

5.3 Natural Gas Processing

5.3.1 General¹

Natural gas from high-pressure wells is usually passed through field separators at the well to remove hydrocarbon condensate and water. Natural gasoline, butane, and propane are usually present in the gas, and gas processing plants are required for the recovery of these liquefiable constituents (see Figure 5.3-1). Natural gas is considered "sour" if hydrogen sulfide (H₂S) is present in amounts greater than 5.7 milligrams per normal cubic meters (mg/Nm³) (0.25 grains per 100 standard cubic feet [gr/100 scf]). The H₂S must be removed (called "sweetening" the gas) before the gas can be utilized. If H₂S is present, the gas is usually sweetened by absorption of the H₂S in an amine solution. Amine processes are used for over 95 percent of all gas sweetening in the United States. Other methods, such as carbonate processes, solid bed absorbents, and physical absorption, are employed in the other sweetening plants. Emission data for sweetening processes other than amine types are very meager, but a material balance on sulfur will give accurate estimates for sulfur dioxide (SO₂).

The major emission sources in the natural gas processing industry are compressor engines, acid gas wastes, fugitive emissions from leaking process equipment and if present, glycol dehydrator vent streams. Compressor engine emissions are discussed in Section 3.3.2. Fugitive leak emissions are detailed in *Protocol For Equipment Leak Emission Estimates*, EPA-453/R-95-017, November 1995. Regeneration of the glycol solutions used for dehydrating natural gas can release significant quantities of benzene, toluene, ethylbenzene, and xylene, as well as a wide range of less toxic organics. These emissions can be estimated by a thermodynamic software model (*GRI-GLYCalcTM*) available from the Gas Research Institute. Only the SO₂ emissions from gas sweetening operations are discussed here.

5.3.2 Process Description²⁻³

Many chemical processes are available for sweetening natural gas. At present, the amine process (also known as the Girdler process), is the most widely used method for H₂S removal. The process is summarized in reaction 1 and illustrated in Figure 5.3-2.



where:

- R = mono, di, or tri-ethanol
- N = nitrogen
- H = hydrogen
- S = sulfur

The recovered hydrogen sulfide gas stream may be: (1) vented, (2) flared in waste gas flares or modern smokeless flares, (3) incinerated, or (4) utilized for the production of elemental sulfur or sulfuric acid. If the recovered H₂S gas stream is not to be utilized as a feedstock for commercial applications, the gas is usually passed to a tail gas incinerator in which the H₂S is oxidized to SO₂ and is then passed to the atmosphere out a stack. For more details, the reader should consult Reference 8.

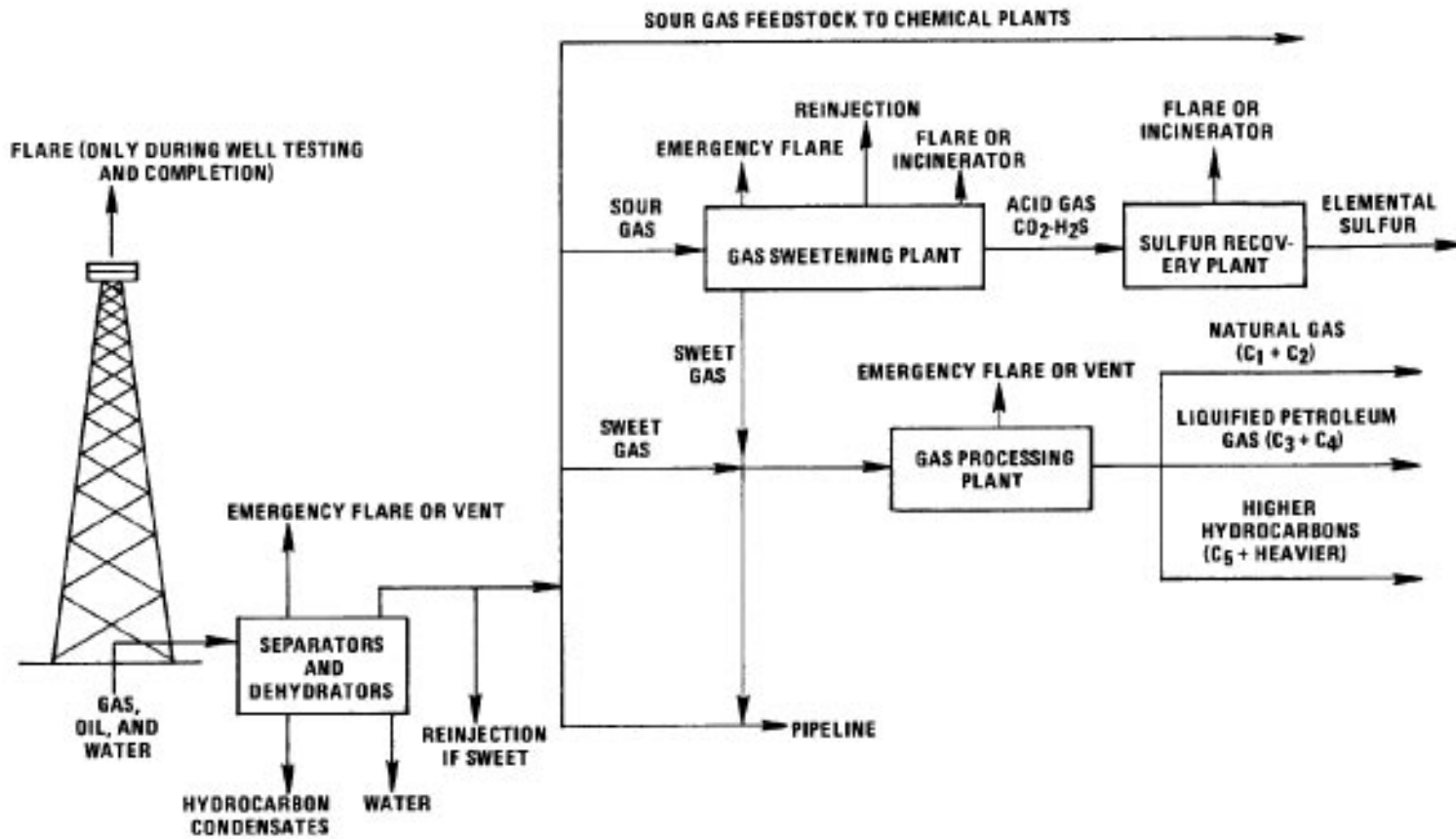


Figure 5.3-1. General flow diagram of the natural gas industry.

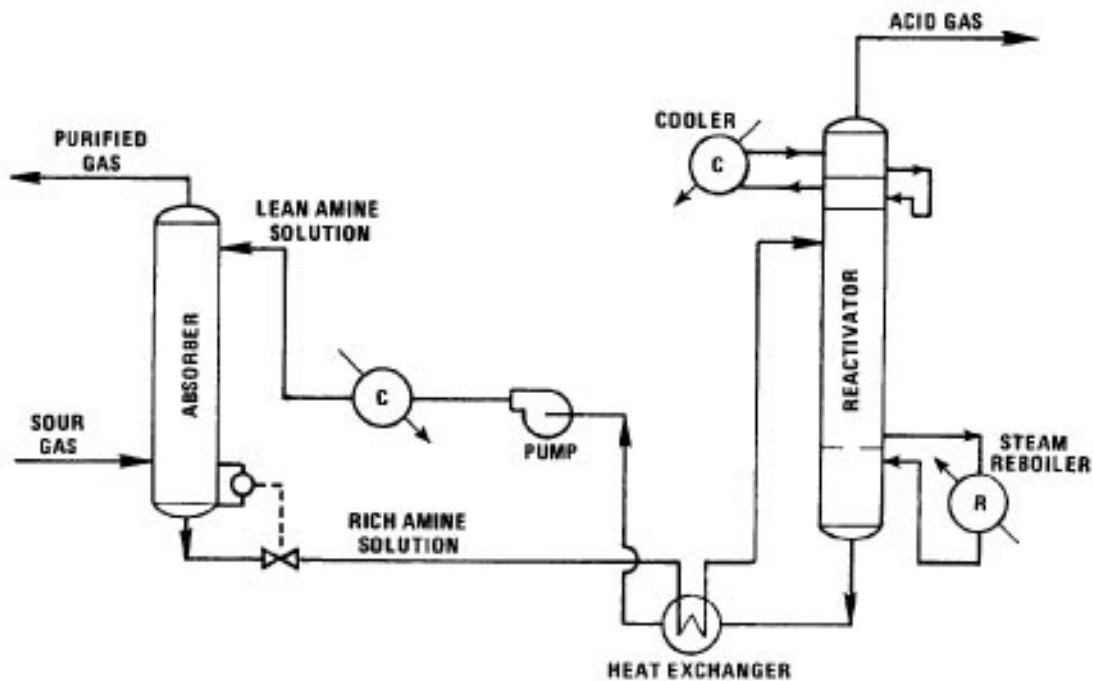


Figure 5.3-2. Flow diagram of the amine process for gas sweetening.

5.3.3 Emissions⁴⁻⁵

Emissions will result from gas sweetening plants only if the acid waste gas from the amine process is flared or incinerated. Most often, the acid waste gas is used as a feedstock in nearby sulfur recovery or sulfuric acid plants. See Sections 8.13 "Sulfur Recovery", or 8.10, "Sulfuric Acid", respectively, for these associated processes.

When flaring or incineration is practiced, the major pollutant of concern is SO_2 . Most plants employ elevated smokeless flares or tail gas incinerators for complete combustion of all waste gas constituents, including virtually 100 percent conversion of H_2S to SO_2 . Little particulate, smoke, or hydrocarbons result from these devices, and because gas temperatures do not usually exceed 650°C (1200°F), significant quantities of nitrogen oxides are not formed. Emission factors for gas sweetening plants with smokeless flares or incinerators are presented in Table 5.3-1. Factors are expressed in units of kilograms per 1000 cubic meters ($\text{kg}/10^3 \text{ m}^3$) and pounds per million standard cubic feet ($\text{lb}/10^6 \text{ scf}$).

Some plants still use older, less-efficient waste gas flares. Because these flares usually burn at temperatures lower than necessary for complete combustion, larger emissions of hydrocarbons and particulate, as well as H_2S , can occur. No data are available to estimate the magnitude of these emissions from waste gas flares.

Table 5.3.1 (Metric And English Units). EMISSION FACTORS FOR GAS SWEETENING PLANTS^a

EMISSION FACTOR RATING: SULFUR OXIDES: A
ALL OTHERS: C

Process ^b	Particulate	Sulfur Oxides ^c (SO ₂)	Carbon Monoxide	Hydrocarbons	Nitrogen Oxides
Amine					
kg/10 ³ m ³ gas processed	Neg	26.98 S ^d	Neg	— ^e	Neg
lb/10 ⁶ scf gas processed	Neg	1685 S ^d	Neg	— ^e	Neg

- ^a Factors are presented only for smokeless flares and tail gas incinerators on the amine gas sweetening process with no sulfur recovery or sulfuric acid production present. Too little information exists to characterize emissions from older, less-efficient waste gas flares on the amine process or from other, less common gas sweetening processes. Factors for various internal combustion engines used in a gas processing plant are given in Section 3.3, "Gasoline and Diesel Industrial Engines". Factors for sulfuric acid plants and sulfur recovery plants are given in Section 8.10, "Sulfuric Acid", and Section 8.13, "Sulfur Recovery", respectively. Neg = negligible.
- ^b References 2,4-7. Factors are for emissions after smokeless flares (with fuel gas and steam injection) or tail gas incinerators.
- ^c Assumes that 100% of the H₂S in the acid gas stream is converted to SO₂ during flaring or incineration and that the sweetening process removes 100% of the H₂S in the feedstock.
- ^d S is the H₂S content of the sour gas entering the gas sweetening plant, in mole or volume percent. For example, if the H₂S content is 2%, the emission factor would be 26.98 times 2, or 54.0 kg/1000 m³ (3370 lb/10⁶ scf) of sour gas processed. If the H₂S mole % is unknown, average values from Table 5.3-2 may be substituted. Note: If H₂S contents are reported in ppm or grains (gr) per 100 scf, use the following factors to convert to mole %:
 10,000 ppm H₂S = 1 mole % H₂S
 627 gr H₂S/100 scf = 1 mole % H₂S
 The m³ or scf are to be measured at 60°F and 760 mm Hg for this application (1 lb-mol = 379.5 scf).
- ^e Flare or incinerator stack gases are expected to have negligible hydrocarbon emissions. To estimate fugitive hydrocarbon emissions from leaking compressor seals, valves, and flanges, see "Protocol For Equipment Leak Emission Estimates", EPA-453/R-95-017, November 1995 (or updates).

Table 5.3-2. AVERAGE HYDROGEN SULFIDE CONCENTRATIONS
IN NATURAL GAS BY AIR QUALITY CONTROL REGION^a

State	AQCR Name	AQCR Number	Average H ₂ S, mole %
Alabama	Mobile-Pensacola-Panama City-Southern Mississippi (FL, MS)	5	3.30
Arizona	Four Corners (CO, NM, UT)	14	0.71
Arkansas	Monroe-El Dorado (LA)	19	0.15
	Shreveport-Texarkana-Tyler (LA, OK, TX)	22	0.55
California	Metropolitan Los Angeles	24	2.09
	San Joaquin Valley	31	0.89
	South Central Coast	32	3.66
	Southeast Desert	33	1.0
Colorado	Four Corners (AZ, NM, UT)	14	0.71
	Metropolitan Denver	36	0.1
	Pawnee	37	0.49
	San Isabel	38	0.3
	Yampa	40	0.31
Florida	Mobile-Pensacola-Panama City-Southern Mississippi (AL, MS)	5	3.30
Kansas	Northwest Kansas	97	0.005
	Southwest Kansas	100	0.02
Louisiana	Monroe-El Dorado (AR)	19	0.15
	Shreveport-Texarkana-Tyler (AR, OK, TX)	22	0.55
Michigan	Upper Michigan	126	0.5
Mississippi	Mississippi Delta	134	0.68
	Mobile-Pensacola-Panama City-Southern Mississippi (AL, FL)	5	3.30
Montana	Great Falls	141	3.93
	Miles City	143	0.4
New Mexico	Four Corners (AZ, CO, UT)	14	0.71
	Pecos-Permian Basin	155	0.83
North Dakota	North Dakota	172	1.74 ^b

Table 5.3-2 (cont.).

State	AQCR Name	AQCR Number	Average H ₂ S, mole %
Oklahoma	Northwestern Oklahoma	187	1.1
	Shreveport-Texarkana-Tyler (AR, LA, TX)	22	0.55
	Southeastern Oklahoma	188	0.3
Texas	Abilene-Wichita Falls	210	0.055
	Amarillo-Lubbock	211	0.26
	Austin-Waco	212	0.57
	Corpus Christi-Victoria	214	0.59
	Metropolitan Dallas-Fort Worth	215	2.54
	Metropolitan San Antonio	217	1.41
	Midland-Odessa-San Angelo	218	0.63
	Shreveport-Texarkana-Tyler (AR, LA, OK)	22	0.55
	Utah	Four Corners (AZ, CO, NM)	14
Wyoming	Casper	241	1.262
	Wyoming (except Park, Bighorn, and Washakie Counties)	243	2.34 ^c

^a Reference 9. AQCR = Air Quality Control Region.

^b Sour gas only reported for Burke, Williams, and McKenzie Counties, ND.

^c Park, Bighorn, and Washakie Counties, WY, report gas with an average H₂S content of 23 mole %.

References For Section 5.3

1. D. K. Katz, *et al.*, *Handbook Of Natural Gas Engineering*, McGraw-Hill Book Company, New York, 1959.
2. R. R. Maddox, *Gas And Liquid Sweetening*, 2nd Ed. Campbell Petroleum Series, Norman, OK, 1974.
3. R. E. Kirk and D. F. Othmer (eds.), *Encyclopedia Of Chemical Technology*. Vol. 7, Interscience Encyclopedia, Inc., New York, NY, 1951.
4. *Sulfur Compound Emissions Of The Petroleum Production Industry*, EPA-650/2-75-030. U. S. Environmental Protection Agency, Cincinnati, OH, 1974.
5. Unpublished stack test data for gas sweetening plants, Ecology Audits, Inc., Dallas, TX, 1974.

6. *Control Techniques For Hydrocarbon And Organic Solvent Emissions From Stationary Sources*, AP-68, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1970.
7. *Control Techniques For Nitrogen Oxides From Stationary Sources*, AP-67, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1970.
8. B. J. Mullins, *et al.*, *Atmospheric Emissions Survey Of The Sour Gas Processing Industry*, EPA-450/3-75-076, U. S. Environmental Protection Agency, Research Triangle Park, NC, October 1975.
9. *Federal Air Quality Control Regions*, AP-102, U. S. Environmental Protection Agency, Research Triangle Park, NC, January 1972.