Heavy Components Control Reservoir Fluid Behavior

William D. McCain Jr., SPE, S.A. Holditch & Assocs. Inc.

The five reservoir fluids (black oils, volatile oils, retrograde gas-condensates, wet gases, and dry gases) are defined because production of each fluid requires different engineering techniques.[1,2] The fluid type must be determined very early in the life of a reservoir (often before sampling or initial production) because fluid type is the critical factor in many of the decisions that must be made about producing the fluid from the reservoir.[1]

Introduction

Reservoir fluid type can be confirmed only by observing a representative fluid sample in the laboratory. However, "rules of thumb" based on initial producing GOR, stock-tank liquid gravity, and stock-tank liquid color usually will indicate fluid type. Initial producing GOR is the most important of these indicators; nevertheless, both stock-tank liquid gravity and color are useful in validating the fluid type inferred from the GOR.[2,3] Darker colors are associated with the largest, heaviest molecules in the petroleum mixtures.

Black oils are mixtures of thousands of different chemical species ranging from methane to large, heavy, virtually nonvolatile molecules. Volatile oils contain fewer of the heavier molecules. Retrograde gases have even fewer of the heavy ends, wet gases still fewer, and dry gases are essentially pure methane. These differences in composition cause the five fluids to have different phase diagrams, which cause differences in behavior in the reservoir and at surface conditions.[1]

The heavy components in the petroleum mixtures have the strongest effect on fluid characteristics. Normally, laboratory tests combine the heavy components as a "heptanes-plus" fraction. **Fig. 1** illustrates the effect of this heavy fraction on the most important of the fluid-type indicators: the initial producing GOR.[4] Black oils, represented at the lower right end of the graph, have the lowest initial GOR's and the highest concentrations of heavy components. Dry gases are located at the upper left of the graph. The other fluids exist in a continuum between these two. The GOR's in Fig. 1 are not normalized to any standard surface facilities or standard operating conditions; nonetheless, the graph is an aid in understanding the differences among the five fluids.

Black Oils and Volatile Oils

Black oils and volatile oils both are liquids in the reservoir, both exhibit bubblepoints as reservoir pressure is decreased during production, and both release gas in the reservoir pore space at pressures below the bubblepoint.[1,5,6] However, there is a good reason for classifying them separately. The "oil material-balance equations," which are used for black oils, will give incorrect results for volatile oils; the behavior of volatile oils does not fit the assumptions inherent in derivation of these equations.[7]

The gas that comes out of solution in the reservoir from a black oil below its bubblepoint is usually a dry gas.[5] As this free gas is produced, it remains a gas as pressure and temperature are reduced to separator conditions. As reservoir pressure decreases, the gas leaving solution becomes richer in intermediate components, and the gas could become a wet gas. However, this occurs late in the life of the reservoir and has little effect on ultimate production.

The gas that comes out of solution in the reservoir from a volatile oil is normally a retrograde gas.[5] This free gas will exhibit retrograde behavior in the reservoir and when produced will release a large amount of condensate at surface conditions. The quantity of condensate released from the free gas associated with a volatile oil is significant; often more than one-half the stock-tank liquid produced during the life of a volatile oil reservoir left the reservoir as free gas.

Thus, the important difference between black oils and volatile oils is that the solution gases from black oils remain solely in the gas phase as they move through the reservoir, the tubulars, and the separator; the solution gases from volatile oils are rich and lose condensate in the separator.[5] One assumption inherent in the derivation of classic material-balance equations is that the free gas in the reservoir remains as gas through the separator.[7]

The material-balance equations treat a multicomponent black-oil mixture as a two-component mixture: gas and oil. Reservoir engineering calculations for volatile oils must treat the mixture as a multicomponent mixture so that the total composition of the production stream is known and separator calculations (which require knowledge of composition) can be performed to determine the amounts of liquid and gas at the surface.[5,8]

Special laboratory procedures can predict the recovery of volatile oils under depletion drive; however, these are somewhat difficult to analyze.[9] Above the bubblepoint, the undersaturated-black-oil material-balance equation can be used for volatile oils. Below the bubblepoint, compositional material-balance calculations normally are required, either with K factors or equations-of-state (EOS). The special laboratory procedures mentioned above help in deriving the K factors or "tuning" the EOS.[1,9,10]

Examination of hundreds of laboratory studies indicates that one should suspect the presence of a volatile oil whenever the initial producing GOR exceeds about 1,750 scf/STB, especially if the stock-tank oil gravity is high. Another indicator of volatile oil is a stock-tank oil gravity exceeding 40°API with some color: brown, reddish, orange, even green.[1,2] If the oil FVF at the bubblepoint is measured in the laboratory, a value of 2.0 RB/STB or greater is expected for a volatile oil.[2]

The data in **Fig. 2** (a subset of the data in Fig. 1) illustrate the differences in composition between volatile oils and black oils. An

This paper is SPE 28214. **Technology Today Series** articles provide useful summary information on both classic and emerging concepts in petroleum engineering. **Purpose:** To provide the general reader with a basic understanding of a significant concept, technique, or development within a specific area of technology.

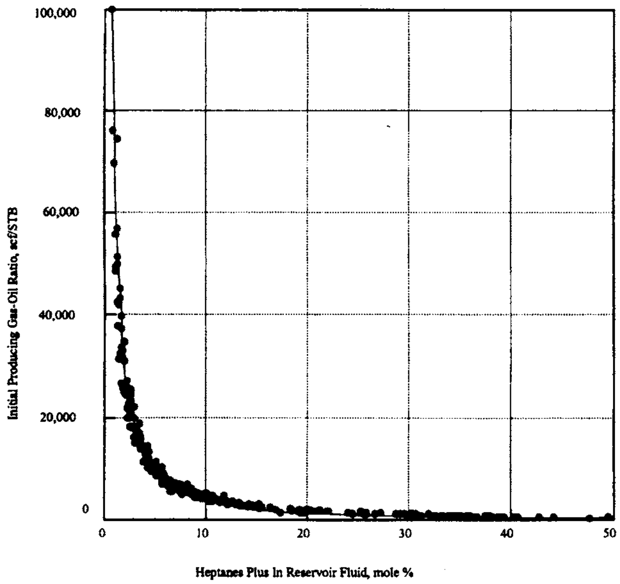

Fig. 1—Relationship between initial producing GOR and heptanes-plus concentration.[4]

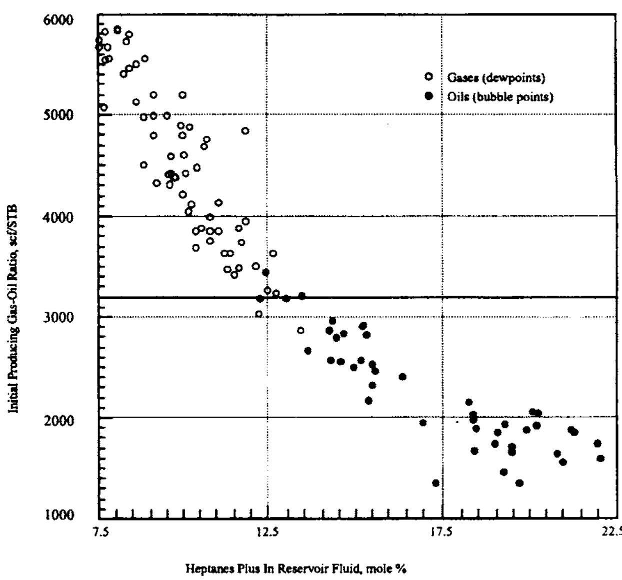

Fig. 2—Relationship between initial producing GOR, phase in reservoir, and heptanes-plus concentration.[11]

initial producing GOR of 1,750 scf/STB corresponds to values of heptanes-plus concentration between about 18 and 22 mol%. So we take 20 mol% as a reasonable, but not necessarily sharply defined, transition point between volatile oils and black oils.

As reservoir pressure decreases in a volatile oil reservoir, the flow stream in the reservoir becomes virtually all gas.[4] However, this gas is a retrograde gas and is rich enough to release large quantities of condensate at surface conditions. Thus, early in the life of a volatile oil reservoir, the stock-tank liquid comes from the oil phase in the reservoir, and late in the life of the reservoir, the stock-tank liquid is condensate from the reservoir gas. The increasing amount of condensate in the production stream causes the stock-tank oil gravity to increase steadily during the life of the reservoir (see **Fig. 3**).

The stock-tank oil gravity of a black oil changes in the opposite way. The large amount of dry gas produced with the black oil apparently strips some of the lighter components from the oil during the trip to the surface. Thus, the stock-tank oil gravity of a black oil gradually decreases during most of the life of the reservoir. Late in the life of the reservoir, when the gas leaving solution is rich enough to be a wet gas, the stock-tank oil gravity will increase because of mixing with the condensate from the produced wet gas. These changes in the gravity of the stock-tank liquids during production often help in differentiating between black oils and volatile oils.

Of course, black oils are not necessarily black. These are very dark, often black, sometimes with a greenish cast, or brown, indicating the presence of heavy hydrocarbons.[2] The stock-tank oil gravities of black oils are expected to be less than 45°API.[2]

Producing GOR's are constant for oils as long as reservoir pressures are above bubblepoint pressure. Both oils exhibit increasing producing GOR's when two phases exist in the reservoir. This increase results from the existence of free gas in the reservoir that has a much lower viscosity than the oil and, therefore, moves more easily to the wellbore. Of course, as reservoir pressure declines further, the amount of gas in the reservoir increases; this causes an increase in the effective permeability to gas and a decrease in the effective permeability to oil. As a result, the ratio of gas to oil in the reservoir flow stream increases (see Fig. 3). Black oils typically have higher surface GOR's than volatile oils during most of the producing time because the gases produced with volatile oils are diminished in volume owing to the loss of condensate in the separators.[5] Notice the decrease in producing GOR's for both oils late at the end of the production period. This turndown results primarily from the severe increase in gas FVF at low reservoir pressures.

Volatile Oil and Retrograde Gases

At reservoir conditions volatile oils exhibit bubblepoints and retrograde gases exhibit dewpoints. Fig. 2 is a portion of Fig. 1 with the data points indicating that the fluid had either a dewpoint or a bubblepoint at reservoir conditions. The scatter in the data reflects both the compositional differences among the fluids and the differences in surface separation facilities and conditions. Differences in the molecular weight of the heptanes plus are a major contribution to the scatter.

Notice in Fig. 2 that only two fluids indicate dewpoints at initial producing GOR's less than 3,200 scf/STB and that only one fluid indicates a bubblepoint above this value. Thus, a value of 3,200 scf/STB appears to be a fairly distinct transition point between volatile oils and retrograde gases.

Also notice that only two fluids with heptanes-plus compositions less than 12.5 mol% exhibit bubblepoints and only three with concentrations above this value exhibit dewpoints. Thus, 12.5 mol% heptanes plus appears to be a useful dividing line between volatile oils and retrograde gases. Actually, volatile oils have been observed with heptanes-plus contents as low as 10 mol% and retrograde gases as high as 15 mol%.[2] These cases are very rare and typically have unusually high stock-tank oil gravities (i.e., high molecular weights and specific gravities of the heptanes-plus fraction).

The retrograde liquid formed in a retrograde-gas reservoir at pressures below the dewpoint pressure of the gas is virtually immobile.[11] Thus, this liquid is lost to production, and the condensate saturation increases as pressure declines. This causes a rapid decrease in effective permeability to gas as total liquid saturation increases. Many operators notice a sharp decrease in gas production rate soon after a retrograde gas reservoir passes through the dewpoint.

Although the flow stream from the retrograde-gas reservoir is virtually all gas, the surface producing GOR will increase after the reservoir pressure declines below the dewpoint (see Fig. 3). This results from the loss of condensate in the reservoir, condensate that would otherwise have ended up in the stock tank. The stock-tank liquid gravity increases as reservoir pressure decreases because the retrograde behavior in the reservoir removes some of the heaviest components from the gas; these components do not get to the stock tank, and the stock tank liquid is lighter (has higher API gravity).

Special laboratory procedures for retrograde gases provide data suitable for predicting future performance of retrograde-gas reservoirs.[2] Compositional material-balance calculations, either with K factors or with EOS, also can be used for future perfor-

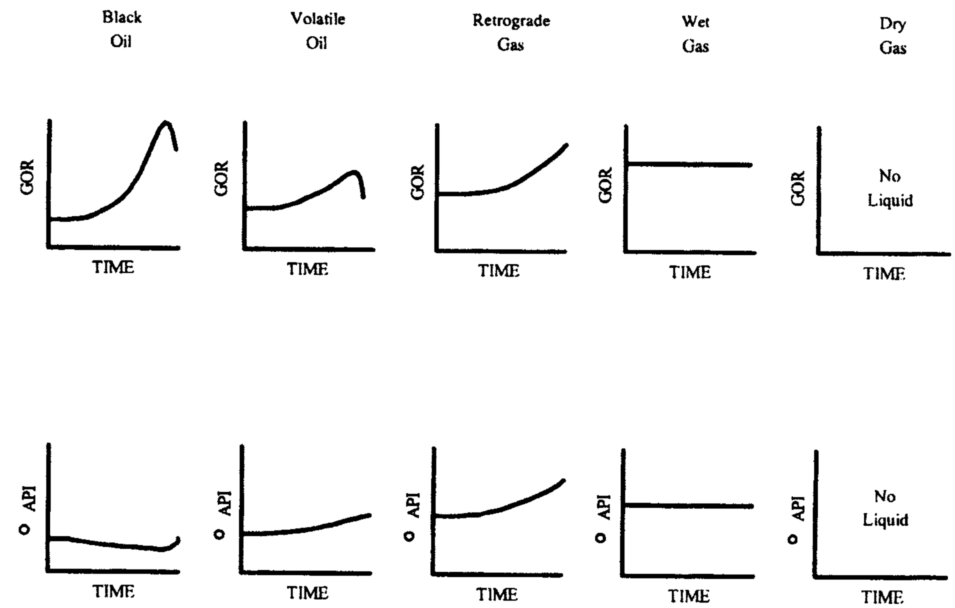

Fig. 3—Production trends for the five reservoir fluids.[17]

mance prediction. The results of the laboratory procedures are necessary to derive the K factors or to "tune" the EOS for these calculations.[10,11] An interesting correlation is available for estimating the composition of the reservoir gas at pressures below the dewpoint.[12]

Retrograde Gases and Wet Gases

Retrograde behavior has been observed in laboratory studies of retrograde gases with initial GOR's exceeding 150,000 scf/STB, although the amount of retrograde liquid is very small (less than about 1% of the reservoir pore space). It appears that nearly all gases that release condensate at the surface probably release some condensate in the reservoir. That is, there are probably very few true wet gases (liquid at the surface but no liquid in reservoir). However, wet gas theory can be applied to retrograde gases that release small amounts of liquid in the reservoir.

The concept of a wet gas is very useful for engineering purposes. The gas material-balance equation can be applied to a wet gas by simply (1) combining the surface gas and condensate by calculation to determine the properties of the reservoir gas and (2) adding the gaseous equivalent of the surface condensate to the surface gas production.[13] Remember, though, if there is a stock-tank gas, its specific gravity (which will be relatively high) must be included with the specific gravity of the separator gas or gases (weighted by gas production rates) to get an estimate of surface gas specific gravity. If the gas production rate and specific gravity of the stock tank vent gas are not known, correlations are available.[13]

If the concentration of heptanes plus is less than 4 mol%, the gas can be treated as if it were a wet gas even though some retrograde liquid forms in the reservoir.[14] Fig. 2 shows that an initial producing GOR of 15,000 scf/STB and greater corresponds to heptanes-plus concentrations of less than 4 mol%. Thus, if the initial producing GOR is greater than 15,000 scf/STB, the fluid can be treated, for engineering purposes, as a wet gas (although there surely will be some retrograde liquid formed in the reservoir).

The producing GOR of a true wet gas remains constant throughout the life of the reservoir. Remember, though, that the guidelines for identifying a wet gas for engineering purposes cut fairly deeply into the range of fluids that exhibit some retrograde behavior. Thus, an increase in GOR later in the production period of a wet gas (as defined for engineering purposes) might be expected.

Wet and Dry Gases

True wet and dry gases remain gaseous in the reservoir throughout depletion; i.e., neither has a dewpoint and neither releases condensate in the reservoir. The difference between the two is that wet gases release condensate as pressure and temperature are reduced to separator conditions, while dry gases remain entirely gaseous at the surface. Note that the words "wet" and "dry" as used in this classification system do not refer to the presence or absence of water or water vapor. Water is always present in petroleum reservoirs, and all gases normally are saturated with water vapor; however, water is excluded from this discussion.

The "gas material-balance equation" was derived originally for dry gases.[15] But it can be used for wet gases if the equivalent gaseous volume of the condensate is included in the cumulative gas production and the quantity and properties of the condensate are added to the surface gas to determine the properties of the reservoir gas.[13] Further, the equation is valid for a retrograde gas if the reservoir is volumetric and if two-phase gas compressibility factors are used.[14,15]

The effects of condensate volume on reservoir gas specific gravity and on cumulative gas production are insignificant when the yield of condensate is 10 bbl/MMscf or less (i.e., when the initial producing GOR is 100,000 scf/STB or more).[16] Even though some condensate is produced to the surface and possibly some retrograde condensate is formed in the reservoir, reservoir fluids with initial producing GOR's this high can be treated as dry gases. The surface gas specific gravity can be used to represent the specific gravity of the reservoir gas, and the surface gas production rates can be equated to reservoir production rates. Fig. 1 shows that gases with less than 0.7 mol% heptanes plus have producing GOR's this high; i.e., if the heptanes-plus concentration is less than this, the fluid can be treated as a dry gas.

Review

Table 1 summarizes the guidelines for determining fluid type from field data.[17] If any of these three properties fails to meet the criteria of Table 1, the test fails and a representative sample of the reservoir fluid must be examined in a laboratory to establish fluid type.

Table 2 shows the expected results of laboratory analysis of the fluids.[17] Fig. 3 summarizes schematically the trends of producing GOR and stock-tank liquid gravity.[17] These fluid types are

TABLE 1—SUMMARY OF GUIDELINES FOR DETERMINING FLUID TYPE FROM FIELD DATA[17]					
	Black Oil	Volatile Oil	Retrograde Gas	Wet Gas	Dry Gas
Initial producing gas/liquid ratio, scf/STB	<1,750	1,750 to 3,200	>3,200	>15,000*	100,000*
Initial stock-tank liquid gravity, °API	<45	>40	>40	Up to 70	No liquid
Color of stock-tank liquid	Dark	Colored	Lightly colored	Water white	No liquid

*For engineering purposes.

TABLE 2—EXPECTED RESULTS OF LABORATORY ANALYSIS OF THE FIVE FLUID TYPES[17]					
	Black Oil	Volatile Oil	Retrograde Gas	Wet Gas	Dry Gas
Phase change in reservoir	Bubblepoint	Bubblepoint	Dewpoint	No phase change	No phase change
Heptanes plus, mol%	>20%	20 to 12.5	<12.5	<4*	<0.7*
Oil FVF at bubblepoint	<2.0	>2.0	—	—	—

*For engineering purposes.

defined for engineering purposes. They should not be confused with reservoir fluid descriptions defined by legal agencies that regulate the petroleum industry. Regulatory definitions of oil, crude oil, condensate, gas, natural gas, casing-head gas, etc., are not related to these engineering definitions and, in fact, often contradict them.

References

1. McCain, W.D. Jr.: *The Properties of Petroleum Fluids*, second edition, PennWell Books, Tulsa (1990) 148–58, 409–11.
2. Moses, P.L.: "Engineering Applications of Phase Behavior of Crude Oil and Condensate Systems," *JPT* (July 1986) 715.
3. McCain, W.D. Jr.: "Reservoir-Fluid Property Correlations—State of the Art," *SPERE* (May 1991) 266.
4. McCain, W.D. Jr.: "Chemical Composition Determines Behavior of Reservoir Fluids," *Pet. Eng. Intl.* (Oct. 1993) 18.
5. McCain, W.D. Jr.: "Black Oils and Volatile Oils—What's the Difference?," *Pet. Eng, Intl.* (Nov. 1993) 24.
6. Jacoby, R.H. and Berry, V.J. Jr.: "A Method for Predicting Depletion Performance of a Reservoir Producing Volatile Crude Oil," *Trans.*, AIME (1957) **210,** 27.
7. Schilthuis, R.J.: "Active Oil and Reservoir Energy," *Trans.*, AIME (1936) **118**, 33.
8. Cordell, J.C. and Ebert, C.K.: "A Case History—Comparison of Predicted and Actual Performance of a Reservoir Producing Volatile Crude Oil," *JPT* (Nov. 1965) 1291.
9. Reudelhuber, F.O. and Hinds, R.F.: "Compositional Material Balance Method for Prediction of Recovery for Volatile Oil Depletion Drive Reservoirs," *Trans.*, AIME (1957) **210,** 19.
10. Coats, K.H. and Smart, G.T.: "Application of a Regression Based EOS PVT Program to Laboratory Data," *SPERE* (May 1986) 277.
11. McCain, W.D. Jr. and Bridges, B.: "Volatile Oils and Retrograde Gases—What's the Difference?," *Pet. Eng. Intl.* (Jan. 1994) 35.
12. Niemstschik, G.E., Poetmann, F.H., and Thompson, R.S.: "Correlation for Determining Gas Condensate Composition," paper SPE 26183 presented at the 1993 SPE Gas Technology Symposium, Calgary, June 28–30.
13. Gold, D.K., McCain, W.D. Jr., and Jennings, J.W.: "An Improved Method for the Determination of the Reservoir-Gas Specific Gravity for Retrograde Gases," *JPT* (July 1989) 747, *Trans.*, AIME, **287.**
14. Rayes, D.G. *et al.*: "Two-Phase Compressibility Factors for Retrograde Gases," *SPEFE* (March 1992) 87, *Trans.*, AIME, **293.**
15. Craft, B.C. and Hawkins, M.F.: *Applied Petroleum Reservoir Engineering*, Prentice-Hall, Englewood Cliffs, NJ (1959) 39–44, 82.
16. McCain, W.D. Jr. and Piper, L.D.: "Reservoir Gases Exhibit Subtle Differences," *Pet. Eng. Intl.*, (March 1994) 45.
17. McCain, W.D. Jr.: "Revised Gas-Oil Ratio Criteria—Key Indicator of Reservoir Fluid Type," *Pet. Eng. Intl.* (April 1994) 57.

William D. McCain Jr. is a senior executive with S.A. Holditch & Assocs. Inc. in College Station, TX, and a part-time visiting professor of petroleum engineering at Texas A&M U. He has written two editions of *Properties of Petroleum Fluids.* He holds a BS degree from Mississippi State U. and MS and PhD degrees from Georgia Inst. of Technology. McCain teaches the SPE short course "Review for the Principles and Practice Examination" and taught the short course on reservoir fluid properties. He is a member of the Editorial Review Committee and was a member of the 1986–89 Career Guidance, 1972–75 Textbook, and 1967–71 Education and Accreditation (1970 chairperson) committees.