5.1 NATURAL GAS PROCESSING OBJECTIVES

- Raw natural gas from production wells may contain a full range of hydrocarbons, carbon dioxide, hydrogen sulfide, nitrogen, water, and other impurities.
- The objective of a natural gas processing is

1- to produce a treated (product) gas by removing the **acid gases**, **heavy hydrocarbons**, **nitrogen**, **water**, and other impurities to acceptable levels that are compatible with the pipeline design and the customer's requirements.

2- Consumers generally have no use for gas in its raw state. Thus, raw natural gas streams must be treated to comply with emissions, regulations, and pipeline gas specifications.

3- The specifications of pipeline gas ensure gas quality to provide a clean and safe fuel gas to consumers and to ensure optimum operation of gas turbines and combustion equipment to minimize NOx, CO, and soot emissions. Off-specification natural gas may cause operational problems associated with pipeline corrosion and/or plugging, which may result in unsafe operation.

4- When the gas is high in heavy hydrocarbon content, it may exceed the maximum allowable British thermal unit (Btu) specification.

- Typical pipeline gas specifications are shown in Table below.

Typical pipeline Gas specification

Characteristic	**Specification**
Water content	4-7 lbm H_2O/MMscf of gas
Hydrogen sulfide content	0.25-1.0 grain/100 scf
Gross heating value	950-1200 Btu/scf
Hydrocarbon dew point	14-40 ^oF at specified pressure
Mercaptan content	0.25-1.0 grain/100 scf
Total sulfur content	0.5-20 grain/100 scf
Carbon dioxide content	2-4 mol%

Oxygen content	0.01 mol% (max)
Nitrogen content	4-5 mol%
Total inert content (N_2 + CO_2)	4-5 mol%
Sand, dust, gums, and free liquid	None
Typical delivery temperature	Ambient
Typical delivery pressure	400 to 1200 psig

5.2 GAS PROCESSING PLANT CONFIGURATIONS

❖ The gas processing plant configuration and complexity depend upon:

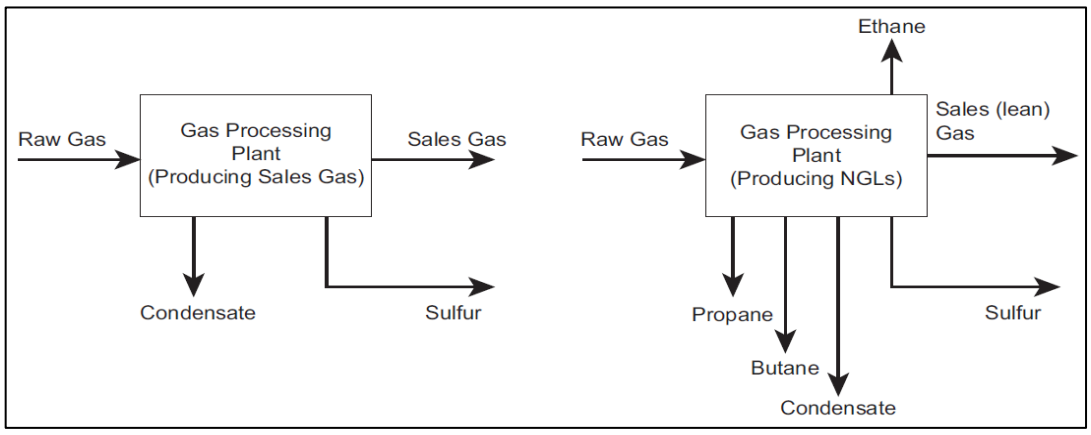
1- The feed gas composition and the levels of treating and processing required in meeting product specifications and emission limits.

2- Liquid product values can also drive the level of NGL components to be recovered, which can affect process complexity.

❖ Fig. below shows two simplified gas processing plant schematics.

1- **The first scheme** is to remove condensate, sulfur, and the heavier components to meet sales gas specifications.

2- **The second scheme** is to process the feed gas for recovery of individual NGL components to increase plant revenues.

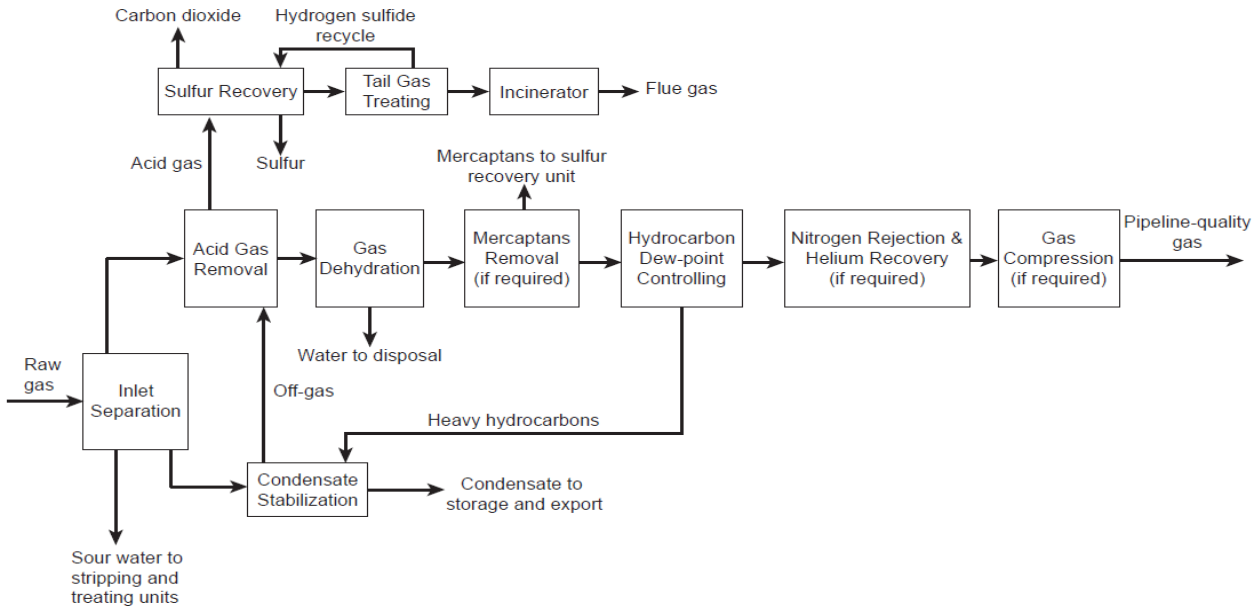


Two different schemes of natural gas processing plants

- While sulfur compounds and other contaminants must be removed to meet emission requirements as shown in both schemes, the extent of processing in the second scheme is project specific. It depends on the commercial agreements between upstream producers and downstream product distributors and buyers.

5.3 GAS PLANT WITH HYDROCARBON DEW POINT CONTROLLING

- Raw gas to a gas processing plant can be relatively lean, that is, containing a small amount of C_{2+} hydrocarbons.
- This lean gas can be processed by the process units as shown in Fig. below.
- The main process units consist of **acid gas removal**, **gas dehydration**, and **hydrocarbon dew point control**.
- There are other support systems such as **sulfur recovery**, **tail gas treating (TGT)**, and **sulfur forming**, which are necessary to meet environmental requirements.
- If the gas contains liquid condensate, a **condensate stabilization** unit is required.
- If the gas contains high levels of nitrogen (greater than 5 mol%), **nitrogen rejection** is required. Other units, such as a gas compression unit may also be required.



Process units in a gas processing plant with hydrocarbon dew point controlling.

1- **Inlet Separation:** Feed gas and liquid from production wells is first separated in the inlet facility,

2- **Condensate Stabilization:** The condensate contains dissolved light hydrocarbons and H_2S, which must be removed to meet the export condensate specifications. A condensate stabilization unit is designed to produce a condensate with 4 ppm H_2S and Reid vapor pressure specifications, ranging from 8 to 12 psi.

3- **Acid Gas Removal:** The acid gas removal unit (AGRU) is designed to remove the acidic components to meet sales gas sulfur and CO_2 specifications.

4- **Sulfur Recovery and Handling:** Acid gas from the amine regenerator contains concentrated H_2S, which cannot be vented for safety reasons or flared due to acid gas pollution.

5- **Gas Dehydration:** Treated gas from the AGRU is fed to the gas dehydration unit to meet the water dew point specification for pipeline transmission, typically 7 lbs water/MMscf.

6- **Mercaptans Removal:** Natural gas coming from the wellhead may contain mercaptans (RSH) and other sulfur components. Therefore, removing mercaptans from the feed gas may be required to meet a maximum total sulfur specification in the treated gas or natural gas liquids

7- **Hydrocarbon Dew Point Controlling:** The hydrocarbon dew point temperature must be reduced to a temperature below the coldest ambient temperature during transmission. This is to avoid hydrocarbon liquid condensation in the pipeline, which is a safety hazard.

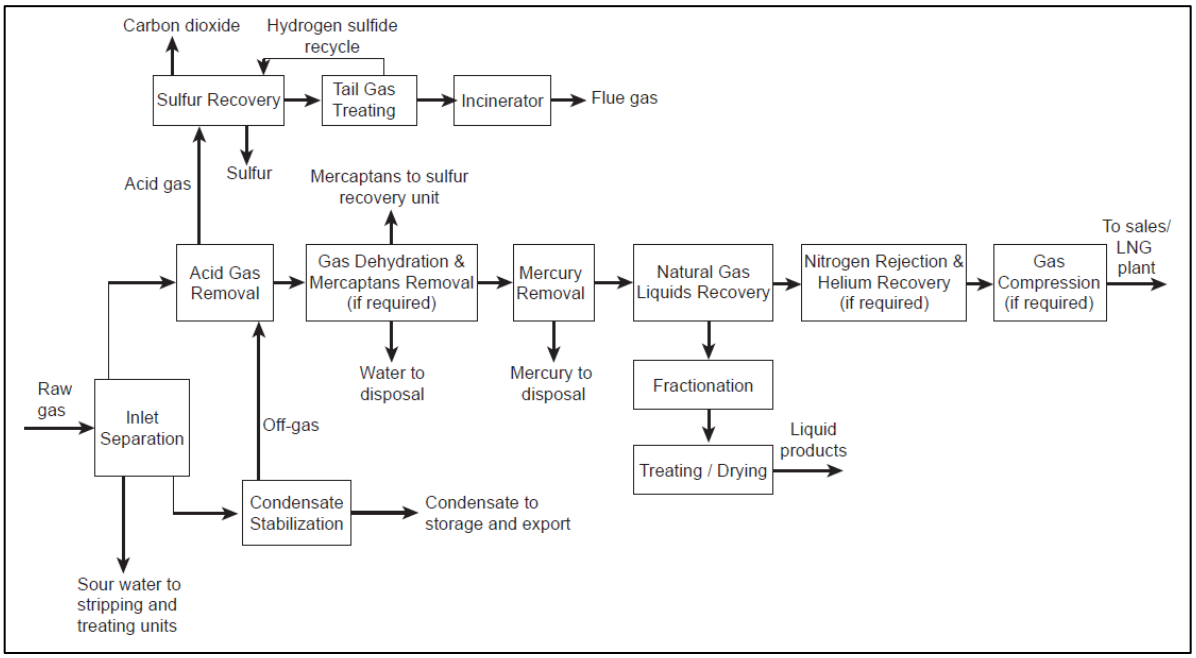
8- **Nitrogen Rejection and Helium Recovery:** Nitrogen content in natural gas varies depending on the gas source. Nitrogen can be naturally occurring in high concentration in some gas fields, Natural gas may also contain helium

9- **Sales Gas Compression, Transmission, and Measurement:** Feed gas to the gas plant is typically reduced in pressure such that phase separation is feasible. Most

often, recompression of the residual (sales) gas to the pipeline pressure is necessary.

5.4 GAS PLANT FOR NATURAL GAS LIQUID PRODUCTION

When the feed gas contains a significant amount of liquids (C3+ hydrocarbons), there are economic incentives to produce the LPG (and sometimes liquid ethane) as by-products. This type of plant is complex and costs more than the simple hydrocarbon dew point controlling plant. Fig. below illustrates a block flow diagram of a gas plant for NGL production.



Process units in a gas processing plant foe natural gas liquid production.

The following points describe the units that are unique to NGL production. The balance of plant is similar to the hydrocarbon dew pointing plant.

1- **Deep CO_2 Removal:** CO_2 removal is required to meet the sales gas CO_2 specification, typically limited to 2-3 mol%. CO_2 may need to be removed to even a lower level to avoid CO_2 freezing in the cold section of the NGL recovery unit.

2- **Deep Dehydration:** For NGL recovery, the deethanizer or demethanizer must operate at low temperatures. This would require sufficient water to be removed to avoid hydrate formation in the columns.

3- **Mercury Removal:** Mercury is often present in the feed gas at pptw or higher levels. Mercury removal is required to avoid the risks of mercury attack on the brazed aluminum heat exchangers.

4- **Natural Gas Liquid Recovery and Fractionation:** There are numerous NGL patents and proprietary technologies for NGL recovery. Unlike an AGRU, the NGL recovery process selection must be evaluated based on meeting the NGL recovery levels, feed gas pressure, temperature, gas compositions, and product specifications, and NGL recovery flexibility.

5.5 FINDING THE BEST GAS PROCESSING ROUTE

- It is important not only to select the proper technology within each processing unit but also to consider interactions between different gas processing units.
- One may adjust the sequence of the processing steps to optimize the whole operation, thereby increasing operating flexibility within the overall gas processing plant.
- The design must be "fit-for-purpose," meeting the immediate requirements but also considering potential modifications to the process for future gas compositions and NGL recovery requirements.
- Designs of the gas treating unit and sulfur recovery/ handling system are more involved and are dependent on the feed gas' acid gas content.
- Prefabricated modular equipment is frequently used to reduce field construction time and lower capital and operating costs.
- In summary, there is no single best design approach for the gas processing plant.
- An optimized gas plant design must be flexible and be suitable for revamp to meet future requirements and project economics, while preserving the key equipment.