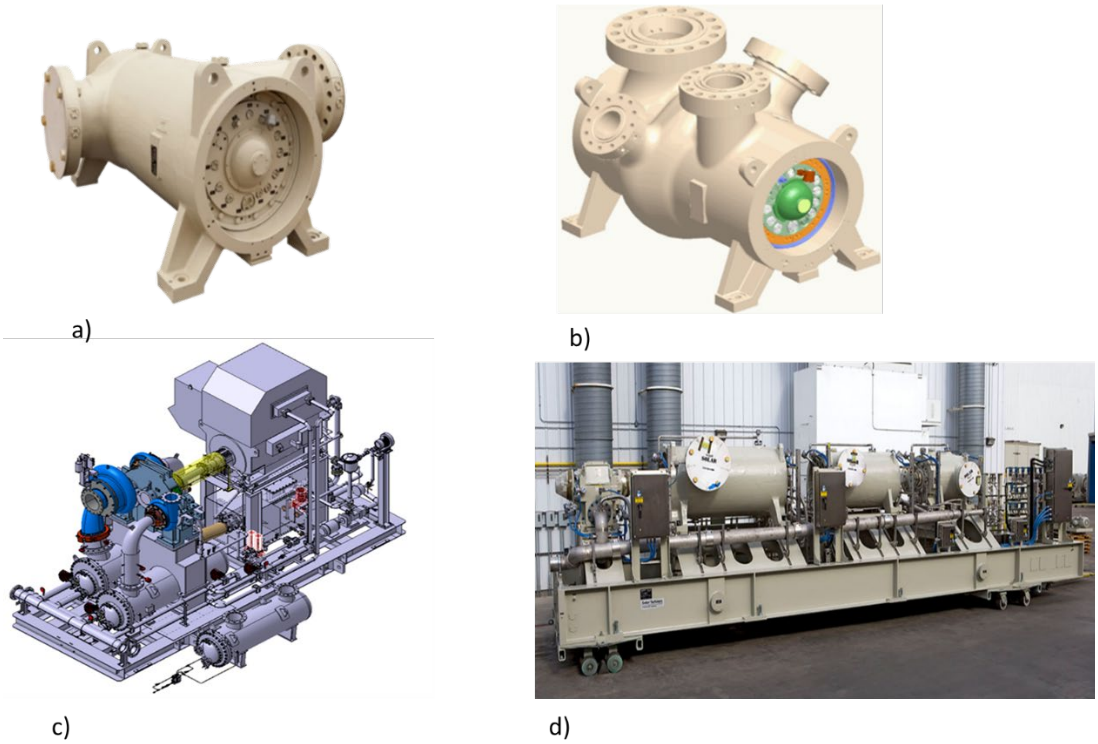


Figure 4: Different Compressor Configurations: a) Single section, straight through Compressor, b) Multi Section Compressor, c) Integral Gear Type Compressor (Courtesy Hanwha), d) multi body tandem.

A variable speed compressor allows operation over a wide range of head and flow requirements. The actual compressor operating point is the result of the compressors interaction with the system around the compressor. The system has a distinct relationship between pressure ratio (or head) and flow. Therefore, the system imposes the suction and discharge pressure upon the compressor, which responds with a certain flow. For a variable speed compressor, either the power input from the driver (if it's a gas turbine), or the driver speed (typical for electric motor drives). Compressor trains can consist of single compressor bodies, or multiple compressor bodies (Figure 5). Multiple compressor bodies (or compressors with multiple sections) are typically required for multiple process streams, or if the high pressure ratio requires intercooling(Figure 4).

1.2 Drivers

For the turbomachinery employed in oil and gas applications, a key question evolves around the type of driver, which can be a 2 shaft gas turbine, a Single Shaft gas Turbine (Figure 5), a Steam Turbine, a Turboexpander, or a variety of different electric motor configurations . Electric motor configurations would include constant speed motors driving the compressor via a gearbox, constant speed motors driving the compressor via a variable speed gearbox, or variable frequency drive speed controlled motors driving the compressor either directly or via a gearbox. Upstream and Midstream applications are dominated by two shaft gas turbine drivers, and variable speed electric motors, with some constant speed electric motor applications. This indicates that for upstream and midstream applications, the compressor can be controlled by varying its speed. Only constant speed drives rely exclusively on suction throttling or recycling [3,4]. LNG (Liquefied Natural Gas) applications use steam turbines, two shaft gas turbines, single shaft gas turbines and variable speed or constant speed electric motors, as well as turbo expanders as drivers. Downstream and refinery applications are dominated by steam turbines and constant speed electric motors as drivers.

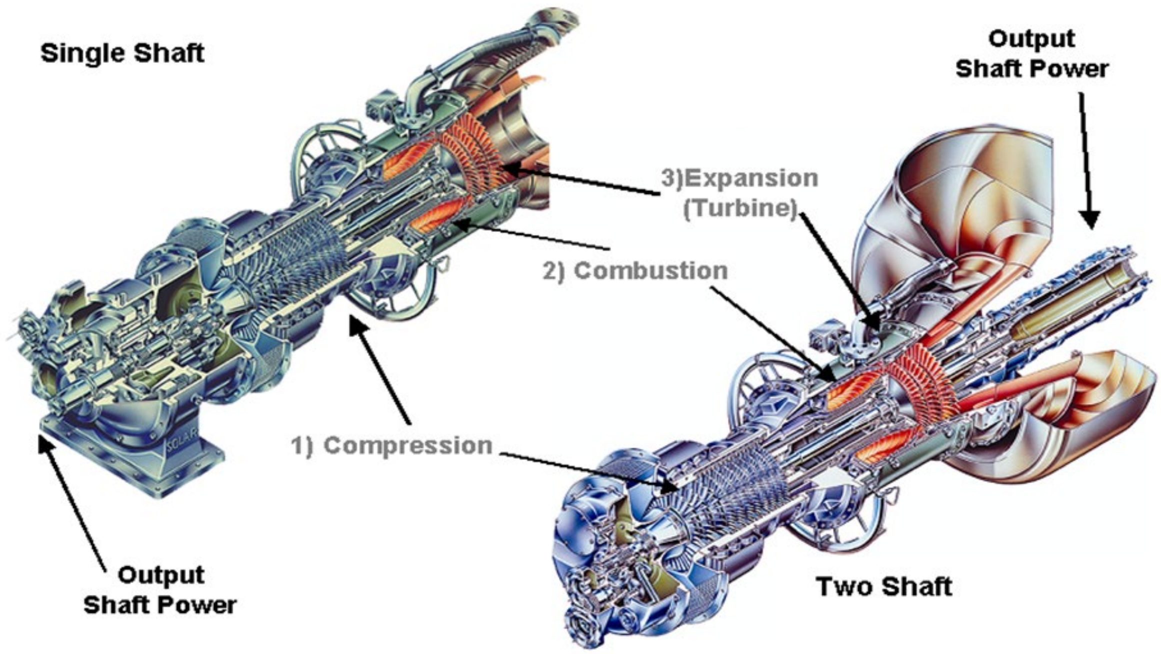


Figure 5: Industrial Gas Turbines

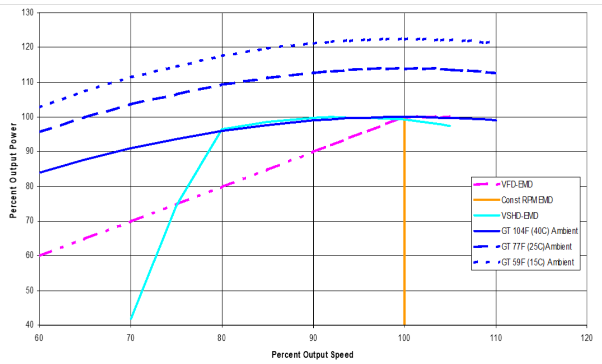


Figure 6: Driver Speed Torque characteristics

The other important distinction is, whether the units are installed on shore, offshore or subsea. This, among other things, determines access to maintenance intervention, as well as the environmental conditions (for example salt in the air) the equipment has to be designed for. If the driver is a gas turbine, the expectation is usually that the fuel is gas available at site, while for electric drivers, the question whether the electricity can be brought to site via transmission lines, or whether it has to be generated on site (usually with gas turbine driven generators).

Of importance for many applications are the performance characteristics of the driver, for example the power as function of ambient conditions, or the power output at various output speeds (Figure 6). Further the starting characteristics, including the amount of torque at low speeds, or, for electric motors, the amount of additional current is required during starting.

1.3 Packages

Compressors and drivers are usually combined to a package, which contains the driver, the compressor train, possibly a gearbox, and the necessary couplings (Figures 7,8,9). It also contains a start system, a lube oil system, a control system, sealing systems, air filtration systems, inlet and exhaust air systems, and an enclosure.

Special requirements apply to offshore applications. Platforms in deeper water impose special requirements, since floating platforms dynamically move [5].

Figure 7: Electric Motor drive Package

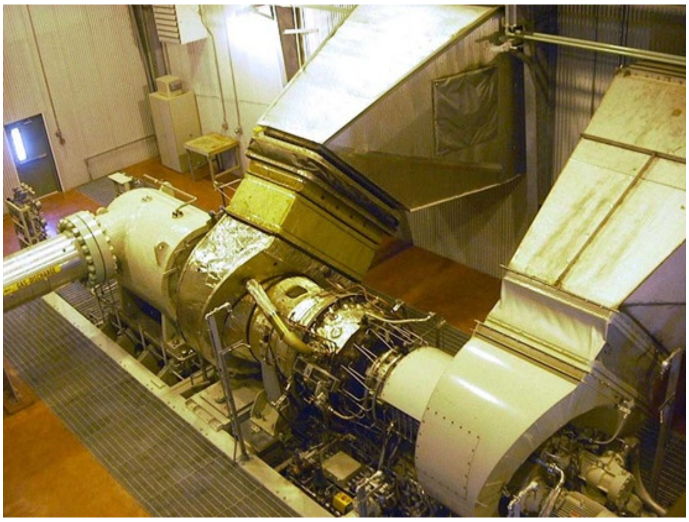


Figure 8: Gas turbine package

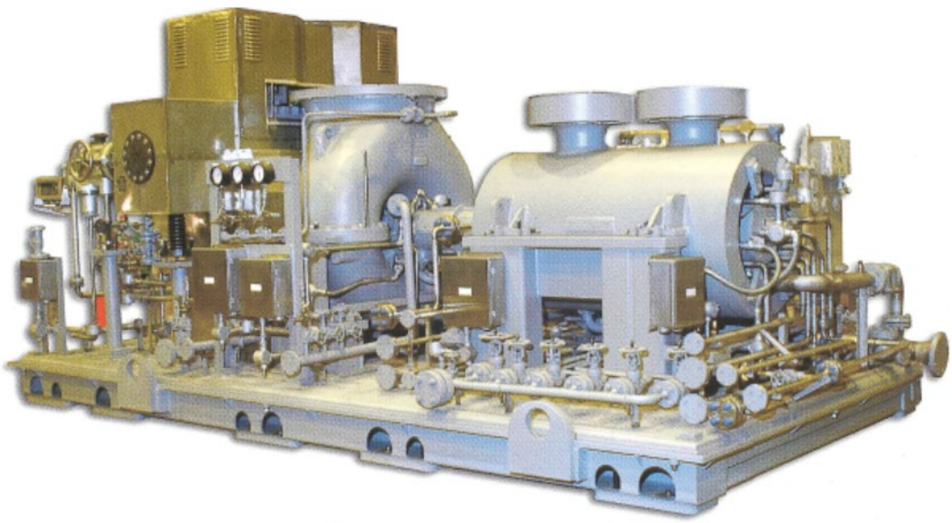


Figure 9: Steam turbine driven compressor package

OIL AND NATURAL GAS

Natural gas and oil are found in reservoirs all over the world. Both oil and gas are contained in the pore spaces of the reservoir rock. Usually, reservoirs contain mixtures of lighter and heavier hydrocarbons, as well as CO2, water, and sometimes H2S. Some types of reservoirs allow the oil and gas to move freely, making it easier to recover. Other reservoirs restrict the flow of oil and gas and require special techniques to move the oil or gas from the pores to a producing well.

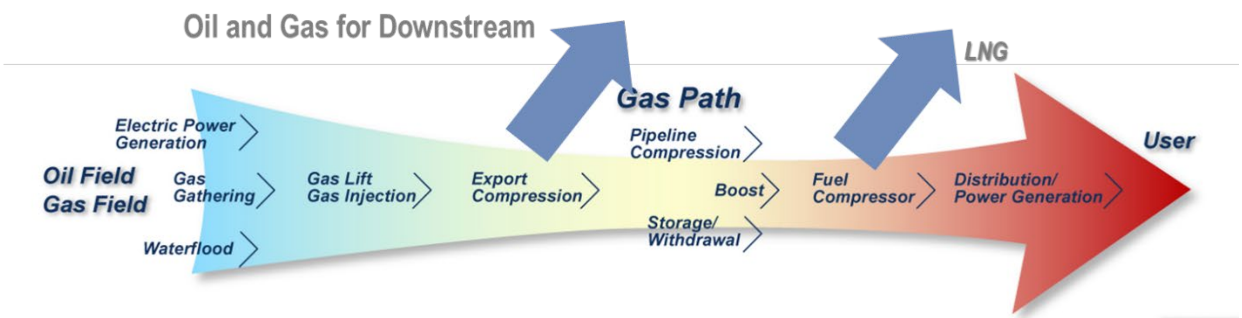


Figure 10: Natural gas from the well to the user

Even today, with advanced technologies, in some reservoirs more than two-thirds of the oil present may not be recoverable. Once an oil or gas reservoir is discovered and assessed, the task is to bring a sellable product to a user, as well as to maximize the amount of oil or gas that can ultimately be recovered. In the past, natural gas was often seen as a byproduct of the oil production, and may have been flared, especially if there was no infrastructure to bring the gas to potential users. However, even in situations like that, the gas can be used to enhance the recovery of oil. On the other hand, countries like the USA have built large networks of pipelines to bring gas from the well to users [6].

Figure 10 shows the path of the gas from well to user. In general, activities close to the oil and gas field are considered upstream, while activities involving the transport and storage of gas are considered midstream applications.

Figure 11: Offshore platform

Many oil and gas wells are on the ocean floor, and production requires an offshore platform (Figure 11) or subsea installations . The reservoirs are typically at elevated pressure. A series of valves and equipment ("Christmas Tree") is installed on top of the well, to regulate the flow of hydrocarbons out of the well. Early in its production life, the underground pressure will often push the hydrocarbons all the way up the well bore to the surface. Depending on reservoir conditions, this "natural flow" may continue for many years. When the pressure differential is insufficient for the oil to flow naturally, mechanical pumps must be used to bring the oil to the surface. This process is referred to as artificial lift [7].

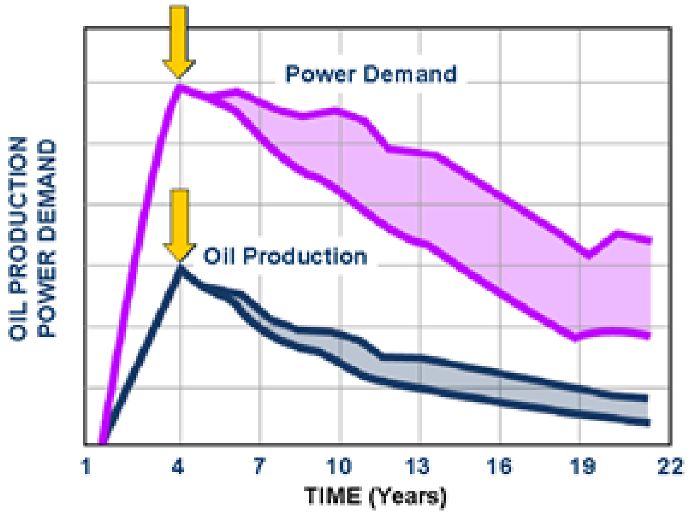


Figure 12: Typical change in oil production form an offshore well

Most wells follow a predictable pattern where production will increase for a short period, then peak and follow a long, slow decline (Figure 12). The shape of this decline curve, how high the production peaks, and the length of the decline are all driven by reservoir conditions. The decline curve can be influenced by cleaning out the well bore to help oil or gas move more easily to the surface, by fracturing or treating the reservoir rock with acid around the bottom of the well bore to create better pathways for the oil and gas to move through the subsurface to the producing well or by drilling additional wells or by employing enhanced oil recovery (EOR) techniques. The techniques collectively referred to as enhanced oil recovery (EOR) employ, depending on reservoir conditions, water injection ('water flooding') or the injection of various other substances (Hydrocarbons, steam, nitrogen, carbon dioxide) into the reservoir to remove more oil from the pore spaces to increase production.
When geologists began studying time-lapse seismic monitoring results ('4-D'), they were surprised to discover that one of the most basic notions about the movement of oil in a reservoir- that it naturally settles between lighter natural gas above and heavier groundwater below- oversimplifies the behavior of real oil fields. Actually, most wells produce complex, fractal drainage patterns that cause the oil to mix with gas and water. It also became clear that traditional techniques may leave 60% or more of the oil behind . This led to the strategy of pumping natural gas, steam, carbon monoxide or nitrogen into the reservoirs. This injection spreads through the pores in the rock and pushes oil that otherwise would have been abandoned toward the existing wells. Application where gas is injected into the oil reservoir for pressure maintenance and to enhance oil recovery by miscible flooding with lean (methane rich) gas are usually referred to as gas re-injection [7].

Most oil wells produce oil, gas, and water. This mixture is separated at the surface. Initially, the oil well may produce mostly oil with a small amount of water. Over time, the percentage of water increases. This produced water varies in quality from very briny to relatively fresh. Where this water cannot be used for other purposes, it may be reinjected into the reservoir — either as part of a waterflooding project or for disposal (returning it to the subsurface).
The oil is then sent to an oil treatment plant. There it is processed in a gas-oil separation system where its pressure is reduced in several stages. In each decompression stage the associated gas (also called flash gas) is released in a separator until the pressure is ultimately reduced to slightly above atmospheric pressure. The crude oil is then sent to a stabilizer column where it is heated and cascaded through a series of bubble trays spaced throughout the column. Hydrogen sulfide (if present) and remaining light hydrocarbons boil off in this process and are collected at the top of the column, while the sweetened heavy crude is drawn off from the bottom. The stabilized oil is then cooled and stored. The streams collected from the top of the stabilizer unit are treated in accordance with environmental regulations.

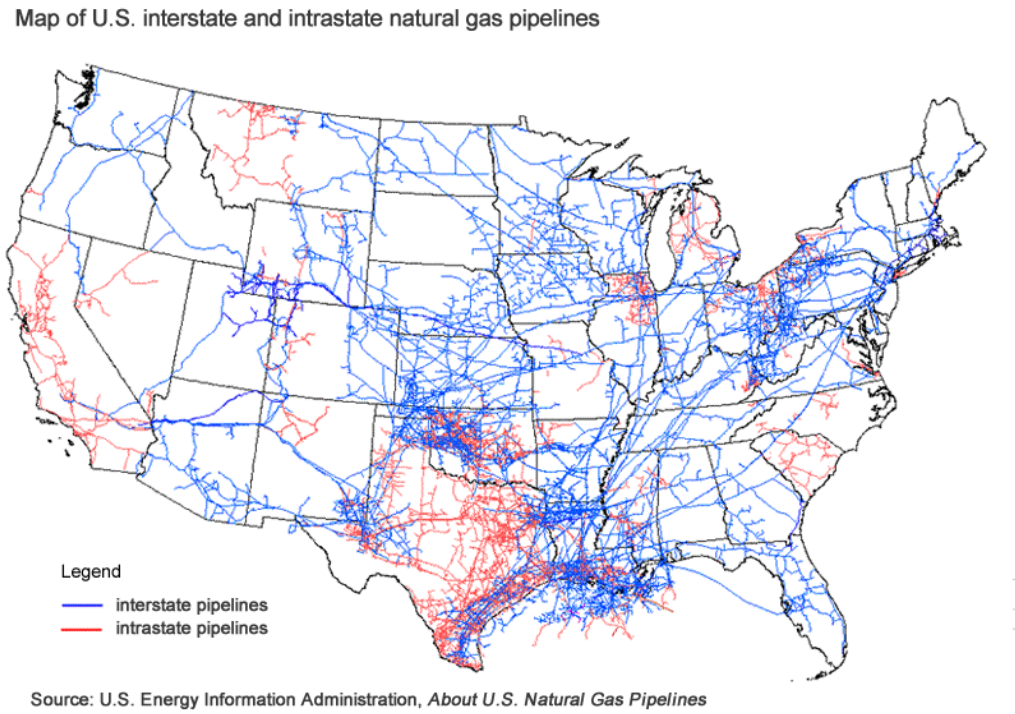


Figure 13: Transmission Pipeline Network

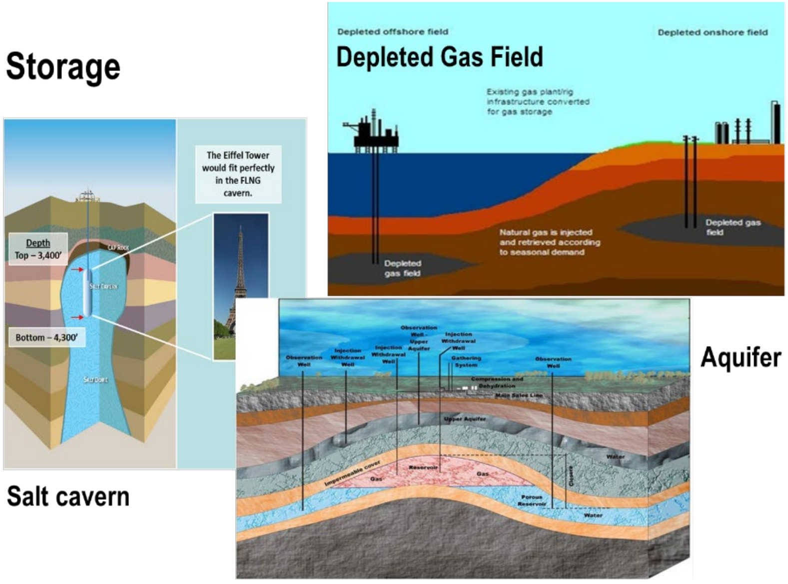


Figure14: Gas Storage

Natural gas wells do not produce oil but usually some amount of liquid hydrocarbons, which are called condensate. Natural gas liquids (ethane, propane, butane) are removed at a gas processing plant, along with other impurities, such as hydrogen sulfide and carbon dioxide. Natural gas liquids often have significant value as petrochemical feedstock. Natural gas wells also often produce water, but the volumes are much lower than is typical for oil wells.
Natural gas is usually transported through pipelines (Figure 13), except in cases where a pipeline cannot economically be built. In that case, the gas can be liquefied (LNG: Liquefied Natural Gas) and transported on a ship. As part of the transportation process in pipelines, gas can be stored in storage facilities, which often use former gas fields, or salt caverns. This allows to balance differences in supply and demand on a seasonal or daily basis (Figure 14) .

Usually, all applications upstream and including a gas plant are considered 'upstream' applications, while the applications related to bringing gas to the ultimate users are referred to as 'midstream'. Applications in refineries, chemical and processing plants are considered 'downstream' applications [6].

Typical Gases

The gas which has to be compressed usually consists of mixtures of light hydrocarbons (alkanes), nitrogen, and carbon dioxide. In many applications, especially midstream pipeline and storage applications, but also in many upstream applications, the dominant component is Methane. Often, especially in upstream applications near the well, the gas is saturated with water. Hydrogen sulfide may also be present. The gas may also have significant levels of CO_2, In refrigeration applications, heavier hydrocarbons may have to be compressed. The conversion of process variables (temperature, pressure, flow, gas composition) into variables relevant for the compressor (enthalpy, entropy, density) is performed using equations of state (EOS). Frequently applied EOS include Redlich-Kwong, Redlich-Kwong-Soave, Peng-Robinson [8], Lee-Kesler-Ploecker [9], the Starling version of the Benedict-Webb-Rubin model [10], and the AGA 8 adaptation in ISO20765-1[11].

Natural gas containing significant amounts of H_2S and CO_2 is usually referred to as sour gas (as opposed to sweet gas). A number of gas fields produce sour gas, and in many instances the removal of H_2S and CO_2 is part of the gas plant operation (see above). In some instances, sour gas is compressed untreated, in particular when it is used in gas re-injection applications[12]. In particular higher levels of H_2S can lead to sulfide stress cracking of materials in an aqueous environment. Carbon dioxide alone is inert and not corrosive. It has, however a high affinity for water, and when combined, forms carbonic acid, which corrodes carbon steel. In the presence of liquid water, H_2S and CO_2 form corrosive acids, and one of the issues when compressing sour gas into the dense phase region is that water can drop out if the temperature is lowered [12]. NACE MR0175 [24] provides information on requirements and recommendations for the selection and qualification of carbon and low-alloy steels, corrosion-resistant alloys, and other alloys for service in equipment used in oil and natural gas production and natural gas treatment plants in H_2S -containing environments, whose failure could pose a risk to the health and safety of the public and personnel or to the environment. It also defines limits for H_2S partial pressure in the gas, depending on the pH value of the environment, beyond which special material considerations apply. The high toxicity of H_2S also requires specific attention to avoid and detect leakages [9].

APPLICATIONS[1]

2.1 Upstream

Reservoirs

There are oil reservoirs and gas reservoirs, and all of them produce hydrocarbon mixtures, albeit at different mole weights. Many oil reservoirs also produce gas (associated gas), and many gas reservoirs also produce heavier hydrocarbons, called condensates.

Oil reservoirs can be either undersaturated, solution drive reservoirs, gas cap drive reservoirs, water drive reservoirs, or combinations of those. The distinction is primarily made by the mechanism that drivers the oil from the reservoir to the well. Undersaturated reservoirs tend to exhibit a rapidly declining reservoir pressure, and they produce very little, or no gas. Solution gas reservoirs also have a fast pressure decline, but produce gas. The produced gas to oil ratio is initially low, rises to a maximum, and then declines again. The reservoir pressure in gas cap reservoirs tends to fall relatively slow, with a continuously rising produced gas to oil ratio. Water drive reservoirs tend to maintain a high reservoir pressure, and produce little gas. All oil reservoirs will only produce a fraction of the oil contained in the formation, even with enhanced recovery methods, such as water (water flooding), steam or gas injection. Gas injection uses produced natural gas, or a miscible gas such as CO2 [13].

Gas reservoirs generally contain no oil, but produce gas, or gas with varying amounts of condensates or water. Typically, primary recover methods are sufficient for porous rock formation. Very tight formations (like shale gas) require fracking to essentially increase the porosity. Dry gas reservoirs produce mostly methane and ethane, with minor amounts of heavier gases. The gas pressure in the reservoir pushes the gas to the surface , and typically a choke is employed to control the flow rate. The gas pressure is reduced when the reservoir is produced. If the gas pressure required at the surface to be at 500 psi (for example, to be fed into a pipeline) , the reservoir flows gas until the reservoir pressure can no longer overcome this pressure. At that point , compression is necessary to further produce gas. Typically, production continuous until the pressure at the well head drops below 70 to 100psi.
Condensate reservoirs contain larger amounts of heavier hydrocarbons, such as propane, butane and pentanes. The can exist either as gas or liquid, depending on pressure and temperature.

Oil production or: What to do with the gas

Natural gas is often a by-product in the oil production. Since the major goal is to produce oil, the question becomes: what to with the gas. The first step is always to separate the oil (and water) from the gas (Figure 15). This separation is often done at about 60 to 100 bar. The problem is that the separation still leaves gas dissolved in the oil, and it leaves water vapor in the gas. To deal with the former, the pressure of the oil is reduced in one or several steps. At each step, the pressure reduction leads gas to flash from the liquid. The lower the pressure becomes, the heavier this flash gas becomes. This flash gas has to be recompressed, usually to about the same pressure as the gas leaving the production separator. The gas can now be used in different ways (Figure 16,17):

-Gas Lift
-Gas Re-injection
-Gas Export

[1] We have made an effort to use the definitions most widely used in the industry. However, some of the definitions are used interchangeably, and some applications might be combined in a single compressor, or compressor train.

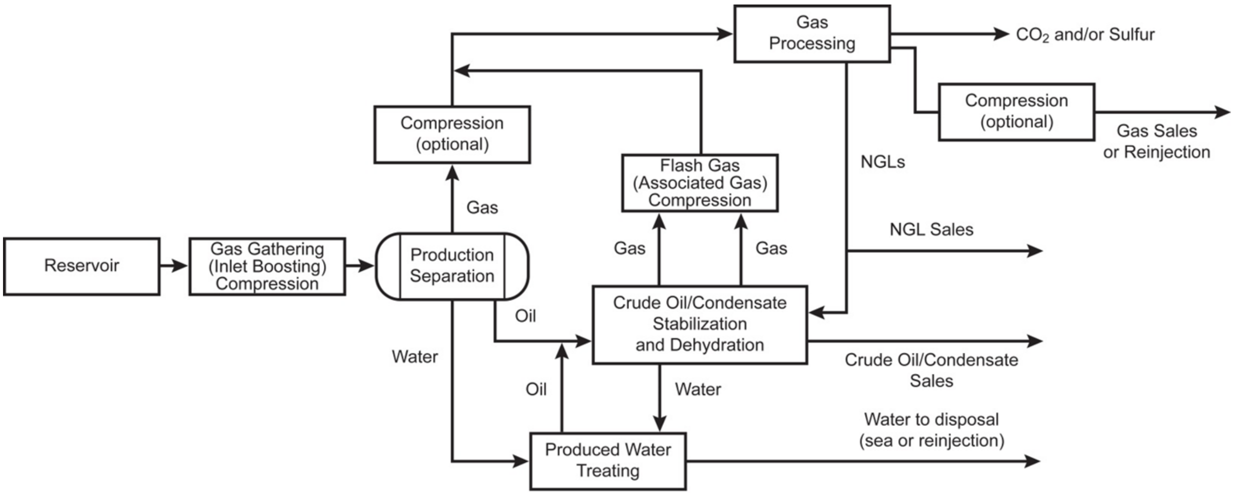


Figure 15: Oil/Gas Field Production steps. Associated Gas is found and produced in association with oil, non-associated gas is natural gas that is not in contact, or dissolved in oil.

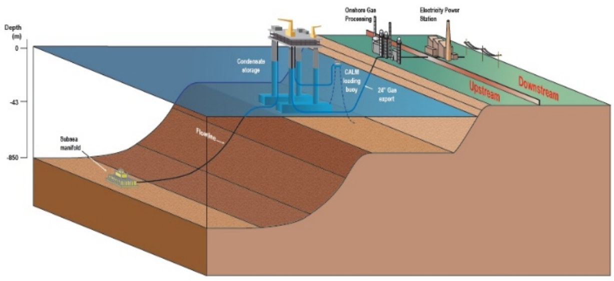


Figure 16 : Offshore platform with depletion compression (gas-reinjection), condensate stabilization (flash ags compression), export compression to onshore gas plant via subsea export pipeline.

Gas Lift (Figure 18)is a method to increase into the oil flow by injection gas into the well to aerate the crude, thus enhancing the flow of crude to the surface. Some operators use the same compressor train to both feed a gas lift service and export compression to feed gas into a pipeline. Gas Lift is a process in which produced gas is compressed to a higher pressure and recycled down the well casing and through gas lift valves into the tubing at a predetermined depth to lighten the column of liquid in the tubing, thus reducing the difference between the downhole pressure and the pressure at the well head. Compressor discharge pressures are typically 100 to 120 bar(1400-1700 psi), but sometimes up to 200bar (2900 psi) may be required for such applications, necessitating compressors with relatively high throughput and a high compression ratio.

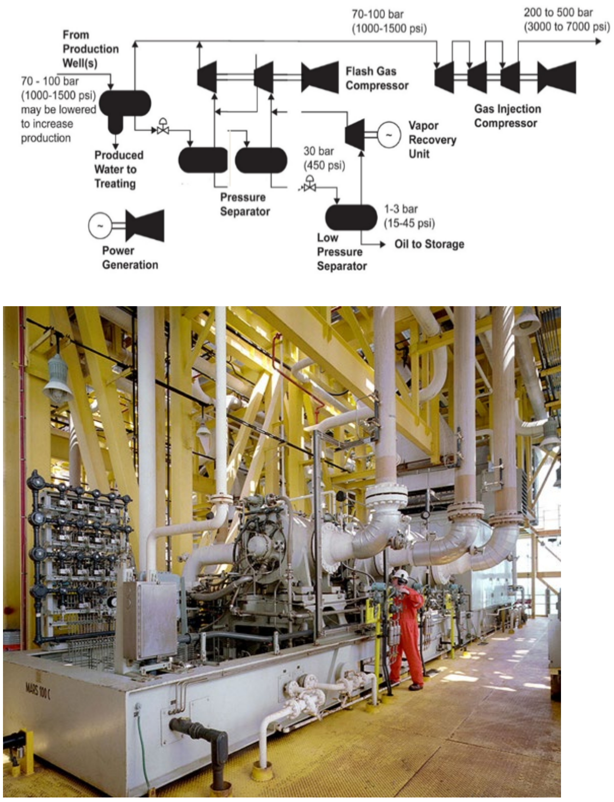


Figure 17: Flash gas Compression and Re-Injection

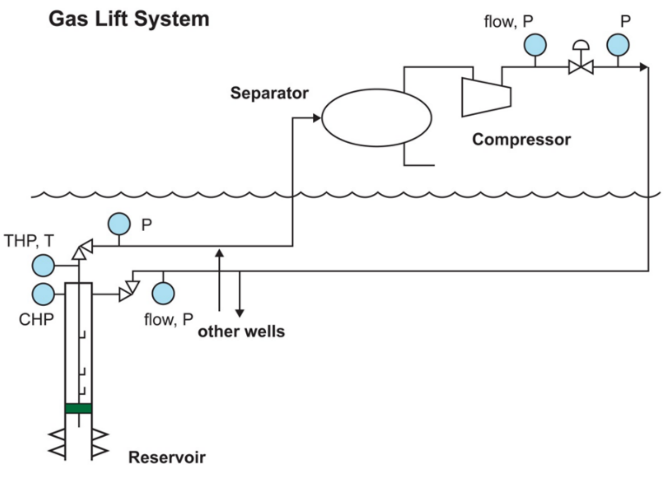


Figure 18: Gas Lift

Re-injection (Figure 16,17) is used as a method of enhanced oil recovery to compensate for the natural decline of an oil field production by increasing the pressure in the reservoir, thus restoring the desired level of production and stimulating the recovery of additional crude oil. Using this technique the field exploitation can be increased by up to 20%. The gas that is re-injected is usually the associated gas separated from the crude oil in the flash and stabilization phases. Other gases, such as nitrogen, or carbon dioxide, may also be used. The gas is re-injected into the reservoir in dedicated wells and forces the oil to migrate toward the well bores of the producing wells. Gas Injection projects may also involve the injection of CO2 or Nitrogen into the reservoir. Especially for deep reservoirs, very high compressor discharge pressures (140 to 820 bar (2000 to 12,000 psi)) are required. Due to the high aerodynamic forces the gas can exert on the rotors, these compressors are challenging from a rotordynamic standpoint. Recent material technology advances allow associated sour gases containing high percentages of H_2S and/or CO_2 to be re-injected without the need for sweetening. Depending on the depth and physical characteristics of the field, very high injection pressures may be required. High pressure barrel compressors are normally used in this application [6].

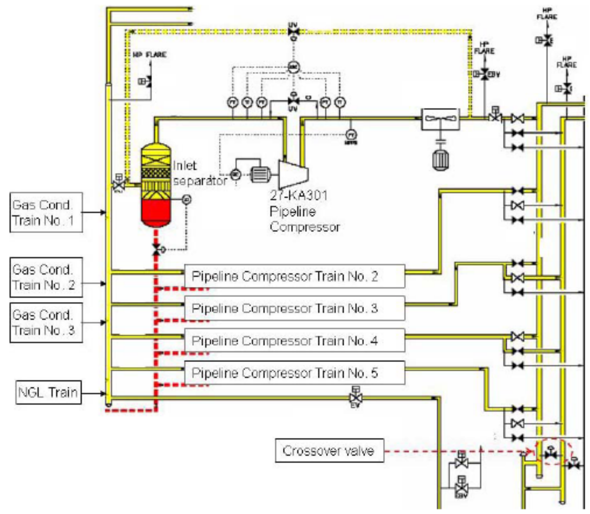


Figure 19 :Gas Export Compression from offshore platform [14] .

Export Compression (Sales Gas Compressor, Figure 19): If the platform or the oil field is reasonably close to a potential consumer of the gas, it may be exported via a pipeline. Export gas is compressed to feed a sub sea pipeline (on an offshore platform) that transports the gas to shore. Discharge pressures are often high (typically 70 to 140 bar(1000 to 2000psi), but sometimes up to about 200 to 240 bar (3000 to 3500psi) to reduce pipe diameter, and also because usually the gas cannot be recompressed between the platform and the shore (Figure 14). Depending whether this compressor gets gas at well pressure, or whether there is a gas gathering train upstream, configurations can vary from machines with only a few stages to triple body trains [6].

Export compressors are also used in gas fields, for the same purpose.

Trade-offs are often the required compression power on the platform versus cost of the pipeline especially if pressure is not dictated by already existing systems. In many applications, the gas contains significant amounts of heavier hydrocarbons, and a concern is the formation of liquid slugs in the flow line, where dropping gas temperatures may lead to condensation.

In all the aforementioned applications, the water that stayed in the gas as a vapor can cause problems, since at high pressures and low temperatures, the water either can drop our as a liquid, thus creating corrosion problems, or form hydrates which may clogg flow lines. The task is therefor to remove water vapor in a dehydration unit (Figure 20)

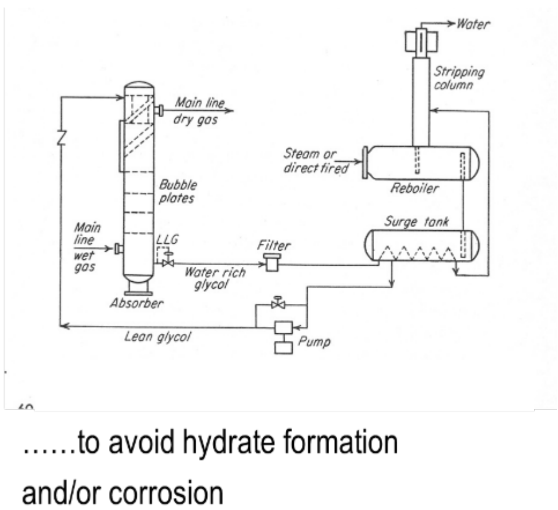


Figure 20: Water removal to avoid hydrate formation and corrosion

Dehydration units are designed absorb water vapor by using liquids like Triethylenglycole (TEG). The liquid can then be separated, and the absorbed water can be removed from the TEG by heating.

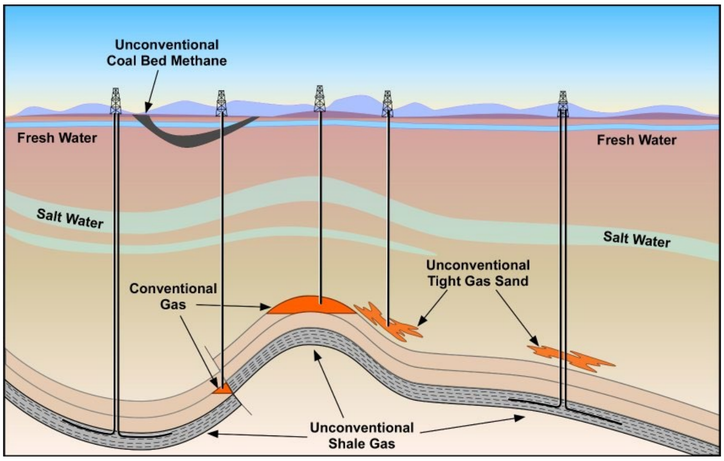


Figure 21: Different gas reservoirs

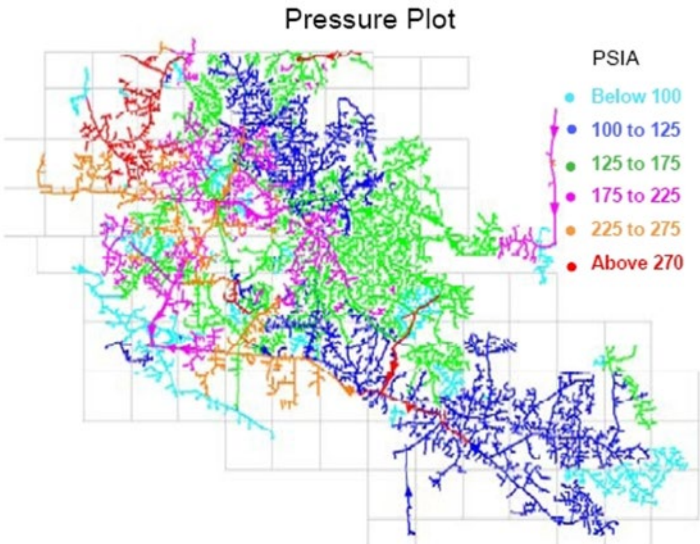


Figure 22 : Gas Field with a network of low pressure pipes

Gas Field

Gas fields (Figures 21,22) produce gas of various compositions:

- Dry (Lean) Gas
  - Water dry (no condensable water)
  - Gas with little or no heavier hydrocarbons that could be recovered as condensates
- Condensate
  - Heavier Hydrocarbons in a gas field that form liquids by precipitation (mostly pentane and heavier)
- Wet Gas
  - Contains condensable hydrocarbons

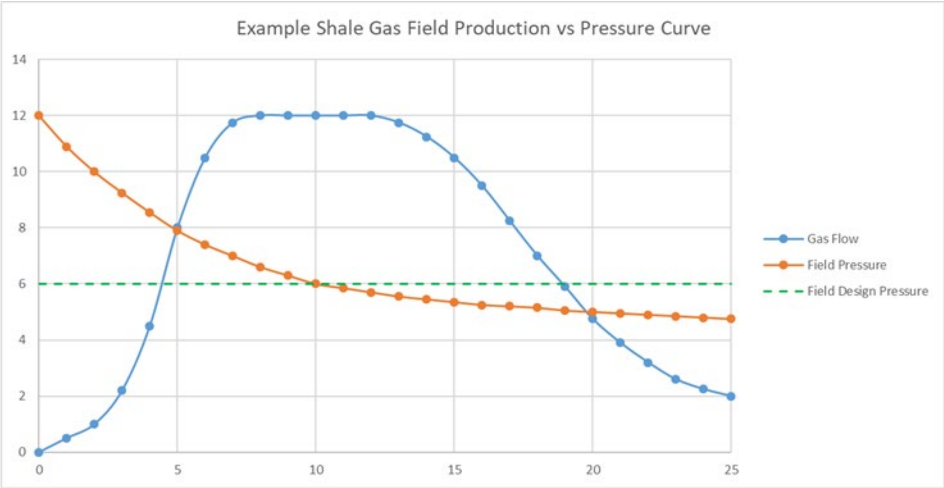


Figure 23: Gas well production profile

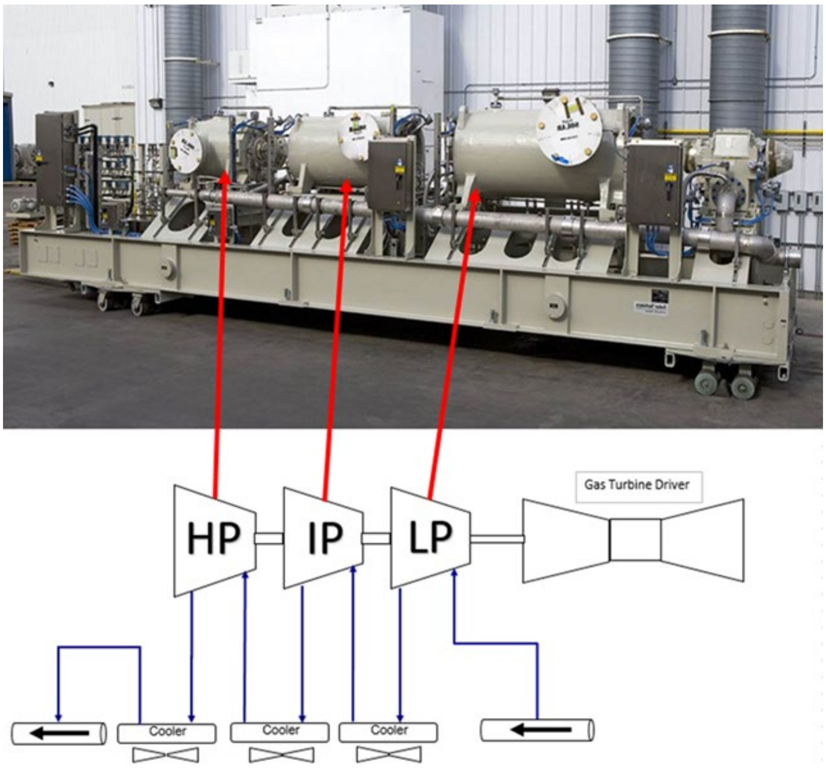
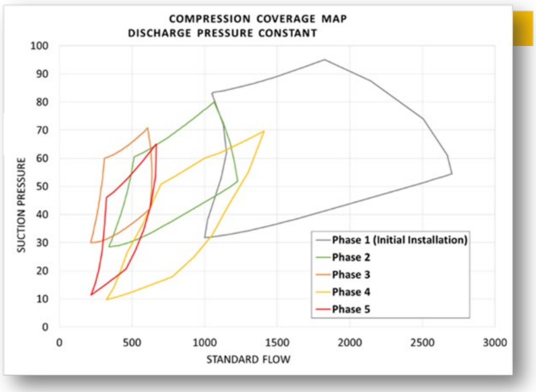
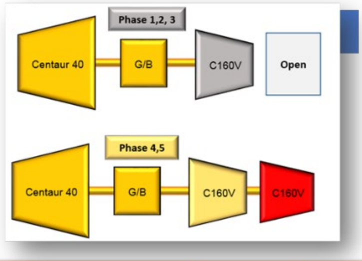


Figure 24: Gas gathering compressor train

As described earlier, for may gas formations, the well head pressure drops (Field pressure in Figure 23) relatively fast, and, in order to produce a large fraction of the gas in the field, additional wells have to be drilled, and gas gathering compression has to be applied [15]. This compression duty sees low suction pressure (3 to 15 bar), and has to bring the gas pressure to about 80 to 100 bar. The compressors have to able to handle the fact that both the gas flow and the suction pressure will decline over time, while the discharge pressure stays relatively constant. Pressure ratios are high, so intercooling between compressor bodies is important. (Figure 24). Depending on the rate of field decline, compressors are either sized for the final pressure conditions, or compressors are restaged. The approach with 2 or 3 individual compressor bodies has the advantage that the train can be optimized for the lower pressure ratio and higher flow in the early live of the field, with a single compressor body, and an additional body can be added to optimize for the high pressure ratio and low flow in later years (Figure 25).



	Compressor 1	Compressor 2
Phase 1	Higher Flow/Field Pressure	None
Phase 2	Medium Flow/Field Pressure	None
Phase 3	Low Flow/Medium Pressure	None
Phase 4	High Flow (Reuse Phase 1)	Medium flow (Reuse Phase 2)
Phase 5	Medium Flow (Reuse Phase 2)	Low Flow (Reuse Phase 3)

Figure 25: Declining Gas Filed

The discussion on wet gas compression (ie compressing gas that carries liquids) has drawn significant attention. Performance prediction for compressors becomes difficult, because a two phase mixture at the inlet, and possibly at the compressor discharge requires to account for evaporation effects and the resulting changes in flow and temperature in the compressor (Figure 26). The possibility of liquid slugs also creates risks for the machine due to transient thrust loads, or due to erosion from large droplets.

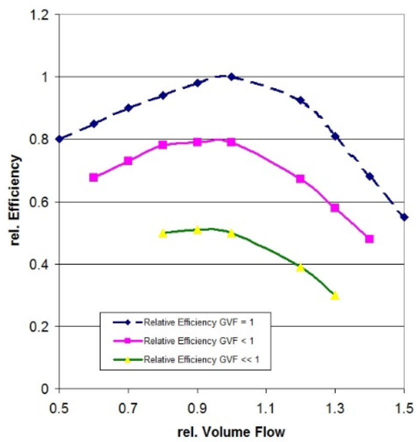


Fig 26: Compressor efficiency for different gas volume fraction (GVF) [16].

Gas Plant Compression

Gas Plants (Figure 27)are designed to produce dry export gas (i.e. gas with very little water, a low hydrocarbon dewpoint, limited amounts of CO2 and other contaminants) and LPG products (Ethane, Propane and Butane). For the range of gas compositions at the inlet, the plants have specified recovery targets for the heavier hydrocarbons. The process steps inside the plant (Fig 16) include: Primary Separation, Front End Compression (Boost Compression, Inlet Compression),Carbon Dioxide Removal, Mercury/Chloride Removal, Gas Dehydration, Gas Expansion (Turboexpander), LPG/Condensate Fractionation, Dry (Sales) Gas Compression, Storage and Utilities [6].

In a gas plant, several compression duties have to be covered:
-Boost Compression (Inlet Compression) to bring the gas from delivery pressure (from the gas gathering system) to plant pressure
-Recompression (Sales Gas Compressor) to bring the natural gas from plant pressure to pipeline pressure, with a suction pressure of 15 to 30 bar, and a discharge pressure of about (depending on the pipeline70 to 100 bar) This duty may also be referred to as pipeline head station (essentially depending on whether the compressor is operated by the gas plant or the pipeline operator)
-Turbo expander/Compressor for the low temperature cryogenic cycle

For the removal of CO2 in a gas plant typically either amine processes, or membranes are used (Fig 28). The

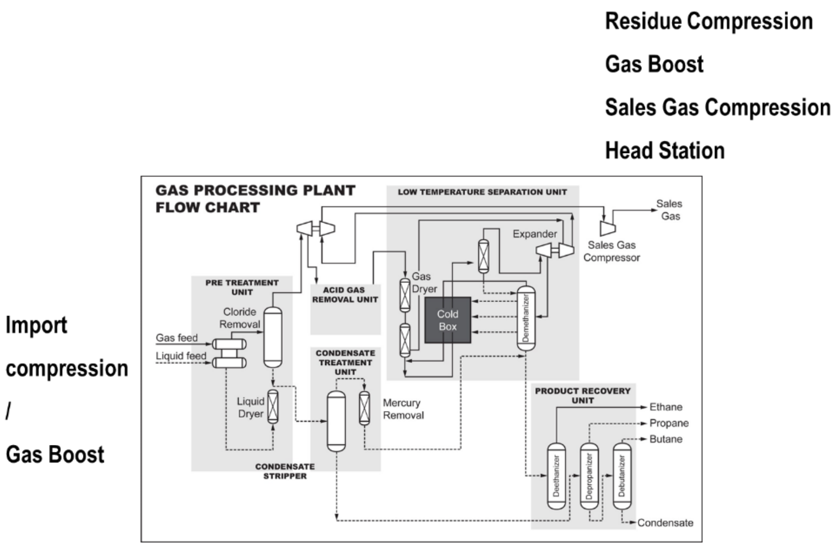


Figure 27: Gas plant

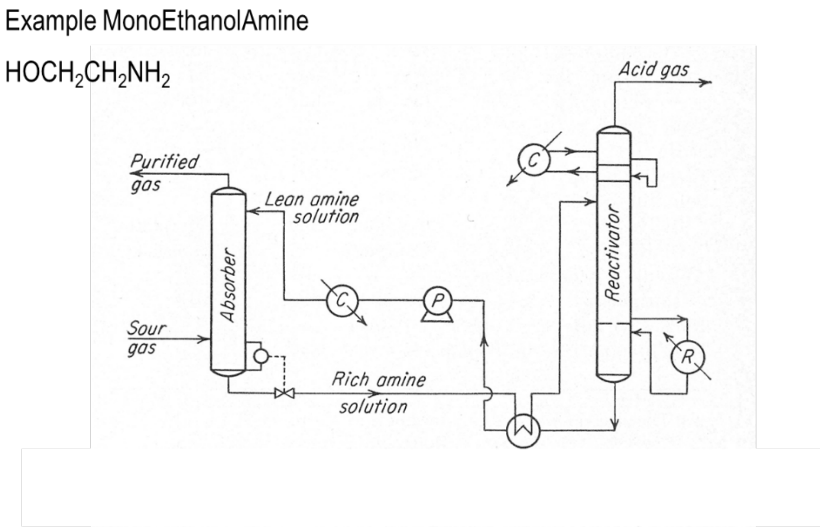


Figure 28: Amine process for CO_2 and H_2S removal (using Mono-ethanolamine $HOCH_2CH_2NH_2$)[6].

The necessary removal of CO_2 is performed in an absorber, where a liquid amine solution is sprayed in the gas column, and absorbs the CO_2 . The rich amine solution can then be heated, thus separating the amine from the CO_2**.**
In many instances, the exhaust heat from a gas turbine can be used as a heat source for this process. After the heating in the reactivator, the amine can be reused.

2.2Midstream

Transport of gas in pipelines is a very effective way of transporting energy over large distances. However, gas flowing in a pipe suffers from pressure losses that increase with flow velocity and the length of the pipe (Figure 29). Every 50 to 100 miles , a compressor station (Figure 29) is necessary to recompress the gas and compensate for the pressure losses. In general, operation as close as possible to the maximum operating pressure of the pipeline reduces power requirements for the compressors, and thus fuel consumption (Figure 30). Therefore, the distance from station to station is subject to careful optimization [17]: The closer the stations are spaced, the lower the pressure ratio per station, as well as the overall pipeline power consumption. On the other hand, the capital expenses increase.

Figure 29: Pipeline Compressor station with 23 compressor trains in parallel

Optimal pipeline pressures, depending on the length of the pipe, as well as the cost of steel, are in the range of 40 to 160 bar (600psi to 2200 psi) balancing the amount of power required to pump the gas with the investment in pipe. Most interstate or intercontinental pipeline systems today operate at pressures between 60 to 100 bar (1000 and 1500 psi), although the pressures for older systems might be lower. The pipeline compressors are arranged in regular distances along the pipeline, usually spaced for pressure ratios between 1.2 and 1.8. The distance between compressor stations is, besides geographic necessities, usually driven by an optimization for CAPEX and OPEX , which allows to determine the best pipeline diameter, number of stations and the station pressure ratio (Figure 31). Higher pressure ratios than normal are found if the pipelines operate in remote areas, or sub sea. Some pipelines transport gas over large distances, without significant gas takeoffs along the way and relatively constant operating conditions, while other pipelines from part of an intricate network with a variety of feeders, and take offs along the line. Here we often find compressor stations with a variety of different sizes and types of compressors and the pipeline operating conditions often see large daily, and hourly fluctuations. For any type of pipeline, the driver power, and its dependency on ambient conditions plays a major role in planning and station layout.

The gas usually has to be compressed to pipeline pressure in a head station (usually coming from a gas plant). This head station often sees pressure ratios of 3 or more.
Sub sea pipelines often only have a head station (often referred to as export compression), but no stations along the line. They are either used to transport gas to shore from an offshore platform (see export compression), or to transport gas through large bodies of water. In either case, relatively high pressures (100 to 250 bar, 1500 to 3700psi) are common [17].

A few onshore pipelines worldwide make use of the added compressibility of the gas at pressures above 140 bar (2000 psi ,depending on gas composition) and operate as 'dense phase' pipelines at pressures between 125 and 180 bar(1800 and 2500 psi). Not only natural gas is transported in pipelines, but also CO_2. CO_2 is non corrosive, as long as it is dehydrated. Most applications transport CO_2 in its dense phase, at pressures above 140 bar(2000psi), in particular to avoid two phase flows when ambient temperatures drop.

The gas pressure in a pipeline is reduced due to the friction losses. These losses depend on the flow velocity of the gas in the pipe. The compressors in the compressor station take the gas from arrival pressure, and recompress (or boost) it back to the pipeline operating pressure. For a given pipeline, this means that the more gas goes through the pipeline, the higher the pressure ratio in the compressor station becomes (Figure 3, 32). Many pipelines operate under constantly changing operating conditions, so that a steady operation is rare. Therefore, the true operating conditions in a compressor station are requiring a wide operating range of the compressors (Figure 33) [1,6]
If the throughput of a pipeline has to be increased, two possible concepts can be used: Building a parallel pipe (looping), or adding power to the compressor station (i.e. adding one or more compressors to the station), or a combination of both. These means can also be combined. If power is added to the station, the discharge pressure can be increased (assuming this is not already limited by the pipeline maximum operating pressure). The station will therefore operate at a higher pressure ratio. The added compressors can either be installed in parallel, or in series with the existing machines. If the pipeline is looped, the pressure ratio for the station typically is reduced, and the amount of gas that can be pumped with a given amount of power is increased. In either scenario, the existing machines may have to be restaged (for more pressure ratio and less flow per unit in the case of added power , for more flow and less pressure ratio in the other case.

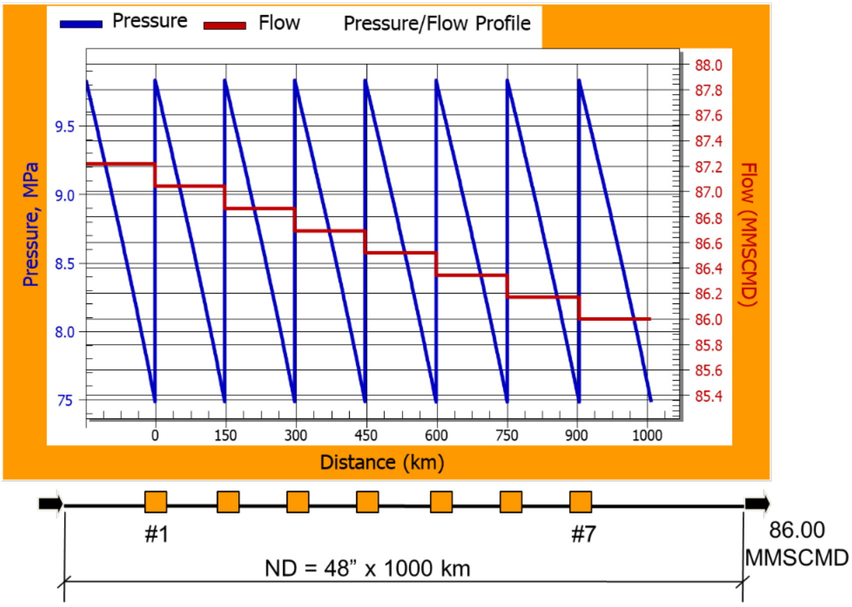


Figure 30 : Pressure and Flow in a Pipeline

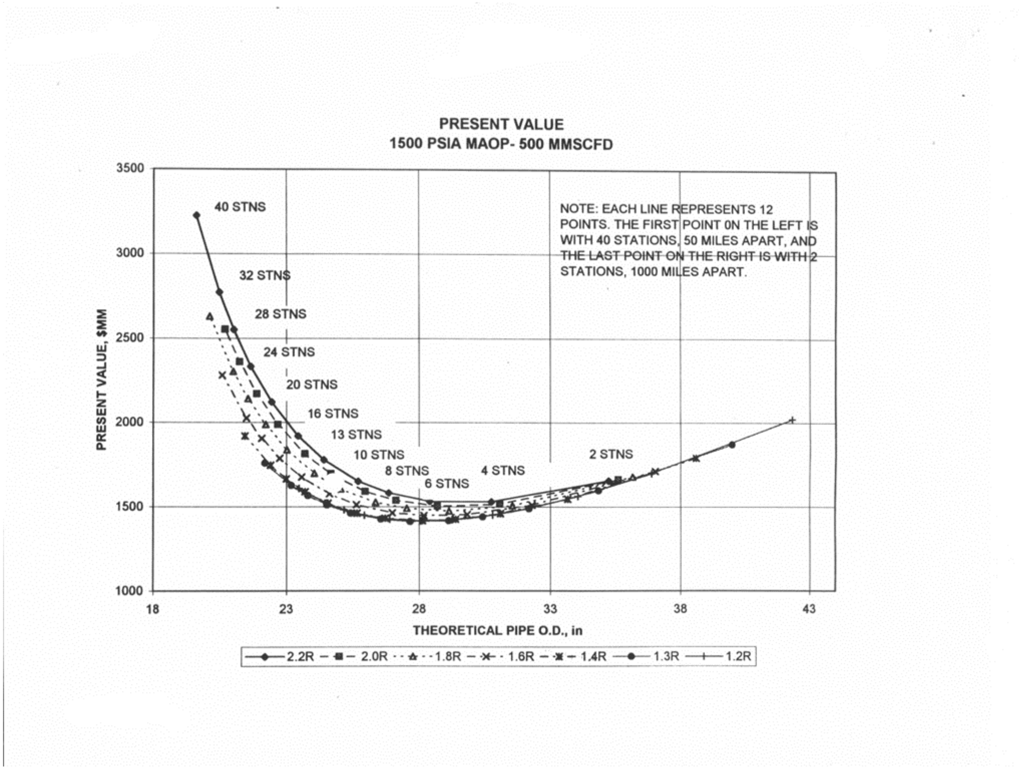


Figure 31: Pipeline design considerations

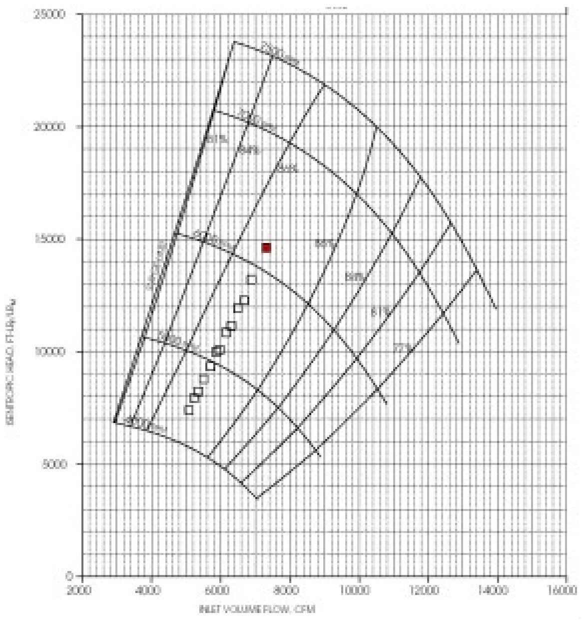


Figure 32: Pipeline operating conditions-Steady sate

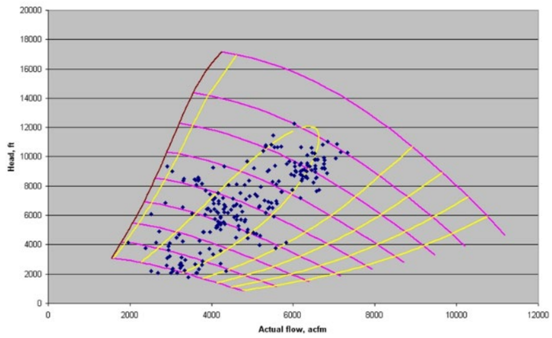


Figure 33 : Upstream and Midstream: the Myth of the design point

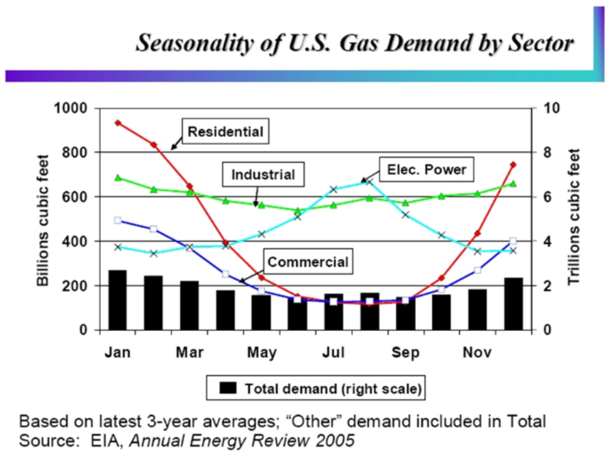


Figure 34: Seasonal change in gas demand , and the need for gas storage

Gas Storage

The first natural gas storage facilities date back to the early 20th century in the US and Canada. They were used to provide local natural gas supply during the winter heating season. This became necessary because the high demand in winter frequently exceeded the capacity of the local pipeline and production infrastructure (Figure 14, 34). The introduction of a gas spot market in the mid 80's has led to an increased demand for gas storage facilities. Currently, there are over 400 facilities in North America, and over 130 in Europe in operation. The vast majority of these gas storage facilities uses depleted hydrocarbon reservoirs, aquifers or salt caverns for storage .The former two options involve storage in porous rock layers, while the latter is created by washing a cavity out of a salt dome. These types of storage facilities are very safe, preventing reliably leaks or other safety hazards. In either case, the pipeline company injects natural gas into the storage field when demand is low and withdraws it from the storage field during times of high demand [18].

Historically, storage was used to respond to the peak needs of cold winter days. Natural gas demand used to be at its highest in winter, primarily due to home heating requirements (Figure 34). In recent years, however, mostly due to increased demand from natural gas fired power plants, demand has become less seasonal. Because of this shift, well-placed natural gas storage has become even more important to natural gas operations.
Today, North American natural gas storage plays a key role in balancing supply and demand, particularly consumption during peak-demand periods.
Storage can reduce the need for both swing natural gas production deliverability and pipeline capacity by allowing production and pipeline throughput to remain relatively constant. Customers may use storage to reduce pipeline demand charges, to hedge against natural gas price increase, or to arbitrage gas price differences.

Pipelines and local distributors use storage for operation flexibility and reliability, providing an outlet for unconsumed gas supplies or a source of gas to meet unexpected gas demand.

Storage at market trading hubs often provides balancing, parking, and loan services.
In the future, additional conventional storage will be needed to meet growing seasonal demands and high deliverability storage will be required to serve fluctuating daily and hourly power plant loads.
Gas supply and demand in many pipeline systems shows significant seasonal changes, which is further aggravated by the periodic influx of liquefied natural gas. Gas storage facilities, where gas is stored during times of low demand or high supply, and removed during times of high demand or reduced supply are an important means in managing the gas supply.

Gas compressors are required to inject gas from a pipeline into the underground for storage, and to extract gas from the storage and feed it into the pipeline. Typical pipeline pressures range from 40 to 100 bar (600 to 1500 psi), and from this pressure, the gas has to be compressed to final storage pressure, typically between 100 and 200 bar (1500 and 3000 psi). The compressor duty is cyclical in nature. Traditionally, the cycles were seasonal, with fluctuating pipeline and storage pressures gradually changing during the course of the season. However, under spot market activity conditions, daily demand cycles, market conditions, or short term weather patterns can require a facility to change their operating patterns several times a day.

Gas compression has to be used to fill the storage facility, as well as to recompress gas when the facility is emptied. The compression task is therefore described as filling a large, constant volume with gas, with the limiting factor being the available driver power (Figure 35). The resulting operating conditions for the compressor are: Initially, the low pressure ratio allows for high flow conditions. The pressure ratio has to increase with an increasing amount of gas in the facility, therefore reducing the possible flow for a power limited compression system (Figure 35). This can be elegantly accomplished with multiple compressors, capable of operating either in a series or a parallel configuration The multiple compressors can either be driven by multiple drivers, or in a tandem configuration, by a common driver (Figure 35)

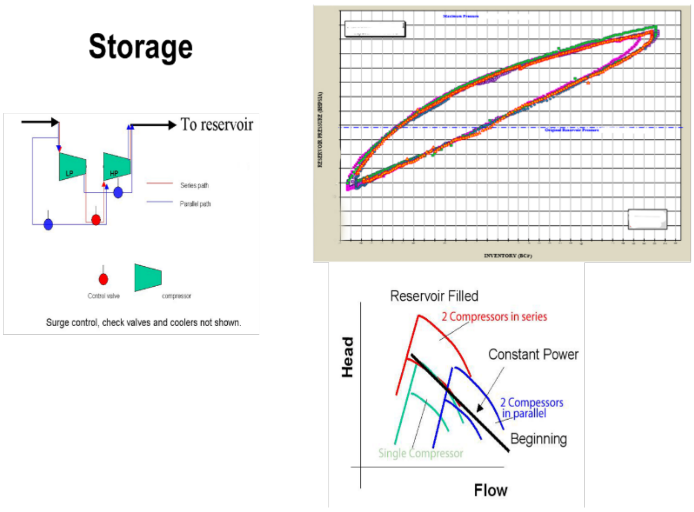


Figure 35 : Gas storage

2.3 LNG

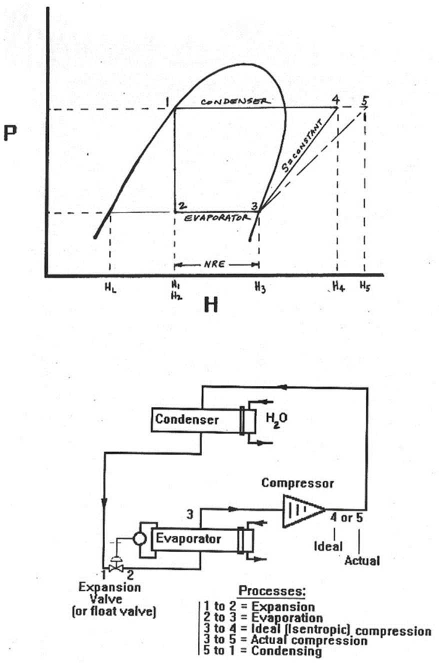
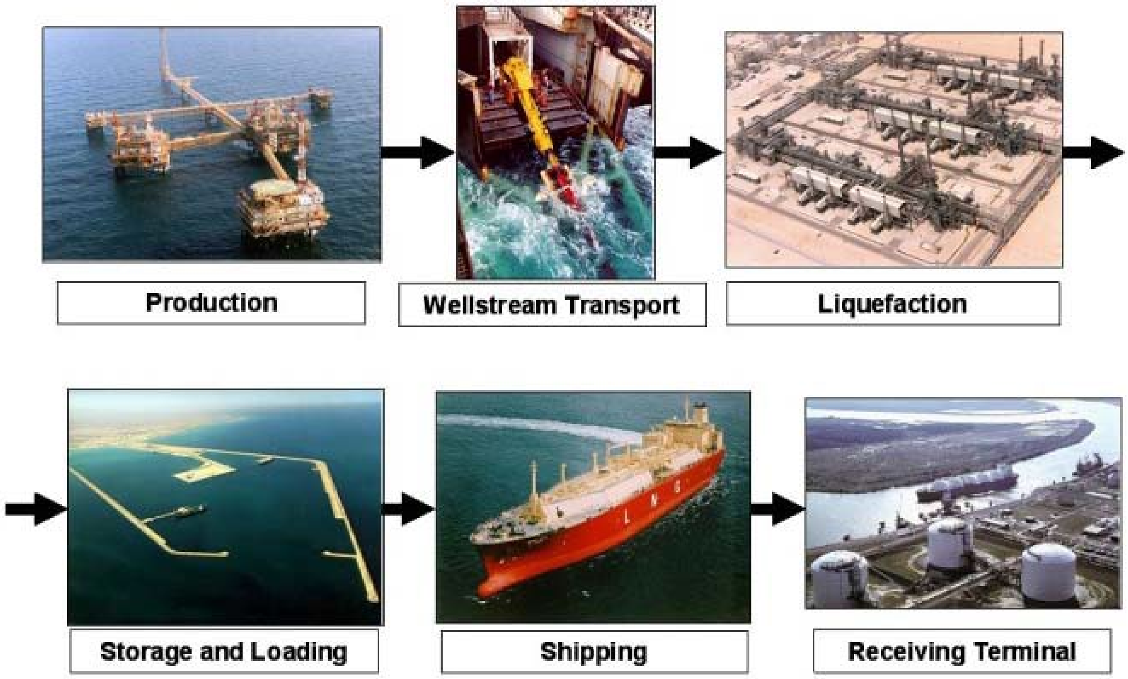


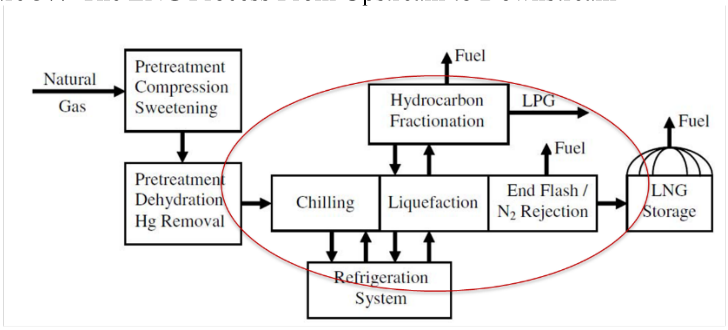
Figure36: Basic Refrigeration Cycle

LNG is essentially large scale refrigeration (Figure 36) to -160 C (-260 degF) , which is the temperature required to liquefy natural gas. Although pipeline quality gas is used, CO_2, water and H_2S are removed for liquefaction. LNG product is methane + some heavies (1000-1100 Btu/scf). The volume reduction from gas to liquid = 600:1. The LNG process evolved from small scale refrigeration compressors powered by steam turbines (1969 was first commercial LNG export by Conoco Phillips from Alaska). Modern plants are built in large scale capacities of 4.4-8.8 MMtpy capacity with GT or EM driven centrifugal compressors. (5.0 MMTPY~ 65 MW compression hp) The LNG process has to be looked at as not simply the LNG production plant but the entire process from wellhead to consumer as shown in Figures 37 and 38 [1,7].



(Courtesy ExxonMobil Corporation)

Figure 37: The LNG Process From Upstream to Downstream



Several separate gas streams: **- Natural Gas (to be Liquefied)**

- Refrigeration Gas(es)

- Fuel Gas

Figure 38: LNG Processing

Specialized turbomachinery designs are required for large scale refrigeration cycles in LNG applications, pushing the envelope of the centrifugal compressor design flows, the cryogenic heat exchanger size and the horsepower rating of the refrigeration drives.

Over the past fifty years, the refrigeration cycles and drivers have continuously evolved to meet the needs of ever larger LNG plants.

As the train size has leveled off and material costs continue to rise, many operators have “standardized” on two types of refrigeration cycles. These cycles effectively dictate the compressor selection and horsepower requirements:

- The APCI Split MR cycle (Split C3MR): Requires two large industrial Frame 7E turbines or synchronous electric motors in the 72-80 MW range.
- The ConocoPhillips Optimized Cascade (CoP OC) cycle: Requires six, 30 MW-range gas turbines or electric motors.
- Other refrigeration cycles: May be closely or equally competitive in terms of efficiency, but difficult to justify given the risk of new technology qualification.

Figure 39 shows the mixed fluid cascade LNG cycle and Figure 40 shows LNG cycle selections over the last 30 years.

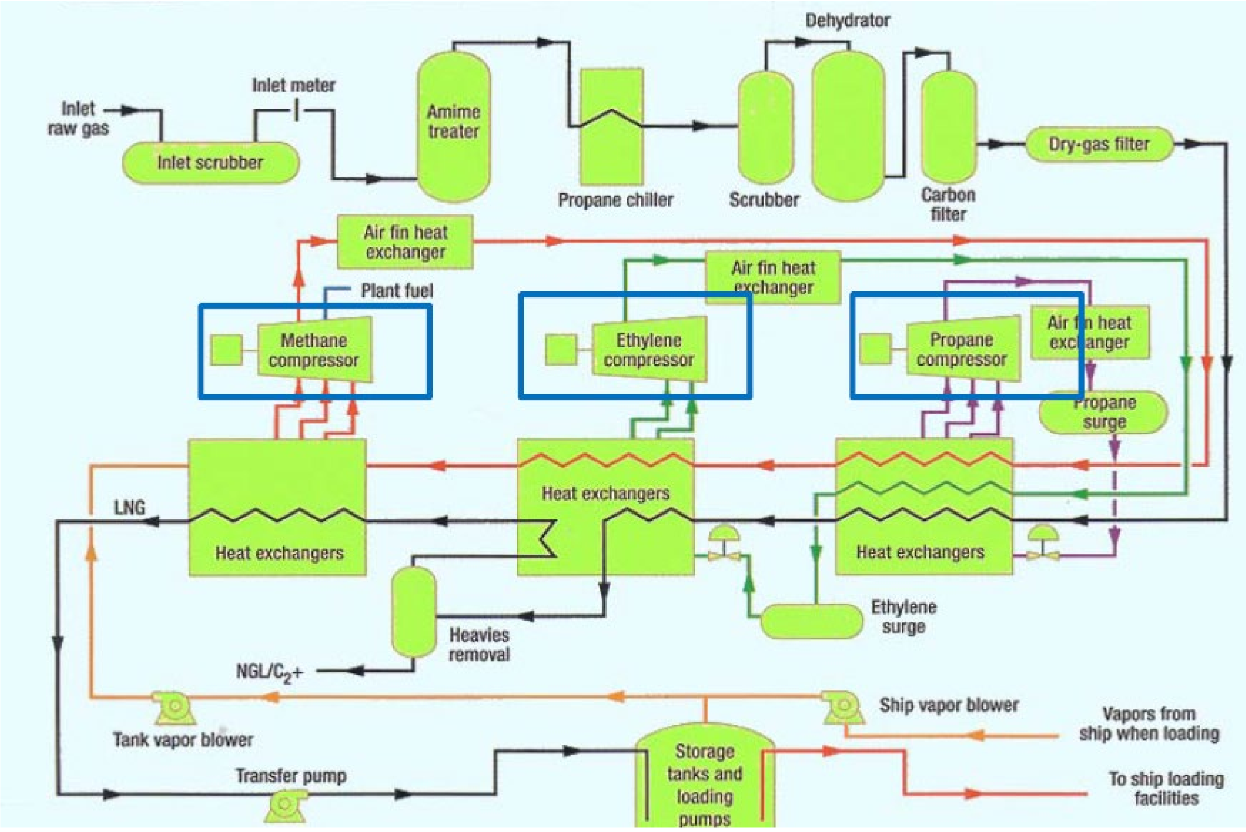


Figure 39: Mixed Fluid Cascade LNG Process

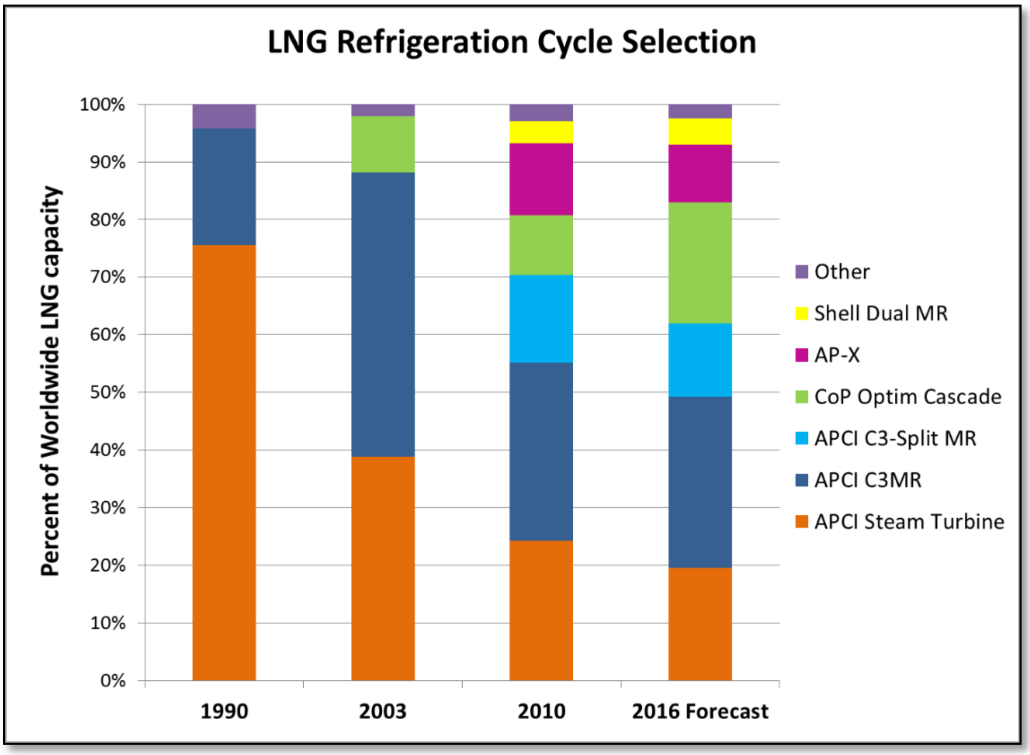


Figure 40: LNG Refrigeration Cycle Selections

True standardization will never be fully possible for LNG plants since each LNG facility must confront unique site development issues, electrical power options (or lack of), construction execution plans and the associated modularization strategy, and its own project economics.

LNG Turbomachinery

The evolution of LNG plants and the related turbomachinery can be divided into distinct time periods:

1. Steam Turbine Drive Era (1970-1989) = Early LNG: Improvements were mainly in terms of train capacity increases, gaining savings through economies of scale.

2. Gas Turbine Drive Development (1990-2009) = Efficiency Gains and Cycle Improvements: New gas turbine validation and cycle innovations pushed efficiency gains, but train capacity began to level off.

3. Recent (2010-current): Higher capital costs and reliability concerns have dictated driver and cycle selection and resulted in more uniformity. Electric motor drive precedent has now been set but still needs further development. A case for smaller train capacities have also driven users to install mid-size aero-derivative turbines instead of frame units. The modern era for LNG plants has just begun and will be determined by the next twenty year cycle.

The typical LNG process turbomachinery can be divided into three steps:

Step 1
Pre-cooling: Propane compressor, Typically largest flow rates and largest hp required.
60-70 MW for 4.5-5.5 Mmtpy. Pushes the limits of electric motor and variable speed drives.
Step 2
Primary Liquefaction: Ethylene or Mixed Refrigerant compressor.
May involve 2-4 stages of compression, 45-55 MW for 4.5-5.5 Mmtpy. Side streams typically used with interstage cooling. Use of more stages can help plant flexibility.
Step 3
Sub-cooling and Plant Fuel Compression. Smallest and simplest design / drive.

Some important considerations for LNG turbomachinery include:

- LNG compressors typically run over a very tight range (+/- 10%). GT emissions and efficiency can be well controlled within this range.

- Size of drive equipment may limit EMD selection to maximum of 65-70 MW for VFD technology to date.
- Emissions / environmental sensitivity of area may restrict GT option although electric power on site for EM can be a challenge.
- Variable speed EMD often considered for ease in starting motor and capacity / speed changes.
- Significant Process interdependencies
- Propane is a heavier MW gas compared to pipeline NG with higher SOS. This changes centrifugal compressor design somewhat.
- Operational range more consistent than upstream or pipeline applications so efficiency of drivers can be exploited to an extent.
- Large flow rates and equipment size, related maintenance strategies for large trains.
- Sidestream and intercooling designs: Differing strategies on mixing sidestream with large axial passage versus injection nozzles with greater mixing and also higher DP. Design predictions must be accurate to match process through-put.
- High flow coefficients and high Mach numbers produce narrow flow maps with limited choke and surge margin.
- Higher sensitivity to choke conditions and increased dynamic forces on blades.
- Importance of robust surge control system design.

Besides large scale LNG development, there is also a market for smaller scale LNG, in the range from 0.1 to 0.5MMTPA. They support efforts to use stranded gas reserves, or to provide an attractive fuel for vehicles, E&P efforts, locomotives, or ships. These smaller installations usually use less capital intensive refrigeration cycle, like the Single Mixed Refrigerant (SMR) cycle, or a reverse Brayton cycle, using Nitrogen or Nitrogen mixtures as refrigerant. The single mixed refrigerant is usually a mixture of methane, ethylene and other hydrocarbons (Figure 41).

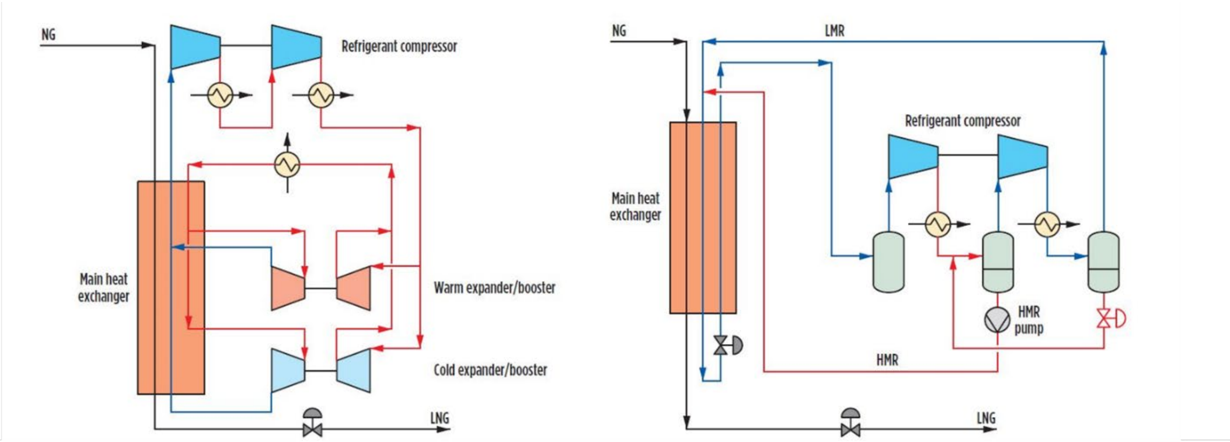


Figure 41: Nitrogen (left) and Single Mixed Refrigerant(right) LNG refrigeration cycles [19]

2.4 Downstream

Refinery Function

A petroleum refinery is an industrial process plant where crude oil is transformed and refined into more useful products such as petroleum naphtha, gasoline, diesel fuel, asphalt base, heating oil, kerosene, liquefied petroleum gas, jet fuel and fuel oils. Petroleum refineries are generally large industrial complexes that involve many different processing units, machinery, and auxiliary facilities such as utility units and storage tanks. Each refinery has its own unique arrangement and combination of refining processes largely determined by the refinery location, desired products and economic considerations. An oil refinery is considered an essential part of the downstream side of the petroleum industry. Some modern petroleum refineries process as much as 800,000 to 900,000 barrels (127,000 to 143,000 cubic meters) of crude oil per day.

Raw or unprocessed crude oil is not generally useful in industrial applications so it must be refined into consumer and industrial products for transportation, heating, and chemical processing. Oil can be used in a variety of ways because it contains hydrocarbons of varying molecular masses, forms and lengths such as paraffins, aromatics, naphthenes (or cycloalkanes), alkenes, dienes, and alkynes. While the molecules in crude oil include different atoms such as sulfur and nitrogen, the hydrocarbons are the most common form of molecules, which are molecules of varying lengths and complexity made of hydrogen and carbon atoms, and a small number of oxygen atoms. The differences in the structure of these molecules account for their varying physical and chemical properties, and it is this variety that makes crude oil useful in a broad range of several applications. Petroleum products are usually grouped into four categories: light distillates (LPG, gasoline, naphtha), middle distillates (kerosene, jet fuel, diesel), heavy distillates and residuum (heavy fuel oil, lubricating oils, wax, asphalt). These require blending various feedstocks, mixing appropriate additives, providing short term storage, and preparation for bulk loading to trucks, barges, product ships, and railcars. This classification is based on the way crude oil is distilled and separated into fractions. Major refinery products, their uses, and their basic physical properties are shown in Table 1.

Petroleum Gas - used for heating, cooking, making plastics
• small alkanes (1 to 4 carbon atoms)
• commonly known by the names methane, ethane, propane, butane
• boiling range = less than 104 degrees Fahrenheit / 40 degrees Celsius
• often liquified under pressure to create LPG (liquified petroleum gas)
Naphtha or Ligroin - intermediate that will be further processed to make gasoline
• mix of 5 to 9 carbon atom alkanes
• boiling range = 140 to 212 degrees Fahrenheit / 60 to 100 degrees Celsius
Gasoline - motor fuel
• liquid
• mix of alkanes and cycloalkanes (5 to 12 carbon atoms)
• boiling range = 104 to 401 degrees Fahrenheit / 40 to 205 degrees Celsius
Kerosene - fuel for jet engines and tractors; starting material for making other products
• liquid

• mix of alkanes (10 to 18 carbons) and aromatics
• boiling range = 350 to 617 degrees Fahrenheit / 175 to 325 degrees Celsius
Gas Oil or Diesel Distillate - used for diesel fuel and heating oil; starting material for other products
• liquid
• alkanes containing 12 or more carbon atoms
• boiling range = 482 to 662 degrees Fahrenheit / 250 to 350 degrees Celsius
Lubricating Oil - used for motor oil, grease, other lubricants
• liquid
• long chain (20 to 50 carbon atoms) alkanes, cycloalkanes, aromatics
• boiling range = 572 to 700 degrees Fahrenheit / 300 to 370 degrees Celsius
Heavy Gas or Fuel Oil - used for industrial fuel; starting material for making other products
• liquid
• long chain (20 to 70 carbon atoms) alkanes, cycloalkanes, aromatics
• boiling range = 700 to 1112 degrees Fahrenheit / 370 to 600 degrees Celsius
Residuals - coke, asphalt, tar, waxes; starting material for making other products
• solid
• multiple-ringed compounds with 70 or more carbon atoms
• boiling range = greater than 1112 degrees Fahrenheit / 600 degrees Celsius

Table 1: Refinery Products

From a physical chemistry perspective a refinery includes three types of fundamental hydrocarbon molecular chain transformation processes:

Cracking
Cracking is the breaking of large hydrocarbon chains. There are two basic varieties of cracking:

- Thermal including steam, vis-breaking, and coking
- Catalytic including fluid and hydrocracking

Alkylation
Alkylation is the altering of molecular structure.

Reforming
Reforming, almost always catalytic reforming, is the combining of molecular chains to form longer chains.

Although many products are derived in a refinery, a typical barrel oil crude oil converts into approximately 40-45% gasoline, 2-6% propane, 15-25% heating oil & diesel, 1-3% asphalt, 10-15% jet fuels, and 15-25% others (lube oil, waxes, plastics, etc.). This is obviously very much dependent on the type and the quality of the starting crude oil and the specific refinery processes.

Figure 42 shows a flow diagram of a typical refinery including the many chemical transformation process. The crude oil distillation unit or distillation column is the first processing unit, and traditionally the most important, in virtually all petroleum refineries. It distills the incoming crude oil into various fractions of different boiling ranges, each of which are then processed further in the other refinery processing units. The distillation unit is often referred to as the atmospheric distillation unit because it operates at slightly above atmospheric pressure.

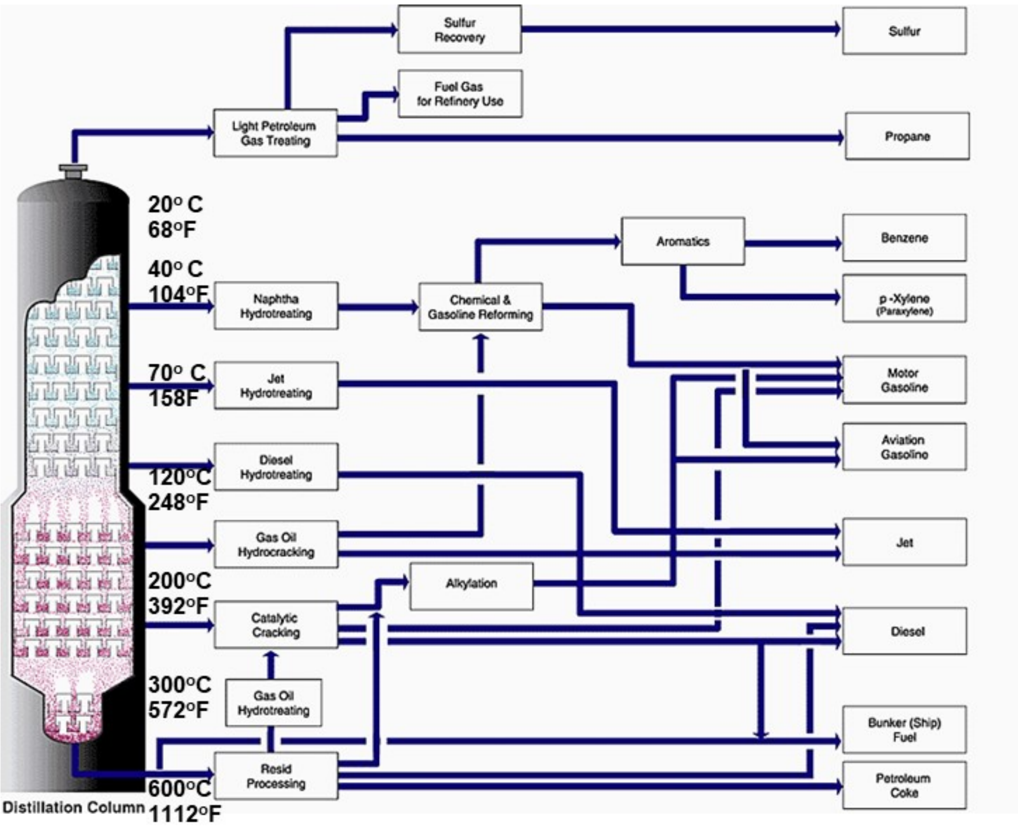


Figure 42: Typical Refinery Process with Distillation Column

Other critical refinery processes include:

Hydrotreating

Hydrotreating is an established refinery process for reducing sulfur, nitrogen and aromatics while enhancing cetane/octane number, density, and smoke point. In the hydrotreating process, oil fractions are reacted with hydrogen in the presence of a catalyst to produce high-value clean products. For the production of e.g. ultra-low-sulfur diesel (temperatures usually range between 350 and 390°C, pressures between 60 and 90 bara). The heart of every hydrotreating process is the reactor section, which features a high-pressure reactor vessel, proprietary catalyst and reactor internals technology.

Hydrocracking

During hydrocracking, complex organic molecules such as kerogens or heavy hydrocarbons are broken down into simpler molecules by the breaking of carbon-carbon bonds in the precursors. The hydrocracking process depends on the nature and quality of the feedstock and the relative rates of the two competing reactions, hydrogenation and cracking. Heavy aromatic feedstock is converted into lighter products under a wide range of high pressures (70 bara/1'000 psia -140 bara/2'000 psia) and fairly high temperatures (400°C/750°F- 800°C/1'500°F), in the presence of hydrogen and special catalysts.

Isomerization

lsomerization is the process by which molecules are transformed into other molecules which have exactly the same atoms, but the atoms have a different arrangement e.g. A-8-C instead of 8-A-C (these related molecules are known as isomers). In refining light naphtha, such as butane C4 or pentane C5, hydrogen is cycled through the isomerization reactors at high temperature and pressures to increase the octane/cetane rating.

Reforming

Catalytic reforming is a chemical process used to convert heavier naphtha (typically having low octane ratings) into high-octane liquid products called reformates. The process converts low-octane linear hydrocarbons (paraffins) into branched alkanes (isoparaffins) and cyclic naphthenes, which are then partially dehydrogenated to produce high-octane aromatic hydrocarbons. The dehydrogenation also produces significant amounts of byproduct hydrogen gas, which is fed into other refinery processes such as hydrocracking. During catalytic reforming the catalytic reformer hydrogen recycle compressors circulates the hydrogen at 5 -45 bara through a set of heaters and catalytic reactors.

Axial and Centrifugal Compressors

Axial and centrifugal compressors are used throughout the refinery to move gas from low pressure areas to higher pressure areas within the various plants. The types of gases moved may be simple such as air or hydrogen; or they can be quite complex and comprised of a multi- component mixture that may vary with plant conditions.

Axial compressor applications are fewer and include the following:

- FCCU main air blower (axial compressors are usually used for larger plants with higher flow requirements)

Centrifugal compressor applications are numerous and include but are not limited to the following:

- Hydrogen recycle
- Wet gas
- FCCU main air blower
- Alkylation refrigeration compressor
- Heat pumps
- Instrument and plant air supply

Both axial and centrifugal compressors operate on the dynamic principle. They are selected based on requirements of flow, range, pressure ratio, performance, and specification. Reliability is a primary concern in refinery operations, and machinery specifications can be quite strict for critical applications. The specifications used for refineries are API 617, "Axial and Centrifugal Compressor and Expander-Compressors" for main chemical processes, and API 672, "Packaged, Integrally Geared Centrifugal Air Compressors for Petroleum, Chemical, and Gas Industry Services" for instrument air. End users may also have their own specifications in addition to those of API.

Turbomachinery in Refineries

There are a large number of turbomachinery applications in refineries ranging from pumping and compression to mechanical drivers and power generation. The wide range of critical machinery applications in a refinery are shown in Figure 43 on a typical refinery process diagram.

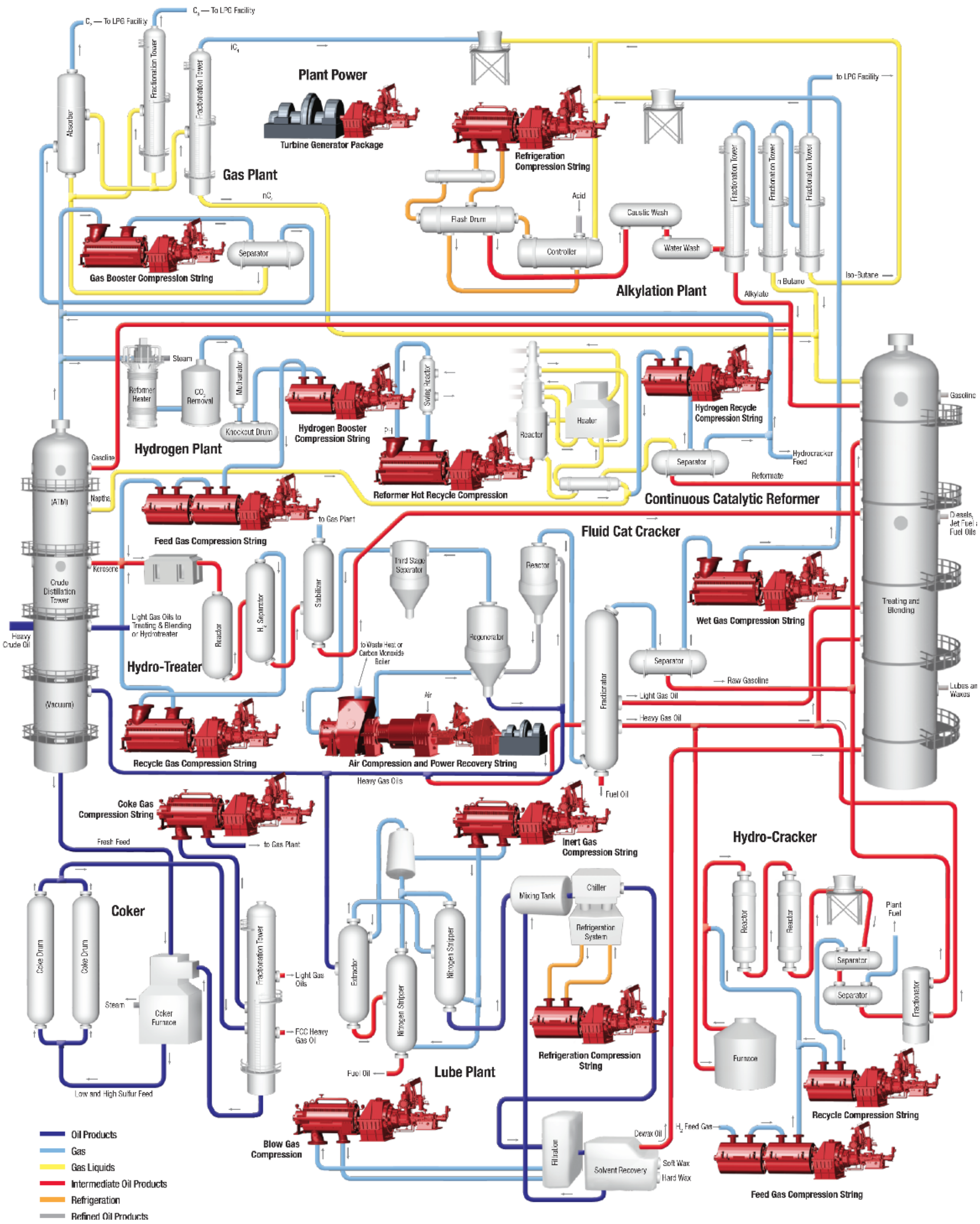


Figure 43: Turbomachinery Applications in Refinery Service

Hydroprocessing

Hydroprocessing encompasses a variety of thermal conversion processes in which hydrogen is used, along with a catalyst, to convert petroleum fractions and products to meet the refiner's objectives. These conversion processes include hydro-desulfurization (hydrotreating) and hydrocracking. In both processes, hydrogen compressors purify the product stream by removing contaminants such as sulfur, nitrogen, and aromatic hydrocarbons. The end products typically include gasoline, jet fuel, diesel fuel, and kerosene. Because of the severe processing conditions and the high pressures required to convert petroleum fractions and products, these compressors are nearly always vertically split designs for highpressure, high-temperature applications. Figure 44 shows a typical hydrotreater unit.

Figure 44: Hydrotreater Unit

Typical hydrotreater centrifugal compressor trains included back-to-back or tandem configurations with side-load streams. Operating pressures range between 100-500 psia suction to a wide range of discharge pressures depending on the process. Pressures as high as 8000 psia are possible. Figure 45 sows a typical hydrotreater compressor and design.

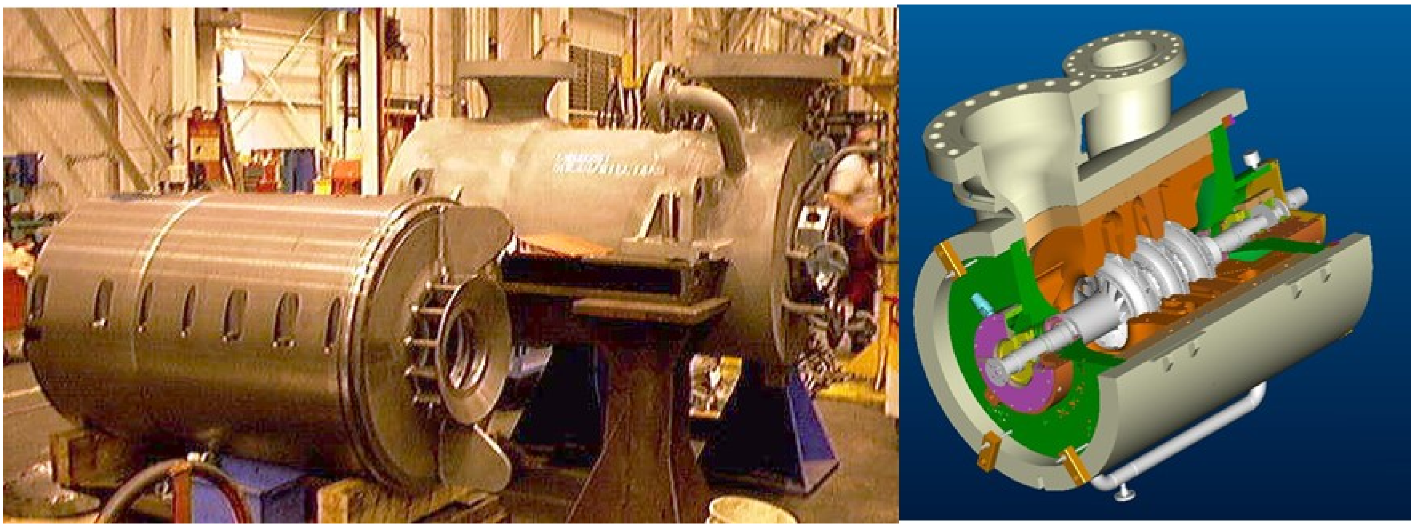


Figure 45: Hydrotreater Compressor

Fluid Catalytic Cracking – Power Recovery

Energy represents the single largest operating expense within a refinery and in some cases, can account for nearly 50% of the total operating cost. Many refiners benefit from energy cost savings through the use of power recovery expanders. These units utilize the energy in hightemperature, low-pressure gas streams to drive generators and/or centrifugal or axial compressors in fluid catalytic cracking service.   High efficiency axial compressors are often incorporated into power recovery trains. The high-flow capacity of axial compressors makes them suitable for larger, more efficient processes and they can be used to supply air to the regenerator and other plant needs. Figure 46 shows a schematic of a fluid catalytic cracking unit.

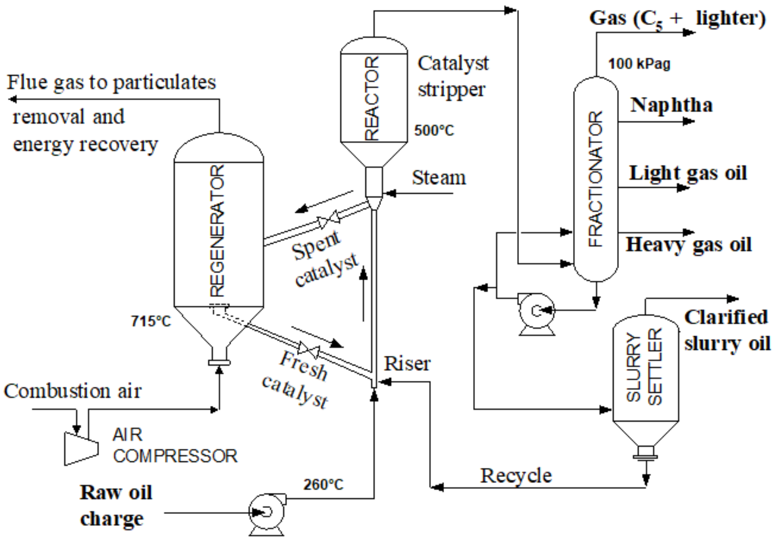


Figure 46: Fluid Catalytic Cracking Unit Process Diagram

Catalytic Reforming

The objective of catalytic reforming is to convert low octane naphtha into a high octane reformate and/or to provide aromatics (benzene, toluene, and xylene) for petrochemical plants. Reforming also produces high purity hydrogen for hydrotreating purposes. Applications include net gas and hydrogen recycle services. Hydrogen recycle compressors usually require an alternate nitrogen operating case for catalyst regeneration and must be carefully evaluated for safe operating range and for temperature limits. Figure 47 shows a hydrogen recycle compressor in reforming service driven by a multi-valve steam turbine. There are several service application ranging from mid-pressure (<1000 psia) to high pressure (>4000 psia).

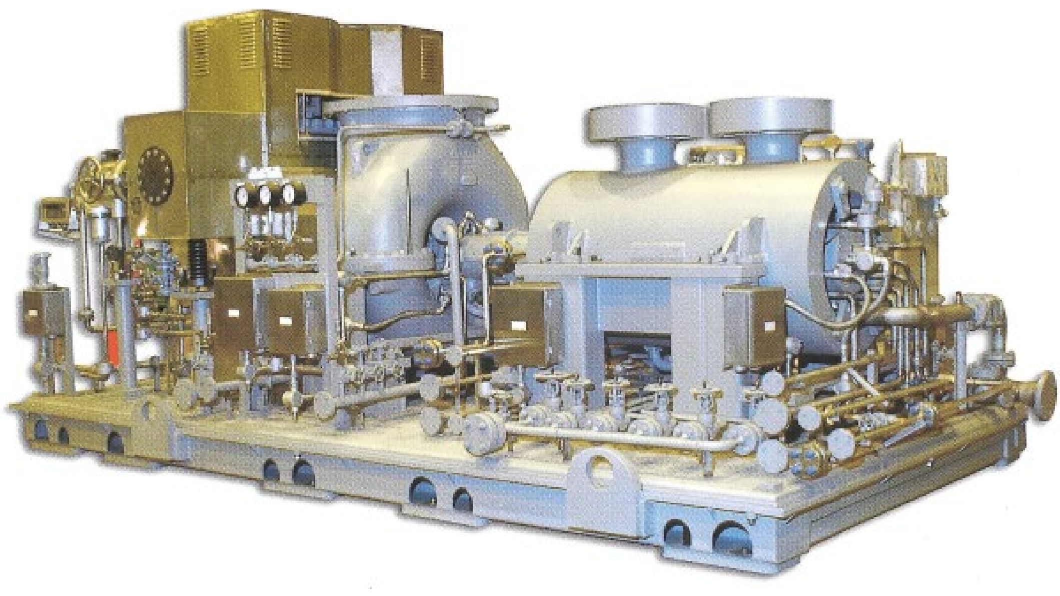


Figure 47: Vertically Split Hydrogen Recycle Compressor Driven by Steam Turbine

Delayed Coking

Delayed coking is a thermal cracking process that upgrades and converts petroleum bottoms into liquid and gas product streams and petroleum coke. Coker applications are challenging due to the wide range of operating conditions required and the fouling properties of the compressed gases. Wet gas compressors for coker service are utilized. These compressors usually require anti-fouling coatings to minimize foulant build-up on the aerodynamic surfaces of the compressor. Foulant build-up can increase rotor vibration, constrict process gas passageways, decrease efficiency, and reduce output. This is discussed in significant detail later herein. A schematic of a delayed coker is shown in Figure 48.

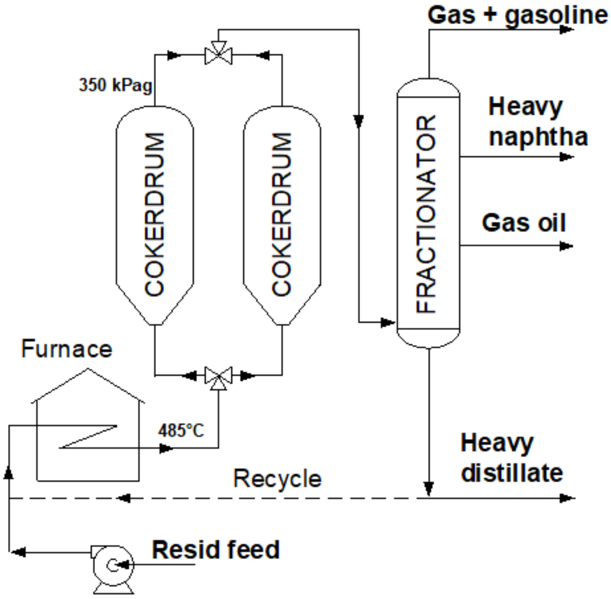


Figure 48: Delayed Coking Process

Alkylation

In the alkylation process, olefin yield, commonly from a fluid catalytic cracker (FCC), is used as a feedstock and reacted with isobutane in the presence of an acid catalyst. A centrifugal compressor is needed to recirculate the isobutane. The resulting alkylate is available for market as high octane fuel, or is blended with lower grade gasoline to raise the octane level. The high-octane value makes alkylate an excellent blendstock for premium grades of gasolines. Since alkylate contains no olefins, no aromatics, and no sulfur, it is also an excellent blendstock for use in reformulated gasolines. Figure 49 shows a photograph of a typical alkylation plant.

Figure 49: Alkylation Plant (Courtesy of Motiva)

CONCLUSION

This tutorial explained applications for centrifugal compressors in oil and gas applications, from the gas or oil well to the ultimate use of these hydrocarbons. The compressors and their drivers are explained, together with the numerous applications they are used in.

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