$$(S_g)_{opt} = \frac{0.001867\, k^{0.634}\, B_o^{0.902}}{\left(\frac{S_o}{\mu_o}\right)^{0.352}\left(\frac{S_{wi}}{\mu_w}\right)^{0.166}\phi^{1.152}}$$

Pressure psi	Bo bbl/STB	μ_o cp	MBE S_o	S_g	Equation 14-3 $(S_g)_{opt}$
1925	1.333	0.600	0.700	0.000	—
1760	1.287	0.625	0.628	0.072	0.119
1540	1.250	0.650	0.568	0.132	0.122
1342	1.221	0.700	0.527	0.173	

The calculated value of $(S_g)_{opt}$ at 1540 psi agrees with the value of S_g as calculated from the MBE. Thus, to obtain the proposed additional recovery benefit, the primary depletion should be terminated at a pressure of 1540 psi and water injection initiated.

The Concept of Variable-Bubblepoint Pressure

The injection into a solution gas-drive reservoir usually occurs at injection rates that cause re-pressurization of the reservoir. If pressure is high enough, the trapped gas will dissolve in the oil with no effect on subsequent residual oil saturations. It is of interest to estimate what pressure increases would be required in order to dissolve the trapped gas in the oil system. The pressure is essentially defined as the "new" bubble-point pressure (P_b^{new}). As the pressure increases to the new bubble-point pressure, the trapped gas will dissolve in the oil phase with a subsequent increase in the gas solubility from R_s to R_s^{new}. As illustrated in Figure 14-7, the new gas solubility can be estimated as the sum of the volumes

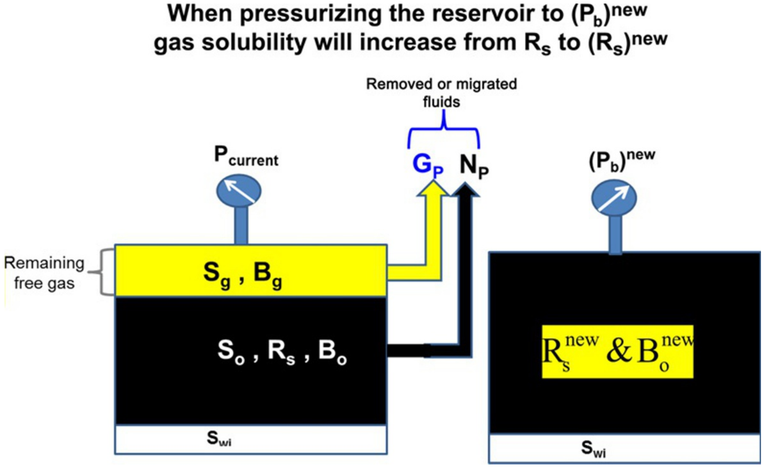

FIGURE 14-7 The concept of variable bubblepoint pressure.

of the dissolved gas and the trapped gas in the reservoir divided by the volume of stock-tank oil in the reservoir, or:

$$R_S^{new} = \frac{\left[\dfrac{(S_O)(\text{Pore volume})}{B_o}\right] R_S + \left[\dfrac{(S_{gt})(\text{Pore volume})}{B_g}\right]}{\dfrac{(S_o)(\text{Pore volume})}{B_o}}$$

Simplifying gives:

$$R_S^{new} = R_S + \left(\frac{S_{gt}}{S_o}\right)\left(\frac{B_o}{B_g}\right) \quad (14\text{-}4)$$

Where:

R_s^{new} = gas solubility at the "new" bubble-point pressure, scf/STB
R_s = gas solubility at current pressure p, scf/STB
B_g = gas formation volume factor, bbl/scf
B_o = oil formation volume factor, bbl/STB
S_{gt} = trapped gas saturation

The pressure that corresponds to the new gas solubility (R_s^{new}) on the R_s vs. p relationship is then identified as the pressure at which the trapped gas will completely dissolve in the oil phase.

Example 14-3

The Big Butte Field is a solution gas-drive reservoir that is under consideration for a waterflood project. The volumetric calculations of the field indicate that the areal extent of the field is 1612.6 acres. The field is characterized by the following properties:

- Thickness $h = 25$ ft
- Porosity $\phi = 15\%$
- Initial water saturation $S_{wi} = 20\%$
- Initial pressure $p_i = 2377$ psi

Results from the MBE in terms of cumulative oil production N_p as a function of reservoir pressure p are given below:

Pressure, psi	N_p, MMSTB
2377	0
2250	1.10
1950	1.76
1650	2.64
1350	3.3

The PVT properties of the crude oil system are tabulated below:

Pressure, psi	B_o, bbl/STB	R_s, scf/STB	B_g, bbl/scf
2377	1.706	921	—
2250	1.678	872	0.00139
1950	1.555	761	0.00162
1650	1.501	657	0.00194
1350	1.448	561	0.00240
1050	1.395	467	0.00314
750	1.336	375	0.00448
450	1.279	274	0.00754

Assume that the waterflood will start when the reservoir pressure declines to 1650 psi; find the pressure that is required to dissolve:

- The liberated remaining gas
- Assuming a remaining trapped gas.

Solution

Step 1. Calculate initial oil in place N:

$$N = 7758\, A\, h\, \phi(1 - S_{wi})/B_{oi}$$
$$N = 7758\,(1612.6)\,(25)\,(0.15)\,(1 - 0.2)/1.706 = 22\,\text{MMSTB}$$

Step 2. Calculate remaining oil saturation by applying Equation 12-5 at 1650 psi:

$$S_o = (1 - S_{wi})\left(1 - \frac{N_p}{N}\right)\left(\frac{B_o}{B_{oi}}\right)$$
$$S_o = (1 - 0.2)\left(1 - \frac{2.64}{22}\right)\left(\frac{1.501}{1.706}\right) = 0.619$$

Step 3. Calculate gas saturation at 1650 psi:

$$S_g = 1 - S_o - S_{wi}$$
$$S_g = 1 - 0.619 - 0.2 = 0.181$$

Step 4. Calculate the gas solubility when all the liberated gas ($S_g = 0.181$) is re-dissolved in the oil by applying Equation 14-4:

$$R_S^{new} = R_S + \left(\frac{S_g}{S_o}\right)\left(\frac{B_o}{B_g}\right)$$

$$R_S^{new} = 657 + \left(\frac{0.181}{0.619}\right)\left(\frac{1.501}{0.00194}\right) = 832\,\text{scf/STB}$$

Step 5. Enter the tabulated PVT data with the new gas solubility of 832 scf/STB and find the corresponding pressure of approximately 2142 psi. This pressure is identified as the pressure that is required to dissolve all the entire remaining liberated gas.

Step 6. Calculate the trapped gas saturation from Figure 14-5 or Equation 14-1, to give:

$$S_{gt} = a_1 + a_2 S_{gi} + a_3 S_{gi}^2 + a_4 S_{gi}^3 + \frac{a_5}{S_{gi}}$$

$$S_{gt} = 12.6\%$$

Step 7. Calculate the gas solubility when all the trapped gas is dissolved in the oil by applying Equation 14-4:

$$R_S^{new} = R_S + \left(\frac{S_{gt}}{S_o}\right)\left(\frac{B_o}{B_g}\right)$$

$$R_S^{new} = 657 + \left(\frac{0.126}{0.619}\right)\left(\frac{1.501}{0.00194}\right) = 814\,\text{scf/STB}$$

Step 8. Enter the tabulated PVT data with the new gas solubility of 814 scf/STB and find the corresponding pressure of approximately 2088 psi. This pressure is identified as the pressure that is required to dissolve the trapped gas.

WATER FLOODING PATTERNS

One of the first steps in designing a waterflooding project is flood pattern selection. The objective is to select the proper pattern that will provide the injection fluid with the maximum possible contact with the crude oil system. This selection can be achieved by (1) converting existing production wells into injectors or (2) drilling infill injection wells. When making the selection, the following factors must be considered:

- Reservoir heterogeneity and directional permeability
- Direction of formation fractures
- Availability of the injection fluid (gas or water)
- Desired and anticipated flood life
- Maximum oil recovery
- Well spacing, productivity, and injectivity

In general, the selection of a suitable flooding pattern for the reservoir depends on the number and location of existing wells. In some cases, producing wells can be converted to injection wells while in other cases it may be necessary or desirable to drill new injection wells. Essentially four types of well arrangements are used in fluid injection projects:

- Irregular injection patterns
- Peripheral injection patterns
- Regular injection patterns
- Crestal and basal injection patterns