Contents

1 Methodology

The objective is to derive the wellhead pressure based on data given for well and the flowing bottom-hole pressure. Firstly, the well data are entered according to the problem sheet. The tubing inclination angle is assumed to be 85 degrees. Water is assumed to be incompressible and hence Bw = 1. Temperatures are in degrees Fahrenheit. Gas gravity and API were equal to the ones given in Assignment #4.

1.1 Marching Algorithm

The middle loop is to determine the bottom-to-top pressure drop for each grid, and the inner-most loop is to correct each guessed pressure for the i'th grid. So, basically the main calculations are carried out in this loop.

An initial guess of $P_w f - 10$ is implemented at first for the above grid in the well, $P(i-1)$, and in each iteration in the middle loop, the guess is corrected according to

$$P(i-1) = P(i) - dP$$

where dP is the pressure drop calculated with the pressure drop correlation in the final lines of the code. In the next step, average pressure is calculated and put into the parameter, P_{av}, using the estimated value for pressure. In the 4th step of the algorithm, fluid PVT properties are derived based on the Standing black-oil model, which means that B_o, and R_s are calculated easily using the correlations provided by Standing and knowing the average pressure in the grid. The procedure for PVT calculation is carried out within a seperate function called 'calcStanding'. Now the tricky part is obtaining the Z-factor for calculating gas PVT parameters.

To calculate the gas deviation factor the implicit Z-factor correlation provided by Standing is used. This equation is solved for the parameter ρ_r using the Newton-Raphson numerical method, and then Z is calculated via its relationship with ρ_r. So, there is a mini-loop implemented for this calculation. Getting the algorithm to converge depends on the equation in this part to be solved accurately as the Newton-Raphson method could converge to an irrelevant (negative) solution for ρ_r which leads to an inaccurate Z-factor. So the first guess for ρ_r is of importance for the marching algorithm to converge. Subsequently, gas density and gas formation volume factor, B_g, are calculated based on the obtained Z-factor.

In the next step, step 5, the flow-rates for each phase are updated based on the obtained volume factors. Oil fraction and water fraction of the fluid phase are calculated to determine the flow-rate of liquid phase, and eventually get to the no-slip liquid hold-up, λ_L, and gas void fraction, λ_G. Superficial velocities and mixture velocity are then calculated along with mixture density to calculated friction factors using the function 'calcFF'. Finally, pressure gradient in the i'th increment of the pipe is calculated via

$$dP/dL(i) = dP_{hydrostatic}(i) + dP_{frictional}(i)$$

where

$$dP_{hydrostatic}(i) = \rho_n \times sin(\phi)$$

and

$$dP_{frictional}(i) = (f_{tp}(i)\rho_n v_m^2)/2/gc/D$$

note that g_c is equal to 32.17.

The final step is to determine an error criteria for the inner loop to converge on a good estimate for $P(i-1)$. This criteria is based on the absolute difference of the guessed pressure drop and the pressure drop calculated via the algorithm. If this criteria is met, the inner loop will be circumvented and the pressure for the a $P(i-1)$ is obtained based on the calculated pressure drop.

1.2 Poettmann-Carpenter vs. Fancher-Brown

For the third assignment, there has been a function created called 'calcFF' to obtain the friction factor based on no-slip mixture density, mixture velocity, tubing inner diameter and the parameter, n, which will be elaborated. In the main code, the outer most loop is revolving the parameter n from 1 to 2. If n = 1, then the calcFF function will calculate the Poettmann-Carpenter friction factor and if it is equal to 2, the Fancher-Brown correlation is chosen.

1.3 Beggs & Brill Method

Assignment #4 uses the same marching algorithm except for minor changes, which will be discussed briefly.

For this assignment the Beggs Brill method, which is a 'type c' method (i.e. slippage and flow patterns are allowed at each increment), is used to derive the frictional and hydrostatic pressure gradient terms. To meet this end two main parameters are to be calculated which are the friction factor and $\overline{\rho}$. These parameters along with other important ones are obtained through two functions called 'calcBB' and 'calcFrictionPressure'. The former is related to calculating the hydrostatic pressure gradient, liquid hold-up and, dominant flow pattern, and the latter is involved with deriving the two-phase friction factor. Note that Chen's equation has been used to derive the non-slip friction factor.

The data are entered based on the problem sheet except for the tubing diameter which is considered to be equal to 6 instead of 1.995 in. This is due mainly to getting better more realistic results from the application. The well deviation from the vertical axis is assumed to be zero.

2 Results

2.1 Assignment (3)

The results generated by running the code are basically two numbers and two figures. The numbers which are shown in the MATLAB Command Window are the wellhead pressure for each friction factor correlation. The mesh independency of the code has been proven by altering dL, which initially is was assumed equal to 200 ft. Figure 1 shows the pressure profile for the conditions defined by the problem sheet plus phase gravities provided by Assignment #4.

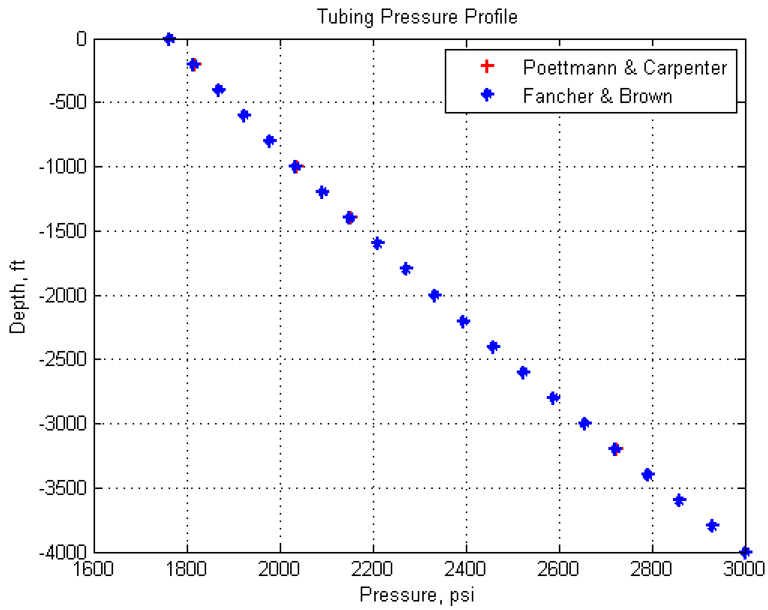


Figure 1: The resulted tubing pressure profile.

As is evident in Figure 1, the two friction factor correlations did not demonstrate much of a difference at estimating the wellhead pressure considering the current well conditions. Their difference, however, is shown in Figure 2 which shows the performance of each correlation at high oil flow-rates.

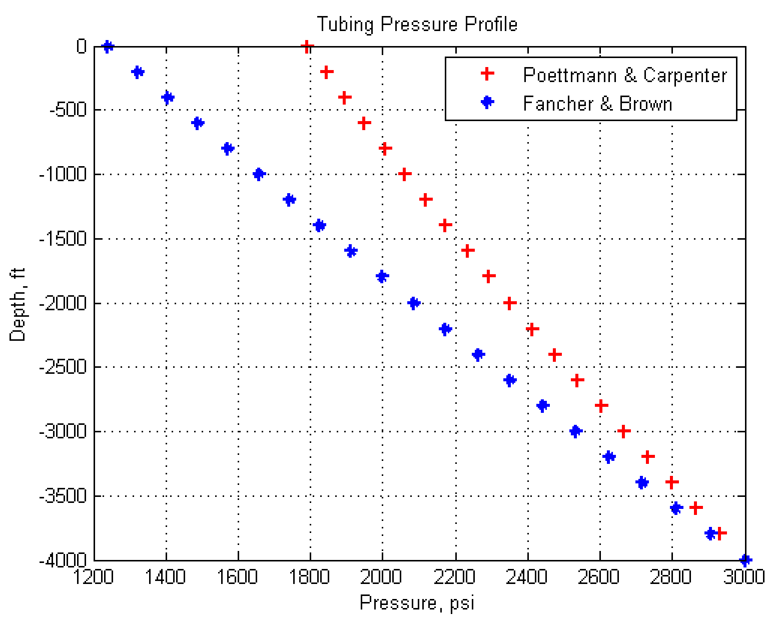


Figure 2: Tubing pressure profile at high oil flow-rates.

Figure 3 provides the contribution of each pressure drop term in the total pressure drop.

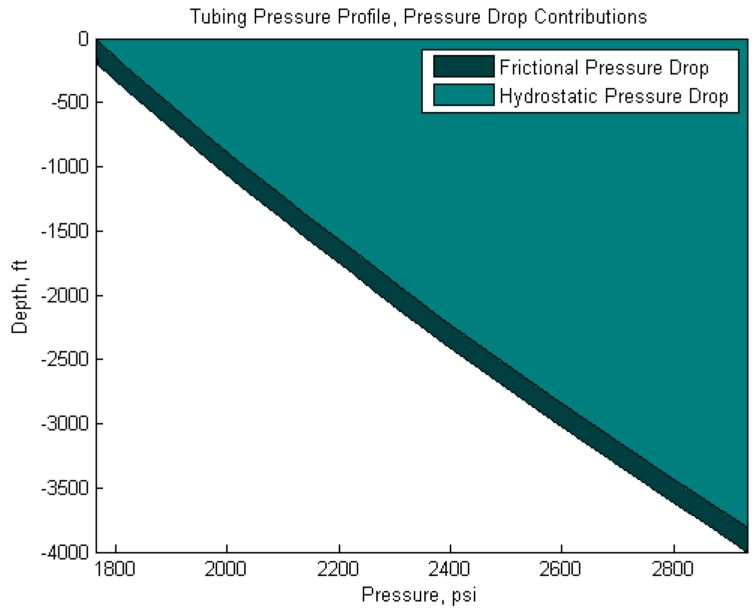


Figure 3: Hydrostatic and frictional pressure drop contributions to the total ΔP.

The model has been run for oil API gravity of 45 degrees instead of the default 30, and gas gravity equal to 1.1 as opposed to 0.75 in the above-mentioned flow-rate condition, i.e. $Q_o = 12000 STB/day$. The resulting wellhead pressure can be inferred from Figure 4 which shows considerable drop in the predicted wellhead pressure, and furthermore, clearly differentiates the Poettmann-Carpenter friction factor correlation from the Fancher-Brown friction factor correlations.

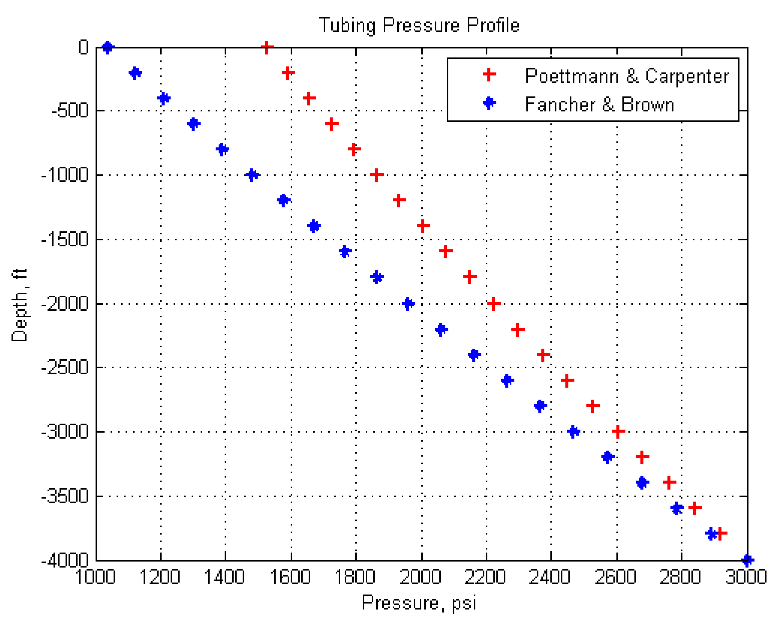
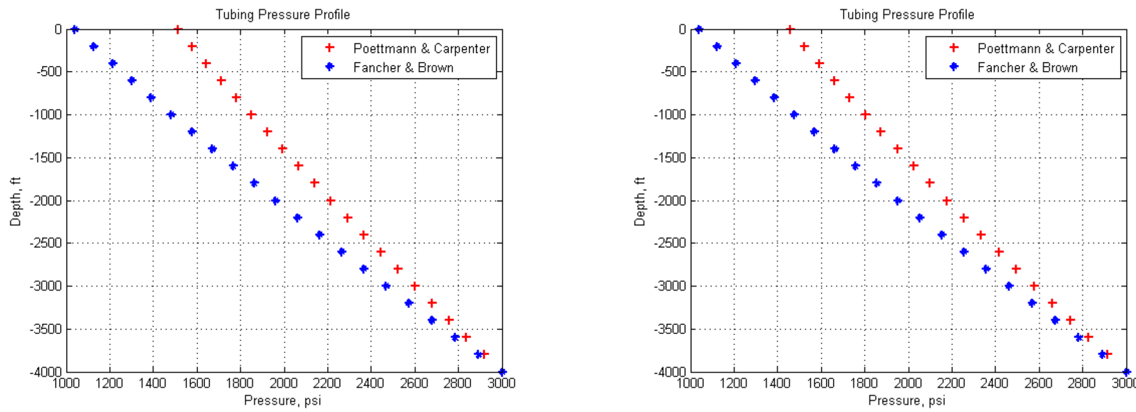


Figure 4: Pressure profile considering API = 45, and $\gamma_g = 1.1$.

2.1.1 Altering the Water-cut

As for the second part of the problem, the water cut, f_o, has been shifted from .25 to approximately half its value by altering Q_o from 200 to 85. The resulting wellhead pressure calculated by the model were 1765 psi for PC correlation, and 1761 psi for the FB correlation which were virtually the same as their originally value ± 2 psi. However, for the above-mentioned 'altered' conditions of gas and oil gravity and oil flow-rate, the water flow-rate has been changed from 5000 STB/day to 1000 STB/day, which essentially reduced water-cut by half, and the changes can be observed in Figure 5.



(a) $Q_w = 1000$ STB/day (b) $Q_w = 5000$ STB/day

Figure 5: The effect of water-cut on estimated wellhead pressure in altered conditions.

It can be seen from Figure 5 that even for the so-called 'altered' case the difference between the estimated wellhead pressure in the two water-cuts is so little. The Poettmann-Carpenter version shows approximately 50 psi reduction in wellhead pressure.

2.2 Assignment (4)

The results for this assignment are presented in three cases which will be further elaborated. Note that the application for this problem may take about 30 seconds or more to run.

2.2.1 Case (a)

As it was mentioned earlier, only one parameter has been adjusted for attaining better results, which would be the tubing diameter. All other data for this case have been kept unchanged. The pressure profile throughout the well is according to Figure 6.

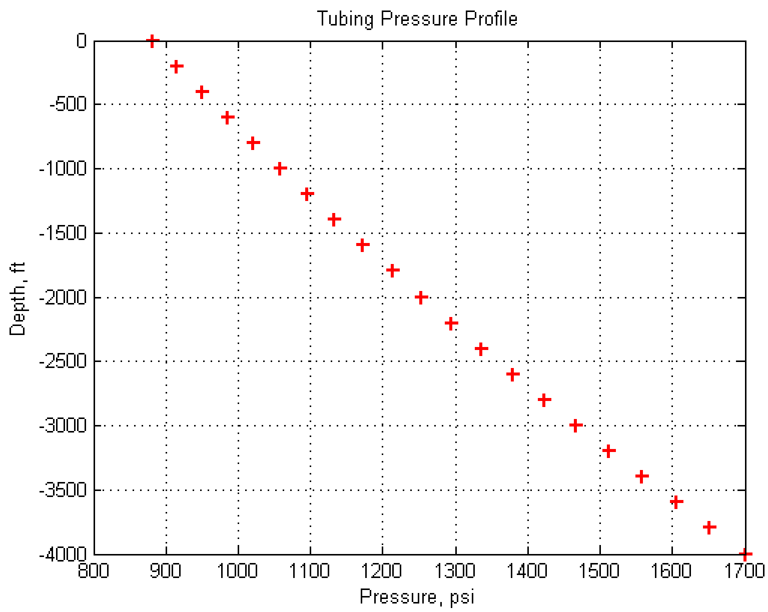


Figure 6: Pressure profile for case (a).

Figure 7 shows the dominant flow pattern according to the Beggs & Brill flow map. For this case fluid flow was following the criteria for the interemittend flow. Figure 8 demonstrates liquid hold-up at all increments.

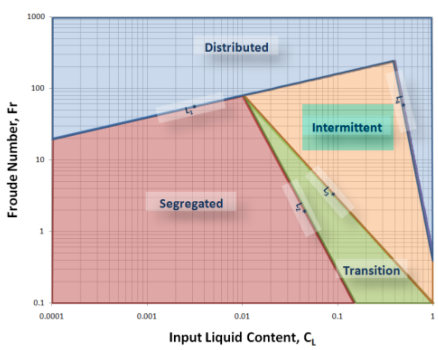


Figure 7: Flow regime for case (a)

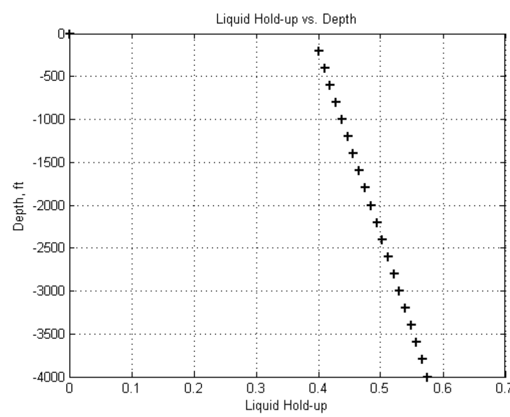


Figure 8: Liquid hold-up distribution for case (a)

2.2.2 Case (b)

The behavior of the model is inspected through some adjustments including $Q_o = 1000$ STB/day, and $R_p = 10$ Mscf/STB which makes it 10 times larger than its previous value. Figure 9 shows the well head pressure has been decreased by 200 psi.

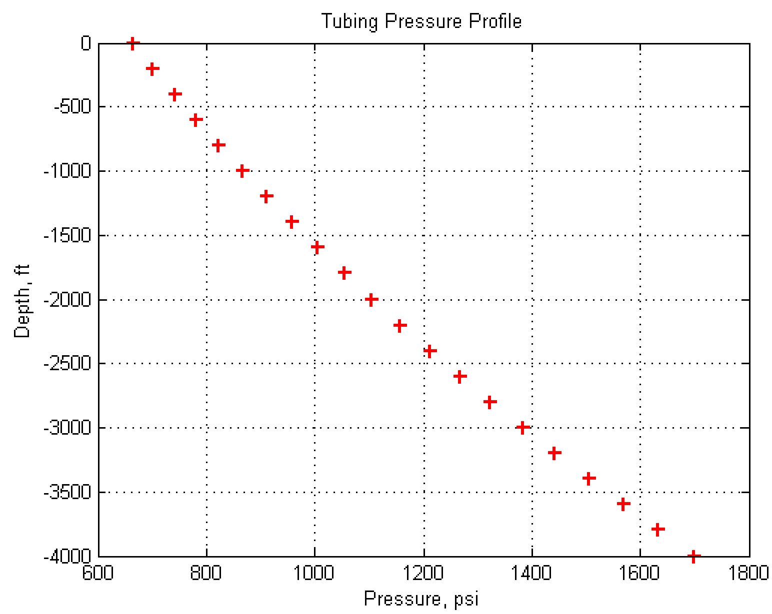


Figure 9: Pressure profile for case (b).

Conversly, liquid hold-up has been shifted upwards especially in deeper increments. Figure 10 and 11 also represent the flow regime and hold-up distribution respectively. The flow regime for this case is diagnosed to be of segregated origin.

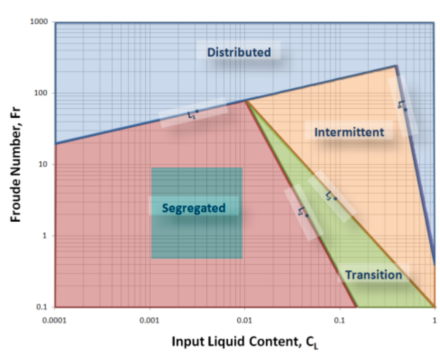


Figure 10: Flow regime for case (b)

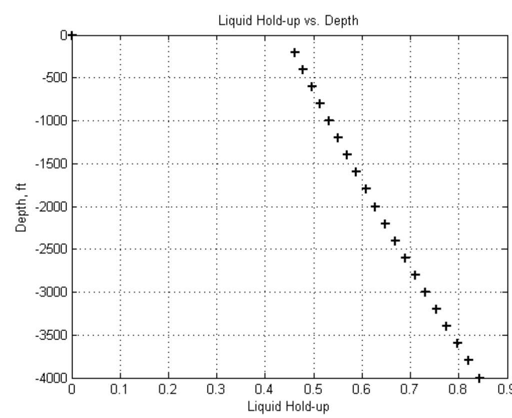


Figure 11: Liquid hold-up distribution for case (b)

2.2.3 Case (c)

Similar to Case (a) altering only the tubing diameter from 6 in to $10\frac{1}{2}$. The results show two flow regimes, one from the bottom to semi-top which is transition, and the second flow regime is intermittent near the well head. Figure 12 and 13 show the plots generated for this case.

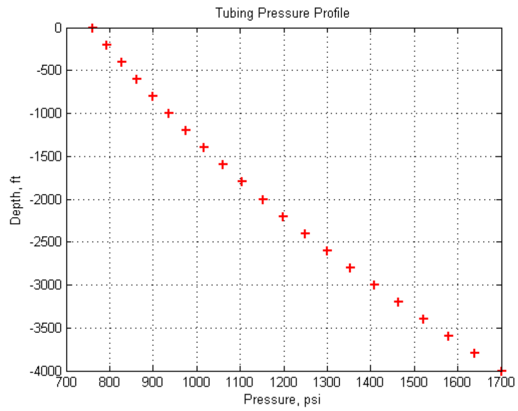


Figure 12: Tubing pressure profile for case (c)

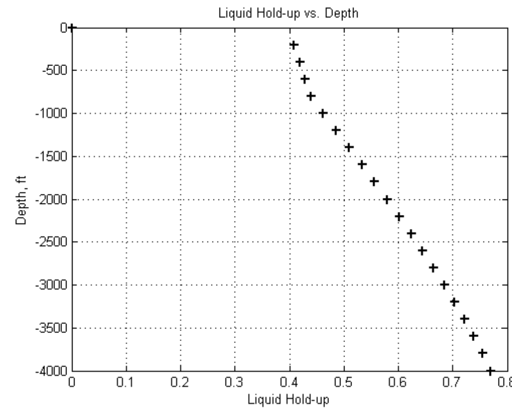


Figure 13: Liquid hold-up distribution for case (c)

References

Course notes, slides and provided documents.