McCain gave guidelines for determining reservoir fluid type from field data. Additional data have shown that some of these guidelines are incorrect.

### Stock-Tank Liquid Gravity as an Indicator of Reservoir Fluid Type

Table 1 from McCain (1994) gives some guidelines for using stock-tank liquid gravities in degrees API for determining reservoir fluid type. The numbers in the table are incorrect, and in fact, stock-tank liquid gravities are not valid indicators of reservoir fluid type. Figure 5–1 presents stock-tank liquid gravities and initial producing gas-liquid ratios for 2,828 different reservoir fluid studies or production tests. Both oils and gas condensates are represented on the graph.

There is obviously a trend in the gravities of the stock-tank liquids; however, the scatter is too large for the use of stock-tank liquid gravities in determining reservoir fluid type. The black oils have stock-tank liquid gravities with values ranging from less than 10ºAPI to more than 60ºAPI. The volatile oils have stock-tank liquid gravities from 30ºAPI to more than 60ºAPI. The gas condensates have stock-tank liquid gravities from slightly more than 30ºAPI to more than 70ºAPI. The overlaps in stock-tank liquid gravities among the three fluids are just too great for stock-tank liquid gravities to be useful in determining reservoir fluid type. One exception to this statement might be that if stock-tank oil gravity is less than 30ºAPI, the reservoir fluid is most likely a black oil.
Stock-tank oil gravity, API, is not an indicator of reservoir fluid type. Data from 2,828 reservoir fluid studies or production tests.

Stock-tank Liquid Color as an Indicator of Reservoir Fluid Type

Table 1 from McCain (1994) also lists guidelines with respect to stock-tank liquid color. While the colors listed in the table are generally correct, the color of the stock-tank liquid is not necessary for determining or confirming the reservoir fluid type.
Initial Producing Gas-Liquid Ratio as an Indicator of Reservoir Fluid Type

The term *initial* as used in this chapter, both in the text and also in the titles of the figures, means “at a time when the average reservoir pressure is above the dew point pressure or bubblepoint pressure of the reservoir fluid.” The time period represented by *initial* may be a matter of days or possibly years, depending on the difference between the initial reservoir pressure and the saturation pressure of the reservoir fluid.

Also, the ratio of surface gas to stock-tank liquid is called *gas-liquid ratio* when comparing oils with gas condensates because the stock-tank liquid produced from a gas condensate is condensate rather than oil. Thus the symbol will be $GLR_i$. The *surface gas* includes the gas from all separators and the stock tank. A correlation procedure given in chapter 3 may be used to estimate the stock-tank gas-liquid ratio if it is not available from field data.

**Volatile oils and black oils**

Service company laboratory people state that the difference between volatile oils and black oils is an oil formation volume factor of 2.0 res bbl/STB when measured at bubblepoint pressure. If the measured oil formation volume factor is greater than 2.0 res bbl/STB, the produced gas is very rich and drops condensate in the gas meter, making gas volume measurement difficult. Thus, the oil is considered to be a *volatile oil* (volatile oils are associated with gas condensates rather than dry gases). Oil formation volume factors at bubblepoint pressures less than 2.0 res bbl/STB indicate black oils (black oils are associated with dry gases).

Figure 5–2 shows initial producing gas-liquid ratios (note that for oils these are the same as solution gas-oil ratios at the bubblepoint, $R_{ob}$) and oil formation volume factors at bubble-point pressure, $B_{ob}$, from 1,496 reservoir fluid samples with worldwide origins. Notice that if the initial producing gas-oil ratios are less than 1,500 scf/STB, all oil formation volume factors are less than 2.00 res bbl/STB, i.e., black oils. If the initial producing gas-oil ratios are greater than 1,900 scf/STB, all oil formation volume factors are greater than 2.00 res bbl/STB, i.e., volatile oils. Between these two values of initial producing gas-oil ratios, some oil formation volume factors are less than 2.00 res bbl/STB and some are greater. Thus, when the initial producing gas-oil ratios are between 1,500 and 1,900 scf/STB, the type of reservoir fluid cannot be determined with field production data.
So the transition point between volatile oils and black oils of 1,750 scf/STB for initial producing gas-oil ratio given in McCain (1994) must be changed. If the initial producing gas-oil ratios are less than 1,500 scf/STB, the reservoir fluids are black oils; if greater than 1,900 scf/STB, the reservoir fluids are volatile oils. If the initial gas-producing ratios are between these values, a sample must be taken to the laboratory for determination of fluid type. When the initial producing gas-oil ratio is between 1,500 and 1,900 scf/STB, the oil should be treated as if it were a volatile oil unless determined otherwise in the laboratory.

**Gas condensates and volatile oils**

The other guidelines listed in table 1 of McCain (1994) with regard to initial producing gas-liquid ratios are based on substantial data and
are valid. In fact, figure 5–3 validates the distinct transition point of an initial producing gas-liquid ratio of 3,200 scf/STB for the difference between volatile oils and gas condensates. The data points on figure 5–3 indicate the laboratory observed dew points or bubblepoints at reservoir temperature. Virtually all the data above the horizontal dashed line exhibit dew points, i.e., the reservoir fluids are gases. Virtually all the data below this line exhibit bubblepoints, i.e., the reservoir fluids are liquids (oils). There are only two samples with bubblepoints and three samples with dew points that do not fit this pattern. Thus, an initial producing gas-liquid ratio of 3,200 scf/STB represents a precise transition from gas condensates to volatile oils.

Fig. 5–3. Volatile oils and gas condensates—what’s the difference? Data from 130 reservoir fluid studies.
Figure 5–3 is a subset consisting of 130 data points from the data shown in figure 5–4. Figure 5–4 shows a correlation of initial producing gas-liquid ratios against the composition of the reservoir fluid represented by the composition of the heptanes plus fraction. The full data set contains 1,451 different reservoir fluid studies (PVT reports) that used reservoir fluid samples with worldwide origins.

Figure 5–4. Initial producing gas-liquid ratio correlates well with composition of heptanes plus in reservoir fluid (data from 1,441 reservoir fluid studies).

Figure 5–5 is a more useful presentation of the data of figure 5–4. Notice that reservoir fluids with initial producing gas-liquid ratios as high as 1,000,000 scf/STB exhibit dew points at reservoir temperature, i.e., they are gas condensates.
The producing gas-liquid ratios reported on figures 5–3 through 5–7 are not normalized to any standard surface facilities, i.e., number of separators, and also are not normalized to any standard operating temperatures and pressures. This lack of standardization causes most of the scatter in the data. The molecular weights of the heptanes plus fractions do have some effect; the higher molecular weights give results that tend along the bottom of the line of data points.

Fig. 5–5. Initial producing gas-liquid ratio correlates well with composition of heptanes plus in reservoir fluid (data from 1,451 reservoir fluid studies).
Wet gases and gas condensates

Dew points at reservoir temperatures have been observed in laboratory studies of gas condensates with initial producing gas-liquid ratios exceeding 1,000,000 scf/STB. However, at high initial producing gas-liquid ratios, the amount of condensate left in the reservoir is very small (less than about 1% of the pore volume). Apparently, nearly all gases that release condensate at the surface also release some condensate in the reservoir. Thus, these gases have dew points at reservoir temperatures and are gas condensates.

There are very few, if any, true wet gases (some condensate at the surface but no condensate in the reservoir). However, wet gas theory can be applied to gas condensates that release small amounts of condensate in the reservoir.

Rayes et al. showed that when the composition of heptanes plus in the reservoir gas is less than 4 mol%, the volume of condensate released into the reservoir is very small, and thus the gas can be treated as a wet gas (although in theory, wet gases do not release any condensate in the reservoir). McCain (1994) indicated that gas condensates with initial producing ratios greater than 15,000 scf/STB can be treated as if they are wet gases. However, no data was shown to confirm this value.

Figure 5–6 is another subset of the data of figure 5–4. It shows that if the initial producing gas-liquid ratios are equal to or greater than 15,000 scf/STB, the compositions of the heptanes plus in the reservoir fluids are definitely less than 4 mole percent. This confirms that gases with initial producing gas-liquid ratios of this value and higher can be treated as wet gases (although there surely will be a dew point and some retrograde condensate formed in the reservoir).

Dry gases

Figure 5–5 shows that many, if not all, reservoir gases that produce initial gas-liquid ratios much larger than 100,000 scf/STB have dew points at reservoir temperature and will release some condensate in the reservoir, and thus the gases are actually gas condensates. However, the small amount of condensate at the surface, less than 10 STB/MMscf, is not enough to strongly affect the recombination calculations that are used to determine the specific gravity of the reservoir gas. Thus, the specific gravity of the surface gas can be used to calculate the properties of the reservoir gas at reservoir conditions. So, for engineering purposes, these gases can be treated as if they are dry gases (although in theory, dry gases do not release any condensate at the surface).
Fig. 5–6. Which gas condensates can be treated as wet gases? (Data are from 349 reservoir fluid studies.)

**Summation of use of initial producing gas-liquid ratio as an indicator of fluid type**

Thus, table 1 of McCain (1994) should be replaced with the table 5–1.

Table 5–1. Determination of reservoir fluid type can be made with the initial producing gas-liquid ratio.

<table>
<thead>
<tr>
<th>Reservoir Fluid</th>
<th>Initial Producing Gas-Liquid Ratio, scf/STB</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dry gas*</td>
<td>100,000 &lt; GLRi</td>
</tr>
<tr>
<td>Wet gas*</td>
<td>15,000 &lt; GLRi, &lt; 100,000</td>
</tr>
<tr>
<td>Gas condensate</td>
<td>3,200 &lt; GLRi, &lt; 15,000</td>
</tr>
<tr>
<td>Volatile oil</td>
<td>1,900 &lt; GLRi, &lt; 3,200</td>
</tr>
<tr>
<td>Indeterminate by GLRi</td>
<td>1,500 &lt; GLRi, &lt; 1,900</td>
</tr>
<tr>
<td>Black oil</td>
<td>GLRi, &lt; 1,500</td>
</tr>
</tbody>
</table>

* The GLRi limits for these gases are defined for engineering applications.
Composition of Heptanes Plus as an Indicator of Reservoir Fluid Type

This book is primarily concerned with situations in which fluid property laboratory reports are not available, i.e., the composition of the reservoir fluid is not available. However, some interesting observations about the compositions of the five reservoir fluids can be determined with the data set of figures 5–4 and 5–5.

**Volatile oils and black oils**

Table 2 of McCain (1994) gives a precise cut-off of 20 mol% heptanes plus in the reservoir fluid between volatile oils and black oils. This is not correct.

As mentioned above, there is a range of initial producing gas-liquid ratios, 1,500 to 1,900 scf/STB, in which the type of reservoir fluid is indeterminate. There is also a range of compositions of heptanes plus in which the type of reservoir fluid cannot be determined.

Figure 5–7, which is another subset of the data of figure 5–4, shows that the composition of heptanes plus in the reservoir fluid must be greater than 26.5 mol% for all of the initial producing gas-liquid ratio data to be less than 1,500 scf/STB (black oils). And the figure shows that the heptanes plus compositions must be less than 18.0 mol% for all of the initial producing gas-liquid ratios to be greater than 1,900 scf/STB (volatile oils). In the region from 18.0 mol% to 26.5 mol%, heptanes plus the initial producing gas-oil ratios vary from less than 1,500 scf/STB to greater than 1,900 scf/STB. Thus in this region, the type of oil cannot be determined using heptanes plus composition.

**Gas condensates and volatile oils**

The same table in McCain (1994) indicates that the transition between volatile oils and gas condensates is a composition of 12.5 mol% heptanes plus in the reservoir fluid. Additional data have been obtained and are included in figure 5–3. Figure 5–3 reveals a fairly precise transition of 12.9 mol% heptanes plus. The vertical dashed line at 12.9 mol% heptanes plus separates those reservoir fluids that exhibited bubblepoints (oils) from those fluids that exhibited dew points (gases).

Thus, if the composition of the reservoir fluid contains more than 12.9 mol% heptanes plus, the reservoir fluid is an oil. If the composition
of heptanes plus in the reservoir fluid is less than 12.9 mol%, the fluid is a gas. The transition from gases to oils is very distinct; only three of the hundreds of data points do not fit this pattern.

![Graph showing the relationship between initial producing gas-liquid ratio (GLR, scf/STB) and composition of heptanes plus in reservoir fluid, mole %]

**Fig. 5–7.** Which composition of heptanes plus defines black oils and volatile oils? (Data are from 217 reservoir fluid studies.)

**Dry gases**

If the values of producing gas-liquid ratios equal to and greater than 100,000 scf/STB are accepted as indicators of gases that can be treated as dry gases, figure 5–5 indicates a corresponding composition of heptanes plus of less than approximately 0.5 mol%.
Summation of use of heptanes plus composition as indicator of fluid type

Thus, table 2 of McCain (1994) should be replaced with table 5–2.¹¹

Table 5–2. Determination of reservoir fluid type can be made with composition of heptanes plus in a sample of the initial reservoir fluid.

<table>
<thead>
<tr>
<th>Reservoir Fluid</th>
<th>Composition of Heptanes Plus in Initial Reservoir Fluid (mol%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Dry gas*</td>
<td>( z_{C7} &lt; 0.5 )</td>
</tr>
<tr>
<td>Wet gas*</td>
<td>( 0.5 &lt; z_{C7} &lt; 4.0 )</td>
</tr>
<tr>
<td>Gas condensate</td>
<td>( 4.0 &lt; z_{C7} &lt; 12.9 )</td>
</tr>
<tr>
<td>Volatile oil</td>
<td>( 12.9 &lt; z_{C7} &lt; 18.0 )</td>
</tr>
<tr>
<td>Indeterminate by ( z_{C7} )</td>
<td>( 18.0 &lt; z_{C7} &lt; 26.5 )</td>
</tr>
<tr>
<td>Black oil</td>
<td>( 26.5 &lt; z_{C7} )</td>
</tr>
</tbody>
</table>

* The \( z_{C7} \) limits for these gases are defined for engineering applications.

Nomenclature

\( B_{ob} \) Oil formation volume factor, measured at bubblepoint pressure, resbl/STB.

\( GLR_i \) Initial producing gas-oil ratio, scf/STB; initial means reservoir pressure > saturation pressure, and the stock-tank liquid could be either oil or condensate.

\( R_{sb} \) Solution gas-oil ratio measured at and above bubblepoint pressure, scf/STB.

\( z_{C7} \) Composition of heptanes plus in the reservoir fluid, mole percent (mol%).
References


2. Ibid.

3. Ibid.

4. Ibid.

5. Ibid.


8. Ibid.

9. Ibid.

10. Ibid.

11. Ibid.