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Introduction

Although many gases are natural (air, for example), the term "natural gas" refers to the hydrocarbon-rich gas that is found in underground formations. These gases are organic in origin, and thus along with oil, coal, and peat are called "fossil fuels." Time and the effects of pressure and temperature have converted the originally living matter into hydrocarbon gases that we call natural gas.

Natural gas is largely made up of methane but also contains other light hydrocarbons, typically ethane through hexane. In addition, natural gas contains inorganic contaminants – notably hydrogen sulfide and carbon dioxide, but also nitrogen and trace amounts of helium and hydrogen.

The formations and the gas contained therein are almost always associated with water, and thus the gas is usually water-saturated. The water concentration depends on the temperature and pressure of the reservoir and to some extent on the composition of the gas.

Natural gas that contains hydrogen sulfide is referred to as "sour." Gas that does not contain hydrogen sulfide, or at least contains hydrogen sulfide but in very small amounts, is called "sweet."

Contaminants in natural gas, like hydrogen sulfide and carbon dioxide, are usually removed from the gas in order to produce a sales gas. Hydrogen sulfide and carbon dioxide are called "acid gases" because when dissolved in water they form weak acids.

Hydrogen sulfide must be removed because of its high toxicity and strong, offensive odor. Carbon dioxide is removed because it has no heating value. Another reason these gases must be removed is because they are corrosive. In Alberta, sales gas must typically contain less than 16 ppm[1] hydrogen sulfide and less than 2% carbon dioxide. However, different jurisdictions have different standards.

Once removed from the raw gas, the question arises as to what should be done with the acid gas. If there is a large amount of acid gas, it may be economical to build a Claus-type sulfur plant to convert the hydrogen sulfide into the more benign elemental sulfur. Once the H_2S has been converted to sulfur, the leftover carbon dioxide is emitted to the atmosphere. Claus plants can be quite efficient, but even so, they also emit significant amounts of sulfur compounds. For example, a Claus plant processing 10 MMSCFD of H_2S and converting 99.9% of the H_2S into elemental sulfur (which is only possible with the addition of a tail gas clean up unit) emits the equivalent of 0.01 MMSCFD or approximately 0.4 ton/day of sulfur into the atmosphere. Note that there is more discussion of standard volumes and sulfur equivalents later in this chapter.

For small acid gas streams, Claus-type sulfur plants are not feasible. In the past, it was permissible to flare small amounts of acid gas. However, with growing environmental concerns, such practices are being legislated out of existence.

In the natural gas business, acid gas injection has quickly become the method of choice for the disposal of such gases. Larger producers are also considering injection because of the volatility of the sulfur markets.

1.1 Acid Gas

As noted earlier, hydrogen sulfide and carbon dioxide are called acid gases. When dissolved in water they react to form weak acids.

The formation of acid in water is another reason that acid gases are often removed from natural gas. The acidic solutions are very corrosive and require special materials to handle them.

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[1] For H_2S 16 ppm is equal to 1 grain per 100 SCF, which is an older unit for expressing H_2S content of a gas.

On the other hand, the acidity of the acid gases is used to our advantage in processes for their removal.

1.1.1 Hydrogen Sulfide

Hydrogen sulfide is a weak, diprotic acid (i.e., it undergoes two acid reactions). The ionization reactions are as follows:

$$H_2S_{(aq)} \leftrightarrow HS^-_{(aq)} + H^+_{(aq)} \tag{1.1}$$

$$HS^-_{(aq)} \leftrightarrow S^{2-}_{(aq)} + H^+_{(aq)} \tag{1.2}$$

The subscript (aq) indicates that the reaction takes place in the aqueous (water-rich) phase.

It is the H^+ ion that makes the solution acidic. Hydrogen sulfide is diprotic because it has two reactions that both form the hydrogen ion. Furthermore, when hydrogen sulfide is dissolved in water it exists as three species – the molecular form (H_2S) and the two ionic forms: the bisulfide ion (HS^-) and the sulfide ion (S^{2-}).

The measure of how far these reactions proceed is the equilibrium ratios. For our purposes, these ratios are as follows:

$$K_{1,H_2S} = \frac{\left[H^+_{(aq)}\right]\left[HS^-_{(aq)}\right]}{\left[H_2S_{(aq)}\right]} = 1.0\times10^{-7} \text{ at } 25°C$$

$$K_{2,H_2S} = \frac{\left[H^+_{(aq)}\right]\left[S^{-2}_{(aq)}\right]}{\left[HS^-_{(aq)}\right]} = 6\times10^{-16} \text{ at } 25°C$$

where the square brackets indicate the concentration of each species. These relations are valid only if the concentration is small. The fact that these ratios are so small indicates that these reactions do not proceed very far, and thus, in an otherwise neutral solution, most of the hydrogen sulfide is found in the solution in the molecular form. The concentration of the ionic species is greatly affected by the presence of an alkaline and to some extend the presence of an acid. And since hydrogen sulfide is an acid, the effect of an alkaline is very significant.

At 25°C and 101.325 kPa (1 atm) the distribution of the various species in the aqueous solution can be calculated from the solubility and the equilibrium ratios. The distribution is:

$[H_2S] = 0.1$ mol/kg
$[HS^-] = 1.0 \times 10^{-4}$ mol/kg
$[S^{-2}] = 6.4 \times 10^{-16}$ mol/kg
$[H^+] = 1.0 \times 10^{-4}$ mol/kg
pH[2] $= 4.0$

The units of concentration used here are molality or moles of species per kg of solvent (water).

1.1.2 Carbon Dioxide

Carbon dioxide is also a weak diprotic acid, but the reactions for CO_2 are slightly different. The first reaction is a hydrolysis (a reaction with water):

$$CO_{2(aq)} + H_2O \leftrightarrow H^+_{(aq)} + HCO^-_{3(aq)} \tag{1.3}$$

The second is a simple acid formation reaction:

$$HCO^-_{3(aq)} \leftrightarrow H^+_{(aq)} + CO^{2-}_{3(aq)} \tag{1.4}$$

Again, these reactions take place in the aqueous phase. The carbon dioxide exists in three species in the aqueous phase – the molecular form CO_2, and two ionic forms: the bicarbonate ion, also call the hydrogen carbonate ion (HCO_3^-), and the carbonate ion (CO_3^{2-}).

The equilibrium ratios for these reactions are:

$$K_{1,CO_2} = \frac{\left[H^+_{(aq)}\right]\left[HCO^-_{3\,(aq)}\right]}{\left[CO_{2\,(aq)}\right]} = 4.5\times10^{-7} \text{ at } 25°\text{C}$$

$$K_{2,CO_2} = \frac{\left[H^+_{(aq)}\right]\left[CO^{-2}_{3\,(aq)}\right]}{\left[HCO^-_{3\,(aq)}\right]} = 4.7\times10^{-11} \text{ at } 25°\text{C}$$

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[2] pH = −log[H^+] and usually the concentration, [H^+] is expressed in moles of solute per kg of water (molality), but for aqueous solutions at low concentration mol/kg of water is approximately equal to moles per litre of solution (molarity).

Again, the square brackets are used to indicate the concentration of the various species. As with hydrogen sulfide, these ratios are very small, and thus in an otherwise neutral solution most of the carbon dioxide exist in the molecular form. At 25°C and 101.325 kPa (1 atm) the distribution of the various species in the aqueous solution is:

$[CO_2] = 0.033$ mol/kg
$[HCO_3^-] = 1.2 \times 10^{-4}$ mol/kg
$[CO_3^{-2}] = 4.7 \times 10^{-11}$ mol/kg
$[H^+] = 1.2 \times 10^{-4}$ mol/kg
pH = 3.9

The pH of the CO_2 solution is slightly less than that for H_2S even though the solubility of CO_2 is significantly less. This is because more of the carbon dioxide ionizes, which in turn produces more of the H^+ ion – the acid ion.

1.2 Anthropogenic CO_2

The disposal of man-made carbon dioxide into the atmosphere is becoming an undesirable practice. Whether or not one believes that CO_2 is harmful to the environment has almost become a moot point. The general consensus is that CO_2 is contributing to global climate change. Furthermore, it is clear that legislators all around the world believe that it is a problem. In some countries there is a carbon tax applied to such disposal. Engineers will increasingly be faced with the problem of disposing of CO_2.

Some of the technologies for dealing with this CO_2 are the same as acid gas injection, and thus they will be discussed here as well.

1.3 Flue Gas

Flue gas, as used here, is the byproduct of the combustion of fuels. Typically the fuels of concern here are natural gas, oil (and distillates from oil such as gasoline), coal, wood, etc.

Combustion is a process involving oxygen. However, air is composed of only 21% oxygen, which is required for combustion, and 79% inerts, mostly nitrogen. Thus for every mole of oxygen consumed in the combustion of a paraffin hydrocarbon, more than 9.5 moles of air must be supplied.

The combustion of a carbon-based fuel (coal, natural gas, or oil) produces a gaseous byproduct called flue gas. First consider the combustion of a paraffin hydrocarbon.

$$2\,C_nH_{2n+2} + (3n+1)\,O_2 \rightarrow 2n\,CO_2 + 2(n+1)\,H_2O \tag{1.5}$$

For example, the reaction for the combustion of methane is:

$$CH_4 + 2\,O_2 \rightarrow CO_2 + 2\,H_2O \tag{1.6}$$

So the combustion of a hydrocarbon releases carbon dioxide and water. In addition, the combustion of one mole of methane consumes 2 moles of oxygen.

Table 1.1 summarizes the amount of oxygen and air required for the combustion of several light paraffin hydrocarbons. It is interesting to note that as the hydrocarbon becomes larger, the amount of carbon dioxide produced by the combustion process also increases.

Table 1.1 Air requirements for the combustion of one mole of various paraffin fuels.

Fuel	**Moles of Oxygen Consumed**	**Moles of Air Required (0% Excess)**	**Moles of Air Required (15% Excess)**	**Moles of CO_2 Produced**
Methane	2.0	9.52	10.95	2.00
Ethane	3.5	16.67	19.17	4.00
Propane	5.0	23.81	23.81	6.00
i-Butane	6.5	30.95	35.60	8.00
n-Butane	6.5	30.95	35.60	8.00
i-Pentane	8.0	38.10	43.81	10.00
n-Pentane	8.0	38.10	43.81	10.00

Table 1.2 Approximate flue gas composition from the combustion of various paraffin hydrocarbon fuels (water-free basis).

	0% Excess Air		15% Excess Air		
Fuel	**Nitrogen**	**CO_2**	**Nitrogen**	**CO_2**	**Oxygen**
Methane	79.00	21.00	79.00	18.26	2.74
Ethane	76.70	23.30	76.99	20.34	2.67
Propane	75.82	24.18	76.22	21.14	2.64
i-Butane	75.35	24.65	75.81	21.57	2.63
n-Butane	75.35	24.65	75.81	21.57	2.63
i-Pentane	75.06	24.94	75.55	21.83	2.62
n-Pentane	75.06	24.94	75.55	21.83	2.62

From table 1.2 we can see that the flues gas is more than three quarters nitrogen and only about 20% carbon dioxide. In addition, when 15% excess air is used in the combustion process, then the flue gas also includes slightly more than 2.5% oxygen. As noted below, the flue gas will also include small amounts of oxides of nitrogen and oxides of sulfur.

It is probably undesirable to attempt to inject the entire flue gas stream. As we shall see, the cost of a disposal stream is directly related to the volume of gas injected.

In some cases, there is insufficient oxygen and one gets incomplete combustion to form carbon monoxide:

$$C_nH_{2n+2} + (3n + 1)\,O_2 \rightarrow n\,CO + (n+1)\,H_2O \qquad (1.7)$$

Carbon monoxide is a very dangerous chemical. It is gaseous at room conditions, and it is colorless, odorless, and highly toxic. It is often referred to as the "silent killer."

1.3.1 Sulfur Oxides

Most of the fuels we use contain some sulfur compounds. Even "sweet" natural gas has some sulfur in it. These sulfur compounds burn to form the so-called sulfur oxides – SO_x : sulfur dioxide (SO_2) and sulfur trioxide (SO_3). At room conditions, pure SO_2 is a gas but pure

SO_3 is a liquid (boiling pt 45°C). Like carbon dioxide and hydrogen sulfide, these compounds form acids when dissolved in water.

More properties of the sulfur oxides are provided in the appendix.

1.3.2 Nitrogen Oxides

There are two sources of nitrogen in the combustion process. Some fuels, notably coal and heavier oil, contain nitrogen compounds. When these fuels are burned they release oxides of nitrogen. The other source of nitrogen is the high temperature reaction of atmospheric oxygen and nitrogen.

More properties of the oxides of nitrogen are given in the appendix.

1.4 Standard Volumes

In the petroleum business it is common to report flow rates in standard volumes per unit time.

1.4.1 Gas Volumes

The common units for the flow rate of a gas stream are MMSCFD, Sm^3/d or Nm^3/d. These are equivalent to the following number of moles of gas:

1 MMSCF = 2635 lb-mol =1.195×10^6 mol
10^3 Sm^3 = 42 210 mol
10^3 Nm^3 = 40 874 mol[3]

The use of the prefix symbol M is a cause of much confusion in the natural gas business. In standard *SI Units*, M means mega and

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[3] The S indicates *standard conditions*, as used in the petroleum industry, which are 15.56°C (60°F) and 101.325 kPa (14.696 psia, 1 atm), whereas N is *normal conditions* 20°C and 101.325 kPa. In chemistry it is common to refer to *Standard Temperature and Pressure* (*STP*), which is 0°C and 1 atm, but this is not the standard used in the petroleum business.

The following are the conversion factors from standard volumes to moles:

379.5 std. ft^3 = 1 lbmol
0.023 690 Sm^3 = 1 mol
0.024 465 Nm^3 = 1 mol

has the multiplier 10^6. Therefore, in *SI Units*, 1 MJ is one megajoule or one million Joules. In American Engineering Units, the M is taken from Roman numerals, where M means one thousand. Thus 1 MSCF is one thousand standard cubic feet and not one million standard cubic feet. To indicate one million, two M's are used (1,000 × 1,000 = 1,000,000), so one million standard cubic feet is denoted 1 MMSCF. In spite of the confusion, this notation will be used in this work.

1.4.2 Liquid Volumes

In the oil business, a barrel is a volume exactly 42 USgal, which is equivalent to 5.61458 ft^3 or 158.99 L. The density of a liquid is affected by the temperature, not as significantly as a gas, but it changes nonetheless. Therefore, a standard barrel is the volume occupied at 60°F (15.56°C).

By definition (GPA, 1996) we have:

1 bbl of H_2S = 280.6 lb = 127.3 kg
1 bbl of CO_2 = 286.4 lb = 129.9 kg

So one standard barrel (usually referred to as a barrel) of liquefied acid gas has a mass of about 280 lb or 127 kg. It will weigh slightly less due to the presence of light hydrocarbon in the mixture. The conversion from standard barrels to standard meters is 1 bbl = 0.158 987 Sm^3 or 6.2898 bbl = 1 Sm^3.

Furthermore, as was given earlier, 1 MMSCF is 1.195×10^6 mol, so 1 MMSCFD of compressed H_2S is equal to 40 728 kg/d, which equals 320 bpd. Similarly for CO_2 1 MMSFD is 405 bpd. Although 1 barrel of H_2S has approximately the same mass as 1 bbl of CO_2, there is a significant difference when converting from standard cubic feet. This is because the molecular mass of CO_2 is significantly larger than that of H_2S. So as an approximation, 1 MMSCFD of acid gas is equal to approximately 350 bbl of liquefied acid gas.

1.5 Sulfur Equivalent

It is common to express the sulfur content of a stream in terms of sulfur equivalent. This assumes that all of the hydrogen sulfide in a gas stream is converted to elemental sulfur via the reaction:

$$H_2S \rightarrow H_2 + S \tag{1.8}$$

According to this reaction, 1 mole of hydrogen sulfide is converted to one mole of S.

First you must determine the number of moles of hydrogen sulfide in the gas stream, as discussed earlier. Therefore to obtain the molar flow rate of H_2S in the gas stream, multiply the flow rate by the molar equivalent given above and then multiply by the mole fraction H_2S in the stream.

$$\dot{n}_{H_2S} = F\,Q\,y_{H_2S} \tag{1.9}$$

where: $\dot{n}_{H_2S}$ – molar flow rate of H_2S in mol/day
Q – flow rate at standard or normal conditions
F – the factor given earlier to convert the standard flow rate into a molar flow rate
y_{H_2S} – mole fraction H_2S in the gas

From the chemical reaction, one mole of H_2S produces one mole of S. Therefore:

$$\dot{n}_S = F\,Q\,y_{H_2S} \tag{1.10}$$

where: $\dot{n}_s$ – molar flow rate of S in mol/day

Finally, use the molar mass of sulfur, 32.066 g/mol, to convert to a molar flow rate in g/day. This is converted to tonne/day using the conversion factor 10^6 g = 1 t.

$$\dot{m}_S = 32.066 \times 10^{-6}\; F\,Q\,y_{H_2S} \tag{1.11}$$

where: $\dot{m}_s$ – mass flow rate of sulfur in t/day

The more common form of sulfur is actually S_8. Therefore the chemically more correct version of the reaction is:

$$8\,H_2S \rightarrow 8\,H_2 + S_8 \tag{1.12}$$

However, when we express the flow rate on a mass basis it is independent of the form of the elemental sulfur. Other species of elemental sulfur also exist, but if the sulfur rate is expressed on a mass basis, it does not matter which species you assume for the elemental sulfur.

Examples

1.1 An acid gas stream of 1 MMCSFD is 75% H_2S. What is the sulfur equivalent for this stream?

Answer: Using equation (1.11) yields:

$$\begin{aligned}\dot{m}_S &= 32.066\times10^{-6}\ F\,Q\,y_{H2S}\\ &= 32.066\times10^{-6}(1.195\times10^{6})(1)(0.75)\\ &= 28.7 \text{ tonne/day}\end{aligned}$$

This is equivalent to 31.6 ton/day[4].

1.2 An acid gas stream of 20 × 10^3 Sm^3/day is 5% H_2S. What is the sulfur equivalent for this stream?

Answer: Again using equation (1.11) yields:

$$\begin{aligned}\dot{m}_S &= 32.066\times10^{-6}\ F\,Q\,y_{H2S}\\ &= 32.066\times10^{-6}(42210)(20)(0.05)\\ &= 1.35 \text{ tonne/day}\end{aligned}$$

1.6 Sweetening Natural Gas

Although many processes are available to sweeten natural gas – that is to remove the acid gases – those based on alkanolamines are the most common.

Alkanolamines are ammonia-like organic compounds. When dissolved in water they form weak bases. The bases react with the acids formed when H_2S and CO_2 dissolve in water. This acid-base reaction greatly enhances the solubility of the acid gases. Because the alkanolamines are weak bases, the process can be reversed. When the solutions are heated, the acid gases are liberated and the solvent regenerated.

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[4] By definition 1 tonne = 1000 kg
and 1 ton = 2000 lb
therefore: 1 tonne = 1.102 ton

The process for absorbing acid gas takes place in two stages: (1) absorption and (2) regeneration. The absorption takes place in a column where the sour gas is contacted with the lean solvent. The rich solvent is sent to a second column where the solvent is regenerated. Heat is applied to the system via a reboiler and the overheads are condensed, typically in an aerial cooler. The solvent regeneration is done not only at higher temperature, but also at lower pressure. Figure 1.1 is a schematic of the process.

Other processes are available for sweetening natural gas, but the alkanolamine systems are by far the most common. More discussion about processes for sweetening natural gas can be found in Kohl and Nielsen (1997).

1.6.1 Combustion Process Gas

In the carbon capture world there are two approaches to capturing the carbon dioxide: 1. post-combustion and 2. pre-combustion.The post-combustion approach is to take the CO_2 from the combustion process, purify it, and then inject it. In the pre-combustion approach, the carbon is removed from the fuel before combustion. These two approaches are discussed in the following sections.

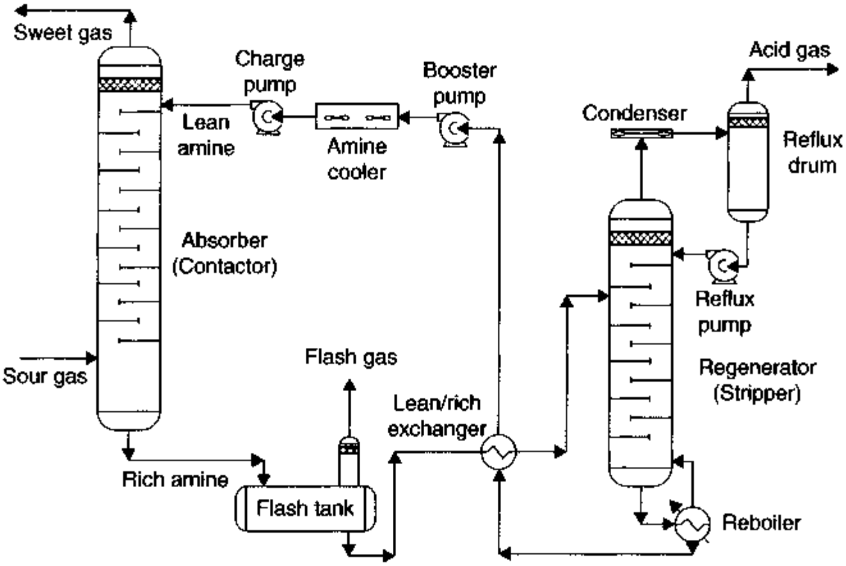

Figure 1.1 A simplified schematic diagram of the process for removing acid gas from natural gas.

1.6.1.1 Post-Combustion

As was mentioned earlier, it is probably wise to separate the carbon dioxide from the flue gas and inject only a CO_2-rich stream. This is the so-call "capture" part of the carbon capture and storage.

At first look, we should be able to achieve this using a process similar to those used for sweetening natural gas. However, there are several factors that complicate this.

1. High Temperature – Since the source of the stream is a combustion process, this stream will be at high temperature. It may be necessary to cool the flue gas stream before sending it to the treating process.
2. Low Pressure – The flue gas stream is produced at near atmospheric pressure. At a minimum, blower will probably have to be used to raise the pressure of the gas to a sufficient level such that it can flow through the process equipment.

   In addition, and perhaps more importantly, the absorption process is favored by higher pressure.

   The low pressure also means that there is a very high actual flow rate. This means that larger diameter towers are required for the absorption process.
3. Solvent Losses – The combination of the high temperature and low pressure noted above result in significant solvent losses. Some extra process, such as a residue gas scrubber, is needed to reduce these losses.
4. Impurities – There are two key impurities in the flue gas: oxygen and oxides of sulfur.
   a. Sulfur Oxides – Sulfur oxides are also acid gases in as much as they form acidic solution in water. However they are much stronger acids than H_2S or CO_2 and for this reason they react irreversibly with most bases, including the alkanolamines commonly used to sweeten natural gas streams.
   b. Oxygen – Oxygen is also known to cause problems in the alkanolamine process.

Chemical vendors and engineering companiesare working diligently to overcome these and other problems associated with the decarbonation of flue gas.

1.6.1.2 Pre-Combustion

The hydrocarbon can be converted to hydrogen and carbon monoxide using the steam reforming reaction.

$$CH_4 + H_2O \rightarrow CO + 3\ H_2 \tag{1.13}$$

Although the reaction given is for methane, other hydrocarbons can be substituted instead and the products remain hydrogen and carbon monoxide. The carbon monoxide can be further reacted with water via the water-shift reaction:

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{1.14}$$

which produces additional hydrogen. The net result of these two reactions is a stream that contains hydrogen and carbon dioxide. The hydrogen and carbon dioxide are separated, and one obtains a high-pressure carbon dioxide stream and a hydrogen stream that can be used as a fuel. The combustion of hydrogen is a relatively clean process producing only water as a by-product.

The reactions given above are not new technology. This is the most commonly used process for producing hydrogen and is used in most petroleum refineries that require hydrogen.

The carbon dioxide from this process can then be injected. Since this is a high pressure stream, it requires only a fraction of the power to compress the low pressure stream that results from the post-combustion separation.

A project like this was proposed by a company lead by BP in Peterhead, Scotland. The CO_2 was to be injected into the offshore Miller field, which had reached the end of its productive life. However, it was canceled largely due to delays by the government regarding incentives.

Another project of this type lead by Shell and Statoil in Tjeldbergodden, Norway, was also abandoned because it was deemed uneconomic.

1.7 Acid Gas Injection

With growing environmental concerns, the disposal of small quantities of acid gas is a problem. In the past, producers could flare these acid gases; however, in many jurisdictions this is no longer the case. New and stricter regulations are curbing the disposal of sulfur compounds into the atmosphere. Usually a sulfur plant is not an option for these small producers. Thus, other methods must be developed to deal with the unwanted acid gas.

Acid gas injection is quickly becoming the method of choice for disposing of these gases. The acid gas is compressed and injected, usually into a non-producing formation. Recently though, some have investigated the value of using the compressed acid gas as a part of a miscible flood scheme. Such a scheme is usually not recommended because it will lead to a build-up of acid gas and ultimately an increased the load on the amine unit. The goal is to dispose of the acid gas, not necessarily to recycle it.

In addition, with the current depressed market for sulfur, some larger producers are considering acid gas injection as an alternative for dealing with unwanted sulfur.

Injection of the acid gas also eliminates the release of carbon dioxide and sulfur oxides to the atmosphere. Sulfur plants emit all of the CO_2 to the atmosphere and even the most efficient emit small amounts of SO_x.

Acid-gas injection basically involves taking the acid gas from the amine regeneration column (the stripper), compressing it to a sufficient pressure, and injecting it into a suitable underground formation. Acid-gas injection is essentially a zero-emission process. During normal operation, "all" of the hydrogen sulfide from the produced gas is re-injected. Only during upsets, when the acid gas is sent to flare, or if there are leaks in the system, which must be attended to, are sulfur compounds emitted into the atmosphere. Of course, there are other locations in the plant where hydrogen sulfide may be emitted, but the acid gas from the regenerator accounts for the vast majority of the produced hydrogen sulfide.

Figure 1.2 shows the basic block diagram for the acid-gas injection process, including a block for the natural gas sweetening unit. For CCS, the sweetening block is replaced by a carbon capture block, but the rest of the process is unchanged. The four main components of the injection scheme are: 1. compression, 2. pipeline, 3. injection well, and 4. reservoir. Each of these will be discussed in some detail in this book.

Both a pump and a dehydration unit are required in only a few cases. A pump may be required if the injection pressure cannot be achieved by compression alone. As will be demonstrated in chapter 6, it is often possible to dehydrate the acid gas using compression and cooling alone.

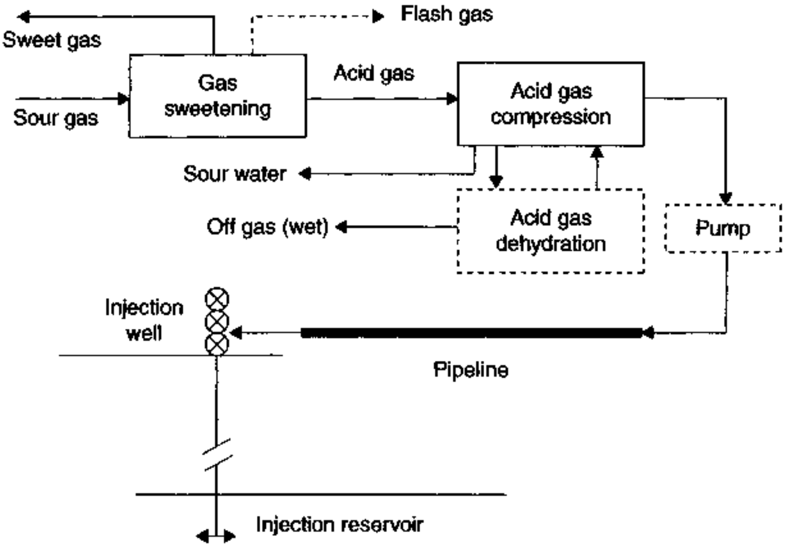

Figure 1.2 Block diagram of an acid gas injection scheme.

However, in some cases additional dehydration is required. Some of the complexities of dehydrating acid gas are discussed in Chapter 7.

1.8 Who Uses Acid Gas Injection?

As was mentioned, acid-gas injection has become a viable option for the disposal of unwanted acid gas.

1.8.1 Western Canada

In Western Canada there are more than 40 injection schemes. The first of these, the Chevron Acheson, near Edmonton, Alberta, began in 1989 and continues in operation today (Lock, 1997). Most of these injection schemes are quite small. About 80% are less than 5 MMSCFD. However, the largest is licensed to inject about 30 MMCFD. The composition of the injected gas ranges from essentially pure CO_2 to essentially pure H_2S and most everything in between. Injection pressures (the pressure at the wellhead) range from 4 000 to 13 000 kPa (600 to 1900 psia). Well depths are typically between 1000 and 3000 m (3,300 and 9,800 ft), with the deepest at about 3500 m (11,500 ft).

A few small injection schemes in Western Canada have been described in the literature in some detail. These include West

Pembina, Alberta (Lock 1997), Wayne-Rosedale, Alberta (Ho et al. 1996), Puskwaskau, North Normandville, West Culp, and Rycroft, all in Alberta (Maddocks and Whiteside, 2004).

Most of these are merely for the disposal of the acid gas, but not all. For example, in 2002 Dominion Energy Canada Ltd commissioned an acid-gas flood for its West Stoddart field near Ft. St. John, BC, Canada. In this flood, 2.5 MMSCFD of acid gas that is a 75% H_2S and 25% CO_2 mixture is injected into a producing reservoir. The acid-gas mixture is delivered from a multistage compressor to an injection well via a 2.25-km long pipeline.

1.8.2 United States

In the USA there are fewer than 20 schemes, but these tend to be slightly larger than those in Canada.

An example of a scheme in the USA is the Anadarko Brady Plant in Wyoming (Miller et al. 1999). The raw gas to this plant contains approximately 40% CO_2 and 1.5% H_2S. The acid gas is removed in two stages. The first, which is an amine plant, removes all of the H_2S and about 1/3 of the CO_2. The second, a Benfield plant, removes the remainder of the CO_2. It is the gas from the first sweetening process that is injected. The injection rate is about 9 MMCFD and the composition of the gas is 85% CO_2 and 14% H_2S.

A few American schemes also have been discussed in the literature. These include: Dumas, Texas, USA (Whatley, 2000); Lisbon, Utah, USA, (Jones et al., 2004), and Artesia, New Mexico, USA, (Root et al., 2007). As the technology continues to prove itself, more and more producers in the USA are considering acid gas as an option for dealing with unwanted acid gas.

1.8.3 Other Locations

Another significant injection scheme is the offshore injection at Sleipner West, in the Norwegian North Sea, operated by Statoil. At this location, the produced gas contains no H_2S and approximately 10% CO_2. The CO_2 is injected at a rate of about 1 million tonne per year (approximately 55 MMCFD).

Norway is one of the few countries in the world that imposes a carbon tax. Tax rates vary from industry to industry, but for gas production in the North Sea the rate is around 308 Norwegian Kroner per tonne CO_2 equivalents (about $45 [US]).

1.8.4 CO_2 Flooding

Although strictly not an acid-gas disposal method, miscible flooding using carbon dioxide is, in some situations, an economic method of enhanced oil recovery. It shares many characteristics with its disposal cousin, particularly the surface equipment.

In Canada, the Encana (originally PanCanadian) project at Weyburn, Saskatchewan, is a significant EOR project. At the Weyburn plant approximately 90 MMSCFD of a CO_2 blend is injected. Currently, the majority of this gas comes from the Dakota Gasification Company (DGC) plant in Beulah, North Dakota, United States, and is transported to Weyburn via a 320-km (220-mile) long pipeline. The remainder of the gas injected is recycled gas (gas separated from the produced oil). The recycle gas is largely CO_2 but also contains a small amount of H_2S and light hydrocarbons. As the project continues, more of the injected gas will come from recycle and less from DGC. The recycled gas is at low pressure and must be compressed for injection. This project produces about 8,000 bpd.

In the United States, there are approximately 70 CO_2 miscible flood projects in Texas, Oklahoma, Wyoming, New Mexico, Kansas, and Michigan. Total production from these projects is about 200,000 bpd.

1.9 In Summary

Acid gas, a mixture of hydrogen sulfide and carbon dioxide, is a toxic by-product of the sweetening of natural gas. Acid-gas injection has become an environmentally friendly way to dispose of this by-product. In the remainder of this book, the detailed design considerations for acid-gas injection are presented.

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Appendix 1A Oxides of Nitrogen

Nitrogen forms several oxides commonly referred to as NO_x. Nitrogen is capable of forming several oxidation states. Of these compounds only the following are significant:

NO: nitrogen (II) oxide

- nitrogen monoxide, nitrogen oxide, nitric oxide
- Molar mass: 30.006
- Color: colorless
- State at room conditions: gas
- Melting point: –164°C
- Boiling point: –152°C
- Density: 1.3 kg/m^3

NO_2: nitrogen (IV) oxide

- nitrogen dioxide, nitrogen oxide
- Molar mass: 46.006
- Color: brown
- State at room conditions: gas
- Melting point:
- Boiling point:
- Density: 2.0 kg/m^3

N_2O: nitrogen oxide

- dinitrogen oxide, nitrous oxide
- Molar mass: 44.013
- Color: colorless
- State at room conditions: gas
- Melting point: –91°C
- Boiling point: –88°C
- Density: 1.9 kg/m^3

N_2O_3: nitrogen (II, IV) oxide

- nitrogen oxide, nitrogen trioxide, dinitrogen trioxide
- Molar mass: 76.012

- Color: pale blue
- State at room conditions: unstable at room temperature
- Melting point: –102°C
- Boiling point: 3°C
- Density: 1400 kg/m^3 (liquid, 2°C)

N_2O_4: nitrogen (IV) oxide

- nitrogen oxide, nitrogen oxide dimer, dinitrogen tetraoxide, dinitrogen tetrooxide
- Molar mass: 92.011
- Color: colorless
- State at room conditions: gas
- Melting point: –10°C
- Boiling point: 22°C
- Density: 1450 kg/m^3 (liquid)

N_2O_5: nitrogen (V) oxide

- nitrogen oxide, nitrogen pentoxide, dinitrogen pentoxide
- Molar mass: 108.01
- Color: white
- State at room conditions: crystalline solid
- Melting point: 30°C
- Boiling point: 47°C
- Density: 2050 kg/m^3 (solid)

Appendix 1B Oxides of Sulfur

From the electron structure of the elements sulfur and oxygen, one would predict that an oxide of the form SO should arise. However, this compound is highly unstable. Sulfur forms two stable oxide: SO_2 and SO_3, commonly referred to as sulfur dioxide and sulfur trioxide.

SO_2: sulfur (IV) oxide

- sulfur dioxide, sulfur oxide
- Molar mass: 64.065
- Color: colorless
- State at room conditions: gas
- Melting point: -72°C
- Boiling point: –10°C
- Density: 2.8 kg/m^3 (gas)

SO_3: sulfur (VI) oxide

- sulfur oxide, sulfur trioxide
- Molar mass: 80.064
- Color: colorless
- State at room conditions: liquid
- Melting point: 17°C (gamma form)
- Boiling point: 45°C
- Density: 1920 kg/m^3