



Calculation of Hydrocarbon-in-Place in Gas and Gas-Condensate Reservoirs—Carbon Dioxide Sequestration

By Mahendra K. Verma

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Calculation of Hydrocarbon-in-Place in Gas and Gas-Condensate Reservoirs—Carbon Dioxide Sequestration

Introduction

The Energy Independence and Security Act of 2007 (Public Law 110-140) authorized the U.S. Geological Survey (USGS) to conduct a national assessment of geologic storage resources for carbon dioxide (CO₂), requiring estimation of hydrocarbon-in-place volumes and formation volume factors for all the oil, gas, and gas-condensate reservoirs within the U.S. sedimentary basins. The procedures to calculate in-place volumes for oil and gas reservoirs have already been presented by Verma and Bird (2005) to help with the USGS assessment of the undiscovered resources in the National Petroleum Reserve, Alaska, but there is no straightforward procedure available for calculating in-place volumes for gas-condensate reservoirs for the carbon sequestration project. The objective of the present study is to propose a simple procedure for calculating the hydrocarbon-in-place volume of a condensate reservoir to help estimate the hydrocarbon pore volume for potential CO₂ sequestration.

Gas and gas-condensate reservoirs are compositionally distinguished from oil reservoirs by the predominance of lighter hydrocarbons, such as methane (60 to 95 percent) and ethane (4 to 8 percent). Craft and Hawkins (1991) identified three types of oil and gas reservoirs based on their hydrocarbon fluid composition: (1) oil (with dissolved gas), (2) gas, and (3) gas condensate (fig. 1). In addition, a two-phase region exists between the bubble point and dew point lines; that is, oil reservoirs with a gas cap. Depending on the reservoir pressure and temperature and the fluid composition, some gas reservoirs may produce only gas, whereas others produce mostly gas with some condensate. In contrast, gas-condensate reservoirs will always produce gas mixed with condensate, with the quantity of condensate varying from one reservoir to another. Gas condensate is a low-density mixture of liquid hydrocarbons that are present as gaseous components in the natural gas.

It is important to recognize that some gas-condensate reservoirs show condensate dropping out within reservoirs, as well as condensate production at the surface due to pressure falling below the dew point during production. This condensate accumulation in the reservoir initially sticks to the rock surface and remains immobile within the pores of the formation until its saturation level reaches a threshold value and becomes mobile. Therefore, from an economic standpoint, fluid trapped within the reservoir pores at low saturation levels is generally considered a loss to reservoir rock. To prevent this potential fluid loss, operators typically inject either water or gas (such as lean gas—usually a natural gas that has been stripped of its condensate) to maintain reservoir pressure above the dew point.

The reservoir management of gas-condensate reservoirs becomes challenging when the condensate begins to build up near the bottom of the wellbore, affecting well productivity due to the relative permeability effect of a two-phase flow. Harris and others (2005) have discussed production problems with two-phase flow encountered in operating some of the world's large condensate fields, for example, Arun field in North Sumatra, Indonesia, Shtokmanovskoye field in Russian Barents field, and the North field in Qatar.

Gas reservoirs lend themselves to easy calculation of the hydrocarbon-in-place through a general gas-law equation. However, calculation of hydrocarbon-in-place of a gas-condensate reservoir is more complex because of the change from a single gaseous phase in the reservoir to two phases (gas and condensate) at the surface. Oil and condensate, being similar in composition and gravity, are commonly mixed and transported through oil pipelines causing some people to believe that it is acceptable to add oil and condensate together. Although it is financially and operationally prudent to transport oil and condensate together, it poses difficulty when estimating hydrocarbon-in-place resource volume, particularly when oil, gas, and condensate are simultaneously produced at the surface. The proposed procedure would account for all the produced gas and associated condensate from a gas-condensate reservoir and help calculate hydrocarbon-in-place volume, a requirement for estimating potential CO₂ sequestration in condensate reservoirs using a volumetric approach.

Procedure

Calculation of hydrocarbon-in-place volume of a gas-condensate reservoir from the geologic, reservoir, and production data requires a clear understanding of the behavior of oil and gas under various reservoir and surface operating conditions. Because of condensate dropping out from a gas-condensate reservoir fluid due to pressure falling below the dew point, it is necessary to recombine the condensate with the gas in a proper ratio to calculate the original volume of gas-in-place in the reservoir, which would help estimate the potential CO₂ sequestration volume in a condensate reservoir.

The proposed method uses standard charts and simple equations to calculate hydrocarbon-in-place volumes in gas-condensate reservoirs. After the assessment of a basin with known geologic and reservoir data, plots of gas compressibility versus reservoir depth could be prepared for use in resource assessment of gas-condensate reservoirs with little or no data.

The proposed method would allow us to see the variability of various geologic and reservoir factors as well as their impact on related parameters, particularly in regions and basins with abnormal pressure and temperature, and therefore would be of great significance in a resource assessment using Monte-Carlo simulation for a probabilistic estimate of resource volumes.

The proposed method, based on correlations established by Rzasa and Katz (1945), provides a means to calculate the gas-in-place volume in a gas-condensate reservoir corresponding to the amount of produced gas and associated condensate. Plots of correlations based on this method are readily available for use. Data required to allow estimates of the gas-in-place volume are:

- Reservoir pressure and temperature, or depth to calculate the required parameters,
- Compositions of oil and gas or their gravities and molecular weights,
- Gravities and production rates of separator condensate and gas,
- Rock porosity,
- Gas or interstitial water saturation, and
- Area and thickness, in the absence of which calculations are based on one acre of reservoir volume.

The following steps summarize the procedure based on the Rzasa and Katz (1945) correlations as illustrated by Standing (1977).

1. Calculate average separator gas gravity, if not known, by averaging the gas gravities from various stage separators using gas flow rates from individual stage separators for weighting.
2. Calculate the produced condensate-to-gas ratio by dividing the daily condensate production (in barrels) by the total gas production (in millions of cubic feet).
3. Use the chart (fig. 2) showing the condensate-to-gas ratio on the x-axis and the well-reservoir-fluid gravity to separator-gas gravity ratio on the y-axis to determine the well-reservoir-fluid gravity, based on the known values of condensate gravity and separator-gas gravity (step 1). Mathews, Roland, and Katz (1942) worked on Oklahoma City (Wilcox) gases and found a relation (shown as reference 14 on fig. 3) that is similar to that for California gases. Standing and Katz (1942) studied high-gravity gases (shown as reference 13 on fig. 3), and their relation obviously differs from others.
4. From figure 3 showing the correlation between pseudo-critical pressure and temperature and the well-reservoir-fluid gravity, determine the two pseudo-critical parameters for a given reservoir-fluid gravity from step 3.
5. Calculate the pseudo-reduced pressure and temperature, based on known pseudo-critical pressure and temperature (step 4) and the reservoir temperature and pressure.
6. Use pseudo-reduced parameters to determine the gas compressibility factor (Z) using the compressibility factor for natural gases (fig. 4) from the study by Standing and Katz (1942).
7. Calculate the hydrocarbon volume of 1 acre-foot of reservoir using porosity and gas (or water) saturation.
8. Calculate the total number of moles in an acre-foot of reservoir rock using the general gas-law equation and the known reservoir hydrocarbon pore volume, reservoir pressure and temperature, and gas compressibility factor (Z),

$$N = PV/ZRT \quad (1)$$

where

N is pound-moles, P is pressure in psia (pounds per square inch absolute), V is volume in cubic feet, Z is compressibility factor, R is gas constant (10.73), and T is temperature in degrees Rankine (temperature in degrees Fahrenheit + 460).

9. If all the hydrocarbons are to be produced as gas at the surface, the gas volume can be calculated by multiplying the number of moles by 379 (one pound-mole of any gas occupies 379 cubic feet at the standard conditions of 14.7 psia and 60° F).
10. On the other hand, if the condensate is produced with gas at the surface, the following equations can help calculate the number of pound-moles in one barrel of condensate:

$$\text{Pound-moles in one barrel of condensate} = (5.615 \times 62.37 \times \text{condensate specific gravity}) / \text{condensate molecular weight} \quad (2)$$

In the above equation, 5.615 is the cubic feet equivalent of one barrel. The multiple of 62.37 (water density in pounds per cubic feet) and condensate specific gravity gives the density of condensate in pounds per cubic feet. Condensate specific gravity is calculated from its gravity in API (American Petroleum Institute) units by using equation 3:

$$\text{Condensate specific gravity} = 141.5 / (131.5 + \text{condensate gravity in API}) \quad (3)$$

On the right side of equation 2, the numerator is the condensate mass in pounds in one barrel of condensate, and the denominator is its molecular weight, thereby giving the number of moles.

11. Calculate the number of pound-moles in gas by dividing the gas-condensate ratio (gas volume in cubic feet per barrel of condensate) by 379.
12. Based on known moles of gas and condensate, determine the fraction of produced gas and condensate in the reservoir fluid stream.
13. To obtain produced gas volume per acre-foot of reservoir rock, first multiply the gas mole fraction (from step 12) by total number of moles (from step 8) to get the total number of gas moles in one acre-foot of rock and then multiply by 379 to determine cubic feet of gas.
14. Multiply the condensate mole fraction (from step 12) by total number of moles (from step 8) to get the number of condensate moles in 1 acre-foot of rock and then divide it by number of moles per barrel of condensate (from step 10) to obtain volume in barrels.

Example

Reservoir pressure	3,000 psia
Reservoir temperature	240°F
Porosity	30 percent
Interstitial water saturation	12 percent
Tank condensate production	400 barrels per day
Tank condensate gravity	50° API
Tank gas production	200 MCF per day
Tank gas gravity	1.25 (air = 1)
Primary trap gas production	4,000 MCF per day
Primary trap gas gravity	0.65 (air = 1)

[psia, pounds per square in absolute; MCF, thousand cubic feet; API, American Petroleum Institute]

Solution

Basis—One acre-foot of reservoir volume

Average separator gas gravity = $\{(4,000 \times 0.65) + (200 \times 1.25)\} / (4,000 + 200) = \mathbf{0.679}$

Condensate-gas ratio = $400 \times 1,000 / (4,000 + 200) = \mathbf{95.2}$ barrels per million of standard cubic feet (MMSCF)

Using the value of condensate-gas ratio of 95.2, gas gravity of 0.679, and condensate gravity of 50° API, the **ratio of reservoir fluid gravity to trap gas gravity** is **1.39** (fig. 2).

Therefore, the **reservoir fluid gravity** = $1.39 \times 0.679 = \mathbf{0.944}$.

Corresponding to gas gravity of 0.944, the **pseudo-critical temperature** is **435° R** and **pseudo-critical pressure** **647 psia** (fig. 3).

Pseudo-reduced temperature = $(460 + 240) / 435 = \mathbf{1.61}$

Pseudo-reduced pressure = $3,000 / 647 = \mathbf{4.64}$

For the above calculated pseudo-reduced parameters, **z** = **0.835** (fig. 4).

Reservoir hydrocarbon volume in acre-foot rock = $43,560 \times 0.3 \times (1 - 0.12) = \mathbf{11,500}$ cubic feet.

Using general gas equation, calculate number of moles,

N = $PV / zRT = (3,000 \times 11,500) / (0.835 \times 10.73 \times 700) = \mathbf{5,500}$ pound moles.

If all this hydrocarbon were to be produced as gas, **gas volume** would be = $5,500 \times 379 = \mathbf{2.08}$ MMCF (million cubic feet) per acre-foot of reservoir rock.

If the reservoir is producing both gas and condensate, we need to find their relative mole fractions.

Basis for calculating moles: **One barrel of condensate**

The 50° API condensate has a molecular weight of 129 (fig. 2) and a specific gravity of 0.78, using the following equation:

Condensate specific gravity = $141.5 / (131.5 + \text{condensate gravity in API})$

Condensate moles = $(5.615 \times 62.37 \times 0.78) / 129 = 273.16 / 129 = \mathbf{2.1 \text{ per barrel}}$

Gas-condensate ratio = $(4,000 + 200) / 400 = \mathbf{10,500}$ cubic feet per barrel of condensate

Gas mole per barrel of condensate = $10,500 / 379 = 27.7$

Gas mole fraction = $27.7 / (27.7 + 2.1) = \mathbf{0.93}$

And so, **gas-in-place** = $0.93 \times 5,500 \times 379 = 1.9 \text{ MMCF per acre-foot of rock}$

Condensate mole fraction = $2.1 / (27.7 + 2.1) = \mathbf{0.07}$

And so, **condensate-in-place** = $0.07 \times 5,500 / 2.1 = \mathbf{183}$ barrels per acre-foot of rock

Reservoir gas-in-place = 2.08 MMCF per acre of rock volume

Some of the parameters (for example the molecular weight) in the above procedure can be calculated from various available equations. One such equation is by Cragoe (1929):

$$\text{Condensate molecular weight} = 6084 / (\text{API} - 5.9) \quad (4)$$

There is another equation given in Terry's (1991) revision of Craft and Hawkins (1991):

$$\text{Condensate molecular weight} = 5954 / (\text{API} - 8.811) \quad (5)$$

Therefore, for a 50° API gravity condensate, the molecular weight would be 129 from figure 2, 138 from equation 4, and 145 from equation 5.

Similarly, there is correlation between gravity and critical pressure and temperature, through which several researchers have tried to fit the curves and have established equations, but the results vary from one correlation to another.

The correlation between the pseudo-reduced pressure and temperature and compressibility factor (Z) is rather complex. The Standing and Katz (1942) chart, which is valid for sweet and dry natural gas, is widely used in the industry because it gives reliable results as long as the percentage of nonhydrocarbon or high-molecular-weight hydrocarbon is low. However, when the percentage of heptane plus (C_7^+) increases, the error increases and dictates the need to use other methods for better results. Of the six methods studied, Elsharkawy and others (2001) found the following three methods give better results: (1) Dranchuk-Abou-Kassem equation, (2) Dranchuk-Purvis-Robinson method, and (3) Hall-Yarborough method. These methods use iterative solution to calculate the compressibility factor. As an example of these kinds of equations, appendix A presents Dranchuk-Abou-Kassem equations for calculating the values of the gas-compressibility factor (Z).

Based on the above brief discussion, it would be reasonable to use the Standing and Katz (1942) method for compressibility factor (Z) unless a specific reservoir has abnormal fluid composition, pressure, or temperature. It is also important to keep in mind that these equations would require good data from at least 5–6 reservoirs for validation prior to their use, and the limited or lack of data would be a major constraint.

Application and Use

The proposed procedure to calculate the volume of reservoir pore space available in gas and gas-condensate reservoirs will be useful for all the reservoirs, as long as the reservoir data (initial reservoir pressure, temperature, porosity and connate water saturation), reservoir fluid characteristics, production data, and separator pressure and temperature information are available. These gas-condensate reservoirs have storage potential for carbon dioxide sequestration.

Depleted oil and gas reservoirs are also resources having potential for carbon dioxide storage.

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Appendix A

Engineering Approach

Dranchuk and Abu-Kassem (1975) fitted an equation of state to the data of Standing and Katz (1942) in order to estimate the gas deviation factor in computer routines. The form of their equation of state is as follows:

$$Z = 1 + c_1(T_{pr})\rho_r + c_2(T_{pr})\rho_r^2 - c_3(T_{pr})\rho_r^5 + c_4(\rho_r, T_{pr}) \quad (1)$$

where

T_{pr} is pseudo-reduced temperature; p_{pr} pseudo-reduced pressure and other terms are calculated using equations 2 through 6 given below.

$$\rho_r = 0.27 p_{pr}/(z T_{pr}) \quad (2)$$

$$c_1(T_{pr}) = A_1 + A_2/T_{pr} + A_3/T_{pr}^3 + A_4/T_{pr}^4 + A_5/T_{pr}^5 \quad (3)$$

$$c_2(T_{pr}) = A_6 + A_7/T_{pr} + A_8/T_{pr}^2 \quad (4)$$

$$c_3(T_{pr}) = A_9 (A_7/T_{pr} + A_8/T_{pr}^2) \quad (5)$$

$$c_4(T_{pr}) = A_{10} (1 + A_{11} \rho_r^2)(\rho_r^2/T_{pr}^3) \exp(-A_{11} \rho_r^2) \quad (6)$$

where A_1 – A_{11} are as follows:

$A_1 = 0.3265$	$A_2 = -1.0700$	$A_3 = -0.5339$
$A_4 = 0.01569$	$A_5 = -0.05165$	$A_6 = 0.5475$
$A_7 = -0.7361$	$A_8 = 0.1844$	$A_9 = 0.1056$
$A_{10} = 0.6134$	$A_{11} = 0.7210$	

Because the Z (compressibility factor) is on both sides of the equation, trial-and-error solution is necessary to solve the above equation of state. Any one of the iteration techniques can be used with the trial-and-error procedure. One that is frequently used is the secant method, which has the following iteration formula:

$$x_{n+1} = x_n - f_n [(x_n - x_{n+1})/(f_n - f_{n-1})] \quad (7)$$

To apply the secant method to the foregoing procedure, equation 1 is rearranged to the form

$$F(Z) = Z - (1 + c_1(T_{pr})\rho_r + c_2(T_{pr})\rho_r^2 - c_3(T_{pr})\rho_r^5 + c_4(\rho_r, T_{pr})) = 0 \quad (8)$$

The left-hand side of equation 8 becomes the function f , and the Z (compressibility factor) becomes x . The iteration procedure is initiated by choosing two values of the Z and calculating the corresponding values of the function f . The secant method provides the new guess for Z , and the calculation is repeated until the function f is zero or within a specified tolerance (that is, $\pm 10^{-4}$).

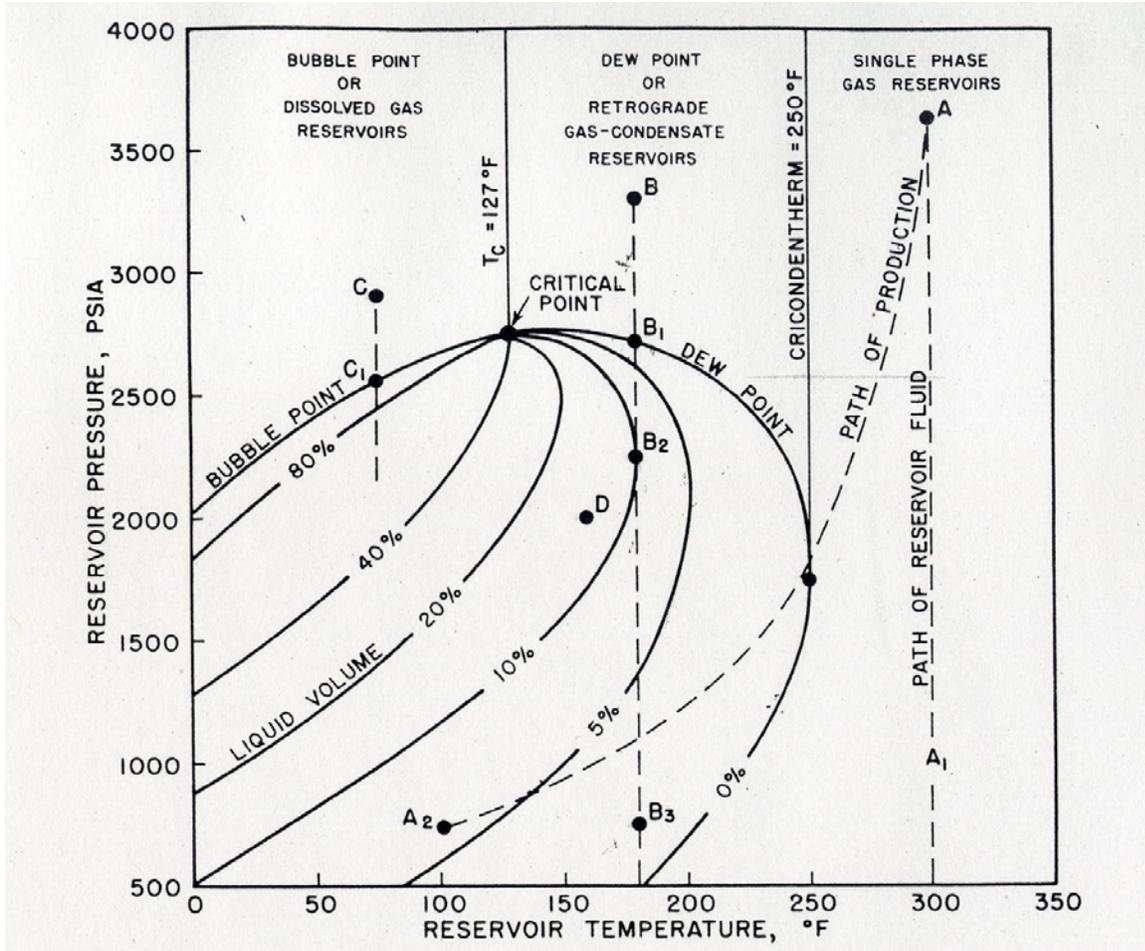


Figure 1. Pressure-temperature phase diagram of a reservoir fluid highlighting the three types of reservoirs—oil (dissolved gas) reservoirs, retrograde condensate reservoirs, and gas reservoirs. The region between bubble point and dew point lines represents the reservoirs with two phases—oil and gas. Taken from Craft and Hawkins (1991).

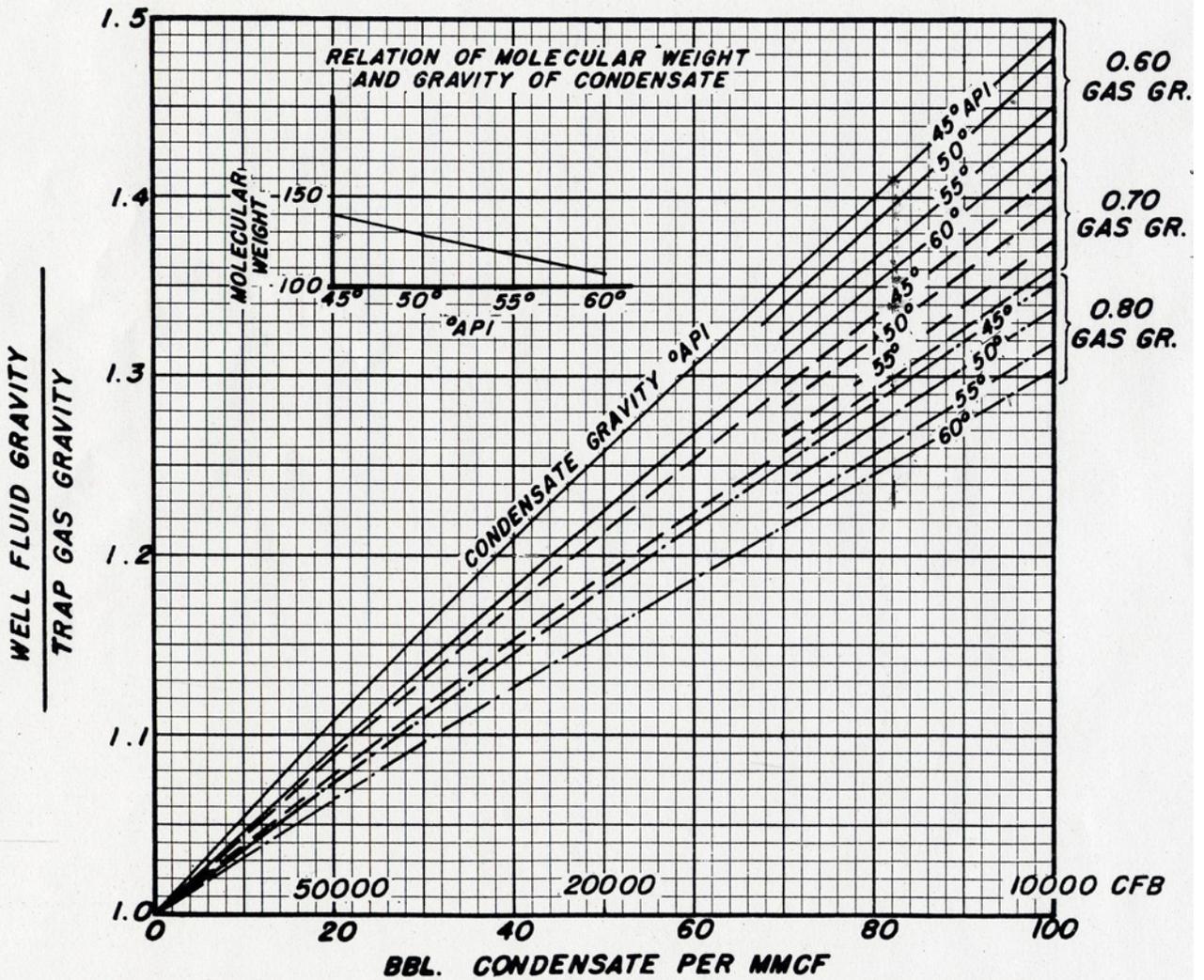


Figure 2. Plot showing correlation between the condensate-gas ratio (BBL per MMSCF) and the ratio of well-reservoir-fluid gravity to separator-gas gravity for various combinations of condensate and gas gravities. An insert graph of condensate (oil) gravity ($^{\circ}$ API) versus molecular weight is also shown. Taken from Rzasa and Katz (1945). BBL, barrels; MMSCF, million standard cubic feet; GR, gravity; CFB, cubic feet per barrel.

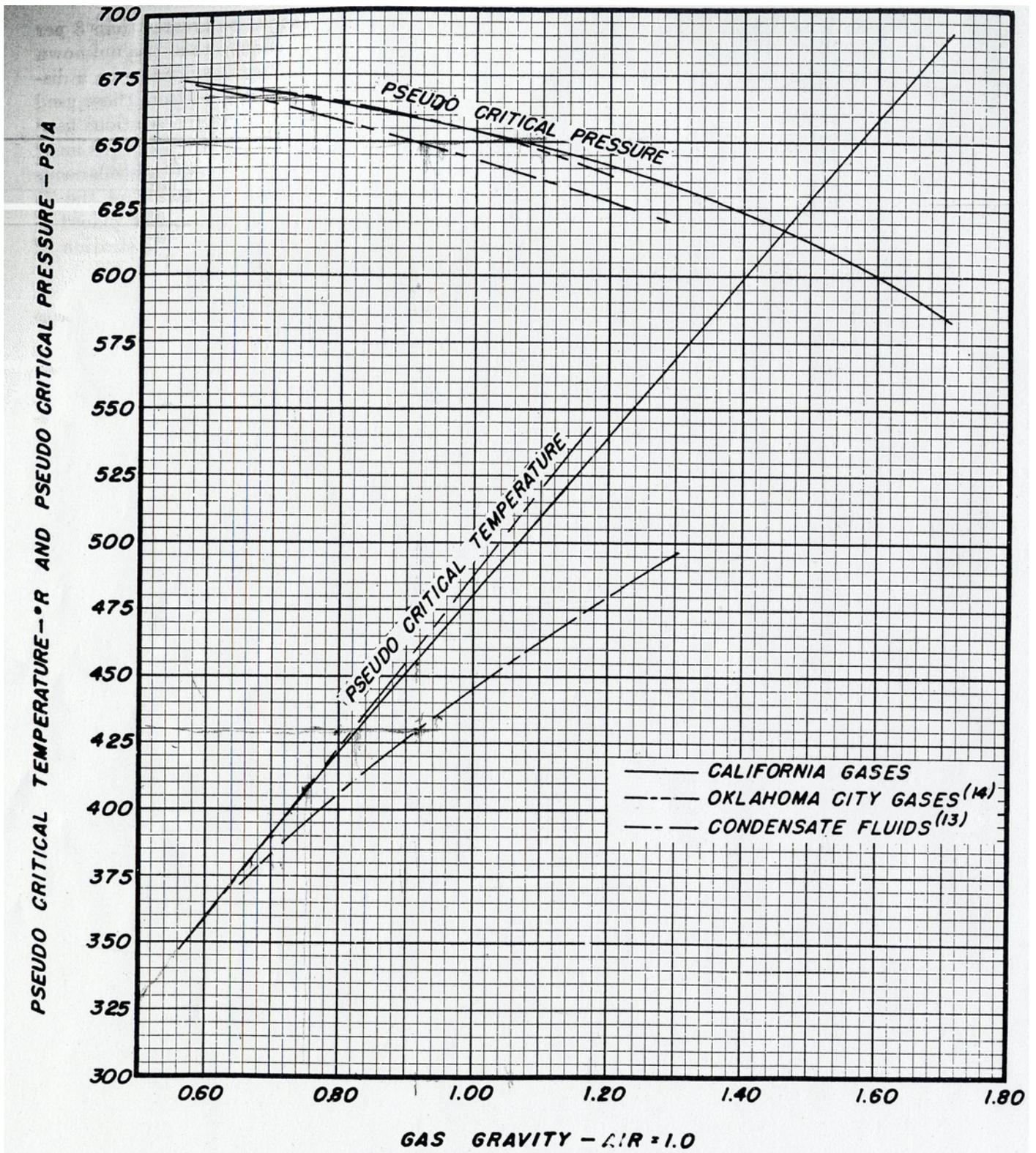


Figure 3. Plots showing pseudo-critical constants of gases (California and Oklahoma) and condensate fluids as a function of gas gravity. Taken from Standing (1977).

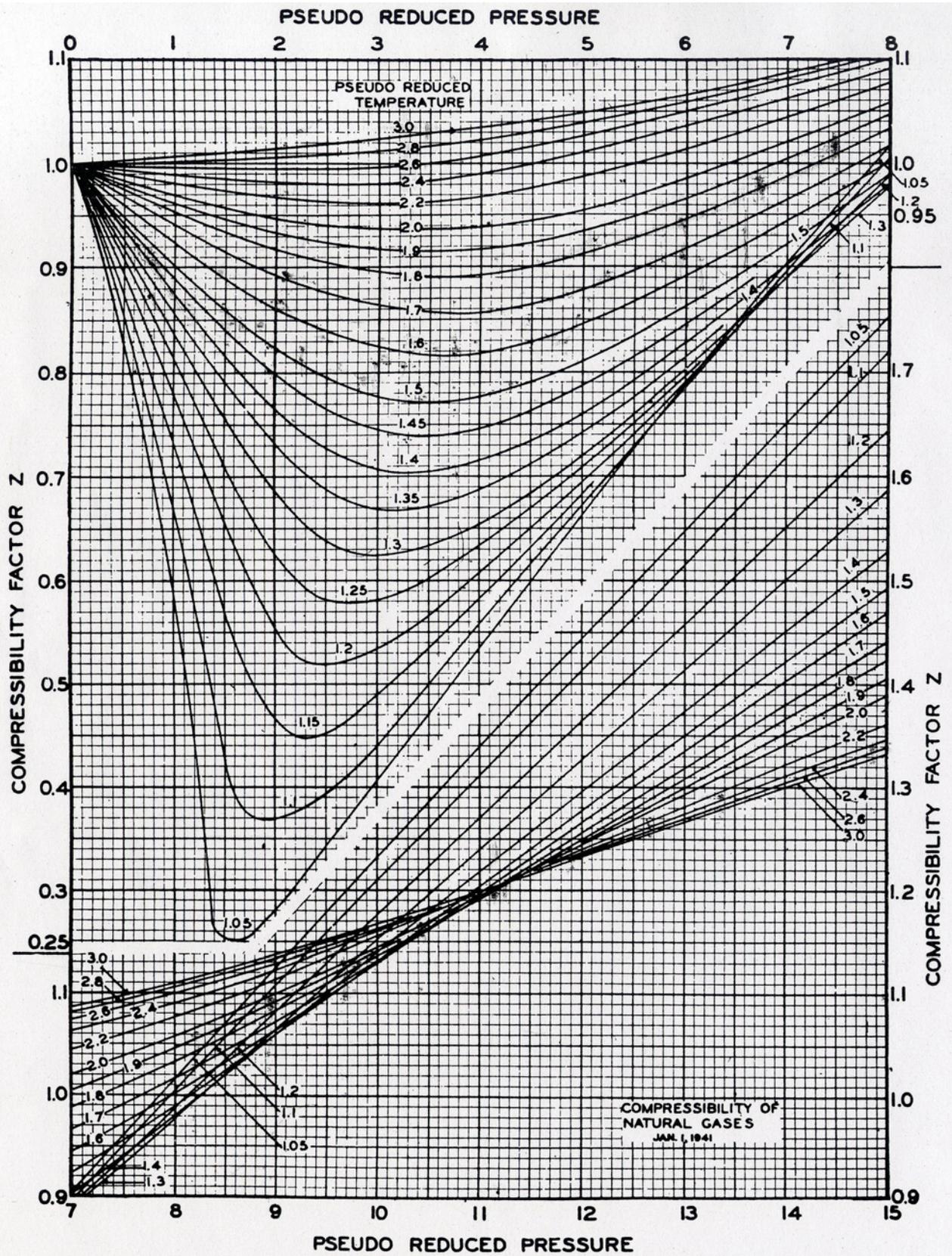


Figure 4. Compressibility factors (Z) for natural gases. Taken from Standing and Katz (1942).