

Applied

**PETROLEUM RESERVOIR
ENGINEERING**

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25 per cent connate water. Then the final water saturation of the flooded portion of the reservoir is

$$\begin{aligned} S_w &= \frac{\text{Connate water} + \text{Water influx}}{\text{Pore space}} \\ &= \frac{(13.04 \times 10^6 \times 0.172 \times 0.25) + 960,400}{13.04 \times 10^6 \times 0.172} \\ &= 0.68 \text{ or } 68 \text{ per cent} \end{aligned}$$

Then the residual gas saturation S_{gr} is 32 per cent.

calculate the water influx when the initial gas in place is known. It also shows the method of estimating the residual gas saturation of the portion of the reservoir which has been invaded by water, where a reliable estimate of the invaded volume can be made. This is calculated from the isopachous map, the invaded volume being delineated by those wells which have "gone to water production." The residual gas saturation calculated in Example 1.7 includes that portion of the lower permeability rock within the invaded area which actually may not have been invaded at all, the wells having been "drowned" by water production from the more permeable beds of the formation. Nevertheless it is still interpreted as the *average* residual gas saturation, which may be applied to the uninvaded portion of the reservoir.

In water-drive reservoirs the relation between G_p and p/z is, of course, not linear, as can be seen by an inspection of Eq. (1.29). Because of the water influx, the pressure drops less rapidly with production than under volumetric control, as shown in the upper curve of Fig. 1.9. Consequently, the extrapolation technique described for volumetric reservoirs is not applicable. Also, where there is water influx, the initial gas in place calculated at successive stages of depletion, *assuming no water influx*, takes on successively higher values; whereas with volumetric reservoirs the calculated values of the initial gas should remain substantially constant.

14. The Gas Equivalent of Produced Condensate and Water. In the study of gas reservoirs in the preceding section it was implicitly assumed that the fluid in the reservoir at all pressures as well as on the surface was in a *single* (gas) phase. Most gas reservoirs, however, produce some hydrocarbon liquid, commonly called condensate, in the range of a few to a hundred or more barrels per million standard cubic feet. So long as the *reservoir* fluid remains in a single (gas) phase, the calculations of the previous sections may be used, provided the cumulative gas production G_p is modified to include the condensate liquid production. On the other hand, if a hydrocarbon liquid phase develops in the reservoir, the methods of the previous sections are not applicable, and these *retrograde*, gas-condensate reservoirs must be treated specially, as described in Chapter 2.

The reservoir gas production G_p , used in the previous section must include the separator gas production, the stock tank gas production, and the stock tank liquid production converted to its *gas equivalent*, symbol GE. The stock tank gas production is the gas in solution in the separator liquid. It can be estimated from the bubble-point correlation for oil systems⁴⁰, the separator pressure being the bubble point of the liquid. The volume of solution gas may also be measured. The produced hydrocarbon liquid is converted to its gas equivalent assuming it behaves as an ideal gas when vaporized in the produced gas. Taking 14.7 psia and 60°F as standard conditions, the gas equivalent of one stock tank barrel of condensate liquid is

$$\begin{aligned} \text{GE} = V &= \frac{nRT_{sc}}{p_{sc}} = \frac{350.5 \times \gamma_o}{M_o} \times \frac{10.73 \times 520}{14.7} \\ &= 133,000 \gamma_o / M_o \text{ SCF/STB} \end{aligned}$$

The gas equivalent of one barrel of condensate of specific gravity 0.780 (water = 1.00) and molecular weight 138 is 752 SCF. The specific gravity may be calculated from the API gravity. If the molecular weight of the condensate is not measured, as by the freezing point depression method, it may be estimated using Eq. (2.3). Table 1.9 gives the gas equivalent of stock tank condensate liquids in the range of 45 to 65° API. If the analysis

Table 1.9. GAS EQUIVALENT OF STOCK TANK CONDENSATE
GE = 133,000 γ_o / M_o

Oil Gravity °API	Oil Specific Gravity = γ_o	*Molecular Weight = M_o	Gas Equivalent of Stock Tank Oil, SCF/STB
45	0.802	156	684
50	0.780	138	752
55	0.759	124	814
60	0.739	113	870
65	0.720	103	930

*Based on Eq. (2.3).

of the separator liquid is available, a more precise determination of its gas equivalent can be made. In this case the dissolved separator gas is included. Example 1.8 shows the calculation of the gas equivalent of the separator liquid and its dissolved gas to find the total reservoir production.

Example 1.8. Calculating the total daily gas production including the gas equivalents of water and condensate.

Given:

Daily separator gas production = 3.25MM SCF

Daily stock tank condensate = 53.2 STB

Daily stock tank gas = 10M SCF
 Daily fresh water production = 5.5 bbl
 Initial reservoir pressure = 4000 psia
 Current reservoir pressure = 1500 psia
 Reservoir temperature = 220°F
 Condensate gravity = 55° API (0.759 sp. gr.)

SOLUTION: The estimated molecular weight of the condensate from Table 1.9 or by Eq. (2.3) is 124. Then the gas equivalent of the condensate is

$$GE = 53.2 \times 133,000 \times \frac{0.759}{124} = 43,000 \text{ SCF}$$

The data of McCarthy, Boyd, and Reid⁴¹ give a water content of 1.00 bbl/MM SCF at 4000 psia and 220°F and approximately 2.00 bbl/MM SCF at 1500 psia and 220°F. Then of the 5.5 bbl, only 3.25 bbl, i.e., 3.25MM × 1.00 bbl/MM, should be converted to gas, the remainder considered as produced water, and

$$GE_w = 3.25 \times 7390 = 24,000 \text{ SCF}$$

Then the daily gas production ΔG_p is

$$\begin{aligned} \Delta G_p &= 3250.0M + 10.0M + 43.0M + 24.0M \\ &= 3.327MM \text{ SCF} \end{aligned}$$

Where water is produced on the surface as a condensate from the gas phase in the reservoir, it will be fresh water and it should be converted to a gas equivalent and added to the gas production. Since the specific gravity of water is 1.00 and its molecular weight is 18, its gas equivalent is

$$\begin{aligned} GE_w &= \frac{nRT_{sc}}{p_{sc}} = \frac{350.5 \times 1.00}{18} \times \frac{10.73 \times 520}{14.7} \\ &= 7390 \text{ SCF/surface barrel} \end{aligned}$$

Studies by McCarthy, Boyd, and Reid⁴¹ indicate that the water vapor content of reservoir gases at usual reservoir temperatures and usual *initial* reservoir pressures is in the range of a fraction to one barrel per million standard cubic feet of gas. Production data from a Gulf Coast gas reservoir show a production of 0.64 barrel of water per million standard cubic feet compared with a reservoir *content* of about 1.00 bbl/MM SCF using the data of McCarthy, Boyd, and Reid. The difference is presumably that water remaining in the vapor state at separator temperature and pressure, most of which must be removed by dehydration to a level of about six *pounds* per million standard cubic feet. As reservoir pressure declines the water content will increase to as much as three barrels per million standard cubic feet. Since this additional content has come from vaporization of the connate water, it would appear that any *fresh* water produced in excess of the *initial* content should be treated as produced water and taken care of in

the W_p term rather than the G_p term. Of course where the water is saline, it definitely is produced water; however, it includes the fraction of a barrel per million cubic feet obtained from the gas phase. If the produced gas is based on the dehydrated gas volume, the gas volume should be increased by the gas equivalent of the water content at the *initial* reservoir pressure and temperature regardless of the subsequent decline in reservoir pressure, and the water production should be diminished by the water content. This amounts to about a one-half per cent increase in the produced gas volumes.

15. Limitations of Equations and Errors. The precision of the reserve calculations by the volumetric method, Eq. (1.13), depends upon the accuracy of the data which enter the computations. The precision of the initial gas in place depends upon the probable errors in the averages of the porosity, connate water, pressure, and gas deviation factor, and in the error in the determination of the bulk productive volume. With the best of core and log data in rather uniform reservoirs, it appears doubtful that the initial gas in place can be calculated more accurately than about 5 per cent, and the figure will range upward to 100 per cent or higher depending upon the uniformity of the reservoir and the quantity and quality of the data available.

The reserve is the product of the gas in place and the recovery factor. For volumetric reservoirs the reserve of the reservoir as a whole, for any selected abandonment pressure, should be known to about the same precision as the initial gas in place. Water-drive reservoirs require, in addition, the estimate of the volume of the reservoir invaded at abandonment and the average residual gas saturation. When the reservoir exhibits permeability stratification, the difficulties are increased, and the accuracy is therefore reduced. In general, reserve calculations will be more accurate for volumetric than for water-drive reservoirs. Where the reserves are placed on a well or lease basis, the accuracy may be reduced further because of lease drainage, which occurs in both volumetric and water-drive reservoirs.

The use of the material-balance Eq. (1.33) to calculate gas in place involves the terms of the gas volume factor as expressed by Eq. (1.7). The precision of the calculations is, of course, a function of the probable error in these terms. The error in gas production G_p arises from error in gas metering, in the estimate of lease use and leakage, and in the estimate of the low pressure separator or stock tank gases. Sometimes underground leakage occurs as from the failure in casing cementing, or from casing corrosion; or in the case of dual completions, leakage between the two zones. Where gas is commingled from two reservoirs at the surface prior to metering, the division of the total between the two reservoirs depends on periodic well tests, which may introduce additional inaccuracies. Meters are usually

calibrated to an accuracy of one per cent, and therefore it appears doubtful that the gas production under the best of circumstances is known closer than two per cent, and average accuracies are in the range of a few to several per cent.

Pressure errors are due to gauge errors and the difficulties in averaging, particularly where there are large pressure differences throughout the reservoir. When reservoir pressures are estimated from measured wellhead pressures, the errors of this technique enter the calculations. When the field is not fully developed, the average pressure is, of course, of the developed portion, which is lower than the reservoir as a whole. Water production with gas wells is frequently unreported where the amount is small, and where it is appreciable it is often estimated from periodic well tests.

In addition to the errors in the data which appear in the material-balance equation, there are some minor factors which have been neglected in the derivation of the equation: the change in volume of the connate water with pressure, the change in porosity with pressure, and the evolution of gas dissolved in the connate water with decrease in pressure. These factors may be included in the material balance where warranted by the precision of the data. The occurrence of small but unaccounted for amounts of water influx and/or retrograde condensation will affect the results. Under the best of circumstances, the material-balance estimates of the gas in place are seldom more accurate than five per cent, and may range much higher. The estimate of reserves is, of course, one step removed.

PROBLEMS

- 1.1. (a) From the list of elements in Table 1.4, find the molecular weights of the first six members of the paraffin hydrocarbon series: methane CH_4 , ethane C_2H_6 , propane C_3H_8 , butane C_4H_{10} , pentane C_5H_{12} and hexane C_6H_{14} .
(b) What is the molecular weight of acetylene whose formula is C_2H_2 ?
- 1.2. The following experimental data were taken in determining the gas constant. An evacuated glass flask weighs 50.000 g. Filled with pure nitrogen at 14.43 psia and 60°F, it weighs 51.160 g. Filled with distilled water at 60°F, it weighs 1050.000 g. Calculate the gas constant from these data. *Ans:* 10.73.
- 1.3. Calculate the volume one pound mole of ideal gas will occupy at (a) 14.7 psia and 60°F, (b) 14.7 psia and 32°F, (c) 14.7 psia plus 10 oz and 80°F, and (d) 15.025 psia and 60°F. *Ans:* 379.4, 359.0, 377.9, 371.2.
- 1.4. A 1000 cubic-foot tank is filled with air to a pressure of 25 psia at 140°F. Calculate and place in tabular form for comparison, the molecular weight, specific gravity, pound moles in the tank, pounds in the tank, molecules in the tank, SCF at 14.7 psia and 60°F, SCF at 14.7 psia and 32°F, SCF at