Natural gas acid gas removal, dehydration & natural gas liquids recovery

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Overview

- Gas treating
- Acid gas removal
  - Carbon dioxide (CO$_2$)
  - Sour gas (H$_2$S, sulphur species)
- Gas dehydration
- Natural gas liquids (NGLs) recovery & separation
- NGL fractionation
Gas treating
Typical composition of natural gas

- Sour gas if $\text{H}_2\text{S} > 5.7\text{mg/m}^3$ of gas

<table>
<thead>
<tr>
<th>Typical Gas Compositions</th>
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<tbody>
<tr>
<td><strong>Canada</strong></td>
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<tr>
<td>-------------------------</td>
</tr>
<tr>
<td>Helium</td>
</tr>
<tr>
<td>Nitrogen</td>
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<tr>
<td>Carbon dioxide</td>
</tr>
<tr>
<td>Hydrogen sulfide</td>
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<tr>
<td>Methane</td>
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<tr>
<td>Ethane</td>
</tr>
<tr>
<td>Propane</td>
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<tr>
<td>Butane</td>
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<tr>
<td>Pentanes and heavier</td>
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</tbody>
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<table>
<thead>
<tr>
<th>Name</th>
<th>Formula</th>
<th>Volume (%)</th>
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<tbody>
<tr>
<td>Methane</td>
<td>CH₄</td>
<td>&gt;85</td>
</tr>
<tr>
<td>Ethane</td>
<td>C₂H₆</td>
<td>3–8</td>
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<tr>
<td>Propane</td>
<td>C₃H₈</td>
<td>1–2</td>
</tr>
<tr>
<td>Butane</td>
<td>C₄H₁₀</td>
<td>&lt;1</td>
</tr>
<tr>
<td>Pentane</td>
<td>C₅H₁₂</td>
<td>&lt;1</td>
</tr>
<tr>
<td>Carbon dioxide</td>
<td>CO₂</td>
<td>1–2</td>
</tr>
<tr>
<td>Hydrogen sulfide</td>
<td>H₂S</td>
<td>&lt;1</td>
</tr>
<tr>
<td>Nitrogen</td>
<td>N₂</td>
<td>1–5</td>
</tr>
<tr>
<td>Helium</td>
<td>He</td>
<td>&lt;0.5</td>
</tr>
</tbody>
</table>

*Tabular mol% data is on a wet basis (1.3 mol% water)

Source: U.S. Bureau of Mines (1972) and Jones et al. (1999).
Gas treating facility design

- Requirements for gas plant design:
  - Raw gas production throughput (plant capacity) [gas reserves]
  - Composition of separator inlet (feed) gas & condensates
  - Condensate/gas rates
  - Residual gas specs
  - Rate of gas sales (exports & local demand)

- End-user assurances:
  - Processed gas quality abiding to sales specs
  - Continuous gas supply at agreed rate

- Pipeline transmission efficiency affected by presence of $\text{H}_2\text{O}$

- Sales gas specs limits:
  - $\text{H/C}$ dew point temp.
  - $\text{H}_2\text{O}$ vapor content
Gas treating

- Wellhead gas is usually saturated with H₂O vapor
- Gas processing (or refining) usually involves several processes to remove:
  - Oil; water vapor (H₂O)
  - Elements of sulphur (H₂S, carbonyl sulfide, ...)
  - Helium (He); carbon dioxide (CO₂)
  - Natural gas liquids; Nitrogen (N₂)
  - Higher hydrocarbons; impurities ie dust, sand
  - Traces of Mercury (Hg) & sometimes
  - Oxygen (O₂)
- Content of dilutents. Some wells contain:
  - 92% of CO₂ (Col., USA)
  - 88% of H₂S (Alberta, Ca)
  - 86% of N₂ (Tx, USA)
Selecting a refining process

- Many **chemical processes** are available for refining natural gas.
- Several variables dictate **process sequence & process selection**:
  - 1. Types & concentrations of gas contaminants;
  - 2. Degree of contaminant removal (how pure);
  - 3. Selectivity of acid gas removal;
  - 4. Temperature, pressure, volume & composition of the gas;
  - 5. The $\text{CO}_2/\text{H}_2\text{S}$ ratio
  - 6. Sulphur recovery due to process economics or environmental issues
  - 7. Mercaptans & carbonyl sulfide in $\text{H}_2\text{S}&\text{CO}_2$ influence choice of sweetening process

- **At wellhead**:
  - Scrubbers (desanders) eliminate sand & other large-size impurities (silt, malt)
  - Heaters avoid the formation of gas hydrates in presence of $\text{H}_2\text{O}$ (21 °C (70 °F))
- NGLs could be left in the NG. Usually are removed because they command commercial value
- Sweetening precedes dehydration & NGL separation
- **Stage I:** *gas treatment* or *gas conditioning* removes acid gases
- **Stage II:** *NGL recovery & fractionation*
- Gas processing involves some of most expensive & complex processes
Nitrogen & helium

- **Nitrogen:** 3 methods used to recover nitrogen from natural gas:
  - Cryogenic distillation
  - Adsorption
  - Membrane separation

- **Helium:**
  - NG main source of helium
  - Recovery is uncommon
  - Possible if helium content > 0.5 vol%.
Acid gas removal (sweetening)
Sweetening (1)

- It involves the removal of acid gases: $CO_2$, $H_2S$, sulphur species
- Goals: meet contractual specs and permit further processing
  - (a) The problems with acid gases?
  - (b) Levels of acid gas concentrations in natural gas
  - (c) How much purification is enough?
  - (d) Acid gases disposal?
  - (e) What processes eliminate acid gases?

(a) The problems with acid gases?
- $H_2S$ is highly toxic. Combination with air creates a corrosive acid (weak sulfuric acid)
- Sulphur species can also generate carbonyl sulfide (COS)
- Threshold limit value (TLM) for prolonged exposure: 10 ppmv (rotten egg smell)
- $[H_2S]>1,000$ ppmv death occurs (odorless; kills nerve receptors in nose in secs)
- If gas TLM is exceeded, carbon disulphide ($CS_2$), mercaptans ($RSH$), sulfides ($RSR$)
- Presence of $CO_2$ generates carbonic acid ($H_2CO_3$)
- $CO_2$ is non-flammable. Therefore, undesirable for combustion
- $H_2S$ detected using copper strip test; ppmv determined using stain tubes
(b) Levels of acid gas concentrations in natural gas
- Subquality natural gas: $\text{CO}_2 \geq 2\%$; $\text{N}_2 \geq 4\%$; $\text{H}_2\text{S} \geq 4\text{ppmv}$
- Upgrading or blending of subquality gas necessary

(c) Gas purification levels
- Inlet conditions of gas processing plant: ambient temp & press. 20 to 70 bar (300 to 1,000 psi)
- 1. Pipeline gas (residential or industrial fuel): $[\text{H}_2\text{S}] = 6 \text{ mg/m}^3$ (0.25g/100scf) & 3-4 mol%
- 2. NGL recovery or nitrogen rejection in turboexpander $\text{CO}_2$ is removed to avoid formation of solids
- 3. LNG quality gas: $\text{H}_2\text{S} \leq 50 \text{ ppmv}$ & $\text{CO}_2 \leq 50\text{ppmv}$
(d) Acid gases disposal

- How are acid gases exploited depends on their quality of H₂S & CO₂
- Carbon dioxide:
  - Frozen CO₂ could clog liquefaction equipment
  - Re-injected in reservoir as part of EOR, if quantities are large
  - Otherwise, CO₂ could be vented provided environmental regulations are met
- Options for H₂S:
  - 1. **Incinerated & vented** provided SO₂ regulations are satisfied
  - 2. Combined with H₂S scavengers (iron sponge)
  - 3. Transformed to elemental sulphur by Claus or other process
  - 4. Underground disposal in geological formations

Low levels

High levels

Sulphur crystals
(e) Purification process

- Distinction btw purification (small) & separation (large volumes)
- Four possible gas removal cases:
  - (i) CO\textsubscript{2} removal from gas containing no H\textsubscript{2}S (sweet gas)
  - (ii) H\textsubscript{2}S removal from gas with no CO\textsubscript{2} (sour gas)
  - (iii) Concurrent extraction of H\textsubscript{2}S & CO\textsubscript{2}
  - (iv) Selective removal of H\textsubscript{2}S from gas containing both CO\textsubscript{2} & H\textsubscript{2}S
Acid gas removal processes

- H$_2$S & CO$_2$ content plus final gas acid levels vary substantially; no single processing process is best
- Two main types of acid gas types processes:
  - Adsorption.
  - Absorption.

**Adsorption**

- Adsorption is a physical–chemical phenomenon. Gas is concentrated on the surface of a solid or liquid to remove impurities.
- Usually, carbon is the adsorbing medium.
- Medium *regenerated* upon desorption
- Granular solids with a large surface area per unit mass
- Captured gas *desorbed* with hot air or steam for recovery/incineration
- Adsorbers increase low gas concentration prior to incineration
Adsorption & Absorption

Adsorption (2)
- Adsorbers’ limitation. Need to minimize particulate matter &/or condensation of liquids (eg H₂O vapor) which could mask the adsorption surface and reduce its efficiency drastically

Absorption processes
- Absorbed gas passes thru absorbent (liquid)
- Besides physical solubility process may include chemical reactions
- Common absorbing media: H₂O, aqueous amine slts, caustic, sodium carbonate & nonvolatile hydrocarbon oils
- Usually, gas–liquid contactor designs are plate columns or packed beds
Acid gas removal processes

- Common processes: Batch type (metal oxide processes); iron & zinc oxide processes; Amine processes (aqueous alkaloamine sltns)
Amine process

- Used on the majority of onshore gas sweeting plants
- Principle solutions (liquids):
  - MonoEthanolAmine (MEA): low P; high outlet gas specs
  - DiEthanolAmine (DEA): medium to high P; no reclaim
- MEA & DEAs are regenerated by temp & pressure changes (or both)
Recovered $\text{H}_2\text{S}$

1. Vented
2. Flared in waste gas flares or smokeless flaring
3. Incinerated into $\text{SO}_2$
4. Converted to elemental sulphur or sulphuric acid

Video
Amine system design

- Design process encompasses:
  - 1. Amine absorbers (MEA or DEA)
  - 2. Flash vessel
  - 3. Amine reboiler
  - 4. Amine regenerator
  - 5. Rich/lean amine heat exchangers
  - 6. Amine cooler
  - 7. Amine solution pumps
Amine circulation rate determined from acid gas flow rate, sln concentration & acid gas loading

In SI units:

\[ L_{\text{MEA}} = \frac{2.55 \ Q_g \ X_A}{c \ \rho \ A_L}, \ L_{\text{DEA}} = \frac{4.39 \ Q_g \ X_A}{c \ \rho \ A_L} \]

- \( L_{\text{MEA}}, \ L_{\text{DEA}} \) the slt circulation rate (m³/h)
- \( Q_g \) the nat gas flow rate (std m³/h)
- \( X_A \) the required reduction in total acid gas fraction (moles acid gas removed/mole inlet gas). NB: MEA & DEA are not selective (\( X_A = \)of components (CO₂, H₂S & mercaptans)
- \( c \) amine weight fraction (kg amine/kg solution)
- \( \rho \) is the slt mas density (kg/m³)
- \( A_L \) is the acid gas loading (mole acid gas/mole amine)
Reboiler duty

- Reboiler provides heat input to amine stripper
- Higher reboiler duty, smaller stripper column
- Typically for a 20 tray stripper reboiler duty:
  - MEA stem = 1,000-1,200Btu/lb (280-330MJ/m³)
  - DEA stem = 900-1,000Btu/lb (250-280MJ/m³)
- Reboiler duty (SI units):
  \[ Q_{reb} = 92,905L_{MEA}, \quad Q_{reb} = 72,421L_{DEA} \]

where: \( Q_{reb} \) is the reboiler duty \( W \) (btu/h), \( L_{\text{MEA, DEA}} \) is the amine circulation rate (m³/h)

Typical, reboiler temps: MEA = 225-260°F (107-127°C)
  - DEA = 230-250°F (110-121°C)
Example

- Ex# 6: DEA processing system
CO$_2$ removal – no H$_2$S

- Selection chart guides most economical choice
Amine SG vs composition

Specific gravity versus composition for aqueous ethanolamine solutions at 20 °C

Solutions containing more than 96° DEA will freeze at 20 °C
Basic design calcs for MEA, DEA & DGA®

- Procedure used when CO$_2$ & H$_2$S are present
- Limitations:
  - Conservative estimation of amine circulation
  - Equations applicable if CO$_2$ & H$_2$S $>$ 5 mol%
  - Max. amine conc. $\approx$ 30 wt%

- DEA (conventional) circulation rate:
  \[ Q_{DEA} \text{ (gpm)} = 45 \, Q_f \left(\frac{y}{x}\right) \]

- Circulation rate for high loading (0.5 mol acid gas pick-up/mole DEA):
  \[ Q_{DEA} \text{ (gpm)} = 32 \, Q_f \left(\frac{y}{x}\right) \]

where $Q_f$ is sour gas feed (MMscfd), $y$ is acid gas conc in sour gas (mol%), $x$ is DEA conc. in liquid slt (mass% or wt%)
Heat exchange & pump power requirements

Fig 1. Estimated heat exchange requirements

<table>
<thead>
<tr>
<th>Duty</th>
<th>Area</th>
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<tr>
<td></td>
<td></td>
</tr>
<tr>
<td>Btu/hr</td>
<td>kW</td>
</tr>
<tr>
<td>Reboiler (Direc fired)</td>
<td>72,000 • GPM</td>
</tr>
<tr>
<td>Rich-Lean Amine HEX</td>
<td>45,000 • GPM</td>
</tr>
<tr>
<td>Amine cooler (air cooled)</td>
<td>15,000 • GPM</td>
</tr>
<tr>
<td>Reflux condenser</td>
<td>30,000 • GPM</td>
</tr>
</tbody>
</table>

Fig 2. Estimated pump power requirements

| Amine Solution Pumps | GPM • PSIG • 0.00065 = hp | m³/h • kPa (ga) • 0.00031 = kW |
| Amine Booster Pumps | GPM • 0.06 = hp | m³/h • 0.20 = kW |
| Reflux Pumps | GPM • 0.06 = hp | m³/h • 0.20 = kW |
| Aerial Cooler | GPM • 0.36 = hp | m³/h • 1.20 = kW |
Amine plant contactor (absorber) diameter

- Absorber diameter (in inches):
  \[ D_A = 44 \left( \frac{Q_{in}}{\sqrt{P}} \right)^{0.5} \]
  \( D_A \) rounding to nearest ±6 in (24”-294”), \( Q_{in} \) is gas inlet flow rate to absorber (MMscfd), \( P \) is the absorber pressure (psia).

- Regenerator bottom diameter (in inches):
  \[ D_r = 3.0 \sqrt{Q_{DEA}} \text{ (gpm)} \]

  where \( Q_{DEA} \) is the amine circulation rate (gpm)

- Diameter of regenerator column above feed point, \( D_{r,t} = 0.67D_r \)
Acid gas treatment calcs.

- Example #7
Gas dehydration
Gas dehydration

- First: determine water content of gas stream
- Obtained from: McKetta & Wehe (1958) pressure–temperature correlation
Gas dehydration

- Natural gas (associated, dry, or tail) contains H₂O in either liquid &/or gaseous form
- Water vapor is the most common contaminant of hydrocarbons
- Operating experience & engineering reasons require control of H₂O
- Dehydration is a pre-requisite for sales gas & NGL recovery
- Dehydration’s important because:
  - 1. Gas hydrates. NG could combine with H₂O to form gas hydrates which can occlude pipeline fluid flow.
  - 2. Corrosion. H₂O condensation in pipeline can promote slug flow leading to erosion & corrosion. Carbon steel prone to corrosion.
  - 3. Calorific value. H₂O increases the volume of natural gas & lowers its energy content.
  - 4. Gas specs. Sales contracts or pipeline contracts dictate max H₂O content of NG: 7 lb (H₂O)/MMscf (3.2 kg(H₂O)/28,316 m³).
  - 5. Downstream processing. H₂O presence may cause side reactions, foaming or catalyst deactivation
If natural gas contains water vapor, it will reduce the efficiency & capacity of pipeline

Dehydration helps meet gas sales contracts:
- Southern USA, Southeast Asia, southern Europe, W. Africa, Australia 7 lb/MMScfd
- Northern USA, Canada, northern Europe, northern & central Asia 2–4 lb/MMScfd
- Cryogenic (turbo expander plants) 0.05 lb/MMscfd
- Solid bed adsorption units are used where very low dew points are required.
Gas dehydration

- H$_2$O vapor **dew point** is the temperature & pressure at which the first drop of water vapor condenses into a liquid
- It is used as a means of measuring the H$_2$O vapor content of natural gas
- Why do H$_2$O droplets form on the outside surface of a cold H$_2$O glass?
- As water vapor is removed from gas stream, the dew point decreases
- Keeping the gas stream above the dew point will prevent hydrates from forming and prevent corrosion from occurring.
Water vapor of natural gas

- Determine gas water content at dew point
Example

- Example #8
Solution (#1)

(i) **Point A**: 1000 psia @ 90°F = 42 lb(H₂O)/MMscf  
**Point B**: 1000 psia @ 35°F = 5.8 lb(H₂O)/MMscf  
Therefore,  
\[ \Delta H₂O \text{ content} = 42 - 5.8 \approx 36.2 \text{ lb/MMscf} \]

(ii) **Point C**: 1000 → 300 psia @ 5.8 lb/MMscf  
Water dew point ≈ 7°F
Dehydration methods

- Most common dehydration methods:
  1. **Absorption**, using the liquid desiccants (e.g., glycols, methanol, ...)
  2. **Adsorption**, using solid desiccants (e.g., alumina, silica gel, ...)
  3. **Cooling/condensation** below the dew point, by expansion and/or refrigeration

Diagram:

- **Dehydration of Natural Gas** (water vapor removal)
- **Absorption**: Removing vapor using solvents
  - MEG
  - DEG
  - TEG
- **Adsorption**: Removing vapor using solid beds of
  - Alumina
  - Molecular Sieves
  - Silica Gel
  - CuO
- **Condensation**: Cooling below dew point by:
- **Inhibition Or Hydrate Point Depressants**: Lowering the dew point to avoid hydrate formation using chemicals
  - Glycols
  - Methanol

MEG: Monoethylene glycol
DEG: Diethylene glycol
TEG: Triethylene glycol
1. Absorption: Glycol dehydration process

- Principles:
  1. “Wet” gas comes into contact with a hygroscopic solvent (triethylene glycol) which extracts the water
  2. Absorption, defined as the transfer of H₂O from the gas into the liquid phase, is favorable at lower temp & higher pressure
  3. Absorption process is *dynamic & continuous*. Therefore, water absorption occurs in a *counterflow* configuration of the feed gas & glycol

- Working press.: 1000-1200psi
- Gas temp.: 80-110°F
- Glycol regen. temp: 370-190°F
2. Adsorption

- Solid desiccants more effective than liquid ones. Attain <0.1 ppmv.
- Often uses in conjunction with glycol dehydrator.
- Removal of water vapor by solid desiccant (alumina, silica gel, molecular sieves).
- When low dew points are needed, solid-bed dehydration is the choice.
- Principle of fixed-bed adsorption of water by solid desiccants.

<table>
<thead>
<tr>
<th>Solid desiccants properties</th>
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<tr>
<td>Desiccant reference</td>
</tr>
<tr>
<td>Pore diameter (Å)</td>
</tr>
<tr>
<td>Bulk density (lb/ft³)</td>
</tr>
<tr>
<td>Heat capacity (Btu/lb°C)</td>
</tr>
<tr>
<td>Minimum dew point (°F)</td>
</tr>
<tr>
<td>Design capacity (wt%)</td>
</tr>
<tr>
<td>Regeneration stream temp. (°F)</td>
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<tr>
<td>Heat of adsorption (Btu/lb)</td>
</tr>
</tbody>
</table>

- Important parameter: design capacity [H₂O mass/mass of desiccant].
2. Adsorption (2)

- Adsorption performance governed by:
  - Relative humidity of inlet gas
  - Gas flow rate
  - Temp of the adsorption zone
  - Granule mesh size
  - Degree of contamination of desiccant
- Bed first loaded with water; regenerated by hot gas; cooled by cold gas
Natural gas liquids recovery & fractionation
Recall: natural gas liquids (NGL) consist of $C_{2+}$: $\text{CH}_4, \text{C}_2\text{H}_6, \text{C}_3\text{H}_8 \& \text{C}_4\text{H}_{10}$

Gas condensates:
- $\text{H}_2\text{S}, \text{CO}_2$, straight-chain alkanes, cyclohexane, napthenes
- Thiols (mercaptants), aromatics (benzene, toluene)

Separation & recovery of NGLs from gas stream based on *phase change*
- (i) Energy separating agent (ESA)
- (ii) Mass separating agent (MSA)

NGLs can be recovered by:
- (i) Partial liquefaction or partial condensation or
- (ii) Total condensation

Types of fractionators with recommended gas streams & products will also be explained
Energy separating agent & Mass separating agent

Energy separating agent (ESA)
- Change in phase recovers NGLs from bulk gas stream
- Expel heat by refrigeration allows heavier H/C components to condense (liquefy):
  \[ \text{A mixture of hydrocarbon vapor} \rightarrow \text{Heat} \rightarrow \text{Liquid} + \text{Vapor} \]
- Partial liquefaction is possible whereas total liquefaction covers entire gas stream

Mass separating agent (MSA)
- A new phase is developed either using adsorption (solid material in contact with gas) or absorption (liquid in contact with gas)
Mass separating agent

• A *phase change* in NGL recovery & separation always involves control of one or more of the following parameters:
  - Operating pressure, $P$
  - Operating temperature, $T$
  - System composition or concentration

• To obtain the desired quantities of particular NGL constituents we control:
  1. Pressure is maintained by direct control. Temperature is lowered by refrigeration:
     - (a) Compression refrigeration
     - (b) Cryogenic separation (expansion across a turbine)
     - (c) Cryogenic separation (expansion across a valve)
  2. Control of the composition or concentration of the hydrocarbons to be recovered
Adsorption (MSA)

- Simply put, adsorption is defined as a concentration control method prior to condensation.
- Solid materials offer “new surface” area which traps H/Cs components to be recovered and separated.
- Once constituents are attached on solid are then “regenerated” in a high concentration.
- About 10-15% of gas feed is recovered as liquids (NGLs).
- Adsorption is usually coupled with refrigeration methods.
Absorption (MSA)

- **Absorption** provides a surface or “contact” area of liquid-gas interface
- Again process efficiency is a function of:
  - Pressure, $P$
  - Temperature, $T$
  - Gas flow rates
  - Contact time
- Likewise, to enhance condensation absorption could be combined with refrigeration
Absorption (2)

- Natural gas stream brought in contact with light oil in absorber
- Rich oil (NGL + solvent) directed to a distillation unit to be separated
- Oil recycled in absorber
Refrigeration process

- Production of NGL at low temperatures is a common extraction process
- Operating pressure for max. liquid recovery: 400 to 600 psia
- Refrigeration operating temp selected on the type of product:
  - If liquid product contains ethane as lightest component then temp $-30^\circ C$ to $-18^\circ C$
  - If operating temp. $> -30^\circ C$, cryogenic range of ethane recovery is preferred

Cryogenic processes

- Natural gas could be separated from natural gas stream by cryogenic expansion (autorefrigeration) processes:
  - 1. NG liquid H/Cs condensed & recovered using a turboexpander
  - 2. Expansion through a valve yields similar results
- Turboexpansion generates lower temps than valve expansion
Turboexpansion

- Operating temp. range: $-73^\circ C$ to $-107^\circ C$ & 68 atm
Fractionation of NGL

- Process of separating stream of NGLs into components called fractionation
- Safety issues govern the min extraction level of NGLs
- Max. extraction defined by technology & relative market value of NGLs
- NGLs are fractionated by heating mixed NGL streams & subjecting them through a series of distillation towers
- Fractionation based on different boiling points of NGL products
Fractionation

- Lightest fraction boils at top of tower while heaviest rerouted to another tower
- Fractionation plants aim to:
  - 1. Produce products with certain specs
  - 2. Control impurities in valuable products
  - 3. Control fuel consumption
Liquid Petroleum Gas (LPG)

- LPG is a hydrocarbon mixture of propane & n-butane. The most common commercial products are propane, butane, or some mixture of the two and are generally extracted from natural gas or crude petroleum.
- Note that LPG is not Liquefied Natural Gas (LNG)
Natural gas classification

- **“Rich”** gas contains $\geq 3$ GPM (gallons of liquids recoverable/Mscf) of $C_2^+$ liquids
- **“Lean”** gas contains <1 GPM of $C_2^+$ liquids
- **“Sweet”** gas contains <4 ppmv of $H_2S$ (p/line-quality gas 0.25-1.0 grains/100scf; 4-16 ppmv) 1 grain = 64.8mg
- **“Sour”** gas contains an appreciable quantity of $CO_2$, $H_2S$, sulfide, or mercaptans
- **“Wet”** gas contains water, or a gas that has not been dehydrated; term synonymous with rich gas.
- **“Dry”** gas that consists mostly of $CH_4$, producing little condensable heavier hydrocarbon compounds such as $C_3H_8$ & $C_4H_{10}$. (<0.1 GPM)
LPG facilitated diving (not to be attempted!)
Thanks for your attention!