

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



Constantinos Hadjistassou, PhD

Associate professor

Programme in Oil & Gas Engineering

University of Nicosia

Marine & Carbon Lab: www.carbonlab.eu

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UNIVERSITY *of* NICOSIA

Overview

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- Gas treating
- Acid gas removal
 - Carbon dioxide (CO₂)
 - Sour gas (H₂S, sulphur species)
- Gas dehydration
- Natural gas liquids (NGLs) recovery & separation
- NGL fractionation

Mexico's first LNG plant?

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- Sempra Energy to build Energia Costa Azul LNG plant
- Banja California (50 mi from San Diego)
- Asia deliveries: 12-15 days vs 32 days for US GOM
- Total to buy 9mtpa from US & Mexico
- Competitors:
 - Global LNG's Calcasieu Pass (LA)
 - Tellurian
 - NextDecade
 - LNG Limited
 - Mexico Pacific Limited (West coast)
- Panama Canal:
 - Transit time: 8-10 hours
 - Transit fees: \$1,000/container
 - Small yacht: \$2,000
 - Containership: \$900,000
 - Richard Halliburton payed \$0.36

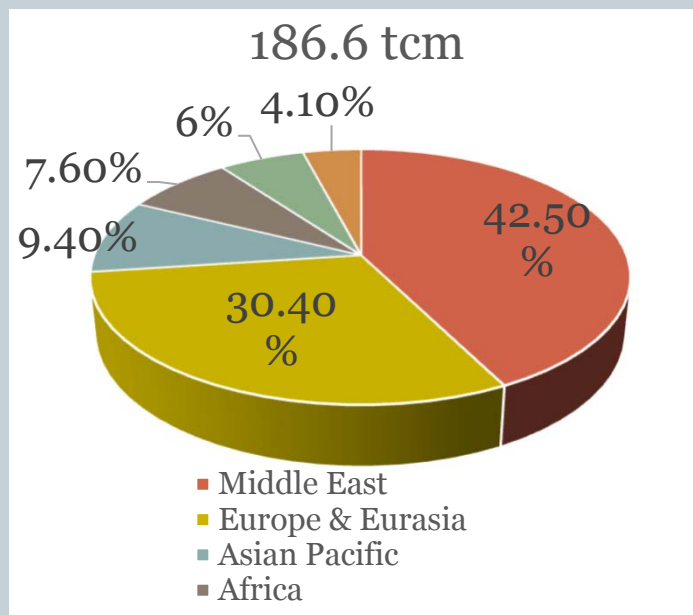


Gas treatment

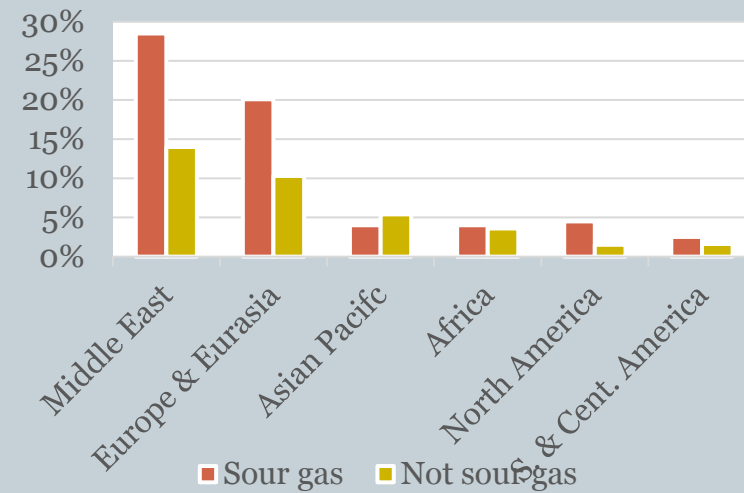
World's raw gas composition

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Total reserves in 2016^{1,3} (%)



Prediction of sour gas reserves^{2,3} (%)



1. BP Statistical Review of World Energy June 2017

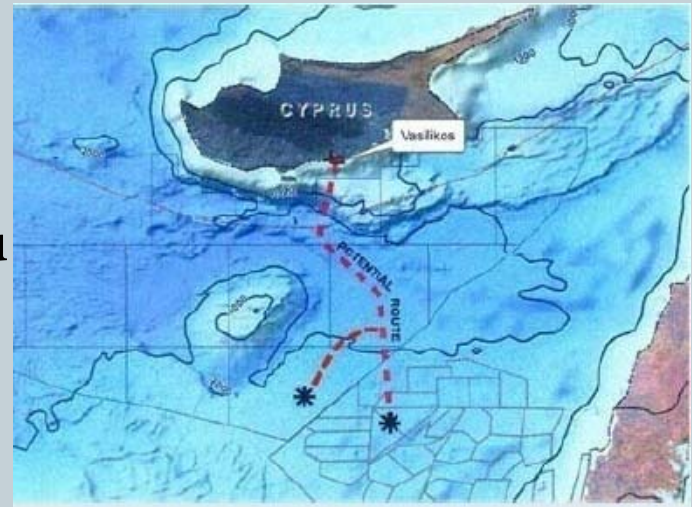
2. H. Devold, ABB, 2013

3. A. Demirbas, Springer 2010

Some LNG comparative costs

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- Aphrodite gas field
- Development costs: \$3.5+2bn
- State revenue: \$9.5bn
- LNG **development** costs: \$2.5/MMBtu
- **Pipeline** costs to Egypt: \$1.5/MMBtu
- **Shipping** costs to Asian markets: \$2/MMBtu
- **Regasification** costs: \$0.5/MMBtu
- Can we decrease/eliminate the regas costs?



Typical composition of natural gas

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

Typical Gas Compositions

	Canada (Alberta)	Western Colorado	Southwest Kansas	Bach Ho Field ^a Vietnam	Miskar Field Tunisia	Rio Arriba County, New Mexico	Cliffside Field, Amarillo, Texas	Name	Formula	Volume (%)
Helium	0.0	0.0	0.45	0.00	0.00	0.0	1.8	Methane	CH_4	>85
Nitrogen	3.2	26.10	14.65	0.21	16.903	0.68	25.6	Ethane	C_2H_6	3–8
Carbon dioxide	1.7	42.66	0.0	0.06	13.588	0.82	0.0	Propane	C_3H_8	1–2
Hydrogen sulfide	3.3	0.0	0.0	0.00	0.092	0.0	0.0	Butane	C_4H_{10}	<1
Methane	77.1	29.98	72.89	70.85	63.901	96.91	65.8	Pentane	C_5H_{12}	<1
Ethane	6.6	0.55	6.27	13.41	3.349	1.33	3.8	Carbon dioxide	CO_2	1–2
Propane	3.1	0.28	3.74	7.5	0.960	0.19	1.7	Hydrogen sulfide	H_2S	<1
Butanes	2.0	0.21	1.38	4.02	0.544	0.05	0.8	Nitrogen	N_2	1–5
Pentanes and heavier	3.0	0.25	0.62	2.64	0.630	0.02	0.5	Helium	He	<0.5

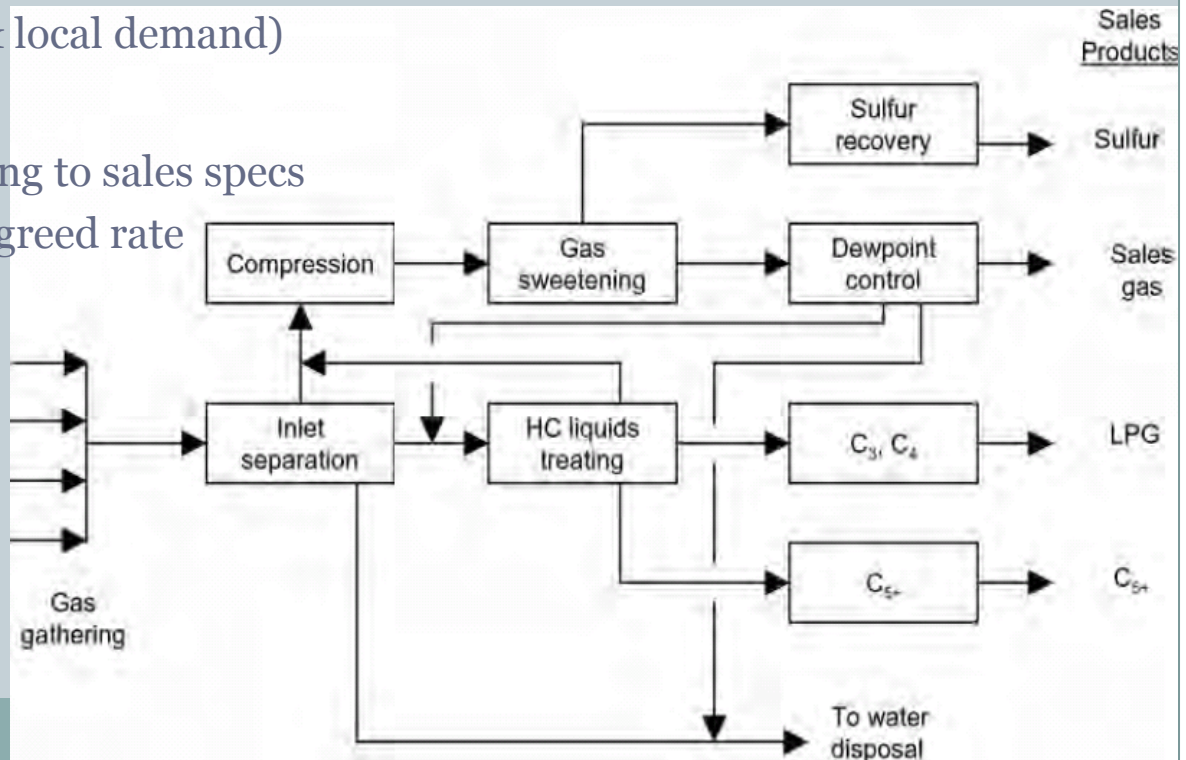
^a Tabular mol% data is on a wet basis (1.3 mol% water)

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

Gas treating facility design

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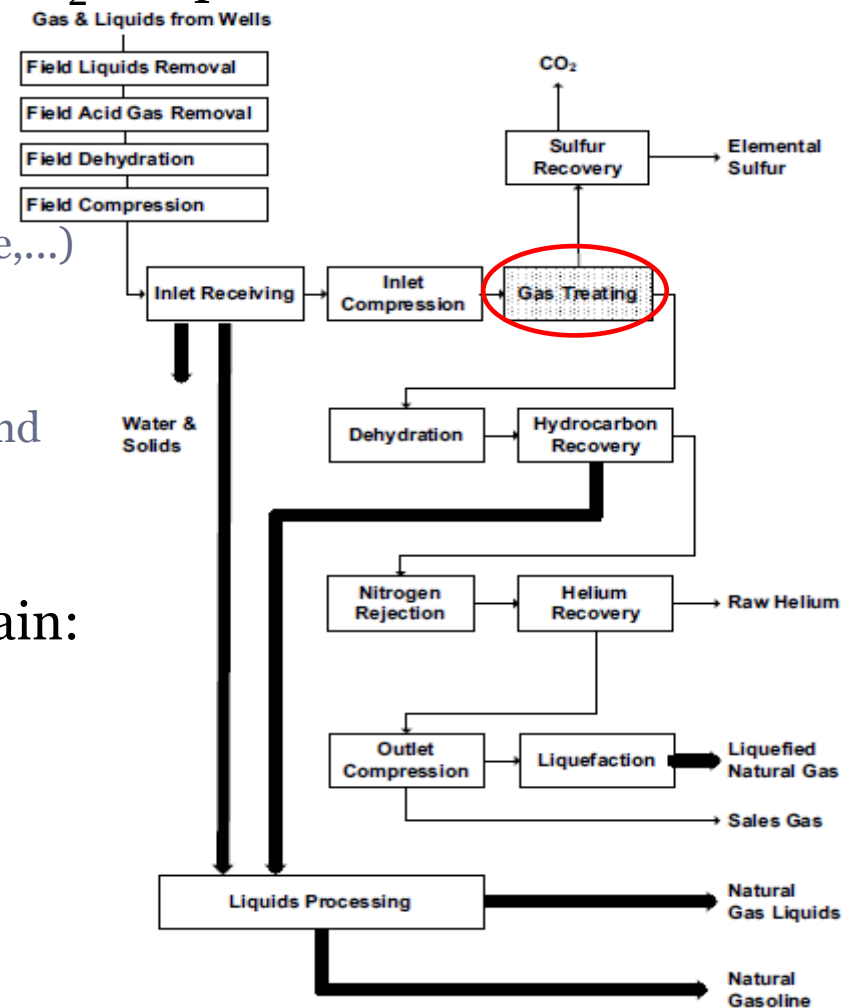
- Requirements for gas plant design:
 - Raw gas production throughput (plant capacity) [gas reserves]
 - Composition of separator inlet (feed) gas & condensates
 - Condensate/gas rates
 - Residual gas specs
 - Rate of gas sales (exports & local demand)
- End-user assurances:
 - Processed gas quality abiding to sales specs
 - Continuous gas supply at agreed rate
- Pipeline transmission efficiency affected by presence of H_2O
- Sales gas specs limits:
 - H/C dew point temp.
 - H_2O vapour content



Gas treating

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- Wellhead gas is usually saturated with H_2O vapour
- Gas processing (or refining) usually involves several processes to remove:
 - Oil; water vapour (H_2O)
 - Elements of sulphur (H_2S , carbonyl sulphide,...)
 - Helium (He); carbon dioxide (CO_2)
 - Natural gas liquids; Nitrogen (N_2)
 - Higher hydrocarbons; impurities ie dust, sand
 - Traces of Mercury (Hg) & sometimes
 - Oxygen (O_2)
- Content of dilutents. Some wells contain:
 - 92% of CO_2 (Col., USA)
 - 88% of H_2S (Alberta, Ca)
 - 86% of N_2 (Tx, USA)



Selecting a refining process

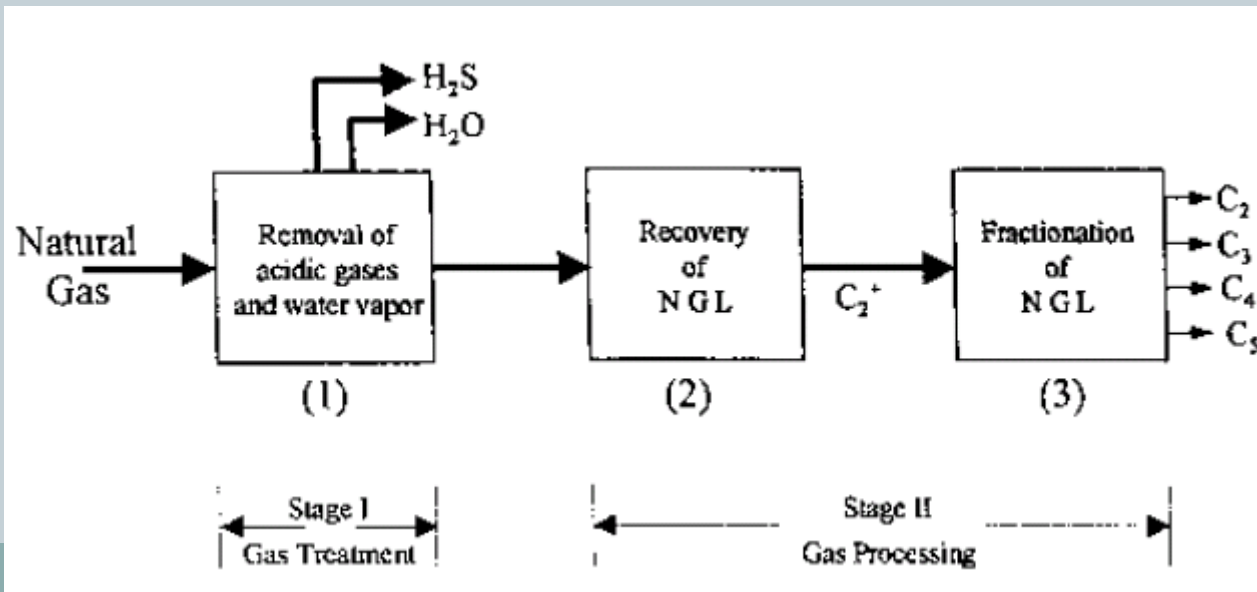
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- Many **chemical processes** are available for refining natural gas.
- Several variables dictate **process sequence** & **process selection**:
 - 1. Types & concentrations of gas contaminants;
 - 2. Degree of contaminant removal (how pure);
 - 3. Selectivity of acid gas removal;
 - 4. Temperature, pressure, volume & composition of the gas;
 - 5. The CO₂/H₂S ratio
 - 6. Sulphur recovery due to process economics or environmental issues
 - 7. Mercaptans & carbonyl sulfide in H₂S & CO₂ 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 H₂O (21 °C (70 °F))

Process sequence

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- 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

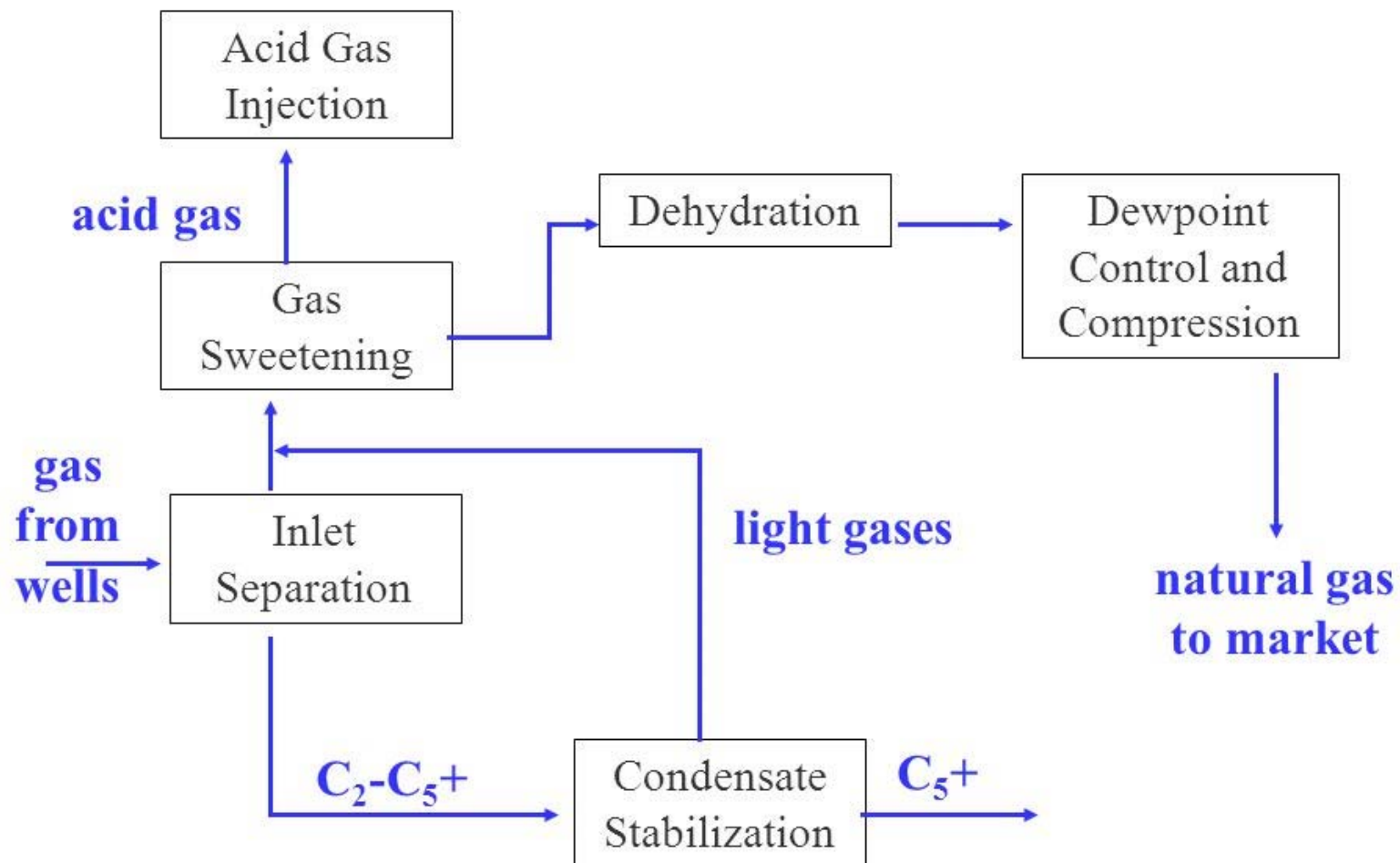
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- Nitrogen: 3 methods used to recover nitrogen from natural gas:
 - Cryogenic distillation
 - Adsorption
 - Membrane separation
- Helium:
 - NG main source of helium
 - Recovery is uncommon
 - Possible if helium content > 0.5 vol%.

Acid gas removal (sweetening)

Gas treatment

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Sweetening (1)

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- 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 (TLV) 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 TLV 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*



Sweetening (2)

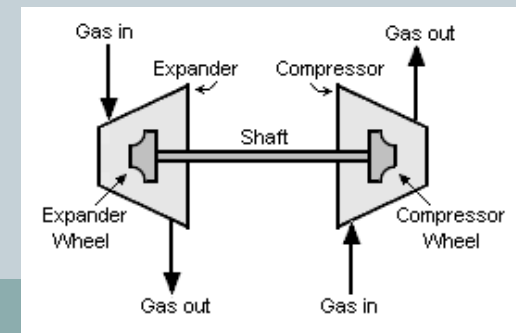
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(b) Levels of acid gas concentrations in natural gas

- 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 sub-quality 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 CO_2 is removed to avoid formation of solids
- **3. LNG quality gas**: $\text{H}_2\text{S} \leq 50 \text{ ppmv}$ & $\text{CO}_2 \leq 50\text{ppmv}$



Sweetening (3)

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(d) Acid gases disposal

- How are acid gases exploited depends on their quality of H_2S & CO_2
- Carbon dioxide:
 - Frozen CO_2 could clog liquefaction equipment
 - Re-injected in reservoir as part of EOR, if quantities are large
 - Otherwise, CO_2 could be vented provided environmental regulations are met
- Options for H_2S :
 - 1. **Incinerated** & **vented** provided SO_2 regulations are satisfied
 - 2. Combined with **H_2S 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

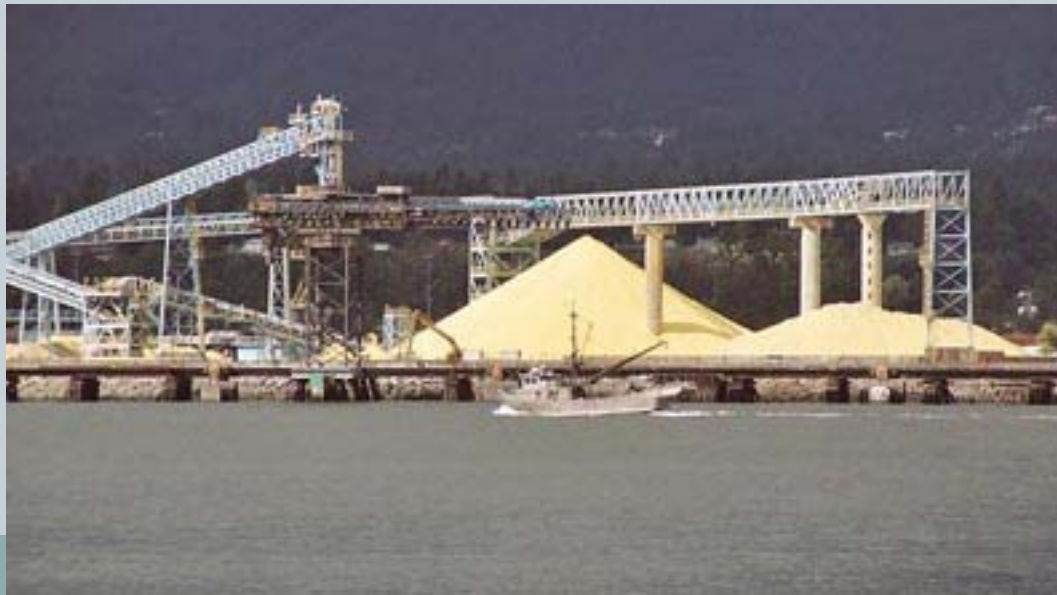


Sweetening (4)

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(e) Purification process

- Distinction btw purification (small) & separation (large volumes)
- Four possible gas removal cases:
 - (i) CO_2 removal from gas containing no H_2S (sweet gas)
 - (ii) H_2S removal from gas with no CO_2 (sour gas)
 - (iii) Concurrent extraction of H_2S & CO_2
 - (iv) Selective removal of H_2S from gas containing both CO_2 & H_2S



Sulphur recovered from H/Cs

Acid gas removal processes

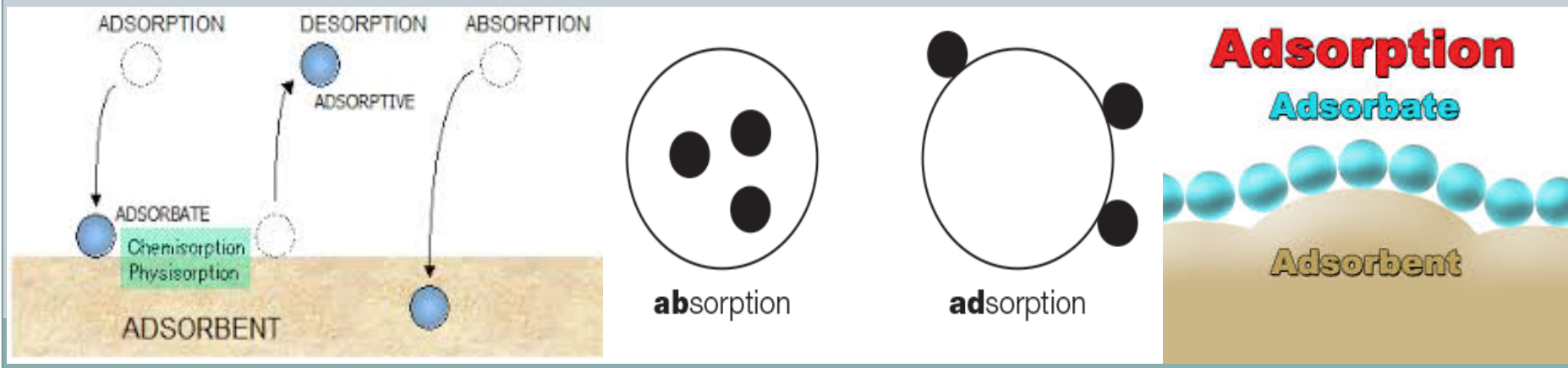
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- H_2S & CO_2 content plus final gas acid levels vary substantially; no single processing process is best
- Two main types of acid gas types processes:
 - Adsorption.
 - Absorption.

Adsorption

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- 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 vs Absorption

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- **Adsorption** is the adhesion of atoms, ions or molecules from a gas, liquid or dissolved solid to a solid surface.
- During **absorption** a fluid is dissolved or permeates in a liquid or solid.
- **Adsorption** is a surface phenomenon vs **absorption** which involves the bulk (entire) volume of the material.
- Adsorption is generally classified as **physisorption** (van der Waals forces), **chemisorption** (covalent bonding), or **electrostatic attraction**.
- Applications of adsorption comprise:
 - Catalysts
 - Activated charcoal
 - Capturing waste heat (adsorption chillers)
 - Water purification



Adsorption & Absorption

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Adsorption (2)

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

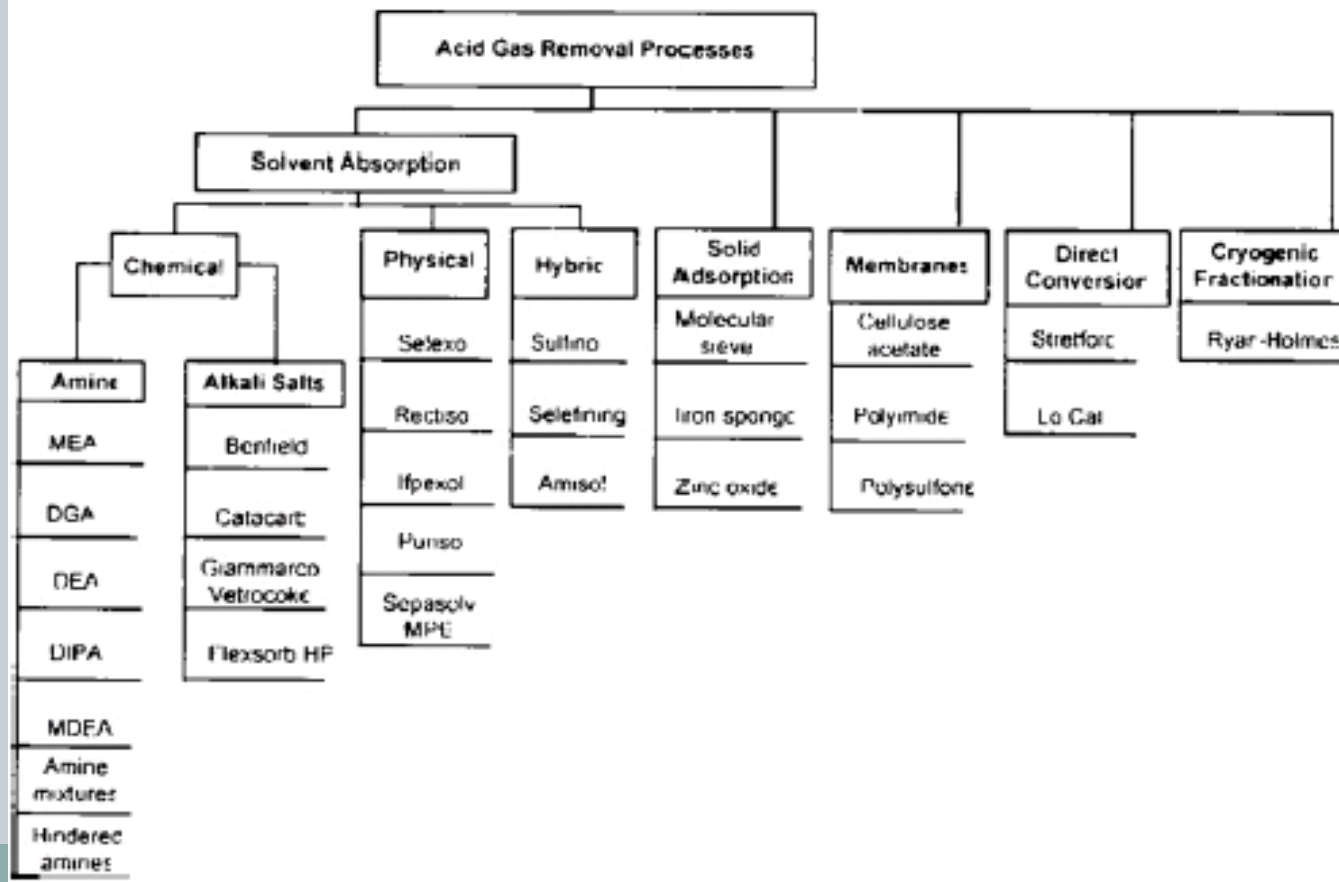
Absorption processes

- 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

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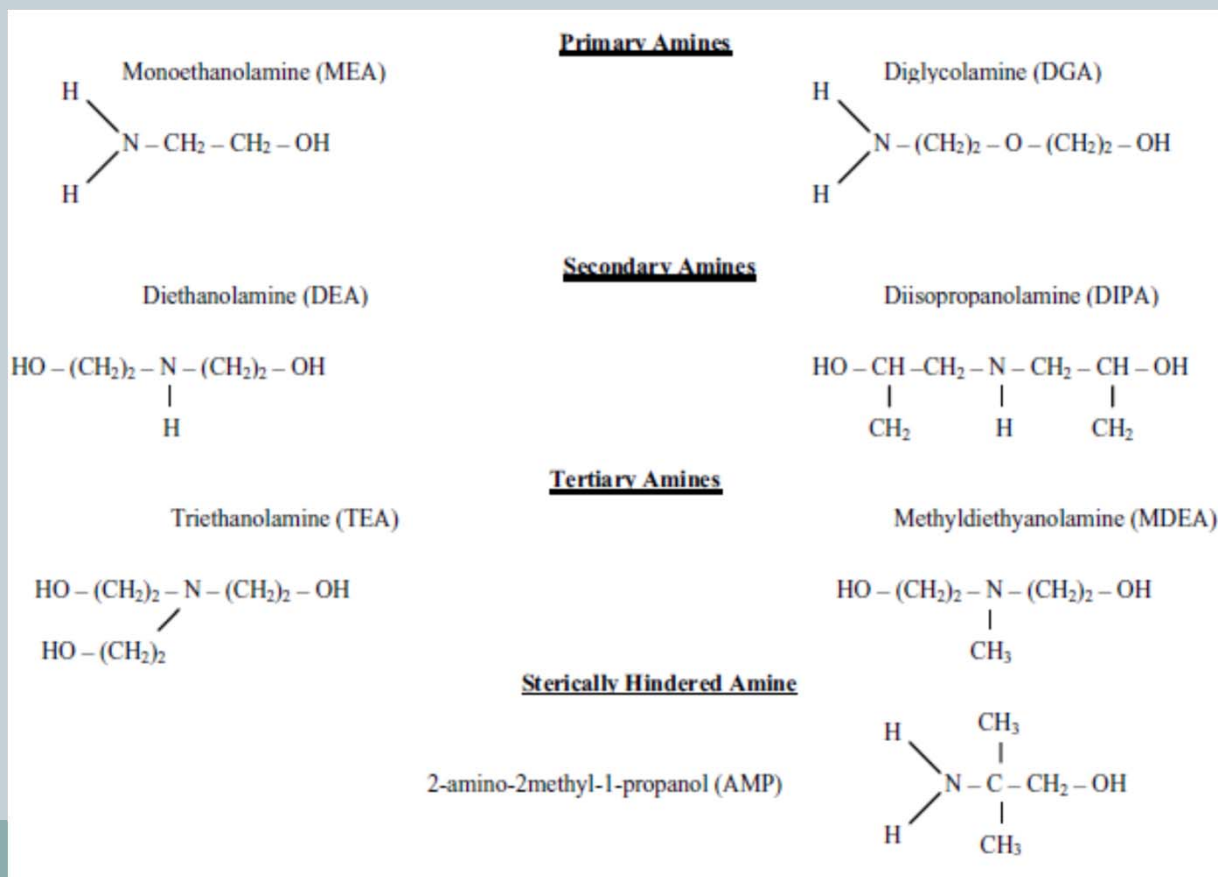
- Common processes: Batch type (metal oxide processes); iron & zinc oxide processes; Amine processes (aqueous alkaloamine slts)



Common amine compounds

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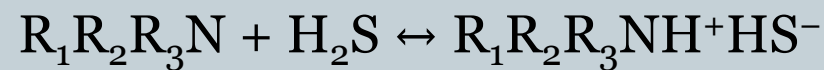
- H atom in NH_3 replaced by a hydrocarbon group
- Amine dissolved of 10-65%wt dissolved in H_2O



Removal of CO₂ & H₂S by amine slt

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- Process of acid gas expulsion accomplished in 2 steps:
 - 1. Absorption of acid gases (H₂S and CO₂) in amine slt
 - 2. Weak gases chemically react with amine slt
- Absorption is governed by H₂S partial pressure (Dalton's law)
- Chemical reaction is governed by reactivity of dissolved species
- Amines form salts by combining with acid gases
- Reaction of amine with acid gases is highly exothermic



Amine hydrosulphide

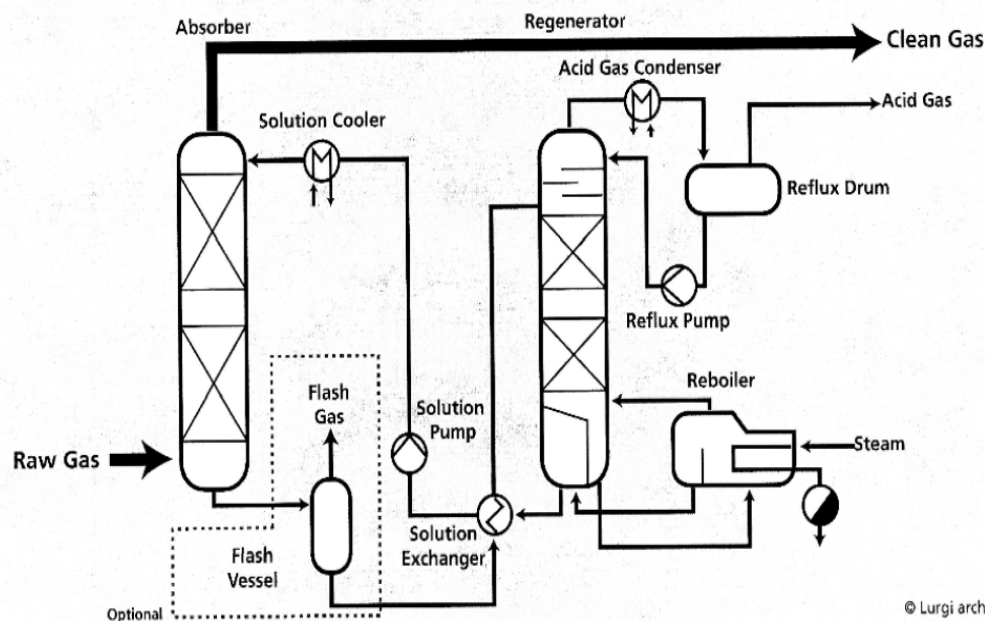


Amine process

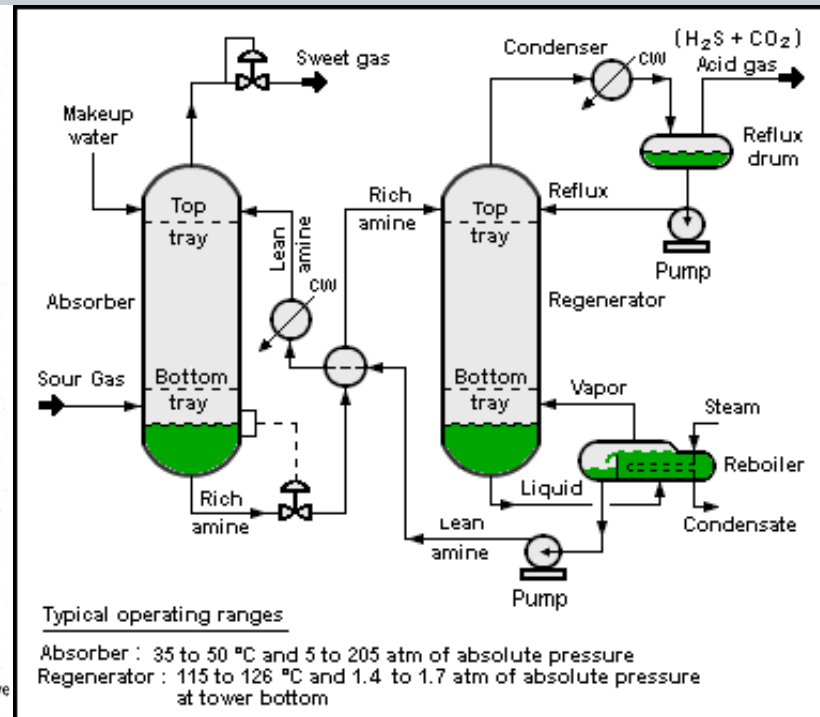
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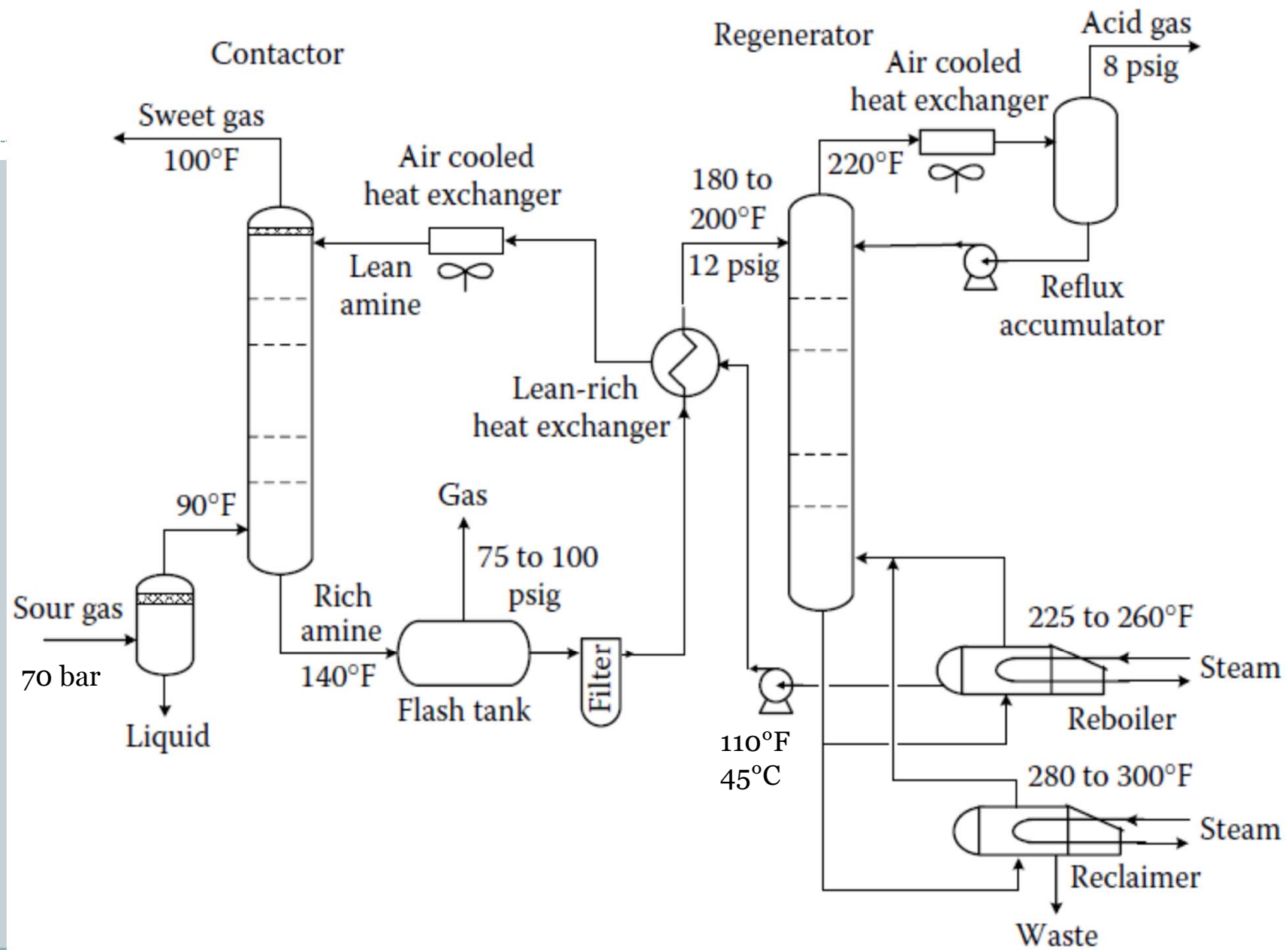
- Used on the majority of onshore gas sweetening plants
- Principle solutions (liquids):
 - MonoEthanolAmine (MEA): low P; high outlet gas specs
 - DiEthanolAmine (DEA): medium to high P; no reclaim
- MEA & DEAs are regenerated by temp & pressure changes (or both)

Gas Sweetening with Amines



© Lurgi archive





MEA acid gas removal process.

Issues with amine process

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- 1. **Corrosion:**
 - Higher amine concentrations foster corrosion
 - Rich amine acid gas loading favours corrosion
 - O₂ concentration promote corrosion
 - Heat stable salts (HSS) accelerate corrosion & foaming
- 2. **Foaming caused by suspended solids, liquid H/Cs, amine degradation, HSS is problematic because:**
 - 1. Reduces process efficiency by lowering gas-liquid interaction
 - 2. Results in poor solution distribution
 - 3. Solution holdup results in carryover and poor spec gas
- 3. **Heat stable salts (HSSs):**
 - Involved in corrosion and foaming
 - Removed by reclaimer

Recovered H_2S

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- 1. Vented
- 2. Flared in waste gas flares or smokeless flaring
- 3. Incinerated into SO_2
- 4. Converted to elemental sulphur or sulphuric acid

- Video



Amine system design

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- 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



Monoethanolamine (MEA)

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- **Advantages of MEA:**

- Very reactive compound, hence complete acid gas removal
- Used for moderate levels of CO_2 & H_2S

- **Drawbacks of MEA:**

- High vapour pressure results in high vaporization losses
- Irreversible rxn products with COS & CS_2
- High energy footprint for regeneration
- Cannot selectively remove CO_2 in presence of H_2S
- High corrosion rates compared to other amine slts
- Combination of MEA with O_2 generates corrosive thiosulphates

Diethanolamine (DEA)

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- **Pros of DEA:**

- DEA is less basic & reactive compared to MEA
- Lower vapour pressure, hence lower evaporation losses
- Suited for higher acid gas loadings
- Lower regeneration energy (to MEA)
- Concentration of DEA's limited by corrosion
- Forms regenerative compounds with COS & H₂S

- **Cons of DEA:**

- Not the best choice for high CO₂ levels as it forms corrosive by-products
- Difficulty of removing the salts, etc.

Amine circulation rate

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- 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_{MEA} , L_{DEA} the amine 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)
- ρ is the slt mass density (kg/m³)
- A_L is the acid gas loading (mole acid gas/mole amine)

Reboiler duty

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- Reboiler provides heat input to amine stripper
- Higher reboiler duty, smaller stripper column
- Typically for a 20 tray stripper reboiler duty:

MEA stm = 1,000-1,200Btu/lb (280-330MJ/m³)

DEA stm = 900-1,000Btu/lb (250-280MJ/m³)

- Reboiler duty (SI units):

$$Q_{\text{reb}} = 92,905L_{\text{MEA}}, Q_{\text{reb}} = 77,421L_{\text{DEA}}$$

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

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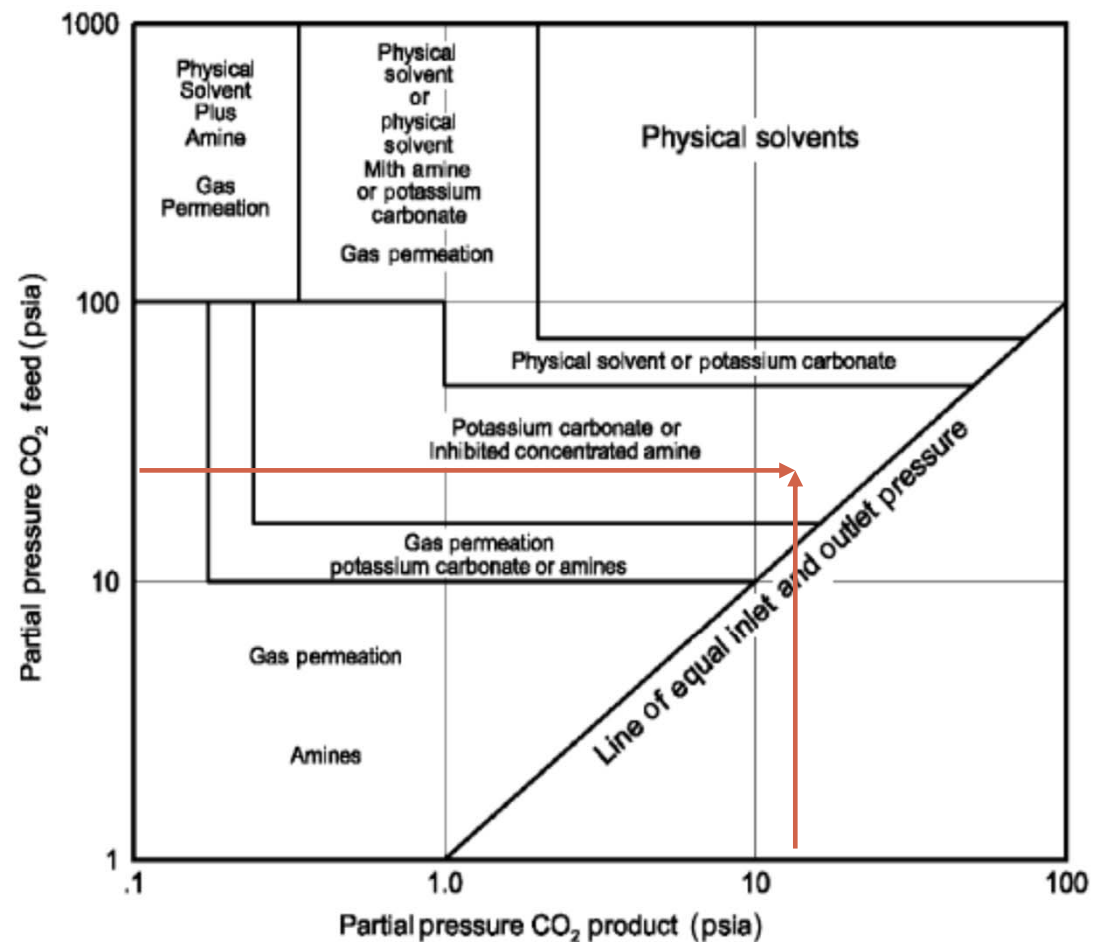
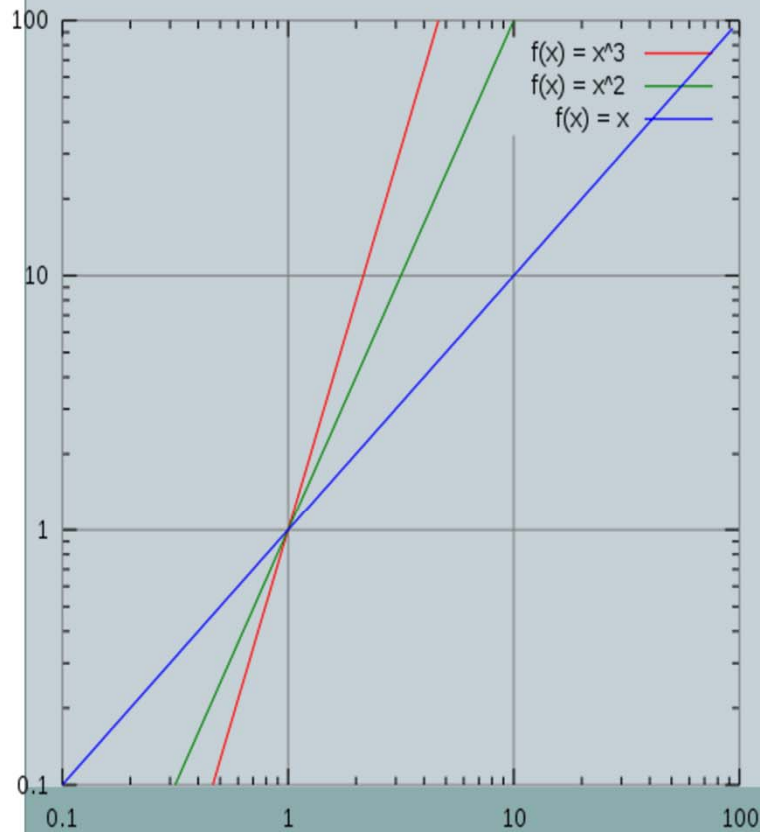
- Ex#6: DEA processing system

CO₂ removal – no H₂S

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- Selection chart guides most economical choice

Fig 1. CO₂ removal– no H₂S



Amine SG vs composition

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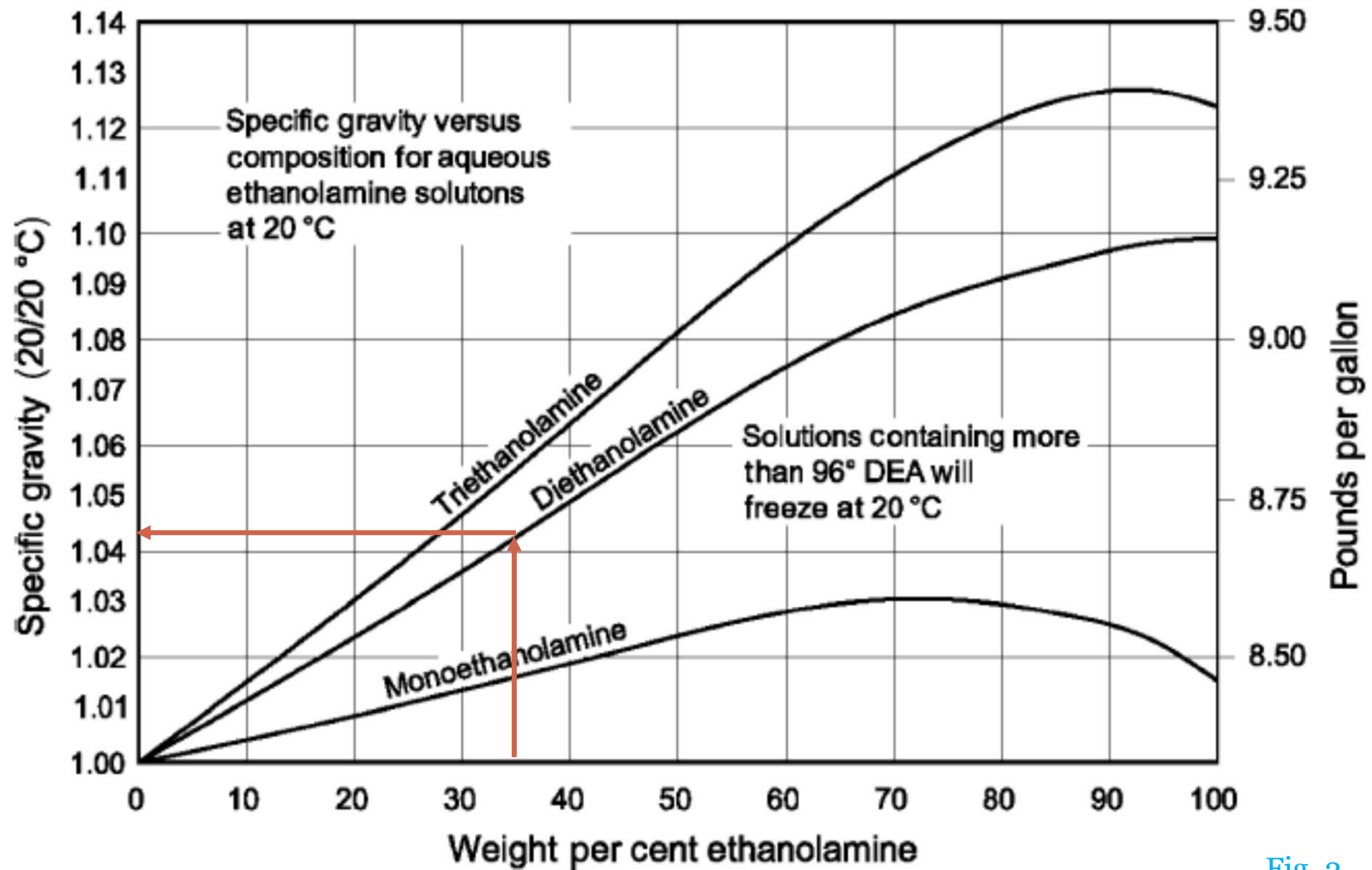


Fig. 2

Basic design calcs for MEA, DEA & DGA^{®*}

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- Procedure used when CO₂ & H₂S are present

- Limitations:

- Conservative estimation of amine circulation
- Equations applicable if CO₂ & H₂S > 5 mol%
- Max. amine conc. ≈ 30 wt%

- DEA (**conventional**) circulation rate:

$$Q_{\text{DEA}} (\text{gpm}) = 45 Q_f (y/x)$$

- Circulation rate for **high loading** (0.5 mol acid gas pick-up/mole DEA):

$$Q_{\text{DEA}} (\text{gpm}) = 32 Q_f (y/x)$$

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%)

*DGA[®]=DiGlycolAmine

Heat exchange & pump power requirements

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Fig 3. Estimated heat exchange requirements

	Duty		Area	
	Btu/hr	kW	Sq. ft.	m ²
Reboiler (Direc fired)	72,000 • GPM	93 • m ³ /h	11.30 • GPM	4.63 • m ³ /h
Rich-Lean Amine HEX	45,000 • GPM	85 • m ³ /h	11.25 • GPM	4.60 • m ³ /h
Amine cooler (air cooled)	15,000 • GPM	19.3 • m ³ /h	10.20 • GPM	4.18 • m ³ /h
Reflux condenser	30,000 • GPM	38.6 • m ³ /h	5.20 • GPM	2.13 • m ³ /h

Fig 3. Estimated pump power requirements

Main Amine Solution Pumps	GPM • PSIG • 0.00065 = hp	m ³ /h • kPa (ga) • 0.00031 = kW
Amine Booster Pumps	GPM • 0.06 = hp	m ³ /h • 0.20 = kW
Reflux Pumps	GPM • 0.06 = hp	m ³ /h • 0.20 = kW
Aerial Cooler	GPM • 0.36 = hp	m ³ /h • 1.20 = kW

Amine plant contactor (absorber) diameter

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- 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, $D_{r,t} = 0.67 D_r$

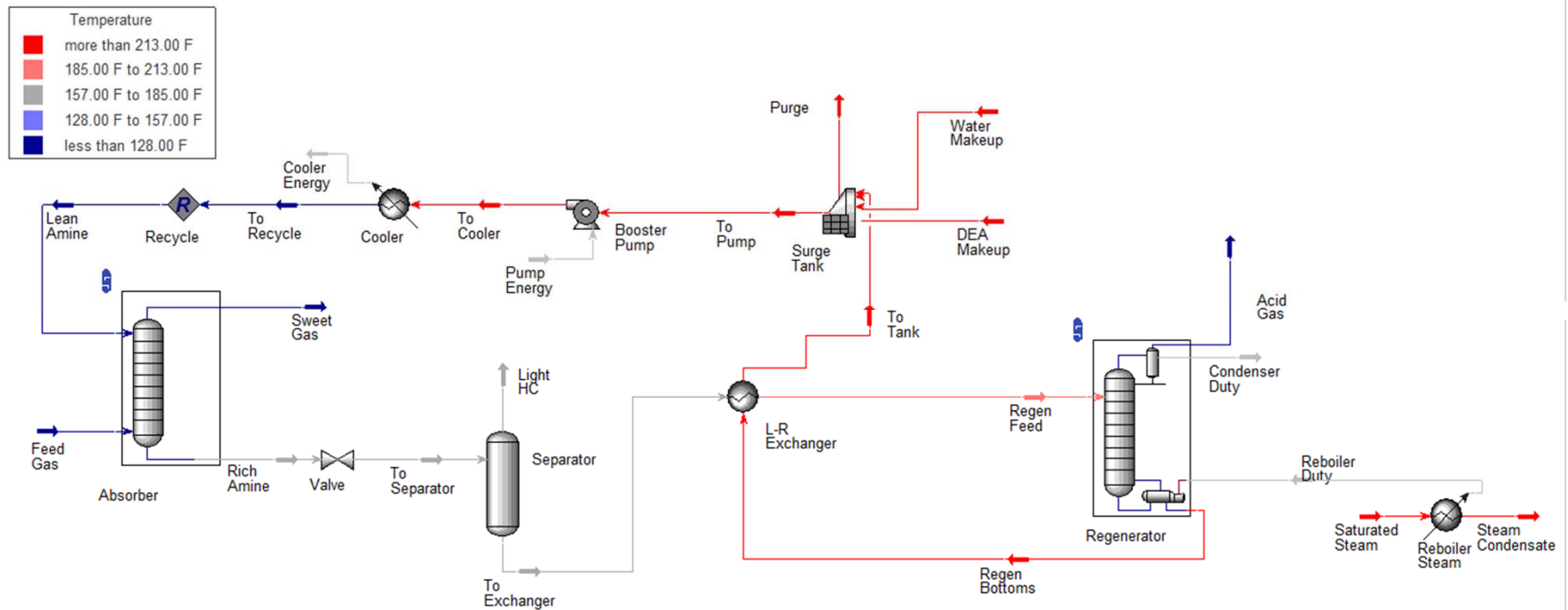
Acid gas treatment calcs.

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- Example #7

Aspen HYSYS acid gas treatment with DEA (unsteady)

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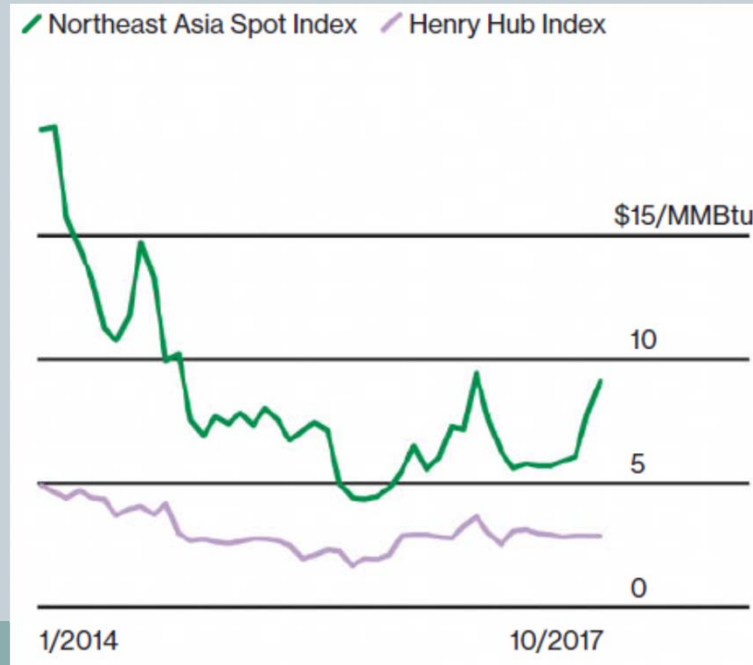


Gas dehydration

Future LNG market determinants

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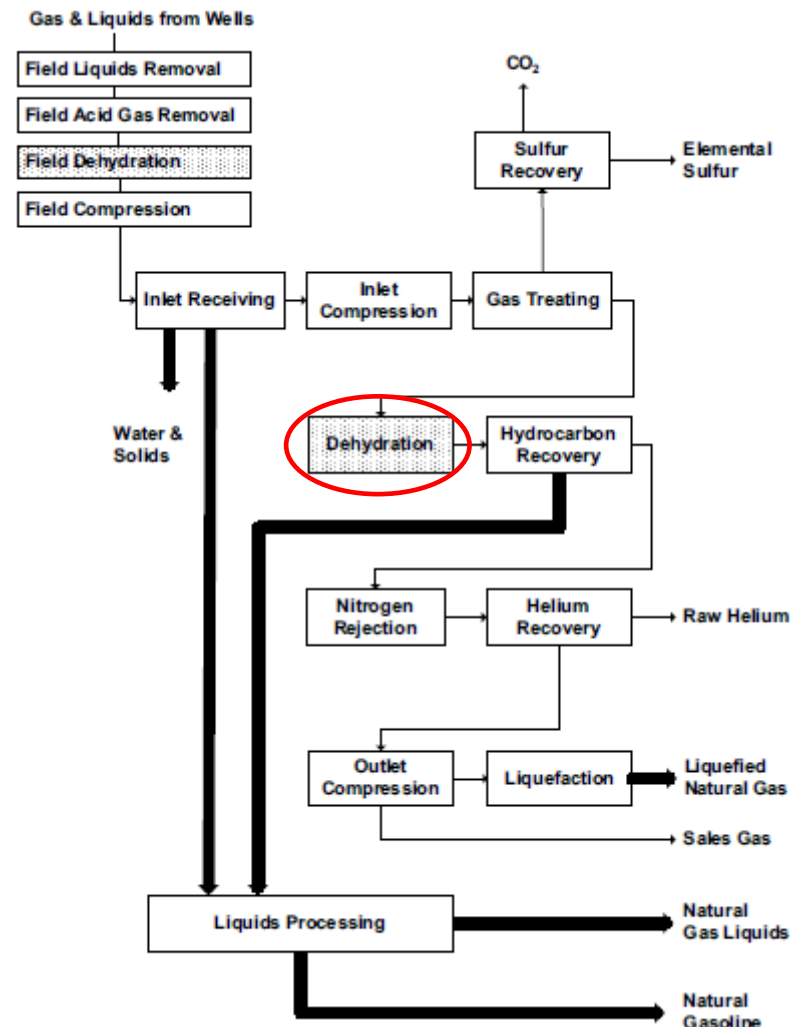
- Current (2017) global LNG market: \$90bn
- 2018-2020: 1/5 LNG contracts said to expire
- 2017-2027: contracts amounting to 80% of LNG to be rewritten
- Qatar to expand production by 30% in foreseeable future
- Iran will not probably enter the LNG sector



Gas dehydration

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



Gas dehydration

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- Natural gas (associated, dry, or tail) contains H_2O in either liquid &/or gaseous form
- Water vapour is the most common “contaminant” of hydrocarbons
- Operating experience & engineering reasons require control of H_2O
- Dehydration is a pre-requisite for sales gas & NGL recovery
- Dehydration’s important because:
 - **1. Gas hydrates.** NG could combine with H_2O to form gas hydrates which can occlude pipeline fluid flow.
 - **2. Corrosion.** H_2O condensation in pipeline can promote slug flow leading to erosion & corrosion. Carbon steel prone to corrosion.
 - **3. Calorific value.** H_2O increases the volume of natural gas & lowers its energy content.
 - **4. Gas specs.** Sales contracts or pipeline contracts dictate max H_2O content of NG: 7 lb (H_2O)/MMscf (3.2 kg(H_2O)/28,316 m^3).
 - **5. Downstream processing.** H_2O presence may cause side reactions, foaming or catalyst deactivation

Gas dehydration (2)

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- If natural gas contains water vapour, 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

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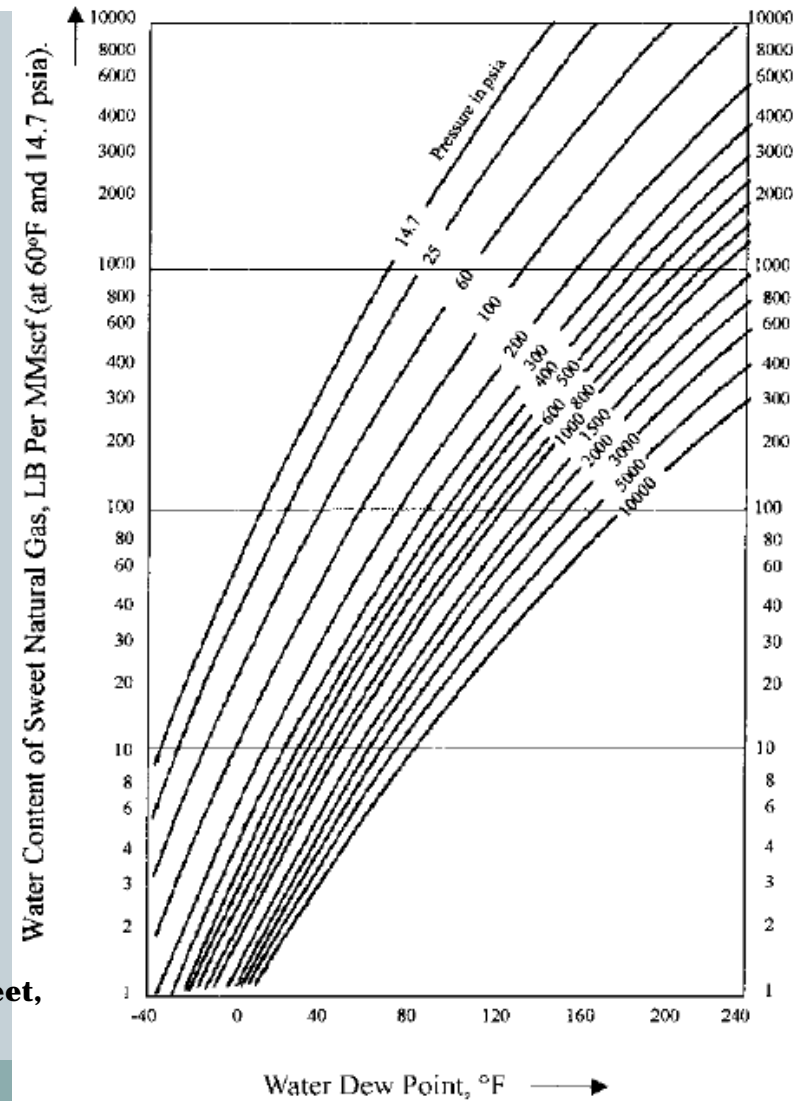
- H_2O vapor **dew point** is the temperature & pressure at which the first drop of water vapor condenses into a liquid
- It is used as a means of measuring the H_2O vapor content of natural gas
- Why do H_2O droplets form on the outside surface of a cold H_2O glass?
- As water vapor is removed from 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

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- Determine gas water content at dew point
- Example #8 (see next page)

Water content of sweet,
lean natural gas



Solution (#1)

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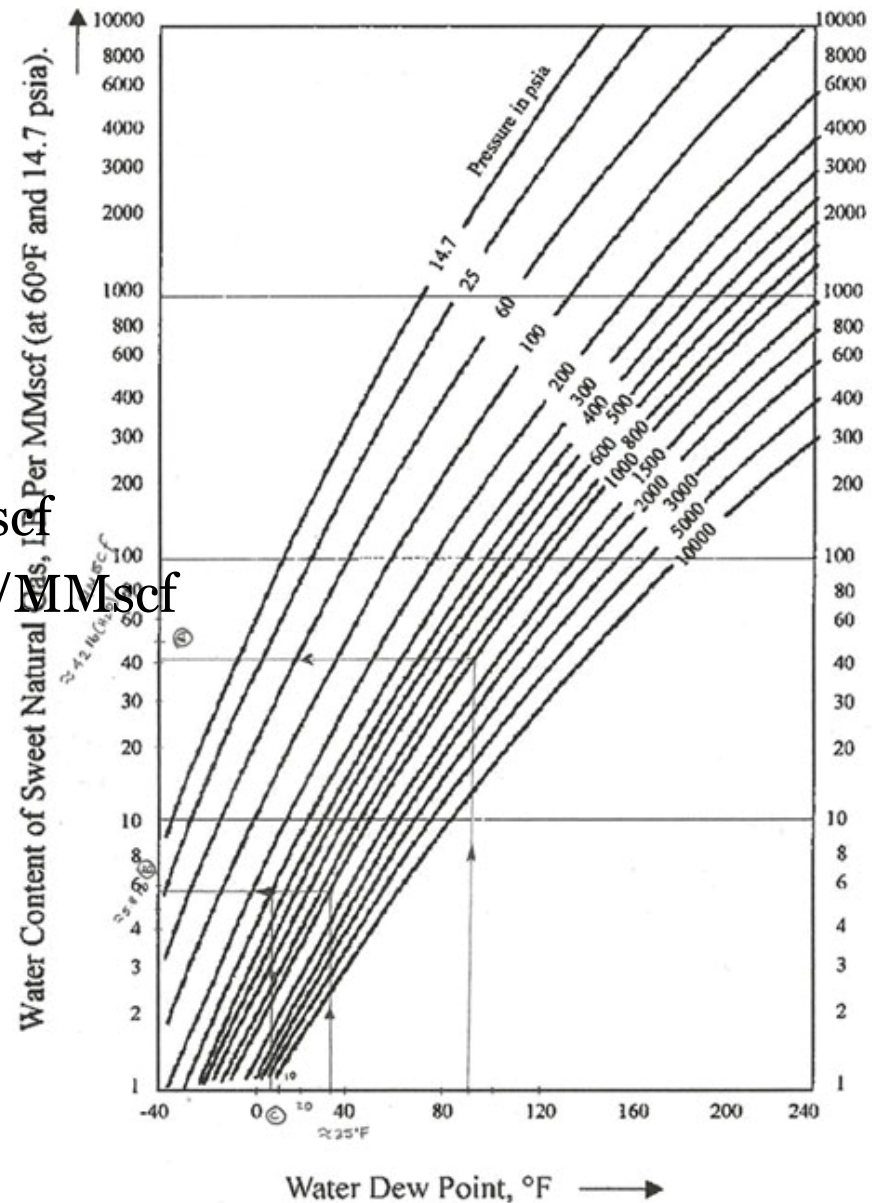
- (i) **Point A:** 1,000psia @ 90°F = 42 lb(H₂O)/MMscf

Point B: 1000psia @ 35°F = 5.8 lb(H₂O)/MMscf

Therefore,

$$\Delta H_2O \text{ content} = 42 - 5.8 \approx 36.2 \text{ lb/MMscf}$$

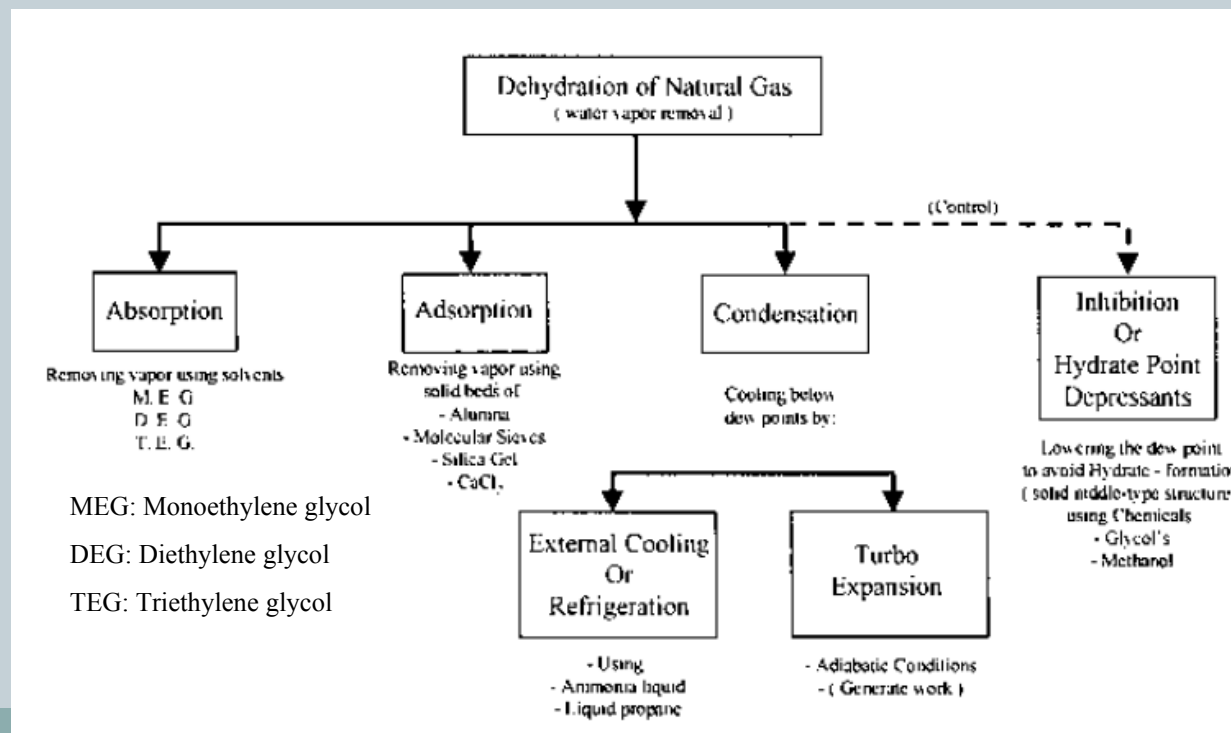
- (ii) **Point C:** 1000 → 300psia @ 5.8lb/MMscf
Water dew point $\approx 7^\circ\text{F}$ ($\approx -14^\circ\text{C}$)



Dehydration methods

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- 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

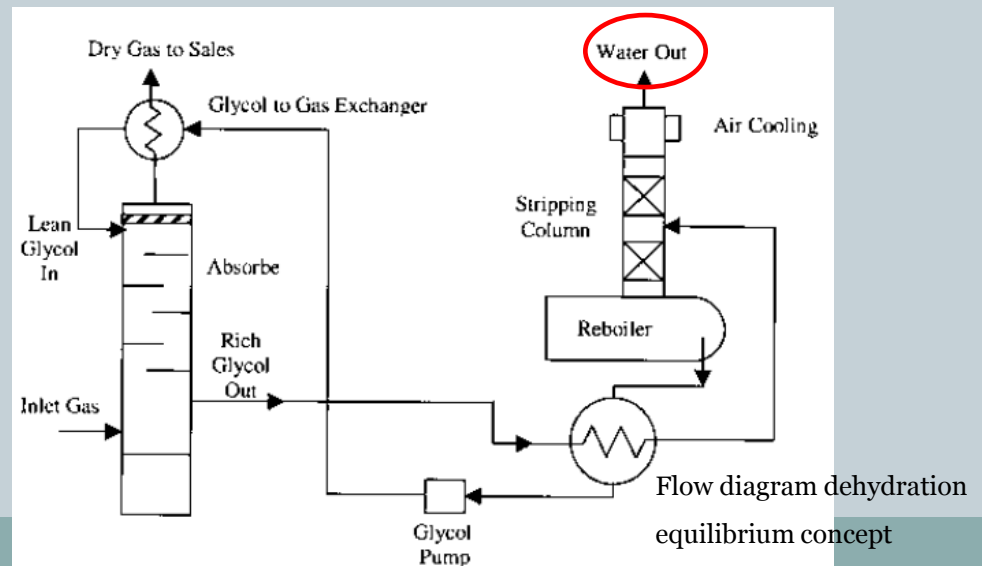


1. Absorption: Glycol dehydration process

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- Principles:
- 1. “Wet” gas comes into contact with a hygroscopic solvent (triethylene glycol) which extracts the water
- 2. Absorption, defined as the transfer of H_2O from the gas into the liquid phase, is favourable 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.: 1,000-1,200psi
- Gas temp.: 80-110°F
- Glycol regen. temp: 370-190°F



2. Adsorption

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- Solid desiccants more effective than liquid ones. Attain <0.1 ppmv
- Often used in conjunction with glycol dehydrator
- Removal of water vapour 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

Solid desiccants properties

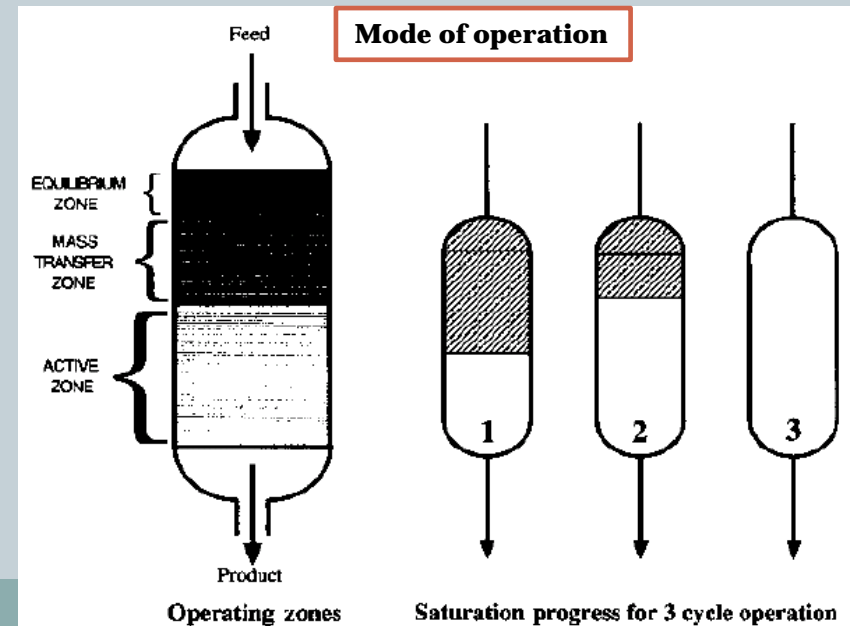
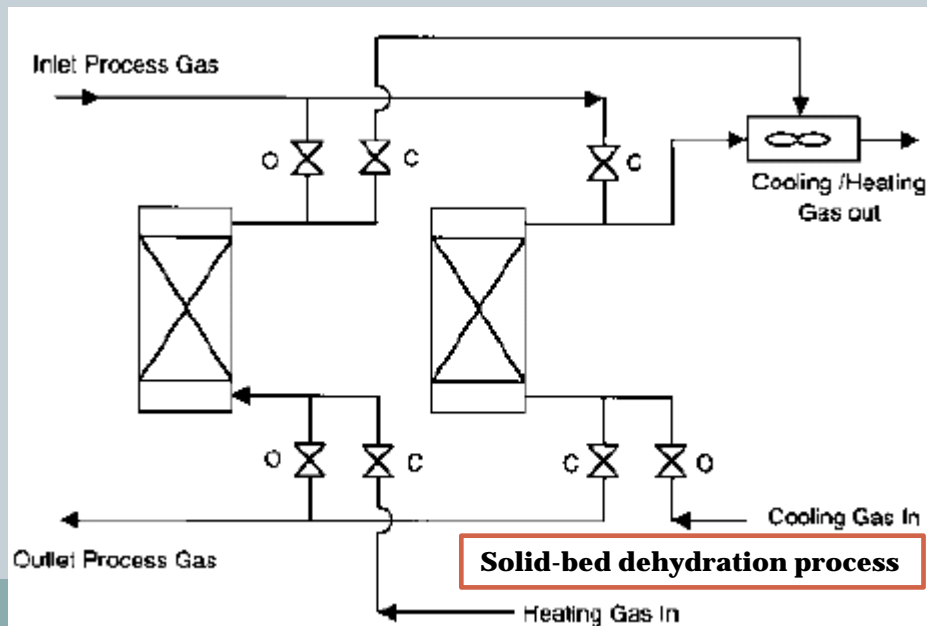
Desiccant reference	Silica gel	Activated alumina	Molecular sieves
Pore diameter (Å)	10–90	15	3, 4, 5, 10
Bulk density (lb/ft ³)	45	44–48	43–47
Heat capacity (Btu/lb°F)	0.22	0.24	0.23
Minimum dew point (°F)	–60 to –90	–60 to –90	–100 to –300
Design capacity (wt%)	4–20	11–15	8–16
Regeneration stream temp. (°F)	300–500	350–500	425–550
Heat of adsorption (Btu/lb)	—	—	1800

- Important parameter: *design capacity* [H₂O mass/mass of desiccant]

2. Adsorption (2)

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- 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

Natural gas liquids & fractionation

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- Recall: natural gas liquids (NGL) consist of C_{2+} : C_2H_6 , C_3H_8 , C_4H_{10} , C_5H_{12}
- Gas condensates:
 - H_2S , CO_2 , straight-chain alkanes, cyclohexane, naphthenes
 - Thiols (mercaptans), 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

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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):

A mixture of hydrocarbon vapor – Heat \rightarrow Liquid + 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

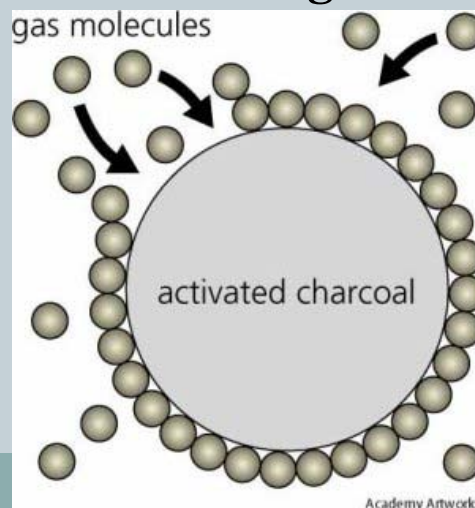
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- A *phase change* in NGL recovery & separation always involves control of one or more of the following parameters:
 - Operating pressure, P
 - Operating temperature, T
 - System composition or concentration
- To obtain the desired quantities of particular 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)

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- Simply put **adsorption** is defined as a concentration control method prior to condensation
- Solid materials offers “new surface” area which traps H/Cs components to be recovered & 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 usually coupled with refrigeration methods



Academy Artworks

Absorption (MSA)

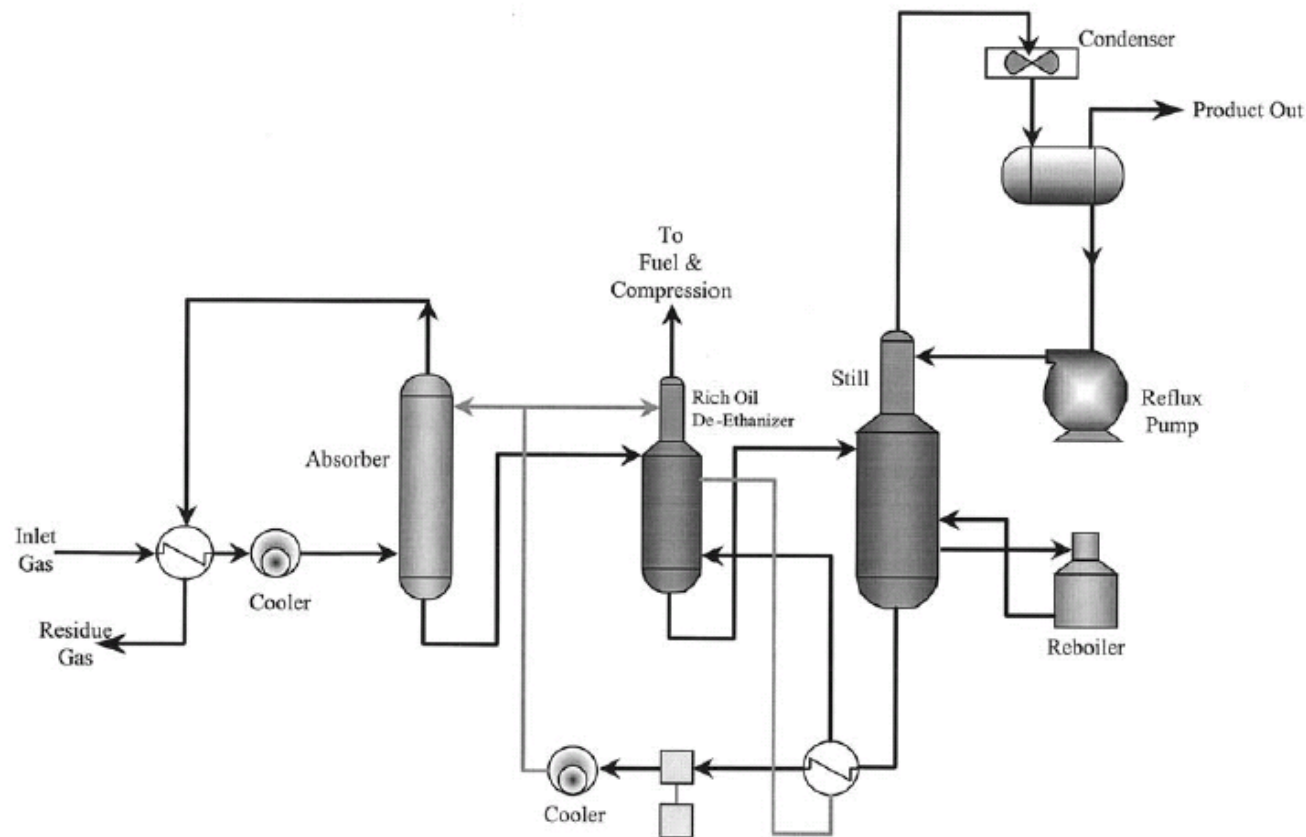
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- **Absorption** provides a surface or “contact” area of liquid-gas interface
- Again process efficiency is a function of:
 - Pressure, P
 - Temperature, T
 - Gas flow rates
 - Contact time
- Likewise, to enhance condensation absorption could be combined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

Absorption (2)

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- 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

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- 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°C to -18°C
 - If operating temp. $> -30^{\circ}\text{C}$, cryogenic range of ethane recovery is preferred

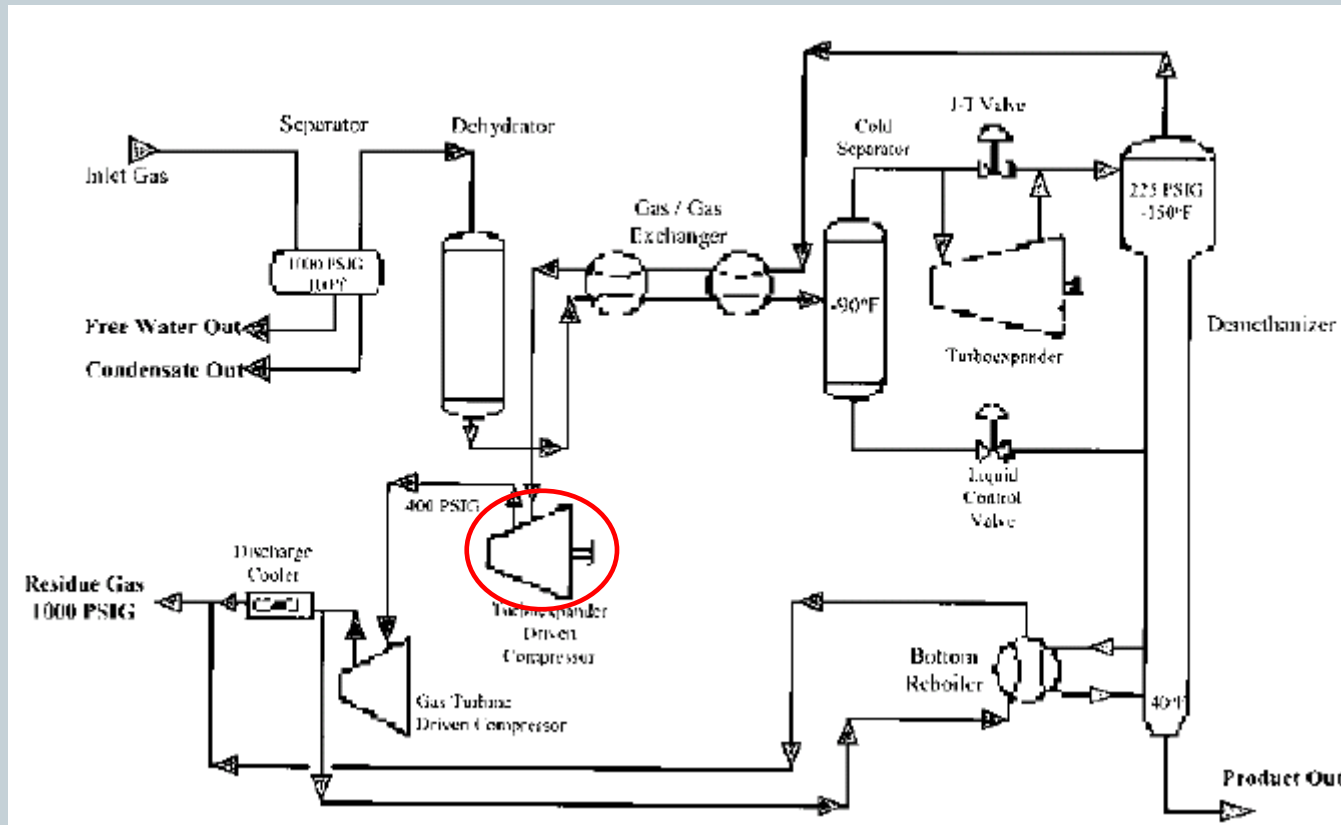
Cryogenic processes

- 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

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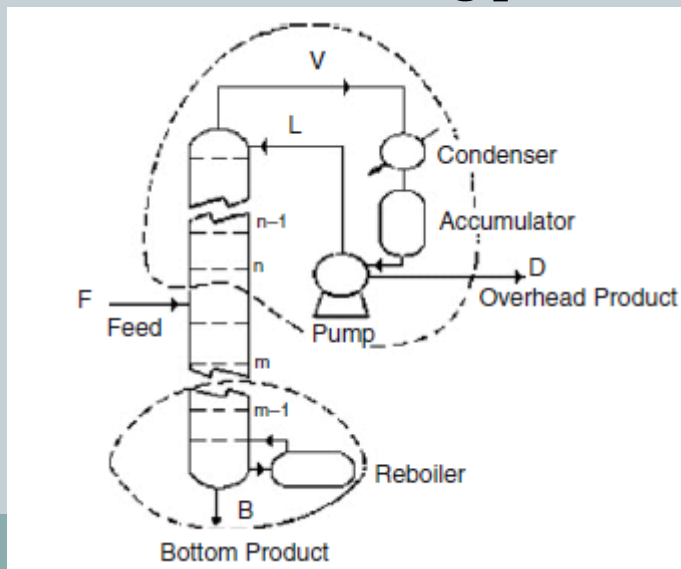
- Operating temp. range: -73°C to -107°C & 68 atm



Fractionation of NGL

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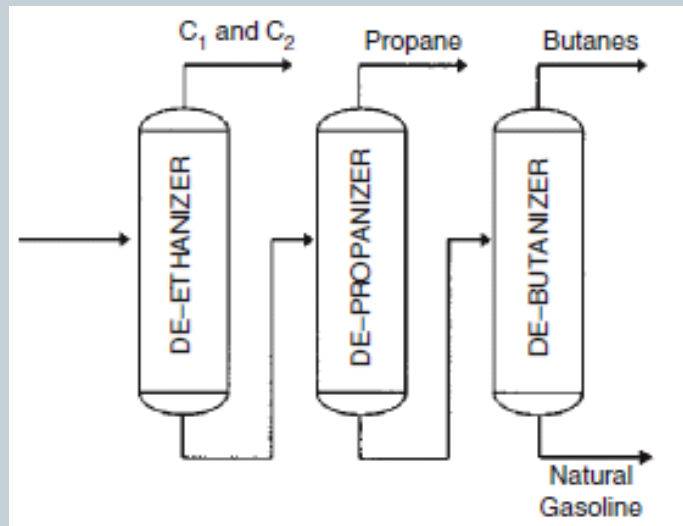
- Process of separating stream of NGLs into components called fractionation
- Safety issues govern the min extraction level of NGLs
- Max. extraction defined by technology & relative market value of NGLs
- NGLs are fractionated by heating mixed NGL streams & subjecting them through a series of distillation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



Fractionation

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- 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)

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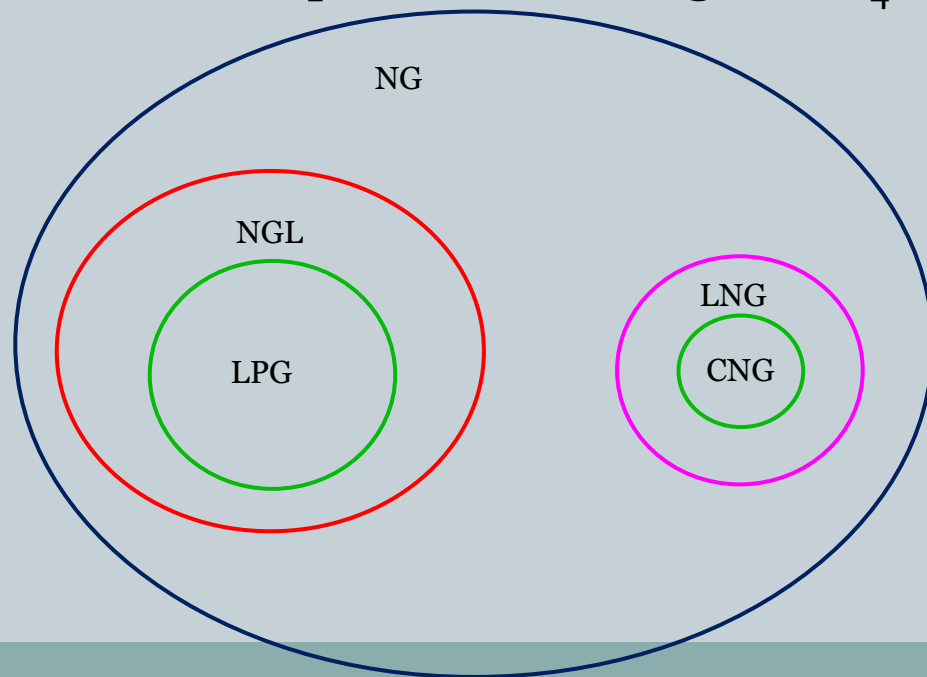
- LPG is a hydrocarbon mixture of propane & n-butane. The most common commercial products are propane, butane, or some mixture of the two and are generally extracted from natural gas or crude petroleum.
- Note that LPG is not Liquefied Natural Gas (LNG)



NG, LNG, LPG, NGL, CNG

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- **Natural gas (NG)**: natural gas: C_nH_{2n+2} , H_2S , CO_2 , He , N_2 , H_2O , ...
- **LNG**: liquefied natural gas: CH_4 , C_2H_6 , C_3H_8 , N_2 , ...
- **NGL**: natural gas liquids: C_2H_6 , C_3H_8 , C_4H_{10} , iso- C_4H_{10} , C_5H_{12}
- **LPG**: liquefied petroleum gas: C_3H_8 & C_4H_{10}
- **CNG**: compressed natural gas: CH_4



Typical LNG Compositions

Component	Composition Range (mol%)
Nitrogen	0.00 – 1.00
Methane	84.55 – 96.38
Ethane	2.00 – 11.41
Propane	0.35 – 3.21
Isobutane	0.00 – 0.70
n-Butane	0.00 – 1.30
Isopentane	0.00 – 0.02
n-Pentane	0.00 – 0.04
HHV gas	1021 – 1157
Btu/scf (kJ/Sm ³)	(38,000 – 43,090)
Wobbe number	1353 – 1432
GPM, on C ₂ + basis	0.71 – 4.08
(m ³ /1,000m ³)	(0.094 – 0.543)

Source: McCartney (2003).

Natural gas classification

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- “**Rich**” gas contains ≥ 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 recommended)

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Thanks for your attention!