TENTAMEN : Production Technology I (mp3440)
November 23 1999

Answer all questions. Answer in either English or Dutch (or a mixture).

Question 1

a) Explain the phase behaviour of a hydrocarbon as it is produced from the reservoir, through the tubing and into the surface facilities.

b) Oil is produced from a reservoir at depth 15000 feet. The reservoir pressure is 5000 psi and the reservoir temperature is 200 F. The oil has API gravity 35, gas specific gravity 0.65, and producing gas/ oil ratio 1000 scf/bbl. Use Standing's black oil correlation to calculate the bubble point pressure for the oil at the reservoir temperature.

c) What are the different flow regimes that can exist in multiphase flow in a tubing. Explain the significance of the bubble-point pressure for flow in a tubing, and the consequences for the flow when gas comes out of solution.

d) This oil is produced by a vertical well with 4½" tubing. The watercut is zero and the PI of the well is 10 bbl/day/psi. The production rate is 1000 bbl/day. Calculate the flowing bottom hole pressure. Estimate from the Duns/Ros curve the depth in the tubing at which gas comes out of solution (accuracy to within 500 ft). Ignore temperature effects - assume oil stays at reservoir temperature.

Question 2

a) Use the Duns/Ros gradient curves to calculate the flowing bottomhole pressure p_{wf} for the following well at the flowrates 600, 1000, 2000, 4000, 6000 and 10000 bbl/day

depth of producing interval	12500 ft
GOR	1500 scf/bbl
Water cut	0%
Tubing size	4½"
Tubing head pressure	750 psi

b) The initial reservoir pressure is 7000 psi and the PI is 2 bbl/day/psi. What is the initial production rate and flowing bottomhole pressure?

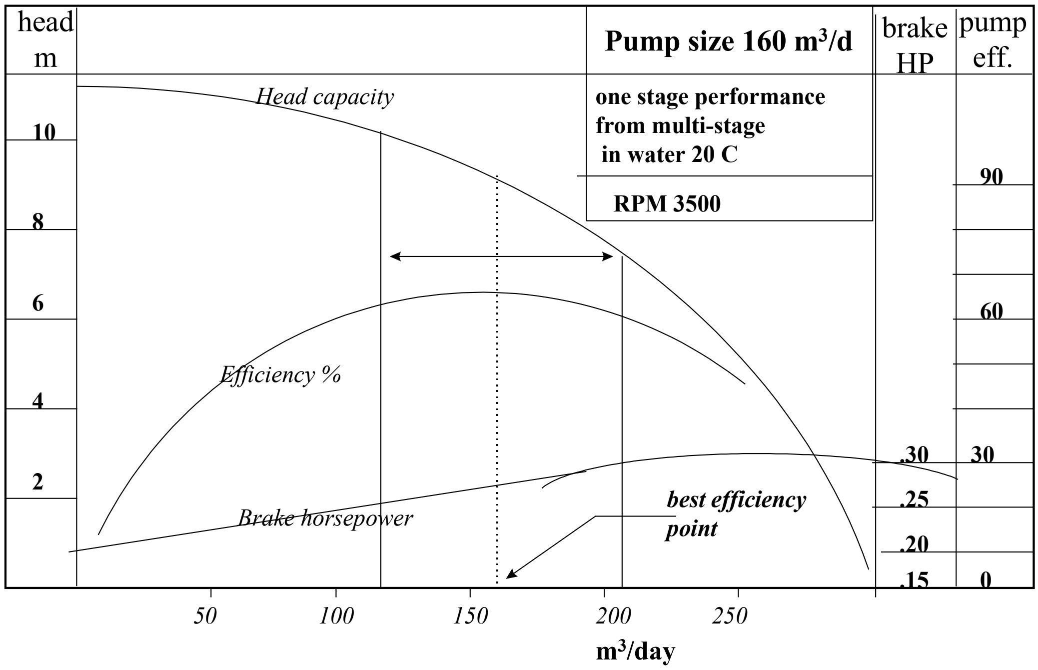
c) If the PI of the well stays constant during production of the well, what is the lowest reservoir pressure at which the well can produce without artificial lift? What is the final production rate in bbl/day?

d) The pressure downstream of the wellhead choke is 200 psi. Show that the flow through the choke is critical. What does this imply for pressure stability in the well?

Question 3

a) What are the advantages and disadvantages of an ESP compared with other forms of artificial lift? How can sand and gas (in moderation) be handled?

b) The performance curve of an ESP at 50Hz frequency is given here



An ESP is constructed from 100 of these stages. What is the range of the pressure increase across the ESP (maximum and minimum pressure increases) and the range of flow rates it can handle, assuming that the operating point stays within its designed operating range. What happens to these ranges if the frequency is varied in the range 40-60 Hz?

Question 4

a) Discuss the costs of gas-lifting. Why is it not always economically attractive to use a high gas injection pressure, even if this allows deeper injection of lift gas.

b) In a well in which it is planned to install gas lift, the closed in tubing head pressure is 200 psi and the static fluid pressure gradient is 0.44 psi/ft. The gas injection pressure on surface is 1200 psi and the gas gradient is 0.04 psi/ft. Determine the deepest point at which gas can be injected without gaslift valves.

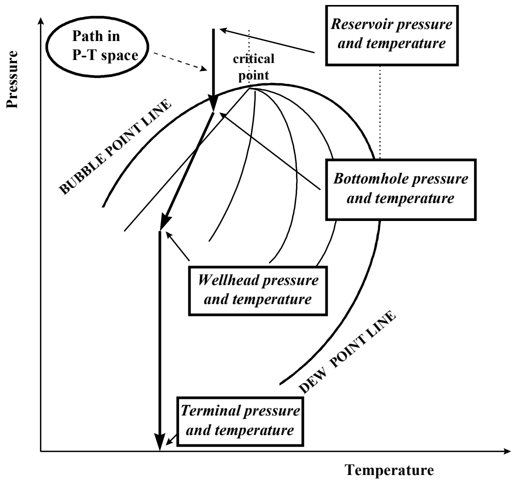
c) When the well is under gaslift, the flowing well gradient is approximately 0.14 psi/ft. The tubing head pressure is maintained at 200 psi. Estimate the deepest point at which gas can be injected with gaslift valves.

d) The gaslift valves are adjusted to operate at a pressure 100 psi above the flowing well gradient. Estimate the deepest point at which gas can be injected with these valves.

e) Estimate the setting depths and pressures of the first three valves.

Solution to Question 1

a) As a hydrocarbon flows from the reservoir through the production system, it follows a path in P-T space.



Critical points in this path are those when the bubble-point line or the dew-point-line are crossed. At these points the flow becomes multiphase; either gas comes out of solution (for an oil reservoir) or liquid condenses (for a gas reservoir.

In an oil reservoir, the gas is generally in solution, and stays there until the oil enters the tubing. As the oil rises in the tubing, the pressure and temperature increase. At a given point gas comes out of solution, and more comes out of solution as the oil rises further in the tubing. As the oil passes through the choke at the wellhead, even more gas comes out of solution.

b) Standing's correlation in field units gives :

$$p_b = 18.2 \{ (R / \gamma_g)^{0.83} \, 10^{[0.00091\, T - 0.0125\, \gamma API]} - 1.4 \}$$

Hence,

$$p_b = 18.2 \{ (1000 / 0.65)^{0.83} \, 10^{[0.00091*200 - 0.0125*35]} - 1.4 \}$$
$$= 4440 \text{ psi}$$

c)

d) Reservoir pressure is 5000 psi and PI is 10 bbl/day/psi. Production rate is 1000 bbl/day. Hence flowing bottom hole pressure is given by :

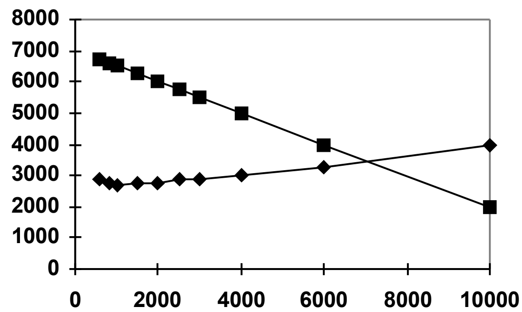
$$p_{wf} = p_r - q/PI = 5000 - 1000/10 = 4900 \text{ psi}$$

Using Duns/Ros curve (4½" tubing, GOR 1000 scf/bbl, 1000 bbl/day) the height at which the bubble point pressure is reached is 2500 ft higher above the reservoir, i.e. at depth 12500 ft.

Solution to Question 2

a)

q bbl/day	p_{wf}	inflow
600	2850	6700
800	2750	6600
1000	2700	6500
1500	2750	6250
2000	2750	6000
2500	2850	5750
3000	2900	5500
4000	3000	5000
6000	3250	4000
10000	4000	2000



b) Initial production rate is about 7000 bbl/day. Flowing bottomhole pressure is 3500 psi.

c) Lowest production rate is about 1000 bbl/day, at bottomhole pressure 2700 psi. If PI stays as 2, reservoir pressure is 2700 + 2*1000 = 4700 psi

d) The ratio of the pressures upstream and downstream of the choke is 750/200 = 3.5, which is greater than the value 1.7 required for critical flow. Hence the flow is critical.

Solution to Question 3

a) Advantages :

does not require gas
can handle deviated wells
can be used offshore

Disadvantages :

requires more careful handling and maintenance
requires careful sizing
cannot handle excessive sand
cannot handle excessive gas

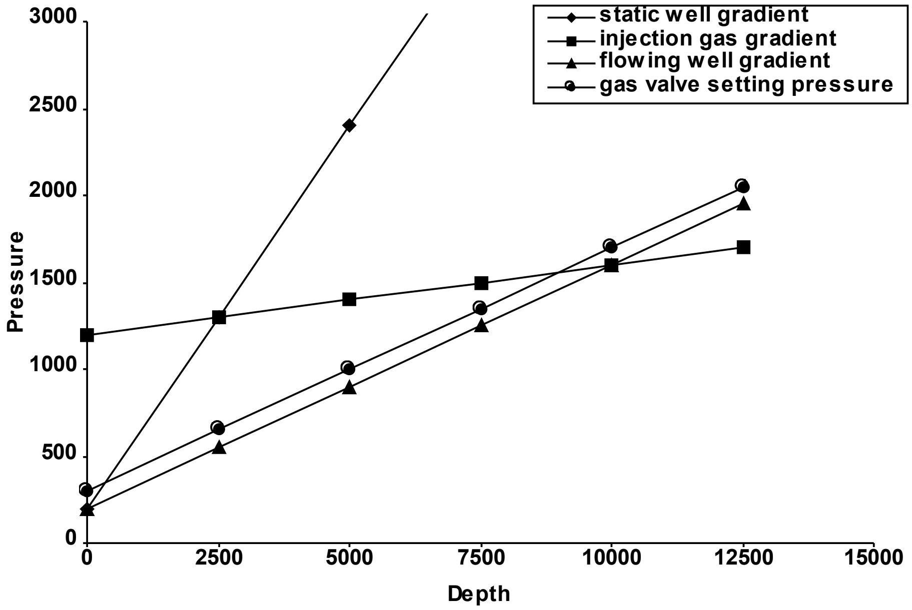
b)

Question 4

a)

b) Depth d at which static oil gradient = gas gradient is given by
200 +0.44 d = 1200 + 0.04 d
d = 1000/0.4 = 2500 ft . Pressure = 200 + 0.44*2500 = 1300 psi

depth	static oil gradient	injection gas gradient	flowing oil gradient	gas valve setting pressure
0	200	1200	200	300
2500	1300	1300	550	650
5000	2400	1400	900	1000
7500	3500	1500	1250	1350
10000	4600	1600	1600	1700
12500	5700	1700	1950	2050



c) From graph estimate deepest injection point is between 10000 ft

d) The valve setting pressures are 100 psi above the flowing well gradient. Thus maximum injection depth is 9000 ft.

e) We can either calculate the valve depths and pressures graphically (see lecture notes) or numerically. Graphically is far quicker, and advised in an examination. Numerically we proceed as follows:

First valve. The first valve is placed at 2500 ft. At this depth, the flowing well pressure is 550 psi. Thus the setting pressure is 650 psi.

Second valve. The fluid gradient line through 650 psi, 2500 ft has equation

$$p = 650 + 0.44*(d - 2500)$$

This meets the gas gradient line when

$$1000 + 0.04*d = 650 + 0.44*(d - 2500) \quad \text{giving } d = 3625 \text{ ft}$$

The second valve is therefore placed at 3625 ft. At this depth, the flowing well pressure is 200 + 0.44*3625 = 1795. Thus the setting pressure is 1895 psi.

Third valve. The fluid gradient line through 1895 psi, 3625 ft has equation

$$p = 1895 + 0.44*(d - 3625)$$

This meets the gas gradient line when

$$1000 + 0.04*d = 1895 + 0.44*(d - 3625) \quad \text{giving } d = 6825 \text{ ft}$$

The third valve is therefore placed at 6825 ft. At this depth, the flowing well pressure is 200 + 0.44*6825 = 3203 psi. Thus the setting pressure is 3303 psi.