INFLOW PERFORMANCE ESTIMATION – CRITICAL FOR ARTIFICIAL LIFT DESIGN

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ABSTRACT

The ability to calculate and predict the inflow performance from a well is critical in designing for any form of artificial lift or to optimize production. The production/lift capability of whatever form of artificial lift chosen should closely match the current and future inflow performance of the well for the economics of the investment to be the highest.

Inflow performance estimation is also required to ensure that production is being optimized. When used with the outflow performance of the lift method, NODAL analysis can be performed to evaluate the entire production system for production enhancements.

This paper discusses the various methods available to determine the inflow performance of a well from the reservoir to the wellbore. The methods include the Productivity Index, Vogel Inflow Performance Relationship and Fetkovich method. In addition, methods to determine the inflow performance when the reservoir pressure is not known and predicting inflow performance as the well is depleted are discussed.

INTRODUCTION

A fundamental question that must be answered by operators is if a well is producing what the reservoir can deliver. To understand what a reservoir can deliver, inflow performance calculations have been developed to describe the relationship between producing bottomhole pressure and production rate.

A good understanding of Inflow Performance is used to a) design artificial lift systems, b) identifying reservoir enhancements (stimulation, reperforation, etc.), c) NODAL systems analysis for use in maximizing and optimizing production, d) surface facility equipment specifications and, e) economic analysis of various production scenarios.

For simplicity a "well test" is defined as a production test with a corresponding producing bottomhole pressure. This paper does not specify how to determine the static or producing bottomhole pressure of a well. The use of downhole pressure gauges is one method and the use of fluid level are another. A very good paper to reference to use fluid levels in calculating bottomhole pressures is the referenced paper written by McCoy, Podio and Huddleston[1].

METHOD 1: PRODUCTIVITY INDEX

Darcy's law for steady state radial flow suggests there is a linear relationship between pressure drawdown and production. The formula for this relationship is shown in equation (1) and known as the Productivity Index (PI).

$$J = \frac{Q}{P_r - P_{wf}} \quad \text{...(1)}$$

where

$$J = Productivity\ Index, {}^{BLPD}/_{psig}$$
$$Q = Production\ rate, BLPD$$
$$P_r = Static\ Reservoir\ Pressure, psig$$
$$P_{wf} = Producing\ Bottomhole\ Pressure\ at\ rate\ Q, psig$$

The Productivity Index works well for liquid (oil, water, or both) reservoirs where solution gas is not relevant or in solution gas drive reservoirs with pressures above the bubble point of the fluid.

Necessary information to determine the Productivity Index are two different well tests or one well test and the static reservoir pressure.

METHOD 2: VOGEL INFLOW PERFORMANCE RELATIONSHIP

At reservoir pressures below the bubble point of the oil, the PI does not provide a realistic estimation of the inflow performance. It was observed that oil flowrates at increasing drawdown pressures declined much faster than the PI indicated. This is because below the bubble point, gas is liberated and becomes free gas. As free gas has a lower viscosity and higher permeability, it reduces the flow of oil within the reservoir.

With the use of computer models, Vogel developed a simple equation (2) that can give much better estimates of inflow performance of solution gas drive reservoirs operating at or below the bubble point pressure [2]. Graphically, the difference between the inflow performance as determined by the PI and that determined by Vogel equation is shown in Figure 1. The Vogel equation has proven to be valid for wells with a water cut up to 97%.

Necessary information to calculate the IPR are a static bottomhole pressure and one well test.

$$Q/_{Q_{max}} = 1 - 0.2\left({}^{P_{wf}}/_{P_r}\right) - 0.8\left({}^{P_{wf}}/_{P_r}\right)^2 \quad \text{...(2)}$$

where

$Q = Production\ rate, BLPD$
$Q_{max} = Production\ rate\ when\ P_{wf}\ is\ 0, BLPD$
$P_r = Static\ Reservoir\ Pressure, psig$
$P_{wf} = Producing\ Bottomhole\ Pressure\ at\ rate\ Q, psig$

The Dimensionless Vogel curve shown in Figure 2 is a useful tool to determine what percentage of the maximum production rate is being achieved, given only the ratio of the Producing BHP to the Static BHP. For example, if the producing bottomhole pressure is 40% of the static reservoir pressure, 80% of the production potential is being realized.

METHOD 3: RESERVOIR PRESSURE ABOVE BUBBLE POINT PRESSURE

In the situation where the reservoir pressure is above the bubble point pressure, a combination of Methods 1 and 2 can be used. The PI method is valid for reservoir pressure exceeding the bubble point pressure and the Vogel Method applies in scenarios when the reservoir pressure is below the bubble point.

$$Q = Q_b + \frac{JP_b}{1.8}\left[1 - 0.2\left({P_{wf}}/{P_b}\right) - 0.8\left({P_{wf}}/{P_b}\right)^2\right] \quad \text{(3)}$$

where

$J = Productivity\ Index, BLPD/psi$
$Q = Production\ rate\ at\ P_{wf}, BLPD$
$Q_b = Production\ rate\ at\ Bubble\ Point\ Pressure, BLPD$
$Q_{max} = Production\ rate\ when\ P_{wf}\ is\ 0, BLPD$
$P_b = Bubble\ Point\ Pressure, psig$
$P_{wf} = Producing\ Bottomhole\ Pressure\ at\ rate\ Q, psig$

The use of this equation is shown in Figure 3.

METHOD 4: FETKOVICH METHOD

While Vogel's work was based on computer simulation, Fetkovich[3] attempted to verify those results using actual isochronal and flow-after-flow multipoint backpressure tests on 40 different wells. These types of tests are generally performed in gas wells, however, in all cases evaluated by Fetkovich, the test results were found to give good results.

Necessary information to calculate the IPR are at least two (but preferably three to four) wells tests and associated bottomhole pressures. The multiple tests are required to determine the *n* exponent. If only one well test and the static reservoir pressure is available, one must assume the *n* exponent then calculate the coefficient *C*. In

Fetkovich's tests, the n exponent was found to range from 0.568 to 1.0. This equation is also known as the Back Pressure Equation.

$$Q = C\left(P_r^2 - P_{wf}^2\right)^n \quad (4)$$

where

$Q = Production\ rate, BLPD$
$C = Flow\ Coefficient$
$P_r = Static\ Reservoir\ Pressure, psia$
$P_{wf} = Producing\ Bottomhole\ Pressure\ at\ rate\ Q, psia$
$n = exponent\ depending\ upon\ well\ characteristics$

Please note that Fetkovich uses pressure in absolute units, psia, whereas in the Vogel equation, gauge units for pressure can be used.

COMPARISON OF METHODS

The Productivity Index is most useful in waterfloods and strong water drive reservoirs. It is also used with the Vogel IPR method when the reservoir pressure falls below the bubble point. The Fetkovich method tends to give more conservative estimate of inflow performance.

Differences between methods may suggest there are errors involved with calculating inflow performance making them meaningless. However, the primary use of these methods is to determine the difference in production that can be achieved by reducing the producing bottomhole pressure. The slope of the IPR curve and the Fetkovich curve are very similar at low producing bottomhole pressures and therefore the change in production rate using either method will result in similar results.

As an example, assume a static reservoir pressure of 500 psia, and production of 250 BLPD at a BHP of 250 psia. Using the Vogel Method, the results are noted below and shown in Figure 4.

	Vogel Method	Fetkovich Method
Maximum Production, Q_{max}, BLPD	357	333
Production at 20% of Static P_r, BLPD	331	320
Production at 10% of Static P_r, BLPD	347	330
Anticipated Production Gain to 20%, BLPD	81	70
Anticipated Production Gain to 10%, BLPD	97	80

As noted earlier, Fetkovich typically yields more conservative results than Vogel. In this case, the difference in Q_{max} is 7%.

IF STATIC RESERVOIR PRESSURE IS NOT KNOWN

In many cases the static reservoir pressure is not known. Methods have been developed to create inflow performance curves by using two separate well tests at different rates and associated bottom hole pressures.

The Vogel equation (Equation 2) can be mathematically converted, with the use of the quadratic formula, that will take two separate well tests and fit it to the Vogel curve shape. The derivation of this method is not offered in this paper, however several spreadsheets have been developed to simplify the creation of the Vogel IPR curve.

The Fetkovich equation can also be used to determine an inflow performance curve if the static reservoir pressure is not known. An assumption for the value of "n" must be made. Examples of using the two-point inflow performance methods is shown in Figure 5.

DETERMINING FUTURE INFLOW PERFORMANCE

Planning for artificial lift can be improved if the future inflow performance can be estimated. The net value of the well can be improved if multiple and/or different forms of artificial over the life of the well can be minimized. An estimation of the future inflow performance at corresponding reservoir pressures will give the designer an idea of the range of production capability the artificial is needed. Two methods of estimating future inflow performance are discussed.

The Standing Method[4] uses current and future estimates of reservoir pressure, viscosity, permeability, and formation volume factor to determine the future inflow performance. Unfortunately, many of these factors may not be known for the current state or in the future. Therefore, an estimation of these parameters is necessary.

As pressure declines in a reservoir, the inflow performance will decline. This is because the reservoir parameters, namely pressure, relative permeability to oil, viscosity and oil Formation Volume Factor will deteriorate. The ratio of the future factors to the present factors is applied to the present Q_{max} to determine the future Q_{max}. Once that is known, the Q_{wf} in the future can be calculated for any producing bottomhole pressure as shown in the equations below.

$$Q_{max,P} = Q_{wf,P} \Big/ \left[1 - 0.2\,\frac{P_{wf,P}}{P_{r,P}} - 0.8\left(\frac{P_{wf,P}}{P_{r,P}}\right)^2\right] \text{ .... (5)}$$

$$Q_{max,F} = Q_{max,P}\left(\frac{P_{r,F}}{P_{r,P}}\right)(RPR) \text{ .... (6)}$$

$$Q_{wf,F} = Q_{max,F}\left[1 - 0.2\frac{P_{wf,F}}{P_{r,F}} - 0.8\left(\frac{P_{wf,F}}{P_{r,F}}\right)^2\right] \text{ .... (7)}$$

where

$Q_{wf,P\ or\ F} = Production\ rate\ either\ Present\ day\ or\ Future\ time, BLPD$

$Q_{max,P\ or\ F} = Production\ rate\ when\ P_{wf}\ is\ 0, Present\ day\ or\ Future\ time, BLPD$

$P_{r,P\ or\ F} = Static\ Reservoir\ Pressure\ either\ Present\ day\ or\ Future\ time, psig$

$P_{wf,P\ or\ F}$

$= Producing\ Bottomhole\ Pressure\ at\ rate\ Q\ Present\ day\ or\ Future\ time, psig$

$RPR\ =\ Reservoir\ Property\ Ratio,\ \left(\frac{k_{ro}}{\mu_o B_o}\right)_F \Big/ \left(\frac{k_{ro}}{\mu_o B_o}\right)_P$

$k_{ro}, \mu_o, B_0\ represent\ relative\ permeability, viscosity\ and$
$Formation\ Volume\ Factor\ in\ Present\ and\ Future\ times.$

Typically, the values of relative permeability, viscosity and Formation Volume Factor are not available. Therefore, an estimation of the RPR should be estimated based on the user's experience. It would likely range between 0.5 and 1.0.

The Fetkovich[4] future inflow performance curves are a function of the changes in Pr over time. To account for this, the coefficient C is adjusted for future is a function of ratio of Pr (present) and Pr (future) as shown in Equation 9.

$$Q_P = C_P\left(P_{r,P}^2 - P_{wf,P}^2\right)^n \quad \text{(8)}$$

$$C_F = C_P\left(\frac{P_{r,F}}{P_{r,P}}\right) \quad \text{(9)}$$

$$Q_F = C_F\left(P_{r,F}^2 - P_{wf,F}^2\right)^n \quad \text{(10)}$$

A graphical representation of the current and future inflow performance estimations is shown in Figure 6. The Fetkovich method again results in a more conservative estimation. However, the range of the inflow performance predicted by each method, at any given P_{wf} is similar.

USE IN ARTIFICIAL LIFT DESIGN AND OPTIMIZATION

The inflow performance curve identifies the production capability of the reservoir into the wellbore. This is the first question that needs to be answered when selecting and designing for new artificial lift or for optimizing existing artificial lift installations.

The easiest application of inflow performance curves is to optimize an existing artificial lift installation by determining how much fluid is being produced versus the amount of production the well can give up. The dimensionless Vogel curve is a great tool for examining the production potential. Recognize that the curve is the steepest at lower producing BHP, meaning the production gains by drawing the well down are the smallest.

Gas lift designs get significant benefit from using future IPR curves. In the scenario in which the available gas injection pressure is not enough to unload the well to the bottom perforation (or TVD in the case of horizontal wells), the initial design will be to lift from the deepest point possible. By using future inflow performance predictions, the gas lift design can add mandrels and dummy valves below the operating point. These dummy valves can later be replaced with unloading or operating valves as the static reservoir pressure drops, as predicted in using either the Standing or Fetkovich future IPR curves. This is shown in Figure 7.

CONCLUSIONS

A good understanding of a well's Inflow Performance capability is critical to the designing and optimizing of artificial lift installations. One must be able to determine the production capacity to size and optimize the artificial lift equipment necessary to produce what the well can deliver.

This paper offered up the most common equations for calculating inflow performance of a well and offered a comparison of them. Other equations exist, many of which are fine tuning of Vogel. For purposes of sizing new artificial lift installations or optimizing existing wells, the simpler Vogel or Fetkovich equations are adequate for the applications discussed.

There are misconceptions that there is not enough information to determine the inflow performance. This paper has demonstrated that a minimum of data can lead to valuable information regarding the current and future performance.

REFERENCES

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3. Fetkovich, M.J.: "The Isochronal Testing of Oil Wells". Paper SPE 4529 presented at the 48th Annual Fall Meeting of SPE, Las Vegas, Nev., 1973.
4. Beggs, Dale: "Production Optimization Using NODAL Analysis", OGCI 2003, pp 40-45.
5. Hernandez, Ali: "Fundamentals of Gas Lift Engineering, Well Design and Troubleshooting", Elsevier 2018, page 456

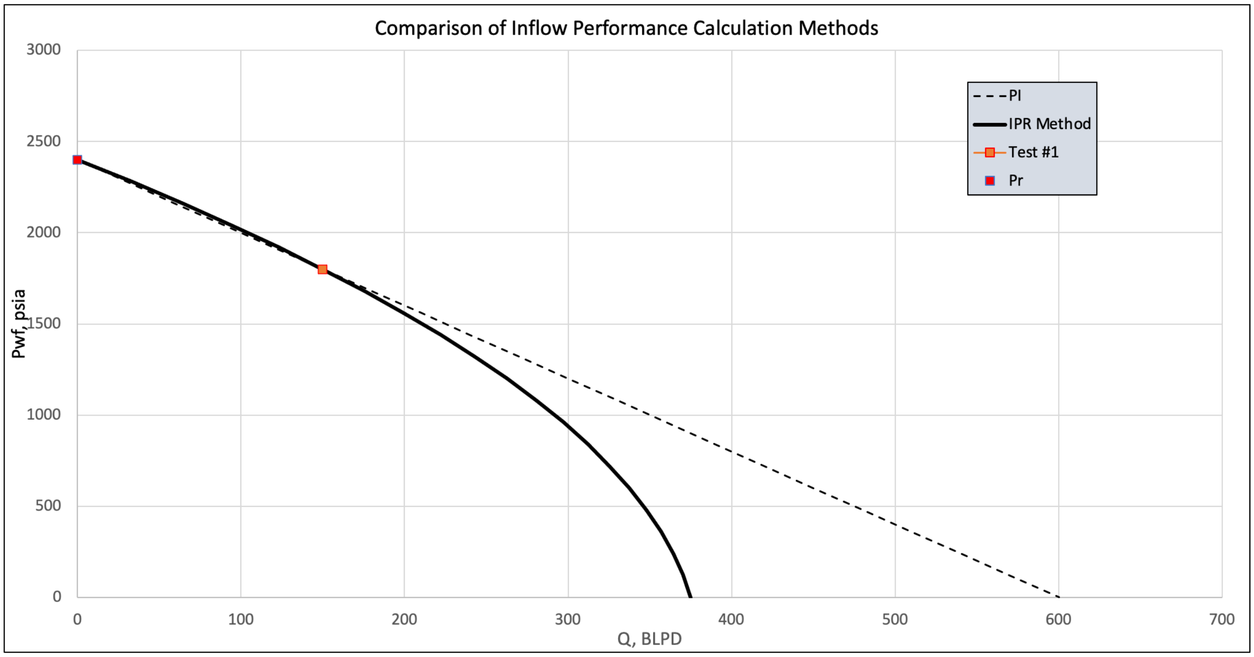

Figure 1: Inflow curve using Darcy Equation (Productivity Index) compared to IPR curve using Vogel Equation

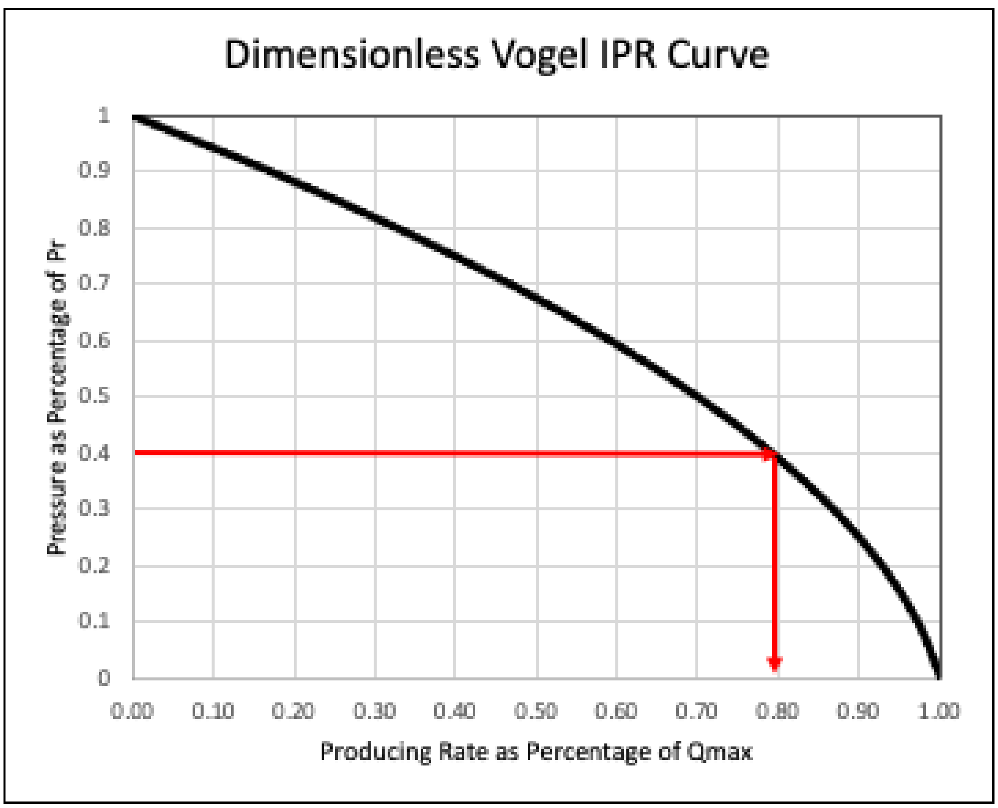

Figure 2: Dimensionless Vogel IPR Curve

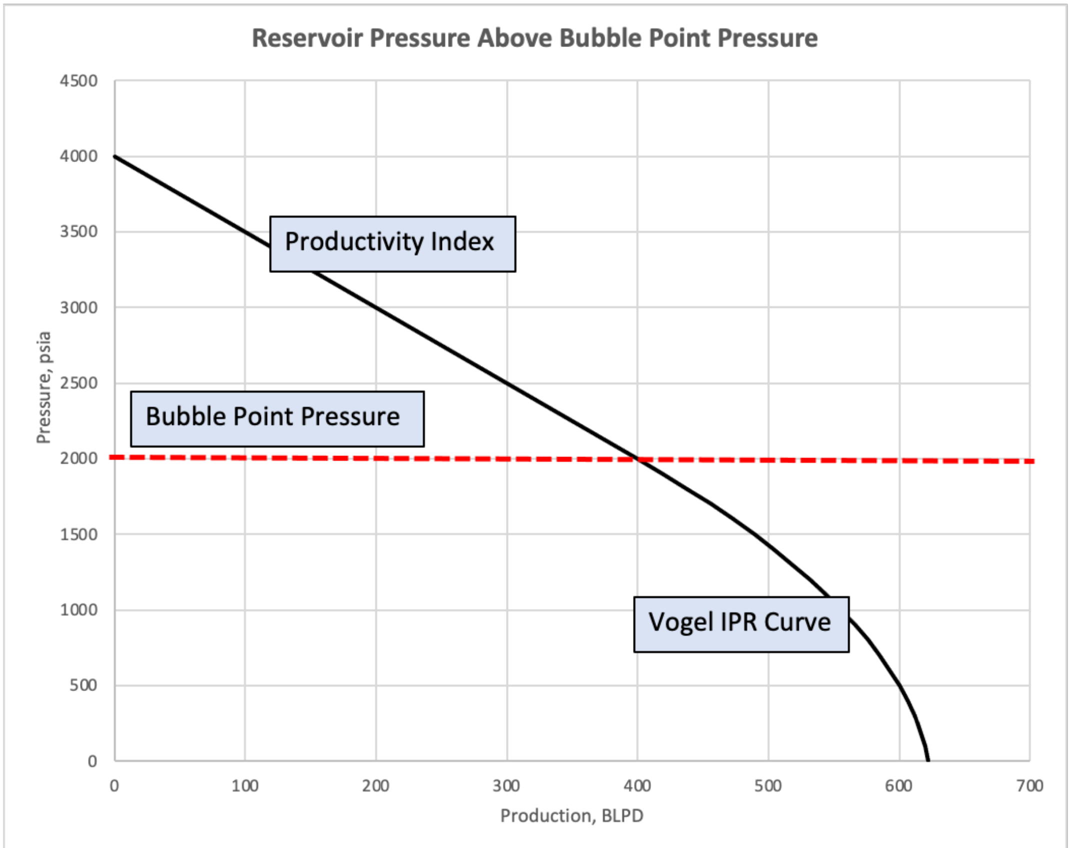

Figure 3: Reservoir Pressure above Bubble Point Pressure

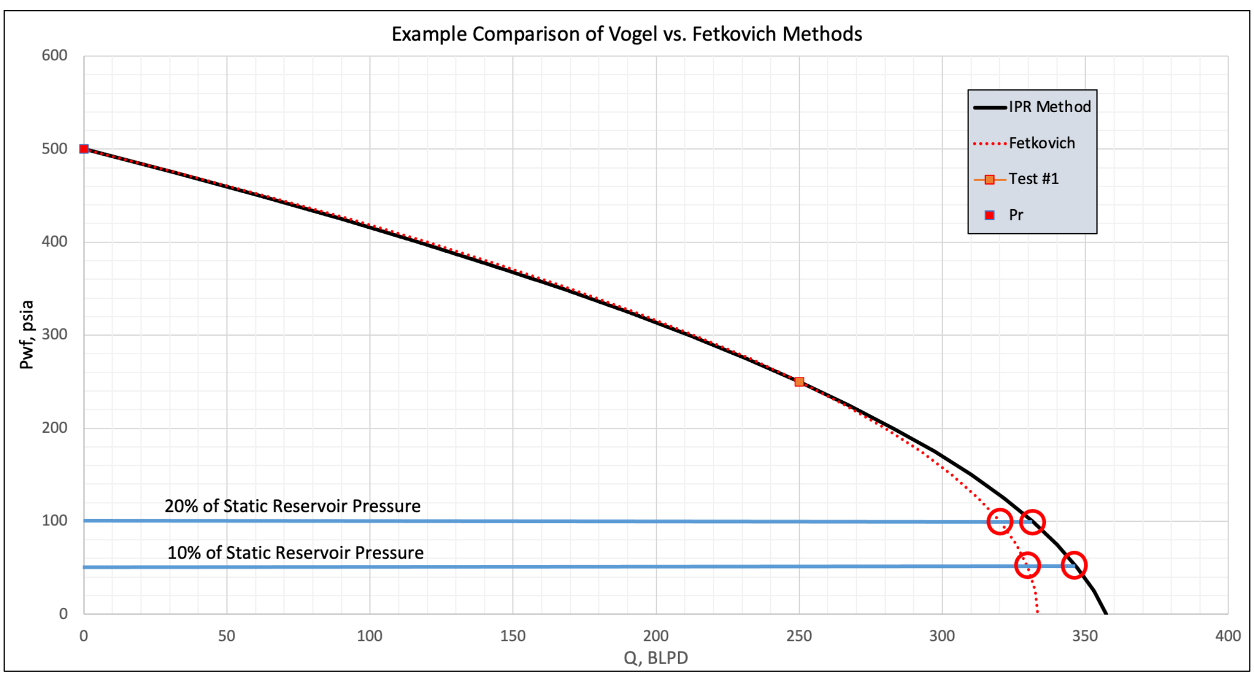

Figure 4: Comparison of Vogel and Fetkovich Methods in Example

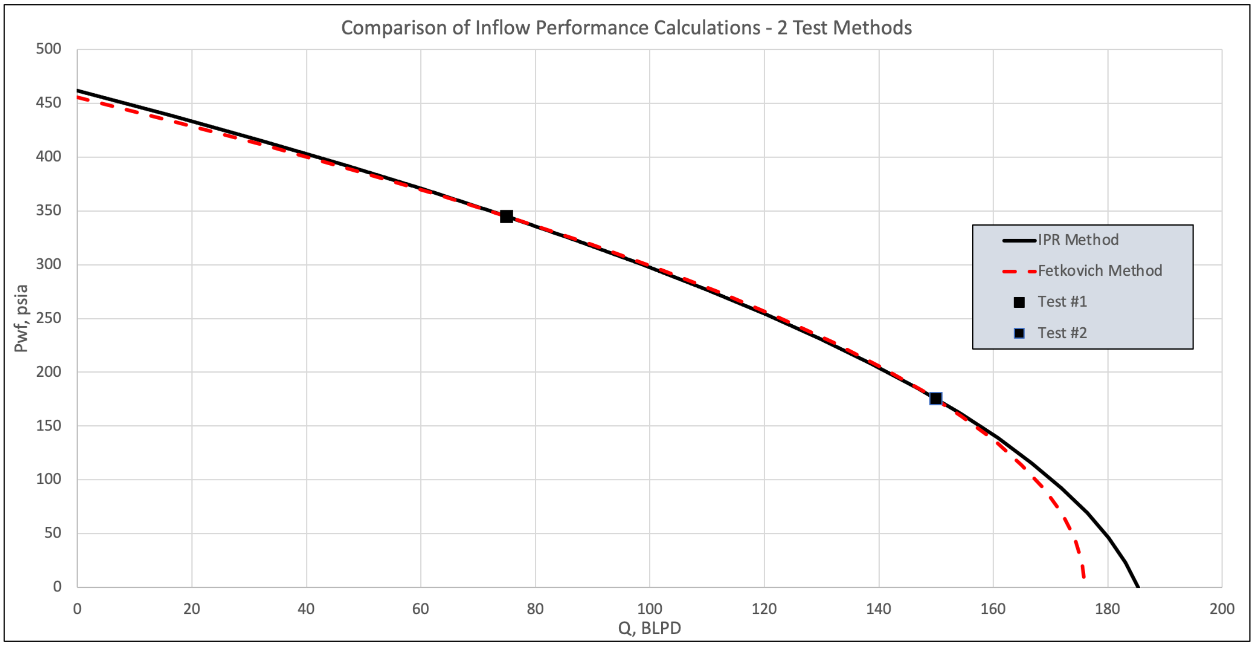

Figure 5: Comparison of Inflow Performance Calculations - 2-test Methods

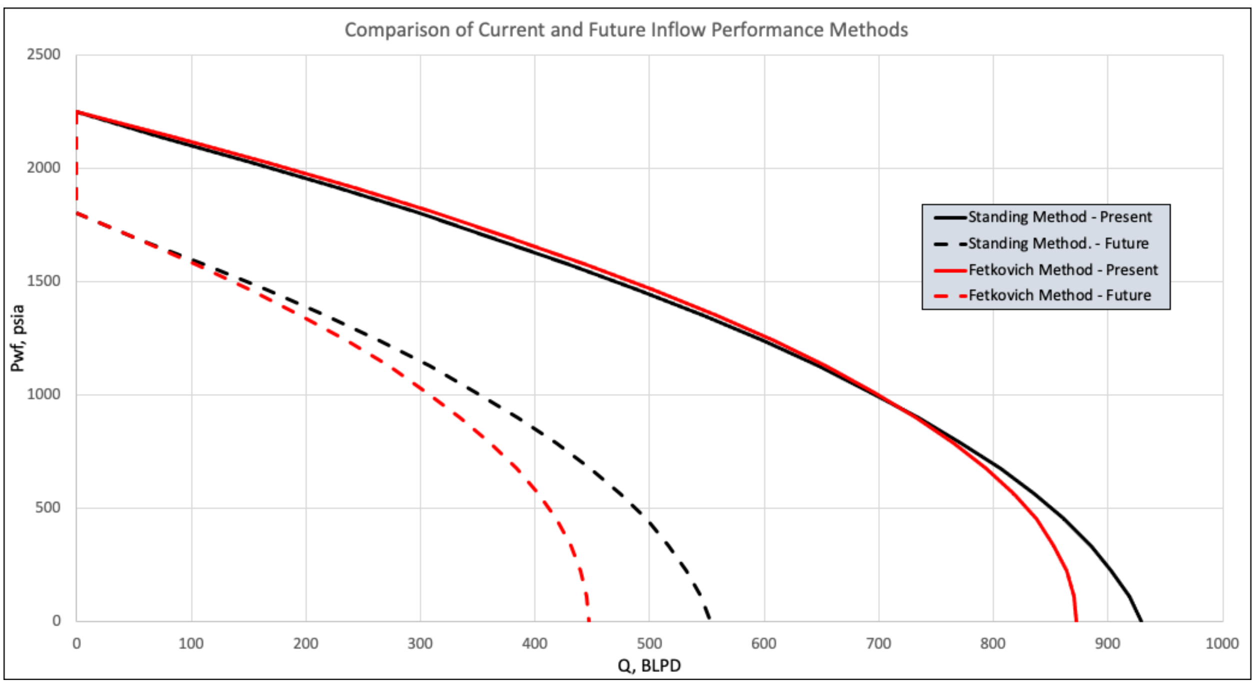

Figure 6: Comparison of Current and Future Inflow Performance Methods

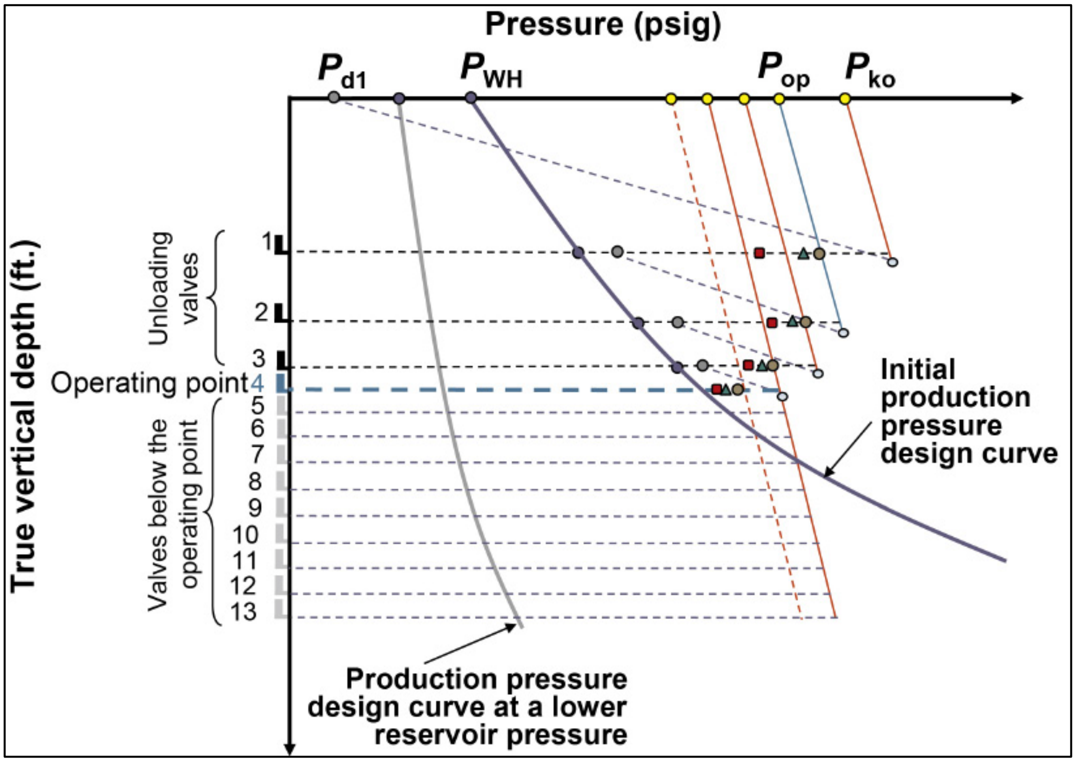

Figure 7: Gas Lift Design using current and future inflow performance curves[5]