are generally quantified in terms of IFT, σ; units of σ are dynes/cm (or equivalently, mN/m). The magnitude of IFT varies from ≈ 50 dynes/cm for crude-oil/gas systems at standard conditions to <0.1 dyne/cm for high-pressure gas/oil mixtures. Gas/oil capillary pressure, P_c, is usually considered proportional to IFT according to the Young-Laplace equation $P_c = 2\sigma/r$, where $\bar{r}$ is an average pore radius.[13-15] Recovery mechanisms that are influenced by capillary pressure (e.g., gas injection in naturally fractured reservoirs) will necessarily be sensitive to IFT.

3.3 Gas Mixtures

This section gives correlations for PVT properties of natural gases, including the following.

1. Review of gas volumetric properties.
2. Z-factor correlations.
3. Gas pseudocritical properties.
4. Wellstream gravity of wet gases and gas condensates.
5. Gas viscosity.
6. Dewpoint pressure.
7. Total volume factor.

3.3.1 Review of Gas Volumetric Properties. The properties of gas mixtures are well understood and have been accurately correlated for many years with graphical charts and EOS's based on extensive experimental data.[16-19] The behavior of gases at low pressures was originally quantified on the basis of experimental work by Charles and Boyle, which resulted in the ideal-gas law,[3]

$$pV = nRT, \quad \text{(3.22)}$$

where R is the universal gas constant given in Appendix A for various units (Table A-2). In customary units,

$$R = 10.73146 \frac{\text{psia} \times \text{ft}^3}{{}^\circ\text{R} \times \text{lbm mol}}, \quad \text{(3.23)}$$

while for other units, R can be calculated from the relation

$$R = 10.73146 \left(\frac{p_{\text{unit}}}{\text{psia}}\right)\left(\frac{{}^\circ\text{R}}{T_{\text{unit}}}\right)\left(\frac{V_{\text{unit}}}{\text{ft}^3}\right)\left(\frac{\text{lbm}}{m_{\text{unit}}}\right). \quad \text{(3.24)}$$

For example, the gas constant for SPE-preferred SI units is given by

$$\begin{aligned} R &= 10.73146 \times \left(6.894757 \frac{\text{kPa}}{\text{psia}}\right) \times \left(1.8 \frac{{}^\circ\text{R}}{\text{K}}\right) \\ &\times \left(0.02831685 \frac{\text{m}^3}{\text{ft}^3}\right) \times \left(2.204623 \frac{\text{lbm}}{\text{kg}}\right) \\ &= 8.3143 \frac{\text{kPa} \cdot \text{m}^3}{\text{K} \cdot \text{kmol}}. \end{aligned} \quad \text{(3.25)}$$

The gas constant can also be expressed in terms of energy units (e.g., $R = 8.3143$ J/mol·K); note that $\text{J} = \text{N} \cdot \text{m} = (\text{N/m}^2)\text{m}^3 = \text{Pa} \cdot \text{m}^3$. In this case, the conversion from one unit system to another is given by

$$R = 8.3143 \left(\frac{E_{\text{unit}}}{\text{J}}\right)\left(\frac{\text{K}}{T_{\text{unit}}}\right)\left(\frac{\text{g}}{m_{\text{unit}}}\right). \quad \text{(3.26)}$$

An ideal gas is a hypothetical mixture with molecules that are negligible in size and have no intermolecular forces. Real gases mimic the behavior of an ideal gas at low pressures and high temperatures because the mixture volume is much larger than the volume of the molecules making up the mixture. That is, the mean free path between molecules that are moving randomly within the total volume is very large and intermolecular forces are thus very small.

Most gases at low pressure follow the ideal-gas law. Application of the ideal-gas law results in two useful engineering approximations. First, the standard molar volume representing the volume occupied by one mole of gas at standard conditions is independent of the gas composition.

$$\begin{aligned} (v_g)_{sc} &= v_{\bar{g}} = \frac{(V_g)_{sc}}{n} = \frac{RT_{sc}}{p_{sc}} \\ &= \frac{10.73146(60 + 459.67)}{14.7} \\ &= 379.4 \text{ scf/lbm mol} \\ &= 23.69 \text{ std m}^3\text{/kmol}. \end{aligned} \quad \text{(3.27)}$$

Second, the specific gravity of a gas directly reflects the gas molecular weight at standard conditions,

$$\gamma_g = \frac{(\rho_g)_{sc}}{(\rho_{\text{air}})_{sc}} = \frac{M_g}{M_{\text{air}}} = \frac{M_g}{28.97}$$

$$\text{and } M_g = 28.97\gamma_g. \quad \text{(3.28)}$$

For gas mixtures at moderate to high pressure or at low temperature the ideal-gas law does not hold because the volume of the constituent molecules and their intermolecular forces strongly affect the volumetric behavior of the gas. Comparison of experimental data for real gases with the behavior predicted by the ideal-gas law shows significant deviations. The deviation from ideal behavior can be expressed as a factor, Z, defined as the ratio of the actual volume of one mole of a real-gas mixture to the volume of one mole of an ideal gas,

$$Z = \frac{\text{volume of 1 mole of real gas at } p \text{ and } T}{\text{volume of 1 mole of ideal gas at } p \text{ and } T}, \quad \text{(3.29)}$$

where Z is a dimensionless quantity. Terms used for Z include deviation factor, compressibility factor, and Z factor. Z factor is used in this monograph, as will the SPE reserve symbol Z (instead of the recommended SPE symbol z) to avoid confusion with the symbol z used for feed composition.

From Eqs. 3.22 and 3.29, we can write the real-gas law including the Z factor as

$$pV = nZRT, \quad \text{(3.30)}$$

which is the standard equation for describing the volumetric behavior of reservoir gases. Another form of the real-gas law written in terms of specific volume ($\hat{v} = 1/\rho$) is

$$p\hat{v} = ZRT/M \quad \text{(3.31)}$$

or, in terms of molar volume ($v = M/\rho$),

$$pv = ZRT. \quad \text{(3.32)}$$

Z factor, defined by Eq. 3.30,

$$Z = pV/nRT, \quad \text{(3.33)}$$

is used for both phases in EOS applications (see Chap. 4). In this monograph we use both Z and Z_g for gases and Z_o for oils; Z without a subscript always implies the Z factor of a "gas-like" phase.

All volumetric properties of gases can be derived from the real-gas law. Gas density is given by

$$\rho_g = pM_g/ZRT \quad \text{(3.34)}$$

or, in terms of gas specific gravity, by

$$\rho_g = 28.97 \frac{p\gamma_g}{ZRT}. \quad \text{(3.35)}$$

For wet-gas and gas-condensate mixtures, wellstream gravity, γ_w, must be used instead of γ_g in Eq. 3.35.[3] Gas density may range from 0.05 lbm/ft^3 at standard conditions to 30 lbm/ft^3 for high-pressure gases.

Gas molar volume, v_g, is given by

$$v_g = ZRT/p, \quad \text{(3.36)}$$

where typical values of v_g at reservoir conditions range from 1 to 1.5 ft^3/lbm mol compared with 379 ft^3/lbm mol for gases at standard conditions. In Eqs. 3.30 through 3.36, R = universal gas constant.

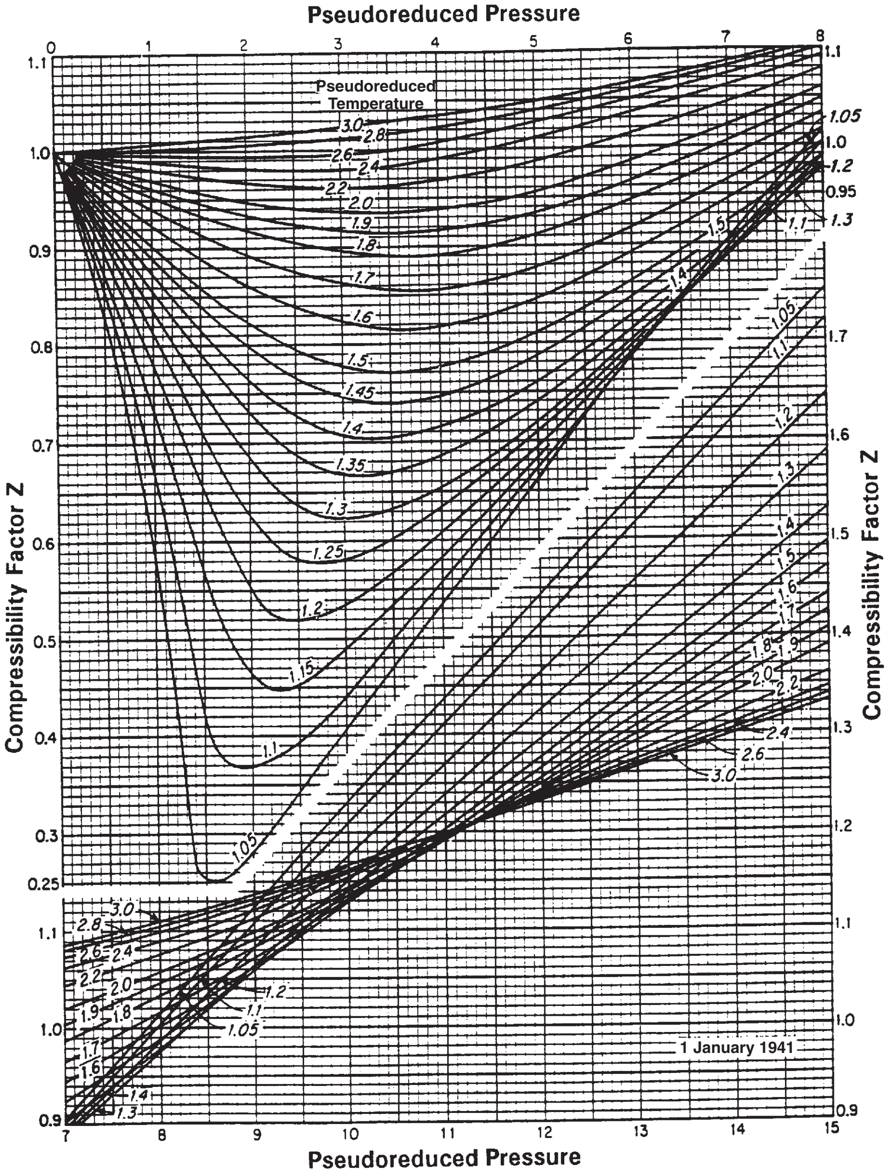

Fig. 3.6—Standing-Katz[4] *Z*-factor chart.

Gas compressibility, c_g, is given by

$$c_g = -\frac{1}{V_g}\left(\frac{\partial V_g}{\partial p}\right)$$

$$= \frac{1}{p} - \frac{1}{Z}\left(\frac{\partial Z}{\partial p}\right)_T \quad \text{. . . . .} \quad (3.37)$$

For sweet natural gas (i.e., not containing H_2S) at pressures less than $\approx 1{,}000$ psia, the second term in Eq. 3.37 is negligible and $c_g = 1/p$ is a reasonable approximation.

Gas volume factor, B_g, is defined as the ratio of gas volume at specified p and T to the ideal-gas volume at standard conditions,

$$B_g = \left(\frac{p_{sc}}{T_{sc}}\right)\frac{ZT}{p}. \quad \text{. . . . .} \quad (3.38)$$

For customary units ($p_{sc} = 14.7$ psia and $T_{sc} = 520$°R), this is

$$B_g = 0.02827 \; \frac{ZT}{p}, \quad \text{. . . . .} \quad (3.39)$$

with temperature in °R and pressure in psia. This definition of B_g assumes that the gas volume at p and T remains as a gas at standard conditions. For wet gases and gas condensates, the surface gas will not contain all the original gas mixture because liquid is produced after separation. For these mixtures, the traditional definition of B_g may still be useful; however, we refer to this quantity as a hypothetical wet-gas volume factor, B_{gw}, which is calculated from Eq. 3.38.

Because B_g is inversely proportional to pressure, the inverse volume factor, $b_g = 1/B_g$, is commonly used. For field units,

$$b_g \text{ in scf/ft}^3 = 35.37 \; \frac{p}{ZT} \quad \text{. . . . .} \quad (3.40a)$$

$$\text{and } b_g \text{ in Mscf/bbl} = 0.1985 \; \frac{p}{ZT}. \quad \text{. . . . .} \quad (3.40b)$$

If the reservoir gas yields condensate at the surface, the dry-gas volume factor, B_{gd}, is sometimes used.[20]

$$B_{gd} = \left(\frac{p_{sc}}{T_{sc}}\right)\left(\frac{ZT}{p}\right)\left(\frac{1}{F_{\bar{g}g}}\right), \quad \text{. . . . .} \quad (3.41)$$

where $F_{\bar{g}g}$ = ratio of moles of surface gas, $n_{\bar{g}}$, to moles of wellstream mixture (i.e., reservoir gas, n_g); see Eqs. 7.10 and 7.11 of Chap. 7.

3.3.2 *Z*-Factor Correlations. Standing and Katz[4] present a generalized *Z*-factor chart (**Fig. 3.6**), which has become an industry standard for predicting the volumetric behavior of natural gases. Many empirical equations and EOS's have been fit to the original Standing-Katz chart. For example, Hall and Yarborough[21,22] present an accurate representation of the Standing-Katz chart using a Carnahan-Starling hard-sphere EOS,

$$Z = \alpha p_{pr}/y, \quad \text{(3.42)}$$

where $\alpha = 0.06125t \exp[-1.2(1-t)^2]$, where $t = 1/T_{pr}$.

The reduced-density parameter, y (the product of a van der Waals covolume and density), is obtained by solving

$$\begin{aligned} f(y) = 0 = & -\alpha p_{pr} + \frac{y + y^2 + y^3 - y^4}{(1-y)^3} \\ & - (14.76t - 9.76t^2 + 4.58t^3)y^2 \\ & + (90.7t - 242.2t^2 + 42.4t^3)y^{2.18+2.82t}, \quad \text{(3.43)} \end{aligned}$$

$$\begin{aligned} \text{with } \frac{df(y)}{dy} = & \frac{1 + 4y + 4y^2 - 4y^3 + y^4}{(1-y)^4} \\ & - (29.52t - 19.52t^2 + 9.16t^3)y \\ & + (2.18 + 2.82t)(90.7t - 242.2t^2 + 42.4t^3) \\ & \times y^{1.18+2.82t}. \quad \text{(3.44)} \end{aligned}$$

The derivative $\partial Z/\partial p$ used in the definition of c_g is given by

$$\left(\frac{\partial Z}{\partial p}\right)_T = \frac{\alpha}{p_{pc}}\left[\frac{1}{y} - \frac{\alpha p_{pr}/y^2}{df(y)/dy}\right]. \quad \text{(3.45)}$$

An initial value of $y = 0.001$ can be used with a Newton-Raphson procedure, where convergence should be obtained in 3 to 10 iterations for $|f(y)| = 1 \times 10^{-8}$.

On the basis of Takacs'[23] comparison of eight correlations representing the Standing-Katz[4] chart, the Hall and Yarborough[21] and the Dranchuk and Abou-Kassem[24] equations give the most accurate representation for a broad range of temperatures and pressures. Both equations are valid for $1 \leqq T_r \leqq 3$ and $0.2 \leqq p_r \leqq 25$ to 30.

For many petroleum engineering applications, the Brill and Beggs[25] equation gives a satisfactory representation (± 1 to 2%) of the original Standing-Katz Z-factor chart for $1.2 < T_r < 2$. Also, this equation can be solved explicitly for Z. The main limitations are that reduced temperature must be >1.2 ($\approx$80°F) and <2.0 ($\approx$340°F) and reduced pressure should be <15 ($\approx$10,000 psia).

The Standing and Katz Z-factor correlation may require special treatment for wet gas and gas-condensate fluids containing significant amounts of heptanes-plus material and for gas mixtures with significant amounts of nonhydrocarbons. An apparent discrepancy in the Standing-Katz Z-factor chart for $1.05 < T_r < 1.15$ has been "smoothed" in the Hall-Yarborough[21] correlations. The Hall and Yarborough (or Dranchuk and Abou-Kassem[24]) equation is recommended for most natural gases. With today's computing capabilities, choosing simple, less-reliable equations, such as the Brill and Beggs[25] equation, is normally unnecessary.

The Lee-Kesler,[26,27] AGA-8,[28] and DDMIX[29] correlations for Z factor were developed with multiconstant EOS's to give accurate volumetric predictions for both pure components and mixtures. They require more computation but are very accurate. These equations are particularly useful in custody-transfer calculations. They also are required for gases containing water and concentrations of nonhydrocarbons that exceed the limits of the Wichert and Aziz method.[30,31]

3.3.3 Gas Pseudocritical Properties. Z factor, viscosity, and other gas properties have been correlated accurately with corresponding-states principles, where the property is correlated as a function of reduced pressure and temperature.

$$Z = f(p_r, T_r)$$

$$\text{and } \mu_g/\mu_{gsc} = f(p_r, T_r), \quad \text{(3.46)}$$

where $p_r = p/p_c$ and $T_r = T/T_c$. Such corresponding-states relations should be valid for most pure compounds when component critical properties p_c and T_c are used. The same relations can be used for gas mixtures if the mixture pseudocritical properties p_{pc} and T_{pc} are used. Pseudocritical properties of gases can be estimated with gas composition and mixing rules or from correlations based on gas specific gravity.

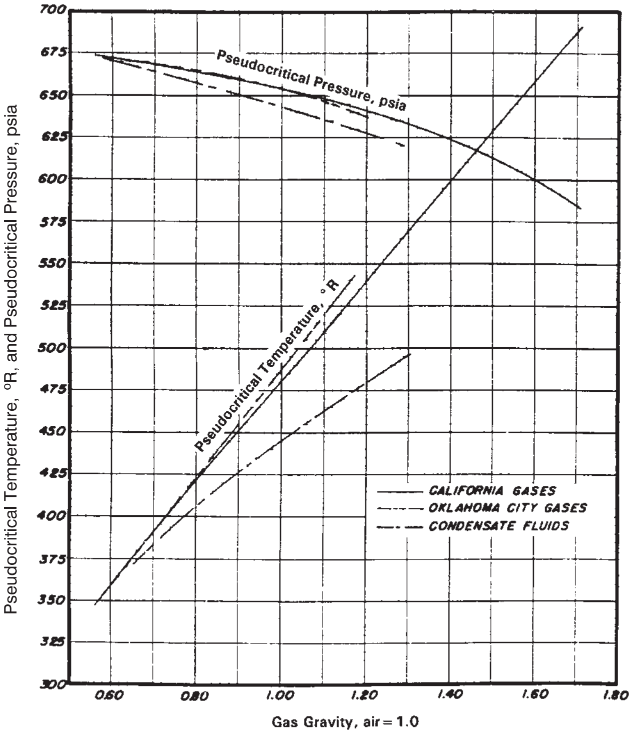

Fig. 3.7—Gas pseudocritical properties as functions of specific gravity.

Sutton[7] suggests the following correlations for hydrocarbon gas mixtures.

$$T_{pc\text{HC}} = 169.2 + 349.5\gamma_{g\text{HC}} - 74.0\gamma_{g\text{HC}}^2 \quad \text{(3.47a)}$$

$$\text{and } p_{pc\text{HC}} = 756.8 - 131\gamma_{g\text{HC}} - 3.6\gamma_{g\text{HC}}^2. \quad \text{(3.47b)}$$

He claims that Eqs. 3.47a and 3.47b are the most reliable correlations for calculating pseudocritical properties with the Standing-Katz Z-factor chart. He even claims that this method is superior to the use of composition and mixing rules.

Standing[3] gives two sets of correlations: one for dry hydrocarbon gases ($\gamma_{g\text{HC}} < 0.75$),

$$T_{pc\text{HC}} = 168 + 325\gamma_{g\text{HC}} - 12.5\gamma_{g\text{HC}}^2 \quad \text{(3.48a)}$$

$$\text{and } p_{pc\text{HC}} = 667 + 15.0\gamma_{g\text{HC}} - 37.5\gamma_{g\text{HC}}^2, \quad \text{(3.48b)}$$

and one for wet-gas mixtures ($\gamma_{g\text{HC}} \geqq 0.75$),

$$T_{pc\text{HC}} = 187 + 330\gamma_{g\text{HC}} - 71.5\gamma_{g\text{HC}}^2 \quad \text{(3.49a)}$$

$$\text{and } p_{pc\text{HC}} = 706 - 51.7\gamma_{g\text{HC}} - 11.1\gamma_{g\text{HC}}^2. \quad \text{(3.49b)}$$

The Standing correlations are used extensively in the industry; **Fig. 3.7** compares them with the Sutton correlations. The Sutton and the Standing wet-gas correlations for T_{pc} give basically the same results, whereas the three p_{pc} correlations are quite different at $\gamma_g > 0.85$.

Kay's[5] mixing rule is typically used when gas composition is available.

$$M = \sum_{i=1}^{N} y_i M_i, \quad \text{(3.50a)}$$

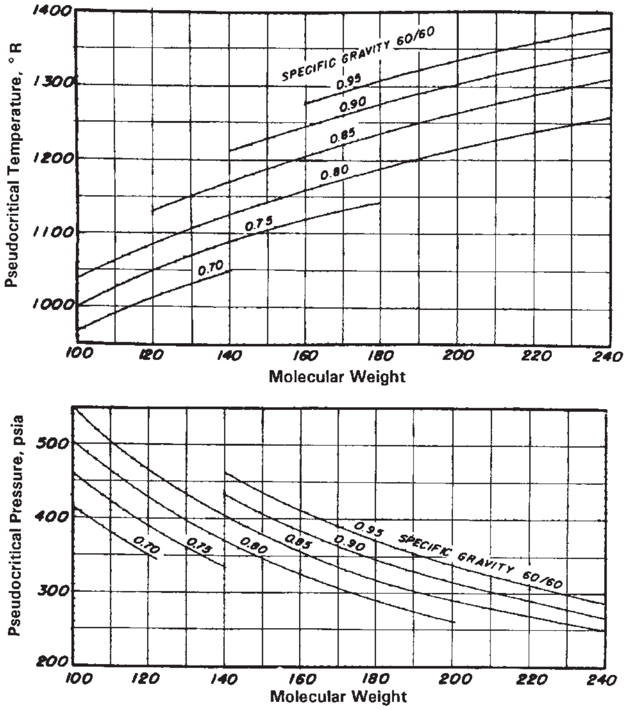

Fig. 3.8—Heptanes-plus (pseudo)critical properties recommended for reservoir gases (from Standing,[33] after Matthews *et al.*[32]).

$$T_{pc} = \sum_{i=1}^{N} y_i T_{ci}, \quad \ldots\ldots (3.50b)$$

$$\text{and } p_{pc} = \sum_{i=1}^{N} y_i p_{ci}, \quad \ldots\ldots (3.50c)$$

where the pseudocritical properties of the C_{7+} fraction can be estimated from the Matthews *et al.*[32] correlations (**Fig. 3.8**),[3]

$$T_{cC_{7+}} = 608 + 364 \log\left(M_{C_{7+}} - 71.2\right) + \left(2{,}450 \log M_{C_{7+}} - 3{,}800\right) \log \gamma_{C_{7+}} \quad \ldots\ldots (3.51a)$$

$$\text{and } p_{cC_{7+}} = 1{,}188 - 431 \log\left(M_{C_{7+}} - 61.1\right) + \left[2{,}319 - 852 \log\left(M_{C_{7+}} - 53.7\right)\right]\left(\gamma_{C_{7+}} - 0.8\right). \quad \ldots\ldots (3.51b)$$

Kay's mixing rule is usually adequate for lean natural gases that contain no nonhydrocarbons. Sutton suggests that pseudocriticals calculated with Kay's mixing rule are adequate up to $\gamma_g \approx 0.85$, but that errors in calculated Z factors increase linearly at higher specific gravities, reaching 10 to 15% for $\gamma_g > 1.5$. This bias may be a result of the C_{7+} critical-property correlations used by Sutton (not Eqs. 3.51a and 3.51b).

When significant quantities of CO_2 and H_2S nonhydrocarbons are present, Wichert and Aziz[33,31] suggest corrections to arrive at pseudocritical properties that will yield reliable Z factors from the Standing-Katz chart. The Wichert and Aziz corrections are given by

$$T_{pc} = T^*_{pc} - \epsilon, \quad \ldots\ldots (3.52a)$$

$$p_{pc} = \frac{p^*_{pc}\left(T^*_{pc} - \epsilon\right)}{T^*_{pc} + y_{H_2S}\left(1 - y_{H_2S}\right)\epsilon}, \quad \ldots\ldots (3.52b)$$

$$\text{and } \epsilon = 120\left[\left(y_{CO_2} + y_{H_2S}\right)^{0.9} - \left(y_{CO_2} + y_{H_2S}\right)^{1.6}\right] + 15\left(y^{0.5}_{H_2S} - y^{4}_{H_2S}\right), \quad \ldots\ldots (3.52c)$$

where T^*_{pc} and p^*_{pc} are mixture pseudocriticals based on Kay's mixing rule. This method was developed from extensive data from natural gases containing nonhydrocarbons, with CO_2 molar concentration ranging from 0 to 55% and H_2S molar concentrations ranging from 0 to 74%.

If only gas gravity and nonhydrocarbon content are known, the hydrocarbon specific gravity is first calculated from

$$\gamma_{gHC} = \frac{\gamma_g - \left(y_{N_2}M_{N_2} + y_{CO_2}M_{CO_2} + y_{H_2S}M_{H_2S}\right)/M_{air}}{1 - y_{N_2} - y_{CO_2} - y_{H_2S}}. \quad \ldots\ldots (3.53)$$

Hydrocarbon pseudocriticals are then calculated from Eqs. 3.47a and 3.47b, and these values are adjusted for nonhydrocarbon content on the basis of Kay's[5] mixing rule.

$$p^*_{pc} = \left(1 - y_{N_2} - y_{CO_2} - y_{H_2S}\right)p_{pcHC} + y_{N_2}p_{cN_2} + y_{CO_2}p_{cCO_2} + y_{H_2S}p_{cH_2S} \quad \ldots\ldots (3.54a)$$

$$\text{and } T^*_{pc} = (1 - y_{N_2} - y_{CO_2} - y_{H_2S})T_{pcHC} + y_{N_2}T_{cN_2} + y_{CO_2}T_{cCO_2} + y_{H_2S}T_{cH_2S}. \quad \ldots\ldots (3.54b)$$

T^*_c and p^*_c are used in the Wichert-Aziz equations with CO_2 and H_2S mole fractions to obtain mixture T_{pc} and p_{pc}.

The Sutton[7] correlations (Eqs. 3.47a and 3.47b) are recommended for hydrocarbon pseudocritical properties. If composition is available, Kay's mixing rule should be used with the Matthews *et al.*[32] pseudocriticals for C_{7+}. Gases containing significant amounts of CO_2 and H_2S nonhydrocarbons should always be corrected with the Wichert-Aziz equations. Finally, for gas-condensate fluids the wellstream specific gravity, γ_w (discussed in the next section), should replace γ_g in the equations above.

3.3.4 Wellstream Specific Gravity. Gas mixtures that produce condensate at surface conditions may exist as a single-phase gas in the reservoir and production tubing. This can be verified by determining the dewpoint pressure at the prevailing temperature. If wellstream properties are desired at conditions where the mixture is single-phase, surface-gas and -oil properties must be converted to a wellstream specific gravity, γ_w. This gravity should be used instead of γ_g to estimate pseudocritical properties.

Wellstream gravity r_p represents the average molecular weight of the produced mixture (relative to air) and is readily calculated from the producing-oil (condensate)/gas ratio, r_p; average surface-gas gravity $\bar{\gamma}_{\bar{g}}$; surface-condensate gravity, $\gamma_{\bar{o}}$; and surface-condensate molecular weight $M_{\bar{o}}$.

$$\gamma_w = \frac{\bar{\gamma}_{\bar{g}} + 4{,}580\, r_p \gamma_{\bar{o}}}{1 + 133{,}000\, r_p (\gamma/M)_{\bar{o}}}, \quad \ldots\ldots (3.55)$$

with r_p in STB/scf. Average surface-gas gravity is given by

$$\bar{\gamma}_{\bar{g}} = \frac{\sum_{i=1}^{N_{sp}} R_{pi}\gamma_{gi}}{\sum_{i=1}^{N_{sp}} R_{pi}}, \quad \ldots\ldots (3.56)$$

where R_{pi} = GOR of Separator Stage *i*. Standing[33] presents Eq. 3.55 graphically in **Fig. 3.9.**

When $M_{\bar{o}}$ is not available, Standing gives the following correlation.

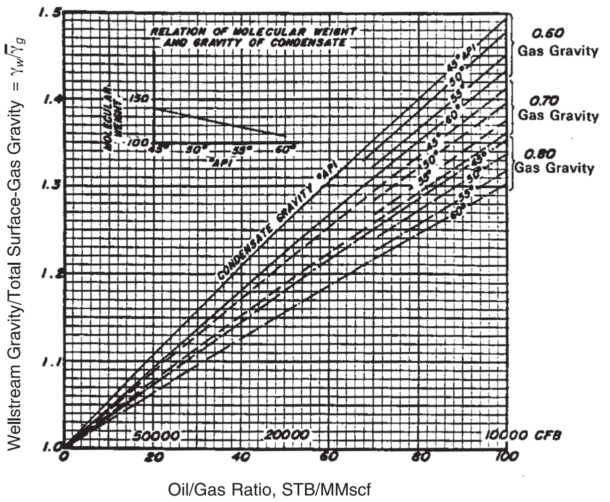

Fig. 3.9—Wellstream gravity relative to surface average gas gravity as a function of solution oil/gas ratio and surface gravities.

$$M_{\bar{o}} = 240 - 2.22\gamma_{\text{API}}. \quad \ldots\ldots (3.57)$$

This relation should not be extrapolated outside the range $45 < \gamma_{\text{API}} < 60$. Eilerts[34] gives a relation for $(\gamma/M)_{\bar{o}}$,

$$(\gamma/M)_{\bar{o}} = \left(1.892 \times 10^{-3}\right) + \left(7.35 \times 10^{-5}\right)\gamma_{\text{API}} - \left(4.52 \times 10^{-8}\right)\gamma_{\text{API}}^2, \quad \ldots\ldots (3.58)$$

which should be reliable for most condensates. When condensate molecular weight is not available, the recommended correlation for $M_{\bar{o}}$ is the Cragoe[35] correlation,

$$M_{\bar{o}} = \frac{6,084}{\gamma_{\text{API}} - 5.9}, \quad \ldots\ldots (3.59)$$

which gives reasonable values for all surface condensates and stock-tank oils.

A typical problem that often arises in the engineering of gas-condensate reservoirs is that all the data required to calculate wellstream gas volumes and wellstream specific gravity are not available and must be estimated.[36-38] In practice, we often report only the first-stage-separator GOR (relative to stock-tank-oil volume) and gas specific gravity, R_{s1} and γ_{g1}, respectively; the stock-tank-oil gravity, $\gamma_{\bar{o}}$; and the primary-separator conditions, p_{sp1} and T_{sp1}.

To calculate γ_w from Eq. 3.55 we need total producing OGR, r_p, which equals the inverse of R_{s1} plus the additional gas that will be released from the first-stage separator oil, R_{s+},

$$r_p = \frac{1}{\left(R_{s1} + R_{s+}\right)}. \quad \ldots\ldots (3.60)$$

R_{s+} can be estimated from several correlations.[37,39] Whitson[38] proposes use of a bubblepoint pressure correlation (e.g., the Standing[40] correlation),

$$R_{s+} = A_1\gamma_{g+} \quad \ldots\ldots (3.61a)$$

$$\text{and } A_1 = \left[\left(\frac{p_{sp1}}{18.2} + 1.4\right)10^{\left(0.0125\gamma_{\text{API}} - 0.00091T_{sp1}\right)}\right]^{1.205}, \quad \ldots\ldots (3.61b)$$

with p_{sp1} in psia, T_{sp1} in °F, and R_{s+} in scf/STB. γ_{g+} is the gas gravity of the additional solution gas released from the separator oil. The Katz[41] correlation (**Fig. 3.10**) can be used to estimate γ_{g+}, where a best-fit representation of his graphical correlation is

$$\gamma_{g+} = A_2 + A_3R_{s+}, \quad \ldots\ldots (3.62)$$

where $A_2 = 0.25 + 0.02\gamma_{\text{API}}$ and $A_3 = -(3.57 \times 10^{-6})\gamma_{\text{API}}$.

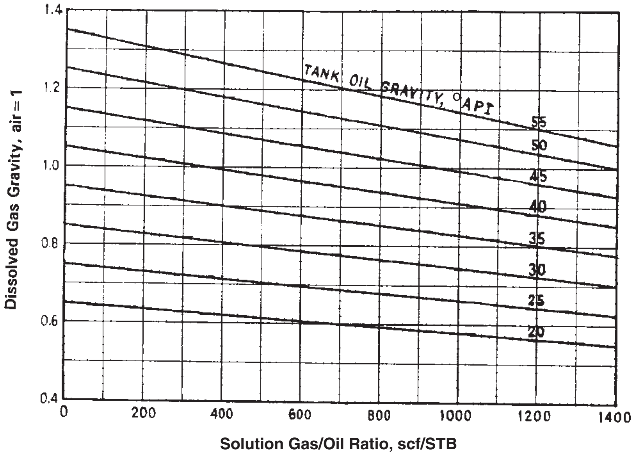

Fig. 3.10—Correlation for separator-oil dissolved gas gravity as a function of stock-tank-oil gravity and separator-oil GOR (from Ref. 41).

Solving Eqs. 3.61 and 3.62 for R_{s+} gives

$$R_{s+} = \frac{A_1A_2}{\left(1 - A_1A_3\right)}. \quad \ldots\ldots (3.63)$$

Average surface separator gas gravity, $\overline{\gamma}_{\bar{g}}$, is given by

$$\overline{\gamma}_{\bar{g}} = \frac{\gamma_{g1}R_{s1} + \gamma_{g+}R_{s+}}{R_{s1} + R_{s+}}. \quad \ldots\ldots (3.64)$$

Although the Katz correlation is only approximate, the impact of a few percent error in γ_{g+} is not of practical consequence to the calculation of γ_w because R_{s+} is usually much less than R_{s1}.

3.3.5 Gas Viscosity. Viscosity of reservoir gases generally ranges from 0.01 to 0.03 cp at standard and reservoir conditions, reaching up to 0.1 cp for near-critical gas condensates. Estimation of gas viscosities at elevated pressure and temperature is typically a two-step procedure: (1) calculating mixture low-pressure viscosity μ_{gsc} at p_{sc} and T from Chapman-Enskog theory[3,6] and (2) correcting this value for the effect of pressure and temperature with a corresponding-states or dense-gas correlation. These correlations relate the actual viscosity μ_g at p and T to low-pressure viscosity by use of the ratio μ_g/μ_{gsc} or difference $(\mu_g - \mu_{gsc})$ as a function of pseudoreduced properties p_{pr} and T_{pr} or as a function of pseudoreduced density ρ_{pr}.

Gas viscosities are rarely measured because most laboratories do not have the required equipment; thus, the prediction of gas viscosity is particularly important. Gas viscosity of reservoir systems is often estimated from the graphical correlation $\mu_g/\mu_{gsc} = \text{f}(T_r, p_r)$ proposed by Carr *et al.*[42] (**Fig. 3.11**). Dempsey[43] gives a polynomial approximation of the Carr *et al.* correlation. With these correlations, gas viscosities can be estimated with an accuracy of about ± 3% for most applications. The Dempsey correlation is valid in the range $1.2 \leqq T_r \leqq 3$ and $1 \leqq p_r \leqq 20$.

The Lee-Gonzalez gas viscosity correlation (used by most PVT laboratories when reporting gas viscosities) is given by[44]

$$\mu_g = A_1 \times 10^{-4}\exp\left(A_2\rho_g^{A_3}\right), \quad \ldots\ldots (3.65a)$$

$$\text{where } A_1 = \frac{\left(9.379 + 0.01607M_g\right)T^{1.5}}{209.2 + 19.26M_g + T},$$

$$A_2 = 3.448 + \left(986.4/T\right) + 0.01009M_g,$$

$$\text{and } A_3 = 2.447 - 0.2224A_2, \quad \ldots\ldots (3.65b)$$

with μ_g in cp, ρ_g in g/cm^3, and T in °R. McCain[19] indicates the accuracy of this correlation is 2 to 4% for $\gamma_g < 1.0$, with errors up to 20% for rich gas condensates with $\gamma_g > 1.5$.