Gas treating is featured in many process plants in many contexts. There are almost always unwanted components that need to be removed from a gas stream. These components may need to be removed for a number of reasons like:

- Contamination of product
- Catalyst poison
- Reaction by-product
- Corrosion
- Dew point, unwanted condensation downstream
- Environmental considerations.

The challenges are many, and they occur when dealing with natural gas, synthesis gas, air and latterly, the challenge associated with CO_2 abatement. Different settings, seemingly different challenges, but for the chemical engineer there is a common denominator as shall become clear by the end of this book.

No matter what the application is, and no matter what the treatment needs are, cost effective solutions are always targeted. Having said that, it must be remembered that operational costs and any lost production are also factors included in this equation. There is always competition and the operator with the best profit margin will be better off in the longer term.

1.1 Definitions

Natural gas is the gas produced from hydrocarbon reservoirs. Some fields are gas fields producing nothing but natural gas, but natural gas is also produced as so-called associated gas where the gas comes from the reservoir along with the oil. The composition of natural gas varies, but is dominated by the presence of methane. It may be contaminated by CO_2 and H_2S , and there may be more or less of ethane and heavier hydrocarbons.

Gas Treating: Absorption Theory and Practice, First Edition. Dag Eimer.

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Most natural gas is transported to its point of use by pipeline, but there are markets that are too far away from the natural gas source. Japan is a case, and is served by liquefied natural gas, LNG, that is shipped in on gas tankers. LNG is mostly methane, it is made to be liquid at atmospheric pressure and requires a temperature down towards 111 K. The low temperature requires that higher boiling components must be removed in order not to precipitate, and water, CO_2 and H_2S must naturally be removed in order not to freeze out in the condensation process and thus block the flow channels.

Natural gas liquids, or NGLs, is a term that is used to describe the hydrocarbon condensate separated from natural gas on cooling. It is essentially ethane and heavier. In the case of NGL there is no particular refinement of the product such that there can be a tail of heavier hydrocarbons. This is different from liquefied petroleum gas, LPG, which is a tailored product that is mainly ethane and propane and may also contain a little butane, but nothing heavier.

Natural gas may also be referred to as lean or rich. A rich gas implies that there are significant amounts of ethane and heavier components that may be recovered for extra value. If a gas is lean, no such condensate would be economical to recover and the gas is sold for fuel.

Next there is synthesised gas, often referred to as syngas. This is gas that has been synthetically manufactured. Often natural gas has been the raw material, but it could also be produced as part of the activity in an oil refinery although this is more likely referred to as refinery gas. Ammonia production involves the making of syngas. Here natural gas is heated in the presence of steam and methane is converted to hydrogen, carbon monoxide and carbon dioxide. This gas is further processed with steam to convert monoxide to hydrogen and CO_2 and so on.

Flue gas or exhaust gas is the waste stream coming off a power plant. Offgases from syngas plants are usually referred to as bleeds or waste stream. The flue is usually the chimney, or at least the exhaust channel.

In the natural gas industry the Wobbe number is sometimes used. (Geoffredo Wobbe was an Italian Physicist who experimented with combustion of gases.) It is a way of judging if two fuel gases may be interchanged without affecting the performance of the burner. This number is defined as

Wobbe no = (Upper heating value of the gas) $/\sqrt{\text{(specific gravity of the gas)}}$ (1.1)

This sounds simple enough, but specific gravity (note: not 'specific weight') is a ratio. For a gas it is the ratio of the density of the gas and that of air. The gas is usually at atmospheric conditions as is the case for the reference air. The related temperatures and pressures must be defined, and in the case of air its water content is also important for its density. Specific gravity is dimensionless. The upper heating value is used but the lower may also be specified. The units should in any case be given, but it has been practised not to do this in order not to get it confused with the gas' volumetric heating value. It is practised to quote the Wobbe number in Btu/ft³, but in Europe it is more common to use MJ/Nm³. Common values of the Wobbe number are 39-45 MJ/Nm³. It is heavily influenced by the gas' content of nitrogen and C_2^+ . If it is specified in a gas sales contract, it is important to understand the implications. Further discussions on this subject may be found in a couple of documents issued by the American Gas Association (Ennis, Botros and Engler, 2009; Halchuk-Harrington and Wilson, 2007).

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Introduction 3

1.2 Gas Markets, Gas Applications and Feedstock

The natural gas market world-wide is huge. Although there is a need to provide a standardised gas such that all the end users' gas burners will function as intended, there are regional differences in specifications. The US market has this challenge that makes the interchangeability of gases difficult, and the cost and feasibility of standardising has been considered but discarded. In the UK, however, a similar conversion was done area by area in the 1960s and 1970s as the market was converted from 'town gas' to 'North Sea gas'. (Town gas was synthesised by gasification of coal.) Town gas was common in Europe until the advent of gas finds in the North Sea. Pipelines from these and Russian fields serves this market today. North America has had a change of fortune in recent years by technology enabling the production of so-called shale gas. There have also been LNG projects developed, with more coming on stream in the next few years. Gas is challenged by other forms of energy. Although existing users are to an extent 'sitting ducks' due to investments made, provision costs of gas must be kept in check to keep its market share. Electricity is the immediate competitor in the retail market, and that in turn could be provided through the combustion of gas, coal or oil, and other sources are nuclear power plants and hydroelectricity. The more alternatives that are available in any one market, the more the focus on provision cost of energy in the market. Deeper discussions of these issues may be found elsewhere (BP, 2011; IGU, 2013a,b; Natural Gas Supply Association, 2005).

Specifications of natural gas as a product is a very interesting topic in many ways and the specifications really determine what treatment a gas eventually needs. There are two dimensions to this. One is the transport system that supplies a market and what treatment the gas needs to uphold flow assurance in the supply chain. The other is the end market with its appliances where gas burners have been fitted with certain gas properties in mind. Interchangeability of gas cannot be taken for granted. There are many stumbling blocks to this (IGU, 2011).

Methane, or natural gas, is less reactive than their heavier analogues like ethane, propane and so on. As feedstock for making hydrogen as in the ammonia process it is the preferred starting point as the ratio of hydrogen to carbon is highest in methane. For this reason, and because of the pricing, natural gas is the feedstock of choice for this purpose.

The C_2 + fraction of the natural gas has in the main a higher market value as feedstock than as fuel. Hence the opportunity to separate these components from the gas is often taken. The economics of this has varied over time though.

1.3 Sizes

For various assessments it is valuable to have a feel for sizes of plants and associated variables. The question being, what is big, what is small, what is a challenge and what is trivial. Plant sizes and complexities will vary widely. Perhaps the simplest gas treating plant to be encountered in this context will the end-of-pipe solution scrubber where some contaminant is to be removed from an effluent gas stream before being released. Maybe this scrubber has a packing height of 3 m and a diameter of 2 m, and furthermore when the absorbent has done its job, it may be returned to the process without further ado. A 400 MW CCGT

(Combined Cycle Gas Turbine) power plant that needs CO_2 abatement will have a gas stream in the order of 1.8 million m³/h, and the absorber would have a diameter around 17 m if there is one train only.

A large synthesis gas train may have a gas flow in the order of $10\,000$ kmol/h. This would be 224 000 Nm³/h. However, the pressure could be around 25 bar if this was an ammonia plant, and this would imply a real gas stream in the order of $10\,000$ m³/h.

In natural gas treating there is a wide range of plants. A fairly small one might be 10 MMSCFD. This is a typical way of specifying plant size in North America. MM stands for 'mille-mille', which is Latin inspired, meaning 1000×1000 (or a million). SCF is Standard Cubic Feet, and D implies per 24 hours (a Day). In North America 'Standard' means the gas volume is at 60°F and an absolute pressure of 14.696 psi (psi = pounds per square inch). Wikipedia points out that the 'standard' pressure may also be 14.73 psi, which is based on a pressure of 30 in. of a mercury column. Beware; if you are buying gas the difference in what you get is 0.23%, which is not to be given away easily in negotiations.

A large gas plant could be in the region of 2 million Sm³/day. This is typical of a gas field in the North Sea. This is in metric units, and the 'standard' now implies 15°C and 1.013 bar. If this was indeed the gas's temperature and pressure it would be at its 'standard conditions.' Note that 15°C and 60°F are not identical. European and American standard conditions are not equal: something to be kept in mind when selling and buying.

An often used specification for H_2S allowed in natural gas is 0.25 grain per 100 SCF. This is a US term. One 'grain' is 1/7000th of a pound (lb).

LNG plants are usually referred to in million tonnes of LNG per year. A plant of 3 million tonnes per year was considered big less than 10 years ago, but one-train capacities have been stretched to 5-7 and there is a new generation of plants with a third refrigeration loop that could take the capacity to 10 million or more.

A large ammonia plant today would typically be 2000 tonnes per day. This is almost the double of what was usual around 1970. Cryogenic air separation units (ASU) could be as big as 3500 tonne of oxygen per day, but this size of plant is rare. Traditionally they have been built to provide oxygen for steel works. However, they figure in present day studies on oxy-fuel plants. That is, power plants where hydrocarbons, or coal more likely, is combusted with oxygen to make the CO_2 resulting more easily accessible for capture and storage.

It is good to develop an intuitive sense for plant sizes and put them into perspective. The ability to distinguish between the various 'standard' units of gas quantity is a must. To help in this direction and to summarise the earlier discussion of plant sizes, Table 1.6 is provided at the end of the example problems.

1.4 Units

There are a number of units being used in the industry that are not intuitive and will be unfamiliar to newcomers. To fill in the void, this section will go through a number of such units. The reader will undoubtedly come across further units before finishing and these will need to be deciphered using reference works.

	1				/	
	Pint	Gall (imp)	Firkin	Kilderkin	Barrel	Hogshead
Pint	1	8	72	144	288	432
Gall (imp)		1	9	18	36	54
Firkin			1	2	4	6
Kilderkin				1	2	3
Barrel					1	1.5
Hogshead						1

Table 1.1 Imperial volumetric relations. (from 1824 onwards in the brewery business.)

Let us start with the measurement of liquid. For most purposes a chemical engineer could use m^3 for volume and be done. However, the oil and gas business has a few special quirks when it comes to volumetric units, and oil, in North America in particular, is reported in barrels. Barrels are part of an old system of volumetric units where the sizes have changed over the centuries, and they have also differed between businesses. Today, a barrel as used in the oil industry is 158.98731. This is supposed to represent exactly 42 US gal. The reader will no doubt have come across various non-metric units of volume in non-professional context, and Table 1.1 is included to put these volumes into perspective. Oil density varies significantly and there will typically be 6–8 barrels per tonne.

Gas volumes are straightforward in the sense that either metric or well-defined Anglo-American measures are used. The important part here is to be able to distinguish between the various 'standard' or 'normal' conditions used. These must be defined in any gas sales contract to avoid legal disputes later. This is discussed previously to the necessary extent. However, the reader may well meet further definitions in the future since IUPAC changed their recommendation for standard pressure to 1 bar (100 kPa) in 1982. In other fields of gas processing so-called 'normal' conditions are also in use. These are defined as 0° C and 1 atm = 1.01325 bar.

It is prudent to mention that absolute temperatures in the 'Fahrenheit spirit' is known as °R (degrees Rankine) and

$^{\circ}R = ^{\circ}F + 459.67$

A final topic worth mentioning is pressure units. They are mostly self-explanatory, but there is a unit called 'atmosphere.' If this is spelt 'atm', it is 'one' when the pressure is 760 mm Hg or 1.013 bar. However, if it is merely spelt 'at', we are talking about a 'technical atmosphere' (which is an old European tradition). This equals 'one' when the pressure is 1 kp/cm^2 . (kp, or kilopond, is the same as kg_f). It is not often used these days, but it may still be found. Varieties are ato (gauge pressure, o = 'overpressure') and atü (gauge pressure, German: *überdruck*). It is slightly higher than 736 mm Hg. The term mm Hg as a pressure unit should strictly be the height of a mercury (Hg) column at 0°C; that is, that mercury has the density it has at 0°C.

To round off this discussion of units a table of conversion factors is provided to enable quick conversion of data discussed in the text to make life easier for those that do not have their reference values in metric units (Table 1.2).

It is also worth mentioning that the unit ton is not necessarily unambiguous. In the metric world the ton is 1000 kg while in the Anglo–American units it is 2240 lbs. Often the metric

From unit to unit	Multiply by	From unit to unit: divide by the same number
	0.00.400	
ft to m	0.3048^{a}	m to ft
lb to kg	0.45359237^{a}	kg to lb
lb mol to kmol	0.45359237 ^a	kmol to lb mol
°F to °C	Subtract 32, then $\times 1.8^{a}$	°C to °F
bar to psi (lb _f /sq in.)	14.5037744	Psi to bar
1 mm to micron (μ)	1000	micron to mm
Btu ^b to kJ	1.05435026444	kJ to Btu
kJ to kWh	3600	kJ to kWh
Btu/lb to kJ/kg	2.32444	kJ/kg to Btu/lb
Btu/ft ² ·F·h to W/m ² ·K	1.751378	W/m ² ·K to Btu/ft ² ·F·hr
hp (metric) kW	735.49875	kW to (metric) hp
bhp to kW	745.69987	kW to bhp
Imp gallon to m ³	0.00454609	m ³ to imp gallon
US gallon (g) to m3	0.003785412	m ³ to US gallon
gpm (per minute) to m ³ /s	0.00006309	m ³ /s to US gpm

Table 1.2Unit conversion factors.

^aImplies exact conversion factor, otherwise derived.

^bThis is based on the thermochemical value of BTU, but other definitions range from this value to as high as 1.05987 kJ.

Table 1.3Tons, long tons, short tons and tons, and so on.

Type of ton	Content
1 metric ton (tonne)	1000 kg (approximately 2205 lb)
1 Anglo-American ton (ton, sometimes long ton))	2240 lb (approximately 1016 kg)
1 short ton (in USA and Canada often referred to as 'ton')	2000 lb (approximately 907.2 kg)

Table 1.4Various often quoted volumes of gas of given mole mass.

kmol	Nm ³	Sm ³ (metric)	Sm ³ (US)	SCF (US
1	22.414	23.645	23.690	836.62

ton is referred to by 'tonne', but if important, this should be verified on a case to case basis. The world of tons is summarised in Table 1.3.

In the air gases industry it is common to talk about plant capacities in tons per day. Clearly it is essential to know which tons are quoted. Ammonia plants are commonly described in tons per day and LNG plant in million tons per year. It is quick to find yourself shortchanged.

A very useful summary of conversions between gas volumes and mole contents are given in Table 1.5. Note that the 'normal m³' is defined at the 'normal conditions', at NTP (normal

(psi is lb _f /square in.)	
8.31447	J/(mol K)
0.0831447	m ³ bar/(kmol K)
0.0820574	m ³ atm/(kmol K)
8.31447	m ³ Pa/(mol K)
8.31447	m ³ kPa/(kmol K)
1.98721	cal/(mol K)
10.73159	ft ³ .psi/(lb mol R)

Table 1.5Values of the gas constant, R.

temperature and pressure). The 'standard m³' are at STP (standard temperature and pressure). The standard temperature is not the same in Europe and the US.

Another useful compilation is a collection of different values of the gas constant R. These will come in useful as the situation arises.

Ambient Conditions 1.5

Plants have been built in all sorts of places. Some are hot, some are cold and some are to be found at a high altitude where the air is thin. When comparing plant costs and efficiencies, this must be kept in mind. An LNG plant will of course have a better efficiency if the heat sink is at 5°C compared 35°C. On the other hand winterisation may be costly. Special precautions must be made if it is to be operated for weeks on end at -40° C.

Objective of This Book 1.6

The objective of this book is to give the reader a general background for the world of gas processing. It is also a target to provide specialised teaching with respect to the absorptiondesorption process in general, and to mass transfer coupled with chemical reaction in particular.

Some topics in this book are treated cursorily and the only justification for including these chapters is to create a starting point for the reader to dive further into those topics. The book that gives specialist in-depth treatment of all you need to know is still to be written.

1.7 **Example Problems**

Throughout this book we shall need relevant case studies to illustrate the use of the tools and theories developed. The development of these case studies starts here, and they will be based on the problems outlined when discussing typical plant sizes. To a degree reverse engineering will be applied to extract the problems relevant for discussion in this book. Immediate question: Which is the bigger gas processing plant of the following: Flue gas from a 400 MW CCGT, 600 MW coal power, 2000 tonnes per day ammonia plant, 30 MMSCFD natural gas, 3 million Sm^3 per day natural gas plant, or a 7 million tonnes

per year LNG plant? After working the example problems, you will know. When gas concentrations are given, they are on a molar (or volumetric) basis unless otherwise specifically stated. Ideal gas is assumed throughout these examples.

1.7.1 Synthesis Gas Plant

A good and well-defined example is an ammonia plant. Here the synthetic gas is eventually converted to ammonia (NH₃). Such a plant is in most situations fed by natural gas at pressure. The gas needs to be treated for sulfur compounds to avoid poisoning of catalysts before processing can proceed. This is followed by 'reforming' the natural gas to H₂ and CO in the first sections of the plant before the CO is converted to H₂ by the help of steam.

$$CH_4 + \frac{1}{2}O_2 = CO + 2H_2$$

 $CO + H_2O = CO_2 + H_2$

Thereafter the CO_2 must be removed. At this stage we ask ourselves, how much gas must be treated if the ammonia plant has a capacity of 2000 tonnes per day. The eventual reaction is:

$$\frac{1}{2}N_2 + \frac{1}{2}H_2 = NH_3$$

Now, 2000 tonnes per day work out at:

$$(2000 \text{ ton/d}) (1 \text{ d/}24 \text{ h}) (1000 \text{ kg/ton}) = 83 333 \text{ kg/h}$$

and since the molecular weight of ammonia is 17, it follows that the ammonia production is:

$$(83\,333\,\text{kg/h}) / (17\,\text{kg/kmol}) = 4902\,\text{kmol/h}$$

Next it is observed that in the ammonia synthesis reaction $0.5 + 1.5 = 2 \mod N_2$ and H_2 gas are converted to 1.0 mol of ammonia. Hence, the net stream of treated gas after CO₂ removal will be:

$$(2)(4902 \text{ kmol/h}) = 9804 \text{ kmol/h}$$

Let us assume that the conversion efficiency is 99% and call that 9804/0.99 = 9903 kmol/h.

It may be worked out from analysis of the ammonia train from the start, but we shall take it as read that the CO_2 content of the gas prior to CO_2 removal is 20% (mol) with a gas pressure of 25 bar and a temperature of 40°C. On this basis the feed to the CO_2 removal unit is:

(9903 kmol/h) / (1 - 20/100) = 12378 kmol/h

 CO_2 to be removed is thus: 12378 - 9903 = 2475 kmol/h.

In this industry it is also quite common to quote flows in Nm³/h and that works out at:

$$(12\,378\,\text{kmol/h})(22.414\,\text{Nm}^3/\text{kmol}) = 277\,440\,\text{Nm}^3/\text{h}.$$

With the temperature and pressure given, this means that the actual flow of gas at operating conditions is:

$$(277\,440\,\text{Nm}^3/\text{h})(1.013/25)((273+40)/273) = 12\,888\,\text{m}^3/\text{h}$$

1.7.2 Natural Gas Treatment

Characterising a natural gas treatment plant as small or large is not an exact science. The following example could, for what it is worth, be described as mid-range. A plant is needed to process a stream of 30 MMSCFD.

Using the conversion factor available from Table 1.4, this stream becomes:

(30 MMSCFD) / (255.002 MMSCFD/kmol) = 4902 kmol/h

This is turn is:

 $(4902 \text{ kmol/h}) (23.645 \text{ Sm3/kmol}) = 115908 \text{ Sm}^3/\text{h}$

With temperature and pressure given as 40°C and 35 bar, the actual gas flow at operating conditions are:

 $(115908 \,\mathrm{Sm^3/h}) (1.013/35) ((273 + 40)/288) = 3645 \,\mathrm{m^3/h}$

If 8% of this feed is CO_2 , then there are $(0.08)(4902) = 392 \text{ kmol } CO_2/\text{h}$ in the feed.

1.7.3 Natural Gas Treatment for LNG

LNG plants are complex and as such their economics thrives on economics of scale. Plant sizes in excess of 10 million tons per year are possible, but we shall look at the implications of a 7 Mton/year capacity.

We shall assume that this capacity is reached by being on-stream for 8600 hours per year. Furthermore, it will be assumed that the average molecular weight of the LNG is 17. Capacity may then be rated as:

 $((7\,000\,000\,\text{ton/y})(1000\,\text{kg/ton})/(8600\,\text{h/y}))/(17\,\text{kg/kmol}) = 47\,880\,\text{kmol/h}.$

If there is 12% CO₂ in the feed, its CO₂ removal plant will receive:

 $47\,880/(1 - 0.12) = 54\,409\,\text{kmol/h}$ and there will be 5441 kmol CO₂/h.

Given a temperature of 40°C and a pressure of 50 bar, this implies a flow at operating conditions equal to:

 $(54409 \text{ kmol/h})((22.414 \text{ Nm}^3/\text{kmol})(1.013/50)((273 + 40)/273) = 26120 \text{ m}^3/\text{h}.$

1.7.4 Flue Gas CO₂ Capture from a CCGT Power Plant

The abbreviation CCGT stands for combined cycle gas turbine (power plant). These plants are often described in terms of CO_2 emission, but we shall approach this from its power rating. A state of the art CCGT will be as big as 440 MW rated power output, and its power efficiency is 58% or more. In this plant gas is burnt under pressure, expanded in the gas turbine and the heat in the hot exhaust is recovered to make steam that is in turn used in steam turbines to boost energy efficiency.

We shall assume a fuel gas feed of 83% (mol) CH_4 , 9% C_2H_6 , 4% C_3H_8 , 1% C_4H_{10} , 2.5% CO_2 and 0.5% N_2 . There is also expected to be 3 ppm of H_2S , but this is neglected for the

present considerations. Based on heat of combustion data from Perry and Green (1984), the average upper heat of combustion for this gas is 997.06 kJ/mol. The 'upper' value is used since the power process is expected to use a condensing steam turbine at the end. Average molecular weight is estimated to be 18.84. The need for fuel gas is accordingly:

 $(3600)((440\,000\,\text{kW})/(997\,060\,\text{kJ/kmol}))/0.58 = 2739\,\text{kmol/h}.$

The combustion stoichiometry means that 1 mol of CO_2 is formed from 1 mol of CH_4 , 2 mol from C_2H_6 , and so on. CO_2 itself will of course pass through the combustion unchanged. The CO_2 content of the flue gas may now be estimated:

$$(2739 \text{ kmol/h}) [1 \times 0.83 + 2 \times 0.09 + 3 \times 0.04 + 4 \times 0.01 + 0.025] = 3273 \text{ kmol/h}.$$

Water in the flue gas from combustion may be similarly estimated based on $1 \mod CH_4$ giving 2 mol of water, and so on:

$$(2739 \text{ kmol/h}) [2 \times 0.83 + 3 \times 0.09 + 4 \times 0.04 + 5 \times 0.01] = 5862 \text{ kmol/h}.$$

The oxygen needed for combustion is given from stoichiometry and the need to provide excess oxygen. Here 1 mol O_2 is needed to make 1 mol of CO_2 and 1/2 mol O_2 is needed to make 1 mol of H_2O . Hence the stoichiometric amount of O_2 needed is:

 $1 \times 3273 + \frac{1}{2} \times 5862 = 6136 \text{ kmol/h}.$

However, air (O_2) is added to the combustion process in excess. An excess factor of 2.8 is quite typical. Using this, the actual O_2 addition will be:

 $(6136 \text{ kmol/h})(2.8) = 17\,180 \text{ kmol/h}.$

The accompanying nitrogen (which here includes the argon) will be:

$$(17\,180\,\text{kmol/h})(79/21) = 64\,628\,\text{kmol}\,\text{N}_2/\text{h}.$$

Oxygen in the flue gas will be:

 $17\,180\,\text{kmol/h} - 6136\,\text{kmol/h} = 11\,044\,\text{kmol/h}.$

Assuming a dew point of 10°C for water in combustion air, water in with that is:

 $(0.01227 \text{ bar}/1 \text{ bar}) (64\,628 \text{ kmol/h}) = 1004 \text{ kmol/h}.$

Total water from the power plant is then: 1004 + 5862 kmol/h = 6866 kmol/h. Sum flue gas:

 $64\,628\,\mathrm{kmol}\,\mathrm{N_2/h} + 11\,044\,\mathrm{kmol}\,\mathrm{O_2/h} + 3273\,\mathrm{kmol}\,\mathrm{CO_2/h} \\ + 6866\,\mathrm{kmol}\,\mathrm{H_2O/h} = 85\,811\,\mathrm{kmol/h}.$

The volumetric flow is:

 $(84\,807\,\text{kmol/h})(22.414\,\text{Nm}^3/\text{kmol}) = 1\,900\,859\,\text{Nm}^3/\text{h}.$

With a temperature of 100°C and a pressure of 1.05 bar, the actual flow at operating conditions will be:

 $(1900859 \text{ Nm}^3/\text{h})(1.013/1.05)((273 + 100)/273) = 2505256 \text{ m}^3/\text{h}.$

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1.7.5 Flue Gas CO₂ Capture from a Coal Based Power Plant

The coal technology considered as the basis here is the conventional one where coal is combusted, steam is raised and the steam is used to drive steam turbines to produce electricity. The question raised is: how much flue gas and CO_2 is created from a 500 MW coal fired power plant? Assume a power efficiency of 40% in this case. A further assumption is that the sulfur content of the coal is 1% (which is a low value in this context). We also assume that the final steam turbine in the train is a 'condensing one', which implies that upper heats of combustion should be used. They are 393.550 kJ/mol for carbon and 394.966 kJ/mol for sulfur. On average the heat of combustion is 393.565 kJ/mol.

The amount of coal needed is:

 $((500 \times 1000 \text{ kW}) / (393565 \text{ kJ/kmol})) / (40/100) = 3.176 \text{ kmol/s} = 11434 \text{ kmol/h}.$

The amount of CO_2 produced is (0.99)(11434) = 11320 kmol/h.

And the amount of SO₂ produced is (0.01)(11434) = 114 kmol/h.

These plants are fired with excess oxygen (or air if you like). We shall assume an excess factor of 1.7. The amount of oxygen needed for combustion is by stoichiometry:

$$11320 + 114 = 11434 \text{ kmol/h}.$$

The actual oxygen feed is accordingly:

(11, 434 kmol/h)(1.7) = 19438 kmol/h.

Excess oxygen is 19438 - 11434 = 8004 kmol/h.

The amount of nitrogen in the air to combustion is (remembering that there is $21\% O_2$ and we assume the rest is all N₂):

$$(19438)(79/21) = 73123 \text{ kmol/h}.$$

The total amount of flue gas is the sum of all the components (CO_2, SO_2, N_2, O_2) :

When this gas arrives at the CO_2 capture plant, it has been cooled by the steam generation and BFW (boiler feed water) heating. We shall assume that the temperature is 45°C and that the pressure is 1.05 bar. The actual flow of gas neglecting H₂O is then:

(11320 + 114 + 73123 + 8004) = 92561 kmol/h.

Its volumetric flow is:

$$(92561)(22.414)(1.013/1.05)((45 + 273)/273) = 2331291 \text{ m}^3/\text{h}.$$

1.7.6 CO₂ Removal from Biogas

There are numerous bioreactors about converting organic waste material to methane. The plant sizes cover a very wide range. However, we shall look at a large (in this context) plant that has a nominal capacity 10 million Sm³ per year. What is the size of gas stream to be treated?

We shall assume that the plant is operating 350 days per year. The temperature is 35°C (assuming mesophilic bacteria), and the pressure is typically 1.1 bar.

Feed gas rate is:

$$(10 \times 10^{-6} \,\mathrm{Sm^3/y}) / ((350 \,\mathrm{d/y}) (24 \,\mathrm{h/d})) = 1190 \,\mathrm{Sm^3/h}.$$

Actual volumetric feed rate is:

$$(1190 \,\mathrm{Sm^3/h}) (1.013/0.9) ((273 + 15)/288) = 1172 \,\mathrm{m^3/h}.$$

Typical CO_2 content of such gas is 35%. The amount of CO_2 in feed is thus:

 $(1190 \,\mathrm{Sm^3/h})(0.35) / (23.645 \,\mathrm{Sm^3/kmol}) = 17.6 \,\mathrm{kmol/h}.$

1.7.7 CO₂ Removal from Landfill Gas

Landfills vary very much in scale, and any gas production from such fills will reflect this. The composition of wellhead gas will also vary, 50% CH_4 , 35% CO_2 and 15% N_2 are values in the mid-range for each of these. In addition there will be found H_2S , O_2 , and ammonia plus siloxanes. The latter represents a challenging removal problem. One such landfill gas plant produced 13 000 US gal of liquefied CH_4 per day. What gas volume was processed?

The density of liquefied CH_4 at atmospheric pressure is roughly 700 kg/m³. Assuming close to 100% conversion of CH_4 , this means that the CH_4 production is:

 $(13\ 000\ US\ gall/d) (0.003785\ m^3/US\ gall) (1\ d/24\ h) (700\ kg/m^3) = 1435\ kg/h,$ $(1435\ kg/h) / (16\ kg/kmol) = 89.70\ kmol/h.$

Since CH_4 constitutes 50% of the feed, the plant feed is:

$$89.70/0.50 = 179.4 \,\mathrm{kmol/h}$$
.

If we further assume that the pressure is 0.9 bar (abs) and the temperature 20°C, then the actual volumetric feed to this plant is:

 $(179.4 \text{ kmol/h}) (22.414 \text{ Nm}^3/\text{kmol}) (1.013/0.9) ((273 + 20)/273) = 4857 \text{ m}^3/\text{h}$:

The amount of CO_2 in the feed is: (179.4 kmol/h)(0.35) = 62.8 kmol/h.

1.7.8 Summarising Plant Sizes Just Considered

To provide a comparison of plant sizes for background references the previously mentioned capacities are summarised in Table 1.6. Since we have converted all the plants to capacities rated in the same units, such a comparison is now meaningful. It is quickly seen that the relative plant sizes depend on whether they are ranked by actual volumetric flow or the amount of CO_2 to be removed.

a reference frame.		
Type of plant	Actual flow of gas (m ³ /h)	CO ₂ in feed (kmol/h)
Feed to CO ₂ treatment in a large ammonia plant	12 888	2 475
Natural gas treatment plant (large)	3 645	392
LNG feed gas	28327	5 4 4 1
Flue gas from 440 MW CCGT gas power station	2 500 000	3 273
Flue gas from 500 MW coal power station	2 331 291	11 320
Biogas reactor treatment feed gas	1 172	17.6
Landfill gas plant feed	4 857	62.8

Table 1.6 Summary of plant sizes provided to give the reader a reference frame.

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