2.1 Introduction

This chapter provides a fairly general and rudimentary exposure to problems in the exploration, drilling, and completion of natural gas wells. The chapter is by no means intended to be comprehensive but instead it provides an engineer, new to natural gas, insight about some of the challenges in accessing these reservoirs. For a petroleum engineer with experience in oil wells, the chapter provides a taste of those unique problems that are different from oil wells. The examples and calculations are also intended to showcase the idiosyncrasies of gas wells, as they differentiate from oils wells.

2.2 Exploration

Until the late 1970s, successful drilling was a hit-and-miss operation. New wells, even in presumably prolific areas, were termed “wildcat,” and a rate of 10% (i.e. one good well and nine dry holes for every ten drilled) was considered attractive.

Few technologies in the history of the petroleum industry can match the importance of 3D seismic measurements and the impact they had on exploration and, today, production (Greenlee et al., 1994).

Aylor (1998) in an extensive study suggested that in the crucial period between 1990 and 1996, the time when 3D seismic measurements became commonplace, the overall success rate in identifying commercial wells increased from 14% to 49%. Also during the same period, wells covered by 3D seismic measurements increased from 1% to 44%. Equally important was the better identification of bad versus
good reservoir prospects. He found that 3D “reliably condemns 1.4 of the average 3.4 previously defined prospects, and discovers two new, previously unknown prospects per (3D) survey.”

Modern seismic surveys allow a considerable improvement in a number of important exploration areas:

- Geologic structure delineation.
- By-passed zone identification.
- Well targeting, and especially avoiding bad ones.
- Reduction of previously required minimum reserves to exploit reservoirs.

Seismic measurements involve the generation of a seismic event, a mini-earthquake that is transmitted downwards from the surface. In the early days of the technology, several thousand pounds of chemical explosives were used. Today, heavy-duty thumper trucks (vibroseis) create vibrations by hammering the ground. The trucks produce a repeatable and reliable range of frequencies and are a preferred source compared with dynamite. In offshore locations, a specially designed vessel with airguns shoots highly pressurized air into the water, which creates a concussion that hits and locally vibrates the sea floor. This seismic energy transmits through the earth’s crust, and as it encounters layers of rock with different acoustic properties, the energy bounces back as reflection (Dobrin, 1976). It is then recorded by an array of sensors called geophones or hydrophones. Figure 2–1 shows the seismic data collection process.

The product of density and velocity ($\rho v$) is called acoustic impedance, $Z$. The amount of energy that is reflected depends on the contrast in acoustic impedance between the rocks. This can be expressed by a simple equation where the reflection coefficient $R_c$ is defined as:

$$R_c = \frac{Z_2 - Z_1}{Z_2 + Z_1},$$

where the subscripts 1 and 2 refer to layers 1 and 2, respectively.

Seismic signals, like all acoustic waves passing through media, separate into compressional ($P$-wave) and shear ($S$-wave) waves. The latter are converted from compressional waves. Compressional waves move along the direction of propagation but shear waves move perpendicular to the direction of propagation.
The velocities of the two waves are given, respectively, by

\[ v_c = \left( \frac{E + \frac{4\mu}{3}}{\rho} \right), \]  
\[ v_s = \left( \frac{\mu}{\rho} \right), \]  

where \( E \) is the elastic modulus, \( \mu \) is rigidity and \( \rho \) is density.

The reflection and arrival back to the surface of shear and compressional waves, and especially the knowledge that shear waves do not propagate through fluid, allows the identification of zones that are likely to contain fluids versus those that do not.

The degree to which seismic energy is converted to shear wave depends on the angle of incidence between layers and the contrast in the Poisson ratio between the two layers. Such contrast is related to lithology, porosity, pore pressure, and fluid content. The conversion of compressional to shear waves is the basis of, what in the seismic
discipline, has been labeled the amplitude versus offset effect (AVO), and it is instrumental in detecting natural gas. The term offset is the distance between the seismic source and the receiver.

In all cases, a seismic wave travels into the ground, traversing layers (strata) to considerable depth. Different geologic strata provide different reflection effects as the seismic wave traverses them.

An example of the type of seismic data and their interpretation is shown in Figures 2–2 and 2–3 from Mallick (2001). Figure 2–2 shows the S-wave impedance as plotted from an inversion of the AVO. It shows how distinct layers and their undulations can be differentiated in the visualization. The boxed region is the zone of interest where the Poisson ratio of layers is calculated. Specifically, this example is from an offshore natural gas deposit marking the bottom-simulating reflector (BSR), which represents the boundary between solid gas hydrates and free gas below it.

Figure 2–3 is a blowup of the zone of interest, showing the calculated Poisson ratios around the BSR. The illustration clearly shows zones of small values of the Poisson ratio denoting gas bearing formations. Poisson ratios between 0.3 and 0.4 denote shales. Water-bearing sands have Poisson ratios between 0.22 and 0.3, whereas gas bearing sands have Poisson ratios between 0.1 and 0.15.

The use of seismic “attributes” is a major advance in seismic data interpretation. As many as 20 different combinations of the character of seismic data have been used to further hone the analysis. An example is shown in Figure 2–4 from Alsos et al. (2002). The ratio of the compressional-reflection to shear-reflection amplitude reveals both lithology and fluid content. In such case the representation shows both the sand deposition and hydrocarbon accumulations inside the area of interest.

It is considerably outside the scope of this book to provide expert analysis and interpretation of seismic signals, and especially, seismic attributes (which are even more advanced). However, for natural gas engineers who use seismic information and the identification of natural gas bearing formations, it is easy to see why natural gas reservoirs are far more readily identifiable than both formations without fluids and those containing mostly liquids (water and oil).

Eqs. (2.1 to 2.3) which form the basis of all seismic analyses contain the density of a layer as one of the prominent variables.

The composite density of a layer would be

\[ \rho = (1 - \phi)\rho_f + \phi(1 - S_w)\rho_{o,g} + \phi S_w\rho_W, \]  
(2.4)
Figure 2–2  S-wave impedance from AVO inversion for an offshore natural gas bearing structure. The boxed region is the area of interest below the BSR (Mallick, 2001)

Figure 2–3  Calculated Poisson ratios for the zone of interest in Figure 2–2 (Mallick, 2001)
where $\phi$ is porosity, $S_w$ is the water saturation, and $\rho_f$, $\rho_w$ and $\rho_o,g$ are the densities of the formation rock, water and oil or gas, respectively. It is worthwhile to see the difference in the respective composite densities for a dry, oil bearing, and gas bearing formations as in the following Example 2–1.

**Example 2–1** Calculation of the composite densities of a dry, an oil bearing, and a gas bearing formation

For both fluids charged formation use $\phi = 0.25$ and $S_w = 0.25$. Densities are $\rho_f = 165$ lb/ft$^3$, $\rho_w = 65$ lb/ft$^3$, and $\rho_o = 55$ lb/ft$^3$. For the gas use $\gamma_g = 0.67$, $T = 180^\circ F$, and $p = 3,000$ psi.

**Solution**

Using Eq. (2.4) for the oil case

$$\rho = (1 - 0.25) \times 165 + 0.25 \times (1 - 0.25) \times 55 + 0.25 \times 0.25 \times 65 = 138 \text{ lb/ft}^3.$$
If there is no oil and therefore the formation has only brine, i.e., $S_w = 1$, then the total density, $\rho = 140 \text{ lb/ft}^3$, which shows a small difference between an oil bearing and a water bearing formation.

For the gas though, using the Dranchuk (1974) correlation, the $Z$-factor is calculated as 0.871. Using Eq. (1.10) and the procedure outlined in Chapter 1, the gas density at the given conditions is 9.8 lb/ft$^3$. Eq. (2.4) gives then $\rho = 129 \text{ lb/ft}^3$, a considerable difference in the composite density and the reason why seismic measurements are so much more definitive in the identification of the presence of gas.

### 2.3 Drilling

Drilling is one of the most important and complex operations in the oil and gas industry. It involves a lot of equipment (drill bits and pipes/strings, casings), fluids (drilling fluids/muds, completion fluids, cement slurries, formation fluid), and movements (equipment movement, fluids and solids/rock cutting movement, and circulation). The drilling process can be operated in a drilling rig that contains all the necessary equipment. A typical drilling method is the well-known rotary drilling, shown in Figure 2–5, where a roller-bit is attached to a drilling pipe or string. While rotating the drill string, the drill bit breaks into the earth and reaches different depths, and eventually hits the targeted pay zone. At the same time, drilling fluid or mud is pumped down through the drilling pipe to provide hydraulic impact, control the pressure, stabilize exposed formation, prevent fluid loss, and bring the rock cuttings to the surface through the annulus formed between the drill pipe and the created hole.

During this process, different types and sizes of bits might be needed depending on the formation rock hardness and borehole size requirements (usually the bit size is smaller when the drilling depth is deeper). Similarly, mud weight has to be changed along with the drilling depth, because at different depth and geologic layers, the formation pressure and permeability are different (the higher the pressure, the heavier the mud weight).

During the drilling process, different types of casing (conductor, surface casing, intermediate casing, etc) are placed in the hole. Cement is usually placed between the outside of the casing and the borehole to provide structural integrity and isolation between different zones (an example of a gas well wellbore is shown in Figure 2–8 in the Section 2.4 “Well Completions”).
The objectives of drilling are to reach the target zone with minimum cost and time, to deliver a usable and stable borehole for further completion and production, to minimize pay zone damage and fluid invasion; and, of course, to ensure all personnel are safe, no contamination to the fresh water, and no (or minimum) damage to the environment.

### 2.3.1 Natural Gas Well Drilling

There are several unique problems that affect the drilling of natural gas wells. While this chapter and this section are not intended to provide a comprehensive description of drilling, below a number of engineering calculations and considerations dealing with the drilling of gas wells are mentioned.

In addition to the issues covered below, there are certain concerns that, while not unique to natural gas wells, may require increased attention (Prof. Ali Ghalambor, Personal Communication, 2009):
• There could be a need for higher grade casing because of the occasional need for higher burst rating in gas wells.

• When using oil based drilling fluids, gas solubility could be a problem. Oil based systems can partially mask the existence of a gas kick, thereby creating well control situations in gas wells.

• Although not exclusive to gas wells, but more likely to occur, when the reservoir fluid is associated with corrosive gases, such as H₂S and CO₂, there would be increase demands from the casing selection, using corrosion resistant alloys.

• Although all industry well control schools stress that to handle well control issues in gas wells is similar to oil wells, the wellhead equipment (blowout preventer or BOP, flanges, connections, etc.) could require higher premium products on some gas wells because of higher wellhead pressures and leak potential.

The reservoir pressure is of crucial importance to drilling and it can lead to a series of problems from lost circulation to blowouts and stuck pipes. There are some differences between oil and gas reservoirs. Oil reservoirs, as discussed in Chapter 1, are likely to be found at far shallower depths than gas reservoirs. The latter may be found beneath impermeable barriers of considerable thickness. Thus, the encountered pressure upon entering a gas reservoir may be quite large, a combination of both hydrostatic pressure and the weight of impermeable overburden. Anticipation of such large pressure is essential for both blowout prevention, and the eventuality of a “gas kick,” a sudden influx of reservoir gas into the drilling fluid column.

Pressure is measured in psi but also, in traditional drilling units, it is measured in EMW (equivalent mud weight) and the unit is lb/gal. In the oil and gas industry lb/gal is often referred to as ppg. Water density of 1 g/cc or 1,000 kg/m³ or 62.4 lb/ft³ is equal to (62.4/7.48=) 8.34 lb/gal.

The hydrostatic pressure in psi with density, \( \rho \) in lb/ft³ is given by

\[
 p = \frac{\rho H}{144},
\]

where \( H \) is the depth in ft.
If the density is 62.4 lb/ft$^3$ (water) then the hydrostatic pressure gradient is the well known 0.433 psi/ft. Similarly, the lithostatic or overburden gradient can be calculated. Using $\rho = 160$ lb/ft$^3$ (sandstone) then the gradient is 1.1 psi/ft. For many reservoir brines the pressure gradient is often equal to 0.465 psi/ft.

Predicting reservoir pressure ahead of entering a layer of interest is important. Assuming that a barrier is at a depth $H_a$ and the depth below the barrier is $H_b$ then the expected pressure upon entering the formation just below the barrier would be:

$$p = 0.465H_a + 1.1(H_b - H_a),$$

(2.6)

where 0.465 psi/ft is the reservoir fluid gradient and 1.1 psi/ft is the lithostatic or overburden gradient.

**Example 2–2 Calculation of the expected pressure at the target zone and required mud weight**

An onshore well is drilled to a depth of 25,000 ft. At 21,000 ft, there is a barrier that extends to the target. Repeat the same calculation for an offshore well with the same depth below the mudline with water depth of 5,000 ft.

**Solution**

1. Onshore: Using Eq. (2.6), the expected pressure is calculated as

$$p = 0.465 \times 21,000 + 1.1 \times (25,000 - 21,000) = 14,165 \text{ psi}.$$ 

Rearranging Eq. (2.5) at 25,000 ft depth with pressure of 14,165 psi, the fluid density is

$$\rho = \frac{144 \times 14,165}{25,000} = 81.6 \text{ lb/ft}^3.$$ 

The required mud weight is $81.6 \text{ lb/ft}^3 / 7.48 = 10.9 \text{ lb/gal}$.

2. Offshore: Using a modification of Eq. (2.6)

$$p = 0.465 \times 26,000 + 1.1 \times (30,000 - 26,000) = 16,400 \text{ psi}$$
The equivalent mud weight is 10.5 lb/gal, at a total depth of 30,000 ft.

2.3.2 Drilling Deep Wells

Drilling for gas at depths of more than 15,000 ft below the mudline, especially offshore, where total depth from the surface may exceed 30,000 ft, is likely to encounter temperatures surpassing 600°F and pressures over 40,000 psi. At those conditions, MWD/LWD (measurements while drilling and logging while drilling) tools cannot function, and thus, pressure management during the drilling operation must be made through mathematical models. These models use surface measurements and then extrapolate downhole pressures using fluid density and viscosity (Bland et al., 2005). Pressure and temperature driven compression and expansion of fluids become considerable at the ranges of conditions that are encountered. Figure 2–6 shows actual laboratory measurements of fluid density at 30,000 psi versus extrapolated density based on correlations valid up to 20,000 psi. The departure is significant. Assuming a total depth of 30,000 ft, a depth that is likely to be encountered only in modern offshore applications, the difference in density (0.09 g/cc) could result in 1,200 psi difference between the extrapolated and actual pressures exercised by the drilling fluid column at that depth.

It seems that an inflection point for base drilling fluid density happens at about 7,500 ft for commonly encountered pressures and temperatures. Measured values are shown in Figure 2–7.

2.3.3 Drilling Damage

Aqueous phase trapping is an important consideration in selecting drilling fluids, and while this is true in all wells, it is especially true for low-permeability, low-pressure gas wells. After fitting numerous experimental data, Bennion et al. (1996) presented correlations that allow for the determination of the “index of aqueous phase trap,” $I_{	ext{APT}}$, whose value denotes the potential severity of Aqueous Phase Trapping. $I_{	ext{APT}}$ is given by:

$$I_{	ext{APT}} = 0.25 \log(k_a) + 2.2S_{wi}$$

where $k_a$ is the formation absolute permeability to air and $S_{wi}$ is the initial water saturation, which in certain cases, may not be the interstitial saturation.
For $I_{APT} > 1$ aqueous phase trap is not likely to happen, for $0.8 > I_{APT} > 1$ the formation may exhibit sensitivity to phase trapping, and for $I_{APT} < 0.8$ the formation is likely to undergo significant phase trapping.
The $I_{APT}$ can be adjusted by three factors: the relative permeability adjustment ($I_{RPA}$), the invasion profile adjustment ($I_{IPA}$), and the reservoir pressure adjustment ($I_{PA}$).

Thus,

$$I_{APT} = 0.25\log(k_a) + 2.2S_{wi} - I_{RPA} - I_{IPA} + I_{PA}. \quad (2.8)$$

The three factors are given by

$$I_{RPA} = 0.26\log(x - 0.5), \quad (2.9)$$
$$I_{IPA} = 0.08\log(r_p + 0.4), \quad (2.10)$$
$$I_{PA} = 0.15\log(p) - 0.175, \quad (2.11)$$

where $x$ is the shape factor of the relative permeability curve (ranges between 1 and 8), $r_p$ is the fluid invasion in cm and $p$ is the reservoir pressure in MPa.

**Example 2–3** Determination of the index of aqueous phase trapping

Assume $k_a = 100$ md, $S_{wi} = 0.3$, $x = 2$, $r_p = 100$ cm, and $p = 30$ MPa. Repeat the calculation for $k_a = 1$ md, $r_p = 10$ cm, and $p = 15$ MPa.

**Solution**

Using Eqs. (2.9, 2.10, and 2.11) with the first set of variables, $I_{RPA} = 0.046$, $I_{IPA} = 0.16$, and $I_{PA} = 0$, respectively. Thus,

$$I_{APT} = 0.25 \times \log(100) + 2.2 \times 0.3 - 0.046 - 0.16 + 0.046 = 1,$$

which suggests no aqueous trapping.

Repeating with the second set of variables from Eqs. (2.9, 2.10, and 2.11), $I_{RPA} = 0.046$, $I_{IPA} = 0.08$, and $I_{PA} = 0.046$, respectively, and thus,

$$I_{APT} = 0.25 \log(1) + 2.2 \times 0.3 - 0.046 - 0.08 + 0 = 0.53,$$

which suggests significant aqueous trapping in this low-permeability, under-pressured formation.
2.3.4 Gas Kick

A sudden influx of reservoir fluids into the drilling fluid column, often happening in gas wells and known as a “gas kick,” is an unwanted event, and results in the increase in the annular pressure compared with the shut-in drill pipe pressure. This would require weighing the drilling mud further in order to circulate the gas kick out and also to prevent further gas influx.

The initial shut-in pressure in the drill pipe, $p_{dp,i}$, is given

$$p_{dp,i} = [(dp / dH)_r - (dp / dH)_{df}]H,$$

(2.12)

where $(dp/dH)_r$ and $(dp/dH)_{df}$ are the gradients of the reservoir and drilling fluids, respectively in psi/ft and $H$ is the vertical depth. After a kick the stabilized pressure at the annulus head will be

$$p_{dp,i} = (dp / dH)_r H - (dp / dH)_k \Delta H_k - (dp / dH)_{df}(H - \Delta H_k),$$

(2.13)

where $(dp/dH)_k$ is the gradient of the kick and $\Delta H_k$ is the kick height.

The following example shows the expected pressure increase in two reservoirs, one shallow, one deep, as a result of a gas kick. The example shows the considerable difference between shallow and deep formations and the inherent danger involved in the latter because of the subtlety of gas kick which may not be detected (Schöffmann and Economides, 1991).

**Example 2–4** Calculation of the expected increase in pressure at the top of the annulus

Two reservoirs, one shallow ($H = 5,000$ ft, $T = 150^\circ$F, $p = 2,500$ psi) and one deep ($H = 25,000$ ft, $T = 450^\circ$F, $p = 12,000$ psi) experience kicks, each of 20,000 scf of 0.6 gravity gas. The hole diameter is 9 5/8 in. and the drill pipe diameter is 5 in. The reservoir pressure and the drilling fluid gradients are 0.5 and 0.45 psi/ft, respectively.

**Solution**

Using the hole and the drill pipe diameters, the cross-sectional area of the annulus is 0.37 ft².

For the shallow well, using the physical property calculations of Chapter 1 at the given pressure and temperature, the formation volume factor, $B_g = 5.94 \times 10^{-3}$ resft³/scf and the density, $\rho = 7.68$ lb/ft³. For the deep well, the corresponding values are $B_g = 3.1 \times 10^{-3}$ resft³/scf
and the density, \( \rho = 14.74 \text{ lb/ft}^3 \). The kick gradients are the densities in \( \text{lb/ft}^3 \) divided by 144 and they would be 0.053 psi/ft and 0.102 psi/ft, respectively.

Multiplying the 20,000 scf by the respective formation volume factors, the kick volumes are 119 and 62 ft\(^3\), respectively. Dividing by the annular area of 0.37 ft\(^2\) provides the initial heights of the two kicks: 321 and 167 ft, respectively.

Using Eq. (2.12), the shut-in pressure for the shallow well is 250 psi. Using Eq. (2.13) the annulus head pressure is 378 psi, 51% larger than the static shut-in pressure.

For the deep well, the shut-in pressure is 1,250 psi but the annulus head pressure is 1,308 psi, less than 5% increase over the static pressure. Such small increase may mask a kick in deep gas wells. It is essential that, during drilling, such eventuality is anticipated and measures are taken to control it.

### 2.4 Well Completions

Once the well is drilled to the designated depth and the gas reservoir is evaluated to be economically attractive, the well is then ready to be completed. The completion is very important as it is the channel to connect the wellbore and the reservoir. It is a multi-disciplinary exercise that requires the completion, drilling, reservoir, and production engineers and rock mechanics specialists to work together to make it successful.

As discussed in the drilling section, a wellbore, shown in Figure 2–8, usually contains several casing strings: drive pipe, conductor pipe, surface casing, and production casing. Some of them contain intermediate casing and liner(s). All of these pipes are cemented in place to either protect fresh water (surface pipe), or prevent loose shale, sand, and gravel (if gravel is used in the completion) from coming into the wellbore causing near wellbore damage. Inside these casing strings, the production tubing, where the reservoir fluid will be produced from the reservoir, enter through the well completion, and get to the surface. Between the production tubing and casing, annular fluid is filled in to prevent tubing burst due to the pressure inside of the tubing. Details inside the tubing such as safety valve and nipples are not shown.

Several completion types (shown in Figure 2–9) can be chosen. A “barefoot” or open completion consists of a packer and tubing above the interval of interest. Slotted liners or gravel packed wells with screens often in association with cemented, cased, and perforated
wells is another family of completions. Finally, fully automated completions with measurement and control systems optimize well and reservoir performance and reservoir economics without human intervention (an “intelligent” completion) (Schlumberger, 2009). How to choose the proper completion type is an important question. It usually depends on the reservoir rock properties to determine if sand control is needed, well life expectancy, and the cost. One thing that has not been taken into account in gas well completion and is critical in the gas well production is turbulent flow. This will be discussed in depth in Chapter 3 when dealing with natural gas production.

Again, as with other sections of this chapter, the intention here is not to dwell on the general issues related to well completion, but to discuss some of the unique aspects or those with more serious impact for gas wells.

### 2.4.1 Liquid Loading in Gas Wells

Liquid loading in gas wells is not a new subject. It has been known for many years (Turner et al., 1969; Lea and Nickens, 2004; Gool and Currie, 2008; Solomon et al., 2008). It happens when the gas velocity
drops below a certain “gas critical velocity,” and the gas can no longer lift the liquids (hydrocarbon condensate liquid or reservoir water) up to the surface. The liquids will fall back and accumulate at the bottom of the well, reduce gas production, or even “kill” the well.

There are several models (Turner et al., 1969; Coleman et al., 1991; Nosseir et al., 1997) to calculate the gas critical velocity, $v_{gc}$ in ft/s. One of the most commonly used is Turner et al’s (1969) “droplet model”:
(2.14) where $\sigma$ is the surface tension in dynes/cm (g-cm/s$^2$) or lbm-ft/s$^2$ depending on the units of the gas and liquid densities. The assumption is the Reynolds number is in the range of $10^4$ to $2 \times 10^5$, the drag coefficient is about 0.44, and the Weber number, a dimensionless number in fluid mechanics to analyze fluid flows where there is an interface between two different fluids, is between 20–30 (Turner et al., 1969).

Once the tubing size is known, the tubing cross-sectional area, $A$, can be calculated. Further, the gas critical flow rate can be obtained as $Avg_c$ in ft$^3$/s. By using gas law, the gas critical flow rate in MMscf/d can be calculated

\[
q_{gc} = \frac{3.06 p v_{gc} A}{Z T}.
\]  

(2.15)

The constant 3.06 equals to $60 \times 60 \times 24 \times 520/(14.7 \times 10^6)$.

Eqs. (2.14 and 2.15) are valid at any given well depth but for convenience, the gas critical velocity is usually evaluated at the wellhead. It is clear that if there is no liquid in the wellbore or the gas rate is high enough to lift the liquid upwards, then liquid loading problem can be prevented or alleviated. Therefore several approaches can be used to reduce liquid loading in gas wells (Lea and Nickens, 2004):

- Prevent liquids formation in the downhole.
- Use smaller tubing.
- Lower wellhead pressure.
- Use pump or gas lift.
- Foam the liquids.

Sizing production tubing to eliminate liquid loading is not a trivial task in gas well completions. A brand new gas well with high reservoir pressure might need a big tubing to ensure maximum productivity. When the well is produced for a while and the reservoir pressure declines or the well produces a lot of liquid, a smaller diameter tubing might be better.
**Example 2–5** Determination of the gas critical velocity to prevent liquid loading

A gas well with tubing OD = 3.5 in. has tubing weight and grade of 9.3 lbm/ft and H-40, respectively. Important variables are: \( \sigma = 65 \text{ dynes/cm}, \rho_s = 62.4 \text{ lbm/ft}^3, T = 190^\circ\text{F}, \gamma_s = 0.61 \). Assume there is neither H\(_2\)S nor CO\(_2\). Determine the gas critical velocity and flow rate at flowing tubing pressures \( p_{ft} = 500, 750, 1,000, 1,250, \) and 1,500 psi, respectively.

**Solution**

Using the Schlumberger handbook, the tubing ID is obtained as 2.992 in. Then \( A = 3.14 \times (0.5 \times 2.992/12)^2 = 0.488 \text{ ft}^2 \).

The following calculation demonstration is based on \( p_{ft} = 500 \text{ psi} \).

Use correlation discussed in Chapter 1, calculate \( Z = 0.962 \). Calculate gas density, \( \rho_g \), by Eq. (1.10):

\[
\rho_g = 2.7 \frac{500 \times 0.61}{(190 + 460) \times 0.962} = 1.32 \text{ lbm/ft}^3.
\]

The gas critical gas velocity can be calculated by Eq. (2.14)

\[
v_{gc} = 17.6 \times \frac{(65/13825)^{0.25} \times (62.4 - 1.32)^{0.25}}{1.32^{0.5}} = 11.2 \text{ ft/s}.
\]

The gas critical flow rate can be calculated by Eq. (2.15)

\[
q_{gc} = \frac{3.06 \times 500 \times 11.2 \times 0.0488}{(190 + 460) \times 0.962} = 1.34 \text{ MMscf/d}.
\]

Similar calculation can be conducted at different flowing tubing pressure for the same well. The results are summarized in Table 2–1. Results show that the higher the flowing tubing pressure is, the higher the critical flow rate has to be to prevent liquid loading.

If changing the tubing to ID = 3.548 in. (OD = 4 in., weight = 9.5 lbm/ft, grade = J-55), similar calculations can be performed. The gas critical flow rates are also summarized in Table 2–1 (the last
The gas critical flow rate versus the flowing tubing pressure for both 3.5 and 4 in. tubings is plotted in Figure 2–10. Results show that, at the same flowing tubing pressure, bigger tubing requires higher gas flow rate to lift the liquid.

It is worth noting that some of the later studies (Nosseir et al., 1997, Solomon et al., 2008) have indicated the results from the Turner et al. model should be adjusted by 20% to fit field data with wellhead pressure of 800 psia or above. That means the gas critical flow rate should be 20% higher than those calculated from the Turner et al. model (see dashed lines in Figure 2–10).

Completion can be very expensive, especially offshore. Before installing smaller diameter tubing, several factors should be taken into account (Lea and Nickens, 2004):

- Is a smaller tubing indicated for the long-term or, is existing tubing adequate with simple modifications, such as plunger lift?
- After installing smaller tubing, will the flow be above critical velocity at all depths including the bottom of the tubing?

At the same time, the tubing should be extended near the perforations to eliminate casing flow.

### 2.4.2 Casinghead Pressure

Casinghead or casing pressure is another challenging issue especially in gas wells. Theoretically, the casing pressure in the annulus should

<table>
<thead>
<tr>
<th>$p_{\text{psia}}$</th>
<th>$Z$</th>
<th>$\rho_g$ lbm/ft$^3$</th>
<th>$v_{gc}$ ft/s</th>
<th>$q_{gc}(3.5\text{&quot;})$ MMscf/d</th>
<th>$q_{gc}(4.0\text{&quot;})$ MMscf/d</th>
</tr>
</thead>
<tbody>
<tr>
<td>250</td>
<td>0.98</td>
<td>0.65</td>
<td>16.1</td>
<td>0.94</td>
<td>1.32</td>
</tr>
<tr>
<td>500</td>
<td>0.962</td>
<td>1.32</td>
<td>11.2</td>
<td>1.34</td>
<td>1.88</td>
</tr>
<tr>
<td>750</td>
<td>0.945</td>
<td>2.01</td>
<td>9.06</td>
<td>1.65</td>
<td>2.32</td>
</tr>
<tr>
<td>1,000</td>
<td>0.930</td>
<td>2.72</td>
<td>7.76</td>
<td>1.92</td>
<td>2.69</td>
</tr>
<tr>
<td>1,250</td>
<td>0.917</td>
<td>3.45</td>
<td>6.87</td>
<td>2.15</td>
<td>3.02</td>
</tr>
<tr>
<td>1,500</td>
<td>0.907</td>
<td>4.19</td>
<td>6.22</td>
<td>2.36</td>
<td>3.32</td>
</tr>
</tbody>
</table>
2.4 Well Completions

be zero as the casing annulus is either cemented or filled with fluid as shown in Figure 2–8. In reality, very often the casing head pressure is not zero. The possible reasons are hole(s) in the tubing caused tubing-casing communication; packer seal leak; or poor cementing job.

The US Minerals Management Service (MMS) has strict and detailed policies regarding wells with sustained casing pressure. For instance, according to a letter by MMS (Bourgeois, 1994), for wells operated in the Gulf of Mexico (GoM) Outer Continental Shelf (OCS), all casinghead pressures, excluding drive or structural casing, need to be reported to the District Supervisor in a timely manner either in writing or by telephone. Below are the detailed requirements and are taken directly from the same source mentioned above: If the sustained casinghead pressure is less than 20% of the minimum internal yield pressure (MIYP) of the affected casing and can be bled to zero pressure through a ½-inch needle valve within 24 hours or less, the well with sustained casing pressure may continue producing hydrocarbons from the present completion, at the same time, the operators need to monitor and evaluate the well by performing the diagnostic tests required by MMS.

Here the MIYP of the casing is also called burst resistance. It is a function of the specified minimum yield strength, the outside diameter and wall thickness of the casing. It can be found from vendors’ handbooks, as shown in Table 2–2. For example, assume the production...
casing shown in Figure 2–8b has an OD of 7 in. with weight of 23 lbm/ft and grade of N-80, then from Table 2–2 the MIYP can be found as 6,340 psi, so the 20% of MIYP would be 1,268 psi.

According to the same source, if the well has casings with sustained pressure greater than 20% of the MIYP of the affected casing or pressure, and the pressure cannot be bled to zero through a ½-inch needle valve, it must be submitted to the regional MMS office for approval of continuous operations. If the request for a departure from the policy (concerning sustained casing pressure) is denied by the MMS, the operator of the well will have 30 days to respond to the MMS District Office with a plan to eliminate the sustained casinghead pressure. Based on well conditions, certain denials may specify a shorter time period for corrections. In this case, most likely a well workover or recompletion (pulling tubing, reset packer, cementing job, etc) will be needed depending on what is the root cause. It can be very costly especially when the water is deep. For unmanned platforms, a liftboat sometimes fitted with a drilling rig will be needed.

If unsustained casinghead pressure is deliberately applied, such as the result of thermal expansion, gas-lift, backup for packers, or for

### Table 2–2 API Recommended Performance Casing *(Schlumberger i-Handbook)*

<table>
<thead>
<tr>
<th>OD (in.)</th>
<th>Weight (lbm/ft)</th>
<th>Grade</th>
<th>ID (in.)</th>
<th>Collapse Resistance (psi)</th>
<th>Pipe Body Yield (lbm)</th>
<th>Pipe Body Internal Yield (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>7.000</td>
<td>23.00</td>
<td>L-80</td>
<td>6.366</td>
<td>3830</td>
<td>532000</td>
<td>6340</td>
</tr>
<tr>
<td>7.000</td>
<td>23.00</td>
<td>N-80</td>
<td>6.366</td>
<td>3830</td>
<td>532000</td>
<td>6340</td>
</tr>
<tr>
<td>7.000</td>
<td>23.00</td>
<td>C-90</td>
<td>6.366</td>
<td>4030</td>
<td>599000</td>
<td>7130</td>
</tr>
<tr>
<td>7.000</td>
<td>23.00</td>
<td>C-95</td>
<td>6.366</td>
<td>4140</td>
<td>632000</td>
<td>7530</td>
</tr>
<tr>
<td>7.000</td>
<td>23.00</td>
<td>C/T-95</td>
<td>6.366</td>
<td>4140</td>
<td>632000</td>
<td>7530</td>
</tr>
<tr>
<td>7.000</td>
<td>26.00</td>
<td>J-55</td>
<td>6.276</td>
<td>4330</td>
<td>415000</td>
<td>4980</td>
</tr>
<tr>
<td>7.000</td>
<td>26.00</td>
<td>K-55</td>
<td>6.276</td>
<td>4330</td>
<td>415000</td>
<td>4980</td>
</tr>
<tr>
<td>7.000</td>
<td>26.00</td>
<td>M-65</td>
<td>6.276</td>
<td>4810</td>
<td>492000</td>
<td>5880</td>
</tr>
<tr>
<td>7.000</td>
<td>26.00</td>
<td>L-80</td>
<td>6.276</td>
<td>5410</td>
<td>604000</td>
<td>7240</td>
</tr>
<tr>
<td>7.000</td>
<td>26.00</td>
<td>N-80</td>
<td>6.276</td>
<td>5410</td>
<td>604000</td>
<td>7240</td>
</tr>
</tbody>
</table>
reducing the pressure differential across a packoff in the tubing string, the operator does not need to submit a letter to the regional MMS office reporting the unsustained casinghead pressure. However, if the pressure due to the thermal expansion is greater than 20% of the MIYP of the affected casing, or does not bleed to zero through a ½-inch needle valve, then a report must be made.

In summary, gas well drilling and completion are very important in ensuring gas well productivity, and they are very expensive operations. Since most of the new discoveries are in deepwater offshore locations with high pressure and high temperature (HPHT), some of them with high contents of H₂S and CO₂, drilling and well completions become more challenging and costly. New wells will have higher requirements on the drilling and completion fluids, equipments, tubular metallurgy, and sand control means if the formation sand is unconsolidated. Because of environmental and regulatory concerns, we must do it right the first time.

### References


