Facilities Engineering: Things I wish I'd Known when I Started

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Contents

1. Background 4
2. Fluid Terminology 4
2.1. Oilfield Units 5
2.2. g_c 6
2.3. Reservoir Fluids 7
2.3.1. Liquids 7
2.3.2. Gas 10
3. Fluid Characteristics 16
3.1. Intrinsic and extrinsic properties 16
3.2. Selected Properties 16
3.3. Specific Heat at Constant Pressure (c_p) 17
3.4. Adiabatic Constant 18
3.5. Joule-Thomson coefficient (μ_{jt}) 19
3.6. Combustion Characteristics 20
3.7. Including water vapor 21
3.8. Inherent Energy 23
3.9. C6 Plus 23
3.10. Pseudo-reduced properties 24
4. Topics in Fluid Mechanics 26
4.1. Statics 27
4.1.1. Hydrostatic pressure 27
4.1.2. Buoyancy 28
4.2. Dynamics 28
4.2.1. Navier-Stokes Equation 29
4.2.2. Bernoulli Equation 30
4.2.3. No-Flow Boundary 31
4.2.4. Similitude 32

5. Parameter Measurement....32
5.1. Accuracy....33
5.2. Pressure and temperature measurement....34
5.3. Total pressure....35
5.4. Pressure Continuum....36
6. Standard Conditions....37
7. Empirical Equations....41
8. References....42
9. Nomenclature....43
10. Units....45

Introduction

1. Background

When I started working in Oil & Gas in 1980, there was a very long list of things that I wish I had known. In retrospect, more than anything else, I needed access to the terminology that specialists in various parts of the industry used. For example, when a Tool Pusher was installing a downhole pump that I was experimenting on he asked me "do you want it set in tension or compression?" I did the "engineering thing" and made up an answer without anything to base it on. It turns out that I made the right choice, but coin tosses are a poor basis for an engineering decision. In this case I simply did not know exactly what he meant (I knew the terms, but I didn't know at that time how the terms applied). This document is an attempt to make the esoterica of the onshore upstream gas portion of the industry a bit more accessible to engineers whose remit is surface facilities.

Any study of an industry faces the related dilemmas of "where to start?" and "what level of prior knowledge can be assumed?" It is certainly safe to assume that anyone who picks up this document is comfortable with the concepts of Algebra, but how about Newton's laws of motion? The general laws of Thermodynamics? Kinematics? Organic chemistry? How much fluid mechanics can be assumed? There are no clear answers to these questions, but there are a few concepts that are used across all engineering disciplines in Oil & Gas that tend to get lost in the noise. For example, every part of Oil & Gas uses "volume flow rate at standard conditions". That idea is basic to reserves estimates, well-bore tubular requirements, pipe design, vessel capacity, and plant operations.

Everyone understands SCF (or SCm) don't they? Maybe not. In my Master's Thesis I used a volume flow rate at standard conditions to calculate a "velocity" that was central to my basic assertions and calculations. I defended this paper in front of my Thesis Committee and none of them even hinted that all of the conclusions contained in my Thesis were absolutely invalid because of this bonehead mistake. This experience leads to the conclusion that the concept of volume flow rate at standard conditions is so ubiquitous in the industry that everyone assumes that everyone else understands it properly. Almost all of us are wrong about almost all of us. This document is focused on removing the veil of complacency from several of these ubiquitous concepts so we don't need to revisit them multiple times in further study. If you are uncomfortable with Algebra you might want to go elsewhere for a refresher prior to proceeding.

2. Fluid Terminology

When discussing the fluids we encounter in Oil & Gas, definitions often get blurred and many of the differences are of critical importance to selection and operation of surface equipment.

Crude Oil: a mixture of naturally occurring chemicals which contain hydrocarbons and which is liquid at reservoir conditions and remains liquid at temperatures experienced in tanks at atmospheric pressure on the surface.

Condensate: a mixture of naturally occurring chemicals which contain hydrocarbons that are gaseous at reservoir conditions and liquid at surface ambient conditions. Condensate generally includes species of hydrocarbons including pentane (C_5H_{12}), hexane (C_6H_{14}), and occasionally heptane (C_7H_{16}) and octane (C_8H_{18}). Lighter hydrocarbon species can be present in condensate, but over time it will boil off. API gravity (see below) of condensate is generally 45-75 °API. [Braziel]

Dry gas: a mixture of gases that does not contain saleable quantities of hydrocarbon species that become condensate. Notice that "Dry gas" does not mean that there is no liquid, it means that there is no marketable liquid hydrocarbons, there can be a considerable quantity of water in a "dry gas" field.

Notice that all of these definitions start with "a mixture". This is because no reservoir has pure fluids, Mother Nature just doesn't work that way. The exact mix of fluids is quite variable from field to field and even from well to well within a field. A term like "West Texas Intermediate (WTI)", "North Sea Brent", or "Saudi Light" actually refer to a narrow range of specific gravities and API gravities (see below) and upper limits of contaminants.

Natural Gas Liquids (NGL): Hydrocarbon species whose boiling point is near-ambient and cannot be reliably stored at atmospheric pressure in a vented vessel. NGL generally includes ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and isobutane (C_4H_{10}).

Specific Gravity: Specific gravity is a convenient way to represent a fluid's mass relative to a reference fluid. If is known that a liquid's density is 60% of the density of water, then you can input the density of water in units that are convenient for the current calculation and multiply it times 0.60.

Wet gas: a mixture of gases that include hydrocarbon species that become liquid with pressure or temperature changes of a magnitude expected in normal gas production.

2.1. Oilfield Units

Traditional oilfield units are based on the foot-pounds-second (FPS) system as bastardized by the industry. Primary oilfield units are:

- bbl → Barrel, used for all liquid measurements defined as 42 U.S. gallons [159 L]
- SCF → Standard cubic feet, volume of gas stated as though it were measured at a reference pressure and temperature (see below).
- M → Roman numeral for 1000

- MM → Multiplication of Roman numerals (i.e., in Roman Numerals "MM" would be 2,000, but in Oil & Gas "MM" is one million or 1000 × 1000)
- B → Abbreviation for "billion" or 10^9
- T → Abbreviation for "trillion" or 10^{12}

The suffix "M" and "MM" are only used in this document to mean "1,000" and "1,000,000" respectively with traditional oilfield units, not SI units.

The SI units that this document will use are:

- m^3 → Cubic meter, only used here for physical volumes like liquid volumes and gas volumes at actual conditions (never for gas volumes at standard conditions).
- SCm → Standard cubic meters, volume of gas stated as though it were at a reference pressure and temperature (see below).
- k → Kilo, as a prefix it is the base value times 10^3
- M→ Mega, as a prefix it is the base value times 10^6 (this document will try to avoid the used of "M" as an SI unit, but values like MPa are far too ubiquitous and useful to completely forego)
- G → Giga, as a prefix it is the base value times 10^9
- T → Tera, as a prefix it is the base value times 10^{12}
- P → Peta, as a prefix it is the base value times 10^{15}
- E → Exa, as a prefix it is the base value times 10^{18}

2.2. g_c

Mass in the fps system is messy. The "official" mass unit is the "slug" which is designated as "the mass that would represent a weight of 32.174 lbf on the surface of the earth". Slugs tend to be a difficult concept for many people and calculation errors with mass in fps are so common that an informal unit called "pounds mass" and designated "lbm" was developed. One lbm weighs 1 lbf on the surface of the earth, which creates a whole new package of confusion. The mathematical representation of mass and weight in the fps system is (Eq 1, all variables are defined in the "Nomenclature" section at the end of this chapter):

$$lbf = g \cdot lbm \Rightarrow 1 = g \cdot \frac{lbm}{lbf} \therefore g_c = g \cdot \frac{lbm}{lbf} = 32.174 \cdot \frac{ft \cdot lbm}{s^2 \cdot lbf} \qquad \text{Eq 1}$$

Someone doing calculations in the fps system decides whether to include a g_c or not when they determine if the equation includes lbm and needs the results in lbf (e.g., a column of liquid

has a mass and a density, but we frequently need the force that that column will exert at the bottom of the column in lbf per unit area), includes lbf and needs lbm, or has both and needs to cancel them. If you were to take a mass to the moon, calculations would have to use a different gravitational constant and could not use g_c so "slug" or "kg" would be much less confusing ways to represent mass.

This term has always been unique to the fps system, but recently the SI folks have been using kg/cm^2 instead of kPa or bar so they will have to develop their own nonsense. The official SI pressure unit is the Pascal.

2.3. Reservoir Fluids

The Oil & Gas Industry exists to exploit in situ fluids in subterranean reservoirs. Any action that the industry takes that is not intended to facilitate that imperative is a waste of resources. Some fluid characteristics are so specific to a particular process, that it is appropriate to define those characteristics closer to the process (e.g., a document dealing with Produced Water seems like the appropriate place to discuss what to expect within the produced water that must be collected and disposed of). There are some general concepts that are appropriate for this document.

Do we need to consider safety of employees and the public? Absolutely, but we need to take those safety actions in ways that consider the fact that the only reason that these safety considerations exist is because we are trying to extract, transport, and process reservoir fluids into compounds that are useful to people.

Reservoir fluids are central to every appropriate action that any of us will ever take within our roles in the industry. Consequently, the discussion of these fluids is appropriate in this portmanteau document rather than in a Reservoir document.

Mother Nature has allowed some fluids to be trapped within subterranean reservoirs. These fluids include natural gas (methane through about hexane), condensate, oil, sulfur compounds, CO_2, nitrogen, oxygen, and water. These mixtures are not very neat or tidy or in any way homogenous. For example, what we include as "water" may have total dissolved solids (TDS) between 80 mg/L (ppm) and 400,000 mg/L with solids made up of nearly the entire Periodic Table of the Elements. As Facilities Engineers we need to be able to accept whatever a reservoir might give us and to render it either a valuable commodity or a safely removed waste stream.

2.3.1. Liquids

The liquids that we deal with can be grouped as produced water, oil, and condensate. The field of oil chemistry is vast and complex. Since this document is only intending to consider the issues of gas wells, crude oil as a detailed topic seems to be outside of the intended scope. Many gas wells

produce both condensate and natural gas liquids, but it seems more appropriate to discuss those topics in a Plant Process document.

2.3.1.1 Liquid specific gravity

The specific gravity of a liquid is (Eq 2, all variables are described in the "Nomenclature" section at the end of the chapter):

$$\gamma_{liquid} = \frac{\rho_{liquid@60F}}{\rho_{water@60F}} \qquad \text{Eq 2}$$

If the specific gravity of the liquid is known, we don't have to care if we call the density of water 62.4 lbm/ft^3 or 1000 kg/m^3 to determine the density of the liquid. Defining the specific gravity of liquid relative to water also has the benefit of allowing someone to tell at a glance whether the liquid will float or sink in a body of water.

Density is an extrinsic property of a liquid (see below). Density will change (slightly for water, significantly for many hydrocarbon liquids) with changes in either pressure or temperature. Consequently, it is necessary to define specific gravity of a liquid at a reference temperature and pressure. For most engineering problems, the magnitude of the density change with pressure or temperature is less than the uncertainty in the calculation (e.g., if you are estimating bottom hole temperature ±20°F [±11.1°C] then a density uncertainty of 0.02 lbm/ft^3 [0.32 kg/m^3] is unlikely to make a material difference in your total uncertainty).

One area where the actual temperature and pressure of the fluid is critical to fluid density and specific gravity is situations with volatile hydrocarbons. Small changes in either pressure or temperature can cause phase-change events including liquids flashing to a gas or gases condensing back to a liquid. These phase changes can easily make a material difference in the mass of fluid in your tank or pipeline. Dealing successfully with volatile hydrocarbon species is a specialized activity that is rarely central to upstream decisions and while it is important to understand that it happens, the mechanics of accounting for hydrocarbon phase change is beyond the scope of a document focused on gas.

2.3.1.2 API Gravity

"API Gravity" is unit specific to commercial transactions dealing with crude oil and condensate. It is basically a normalized density, but it is presented as a temperature in Eq 3.

$$^{\circ}API = \frac{141.5}{SG_{\text{at } 60^{\circ}F}} - 131.5$$

$$SG_{\text{at } 60^{\circ}F} = \frac{141.5}{131.5 + {}^{\circ}API}$$

Eq 3

The "at 60°F" designation is important since crude and condensate can change density rapidly with changes in temperature when you pass the boiling point of volatile hydrocarbon components.

The commodities market breaks the °API numbers down into:

- °API > 31.1 → Light crude oil and condensate
- 22.3 < °API < 31.1 → Medium crude oil
- 10 < °API < 22.3 → Heavy crude oil
- °API < 10 → Extra heavy crude oil (will not float on water)

WTI is defined as 39.6 °API, North Sea Brent is 38.06 °API, and Dubai Crude is 31.00 °API [Petroleum], the heavy crude from the Athabasca Oil Sands is around 8 °API. Shale oil from the Eagle Ford field tends to be 40-45 °API.

Refineries are designed for a very narrow range of °API and they can operate only as long as they can find a mix of crude that can be blended to match the design range. Trying to bring oil sands crude into a refinery designed for WTI requires a large amount of Eagle Ford (or similar) light crude to get the combined mix to 39.6 °API (and conversely, processing Eagle Ford crude requires some heavier oil to get down to the WTI target).

2.3.1.3 Barrel of Oil

King Richard III (1452-1485) decreed that a "tierce" would hold 42 gallons [159 L]. When oil was discovered in Titusville, PA in 1859 and started the process of creating the Oil & Gas Industry, it was not known how oil would be packaged or sold since the internal combustion engines patented before that time were impractical (i.e., they did not compress the fuel/air mixture in conjunction with combustion and developed inadequate power for most tasks) and the Titusville crude was not originally thought to be a motor fuel (the first Otto patent with compression wasn't until 1876).

Producers in Titusville looked at the various standard size vessels and found that a tierce full of oil weighed about 300 lbm [136 kg] which was about as much as two men could handle. They also found that 20 tierces would fit in a railroad car without significant wasted space. Based on these findings the state of Pennsylvania defined the unit of commerce for crude oil as a 42 gallon tierce. [Historical, 2016]

By 1901 when the Spindletop field was discovered in East Texas, industry in the U.S. was looking for a steel alternative to wooden barrels. In 1905, Henry Wehrhahn, an employee of Nellie Bly's Iron Clad company patented a 55 gallon [208 L] barrel for bulk liquids [Historical, 2]. Most of the bulk movement of crude within the Spindletop field was by horse-drawn wagons on very primitive roads. The teamsters did not want to take the time to attach drum lids and they found that if they only put 42 gallons in a 55-gallon drum, the spillage was acceptable and the teamsters began painting a fill-line in the drums at the 42 gallon level. The teamsters were paid by the drum, not by hauled volume. Since you get what you measure, a different basis for payment certainly would have resulted in a different outcome, but they were counting drums.

Eventually the Spindletop experience was matched with the earlier Titusville experience and an oilfield barrel was defined as 42 gallons [159 L] in time to begin supplying bulk fuel to the limited mechanization that occurred during World War I.

The abbreviation for "barrel" is "bbl". There is an apocryphal story in the industry [Historical, 2] that the abbreviation comes from the documented Standard Oil requirement that all barrels used for Standard's oil be painted blue and that the abbreviation stands for "Blue BarreL". Oil & Gas historians have uncovered 18th century bills of lading which referred to the quantity of many bulk liquids as being in "bbl" containers. The actual genesis of that abbreviation has been lost to antiquity, but it did not refer to the color of containers.

2.3.1.4 Liquid Compressibility

For most calculations involving liquid it is reasonable to assume that liquids are incompressible, but they are not actually incompressible. The term "bulk modulus" is used to indicate the amount of pressure required to lower the volume occupied by a specified mass of a fluid by 1%. For a gas the bulk modulus is very close to zero. For water it is 319,000 psi [2.2 GPa].

A column of liquid water 196 miles [314 km] high would cause the water at the bottom to be 1% denser than the water at the top, not a real concern. On the other hand a cyclical hydraulic system that imparts 20,000 psig [137,900 kPag] on a string of 3-inch diameter pipe running 16,000 ft into the ground and then releases the pressure to retract a plunger and then repeats will have to add nearly 5 gallons of water on the pressurization stroke and then have a place for that water to go on the depressurization step—a 3 gallon supply tank would run dry, a 6 gallon supply tank would likely hit a low level alarm every step.

2.3.2. Gas

2.3.2.1 Gas Mixtures

Mixtures of gases take on the properties of the sum of the components of the gas (Eq 4).

$$y = \Sigma y_i \cdot x_i \qquad \text{Eq 4}$$

Using Eq 4 you can determine the molecular weight of a mix of gases for example (Eq 5).

$$MW = \Sigma\left(MW_i \cdot x_i\right) \qquad \text{Eq 5}$$

This says that the total molecular weight of the mixture is equal to each component's molecular weight times that component's mole fraction. We generally refer to "mole fraction" as "volume fraction" because it is a function of the amount of space that each molecule takes up in a mixture. Volume fraction is calculated using a "partial molar volume" technique, but it is generally taken in our industry as being equal to mole fraction.

Mass fraction is the percent of the total mass represented by the mass of a given component Eq 6.

$$MassFraction = \frac{x_i \cdot MW_i}{\Sigma\left(x_i \cdot MW_i\right)} \qquad \text{Eq 6}$$

Mass fraction is used much less often than volume fraction, and using mass fraction in most calculations will lead to wrong answers.

2.3.2.2 Sample gas types

Throughout this document we will use examples that require a gas analysis (or at least a specific gravity or adiabatic constant). To reduce the need for the reader to guess what gas is being discussed, Table 1 gas mixtures will be used throughout this discussion. When an example says "sweet gas" then any intrinsic parameters needed will come from the "sweet gas" column of Table 1 (all columns use the C6+ characteristics below).

Table 1: Example gas compositions

Component	Sour Gas Mole %	Sweet Gas Mole %	CBM (CSG) Mole %
C1	81.02%	76.58%	92.00%
C2	4.00%	13.86%	0.00%
C3	2.00%	6.21%	0.00%
i-C4	0.50%	0.56%	0.00%
n-C4	1.50%	1.67%	0.00%
i-C5	0.20%	0.22%	0.00%
n-c5	0.80%	0.89%	0.00%
C6+	0.01%	0.01%	0.00%
H_2S	2.90%	0.00%	0.00%
CO_2	7.07%	0.00%	8.00%
Total	100.00%	100.00%	100.00%

Using these mixtures, you can determine intrinsic properties for each gas mixture.

Table 2: Sour Gas Example

	Mole Fraction	Contribution to total				
		MW	Specific Gravity (γ)	NHV (MMBTU/ MSCF)	cp (BTU/lb/°F)	Adiabatic Constant (k)
C1	81.02%	12.9980	0.4488	0.7368	0.4267	1.0591
C2	4.00%	1.2028	0.0415	0.0647	0.0163	0.0477
C3	2.00%	0.8819	0.0305	0.0463	0.0078	0.0226
i-C4	0.50%	0.2906	0.0100	0.0150	0.0019	0.0055
n-C4	1.50%	0.8718	0.0301	0.0452	0.0059	0.0164
I-C5	0.20%	0.1443	0.0050	0.0074	0.0008	0.0022
n-C5	0.80%	0.5772	0.0199	0.0297	0.0031	0.0086
C6+	0.01%	0.0096	0.0004	0.0005	0.0000	0.0001
H2S	2.90%	0.9884	0.0341	0.0170	0.0069	0.0384
CO2	7.07%	3.1115	0.1074	-	0.0141	0.0914
Mixture total	100%	21.0762	0.7278	0.9265	0.4836	1.2921

Table 3: Sweet Gas Example

	Mole Fraction	Contribution to total				
		MW	Specific Gravity (γ)	NHV (MMBTU/ MSCF)	cp (BTU/lb/°F)	Adiabatic Constant (k)
C1	76.58%	12.2857	0.4242	0.6964	0.4033	1.0011
C2	13.86%	4.1677	0.1439	0.2242	0.0565	0.1654
C3	6.21%	2.7384	0.0946	0.1438	0.0241	0.0702
i-C4	0.56%	0.3255	0.0112	0.0168	0.0022	0.0061
n-C4	1.67%	0.9707	0.0335	0.0503	0.0066	0.0183
I-C5	0.22%	0.1587	0.0055	0.0081	0.0008	0.0024
n-C5	0.89%	0.6421	0.0222	0.0330	0.0035	0.0096
C6+	0.01%	0.0096	0.0004	0.0005	0.0000	0.0001
H2S	0.00%	-	-	-	-	-
CO2	0.00%	-	-	-	-	-
Mixture Total	100.00%	21.2984	0.7355	1.1731	0.4971	1.2732

Table 4: CBM Example

	Mole Fraction	Contribution to total				
		MW	Specific Gravity (γ)	NHV (MMBTU/ MSCF)	cp (BTU/lb/°F)	Adiabatic Constant (k)
C1	92.00%	14.7596	0.5096	0.8366	0.4846	1.2027
C2	0.00%	-	-	-	-	-
C3	0.00%	-	-	-	-	-
i-C4	0.00%	-	-	-	-	-
n-C4	0.00%	-	-	-	-	-
I-C5	0.00%	-	-	-	-	-
n-C5	0.00%	-	-	-	-	-
C6+	0.00%	-	-	-	-	-
H2S	0.00%	-	-	-	-	-
CO2	8.00%	3.5208	0.1216	-	0.0159	0.1034
Mixture Total	100.00%	18.2804	0.6312	0.8366	0.5005	1.3061

2.3.2.3 Gas Equation of State (EOS)

The Oil & Gas Industry has developed several refinements of the Classical Ideal Gas Law [Wikipedia, 1] taught in college chemistry classes. The refinements that are used in Oil & Gas primarily in high pressure/high temperature reservoir calculations and within plant processes. For field operations in gas, the complexities of most of these refinements do not result in different decisions from the decisions you would reach with a simple EOS. Consequently, we will use Eq 7.

$$P \cdot V = n \cdot \bar{R} \cdot T \Rightarrow P \cdot V = m \cdot R_{gas} \cdot T \text{ (for an ideal gas)}$$
$$P \cdot V = m \cdot R_{gas} \cdot T \cdot Z \text{ (for real gases)} \qquad \textit{Eq 7}$$

As will be discussed below, the "Z" term is called "Compressibility" and represents a gas' deviation from ideal behavior. By convention, air is assumed to be an ideal gas (Z=1.0) even though it does exhibit a slight deviation from ideal behavior which is typically well below the error introduced by measuring temperature and pressure (and gas composition for that matter).

2.3.2.4 Gas Specific Gravity (γ)

Gas density is not as convenient a term to use as liquid density—it is far too variable. Instead, in gas we use the ratio of the molecular weight of a gas to the molecular weight of air. This is an intrinsic value and it remains constant over the complete range of temperatures and pressures that a gas could be subjected to. The molecular weight of air is taken as 28.962 lb/lb-mole (28.962 gm/gm-mole).

Using molecular weight leads to an interesting observation. The universal gas constant is shown in Eq 8.

$$\bar{R} = 1545.3 \cdot \left(\frac{ft \cdot lbf}{R \cdot lb\text{-}mole} \right) = 8.314 \cdot \left(\frac{J}{K \cdot mole} \right) \qquad \text{Eq 8}$$

The universal gas constant is rarely useful to a Facilities Engineer since we tend not to work in moles. The specific gas constant is more useful and it is defined in Eq 9.

$$R_{gas} \equiv \frac{\bar{R}}{MW_{gas}} \Rightarrow R_{air} \equiv \frac{\bar{R}}{MW_{air}} \Rightarrow R_{gas} = \frac{R_{air} \cdot MW_{air}}{MW_{gas}} = \frac{R_{air}}{\gamma_{gas}} \qquad \text{Eq 9}$$

Now, to get to a gas constant that we can work with in familiar units we only have to know gas specific gravity and the value for the specific gas constant for air (Eq 10).

$$R_{air} = 53.355 \cdot \frac{ft \cdot lbf}{R \cdot lbm} = 287.068 \cdot \frac{J}{K \cdot kg} \qquad \text{Eq 10}$$

2.3.2.5 Gas Compressibility

Gas is quite compressible, and when you stack it vertically you find that the pressure exerted by the gas stacked above it changes via both linear and non-linear mechanisms. The primary non-liner mechanism is called "compressibility" (symbol "Z") which is fundamentally a measure of the amount that a gas deviates from ideal gas behavior. Air is very nearly an ideal gas where Z=1.0. Methane and CO_2 exhibit distinctly non-linear (and often non-trivial) response to applied force.

Gas compressibility is clearly a function of gas composition. At 1,000 psig [6,700 kPag] and 60°F [15.6 C] Sweet Gas has Z=0.727, Sour Gas has Z=0.791, and CBM has Z=0.863 (see Table 1)—a range of 17% relative to the average. Sweet gas at STP has Z=0.99 and at 2000 psia it is Z=0.59. Ignoring deviation from ideal behavior is one of the most common sources of engineering failure in Oil & Gas.

Gas compressibility is not an intrinsic characteristic of a gas mixture and methods of determining it range from very difficult to quite easy and the results range from an excellent representation of reality to a poor representation of reality, and there is not much correlation between ease of calculation and quality of results. The main techniques to develop compressibility relationships are:

- Equation of State. These values tend to be consistent and reliable, but generally require very complex programming. Programs like REFPROP.EXE from the U.S. National Institute of Standards and Technology (NIST) which is inexpensive and quite capable and the HYSYS from Aspen Technologies which is quite expensive and able to evaluate very complex chemical and flow relationships are required to use the Equation of State method.
- Corresponding States. This method uses critical behavior (see below) to predict deviation from ideal behavior. A very commonly used method is the Hall-Yarborough Equation. Hall-Yarborough provides good results for hydrocarbon gases, but so-called acid gases (e.g., CO_2 and H_2S) cause it to provide numbers that deviate too much from the Equation of State methods. Some later researchers have developed adjustments that improve performance in acid gases. This "equation" is a complex multi-stage program that requires upwards of 30 steps in an application like MathCad.
- Closed Form. GPSA has a pair of equations that do a good job for many gases. For our Sweet Gas composition both Equation of State and Corresponding States show a distinct

upturn in the compressibility value above 2000 psia [13,800 KPaa] that the GPSA equation dos not match. For our Sour Gas composition, up to about 1300 psia [8,900 kPaa] the GPSA is closer to the Equation of State than Corresponding States is. For our CBM Gas composition all three methods are close. The GPSA equations [GPSA] are in Eq 11.

For pressure < 145 psia

$$Z = \frac{1}{1 + 0.0002 \cdot P_{avg_psia}}$$

For pressure ≥ 145 psia

$$Z = \frac{1}{1 + \frac{P_{avg} \cdot 3.444 \times 10^5 \cdot 10^{1.785 \cdot SG}}{T_{avg}^{3.825}}}$$

Eq 11

The GPSA book shows the shift from one equation to the other to be 100 psia, but I find that value to have too much discontinuity. Allowing the low pressure equation up to 145 psia [10 bara] reduces the discontinuity which is further support for using 145 psia (below) as a break point in physical performance as was discussed below. Of course, both of these equations are empirical (see below) and must be solved with pressure in psia and temperature in Rankine.

For pressures above about 2,000 psia [13,800 kPaa] it is imperative that you use Equation of State Method. For Sweet Gas at 8,000 psia [55,100 kPaa] and 60°F [15.6 C] REFPROP shows Z=1.29 and GPSA shows Z=0.42.

2.3.2.6 Gas Density and atmospheric pressure

Gas density is derived from the EOS and is defined as the ratio of the mass present divided by the volume it occupies (Eq 12).

$$\rho = \frac{m}{V} = \frac{P}{R_{gas} \cdot T \cdot Z} = \frac{P \cdot \gamma}{R_{air} \cdot T \cdot Z}$$

Eq 12

An important special case is calculation of local atmospheric pressure. The density of air is a function of pressure and temperature. Air temperature is a linear function of elevation above sea level (the slope of the line is 3°F/1000ft [5.468C/km]. Weather impacts (i.e., current temperature, barometric pressure, precipitation, etc.) are insignificant relative to the weight of the entire column of air. If you know your local elevation, then you can determine local atmospheric pressure by [Wikipedia, 2] Eq 13.

$$P_{atm} = P_{std}\left(1 - \frac{0.003 \cdot h_{ASL}}{T_{std}}\right)^{\frac{g}{0.003 g_c \cdot R_{air}}} = 14.73 psi\left(1 - \frac{5.77 \times 10^{-6}}{ft} h_{ASL}\right)^{6.248}$$

$$P_{atm} = P_{std}\left(1 - \frac{0.005468 \cdot h_{ASL}}{T_{std}}\right)^{\frac{g}{0.005468 \cdot R_{air}}} = 101.56 kPa\left(1 - \frac{18.94 \times 10^{-6}}{m} h_{ASL}\right)^{6.248}$$

Eq 13

Eq 13is valid up to about 360,000 ft [110 km] above sea level (ASL).

3. Fluid Characteristics

Mother Nature has allowed some fluids to be trapped within subterranean reservoirs. These fluids included natural gas (methane through about hexane), condensate, oil, sulfur compounds, CO_2, nitrogen, oxygen, and water. These mixtures are not very neat or tidy or in any way homogenous. For example, what we include as "water" may have total dissolved solids (TDS) between 80 mg/L (ppm) and 400,000 mg/L with solids made up of nearly the entire Periodic Table of the Elements. As Facilities Engineers we need to be able to accept whatever a reservoir might give us and to render it either a valuable commodity or a safely removed waste stream.

3.1. Intrinsic and extrinsic properties

All fluid properties are either "intrinsic" or "extrinsic". "Intrinsic" is defined as "of or relating to the essential nature of a thing; inherent." "Extrinsic" is defined as "originating from the outside; external." So when we talk about specific gravity of a gas, it is part of the essential nature of the gas. On the other hand, the density of a gas is a function of pressure and temperature and originates from the outside. The specific gravity of a liquid can only be defined at a specific temperature which makes it extrinsic, while for most calculations density of water can be treated as an intrinsic property (it is not, but the difference only matters in very specific cases).

3.2. Selected Properties

Some of the fluid properties that are most commonly used in our industry are included in Table 5 and Table 6. This data is extracted from the GPSA Engineering Data Book [GPSA] which is the one indispensable reference for all engineers in the Oil & Gas Industry. Other authors have other recommendations for "the one indispensable reference", but for many years the only book on my shelf that was ever opened was GPSA (and I have all of reference books that I've ever heard described as "indispensable"). GPSA's Engineering Data Book is far from perfect, but it is almost always "good enough".

Table 5: Selected Properties (fps) [GPSA]

	Formula	MW	Boiling Point (°F) at std press	SG (relative to air)	Net Heating Value (MMBTU/ MSCF)	c_p @ STP (BTU/lb-°F)
C1—Methane	CH_4	16.043	-258.7	0.5539	0.9094	0.52669
C2—Ethane	C_2H_6	30.070	-127.5	1.0382	1.6178	0.40782
C3—Propane	C_3H_8	44.097	-43.7	1.5226	2.3149	0.38852
C4—Butane	C_4H_{10}	58.123	n: 31.1 i: 11.1	2.0068	n: 3.0108 i: 3.0004	n: 0.39499 i: 0.38669
C5—Pentane	C_5H_{12}	72.150	n: 97.0 i: 82.1	2.4912	n: 3.7069 i: 3.6990	n: 0.38825 i: 0.38440
C6—Hexane Plus	Various	95.514	>100	3.2979	4.9898	0.36724
Carbon Dioxide	CO_2	44.010	-109.1	1.5196	0	0.19908
Hydrogen Sulfide	H_2S	34.082	-76.5	1.1767	0.5868	0.23839
Air	$N_2 + O_2$	28.963	-317.6	1.0000	0	0.23980
Water Vapor	H_2O	18.014	212.0	0.6220	0	0.44401
Water (liquid)	H_2O	18.014	212.0	815.7	0	1.00000

The data is also available in the S.I. Version of [GPSA]

Table 6: Selected properties S.I.

	Formula	MW	Boiling Point (°C) at std press	SG (relative to air)	Net Heating Value (MJ/ SCm)	c_p (J/gm/°C)
C1—Methane	CH_4	16.043	-161.5	0.5539	33.88	2.205
C2—Ethane	C_2H_6	30.070	-88.6	1.0382	60.28	1.707
C3—Propane	C_3H_8	44.097	-42.1	1.5226	86.25	1.627
C4—Butane	C_4H_{10}	58.123	n: -0.5 i: -11.6	2.0068	n: 112.18 i: 111.79	n: 1.654 i: 1.619
C5—Pentane	C_5H_{12}	72.150	n: 36.1 i: 27.8	2.4912	n: 138.12 i: 137.82	n: 1.626 i: 1.609
C6—Hexane Plus	Various	95.514	>38	3.2979	189.05	1.538
Carbon Dioxide	CO_2	44.010	-78.4	1.5196	0	0.834
Hydrogen Sulfide	H_2S	34.082	-60.3	1.1767	21.86	0.998
Air	$N_2 + O_2$	28.963	-194.2	1.0000	0	1.000
Water Vapor	H_2O	18.014	100.0	0.6220	0	1.859
Water (liquid)	H_2O	18.014	100.0	815.7	0	4.187

3.3. Specific Heat at Constant Pressure (c_p)

Specific heat at constant pressure (c_p) is "a measure of the amount of heat needed to change the temperature of a fixed mass of a substance by a specific amount".

$$c_p = \frac{1}{m} \cdot \left(\frac{\partial Q}{\partial T} \right)_P \qquad \text{Eq 14}$$

Specific heat at constant pressure is not an intrinsic property (Eq 14) as it changes with temperature and pressure, it is included in Table 5 and Table 6 because it is (too) often taken as a constant.

The magnitude of the variance can be significant (in Table 7, using atmospheric pressure in the denominator, c_p increases by 93 percent for a pressure change of less than 2000 psia), but it is rare to consider it. The additional columns in Table 7 will be discussed below.

Table 7: Effect of pressure on Sweet Gas Mixture

Pressure at 60°F	c_p (BTU/lbm-R)	k	μ_{jt} (°F/psia)	Z
14.73 psia	0.49710	1.2732	0.070155	0.99729
100 psia	0.50954	1.3006	0.070086	0.98150
500 psia	0.57228	1.4219	0.068214	0.90673
1000 psia	0.68551	1.6451	0.061489	0.81620
2000 psia	0.90924	2.0942	0.035108	0.70458

Specific heat at constant volume is a derived property that is described by Eq 15.

$$c_v = c_p - R_{gas} = c_p - \frac{R_{air}}{\gamma} \qquad \text{Eq 15}$$

3.4. Adiabatic Constant

The term "adiabatic" is defined as "relating to or denoting a process or condition in which heat does not enter or leave the system concerned." [Webster]. Adiabatic conditions are very common in many areas of our industry. In many other situations there is heat leaving the system (if you've ever laid your hand on a compressor discharge pipe you will have experienced heat leaving the system very rapidly, into your hand), but the heat that enters or leaves is small relative to the system as a whole. The assumption that a process is "close enough" to adiabatic is often very useful.

This allows the definition of an "Adiabatic Constant" as (Eq 16, sometimes the adiabatic constant is represented as the Greek letter "kappa" or "gamma", there isn't anything approaching a standard nomenclature, this document will use "k"):

$$k = \frac{c_p}{c_v} = \frac{c_p}{c_p - \frac{R_{air}}{\gamma}} = \frac{c_p \cdot \gamma}{c_p \cdot \gamma - R_{air}} \qquad \text{Eq 16}$$

As can be seen in Table 7, raising pressure from atmospheric to 2000 psia (13.8 MPaa) will increase the adiabatic constant by 63 percent. The adiabatic constant is often used in many adiabatic processes, including several calculations related to positive-displacement compressors. It is often used to predict temperature increases through a positive-displacement gas compressor using Eq 17. If the suction temperature was 60°F (519.67 R, 289 K) and the compressor raised the pressure from 500 psia (3.44 MPaa) to 2000 psia (13.8 MPaa) or four compression ratios, the

predicted discharge pressure would be predicted to rise to 244°F (118°C) using the constant for atmospheric pressure; 324°F (162°C) using the constant for 500 psia (likely the correct one); and 612°F (322°C) using the constant for 2000 psia—a spread of 52 percent from the published value to the correct value.

$$T_{discharge} = T_{suct} \cdot \left(\frac{P_{discharge}}{P_{suct}} \right)^{\frac{k-1}{k}} \qquad \text{Eq 17}$$

3.5. Joule-Thomson coefficient (μ_{jt})

When a non-ideal gas suddenly expands from a high pressure to a low pressure (as through a pressure-reducing valve or a fixed orifice) there is often a temperature change. Note that this is not a reversible process. It is however an adiabatic process due to the fact that the pressure change occurs too quickly for significant heat transfer to occur. Thermodynamically, the Joule–Thomson coefficient is defined by Eq 18.

$$\mu_{jt} = \left(\frac{\partial \mathrm{T}}{\partial \mathrm{P}} \right)_{\mathrm{H}} \qquad \text{Eq 18}$$

Using thermodynamic relationships, alternative expressions can be written. For example, using the cycling rule we may write Eq 19.

$$\mu_{jt} = \frac{\bar{\mathrm{R}} \cdot \mathrm{T}^2}{\mathrm{P} \cdot \mathrm{c}_\mathrm{p}} \left(\frac{\partial \mathrm{Z}}{\partial \mathrm{T}} \right)_{\mathrm{P}} \qquad \text{Eq 19}$$

As you can see from Table 7 and Eq 19, the Joule-Thomson coefficient must go down with increasing starting pressure. To calculate a temperature drop for a given pressure drop, you need to determine the J-T coefficient for the upstream pressure and multiply it times the pressure drop. If you open a blowdown valve on a 2000 psia system, the expected temperature drop would be 102°F once the system reaches steady state. But if the line is depressurizing, as the pressure comes down the J-T coefficient increases. Taking the line from 500 psia would drop the temperature 34°F. If the object of the exercise is to avoid freezing the water vapor in the line and plugging the blowdown line, it is prudent to recalculate the pressure drop periodically. If the goal is a fixed temperature drop with constant upstream pressure, then you only need to calculate one J-T coefficient.

An interesting observation from the Eq 19 for the Joule–Thomson coefficient is that the Joule–Thomson coefficient of an ideal gas is identically equal to zero (because compressibility does not change with changing temperature). However, real fluids take positive or negative Joule–Thompson values.

3.6. Combustion Characteristics

Combustion of natural gas is an exothermic chemical reaction between a flammable gas and oxygen. Each species of hydrocarbon in the mixture that we call "natural gas" has a flammable range. For methane the flammable range is 5-15 percent by volume at atmospheric pressure (Figure 1). This says that if there is less than 4 volume percent methane in air, then you shouldn't be able to ignite the mixture. If there is more than 15 volume percent methane in air at atmospheric pressure then the mixture is "too rich to burn" and shouldn't ignite. There are a couple of important, but often ignored phrases in that statement. The first is "at atmospheric pressure", increasing pressure increases the flammable range of any hydrocarbon species (the outer ring in Figure 1 shows the upper explosive limit (UEL) as increasing from 15 percent at atmospheric pressure to 40 percent at only 400 psig [2.8 MPag]). The other important phrase is "in air". At atmospheric pressure, you need about 20 times as much air as methane to reach the lower explosive limit (LEL) and you need slightly more oxygen than methane (on a volume basis) to reach the UEL. In a pure-oxygen atmosphere, the UEL for methane at atmospheric pressure is about 45 volume percent. Hand-held and fixed LEL meters are calibrated for methane, and the reading on the instrument is stated as a percentage of the LEL of methane in air (percent of 5 percent).

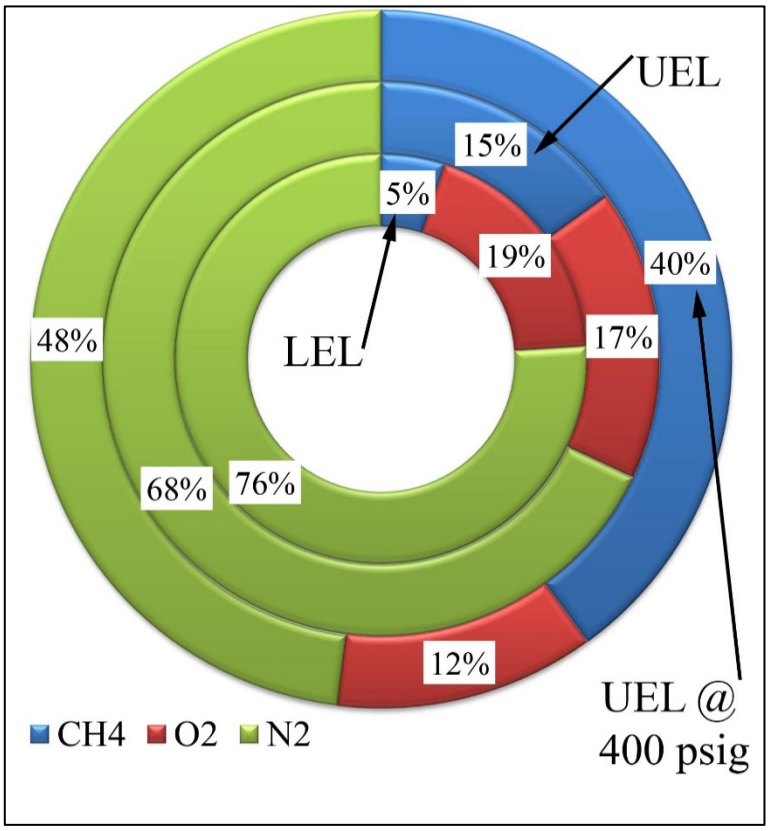

Figure 1: Explosive Range of Methane

Each species of hydrocarbon has its own characteristics that they carry into the natural gas mix. For example, the LEL of ethane is 3.0 volume percent, and butane is 1.9 volume percent. It is rarely practical to adjust expected LEL for a mixture of hydrocarbon gases, but it is important to note that explosive atmosphere detectors are calibrated for methane. If a detector says that the atmosphere is "80 percent" that means that the gas mixture is 80 percent of 4 percent or 3.2 volume percent explosive gas—very possibly the 80 percent reading is over the LEL of the actual mix of hydrocarbons which are currently inside the explosive range of the mixture.

The autoignition temperature (i.e., the temperature at which combustion begins without an external flame source) of methane has been generally accepted to be 1000°F [537°C] based on theoretical calculations. Recent experiments have been unable to reach autoignition of methane in air at that temperature. Experimental evidence suggests that the minimum autoignition temperature of methane is closer to 1115°F [600°C], but most Material Safety Data Sheets (MSDS) show the theoretical value. While methane in air (in the proper proportions) will spontaneously ignite at some value below 1115°F, a flame temperature of about 1400°F [760°C] is required to reliably ignite a methane/air mixture. Once the mixture is ignited, it has a flame temperature of 3542°F [1950°C].

Natural gas is lighter than air, so it can dissipate into the air rapidly, making accidental combustion difficult. If not in a confined space, ignition of natural gas in air will result in a deflagration, which involves the subsonic propagation of the flame, as opposed to supersonic propagation that results in an explosion.

3.7. Including water vapor

Field gas always has considerable water vapor. Any time a gas is in contact with a coherent gas/water interface, the water will evaporate until the relative humidity (RH) at the surface is 100%. A very small distance from the interface, the humidity will have decreased, but at the interface the gas is fully saturated with water vapor. Theoretical water vapor is usually determined from a chart called McKetta-Wehe which presents temperature on the x-axis and water content at 100% RH on the y-axis, with individual lines for pressures. If you get a water vapor content from this graph and call it "W" then Eq 20 describes the method to reduce the mixture to "dry".

$$MoleFraction_{water} = \frac{\frac{W}{lbm/MMSCF} \cdot 3.8068 \times 10^{-4}}{MW_{water} + \frac{W}{lbm/MMSCF} \cdot 3.8068 \times 10^{-4}}$$

$$= \frac{\frac{W}{lbm/MMSCF} \cdot 3.8068 \times 10^{-4}}{18.0153 + \frac{W}{lbm/MMSCF} \cdot 3.8068 \times 10^{-4}} \qquad \textit{Eq 20}$$

$$= \frac{\frac{W}{mg/SCm} \cdot 2.3765 \times 10^{-5}}{18.0153 + \frac{W}{mg/SCm} \cdot 2.3765 \times 10^{-5}}$$

This says that if water takes up 4% of the gas mixture, there is only 96% of the total remaining for the other components. In that case you would "normalize" the analysis by Eq 21.

$$MoleFraction_i = \left(1 - MoleFraction_{water}\right) \cdot AnalysisMoleFraction_i \qquad \text{Eq 21}$$

This adjustment is often trivial, but it can be significant in specific cases. For example, field gas gatherers must provide pipeline capacity for water vapor and rightly want to be paid for it. To aid in the calculation of "wet gas volume" the gathering company wants to call the gas saturated at STP instead of at field conditions. Gas will rarely be at 100% RH, but that difference represents a small variance. The "at STP" assumption is more problematic. If we have field gas at:

- Flowing conditions of 250 psig [1724 kPag], 100°F [38C], 100 MSCF/day [2.83 kSCm/day], "Sweet Gas" as defined above.
- Water content from the McKetta-Wehe chart at flowing conditions is 187.4 lbm/MMSCF [3,000 mg/SCm] or 0.39% RH.

$$MoleFraction_{water} \frac{\frac{W}{lbm/MMSCF} \cdot 3.8068 \times 10^{-4}}{18.0153 + \frac{W}{lbm/MMSCF} \cdot 3.8068 \times 10^{-4}} = \frac{187.4 \cdot 3.8068 \times 10^{-4}}{18.1053 + 187.4 \cdot 3.8068 \times 10^{-4}} = 0.003944$$

$$C_{1reduced} = \left(1 - MoleFraction_{water}\right) \cdot AnalysisMoleFraction = \left(1 - 0.00392\right) \cdot 0.7658 = 0.7628 \qquad \text{Eq 22}$$

Using the same technique, the remaining reduced percentages can be calculated using Table 3, 5, and 8:

$$NHV = \left(0.7628 \cdot 0.9094\ MMBTU/MSCF\right)_{c1} + \left(0.1381 \cdot 1.6178\ MMBTU/MSCF\right)_{C2} + \left(0.0619 \cdot 2.3149\ MMBTU/MSCF\right)_{c3} +$$
$$\left(0.0055 \cdot 3.0004\ MMBTU/MSCF\right)_{iC4} + \left(0.0166 \cdot 3.0108\ MMBTU/MSCF\right)_{nC4} + \left(0.0022 \cdot 3.6990\ MMBTU/MSCF\right)_{ic5} +$$
$$\left(0.0089 \cdot 3.7069\ MMBTU/MSCF\right)_{nC5} + \left(0.0001 \cdot 4.9898\ MMBTU/MSCF\right)_{C6+} + \left(0.0039 \cdot 0.6220\ MMBTU/MSCF\right)_{water} = 1.169\ MMBTU/MSCF$$

- Water content from the McKetta-Wehe chart at STP is 3,080 lbm/MMSCF [33,300 mg/SCm] or 6.11%, reducing the net heating value to 1.138 MMBTU/MSCF.
- Annual sales at $4/MMBTU
    - Dry: $171,389
    - Saturated at flowing conditions $170,791 (-$598)
    - Saturated at STP $166,261 (-$5,128)

Most gas producers find a cost of $298 to move 1.4 MMSCF of water vapor to be reasonable, and over $5,000 to move the same water content to be excessive.

There are instruments that can directly measure water content, but their uncertainty and repeatability have been poor. The first such instrument is a Draeger Tube that has a substance in it that changes color with water. Substances with different sensitivities can be changed out to measure greater or lesser water content. The device requires considerable expertise to use and even experienced operators often get very different results from multiple samples. Today it is possible to use an electronic instrument to measure water vapor, but the instruments tend to have a variable uncertainty (i.e., any liquid water in contact with the probe changes the uncertainty) and are not suitable for financial transactions.

3.8. Inherent Energy

When someone purchases a fuel they are interested in the amount of heat that can be extracted from it. One of the intrinsic parameters of a gas is its "heat content" or "heating value". This term comes in two flavors [DOE]:

- Gross Heating Value: the energy released by a specified volume of gas when a compound undergoes complete combustion with oxygen at standard conditions and then cooling the exhaust gases back to a reference temperature. This value can be measured in a laboratory.
- Net Heating Value: Theoretical value calculated by determining the Gross Heating Value and deducting the latent heat of vaporization of the mass of water condensed on cooling. This value cannot be measured.

The Net Heating Value, while it cannot be measured is the number that represents how much heat you can extract from a fuel in real life, and is always used in commercial transactions. Methane has a Net Heating Value of 909 BTU/SCF [33800 kJ/SCm].

It is common in some companies to assign an arbitrary value to Natural Gas of 948 BTU/SCF [35300 kJ/SCm] and then:

- 1 GJ ≈ 1 MSCF
- 1 TJ ≈ 1 MMSCF
- 1 PJ ≈ 1 BSCF

These conversions are generally not very accurate, but are often good enough for everyday work (e.g., if a well produced 200 GJ yesterday and 210 GJ today, then it is doing better).

3.9. C6 Plus

Commercial gas chromatographs are a tradeoff between cost and functionality. Most of them have the ability to identify hydrocarbon gases through pentane (C5) but lack the processing equipment necessary to distinguish heavier components one from the other. To accommodate not wanting to spend the money (and training and maintenance) on the more complex equipment, the industry has accepted that components heavier than C5 are generally a very small proportion of any real gas and can be represented by an "average" or "typified" value. The characteristics of C6+ can be very different from lab to lab. One lab developed the data in Table 8 from an extended analysis of the inlet to a specific plant on a specific day and have used it in millions of gas samples since then. They periodically reassess this value and find that the relative proportions of the various components have remained reasonably constant over time.

Table 8: Extended Analysis

	% in Sample	Normalized %	MW	SG	Net Heating Value (MMBTU/M SCF)	c_p (BTU/lb-°F)
n-Hexane	0.049%	12.1%	10.401	0.3591	0.4474	0.04662
Other Hexanes	0.155%	37.7%	32.476	1.1213	1.9182	0.14330
Heptanes	0.090%	21.9%	21.966	0.7584	1.1180	0.08428
Octanes	0.037%	9.1%	10.410	0.3594	0.5282	0.03493
Nonanes	0.013%	3.2%	4.107	0.1418	0.2079	0.01225
Decanes+	0.015%	3.7%	5.257	0.1815	0.2656	0.01411
Benzene	0.023%	5.7%	4.425	0.1528	0.2034	0.01376
Toluene	0.017%	4.2%	3.858	0.1332	0.1789	0.01089
Ethylbenzene	0.001%	0.2%	0.261	0.0090	0.0122	0.00068
Xylenes	0.009%	2.2%	2.353	0.0813	0.1099	0.00642
Mixture Total	0.410%	100.0%	95.514	3.2979	4.9898	0.36724

In this particular case, the lab determined that C6+ made up 0.410% of the total sample. The extended analysis of that 0.410% is normalized as discussed above. Multiplying the normalized percentage times an inherent characteristic of a component yields its contribution (e.g., the MW of n-Hexane is 86.18 lbm/lb-mole, multiplying that times 12.1% gives you 10.401 lbm/lb-mole). Then adding the individual contributions gives you the effective value of the made-up component "C6+".

It is important to note that if you are required to report "BTEX" (i.e., Benzene, Toluene, Ethylbenzene, and Xylene) to a regulatory agency it is unacceptable to use a typified analysis for those components.

3.10. Pseudo-reduced properties

According to the theory of corresponding states, substances at corresponding states will exhibit the same behavior. "Reduced pressure" and "reduced temperature" are dimensionless parameters that allow the use of "similitude" to compare the effect of a change in conditions on one substance to the effect of a similar change on another substance. The reduced pressure and reduced temperature are defined in Eq 23.

$$P_r = \frac{P}{P_c} \text{ and } T_c = \frac{T}{T_c} \qquad \text{Eq 23}$$

The values of critical pressure and critical temperature of a mixture can be estimated from Eq 23 (see *Table 9* for an example) if the composition of the gas and the critical properties of the individual components are known.

$$P_{pc} = \sum_i^n P_{Ci}\ y_i \text{ and } T_{pc} = \sum_i^n T_{ci}\ y_i \qquad \text{Eq 24}$$

Critical properties of the mixture are calculated as stated in Eq 24. Properties like compressibility or gas heat capacity can be uniquely defined for a mixture as a function of pseudo-reduced pressure and pseudo-reduced temperature.

Table 9: Example of pseudo-critical conditions

	Col 2 Critical Pressure (psia)	Col 3 Critical Temperature (R)	Col 4 Mole percent	Col2 * Col4 Contribution to pseudo-critical pressure	Col3*Col4 Contribution to pseudo-critical temperature
Methane	667.0	343.0	92%	613.6	315.6
Ethane	706.6	549.6	6%	42.4	33.0
Propane	615.5	665.6	2%	12.3	13.3
Calculated Pseudo-critical conditions			100%	668.3 psia	361.9 R
From Eq 23 and Eq 24				675.2 psia	355.6 R
From EOS (NIST Refprop.exe)				681.9 psia	361.7 R

This "simple" mixture is very representative of most natural gases—the "easy" methods to determine thermodynamic properties are sometimes very close to measured data and data from empirical equations, but sometimes the variance is too great. In this case the three critical temperatures and pressures are very close to each other. If you take all three sets of data into Eq 24 you will find that using the critical values from the EOS will yield compressibility values from that figure that match with GPSA (2004), the Corresponding States correlations discussed above, and with values calculated by a competent EOS better than the other two methods.

The values of critical pressure and critical temperature for a mixture can alternatively be estimated from the mixture's specific gravity if the composition of the gas and the critical properties of the individual components are not known. The method uses a correlation to estimate pseudo-critical temperature and pseudo-critical pressure values from the specific gravity of the mixture. There are several different correlations available. The most common is the one proposed by Sutton (1985), which is based on the measured values of 264 different gas samples. Sutton (1985) used regression analysis on the raw data to obtain second order fits for the pseudo-critical properties Eq 25 and Eq 26).

$$P_{pc} = 756.8 - 131.07\gamma_g - 3.6\gamma_g^2 \qquad \textit{Eq 25}$$

$$T_{pc} = 169.2 + 349.5\gamma_g - 74.0\gamma_g^2 \qquad \text{Eq 26}$$

These equations are valid over the range of specific gas gravities with which Sutton (1985) worked $0.57 < \gamma_g < 1.68$.

4. Topics in Fluid Mechanics

This is not a Fluid Mechanics textbook. In a Fluid Mechanics course we have to pretend that $\delta v/\delta t$ has meaning even if we do not have an equation for the change in velocity with respect to time to differentiate, and even when non-linear, 2nd order differential equation really doesn't have much usefulness to a practical engineer. The number of fluid mechanics equations that have a closed-form solution is miniscule, and few field engineers have access to (or the time to master) the tools of converting second-order, non-linear partial differential equations into answers that can impact real-time decisions. In a Fluid Mechanics course we also spend considerable time proving that if we actually knew any useful equations for $\delta v/\delta \rho$ we could do such fine, fair, and wonderful things. As an academic exercise, Fluid Mechanics is a fascinating subject for study and I am glad that I've had the opportunity to study it both as an undergraduate and in graduate school, but not many practical tools have come directly from it.

This document is about doing a good-enough job of describing and understanding physical phenomena that we can reach useful, informed decisions. Consequently, most of practical engineering uses empirical equations rather than closed-form equations, and for the few closed-form equations that exist we'll explore the simplifying assumptions that were required to get from the general to the specific.

This document tries very diligently to be clear on terms. When the word "fluid" is used, you should expect to be talking about "a substance without a fixed shape that can persist under mild external forces", which would include gases, liquids, emulsions and other non-Newtonian substances that do not have a fixed shape that will persist under mild external forces. When it says "liquid" it means a fluid that will exhibit a coherent gas-liquid boundary. When it says "gas" it means a fluid that will expand to the 3-dimensional limits of a container. It is very common in Artificial Lift and Deliquification to interchange the words "liquid" and "fluid" which is imprecise and often quite wrong. This document tries to avoid interchanging these words, but the usage in that field is so pervasive that it can be hard to identify where you are making that particular mistake. If I missed any places where I said "fluid" and meant "liquid" please forgive me and know that it was not intentional.

Virtually all of the liquids that non-engineers work with are Newtonian. A Newtonian fluid is a fluid that exhibits linear stress-strain relationships. This means that if a stress is applied to the fluid, regardless of starting stress, the fluid will exhibit a displacement proportional to the applied stress. In other words an unconstrained (i.e., it has some place to go when you apply stress) Newtonian fluid does not have the ability to withstand imposed stresses. A Newtonian fluid constrained in three dimensions will have a very different stress-strain relationship, but that is due to the constraining material, not inherent to the fluid.

Conversely, non-Newtonian fluids have a non-linear stress-strain relationship. Examples of non-Newtonian fluids are things like toothpaste and paint where it takes more applied stress to start the fluid flowing than it takes to keep the fluid flowing after it starts. In Oil & Gas we have to be more concerned about non-Newtonian fluids than most engineers. Fluids with high levels of paraffin or asphaltene, and many emulsions and foams exhibit non-linear stress-strain relationships and predicting pressure drops (for example) of any of these fluids can be very tricky. For example, diesel has a very high paraffin content and at Laminar flow rates and/or at lower temperatures will often be "hard to pump", in that it takes more energy to start it flowing than to keep it flowing. When you get into the turbulent region, it starts acting like a Newtonian fluid and our standard equations effectively represent field data.

4.1. Statics

"Fluid Statics" is the study of fluids at rest or in constant motion in the absence of viscous drag. The basic equation of is shown in Eq 27.

$$P_{bottom} = \rho \cdot g \cdot h + \left(P_{imposed} + P_{atm} \right) \qquad \text{Eq 27}$$

If we are talking about the pressure at the bottom of a lake then $P_{imposed}$ is zero (i.e., atmospheric pressure). If we are talking about the pressure at the bottom of a well-bore then $P_{imposed}$ is flowing tubing pressure (in gauge). In either case, you only add atmospheric pressure once. In fps units, density is in lbm/unit-volume and the answer has to be in lbf/unit-area so in fps units (Eq 28).

$$P_{bottom} = \rho \cdot \frac{g}{g_c} \cdot h + \left(P_{imposed} + P_{atm} \right) \qquad \text{Eq 28}$$

While the force per unit area that a column of fluid exerts is only a function of height, the weight of the column is very much dependent on the volume of fluid in the column (Eq 29)

$$W = \rho \cdot g \cdot V \qquad \text{Eq 29}$$

This can be important if you are looking at structural supports for above-ground piping or vessels. It is very important if you have to lift the column of liquid. For gases, it is less likely to be a major factor, and it is often reasonable to ignore the first term in Eq 28 (if you don't ignore it, then you need a relationship for density vs. pressure).

4.1.1. Hydrostatic pressure

Since Oil & Gas wells are very long vertical conduits we have to be more concerned about the effects of stacking fluids vertically. An incompressible fluid we has a linear pressure gradient from the top of the column increasing to a maximum at the bottom. A gas gradient is a bit more

complex. In both cases the size of the column has no impact on the pressure at the bottom, just the height.

4.1.1.1 Liquid

For a liquid the pressure at the bottom of a column is Eq 30:

$$P_{bot} = \rho \cdot g \cdot h + P_{top} = \rho_{water} \cdot \gamma_{liquid} \cdot h + P_{top} \qquad \text{Eq 30}$$

It is common to replace the density times gravity term with a pressure gradient term as in Eq 31.

$$grad = \rho \cdot g = \rho_{water} \cdot \gamma \cdot g = \left(0.433 \cdot \frac{psi}{ft} \right) \cdot \gamma = \left(9.81 \cdot \frac{kPa}{m} \right) \cdot \gamma \qquad \text{Eq 31}$$

This makes it simple, if you have a 20 ft [6.1 m] standpipe going into a tank, it is going to take at least 8.7 psig [59.7 kPag] for a pump to overcome before the water can enter the tank.

4.1.1.2 Gas

Gas hydrostatic pressure is more complex than liquid (Eq 32).

$$P_{bot} = P_{top} \cdot \exp\left(\frac{0.01875 \cdot \gamma \cdot \frac{h}{ft}}{\frac{T_{avg}}{R} \cdot Z_{avg}} \right) = P_{top} \cdot \exp\left(\frac{0.03418 \cdot \gamma \cdot \frac{h}{m}}{\frac{T_{avg}}{K} \cdot Z_{avg}} \right) \qquad \text{Eq 32}$$

Eq 32 works out to a very small number that can often be ignored without impacting a decision. For example at 1000 m [3280 ft] the exponent term works out to 1.07 times pressure at the top so if the imposed pressure is 500 kPaa [73 psia] then the pressure at the bottom would be 535 kPaa [78 psia].

4.1.2. Buoyancy

Buoyancy is a static vertical force on a body submerged in a fluid. If the mass of the displaced fluid is greater than the mass of the submerged substance, then the submerged substance will try to rise. This why a ship that weighs thousands of tonne can float, it displaces more liquid than it weighs. When we talk about droplets, the size of the droplet will determine whether the heavy liquid will be buoyant in the light gas. If the droplet is large then it displaces a smaller mass of gas than it contains and it falls. If the droplet is small, then it displaces a mass of gas that is near to the droplet mass and the droplet tends to remain in suspension for a time. Buoyant forces are often necessary to explain why things happen in facilities the way they do.

4.2. Dynamics

Fluid dynamics describes every possible force on a flow stream, including:

- Pressure
- Temperature
- Body forces (like gravity, buoyancy, and magnetic attraction/repulsion)
- Friction
- Rotation
- Compression and expansion

Every force can be a function of time, point of reference, an intrinsic property of the fluid, or an extrinsic property of the fluid. When you put all the forces into all the proper relationships, the result shown in Eq 33 is messy.

4.2.1. Navier-Stokes Equation

French engineer Claude-Louis Navier first proposed a series of equations that represent fluid dynamics in 1822. In 1845, Irish mathematician-physicist George Gabriel Stokes re-developed this equation that now carries the name "Navier-Stokes Equation". One representation of the expansion of the Navier-Stokes Equation is shown in Eq 33.

$$\rho\cdot\left(\frac{\partial u_i}{\partial t}+u_j\cdot\frac{\partial u_i}{\partial x_j}\right)=\rho\cdot\Sigma F_{body}-\frac{\partial P}{\partial x_i}+\frac{\partial}{\partial x_i}\left(\mu\cdot\left(\frac{\partial u_i}{\partial x_j}+\frac{\partial u_j}{\partial x_i}-\frac{2}{3}\cdot\left(\frac{\partial u_k}{\partial x_k}\right)\cdot\delta_{i,j}\right)\right)$$

If gravity is the only body force, then expanding in Cartesian coordinates (z vertical) yields:

$$\rho\cdot\left(\frac{\partial u}{\partial t}+u\cdot\frac{\partial u}{\partial x}+v\cdot\frac{\partial u}{\partial y}+w\cdot\frac{\partial u}{\partial z}\right)=\cancel{\rho\cdot g_x}-\frac{\partial P}{\partial x}+\frac{\partial}{\partial x}\left[\mu\cdot\left(2\cdot\left(\frac{\partial u}{\partial x}\right)-\frac{2}{3}\cdot\left(\frac{\partial u_k}{\partial x_k}\right)\right)\right]+$$
$$\frac{\partial}{\partial y}\left[\mu\cdot\left(\left(\frac{\partial u}{\partial y}\right)+\left(\frac{\partial v}{\partial x}\right)\right)\right]+\frac{\partial}{\partial z}\left[\mu\cdot\left(\left(\frac{\partial u}{\partial z}\right)+\left(\frac{\partial w}{\partial x}\right)\right)\right]$$

$$\rho\cdot\left(\frac{\partial v}{\partial t}+u\cdot\frac{\partial v}{\partial x}+v\cdot\frac{\partial v}{\partial y}+w\cdot\frac{\partial v}{\partial z}\right)=\cancel{\rho\cdot g_y}-\frac{\partial P}{\partial y}+\frac{\partial}{\partial x}\left[\mu\cdot\left(\left(\frac{\partial v}{\partial x}\right)+\left(\frac{\partial u}{\partial y}\right)\right)\right]+ \qquad \text{Eq 33}$$
$$\frac{\partial}{\partial y}\left[\mu\cdot\left(2\cdot\left(\frac{\partial v}{\partial y}\right)-\frac{2}{3}\left(\frac{\partial u_k}{\partial y_k}\right)\right)\right]+\frac{\partial}{\partial z}\left[\mu\cdot\left(\left(\frac{\partial u}{\partial z}\right)+\left(\frac{\partial w}{\partial x}\right)\right)\right]$$

$$\rho\cdot\left(\frac{\partial w}{\partial t}+u\cdot\frac{\partial w}{\partial x}+v\cdot\frac{\partial w}{\partial y}+w\cdot\frac{\partial w}{\partial z}\right)=\rho\cdot g_z-\frac{\partial P}{\partial z}+\frac{\partial}{\partial x}\left[\mu\cdot\left(\left(\frac{\partial w}{\partial x}\right)+\left(\frac{\partial u}{\partial z}\right)\right)\right]+$$
$$\frac{\partial}{\partial y}\left[\mu\cdot\left(\left(\frac{\partial w}{\partial y}\right)+\left(\frac{\partial v}{\partial z}\right)\right)\right]+\frac{\partial}{\partial z}\left[\mu\cdot\left(2\cdot\left(\frac{\partial w}{\partial z}\right)-\frac{2}{3}\cdot\left(\frac{\partial u_k}{\partial z_k}\right)\right)\right]$$

Every term in Eq 33 represents a function. Something like velocity in the "x" direction ("u" in Eq 33) will have an equation that is time dependent, another equation that is dependent on position in the "x" direction, another equation for the "y" direction and a fourth equation for the "z" direction. All may be material. If you were able to resolve all the variables into equations for each parameter for a specific flow, then it would likely be worthless for the next flow you pattern you want to analyze.

Many people have worked on a closed-form solution to Navier-Stokes, and there is a $1 million USD bounty for anyone who can develop a general solution. In spite of many close calls (the latest in 2006 and 2014), the prize remains unclaimed.

There have been a few useful special cases that throw out the hard terms, but they tend to have so many simplifying assumptions that they lack universal applicability.

4.2.2. Bernoulli Equation

If you start with the assumption that the flow is:

- Inviscid (i.e., viscosity and friction are zero)
- Incompressible
- Irrotational (neither vorticity nor rigid body rotation)
- Reversible
- Isothermal
- Isentropic (flow not a function of position)
- Adiabatic (no heat is gained from or lost to the environment)
- There is no work done on or by the fluid
- No fluid is added or removed from the control volume being investigated

Then you can reduce Eq 33 to Eq 34.

$$\frac{\rho \cdot v^2}{2} + \rho \cdot g \cdot h + P_{static} = \text{constant} \qquad \text{Eq 34}$$

We've assumed that density is constant (i.e., the flow is incompressible), so this equation for two points in the same control volume (e.g., pipe, conduit, section of atmospheric air surrounding a moving body), then Eq 34 becomes Eq 35.

$$\frac{\rho \cdot v^2}{2} + \rho \cdot g \cdot h + P_{static} = \frac{\rho \cdot v^2}{2} + \rho \cdot g \cdot h + P_{static}$$

$$\frac{\rho}{2} \cdot \left(v_1^2 - v_2^2\right) + \rho \cdot g \cdot \left(h_1 - h_2\right) = P_2 - P_1 \qquad \text{Eq 35}$$

If you can pick a control volume where the two reference heights are equal, then Eq 35 relates a static pressure change to the square of a velocity change (the velocity term is referred to as "dynamic pressure" in Eq 36). This turns out to be quite useful. The square-edged-orifice flow-measurement equations started with Bernoulli's Equation. This equation describes why airplanes can fly. It allows HVAC engineers to predict flow in ducts.

Bernoulli's equation is not Navier-Stokes. It cannot have friction, so it is limited to small control volumes. It can't have changes in density. It can't have rotation. It can't have heat loss/gain. If you satisfy all of the assumptions then it can yield amazing results. If you don't satisfy all of the assumptions then you get numbers.

Many of the current generation of Fluid Mechanics texts include an abomination called the "Modified Bernoulli Equation". This equation purports to take the Bernoulli Equation and scab a "friction loss" term onto the end of it. Nonsense. You cannot derive the Bernoulli Equation if you can't eliminate all the terms involving friction, or flow changes with regard to density or position. The assumptions allow you to discard fully half of the terms in Navier-Stokes and essentially all of the really hard ones. Then to come back after the fact and add a friction term is just foolishness.

4.2.3. No-Flow Boundary

The fluid molecules that touch a foreign substance (i.e., a solid or another phase of fluid or another species of fluid) must have the same velocity as the foreign substance. The easiest example of this is a fluid flowing within a pipe. The fluid will create a "boundary layer" of some non-zero thickness that will have a velocity gradient ranging (more or less as a straight line) from zero at the pipe wall to some small velocity at the edge of the boundary layer. The bulk of the flow will also have a velocity gradient from a minimum at the edge of the boundary layer to a maximum in the centerline of the pipe (Figure 2).

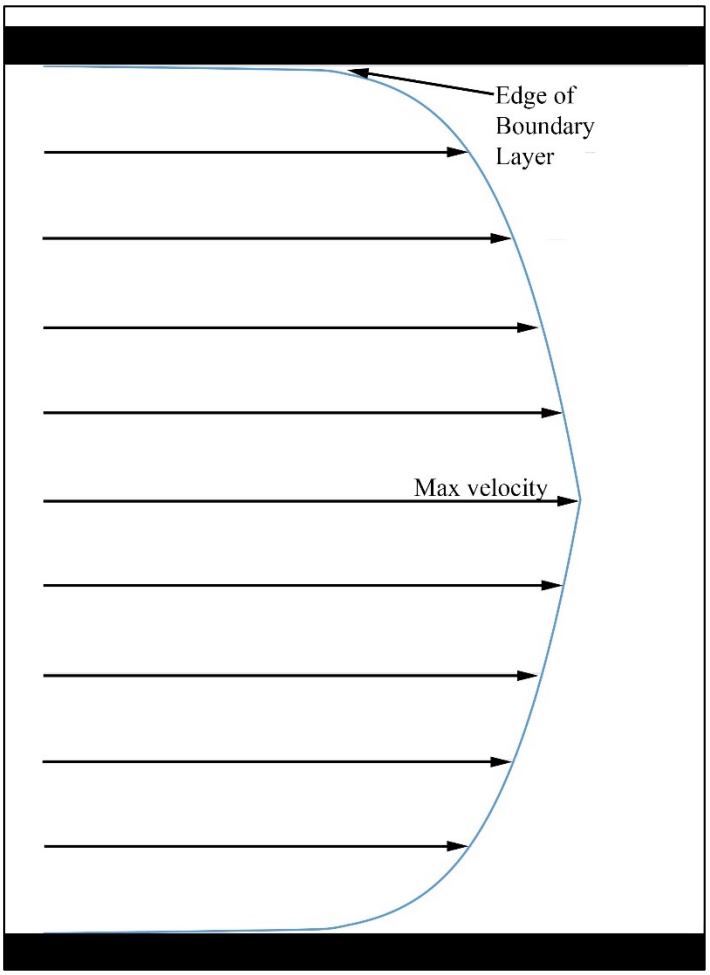

Figure 2: Turbulent flow Profile

The no-flow boundary may be (and is) physically small, but it is crucial to understanding flow. For example, without this concept it would be impossible to explain why a flowing gas stream can transport a liquid droplet or how a jet pump works.

4.2.4. Similitude

Fluid mechanics has a concept called "similitude" that says that if you can define a ratio of forces that can be resolved to a non-dimensional parameter then any system with the same value for that non-dimensional parameter as a model of that system would have similar responses to external forces. It is generally required to have more than one of the non-dimensional parameters match before conclusions based on a model can be thought to be reliably representative of a full system. Some of the more common non-dimensional parameters are shown in Table 10.

Table 10: Various Non-Dimensional Numbers

Non-Dimensional Parameter	Forces	Equations
Reynolds Number	Inertial forces / viscous forces	$\mathrm{Re} = \frac{\rho \cdot \vec{v} \cdot L_{characteristic}}{\mu}$
Weber Number	Inertial forces / Interfacial tension	$We = \frac{\rho \cdot v^2 \cdot L_{characteristic}}{\sigma}$
Mach Number	Velocity / Sonic Velocity	$M = \frac{v}{v_{sonic}}$
Euler Number	Pressure forces / Inertial forces	$Eu = \frac{P_1 - P_2}{\rho \cdot v^2}$
Cavitation Number	Distance from vapor pressure / Kinetic energy	$Ca = \frac{P - P_{vapor}}{\left(\frac{1}{2}\right) \cdot \rho \cdot v^2}$
Froude Number	Flow inertia / Body forces	$Fr = \frac{v}{\sqrt{L_{characteristic} \cdot g}}$
Strouhal Number	Vortex shedding frequency / velocity	$St = \frac{f_{vortexShedding} \cdot L_{characteristic}}{v}$

5. Parameter Measurement

We "measure" many things. Decisions are based on pressure/temperature "measurements", fluid velocity "measurements", volume flow rate "measurements", etc. But what can actually be measured is almost nothing. We can directly measure distance and time with good results, but we have to infer values for most other parameters. Since it is possible to measure distance, it is easy to extend that to area and volume. For other measurements you have to rely on a materials response to a change in the parameter you are trying to ascertain.

For example, when you measure temperature with a glass thermometer, you are actually measuring the change in volume of a liquid (e.g., mercury) in response to a change in temperature. Using a resistance temperature detector (RTD), you are measuring the change in electrical resistance of a specific material to a change in temperature. But wait, how are you measuring the electrical resistance? In an RTD, a precise voltage is applied to a circuit with constant current flow

and the drop in voltage through the sensing resister is proportional to the temperature. How do you measure the voltage difference across the variable resister? That is done with a circuit that generates a series of pulses and then the circuit counts the pulses larger than a certain magnitude (i.e., time and distance).

Inferential measurement is not bad, but it is based on "known" materials responses to external stimuli. These material responses must be based on several assumptions. When field conditions match the assumptions then the results are useful. Deviate from the assumptions and the results are numbers. A good example of this is gas measurement using a square-edged orifice meter. Start with the list of assumptions associated with the Bernoulli Equation. To that list, gas measurement adds:

- Tube is long, straight, and level (removing the elevation term from Bernoulli).
- Flow profile is fully developed (i.e., it matches the power law shown in Figure 2 and has no asymmetry).
- Single-phase flow.
- Fluid properties known and constant.
- Enough friction to dampen swirl (remember that the assumptions for the Bernoulli Equation specify zero friction and zero rotation of any kind).
- Tube roughness in a very narrow range.
- Condition of the flow restriction meets published specifications.
- Meter tube ID is in the range 2 to 36 in (51 to 914 mm)
- Ratio of orifice diameter to tube diameter (i.e., "β-ratio") must be in a range defined by Reynolds number.

So, for example, if an orifice plate is changed, but the new information is not fed into the calculation process, then the result is numbers, not gas measurement. Same with a backwards orifice plate, or the presence of liquid, or a dirty tube. ALL the assumptions must be satisfied to allow the inference of a parameter from seemingly unrelated data.

5.1. Accuracy

People talk about "accuracy" a lot. The trouble is that no one has a definition of the term. Webster calls it "freedom from mistake or error", but that doesn't really help much since we haven't defined exactly how free from mistake or error is required to call a measurement accurate. That is always situational, it is far better to use the terms "uncertainty" and "repeatability".

"Uncertainty" is an objective measure of an error band. If we report a pressure as "118 psig ±1 psi" then a user of the data knows that the actual reading is in the range 117-119 psig, and can decide if that uncertainty is adequate for their needs. If the user is trying to identify 0.1 psi variances in a physical system then data with that uncertainty is worthless. If the user is trying to find when the pressure drops below 100 psig or goes above 125 psig then it is perfectly adequate. On an analog pressure or temperature instrument (Figure 3) it is simple to determine the uncertainty—it is half the smallest increment on the dial or scale and the uncertainty of the gauge in Figure 3 and Figure 4 uncertainty is ±0.5 psig. Digital instruments are an entirely different kettle of fish. A digital pressure gauge (or thermometer or pressure transducer or resistance temperature detector) will have an uncertainty clearly stated in the published specifications and it is important for someone needing precise data to look them up. For example, a digital pressure gage may have an uncertainty of ±0.05 psi which is very nice, except the pressure might be displayed as 118.367851 psi. The data after the "6" is simply random noise and gives one the feeling that the uncertainty of the device is ±0.000001 psi, which it most certainly is not.

"Repeatability" is a measure of an instrument's ability to yield the same output when confronted with a fixed input. An instrument with acceptable repeatability will display the same output (within the instrument's uncertainty) every time it receives a given input. Ten readings on a ±1 psi pressure gauge of a fixed 118.635 psig actual input should all fall between 117.5 and 119.5 psig (since you can only extrapolate half the printed increment on the gauge, see below). You evaluate the uncertainty of an instrument with another instrument with no more than half the uncertainty of the instrument under test (i.e., you evaluate a ±1 psi gauge with a test gauge which has an uncertainty of ±0.5 or less).

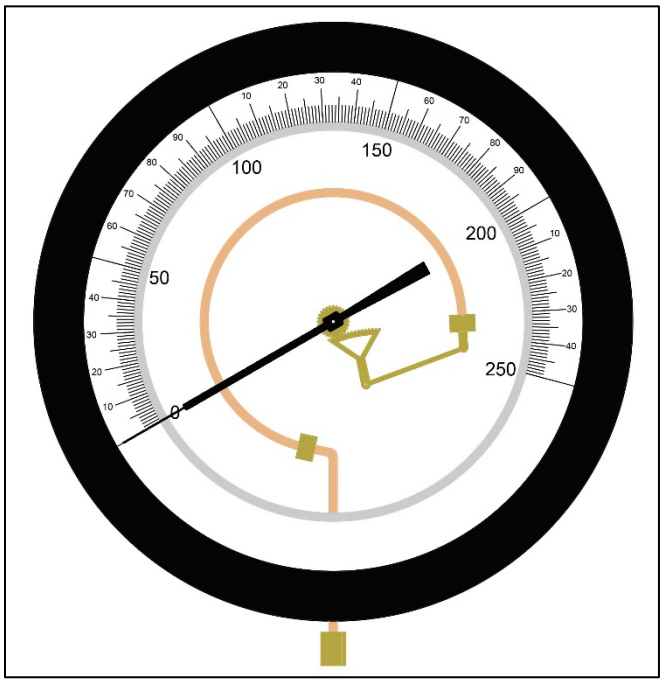

Figure 3: Bourdon Tube Pressure Gauge

An instrument that meets the project requirements for uncertainty and repeatability is "accurate" enough.

5.2. Pressure and temperature measurement

Every subject discussed in Oil & Gas has pressure and/or temperature lurking somewhere in the conversation. We cannot measure either one of them directly, but there are surrogates that provide very reliable indications of their values. The change in volume of many

substances is linear with regard to temperature change over a specified range, so a mercury thermometer can be put into a calibrated glass tube and give us a simple instrument that reflects temperature, but we can't "measure" temperature.

Pressure is even harder to measure. The most common analog instrument is a Bourdon Tube (Figure 3) where a bent tube is connected to gears through a rack and pinion arrangement connected to a dial indicator. As pressure increases, the tube tries to straighten, rotating the dial towards a higher pressure and vice versa. This pressure indicator is only measuring a part of the total "pressure", the "static pressure" but there are two other components to total pressure ("dynamic pressure" and "hydrostatic pressure") that a Bourdon Tube cannot react to.

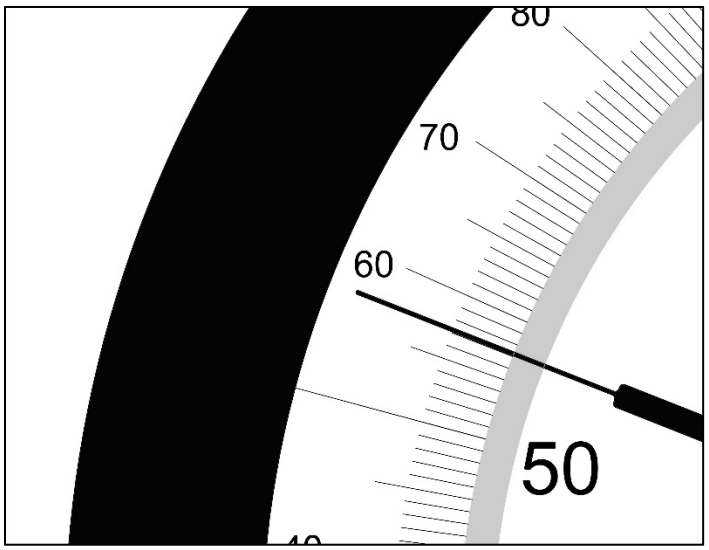

Figure 4: Analog gauge parallax

The gauge in Figure 3 is called a "test gauge". The thin silver circle that goes all the way around the gauge is a mirror. The end of the indicator needle is rotated to perpendicular with the face of the gauge and when you position your eye such that you cannot see a reflection of the needle, then you can read the proper pressure without a parallax error (i.e., a displacement in the apparent position of an object viewed along two different lines of sight, a major cause of gauge-reading errors). There is a rule for reading any gauge, but especially a test gauge: You can only interpolate to the midpoint between the smallest increments. So in the gage in Figure 4, the pressure is 57 psig, not 57.1 or 57.2. If the pressure were a little higher then you would have to decide if it is 57, 57.5, or 58, but it is never 57.3. If you need to differentiate 57.3 from 57.4, then you need a gauge marked in 0.1 psi increments. Pressure gauges can only give you static pressure above atmospheric pressure (i.e, psig, kPag, or barg), not absolute pressure (i.e., psia, kPaa, or bara). Occasionally a clever measurement tech will shift the face of a gauge so that when it is depressurized it reads some value other than zero which is purported to be local atmospheric pressure—it almost never is actually local atmospheric pressure and this is a horrible practice.

5.3. Total pressure

Total pressure is made up of three components shown in Eq 36.

$$P_{total} = P_{dyanamic} + P_{static} + P_{hydrostatic}$$

$$P_{total} = \frac{\rho_{flowingFluid} \cdot \vec{v}^2}{2} + P_{static} + \rho_{fluidMixAbove} \cdot g \cdot h \qquad \text{Eq 36}$$

Within a system of incompressible fluids flowing at low velocities, total pressure must remain constant with changes in dynamic or hydrostatic pressure (e.g., if the fluid begins flowing faster, then the dynamic pressure will increase while the effect of the hydrostatic pressure will be diminished). Systems flowing at a significant fraction of the speed of sound (i.e., something over 30% of sonic velocity) will not have a constant total pressure, but those cases are uncommon enough to generally start with the assumption that total pressure is constant.

For a system at rest in effectively still air, the $P_{hydrostatic}$ is local atmospheric pressure and the total pressure is $P_{static} + P_{atmospheric}$.

5.4. Pressure Continuum

In field operations it is common to talk about "high pressure" or "low pressure" and typically these terms are relative to some value that is clear in the speaker's mind, but not communicated in the current discussion. This often leads to sub-optimal decisions or poor understanding of the issues.

While doing work on evaporation, I noticed that there were three distinctly different regions on the plot I was generating (Figure 5).

It appears that above 145 psia [10 bara], this particular data could be reasonably represented as a straight line. It is also clear that below 43.5 psia [3 bara] the high pressure straight line had no relationship to the data and in fact no straight line would do an adequate job of representing the data. Between these two points was a transition region that matched a straight line better than the low-pressure region, but still not very well. I found this to be intriguing and generated a number of plots including "Entropy vs. Pressure", and "Pipe Performance vs. Pressure". All the data reviewed could be divided into the three categories we saw with the evaporation data with the lines in the same places. The result was:

- > 145 psia [10 bara] → High pressure. Equations developed for oil fields tend to work very well, it is usually safe to ignore evaporation, and dehydration can be a reasonable process.

- 43.5 psia [3 bara] to 145 psia [10 bara] → Normal pressures. Error band on oil field equations tends to increase, ignoring evaporation has higher risk, dehydration becomes less effective
- < 43.5 psia [3 bara] → Low pressures. Traditional equations range from "mostly useless" to "misleading", evaporation represents a major challenge to all equipment performance and must be considered in any facilities decision, the amount of water in the gas makes dehydration too expensive to be considered (the problem is the mass of water that must be cooked out of the dehydration media in the recharge step becomes too large for reasonably sized equipment and fuel load).

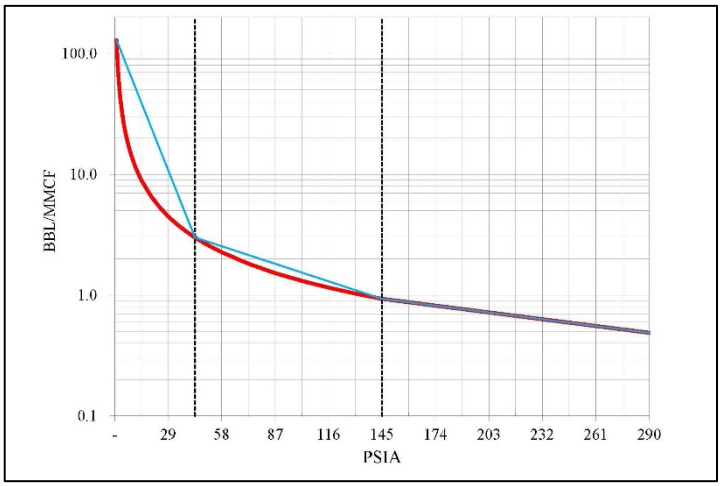

Figure 5: Water Content vs. Pressure

There are other changes that can occur at very high pressure (probably above 10,000 psia [70,000 kPaa]), but environments with that magnitude of pressure should not be managed via rules of thumb.

6. Standard Conditions

It is often useful to pretend that a gas is at a constant temperature and pressure as it moves through various processes. It is very important to keep in mind that the pressures and temperatures you are pretending the gas is at are simply a fantasy that does not control the physical forces and reactions on or of the gas. For example, if you calculate a gas velocity by dividing a volume flow rate at standard conditions by the flow area you will get a number. You should be aware that the number you get will have velocity units, but will not represent any velocity that actually exists in the world. Consequently, one should never cancel ft^3 with SCF or vice versa. SCF is an imaginary unit and ft^3 is a physical unit.

The fantasy conditions that industry uses are called "Standard Temperature and Pressure (STP)". This is an unfortunate term because the exact values for pressure and temperature in the fantasy world are anything but "standard". Table 4 has a sampling (far from complete, see [Wikipedia, 3] for a longer list that is still far from complete) of some of the values that are regularly used for STP.

Table 11: Selection of STP Definitions

	Pressure	Temperature
Undergrad Chemistry Texts	14.696 psia [101.325 kPaa]	60°F [15.56°C]
Gas Measurement (USA)	14.73 psia [101.56 kPaa]	60°F [15.56°C]
EPA Reporting	14.696 psia [101.325 kPaa]	20°C [68°F]
NM and LA State Reporting	15.025 psia [103.59 kPaa]	60°F [15.56°C]
ISO	101.33 kPaa [14.696 psia]	0°C [32°F]
Gas Measurement (Europe)	100.0 kPaa [14.5 psia]	15°C [59°F]
Gas Measurement (Queensland)	101.325 kPaa [14.696 psia]	15°C [59°F]

The reader might assume that I don't approve of reporting gas at standard conditions, and nothing could be further from the truth. Using volume flow rates at standard conditions (for purposes of this discussion we will call that "SCF") is an elegant solution to the complementary problems of: (1) we do not have a way to measure mass flow rate; and (2) volume flow rate at actual conditions varies widely for the same mass flow rate at varying pressures and temperatures. Using SCF per unit time solves both of these problems nicely: (1) we have instruments that can infer a volume flow rate from parameters that we can measure; and (2) SCF remains constant (for a given mass flow rate) across any range of pressure and temperature. Using SCF is a fantastic solution to the requirement to do commerce at varying pressures (e.g., as a homeowner you purchase 100 SCF of gas delivered at a pressure of 15 psia, the molecules that made up your delivery left a processing plant at 1,000 psia, and they might have left the gas well at 50 psia, it is the same number of molecules and it is the same 100 SCF in all three cases). SCF can be called "a surrogate for mass flow rate" because, like mass flow rate, a fixed number of gas molecules are contained in a given delivery unit (i.e., lbm or SCF) regardless of pressure or temperature.

Volume flow rate at standard conditions is a useful tool, as long as there is communication. Just because a government regulator defines "standard pressure" as 15.025 psia [103.59 kPaa] that only means that when you report to that bureau you have to pretend your gas was at 15.025 psia [103.59 kPaa] instead of pretending another value. Your delivery contract may specify that "standard pressure" is 14.73 psia [101.56 kPaa] (which is very common). At the same time you may be subject to extracting flow data from a corporate database that defines "standard pressure" as 14.5 psia [100 kPaa]. It is incumbent on the user of flow data to know: (1) how the data is stored; (2) what fantasy value is required; and (3) how to convert from one to the other. The last item is pretty easy if you take care. We know that if we don't add or remove fluids from an enclosed system, mass flow rate must be the same everywhere. We also know that mass flow rate is volume flow rate times density, so use the relationship in Eq 37

$$\dot{m} = q_1 \cdot \rho_1 = q_2 \cdot \rho_2 \therefore q_2 = q_1 \cdot \frac{\rho_1}{\rho_2} \qquad \text{Eq 37}$$

This says that to change from any pressure and temperature to any other pressure and temperature, divide the old mass flow rate by the new density. Looking at Eq 37 you can see that many of the terms can be cancelled (Eq 38).

$$q_2 = q_1 \cdot \frac{\rho_1}{\rho_2} = q_1 \cdot \frac{\left(\frac{P_1 \cdot \cancel{\gamma}}{\cancel{R_{air}} \cdot T_1 \cdot Z_1}\right)}{\left(\frac{P_2 \cdot \cancel{\gamma}}{\cancel{R_{air}} \cdot T_2 \cdot Z_2}\right)} = q_1 \cdot \frac{P_1}{P_2} \cdot \frac{T_2}{T_1} \cdot \frac{Z_2}{Z_1} \qquad \text{Eq 38}$$

For any conversion from one version of STP to another, the compressibility will cancel. If the temperature is close enough it will also cancel. For non-financial purposes, this calculation can usually be reduced to Eq 39

$$q_2 = q_1 \cdot \frac{P_1}{P_2} \qquad \text{Eq 39}$$

If we wanted to convert 100 MSCF/day from STP of 14.73 psia and 60°F to 14.5 psia at 59°F we would do the calculation in Eq 40.

$$q_{15.025} = 100 \cdot \frac{MSCF}{day} \cdot \frac{14.73 \cdot psia}{14.5 \cdot psia} \cdot \frac{519.63R}{518.63R} \cdot \frac{0.997533}{0.997510} = 101.393 \cdot \frac{MSCF}{day}$$

$$q_{15.025} = 100 \cdot \frac{MSCF}{day} \cdot \frac{14.73 \cdot psia}{14.5 \cdot psia} = 101.586 \cdot \frac{MSCF}{day} \qquad \text{Eq 40}$$

You have to decide if your calculation can handle a 0.19 percent error or not (most can, some can't).

You cannot use SCF to calculate physical properties (such as velocity). To calculate physical properties of a gas flow you must convert the volume flow rate from imaginary flow rates to actual, physical flow rates using the technique in Eq 38 or Eq 39 before starting on further calculations.

There is no universal SI nomenclature around standard flow rates. Nearly everyone working in the industry is familiar with the term SCF (often pronounced "scuff"), but contracts and regulations require SI-ish measurements:

- NCM: a common to abbreviation for "normal cubic meters" which is different from "standard cubic meters". The definition of these "normal" volumes varies from field to field and plant to plant, but it often refers to a pressure/temperature base that is different from the regulatory-mandated pressure/temperature base and it is always confusing to outsiders.

- m^3: Many jurisdictions simply use "m^3" to mean both "cubic meters at standard conditions" and "cubic meters at actual conditions".
- E3M3: The first place that this was seen was in Alberta, Canada and it stands for "1000 cubic meters at standard conditions" (i.e., "E3" is a computer convention for 1000). Almost every time I've seen this it has been limited to standard conditions, but in one field that I worked in Australia it was used for either standard or actual.
- MM3: This designation either means "1000 standard cubic meters" (oilfield reference) or "1,000,000 standard cubic meters" (SI reference), and it is unclear whether anyone ever uses it consistently. For a first assumption it is best to assume that it refers to the SI "mega" prefix for 10^6, but it is better to ask if possible.

As can be seen throughout this document we've used "SCm" to mean "standard cubic meters" and use standard SI prefixes while "m^3" to mean "physical cubic meters" and no SI prefixes are used. This is not in any way an industry standard, but I've found it to be much clearer and less ambiguous.

Example: 3. 23 MMSCf/day of sweet natural gas is flowing in a 6-inch standard wall pipe (I.D. 6.063 in) pipe at 104°4 and 150 psig along a coastline (atmospheric pressure 14.5 psia). Standard conditions are 14.5 psia and 59°F. What is the average gas velocity in the line? If compressibility of the gas at standard conditions is 0.998 and compressibility at flowing conditions is 0.969, what error is introduced using Eq 39 instead of Eq 38?

Solution: The term "Sweet Gas" refers to the proportions of components presented in Table 1 and expanded to specific properties in Table 3. Since integrating the curve in Figure 2 is unreasonable (the exact flow profile is very much a function of instantaneous conditions and a solution at one point would not be valid just inches downstream) "average gas velocity" must be defined as "volume flow rate at actual conditions divided by flow area. Since compressibility was not given in the problem statement, Eq 39 will be used to convert volume flow rate at standard conditions to volume flow rate at actual conditions.

$$v = \left(\frac{q_{std}}{A}\right)\cdot\left(\frac{P_{std}}{P_{actual}}\right) = \left(\frac{\left(23\,{}^{MMSCF}/_{day}\right)\left(1000000\,\frac{SCF}{MMSCF}\right)\left(\frac{day}{86400s}\right)}{\left(\frac{\pi}{4}\right)\left(\frac{6.063in}{12\,{}^{in}/_{ft}}\right)^2}\right)\cdot\left(\frac{14.5psi}{150psi+14.5psi}\right) = 116.8\,{}^{ft}/_{s} \quad \text{Eq 41}$$

It is always best to base an error estimate on the most reliable information available, so the denominator of our error calculation will be based on the Eq 38 value.

$$\gamma_{table3} = 0.7355$$

$$\rho_{std} = \frac{P_{std} \cdot \gamma_{table3}}{R_{air} \cdot T_{std} \cdot Z_{std}} = \frac{14.5\,{}^{lbf}/_{in^2} \cdot 0.7355 \cdot \frac{144 in^2}{ft^2}}{53.355\,{}^{ft \cdot lbf}/_{R \cdot lbm} \cdot (15 + 459.67) R \cdot 0.998} = 0.0556\,{}^{lbm}/_{ft^3}$$

$$\rho_{flowing} = \frac{(150 + 14.5)\,{}^{lbf}/_{in^2} \cdot 0.7355 \cdot \frac{144 in^2}{ft^2}}{53.355\,{}^{ft \cdot lbf}/_{R \cdot lbm} \cdot (104.4 + 459.67) R \cdot 0.969} = 0.5870\,{}^{lbm}/_{ft^3}$$

Eq 42

$$v_{eq38} = \left(\frac{q_{std}}{A}\right) \cdot \left(\frac{P_{std}}{P_{actual}}\right) = \left(\frac{\left(23\,{}^{MMSCF}/_{day}\right)\left(1000000 \frac{SCF}{MMSCF}\right)\left(\frac{day}{86400 s}\right)}{\left(\frac{\pi}{4}\right)\left(\frac{6.063 in}{12\,{}^{in}/_{ft}}\right)^2}\right) \cdot \left(\frac{0.0556\,{}^{lbm}/_{ft^3}}{0.5870\,{}^{lbm}/_{ft^3}}\right) = 123.7\,{}^{ft}/_{s}$$

$$Error = \frac{v_{eq38} - v}{v_{eq38}} 100 = \frac{123.7 - 116.8}{123.7} = 5.5\%$$

Each project team must decide on each project is this sort of error is a problem or if it is within the uncertainty of the other calculations and data.

7. Empirical Equations

Empirical equations take advantage of coincidences in a physical phenomenon that can be exploited. For example, if you are interested in knowing how much water will be needed to fill a pipeline for a hydrostatic pressure test, you can calculate the volume by Eq 43.

$$V = \left(\frac{\pi}{4}\right) \cdot ID^2 \cdot Len$$

Eq 43

Since we would typically source the water in "barrels", and Eq 43 would yield inch^2 times feet, some unit conversions must be added (Eq 44).

$$V = \left(\frac{\pi}{4}\right) \cdot ID^2 \cdot Len \cdot \left(\frac{ft^2}{144 \cdot in^2}\right) \cdot \left(\frac{bbl}{5.61 ft^3}\right)$$

Eq 44

If the length is fixed at 1,000 ft, then the constants and unit conversions resolve to 0.9722≈1.0 and Eq 44 can be approximated as Eq 45.

$$V_{bbl_per_1000\,ft} \approx \left(\frac{ID}{in}\right)^2$$

Eq 45

Notice a crucial element of empirical equations—they only "work" with exactly one set of units. Using Eq 45, it is easy to estimate that you'll need 144 bbl [22.9 m^3] of water to fill 1000 ft [304 m] of 12 in [DN 300] ID pipe (Eq 43 gives you 139.9 bbl [22.24 m^3], so Eq 45 allows some extra for partially filled trucks and spillage), but what if you input millimeters and meters into the equation? The answer is not so simple (Eq 46).

$$V_{SI} = (304.8 \cdot mm)^2 = 92416 \cdot ????$$ Eq 46

Squaring the ID, gives you a number, but what the heck does it mean? Let us look at an SI version of Eq 43 (Eq 47).

$$V = \left(\frac{\pi}{4}\right) \cdot ID_{mm}^2 \cdot Len_m = \left(\frac{\pi}{4}\right) \cdot \left(\frac{304.8 \cdot mm}{\frac{1000 \cdot mm}{m}}\right)^2 \cdot 304.8 \cdot m = 22.24 \cdot m^3$$ Eq 47

If the length is fixed at 1000 ft [304.8 m] then you can collapse all of the non-ID terms into 0.0002394, but so what? This is not a memorable number and it is much easier to just use the actual calculation. In the field, I have a chance of successfully squaring "12" and multiplying it times the number of 1000 ft increments in the line in my head. There is nothing magical about choosing a 1000 ft length, you can choose any number of meters you want and the result is more complex than just calculating the volume.

This trivial example is important because while a University Engineering curriculum distains empirical equations, Oil & Gas is full of them, and every one of them only works with exactly one set of units. An equation that works with 22 percent input as 22.0 will not work with 22 percent input as 0.22 (regardless of how "correct" 0.22 is and how "incorrect" 22.0 is). An equation that wants length in miles will not work with length in meters, kilometers, or feet. Often the units defy a logical explanation. Fine. Don't try to find logic, just use the equation with the units that take advantage of the coincidence.

Any equation that contains a numerical constant that is not a small integer or a physical constant (e.g, π or the Ideal Gas Constant), is likely an empirical equation and requires a precisely defined set of units.

Another important tell-tale is when units don't cancel within a term that is then raised to a non-integer exponent (or a logarithm or included in a term that is used as an exponent). Look at Eq 32 above (reproduced as Eq 48).

$$P_{bot} = P_{top} \cdot \exp\left(\frac{0.01875 \cdot SG \cdot h}{T_{avg} \cdot Z_{avg}}\right)$$

$$psi = psi \cdot \exp\left(\frac{ft}{R}\right)$$ Eq 48

There is no way to take an exponent of a "ft/R". That is a dead giveaway that this is not a closed-form equation, but an empirical equation.

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9. Nomenclature

Symbol	Name	fps units	SI units
c_p	Specific heat at constant pressure	BTU/lbm/R	J/gm/K
c_v	Specific heat at constant volume	BTU/lbm/R	J/gm/K
$f_{vortexShedding}$	The frequency that von Karman Streets are shed around a bluff body in flow	decimal	decimal
g	Gravitational constant	32.174 ft/s^2	9.81 m/s^2
g_c	Unit converter	32.174 ft-lbm/s^2-lbf	N/A (for now)
h	Height	ft	m
H	Enthalpy	BTU	kJ
ID	Inside diameter	in	mm
k	Adiabatic constant (c_p/c_v)	none	none
Len	Length	ft	m
$L_{characteristic}$	Some length related to an analysis, can be OD, length, hydraulic diameter, etc.	ft	m
m	Mass	lbm	kg
$\dot{m}$	Mass flow rate	lbm/s	kg/s
MW	Molecular weight	lbm/lb-mole	gm/gm-mole
MW_{air}	Molecular weight of air	28.962 lb/lb-mole	28.962 gm/gm-mole
n	Number of moles		
P	Pressure	psia	Paa, bara
P_{vapor}	Vapor pressure of a component of a liquid	psia	Paa, bara
q	Volume flow rate at standard conditions	SCF/day	SCm/day
Q	Heat Capacity	BTU/R	J/gm
$\bar{R}$	Universal gas constant	1545.3 ft*lbf/R/lb-mole	8.314 J/K/mole
R_{air}	Specific gas constant for air	53.355 ft*lbf/R/lbm	287.068 J/K/kg
R_{gas}	Specific gas constant for any specified gas	R_{air}/SG_{gas}	R_{air}/SG_{gas}
v	Velocity	ft/s	m/s
v_{sonic}	Sonic Velocity	ft/s	m/s
V	Volume	ft^3	m^3
$\dot{V}$	Volume flow rate at actual conditions	ft^3/s	m^3/s
W	Water vapor in a gas	lbm/MMSCF	mg/SCm
W	Weight	lbf	N
x	Mole fraction of a component in a	none	none

	mixture		
y	Any intrinsic property of a element or compound (e.g., specific heat at constant pressure)	various	various
Z	Compressibility	none	none
μ_{jt}	Joule-Thomson Coefficient	R/psia	K/kPaa
γ	Specific Gravity	none	none
ρ	Density	lbm/ft^3	kg/m^3
σ	Interfacial Tension	cP	Pa×sec

Subscripts	
ASL	Above sea level
atm	Atmospheric
gas	Variable is referring to the gaseous phase
i	Array counter
liquid	Variable is referring to the liquid phase
SI	Metric version of equation
std	Indicates variable is at standard conditions
unit	Indicates variable may be in non-standard units
water	Variable is referring to the characteristics of pure water at atmospheric pressure and 60°F [15.6C]
1	Upstream conditions, or first state
2	Downstream conditions, or second state

10. **Units**

Symbol	Name	Type unit	Equivalent unit
bbl	Barrel (42 U.S. gallons)	fps—volume	0.1590 m^3
BTU	British Thermal Unit	fps--energy	1.055 kJ
°C	Celsius	SI--temperature	°C*9/5+32=°F
cm	Centimeter	SI—length	0.394 in
cm^2	Square centimeters	SI—area	0.155 in^2
dyne	Dyne	SI—force	2.248E-6 lbf
°F	Fahrenheit	fps—temperature	(°F - 32)*5/9=°C
ft	Foot	fps—length	0.3048 m
ft^2	Square feet	fps—area	0.0929 m^2
ft^3	Cubic feet	fps—volume	0.02832 m^3
gm-mole	Gram mole (mass of one mole of gas)	SI—molar mass	lb-mole
in	Inch	fps—length	25.4 mm
in^2	Square inches	fps—area	0.000645 m^2
J	Joule	SI—energy	947.8E-6 BTU
K	Kelvin (°C+273.15)	SI—temperature	R*5/9=K
kg	Kilogram	SI—mass	2.205 lbm
km	Kilometer	SI—length	3281 ft
lbf	Pounds force	fps—force	4.448 N
lbm	Pounds mass	fps—mass	0.454 kg
lb-mole	Pound mole (mass of one mole of gas)	fps—molar mass	gm-mole
mm	Millimeter	SI—length	0.0393 in
m	Meter	SI—length	3.281 ft
m^2	Square meters	SI—area	10.764 ft^2
m^3	Cubic meters	SI—volume	35.314 ft^3
N	Newton	SI—force	0.225 lbf
Pa	Pascal	SI—Pressure	1 J/m^3
psi	Pounds force per square inch	fps—Pressure	6.895 kPa
R	Rankine (°F+459.67)	fps—temperature	K*5/9=R
s	Second	all—time	
SCF	Standard cubic feet	fps—volume	0.283 SCm
SCm	Standard cubic meters	SI—volume	35.314 SCF

Unit Prefixes	
M	fps—Thousand, oil field prefix=1000
MM	fps—Million, oil field prefix=10^6
B	fps—Billion, oil field prefix=10^9
T	fps—Trillion, oil field prefix=10^{12} (duplicates an SI unit, but both have the same magnitude)
k	SI—kilo, 10^3
M	SI—Mega, 10^6 (limited use in this book due to confusion with Oil Field Units)
G	SI—Giga, 10^9
T	SI—Tera, 10^{12}
P	SI—Peta, 10^{15}
E	SI—Exa, 10^{18}