HIGH-PRESSURE-GAS-LIFT: THE CRITICAL VARIABLES AFFECTING YOUR MAXIMUM OUTFLOW POTENTIAL

Victor Jordan Estis
Compression

ABSTRACT:
Since its' introduction to the unconventional oil and gas realm in 2018, Single Point High Pressure Gas Lift (referred to as HPGL going forward) has emerged as one of the top artificial lift choices for operators in the Permian and Anadarko basins. It has become a proven technology with over 1,500 applications to date as more operators are choosing it as their primary form of artificial lift for their unconventional assets. Its ability to achieve sustained high fluid rates as well as having a high sand and gas tolerance makes it the most versatile form of artificial lift offered in today's market.

HPGL is not a new concept having been discussed in SPE 14347. (Dickens, 1988) The concept was revitalized in SPE 187443 (Elmer, Elmer, & Harms, 2017) by which the authors of this paper emphasized its' application for horizontal wells though at the time the needed compressor technology was not widely available to the market. This has changed as compression service companies have begun offering compressors designed to achieve the high discharge pressures needed to initially unload wells. This has led to a surge in HPGL applications as operators are looking to maintain the high fluid output capabilities of ESPs with the benefits of gas lift.

Gas lift is a naturally flowing process; therefore, it is important to understand the pressure drop across the entire system to achieve the desirable outflow potential. There are many components along the flow path from reservoir to sales that affect this pressure drop. HPGL has re-emphasized the importance of Nodal Analysis, and the understanding thereof, to production engineers. Proper design and installation of each node can drastically sway your well's performance capabilities therefore proper modeling must be conducted to ensure the desired outcome is achieved. In this paper we will demonstrate the HPGL design methodology used today to ensure optimal output will be achieved.

INTRODUCTION
Gas lift design has historically revolved around valve sizing, selection, and placement within the wellbore. However, this is not the case for HPGL being there are no valves required. To optimize your HPGL design, engineers should consider the four critical variables affecting their optimal performance. These four variables are: injection depth, cross sectional flow area (tubing and casing selection,) injection rate, and flowing wellhead pressure (FWHP.) It is important that the design engineer understand the affect each variable has on their desired performance. In this paper we will review each four and how changes to each can affect your optimal production potential. We will utilize a representative case study well to demonstrate these effects and demonstrate how we can drive optimal production volumes.

THE CASE STUDY WELL
The case study is based on a free-flowing horizontal well in the Delaware Basin. A history match utilizing nodal analysis was conducted to match the flowing bottom hole pressure based on the known total fluid production rate. The inputs as well as the base case IPR are shown as follows:

- Reservoir Pressure (Pr) = 5,800 psi
- Reservoir Temperature (Tr) = 160 deg F
- Oil API = 45
- Sg Gas = 0.8
- WC = 82%
- Water SG = 1.02
- Flowing Wellhead Pressure (FWHP) = 575 psig
- Static Wellhead Pressure (SWHP) = 1,100 psig
- Separator Pressure (Ps) = 125 psig

- GLR = 260 scf/bbl
- TFPD = 1,392 bbls
- Casing: 5-1/2” 20# set at 22,000 MD (11,850’ TVD)
- Tubing: 2-7/8” 6.5# set at 11,200 MD (11,175’ TVD)
- Flowing up tubing
- Flowline: 3” steel. Length = 750’.

THE CRITICAL VARIABLES

Injection Depth

Conventional gas lift designs revolve around valve placement within the wellbore. In theory, the deeper you can set the top valve, holding all things else constant, the greater pressure drop you can initially create. In other words, the more of the fluid column you can lighten, hence deeper injection point, the greater the pressure drop. “Kick off pressure” is directly related to top valve placement which can be demonstrated via the following equation:

$$Dv1 = \frac{Pko - Pwhu}{g_{ls}}$$

Where as

Dv1 = depth of top valve, ft,

Pko = surface kick off pressure, psig,

Pwhu = surface wellhead unloading pressure, psig,

and

gls = static kill fluid pressure gradient, psi/ft

(Clegg, 2007)

It should be noted that this equation does not account for the injection gas pressure gradient at the valve depth however it is common for this to be neglected to provide a safety factor.

One of the primary limiting factors regarding top valve placement within the wellbore has been the maximum allowable discharge pressure (MADP) of standard compressors available on the market. Standard MADPs for compression, prior to the introduction of HPGL, ranged from 1,200-1,400 PSIG. This limits your top valve placement depth which in turn limits your control of decreasing flowing bottom hole pressure. This limitation decreases your total achievable maximum fluid rate. The introduction of HPGL enabled operators to lower their lift point deeper than that of the MADP of standard wellhead compression. In most cases, the increased MADP of 5,500 psi allows the HPGL user to lower their injection point to depths greater than 10,000’ TVD. For our case study well, we can demonstrate the difference in top valve placement relative to the MADP of standard compression (1,200 psig) versus that of the MADP of HPGL compression (5,500 psig.)

Standard Compression:

$$Dv1 = \frac{1{,}200 - 575}{0.433*1.02} = 1{,}415\text{' TVD}$$

HPGL Compression:

$$Dv1 = \frac{5{,}500 - 575}{0.433*1.02} = 11{,}151\text{' TVD}$$

As you can see under these conditions, the HPGL compressor allows you to lower your initial injection point 9,736’ TVD from that of the standard compressor. We can demonstrate utilizing nodal analysis the effect the difference in injection point has on production potential. We will assume an initial injection rate of 600 MCFD and hold all other variables constant.

The valve placement depth of 1,415' TVD for the standard compression MADP provided an uplift of 289 BFPD (TFPD = 1,681 bbls) relative to base case whereas the top valve placement depth (11,151' TVD) for the HPGL compression MADP provided an uplift of 1,079 BFPD (TFPD = 2,471 bbls) relative to the base case. Figures 2 and 3 demonstrate these results. From this point forward we will utilize the deeper injection depth of 11,151' TVD.

Cross Sectional Flow Area (CFA) – Subsurface

It has been demonstrated that lowering injection depth increases you uplift potential. Now we must review how the flow path's cross-sectional flow area (subsurface in this section) affects your uplift potential. In the previous section we analyzed converting the well to gas lift by injecting down the annulus and flowing up the tubing at various injection depths. However, what if we were to swap flow direction and flow the well up the anulus and inject down the tubing? What effect will that have on our uplift potential? We can demonstrate this via nodal analysis but first let's look at the impact varying tubing sizes and flow path directions have on the CFA for the case study well.

Our case study well is currently flowing up 2-7/8" tubing which has a CFA equivalent to 4.68 in^2. However, note the increase in CFA if we were to switch to annular flow. It increases 2.4X to 11.44 in^2. Note the other annular CFAs associated with other tubing sizes seen in Table 1. This increase in CFA reduces the frictional pressure drop across the length of the flow area which in turn will reduce FBHP.

Let's demonstrate the potential for our case study well by picking up where we left off in the last section having lowered our lift point to 11,151' TVD.

Figure 4 demonstrates the effect of swapping our flow path to the annulus and injection path to the tubing with varying tubing sizes. You can see that the potential uplift ranges from 327 BFPD to 555 BFPD based on the tubing size selected. The 2-3/8" tubing option provides an uplift potential of 468 BFPD, we will use it going forward. Our new estimated production rate based on the changes we have made thus far is 2,939 BFPD.

Injection Rate

A primary benefit of gas lift operations is the ability to affect well performance by varying injection rate. In gas lift operations, producing GLR is directly related to injection rate. As you increase the injection rate, the producing GLR up the wellbore increases. This in turn reduces the flowing density of the wellbore fluids which reduces FBHP to a point. Over injection can occur which can inhibit FBHP reduction. Over injection increases the frictional pressure drop from injection point to surface which can increase the FBHP and in turn inhibit your well's production potential. Therefore, it is important to utilize nodal analysis to determine the optimal injection rate to achieve your desired production. Also, injection rate is a key design parameter for compressor selection. Therefore, it is important to understand the needed injection rate to achieve your production target so that you can select the optimal compressor for your application.

We will utilize nodal analysis to model the effects of varying injection rates on our case study well. We will pick up where we left off in the previous section with an injection point at 11,151' TVD and flowing up the annulus while injecting down the tubing with a 2-3/8" tubing string. Figure 5 demonstrates the uplift potential of increasing injection rate in 250 MCFD increments starting with our initial injection rate of 600 MCFD.

Figure 5 demonstrates an additional uplift potential of 298 to 798 BFPD based on the varying increases in injection rate. Injection rates of +1,600 MCFD are common in HPGL applications. It is important to note that we have yet to hit the point of diminishing returns while increasing our injection rates though we will proceed with selecting 1,600 MCFD as our go-forward injection rate. Our new estimated production rate based on the changes we have made thus far is 3,737 BFPD.

Flowing Wellhead Pressure (FWHP)

For gas lift applications, flowing wellhead pressure should be minimized as much as feasibly possible. Restrictions at surface should be designed out and facility operating pressures (i.e. separator pressure, etc.) should be reduced to the minimum required to operate the facility. The last critical variable we are considering for our case study well is FWHP. So far, we have been utilizing the current FWHP of 575 psig. Our next step is to model the uplift potential of reducing flowing wellhead pressure. Figure 6 demonstrates the uplift potential by decreasing the current FWHP in increments of 100 psig.

Figure 6 demonstrates uplift potential of 264 – 1,158 BFPD. These uplift potentials warrant a facility design and operation review to determine how we can feasibly reduce our FWHP. A few key design considerations to consider are wellhead valve sizing, flow line size, valve and choke sizing, flowback equipment setup and sizing, vessel operating pressures, facility piping designs, etc.

CONCLUSION

We have reviewed the four critical variables affecting your maximum outflow potential. We have utilized a case study well to demonstrate how changes to each variable can increase your outflow potential. Table 2 provides a summary of the design steps made along this process and the uplift potential each step achieved. We see a total uplift potential of 2,345 to 3,503 BFPD which would increase our total fluid production to 3,737 to 4,895.

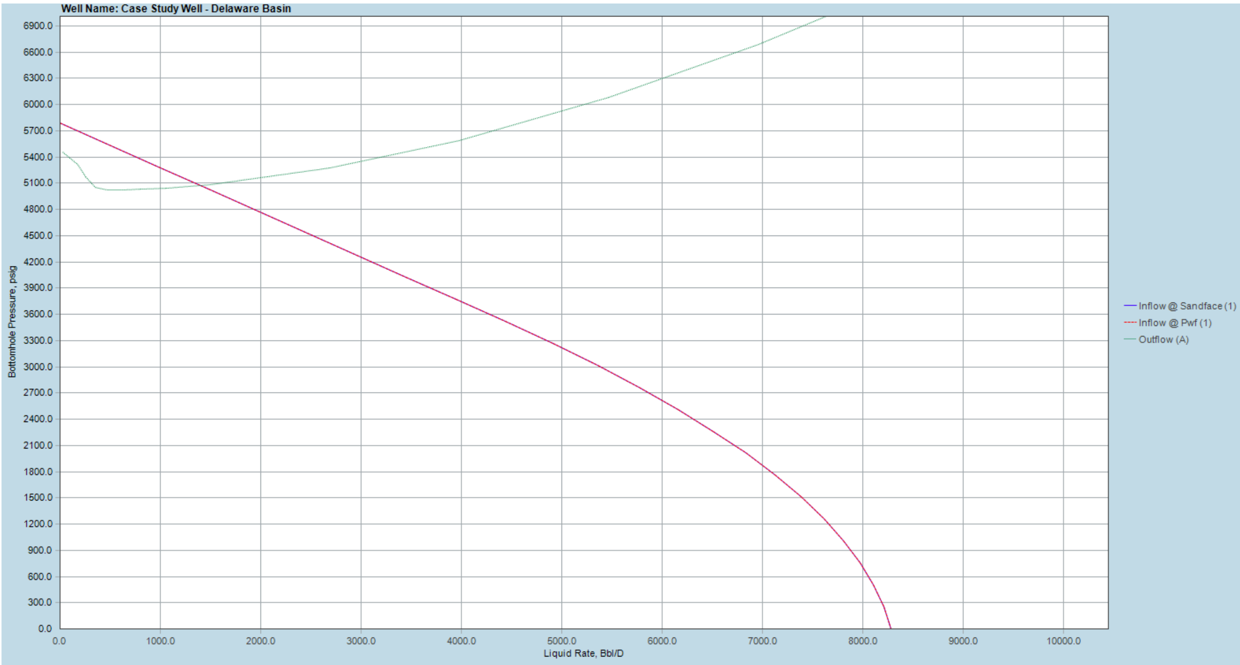

Figure 1: Base Case History Match

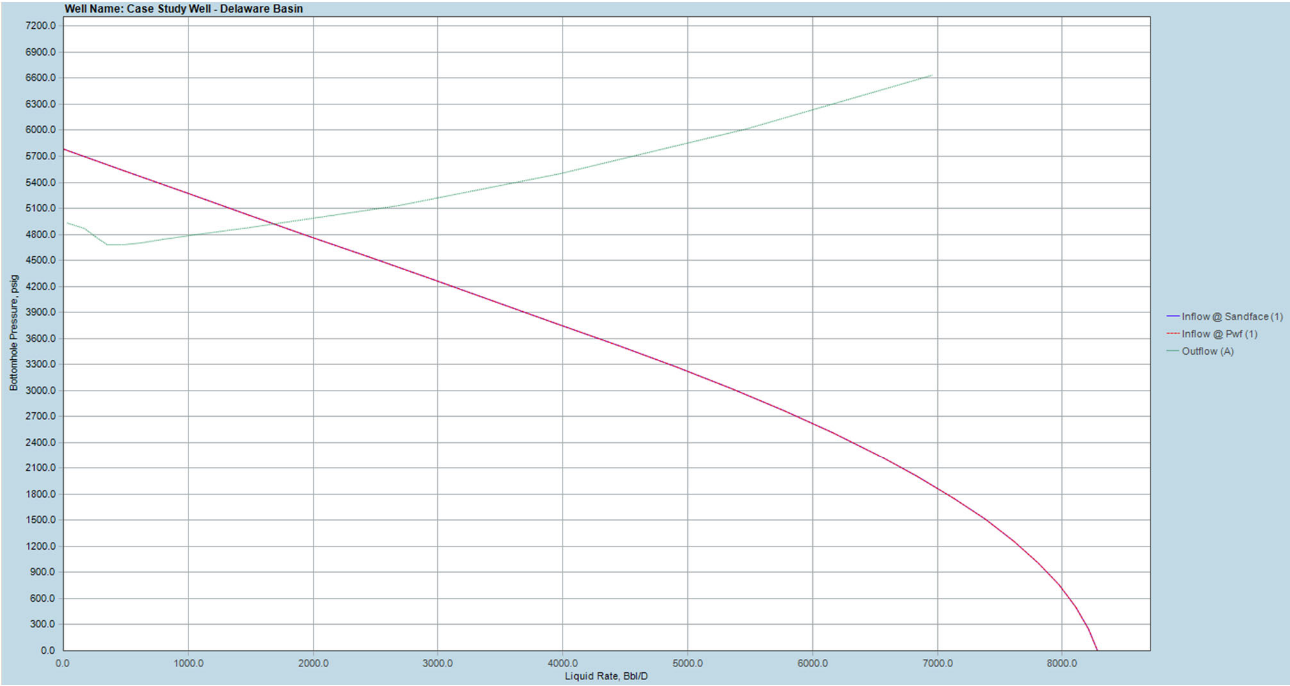

Figure 2: Top Valve Placement = 1,415' TVD (Standard Compression)

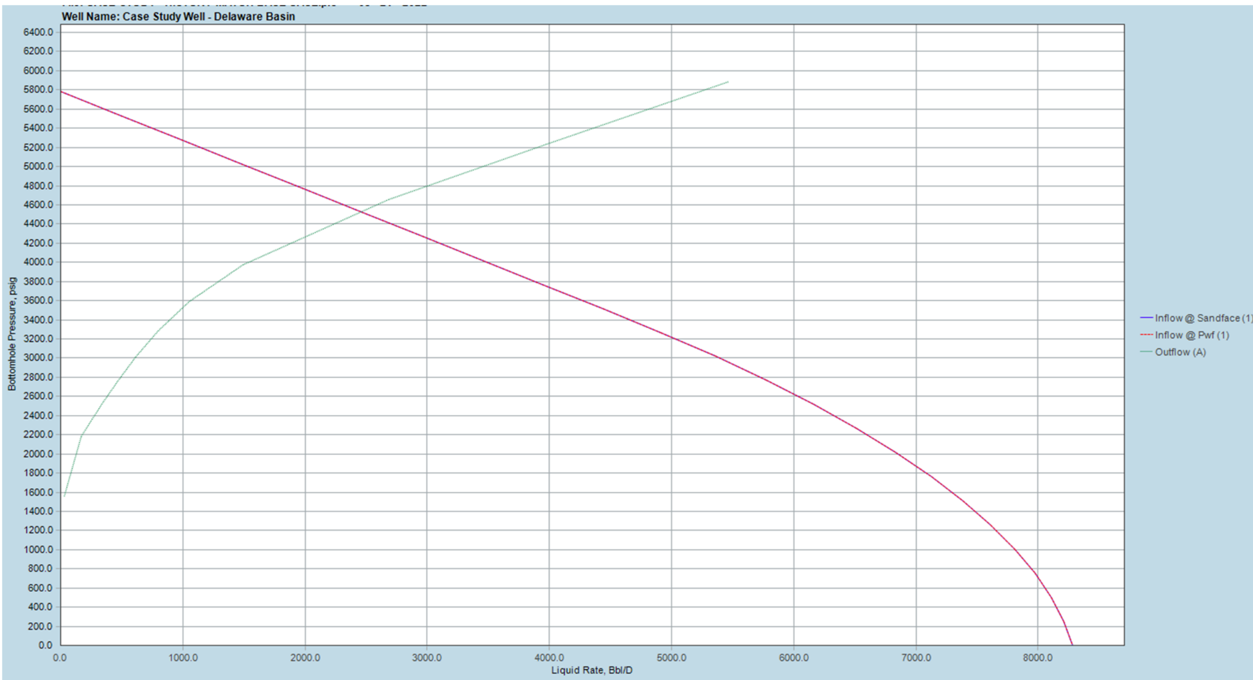

Figure 3: Top Valve Placement = 11,151 TVD (HPGL Compression)

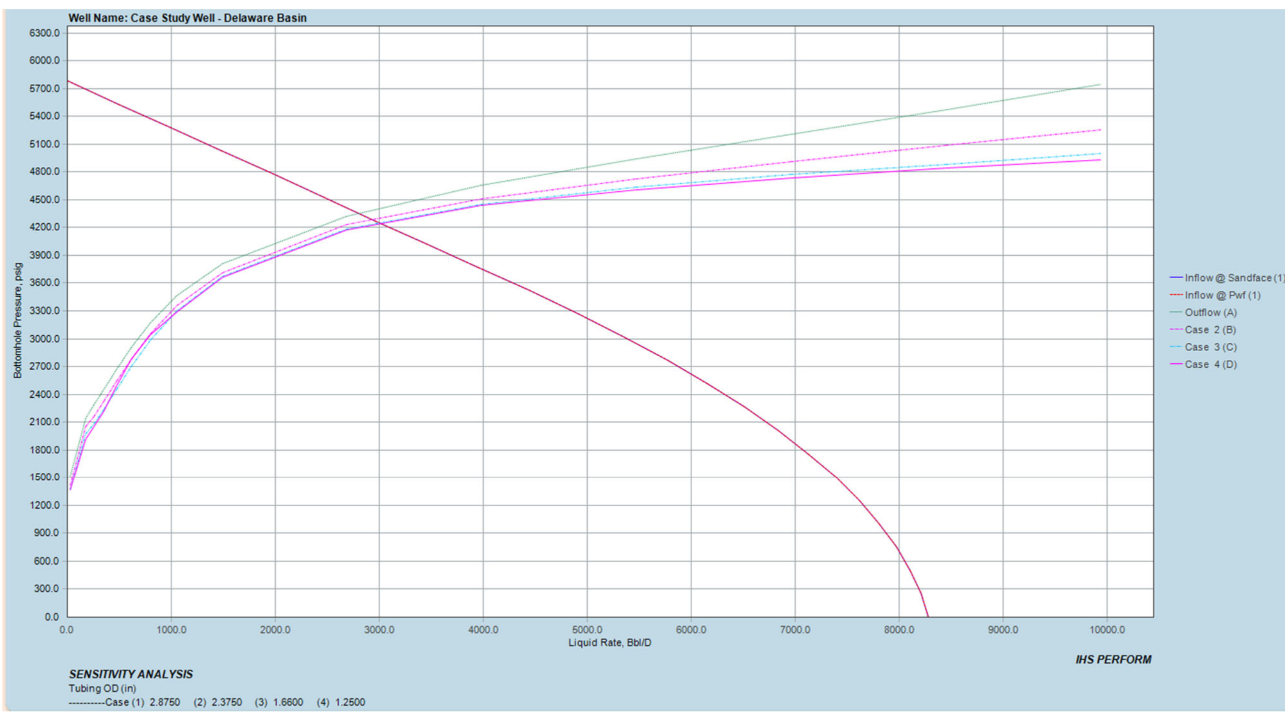

Figure 4: Varying Cross Sectional Flow Areas

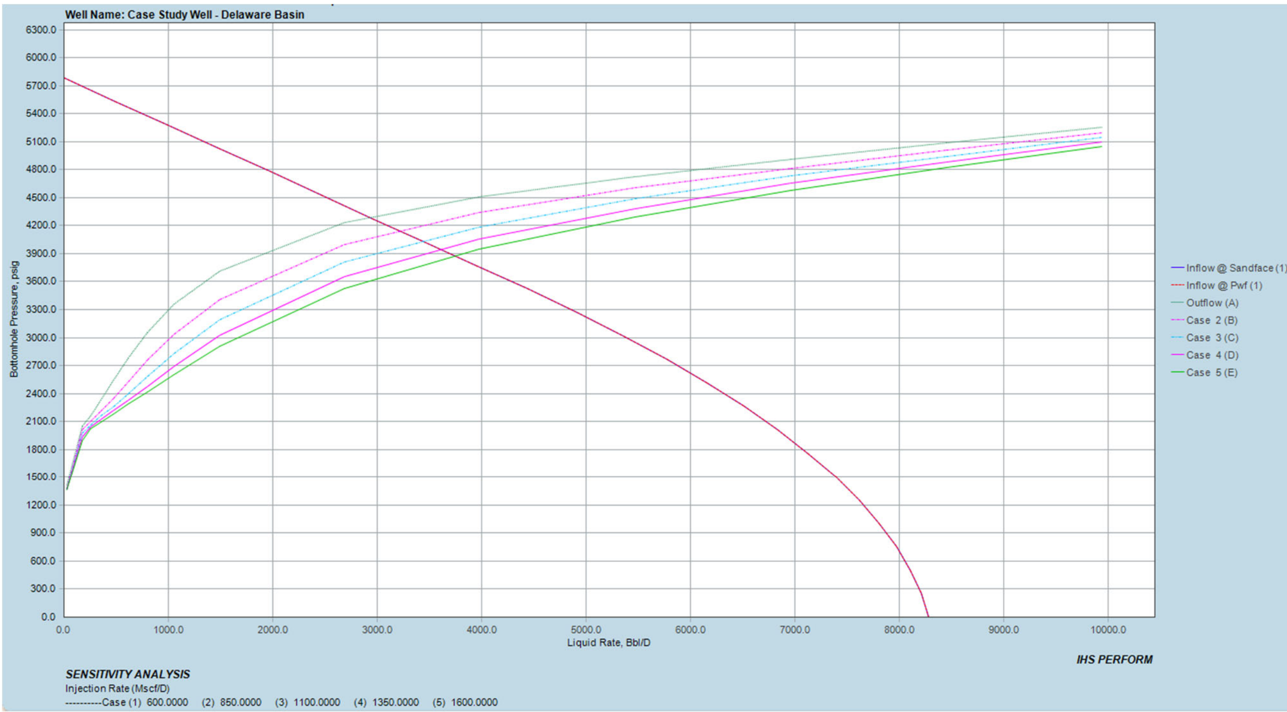

Figure 5: Varying Injection Rates

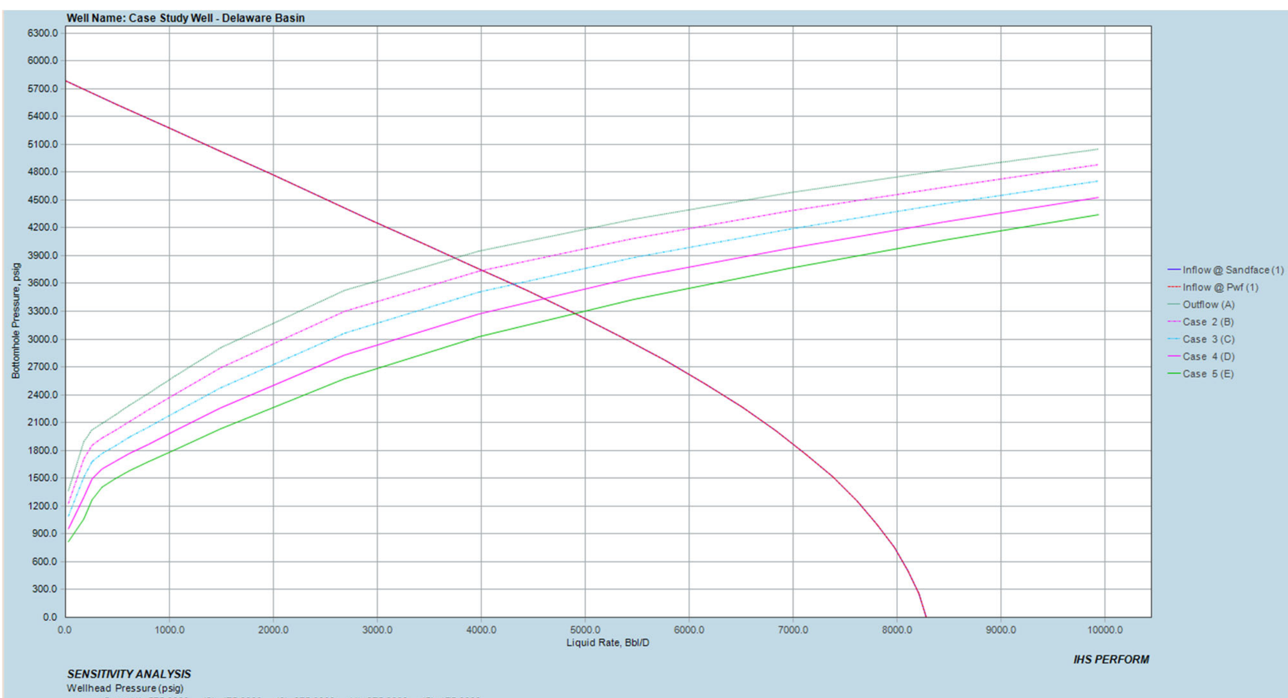

Figure 6: Varying FWHP

Flow Path	Tubulars	Equiv. ID (in)	Area (in^2)
Tubing	2-3/8” 4.7#	1.995	3.13
Tubing	2-7/8” 6.5#	2.441	4.68
Tubing	3-1/2” 9.3#	2.992	7.03
Annulus	2-7/8” x 5-1/2” 20#	3.816	11.44
Annulus	2-3/8” x 5-1/2” 20#	4.146	13.50
Annulus	1-5/8” x 5-1/2” 20#	4.493	15.85
Annulus	1-1/4” x 5-1/2” 20#	4.612	16.71

Table 1: Varying CFA Relative to Tubular Sizes

Putting It All Together			
Case	**Action**	**TFPD (bbls)**	**Incremental Uplift (BFPD)**
Base	Free Flowing up 2-7/8" tbg	1,392	
Inj. Depth	Begin HPGL with inj. depth of 11,151' TVD, flowing up tbg & inj. down annulus	2,471	1,079
CFA	Swap to anular flow with inj. down tbg	2,939	468
Inj. Rate	Increase inj. Rate	3,737	798
FWPH	Decrease FWHP	4,001 - 4,895	264 - 1,158
Total Uplift Potential Relative to Base Case			2,345 - 3,503

Table 2: Uplift Potential Review

Bibliography

Clegg, J. (2007). *Petroleum Engineering Handbook.* Richardson: Society of Petroleum Engineers.

Dickens, R. J. (1988). *High-Pressure Gas Lift for Deep, Sour Production.* SPE.

Elmer, D., Elmer, W., & Harms, L. (2017). *High Pressure Gas-Lift: Is Industry Missing a Potential Huge Application to Horizontal Wells?* SPE.