National Exams May 2019

17-Pet-A3, Fundamental Reservoir Engineering

3 hours duration

NOTES:

1. If doubt exists as to the interpretation of any question, the candidate is urged to submit with the answer paper, a clear statement of any assumptions made.
2. This is a CLOSED BOOK exam.
3. An approved Casio or Sharp calculator is permitted.
4. FIVE (5) questions constitute a complete exam paper.
5. The first five questions as they appear in the answer book will be marked.
6. All questions are of equal value unless otherwise stated and all parts in a multipart question have equal weight.
7. Clarity and organization of your answers are important, clearly explain your logic.
8. Pay close attention to units, some questions involve oilfield units, and these should be answered in the field units. Questions that are set in other units should be answered in the corresponding units.
9. **A formula sheet** is provided at the end of questions.

Question 1 (20 Marks)

Explain (briefly in one or two sentences) the following reservoir engineering concepts.

1) Irreducible water saturation

2) Effective porosity

3) Residual oil saturation

4) Original oil in place

5) Imbibition

6) Water drive

7) Oil-water contact

8) Retrograde gas reservoir

9) Solution gas-oil ratio

10) Under-saturated oil reservoir

Question 2 (20 Marks)

1). Figure 1 shows a capillary tube filled with water and a slug of gas. The left end of the tube is sealed and the pressure in the water $P_w = 110\ kN/m^2$. The internal diameter of the tube is 0.001 cm. The contact angle of water on the tube wall is 15°. The gas-water surface tension is 72 mN/m. Find the pressure in the gas phase.

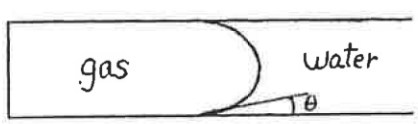


Figure 1. A gas slug in a capillary filled with water

2). An under-saturated oil reservoir has an initial pressure of 3,000 psig and a bubble point pressure of 2,500 psig. The solubility of the solution gas in the oil is 0.25 SCF/STB/psi. Find the initial solution gas oil ratio of the reservoir.

3). The porosity of a core sample is 0.20 and bulk volume of the core is 50 cm^3. The core is saturated with oil and water. Water saturation is 17%. Find the oil volume in the core.

4). A dry core sample of 15 cm in length and 2.5 cm in diameter was measured to be 153.0 grams. After it was saturated with water (ρ_{water} = 1.00 g/cm^3), the core was measured to be 167.7 grams. Calculate the porosity of the core.

Question 3 (20 Marks)

A sand body is 1,000 ft long and has a cross-sectional area of 800 ft^2. The permeability of the sand is 250 md to oil at the irreducible water saturation. The oil has a viscosity of 2.5 cp and a compressibility of 68 $x10^{-6}$ psi^{-1}. The sand is flowing oil at pressure above the bubble point pressure. The oil flow rate is 50 reservoir bbl/day measured at the upstream pressure of 2,500 psia. Calculate:

1) The downstream pressure.
2) The flow rate at the downstream pressure.

Question 4 (20 Marks)

A core sample of 15 cm in length and 2.5 cm in diameter has a porosity of 0.2. The flow rates (in cc/minute) and pressure drops (in atm) of a single water flow test with the core are presented in Figure 2. Table 1 shows the relative permeability measurements of the core as a function of water saturation.

1) Find the permeability of the core from the data given in Figure 2. Water viscosity is 1.05 *cP*.
2) Oil volume in the core at irreducible water saturation.
3) Pressure drop across the core at irreducible water saturation when an oil of 2.0 *cP* is flowed at a rate of 0.02 *cm^3/s*.
4) Pressure drop across the core at residual oil saturation when a brine (water phase) of 1.05 *cP* is flowed at a rate of 0.02 *cm^3/s*.

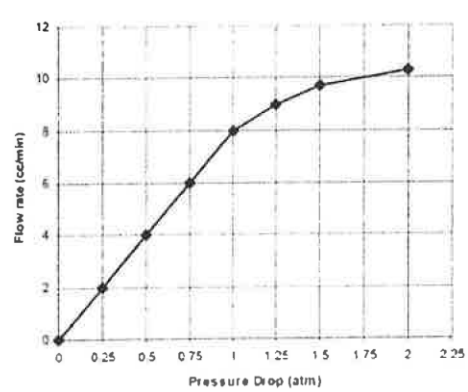


Figure 2. Measured flow rate versus pressure drop curve.

Table 1 Data of relative permeabilities

S_w	$k_{r(water)}$	$K_{r(oil)}$
0.2	0	0.90
0.25	0.0011	0.85
0.3	0.0029	0.72
0.35	0.0047	0.6
0.4	0.0091	0.47
0.45	0.0157	0.35
0.5	0.025	0.24
0.55	0.0372	0.165
0.6	0.053	0.1
0.65	0.073	0.06
0.7	0.097	0.03
0.75	0.1259	0.015
0.8	0.16	0.005
0.85	0.2	0

Question 5 (20 Marks)

The following are for a single-phase gas reservoir:

Reservoir volume	= 5,000 ac-ft
Porosity	= 0.18
Temperature	= 200 °F
Initial pressure	= 5,000 psia
z-factor of gas at 5,000 psia	= 0.95
z-factor of gas at 3,000 psia	= 0.90
z-factor of gas at 750 psia	= 0.95

From the exploration data the initial gas-in-place was estimated to be 7.5 MMM SCF and initial average water saturation was estimated to be 0.32. The reservoir pressure was dropped to 3,000 psia after 3.52 MMM SCF gas was produced. There is no water production. If the estimated initial gas-in-place and the initial water saturation are correct, calculate:

1). The average water saturation in the reservoir at 3,000 psia.
2). The part of gas production which is contributed by water influx.

Question 6 (20 Marks)

The following data are taken from an under-saturated oil reservoir with no water drive and no water production:

Initial water saturation	= 0.25
Initial reservoir pressure	= 3,000 psia
Reservoir temperature	= 150 °F
Bubble point pressure	= 1,775 psia
Formation compressibility (c_f)	= 3×10^{-6} psi^{-1}
Water compressibility (c_w)	= 3×10^{-6} psi^{-1}

Formation volume factor of gas at 1,000 psia= 0.00265 bbl/SCF
Production data and fluids properties are listed in the flowing table:

Pressure (psia)	N_p (STB)	R_p (SCF/STB)	B_o (bbl/STB)	R_{so} (SCF/STB)
3000	0		1.484	845
2500	33,000	845	1.490	845
1000	868,505	1447	1.375	570

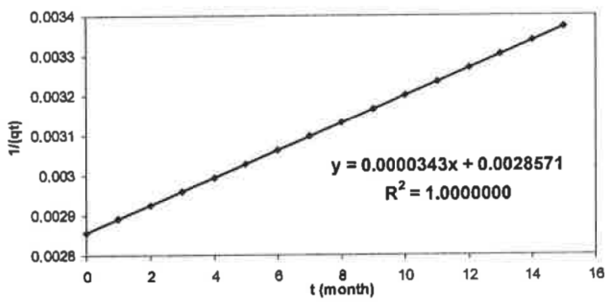
Calculate:

1) Initial oil in place (in STB).
2) Free gas volume in the reservoir at 1,000 psia (in bbl).

Question 7 (20 Marks)

The figure below shows a Harmonic decline-curve plot of a well, $1/q_t$ versus t, where q_t is in *STB/D* and t is in *month*. From the regressed results shown in the diagram, calculate:

1) The initial oil production rate in STB/D. (5 mark)
2) The initial decline rate in month^{-1}. (5 mark)
3) The decline rate at the end of 3 years production. (10 marks)



Decline analysis plot of $1/q_t$ versus t (for Question 7)

Formula Sheet

Capillary pressure

$$P_C = \frac{2\sigma}{r}\cos\theta$$

Darcy's law

$$q = \frac{kA}{\mu}\frac{\Delta P}{L},$$

q = volumetric flow rate (cm^3/sec)
A = cross-sectional area of the sample normal to the flow direction (cm^2)
L = length of the sample in the flow direction (cm)
ΔP = hydrostatic pressure drop (atm)
μ = viscosity of the fluid (cP).

Using these units in Darcy's law results in the practical unit of permeability darcy (D). One darcy is equal to 0.987 $(\mu m)^2$ in SI units. One darcy is a relatively high permeability, and for tight porous materials the unit millidarcy (mD) is used. 1D = 1,000 mD.

$$q_i = \frac{k_{ri}kA}{\mu_i}\frac{\Delta P_i}{L} \qquad i = o, w$$

where q_i is the volumetric flow rate, ΔP_i is the pressure drop, and μ_i is the viscosity of phase *i*. k_{ri} is referred to as "relative permeability" of the porous medium to phase *i*.

Linear Flow of Slightly Compressible Fluids

$$q_R = \frac{0.001127\,kA}{\mu L c}\ln\left[\frac{1+c(p_R - p_2)}{1+c(p_R - p_1)}\right]$$

P_1, P_2	= Pressures, psi	P_R	= Reference pressure, psi
K	= Permeability, md	μ	= Viscosity, cp
L	= Length, ft	A	= Cross-sectional area, ft^2
q_R	= Flow rate at reference pressure, bbl/day		
c	= Isothermal compressibility coefficient, psi^{-1}		

Gas Formation Factor

B_g =0.02829 zT/P ft^3/SCF = 0.00504 zT/P bbl/SCF,

Z = Gas compressibility factor; T = Temperature, °F; P = Pressure, Psia

Material Balance Equations

For Gas Reservoirs

$$G\,(B_g - B_{gi}) + W_e = G_pB_g + W_pB_w$$

For Under-saturated Oil Reservoirs

$$N(B_t - B_{oi}) + NB_{oi}\left[\frac{c_w S_{wi} + c_f}{1 - S_{wi}}\right]\Delta\overline{p} + W_e = N_p[B_t + (R_p - R_{soi})B_g] + W_p B_w$$

$$B_t = B_o + (R_{soi} - R_{so})B_g$$

N	Initial reservoir oil, STB
N_p	Cumulative produced oil, STB
B_{oi}	Initial oil formation volume factor, bbl/STB
B_o	Oil formation volume factor, bbl/STB
B_t	Total oil formation volume factor, bbl/STB
B_{gi}	Initial gas formation volume factor, bbl/SCF
B_g	Gas formation volume factor, bbl/SCF
B_w	Water formation volume factor, bbl/STB
G	Initial reservoir gas, SCF
G_f	Amount of free gas in the reservoir, SCF
R_{soi}	Initial solution gas-oil ratio, SCF/STB
R_{so}	Solution gas-oil ratio, SCF/STB
R_p	Cumulative produced gas-oil ratio at time t, SCF/STB
W	Initial reservoir water, bbl
W_p	Cumulative produced water, STB
W_e	Water influx into reservoir, bbl
c_w	Water isothermal compressibility, psi^{-1}
c_f	Formation isothermal compressibility, psi^{-1}
$\Delta\overline{p}$	Change in average reservoir pressure, psi
S_{wi}	Initial water saturation
z	Gas compressible factor

Harmonic Decline Analysis Equations

$$d = -\frac{1}{q}\frac{dq}{dt}, \quad q_t = \frac{q_i}{(1 + d_i t)}, \quad N_p = \frac{q_i}{d_i}\ln\left(\frac{q_i}{q_t}\right), \quad 1/q_t = 1/q_i + (d_i/q_i)t$$

q_i = initial oil production rate

d_i = initial decline rate

N_p = cumulative production

q_t = production rate at time t

n = hyperbolic decline exponent

Conversion factors:

1 bbl = 5.615 ft^3

1 lb-mole ideal gas = 380 SCF

1Darcy = 9.869233×10^{-13} m^2

1 cP = 0.001 Pa-sec

1 acre-ft= 43,560 ft^3 = 7,758 bbl

1 m^3 = 6.28981 bbl =35.3147 ft^3

1 atm =14.6959488 psi =101.32500 kPa=1.01325 bar

1 m = 3.28084 ft = 39.3701 inch