FOLLOWING GAS THROUGH A BEAM SYSTEM WITH/WITHOUT A GAS SEPARATOR

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INTRODUCTION

This paper shows how to find the total gas present at the intake of a gas separator, how to calculate how much gas is being pumped through the pump and is produced up the tubing and how much is diverted to the casing. The amount of free gas fill in the pump is shown to be more than where the opening of the traveling valve (TV) occurs. Gas up the tubing reduces the gradient in the tubing and reduces the pump discharge pressure. A large percent of the gas below the separator can be diverted to the casing but still there can still be enough gas into the pump to reduce the liquid fillage of the pump substantially. Some comparative results of different types of separators will be shown at the end of the discussion.

SUBJECT

Many shale wells are produced with a beam system with the downhole pump set above the lateral. Gas production can be substantial and must be separated from the pump for successful operation. Horizontal wells do not allow sitting below the perforations. Also there are many conventional near vertical wells with the pump and a gas separator set above the perforations. Most separators for beam systems use reverse flow or gravity separation. The principle is to try to make the liquid travel downward less than about ½ fps (bubble rise velocity). There are some beam separators that set the intake on the low side of a slant portion of the well to attempt to use segregation of gas and liquid in a portion of the well that has a slant or where the downhole pump is horizontal.

To achieve separation using the ½ fps rule, the larger the down flow area in the separator, the larger the flow rate that can be pumped and stay below the down flow velocity rule. Therefore larger diameter poor boy separators or packer separators are used to give the slowest down flow velocity before the liquid enters the pump in an attempt to allow the gas to travel up the casing annulus and not into the pump. For instance a packer separator with~ 5”OD and 2”ID would have down flow area of over 16 sq. in and a flow capacity of over 800 bpd. However the slugging nature of horizontal wells reduces the capacity below what a steady state capacity would be.

Below is an example that may be close to some shale wells that have gas along with the liquid production. The example is a fairly low rate example but could be used to analyze higher and lower production wells. Note: nomenclature definitions are included at the end of the document.

EXAMPLE DATA AND CALCULATIONS

Below is data for the example used to follow gas through the beam system with a gas separator included. Again this example is thought to be close to some gassy shale wells that are produced with a beam system. The intent is to show how to analyze the gas through the system and not to emphasize the particular example. Other data could be used and analyzed using equations and techniques here.

Data:
Depth: 9000 ft.
Pump: 1.75” diameter, 134” downhole stroke, 30% of downhole stroke is load release distance in bottom hole card due to gas in the pump (commonly called gas interference). However there is a greater gas volume in the pump than is indicated by the distance to the TV opening or to the end of the load release in the rods.
SPM: 5.5
BPD: 119 STBPD shown as “measured” and calculated from pump card
PIP: 444 psi WHP: 350 psi (back pressure regulator)
WC: 20 pct. BHT: 250 F WHT: 150F
API: 42 GG: 0.65 WG: 1.06 Bo (oil): 1.4 GLR: 1452 SCF/StkBBL
86 Rods Surface Stroke: 168”

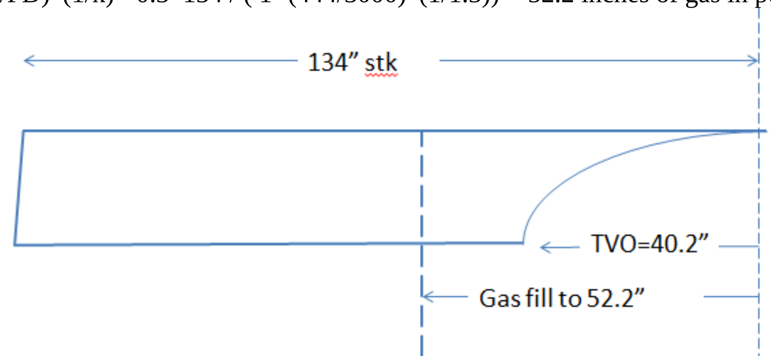
Calculations:
At intake of downhole separator:
Assuming separator has capacity (downward velocity < ½ fps) to handle 122 bpd and separate gas.

FREE GAS

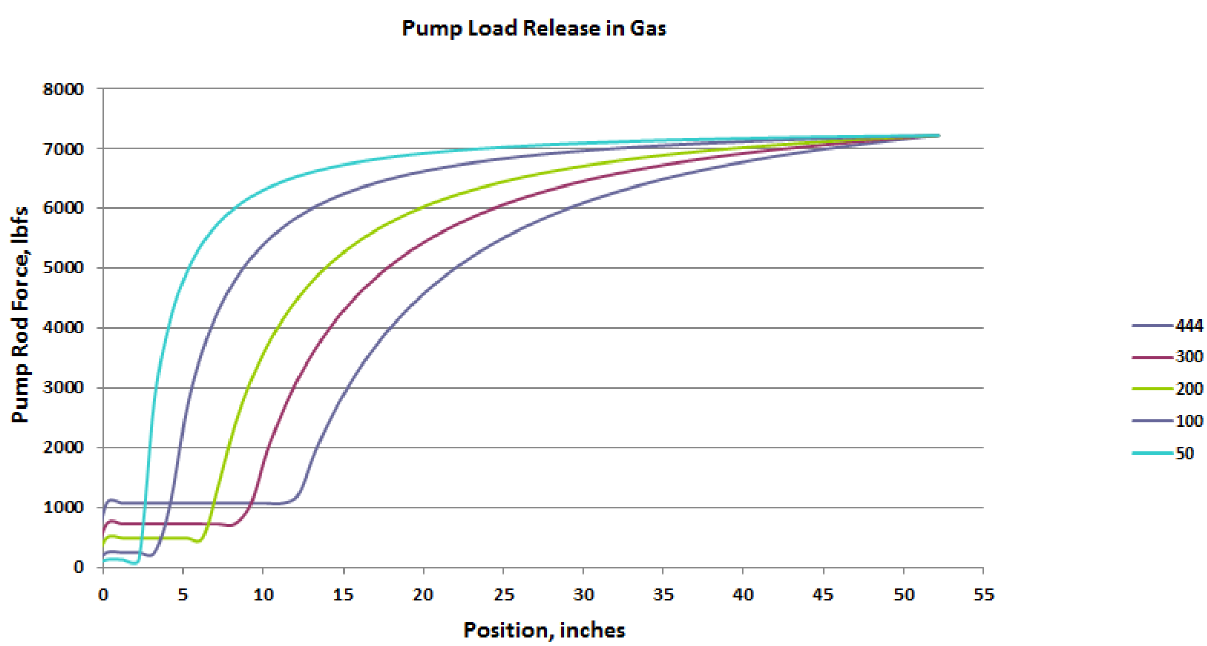
WOR = pct. water/pct. oil = 0.2/0.8 =0.25
GOR=GLR x (1 + WOR) = 1425(1 + 0.25) = 1815 SCF/ST BBL oil
Rs =GG x (PIP/18 x 10^ (((0.0125 x API) – (0.000091 x BHT)))^ 1.2048
= 0.65 x (444/18 x 10^ (((0.0125 x 42) – (0.00091 x 250)))^ 1.2048 = 70.6 SCF/ST BBL Oil
Qgas = BOPD x (GOR – Rs) = 95.04 x (1815-70.6) = 165787 SCFPD free gas before the separator

GAS THROUGH PUMP

Calculate the length of barrel filled with gas (Xpmp)
Assume an isentropic process in pump compression, where k = ratio of specific heats which is about 1.3 for natural gas. For the below example the PD was estimated to be 3000 psia. This is verified later in the discussion.
PIP x (Xpmp)^k= PD x (Xpmp-TVO)^k
Xpmp=TVO/(1- (PIP/PD)^(1/k)= 0.3*134 / (1- (444/3000)^(1/1.3)) = 52.2 inches of gas in pump



The bottom graph below shows the load release for the 444 psi intake case with the PD =3000 psi. Initially the graph was prepared using equations from notes presented by A. Podio, U of TX. Note on the graph that the TV opens about 12 inches before the plunger encounters the liquid at the position zero on the X axis for the intake pressure curve of 444 psi. However at low intake pressures, the TV opens much nearer the liquid below the plunger and is more indicative of the gas in the pump.



The total swept volume in the pump is = π x $D^2/4$ x SL /1728

=3.14 x 1.75^2/4 x 134 x 1/1728 = 0.1864 ft^3
The volume of the gas is 3.14 x 1.75^2/4 x 52.2 x 1/1728 = 0.0726 ft^3
The percent of gas fill of the swept volume is 0.0727/0.1864 x 100 = 39%

Note the gas fill is more than what the TVO would indicate and for high intake pressures there is more gas in the pump than indicated by the TVO but for lower intake pressures the gas in the pump is more closely indicated by the TVO distance. In the calculation below a Z factor of 0.9 is utilized.

Gas in the pump is: volume gas in pump (ft^3) x (PIP/14.7) x (520/((BHT+460)) x Z
= 0.0726 x (444/14.7) x 520/((250+460) x 0.9) = 1.79 SCF of free gas in pump

SCFPD of free gas produced by the pump: 1.79 x SPM x 60 x 24 = 1.79 x 5.5 x 60 x 24 = 14140 SCFPD
In-situ BPD of liquid through the pump is: (0.1864 - 0.0726) x 5.5 x 60 x 24/5.615 = 160.5 BPD
To account for pump leakage: 160.5 x 0.96 = 154 BPD
Note: Slippage can be calculated by: Slip BPD = (0.14 x SPM +1) x 453 x DPC^1.52/Lμ but that is not the emphasis here, therefore only an estimate used.

The calculated STBPD is pct. water x pump rate + (pct. oil x pump rate)/Bo
= 0.2 x 154 + (0.8 x 154)/Bo = 118.8 STBPD

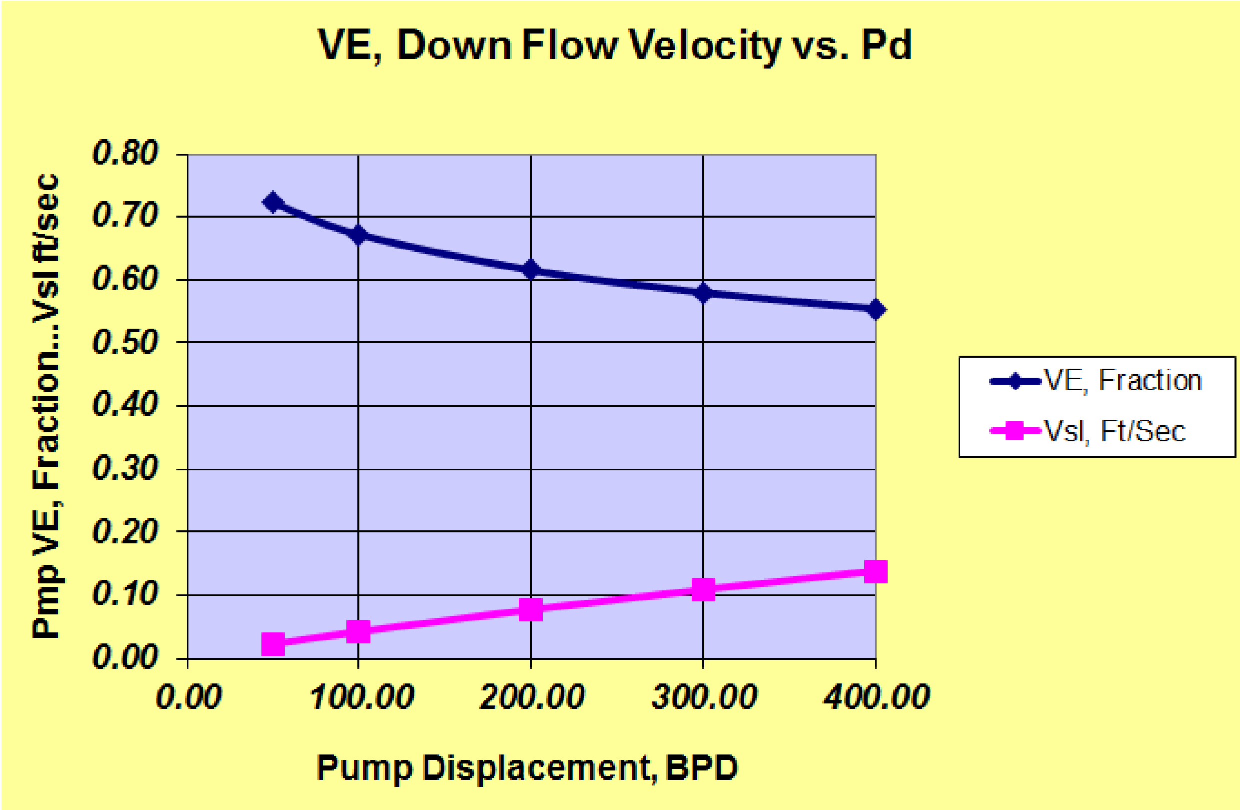
Given the liquid and gas rates, depth, temperatures and fluid gravities; the data can be input into a multiphase flow model (Hagedorn Brown in this case) using the surface pressure of 350 psi. An average effective tubing diameter with the ID of the tubing and the rods OD was used. The calculated BHP in the tubing is about 3000 psi, this is the Pd of the pump. If no gas is present the Pd would be 4800 psi, therefore the gas in the tubing must be considered to know the correct pump load for design or analysis. The gas in solution must be added to the gas in the multiphase flow input. This is the pressure that was used above for calculating the gas in the pump (3000 psi). If the Pd was found to be different than 3000 psi then a series of iterations would be needed until the assumed value agrees with the calculated value.

So now we know 14140 SCFPD went into the pump and 165787 free SCFPD was present before the separator.
The volume of gas present before the separator is: 165787 x 14.7/444 x (460+250)/520 x 0.9 =6745 ft^3 per day
The volume of liquid before the separator is: 154 x 5.615 = 865 ft^3 per day
The percent of free gas by volume before the separator is: (6745)/(6745+865)x100 = 88.6%
The amount of gas separated into the casing is 165787-14140 = 151647 SCFPD

Therefore the separation efficiency (including natural separation and separation by the separator) is 151647/165787 x 100 = 91.4%. See Reference 2 for discussion of natural separation. It would be difficult to calculate the natural efficiency. If the system is run with no separator, the resulting separation efficiency would be the natural separation efficiency. Then under identical conditions with a separator added to the system, the change in efficiency would be that added by the separator. If the separator added a lot of turbulence and mixing of gas and liquids, it might be possible for the addition of a separator to have a less desirable effect.

The ft^3 per day of gas after the separator is: 14140 x (14.7/444) x (250+460)/520 x 0.8 = 575.6 ft^3 per day
The percent free gas by volume after separation and before any liquid slip (total) is: 575/(575+160.5*5.615) = 39 %.
This is the same as calculated earlier using pressure differentials in pump intake and discharge before slip.

Using the equations in Reference 1 the following results are obtained. It shows (with packer separator OD of 5 and ID of 2) that for 120 BPD the VE of the pump would be about 66%.



Now when the 151647scfd bubbles up the casing, the scfd/sq. in is about 7740 for 5 ½ casing so the percent of liquid in the annulus where/when there no liquid flow is about 7740 so the percent of liquid in the annulus is about .25 or 25% liquid and about 75% gas according to the well-recognized Echometer S curve. The percent of liquid in 7 in casing would be about 28%. The annulus conditions are after separation and the pump does not see the conditions in the annulus unless there is no liquid above the pump in the annulus and then the pump takes in excess gas. If the total gas is know from the GOR or GLR and pump gas is calculated from the dyno card, then the gas is known up the casing and should allow determination of the fluid gradient in the annulus using the S curve below. This then can be used to check the PIP from a fluid level shot.

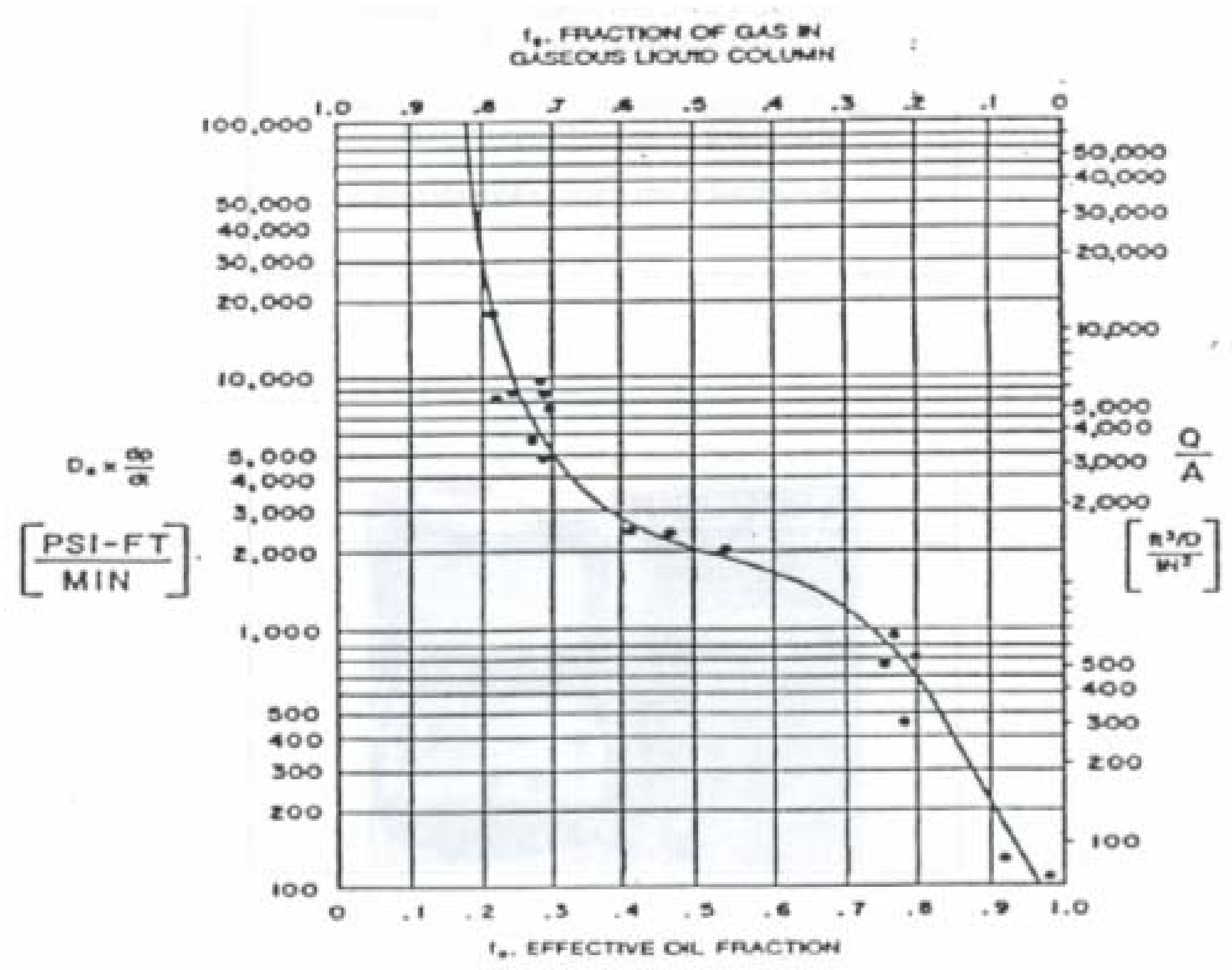
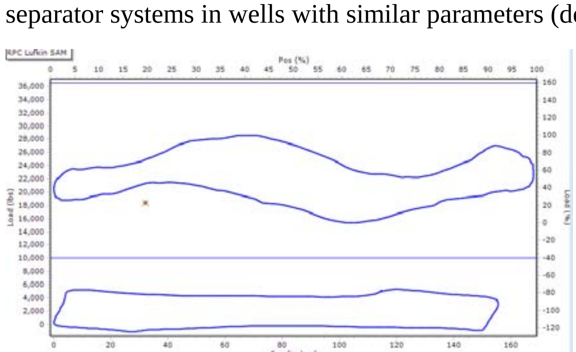
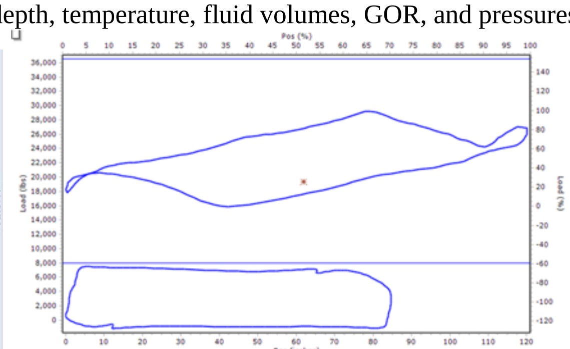


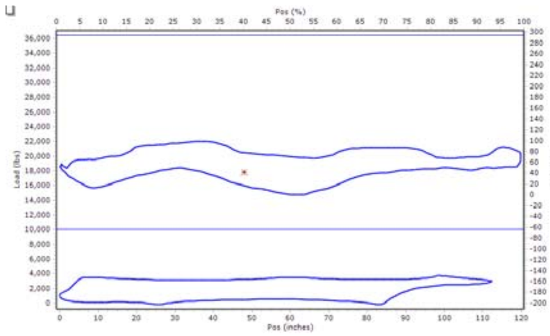
Fig. 7—Echometer gaseous liquid column gradient correction curve.

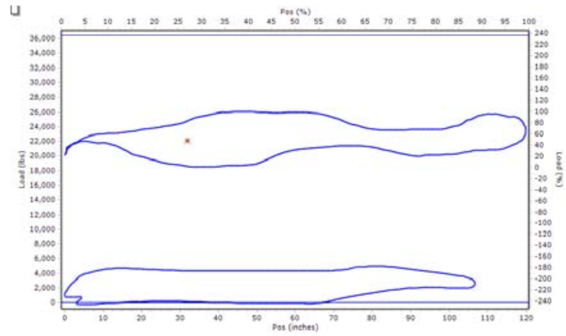
SEPARATOR COMPARISON

Why is there so much interest in gas separation and methods to determine separation efficiencies of down-hole systems? It is evident that gas in the pump has negative effects on pump efficiency, power consumption and shock loads on the system. The following down-hole cards show there can be vast differences in gas separation efficiencies with different styles of down-hole separators. These cards come from four different downhole gas separator systems in wells with similar parameters (depth, temperature, fluid volumes, GOR, and pressures).









SUMMARY

If the data is representative it shows that even with a lot of gas present before the separator, enough gas can be separated to achieve liquid production but the pump can be partially filled with gas. The calculation routine here is not dependent on particular data. It is shown that for high intake pressures that there is more free gas in the pump than signified by where the TV opens. The traveling valve opening occurs when the gas pressure under the plunger reaches the pump discharge pressure at the bottom of the tubing and this can occur with additional gas under the plunger before the plunger nears the liquid in the pump barrel. The percent gas before and after the separator and percent gas in the pump is calculated. The discharge pressure calculated is lighter than an oil and water only gradient would show as gas is pumped up the tubing. Also based on results using Reference 1, it shows that with current types of separators only so much liquid fillage of the pump can be expected when the well is gassy regardless of the fact that the separator is rated for the liquid flow. In practice good separation is also aggravated by the erratic or slugging nature of the flow from laterals. The equations in Reference 1 are somewhat involved and are not discussed here.

NOMENCLATURE

API: Oil gravity

BHT: bottom hole temp, F

D: Pump diameter, in

GG: gas gravity, air=1

GLR: gas/liquid ratio, Scf/stkbbl

GOR: gas/oil ratio, Scf/stk bbl oil

k: ratio of specific heats for natural gas

PD: Pump discharge pressure, psi

Pd: Pump discharge pressure, psi

PIP: pump intake pressure, psi

Qgas: gas rate

Rs: Solution GOR, Scf/stk bbl oil

SL: Stroke length at pump, in

SPM: strokes per minute

STBPD: stock tank barrels per day

TVO: (TV open) distance required to complete load release on downstroke, in

WC: percent water in production

WG: water gravity, water=1

WHP: pressure at top of producing tubing, psi

WHT: surface tubing temperature, F

xpmp: distance of gas fill in pump stroke, in

Z: gas compressibility factor

REFERENCES

1. System Analysis for Sucker Rod Pumping by Z Schmidt and D R Doty, SPE 15426, SPE Production Engineering, May 1989
2. Natural Separation for Electrical Submersible Pump Systems by Carlos Viloria, Tulsa University Master's Thesis, Petroleum Engineering, 1999.

APPENDIX

Instead of using a multiphase flow model to predict the tubing BHP, an alternative simple model was used. The holdup at the bottom and the top of the tubing was calculated using a no slip holdup (holdup is percent of liquid in the tubing). Then the holdup's for gas and liquid were averaged from the top and bottom values and knowing the density of the gas and liquids at the top and bottom values, a gradient in the tubing producing liquids and gas from the pump moving upward in the tubing between the tubing ID and the rods OD's was found. This approach gave a lower BHP than from the multiphase flow model. The result for the example data was a calculate BHP of about 2850 vs. 3000 psi from the multiphase flow model. One could adjust the liquid holdup upward to match real data and might find a value that would work for many cases. If so the simple model is only a few lines in a spread sheet and might be used.

ρgas, top , lbm/cu ft
ρgas, bot, lbm/cu ft
Qliquid, insitu, top , cfd
Qgas,insitu, top, cfd
Qliquid, insitu, bot, cfd
Qgas, insitu, bot, cfd
Hl (no slip), top = Qliquid, insitu, top/(Qliquid,insitu,top+Qgas,insitu,top)
Hl (no slip), bot = Qliquid, insitu, bot/(Qliquid,insitu,bot+Qgas,insitu,bot)
Gradient =(.433γ*Havg, liquid, avg + ρgas, avg/144*(1-Havg,liquid, avg))g/gc ,psi/ft
Pd=WHP +Gradient * Depth, psi