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**1. WELLHEAD AND SURFACE GATHERING SYSTEMS:**

**Abstract:**

**This chapter is concerned with the pressure changes that occur during fluid flow across pipes, chokes and fittings from the wellhead to their processing unit at the surface. It focus more on the flow through horizontal pipes in a single phase flow and two phase flow using some correlations such as Chen’s, Beggs and Brills, Mandle, and moody diagram. It uses the principle of mechanical energy to determine the pressure drops.**

**INTRODUCTION:**

**For the processing of oil and gas, facilities such as two or three phase separators, gas plant, compressor station or from transport line, are used so that as the fluids flows from the well head to the surface where they are processed, the pressure drop across each facilities can be measured either by a device or through the use of established correlations.**

**OUTLINE:**

**Main topic: I. Flow through horizontal pipes**

**Sub topics: i. Single phase flow; Liquid flow “Chen’s correlation and Moody diagram”**

**Gas flow “Real gas law, Reynolds number and Pipeline roughness”**

**Two phase flow; Baker’s and Mandle flow regime maps (1958) and Beggs and Brills flow regime maps (1973) “Beggs and Brills Correlation (1978)”, Mandhane flow regime maps(1974):**

**Flow regime: Segregated flow “stratified wavy, stratified smoothly and annular flows”**

**Distributive flow “bubble, dispersed bubble, mist, and froth flows”**

**Intermittent flow “slug and plug flows”**

**Taitel and Dukler model (1976)**

**ii. Pressure gradient correlations “Beggs and Brills(1973), Eaton(1967), and Duklers (1969)**

**iii. Pressure Transverse Calculations “Integrated Duklers Correlation”**

**iv. Pressure drop through pipe fittings**

**II. Flow through chokes: i. Lengths in valves and fittings**

**ii. Single phase liquid flow ”Crane (1957)”**

**Single phase gas flow “Szilas (1975)”**

**iii. Two phase flow “Gilbert (1954), Ros (1960), Wallis (1969), and Omana(1969)”**

**III. Surface Gathering Systems; Szilas (1975)**

**FLOW IN HORIZONTAL PIPES**

**i. Single phase liquid flow:**

**Originally, mechanical energy equation which com[prises of the potential energy, kinetic energy, and frictional energy is used to calculate pressure drop across pipelines. In the case of an horizontal flow where the fluid is incompressible and the pipe diameter is constant then the pressure drop across the potential energy and kinetics energy becomes zero leaving only the frictional energy, given as:**

∆P = P1-P2 =

**Where ʄ = frictional factor obtained from Chen’s correlation or moody diagram**

**ρ = density**

**u = velocity gotten mostly from and A =**

**gc = gravity constant usually 32.17**

**D = pipeline diameter**

**Example 10-1:**

∆P = P1-P2 =

**ʄ obtained from Chen correlation given as:**

**= -4log(log(**

**Ԑ =**

**= determine turbulent and laminar flows**

**Where Ԑ = Relative roughness**

**σ = Absolute roughness**

**= Reynolds Number**

**μ = Viscosity**

**or Moody diagram given as:**

**ʄ =**

**where = moody friction factor function of (Ԑ, )**

**In the question q, L, D, Ԑ, P2, S.G, μw were given while the NRe , u, ʄ were gotten with formulas and correlations in order to get the P1 and ∆P.**

**∆P = P1 –P2**

**P1 =P2 + ∆P = (100 + 145)psi = 245psi**

**Single phase gas flow:**

**In a high rate, low pressure line, the kinetic energy is significant otherwise can be neglected. The over pressure drop is then given by:**

**+ + =0**

**For real gas equation; PV = nZRT but n=**

**Substituting n, PM = RTZρ**

**ρ =**

**The differential form of kinetic energy is:**

**Udu = [ \***

**Assuming average values for Z and T**

**P12 – P22 = [\*[**

**P12 – P22 =4.195\*10-6[ \*[**

**EXAMPLE 10-2:**

**From the question P1, L, P2, D, S.G, T, Ԑ, μ were used to get q**

**Assuming that the flow is fully rough wall turbulent, ʄ is depended only on Ԑ.**

**Therefore q =**

**Q =10800MScf/day**

**Two phase flow:**

**Beggs and Brills correlation doesn’t change for any type of flow direction. Here, the flow regimes and pressure drops are considered.**

**Flow regime:**

**The slug and its catcher are considered here. They are classified as;**

**i. Segregated flow:- under this we have, stratified smooth, stratified wavy and annular flows.**

**The stratified smooth flow consists of liquid flow along the bottom and the gas flows on the top with smooth interface with low gas rates.**

**The stratified wavy (also known as ripple) flow consists of high gas rates.**

**The annular flow at high gas rates, consists of liquid coating on the wall of the pipes and a central core of gas flow with liquid droplets entrained in the gas.**

**ii. Intermittent flow (also called elongated bubble flow):- under this we have, plug and slug flows.**

**The plug flow comprises of large gas bubble flow along the top filled with liquid.**

**The slug flow consists of large liquid slugs with high velocity gas bubble that almost fills the entire pipe.**

**iii. Distributive flow:- here we have, bubble, dispersed, mist, froth flows.**

**The bubble flow comprises of gas flowing on upper side.**

**The mist flow consists of high gas rates and low liquid rates and gas with liquid droplets entrained.**

**The froth flow is used to describe the mist and annular flow regimes.**

**Flow regimes are predicted with flow regimes maps. They include:**

**i. One of the most popular is the Baker (1953) map modified by Scott (1963) shown in fig 10-2. The plot is of the co-ordinate (,)**

**Where Gl and Gg are the mass fluxes of the liquid and gas respectively.**

**λ = []1/2**

**∅ = [2]1/3**

**Gl = Usl\*ρl**

**Gg = Usg\*ρg**

**Usl =**

**Usg =**

**The shaded region on fig 10-2 indicates that the transitions from one flow to another are not abrupt, but over ranges of which flow conditions will occur.**

**ii. Mandhane (1974) fig 10-3, uses the gas and liquid superficial values as co-ordinates (Usg,Usl).**

**iii. Beggs and Brills (1973) correlation is based on the map that divides the three main flow regimes shown in fig 10-4 and plots (λl, Nfr).**

**Nfr = and Um = Usg + Usl**

**iv. Taitel and Duckler (1976) model used to generate flow regime maps for a particular fluid and pipe size. Fig 10-5 compares prediction with Mandhane et al for air water flow in a 2.5cm pipe. It plots (Usg, Usl).**

**EXAMPLE 10-3:**

**qg, ql, P, T, D, ρl, μl, σl, ρg, μg, Z were given. So in orer to compare among the different correlations, we must determine each of their parameters and read them from their plots. We calculate for A, Usl, Usg, Um, Gl, Gg, σ, λ.**

**The final gave that the Baker map predicted dispersed bubble flow, Mandhane map predicted slug flow, Beggs and Brills map predicted intermittent flow which could be plug or slug flow. Taitel and Duklers map predicted slug flow. Only the Baker map disagrees.**

**NOT INCLUDED IN THYE QUESTION BUT FOR MY UNDERSTANDING:**

**Pressure gradient correlations:**

**The most common correlations used in the industry for pressure gradient determination are the Beggs and Brill (1973), Eaton et al (1967), and Dukler (1969) correlations. Kinetic energy contributes to pressure gradient.**

**i. Beggs and Brill correlation:**

**It is simplified if θ = 0, then making ψ = 1**

**EXAMPLE 10-4**

**Steps:**

**Determine flow regime,**

**Calculate the hold up using ylo =**

**To get friction pressure gradient, get the no-slip friction factor**

**ρm =ρlλl + ρgλg**

**NOTE: no graph and solution to example 10-5.**

**ii. Eaton et al correlation:**

**NOTE STEP 10-25 to 10-37 ARE MISSING**

**It plots (abscissa value, yl) with the abscissa value given as:**

**ʄ() = 0.01**

**Frictional pressure gradient is given as:**

**[f =**

**The Dimensionless numbers are given by:**

**Nvl = 1.938Usl\***

**Nvg = 1.938Usg\***

**ND = 120.872D\***

**NL = 0.15726μL\***

**The Beggs and Brill and Eaton correlations agree which predicts lower pressure gradient.**

**iii. Dukler (1969) correlation:**

**It is based on empirical correlation of ʄ and yL. the pressure gradient consists of kinetic energy and ʄ.**

**i.e = [f + [K.E**

**[f =**

**ρk = +**

**The ʄ is gotten from no-slip friction factor ʄn given as**

**ʄn = 0.0056 + 0.5[NRek]-0.3**

**=**

**Two phase is given by:**

**= 1 -**

**[K.E = ∆( + )**

**EXAMPLE 10-6**

**Using 10-4 and 10-5 question, use Dukler correlation to determine pressure gradient.**

**Step:**

**Assume yL = λL, ρk = ρm, NRek = NRem\***

**Get ʄn, ʄ and [f**

**All the correlation gives the same yL but different**

**Pressure Transverse Calculations:**

**This provides a means of calculating pressure gradient at a point, overall pressure drop, amd change in pressure gradient. Integrating Dukler correlation, we have;**

**∆P = + ∆( + )**

**ʄ, , and are evaluated at the [P1 + P2]/2. If ∆P over the distance L is greater than 10% of inlet pressure, L should be divided into smaller increments, and the pressure drops across each increment should be calculated. The total pressure drop is the sum of the entire smaller increments pressure drop.**

**EXAMPLE 10-7**

**qg, qo, D, P2, T, L were given, the calculate for pressure gradient, the pressure was > 10% of the original pressure. The L was divided into two segments, calculate for the first increment. Get ρg, qg, ql. Get the qt = qg + ql. Get the λL and λg. Get the um from qt/A, estimate the yL = y@extrance.**

**Get the ρk, μm = μlλl + μgλg, get =**

**Get the L =**

**Increment length = Lo- L**

**Follow the same procedure for the second increment.**

**Pressure drop through pipe fittings:**

**When fluids passes fittings or valves, secondary flow and additional turbulence create a pressure drop which is needed to determine total pressure drop and this is done by adding equivalent length of the fittings and valves to the actual length of the straight pipe. The equivalent length are shown in the Table 10-1 and was determined by Crane (1957) who arranged them in order of valves type, patterns, description of fittings, fittings size, equivalent length in pipe diameter. The actual length is gotten by multiplying the equivalent length by the pipe diameter.**

**QUESTION 2**

**1. “10-4”:**

**Using Baker Correlation:-**

**ql = 500bbl/day = 0.0325ft3/sec**

**qg = 1000ft3/bbl \* 500bbl/day = 5\*105ft3/day = 5.78ft3/sec**

**ρl = S.G \* 62.4 = 54lbm/ft3**

**μl = 1.7cp**

**σl = 20dynes/cm**

**ρg = 3.28lbm/ft3**

**A = 0.02182ft2**

**Usl = 1.489ft/sec**

**Usg = 4.34ft/sec**

**Um = 5.527ft/sec**

**To get Gl and Gg:**

**Gl = Usl\*ρl (\*3600) = 2.9\*105lbm/hr-ft**

**Gg = Usg\*ρl (\*3600) = 5.1\*104lbm/hr-ft**

**λ = 6.15**

**∅ = 4.8**

**The plots [,] = [167.86,8.3\*103]**

**It predicts a slug flow**

**Using Mandhane Correlation:**

**[Usg,Usl] = [4.34,1.489]**

**It predicts a slug flow**

**Using Beggs and Brills Correlation:**

**[λl,NFr]**

**NFr = = 5.7**

**λl = = 0.27**

**it predicts atransition dlow which is close to intermittent flow (could be slug or plug flows)**

**Using Taitel and Dukler Correlation:**

**[Usg,Usl] = [4.34,1.489]**

**It predicts a slug flow**

**‘10-6’**

**2. qo= 4000bbl/day = 0.26ft3/sec**

**qg = 2\*106ft3/day = 23.15ft3/sec**

**D =3’’**

**Ԑ = 0.001**

**T = 150oF = 610oR**

**P = 200psia**

**σl = 20dynes/cm**

**A = 0.049ft3**

**For Beggs and Brils pressure gradient correlation:**

**[f =**

|  |  |  |  |
| --- | --- | --- | --- |
| **Flow pattern** | **a** | **b** | **c** |
| **Segregated** | **0.98** | **0.4846** | **0.0868** |
| **intermittent** | **0.845** | **0.5351** | **0.0173** |
| **distributive** | **1.065** | **0.5824** | **0.0609** |

**Yl =**

**Since, it predicted transition flow, then yl =yl segregated + yl intermittent = 0.47**

**ʄ =**

**ʄn = ʄ \* 4**

**NRe = 377.2**

**μm = μlλl + μgλg =0.214**

**ʄtp = ʄn \*es = 0.22**

**x = = 0.54**

**s = 0.26**

**[f = 111.5psi/ft pressure gradient drop**

**For Eaton pressure gradient Correlation:**

**Nvl =13.19**

**Nvg = 101.11**

**ND = 49.65**

**NL = 0.01**

**= 0.039**

**The plot gives YL =0.18**

**ʄ = 0.01**

**m = q\*ρ**

**ʄ = = 0.02**

**[f = 0.149psi/ft**

**Using Dukler pressure gradient Correlation:**

**Plots [λl,yl]**

**ρk = 2.57**

**NRek = 205562**

**ʄn = 0.018**

**= 2.379**

**ʄ =0.043**

**[f = 14.544psi/ft**

**Using Gilbert Correlation to determine choke performance curves:**

**Ptf =**

**The GLR was not given but can be calculated using either or**

**From table:**

|  |  |  |  |
| --- | --- | --- | --- |
| **Correlation** | **A** | **B** | **C** |
| **Gilbert** | **10** | **0.546** | **1.89** |
| **Ros** | **17.4** | **0.5** | **2** |

**For 8/64th: Ptf = = 0.196ql(GLR)0.546 = 0.00952ql**

**For 12/64th: Ptf = = 0.0913ql(GLR)0.546 = 0.00444ql**

**For 16/64th: Ptf = = 0.053ql(GLR)0.546 = 0.00258ql**

**To get GLR, use OIIP and GIP**

**Bo = 0.9759 + 0.00012[ + 1.2T]1.2**

**Rs = K \*Tpc**

**Bo = 4.61**

**Bg = = 0.0181**

**OIIP =**

**GIP =**

**GLR = 0.00393**

**FLOW THROUGH CHOKES (RESTRICTIONS)**

**Flow rate from well is controlled by choke, a device that places a restriction in the flow line shown in fig 10-9. Various factors such as pressure specification, so on, restrict production rate from flowing well.**

**When two phase flow through a choke, the fluid may be accelerated sufficiently to reach sonic velocity in the throat of the choke, this condition is called critical flow and change in pressure downstream of the choke do not affect fow rate because pressure disturbances can not travel upstream faster than the sonic velocity. Therefore to predict flow rate/ pressure relationship through choke, we must check if it is critical or not. Fig 10-10 plots [,q].**

**Where P2 and P1 are the upstream and downstream pressures respectively.**

**Single phase liquid flow:**

**It is rare to occur in choke, because the flowing tubing pressure is almost always ˂ Bubble point**

**Qq = CA**

**Where C = flow Cofficient of choke given in fig 10-11 by Crane (1957) as function of [,]**

**Where Dc = D2 = choke diameter and Dp = D1 = Pipe diameter**

**q is derived by assuming ∆P =**

**The equation is valid for sub critical flow.**

**In field unit;**

**q = 22800C[D2]2**

**D2 = bean size usually 64th of an inch**

**EXAMPLE 10-8**

**S.Go, μo, D2, ∆P, D1 were given;**

**Get , assuming it is independent of NRe, C is gotten from the chart then q can be calculated.**

**Single phase gas flow**

**For isentropic flow of an ideal gas through a choke, q to pressure ratio given by Szilas (1975) is given as:**

**qg = D22P1**

**In field unit:**

**qg =3.505D642**

**𝛾 = heat capacity ratio in Cp/Cv**

**α = flow coefficient**

**Conditions:**

**Both of the qg are used only when pressure ratio is ≥ critical pressure**

**[]c = [𝛾/𝛾-1**

**If pressure ratio is ˂ critical pressure, then**

**= []c  and use qg**

**For air and diatomic gases, 𝛾 = 1.4 and pressure ratio = 0.53**

**If p2 ˂ P1**

**EXAMPLE 10-9**

**D2[8,12,16,20,24], α, S.Gg, 𝛾, P, T were given. Construct a chart of q vs**

**Calculate critical pressure ratio**

**Get qg**

**Gas liquid flow**

**Two phase flow through choke:**

**Empirical correlations for critical flow are used. Some of these correlations are claimed to be valid up to pressure ratio of 0.7 by Gilbert (1954). One means of getting critical two phase flow through a choke is comparing velocity in choke with two phase sonic velocity given by Wallis (1969) for homogeneous mixtures as;**

**Vc =[(λgρg + λlρl)][ + ]**

**Gilbert Correlation (1954) and Ros (1960):**

**Have the same form but differing in their constants A, B, and C given in the table 10-2:**

**[Ros in psia]P1 = = P1 - Psc [Gilbert in psig]**

**Another preferable correlation for certain ranges of conditions is the Omana et al (1969) based on dimensional analysis and series of tests with natural gas and water given as:**

**Nql =0.263Nρ-3.49Npl3.19λl0.657ND1.8**

**With Nρ =**

**NPl = 1.74\*10-2P1()0.5**

**ND = 0.1574D64**

**Nql = 1.84q1()1.25**

**Conditions:**

**For critical flow,qg/ql >1 and pressure ratio < 0.546, suited to low liquid viscosity and D2 of 14/64’ or <. Fluid properties are gotten from P1.**

**EXAMPLE 10-10**

**qo, qg, P, D2, GLR, use Gilbert, Ros and Omana correlations**

**Steps:**

**Determine D64 using Gilbert and Ros correlation**

**For Omana Correlation get Dimensionless groups**

**Use ND to get D2 or D64**

**The Gilbert and Ros correlations gave the more accurate**

**The relationship between the wellhead pressure and flow rate is controlled by choke when produced with critical flow, q can be determined by matching the choke performance with well performance which is determined by combination of well IPR and vertical lift performance. The choke performance plots flowing tubing pressure is liquid q and is obtained from choke correlations assuming critical flow**

**EXAMPLE 10-11**

**D64, GLR, using Gilbert correlation construct performance curve**

**Steps:**

**Get P for each choke diameter**

**Plot the p to q in fig 10-13 with well performance curve. The intersections of the choke performance curve with well performance are q that would occur with choke sizes valid when flow is critical for each choke there will be qbelow which flow is subcritical which is indicated by dashed portions of the choke performance curves.**

**Surface Gathering Systems**

**During production installations, flow from wells will be gathered at a central processing station. Two common types of systems were given by Szilas (1975) in fig 10-14. When each well flow rate are controlled by critical flow through choke, there are interactions among wells. During subcriticals flow, the downstream pressure can be influenced with the well performances having the entire piping network flow to be treated as a system.**

**When individual flow line all join at a common point, P is the same for all. The common point is the separator in the production system. The flowing tubing pressure of the individual well I is related in the separator pressure by:**

**Ptfi = PScp + ∆PLi + ∆PCi + ∆PFi**

**∆PLi = pressure through flowline**

**∆PCi = pressure through choke**

**∆PFi = pressure through fittings**

**In gathering system where individuals wells are tied to a common pipeline, so flow rate is the sum of the upstream well flow rates. In this system, individual wellhead pressures can be calculated by starting at the separator and working upstream. Depending on the lift mechanisms, qi may depend on Ptf. The IPR vertical lift performance and gathering system must be considered.**

**EXAMPLE 10-12**

**Di, valve type, ρo, μo, separator pressure, Ԑ, were given to calculate Ptf of the three wells as shown in fig 10-15.**

**Steps:**

**Calculate pressure drop for each segment shown at fig 10-16**

**Check type and size of valves**

**Results shown in Table 10-3**

**Note: if the IPR and elevation are the same in the three well, A will give the differences in Ptf to be result in different fluid levels in the annuli.**