TECHNICAL INFORMATION

ABOUT

NATURAL GAS CLEANING
AND TREATMENT

1 Natural Gas Cleaning and Treatment

EDL and DBI are able to offer the basic and detail engineering including selection of technology and costing, risk assessment and Hazop studies of the whole natural gas treatment process chain - beginning from raw gas quality up to final natural gas quality for combustion and supply to the natural gas grid.

We are also experienced in sour gas conditioning as well as lean gas treatment.

1.1 Reasons for gas conditioning

Raw natural gas in the reservoirs contains sour components such as carbon dioxide (CO_2), hydrogen sulphide (H_2S) and sulphur compounds, which make the gas corrosive. It also contains solid components like sand, salts, reservoir fines, drilling sludge and corrosion products and even liquid components, e.g. inhibitor and condensate.

Because of its sour nature and its corrosive components the gas must neither be fed into the gas pipeline nor combusted unconditioned. The gas should preferably be conditioned at the gas field to avoid sour gas transportation over long distances.

Configuration and dimensioning of the gas conditioning system depend on the requirements such as raw gas composition, plant size and further use of the natural gas.

A typical raw gas composition is shown in Tab. 1.1 below:

Component		Fraction
CH_4	Methane	82 - 94 Vol.%
C_2H_6 / C_4H_8 / C_6H_{10} / …	Higher hydrocarbons such as ethane, propane, butane, …	3 - 10 Vol.%
N_2	Nitrogen	0.4 – 14.0 Vol.%
CO_2	Carbon dioxide	0.1 – 1.0 Vol.%
H_2S	Hydrogen sulphide	(very different)
	Mercaptan	(very different)

Tab. 1.1 – Typical natural gas composition

Basically, the gas conditioning system comprises the following steps:

- Pressure reduction
- Separation of solids and condensate
- Purification
- Dehydration
- Gas compression
- Sulphur recovery
- Fractionation

1.2 Pre-treatment

Pre-treatment combines the procedural steps required before gas conditioning to avoid damage to downstream units, caused by corrosive solid and liquid gas components and fluctuating or excessive pressure.

1.2.1 Inhibition unit

To avoid gas hydrates in the wells, an inhibitor such as MEA (monoethanolamine) has to be injected into the ground of the well. At the wellhead, the inhibitor is separated and regenerated.

1.2.2 Separator

A separator removes solid components of the gas like sand, salts, reservoir fines, drilling sludge and corrosion products which are caused by the reservoir as well as by liquid components such as inhibitor (e.g. MEA) and condensate (water and higher hydrocarbons) from the raw gas.

1.2.3 Pressure reduction

A pressure reduction may be necessary for the operation of the gas conditioning system, depending on the well head pressure and the pressure required for the feed-in. A pressure reduction can be achieved by using an adequate axial control valve.

1.3 Purification

Purification combines all sweetening and desulphurization processes, where carbon dioxide (CO_2), hydrogen sulphides (H_2S) and mercaptans are removed.

The process or process combination which is best suitable for the gas conditioning depends on the raw gas composition and the required parameters of the product gas.

A typical scheme for a combination of an amine scrubber (CO_2 and H_2S removal) with a molecular sieve (mercaptan removal and drying), which is used for sour gas conditioning is shown in the following Fig. 1.1 (NMP=n-methyl pyrrolidone).
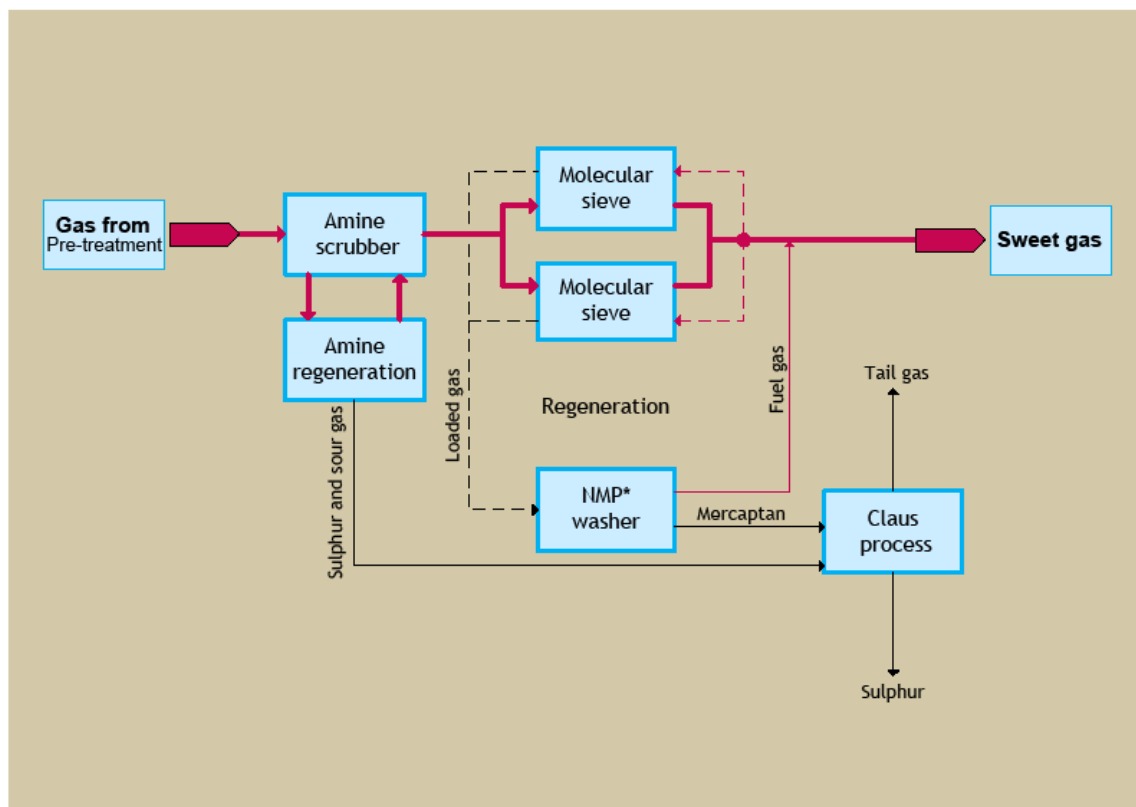

Fig. 1.1 - Sour gas conditioning

1.3.1 Amine scrubbing

The amine scrubbing is a washing process, which uses amine as purifying agent. Carbon dioxide (CO_2) and hydrogen sulphide (H_2S) can almost completely be removed using this technology. The working principle of an amine scrubbing system is shown in the following Fig. 1.2

The amine flows in a closed circuit and is continuously regenerated.

The CO_2- and H_2S-loaded amine needs to be regenerated continuously. Therefore, a second column is needed, where the amine is regenerated by reboiling. The sour gas is exported to the Claus process, where elementary sulphur will be recovered. With this technology and MEA (monoethanolamine) as purifying agent CO_2 can be removed up to less than 50 ppm and H_2S up to less than 3 ppm.
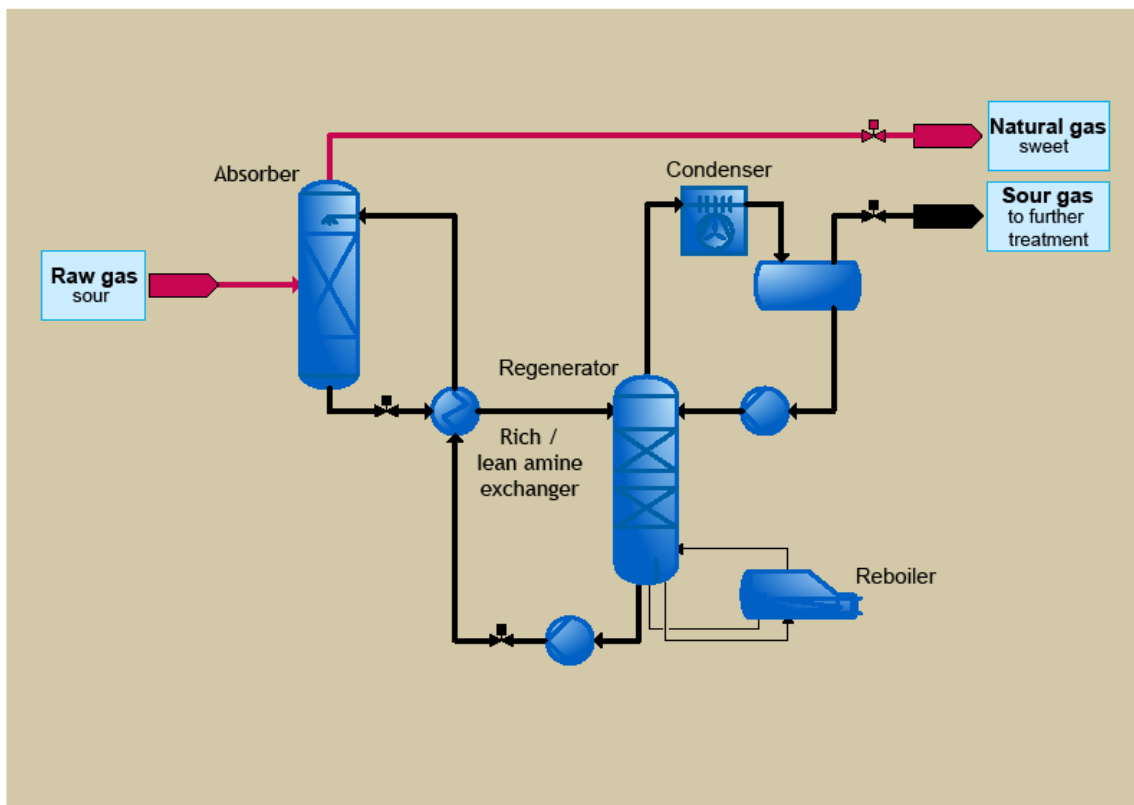

Fig. 1.2 - Amine scrubbing process (principle)

Other purifying agents such as MDEA (methyldiethanolamine), aMDEA (activated MDEA), DEA (diethanolamine) or process alternatives like Purisol, Rectisol or Selexol can be used depending on the gas composition.
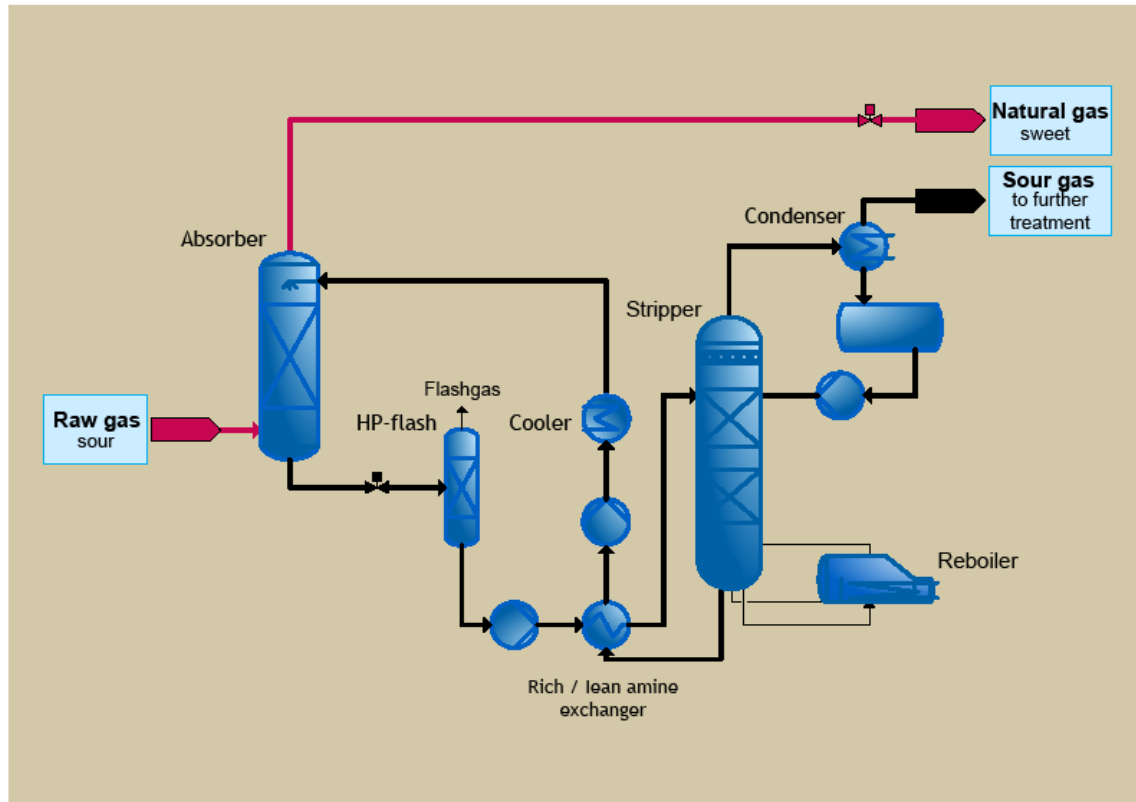

Fig. 1.3 – Single stage aMDEA process (BASF)

1.3.2 Water scrubbing process

The water scrubbing process is a washing process analogue to amine scrubbing. The difference is in the use of water instead of amine as purifying agent. As the capacity of water is considerably lower than of amine, there is a higher energy demand for the circulation pump. Therefore, the water scrubbing process is suitable for low gas loads.

1.3.3 PSA - Pressure Swing Adsorption

A PSA plant basically comprises molecular sieves. Molecular sieves often consist of zeolites, which have open structures through which small molecules can diffuse. Depending on the kind of zeolites, CO_2, mercaptans and humidity can be removed from the gas. If a molecular sieve is fully loaded it has to be regenerated by flushing it with hot natural gas. As the operation mode of a molecular sieve is discontinuous, a continuous operation of the conditioning plant requires two or more molecular sieves.

Due to the discontinuous operation of the molecular sieves which are thermally regenerated at regular intervals, the regeneration off-gas is routed to another washing process where e.g. N-methyl pyrrolidone (NMP) is used as solvent. NMP physically absorbs the off-gas CO_2, H_2S or mercaptans and provides clean fuel gas. The mercaptans and H_2S can be routed to the Claus process.

1.4 Dehydration

As raw gas is usually saturated with water vapour when it comes off the reservoir, and as some conditioning processes (e.g. the water scrubbing process) increase gas humidity during the process, a subsequent drying and adjustment of the water dew point of the gas is necessary before it can be supplied into the natural gas grid. Reasons for this are that free water may convert with the natural gas to gas hydrates and plug pipelines and subsequent plant components. The combination of free water and H_2S or CO_2 creates acid which will cause corrosion in plants and pipelines.

There are several dehydration processes to be selected depending on the parameters of the raw gas and the quality requirements of product gas. One way to dehydrate is using molecular sieves, another possibility is the glycol process.

1.4.1 Molecular sieve

A typical molecular sieve dehydration plant consists of two adsorption towers filled with solid desiccant. One of the adsorption towers is used for the dehydration of wet inlet gas while the parallel installed tower aims to regenerate loaded (water saturated) desiccant. In general, all liquid and solid impurities are removed from the feed stream of a molecular sieve plant by an inlet separator or scrubber (upstream). As wet gas contacts the solid desiccant bed, water vapour is adsorbed until equilibrium is established between the water content in the gas

stream and on the solid desiccant particles. Dried natural gas leaves the bed, flows through the exit switching valve, and finally leaves the dehydration unit via the dry gas outlet header. While one bed is "on drying", the other bed has to be regenerated. Regeneration can be carried out using dry product gas or wet inlet gas. Regenerator gas has to be heated upstream the regeneration tower. Hot regeneration gas heats up the bed, drives the water off the desiccant particles, and carries the resulting water vapour out of the bed. The regeneration stream is cooled down and the water content is separated in the regeneration separator.

Fig. 1.4 shows the principle of a two tower dehydration unit using hot natural gas as regeneration stream.
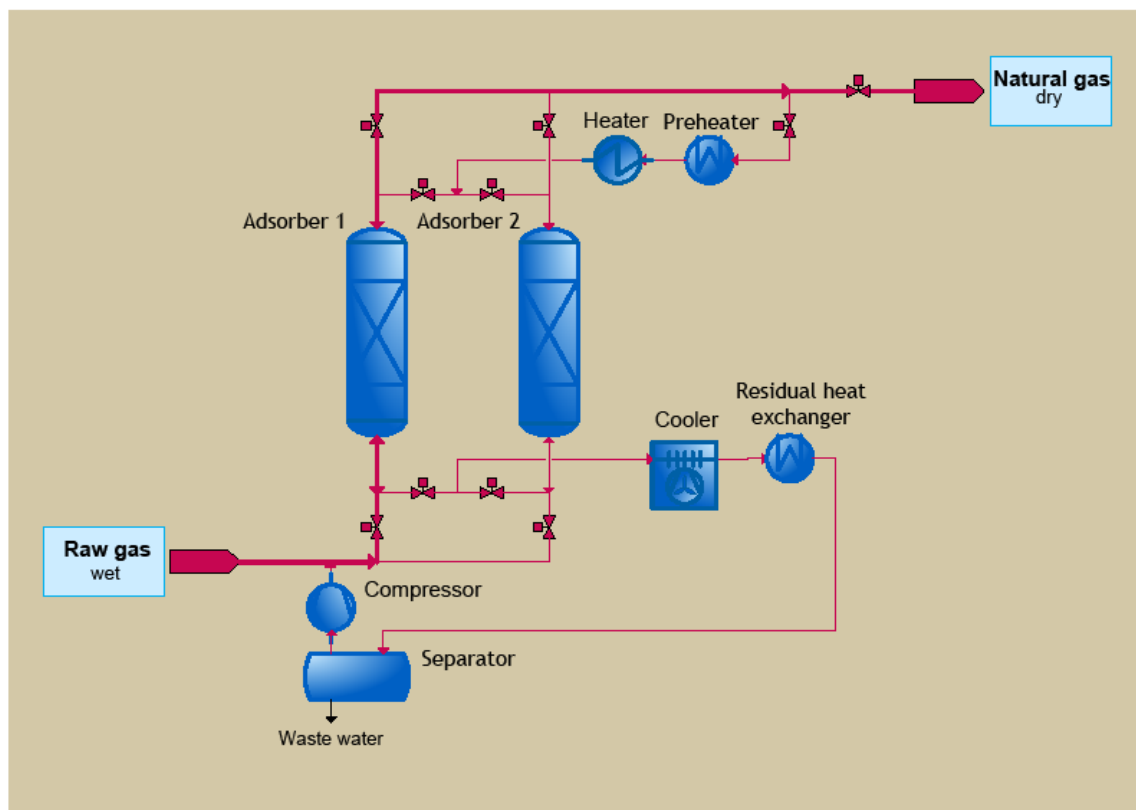

Fig. 1.4 – Molecular sieve dehydration

1.4.2 TEG dehydration

Scrubbing of wet gas with glycol (in most cases TEG - triethylene glycol) is one of the most applied dehydration technologies for natural gas.

The wet gas is flowing through the column (Fig. 1.5) while the glycol in a counterflow absorbs the water. The loaded glycol is regenerated in a stripper column heated by a reboiler. Regenerated glycol flows in a closed circuit back to the glycol column.
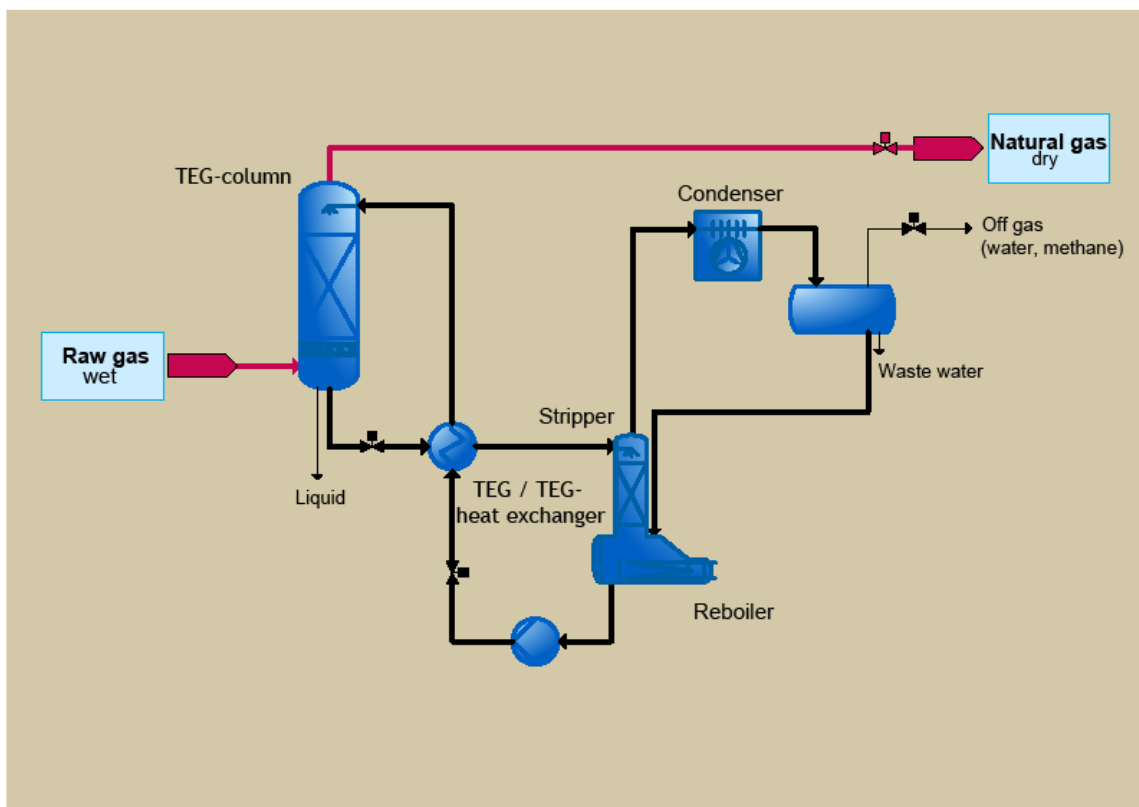

Fig. 1.5 - TEG-dehydration (principle)

1.5 Natural gas liquids (NGL) recovery

1.5.1 Joule-Thomson expansion

A possibility to remove condensed liquids from the natural gas is cooling it down, so that the condensate (water and higher hydrocarbons) will fall out and can be fractionated. Using the Joule-Thomson effect means that the gas temperature decreases during gas expansion e.g. in an expansion valve ("self-refrigeration process"). This effect can be used at the wellhead, where the pressure has to be reduced in most cases, as a pre-dehydration, or after the gas purification using an expansion valve and a gas-gas heat exchanger. This might require a re-compression of the gas before the feed-in.

To meet vapour pressure requirements and composition specs the condensed liquid has to be fractionated.

1.5.2 Refrigeration plant

Refrigeration is the simplest and most direct process for NGL recovery. External refrigeration is supplied by a vapour compression cycle (usually using propane as refrigerant). A cold gas/hot gas heat exchanger provides the first cooling step of the inlet gas. The chiller (mostly a shell-and-tube kettle-type unit) saves final cooling and partial condensation of liquids. The refrigerant (often propane) boils off, leaves the chiller as a saturated vapour, and is fed into the refrigeration plant. Ethylene glycol is often injected at the inlet of the gas/gas exchanger and/or the chiller to prevent hydrate formation or to prevent block exchangers.

The achievable dew point depends on the cooling temperature and the pressure of the gas. This technology may not require a recompression, however, external energy for cooling is needed.

To meet vapour pressure requirements and composition specs the condensed liquid has to be fractionated.

In Fig. 1.6 the principle of an NGL separation process using external refrigeration is shown.
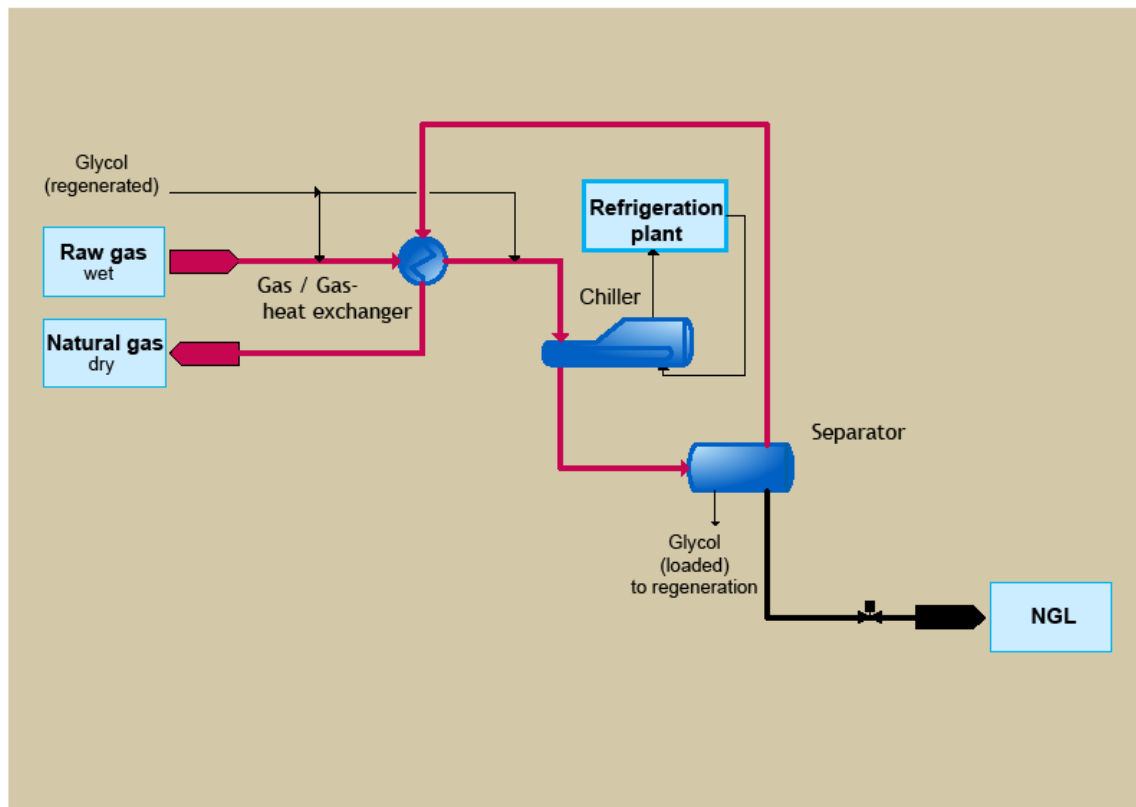

Fig. 1.6 – NGL recovery using external refrigeration (principle)

1.5.3 Turboexpander

If the gas is expanded in a turboexpander it performs work during expansion. This causes a lower temperature decrease than using the Joule-Thomson effect. The expansion work can be used to increase the pressure of the gas in the brake compressor to increase the energy efficiency of the process. After the expansion a recompression to pipeline pressure might be necessary.

Main equipment of a turboexpander plant are the gas-to-gas heat exchangers in combination with a chiller and the corresponding separator(s). The demethanizer tower stabilizes the raw liquid product by reducing the methane content to a required low level.

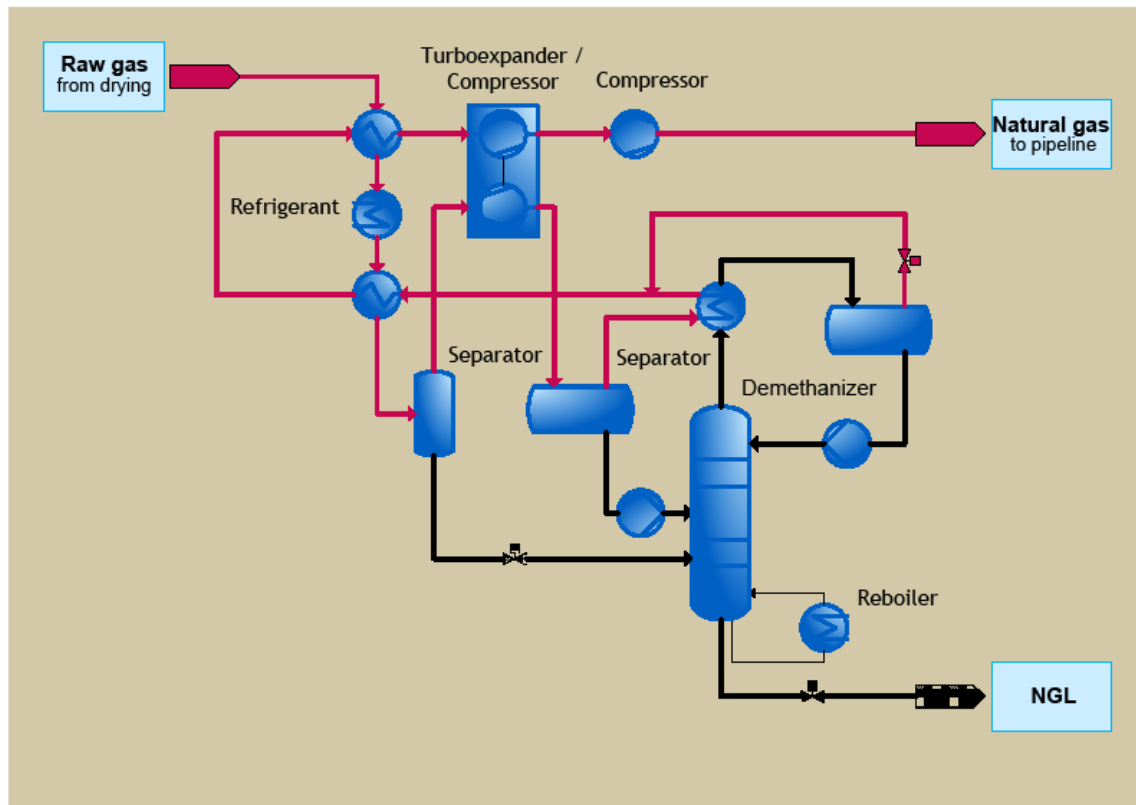An overwiew of a turboexpander process for NGL separation from raw gas is shown in Fig. 1.7.

Fig. 1.7 – NGL recovery using turboexpander (principle)

1.6 Fractionation

Hydrocarbons which are falling out of the raw natural gas during dehydration and separation processes should be fractionated and/or stabilized to meet product specifications and to transfer these liquids into useable products for further applications.

The fractionation process is based on the different boiling points of the higher hydrocarbons so that they can be separated in one or more distillation columns where the products (e.g. propane, butane, …) can be extracted. The structure of such a distillation column depends on the composition of the hydrocarbons in the natural gas liquid feed streams.

A typical fractionation system with depropanizer and debutanizer is shown in Fig. 1.8.
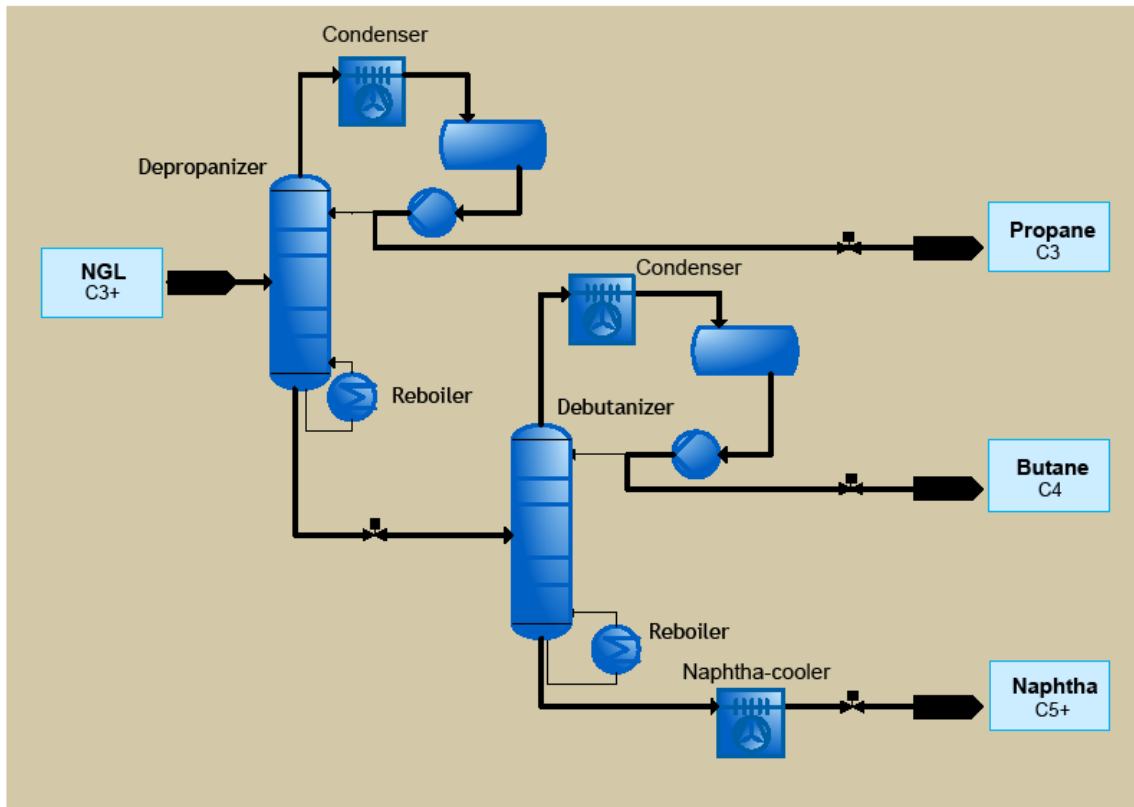

Fig. 1.8 – Liquid fractionation process

1.7 Gas compression

A gas re-compression might be necessary if the gas pressure is too low for gas supply into the natural gas grid or for other applications. The compressor type and its design depend on the gas pressure downstream of the conditioning unit and the pressure required for the feed-in.