ANNULAR FLOW GAS LIFT OPTIONS AND IMPROVEMENTS

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ABSTRACT

Annular flow gas lift has rapidly become a popular method of initial artificial lift in the Permian Basin. The evolution of wells, over time, has resulted in higher flow rates due to advancements; this includes horizontal, multi-staged improvements in frac technology. Smaller casing strings are often installed to save on well costs, but this can limit the type of artificial lift system that can be installed, and ultimately, the flow rates attainable from the reservoir. Annular flow gas lift offers a larger flowing area and less of a pressure loss versus tubing flow applications.

This paper will include some basic inflow and outflow theory and show the differences between annular versus tubing flow in various scenarios. There will be several annular flow gas lift mandrel options explored including fluid, internally mounted, standard configuration side pocket, EC configuration side pocket (EC – external casing), and hybrid combinations of these systems. These different options will be discussed including the advantages and disadvantages of each system.

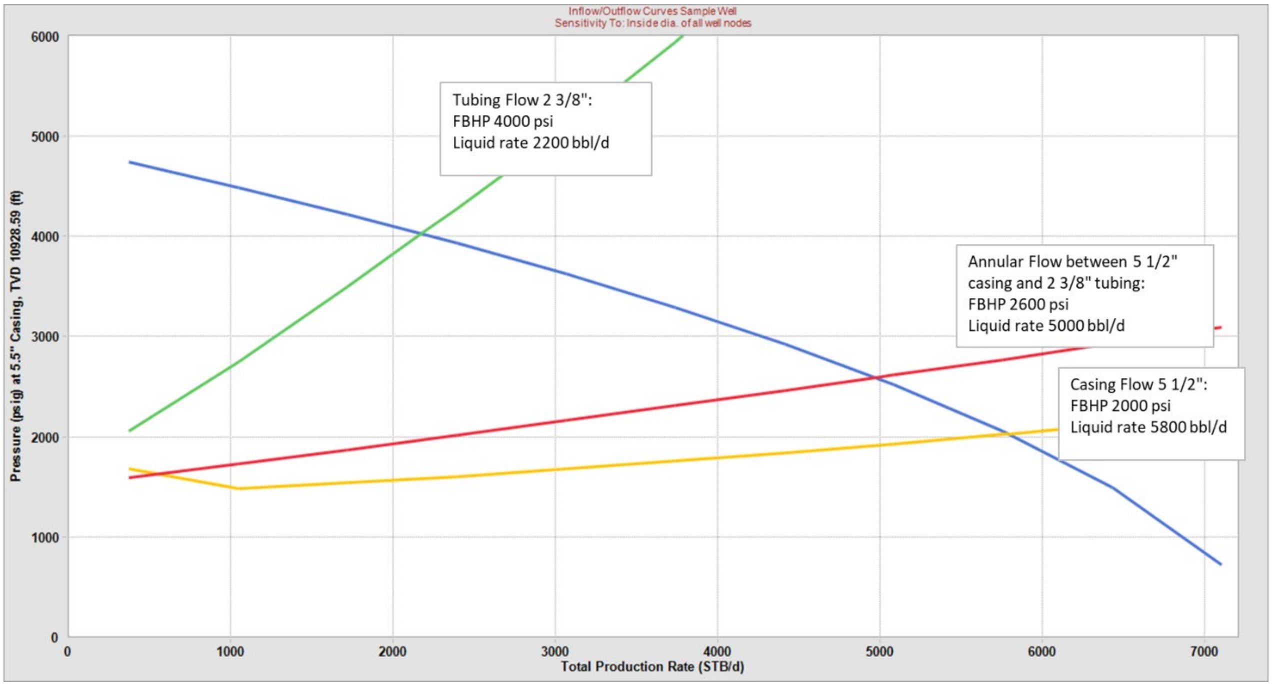
This paper will also cover some important improvements in the EC side pocket system. An issue identified with valves coming out of these pockets became prevalent in many basins; an Engineering group studied this and offered up a solution to reduce the chances of this from occurring. This resulted in it being adopted by the industry. These findings and best practices will be shared with the group during this paper.

INTRODUCTION

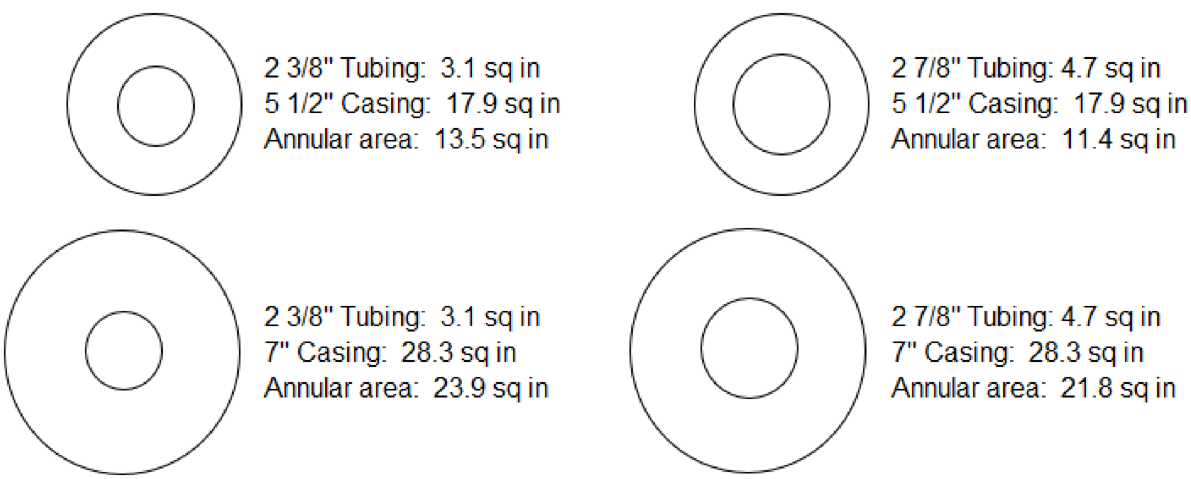
Modeling of inflow and outflow curves is a useful tool to establish a relationship between flow rate and pressure. The inflow curve, referred to as the IPR curve (Inflow Performance Relationship) displays the productive capacity of the well. The outflow curves are obtained by running nodal analysis for specific scenarios. When the inflow and outflow curves are combined on one plot, a quick comparison of production rate and flowing bottomhole pressure can be observed.

A sample well case has been created to show the difference in liquid flow rate compared to flowing bottom hole pressure. Hagedorn-Brown modified correlation was used to generate the outflow curves and Vogel's model was used for the inflow curve. The resulting graph shows the predicted flow rate of the well for 3 different outflow cases: producing up the tubing, the annular space (area between casing and the

tubing), and just the casing (no tubing in the well). In this example the model was built using 5 1/2” casing and 2 3/8” tubing.
Flowing up just the casing with no tubing in the well results in the highest production rate, followed by annular flow, and then tubing flow.



Here is a diagram showing common sizes of tubing and casing used, along with the respective flow areas (not to scale):

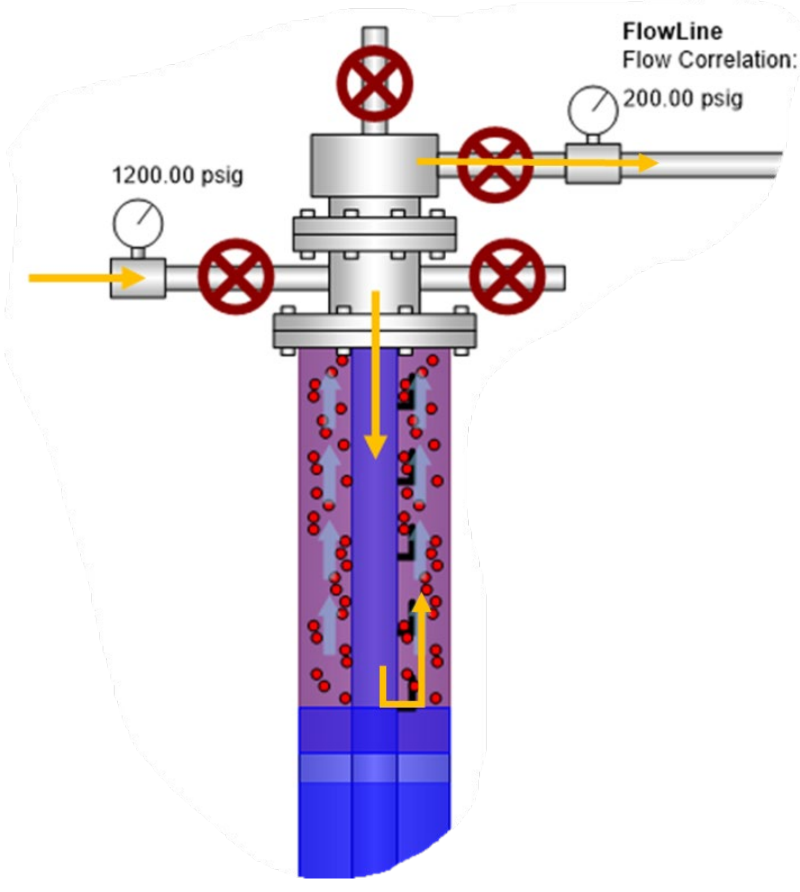


ANNULAR GAS LIFT SYSTEM:

The typical annular flow gas lift system has pressurized natural gas injected down the tubing string and reservoir fluid is produced up the annular side. The pressurized gas, typically in the range of 1000-1250 psi at surface, passes through gas lift stations which typically include a mandrel, valve, and check valve. The gas lift valves are designed to close in sequence from top to bottom with the goal of injecting as deep in the well as possible (maximize drawdown). The check valves are installed to ensure there is only one directional flow through the valves. Annular flow gas lift is considered a form of high-volume artificial lift method, with the capability of lifting volumes much greater than that of tubular flow.

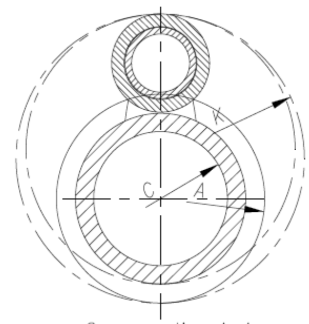
A key consideration of annular gas lift systems is the availability of injection gas. Typically, annular flow systems require more gas to ensure critical lift velocity is being exceeded.

The below diagram shows the flow path of injection gas for an annular flow system.



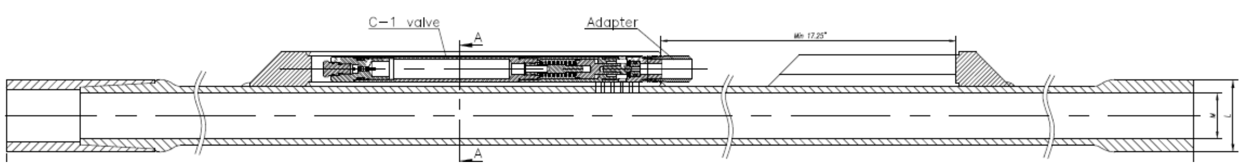
METHODS OF ANNULAR FLOW GAS LIFT

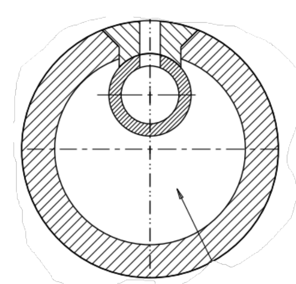
There are several different gas lift mandrel configurations and options available. These are available in different metallurgies, with the most common being L80 or 4130 in both LHT and HHT selections. Annular flow gas lift systems can be installed either with or without a packer. In a system without a packer, a plug is typically set at the bottom of the tubing, this will isolate the tubing injection side from the reservoir fluids produced on the annular side. Systems with a packer typically have an open sliding sleeve with a plug above to direct the flow to the annulus. The plug can be removed and sliding sleeve closed in the future to convert to tubing flow.



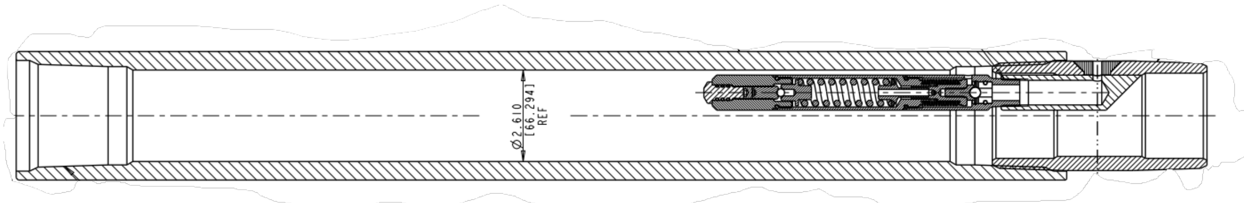
Cross section A–A

Conventional style mandrels (also called fluid mandrels): For this style of mandrel the valves are mounted externally to the mandrel. The overall mandrel length is usually five feet in length. Holes or slots are machined into the side of the mandrel and a tube that houses the gas lift valve is welded over these holes. There is a threaded connection point at the bottom of the tube where the gas lift valve and check valve attach. The advantages of this system is that it is the lowest cost option, has a full inner diameter drift clearance in the tubing, and compatible with a dual check valve option. The disadvantages are that a workover rig is required to pull the system if valves need to be changed and there is tighter clearance or physical fit inside the casing, as the valves are located externally to the mandrel.

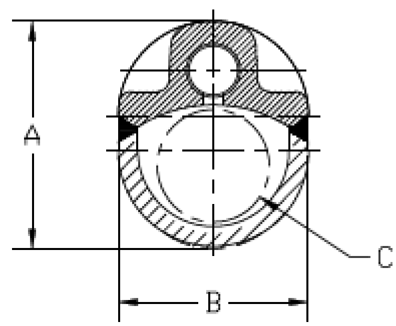




Internally mounted mandrels (also called IM mandrels): These mandrels are also tubing conveyed with the valves installed on the inside of the tubing. The construction of this mandrel consists of two pieces of tubing that are threaded together to allow affixing the valve and check internally to the mandrel. There is a machined port in the lug area that allows passage of the injection gas. Advantages of the IM mandrel are a larger diameter valve can be used (1.5” VS 1”), and there is more clearance around the OD of the mandrel to fit into the casing as the valves are located internally. A disadvantage is there is no internal drift on the tubing and surveys, plugs, or any other wireline equipment cannot be conveyed in or out of the hole. Similar to the fluid mandrel, a workover rig is required to pull the system if valves need to be changed. This option typically costs a little more than the conventional style fluid mandrel.



Sidepocket mandrels: A sidepocket mandrel has a chamber (called a ‘pocket’) on the inside where a gas lift valve can be installed or removed with a wireline unit. This chamber, or pocket is offset in the side of the mandrel to allow full drift in the tubing. The most common sidepocket mandrels used on-shore have either forged or machined pocket sections which are welded onto main body of the mandrel. The top mandrel in the diagram below is an example of mandrel with a forged pocket, and the bottom with a machined pocket.



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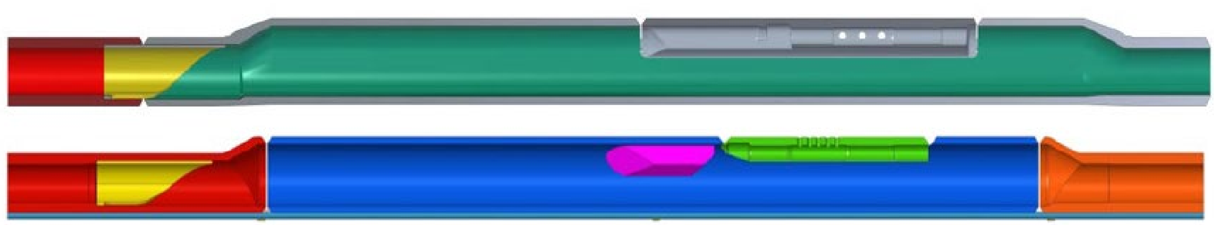
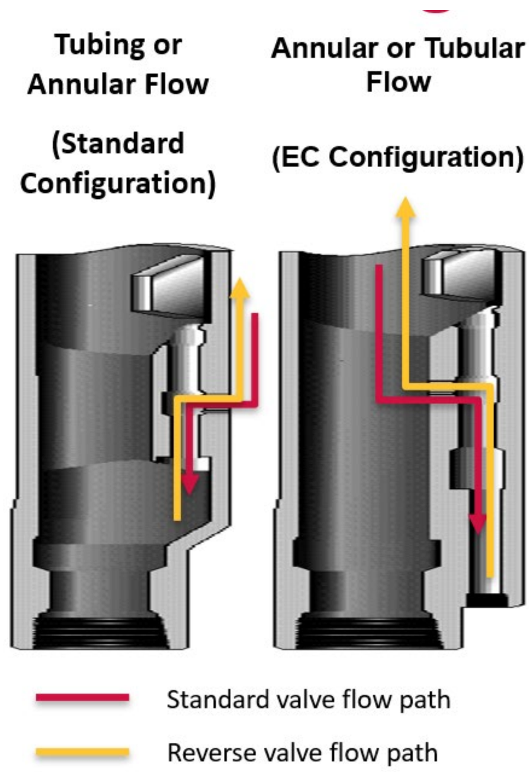
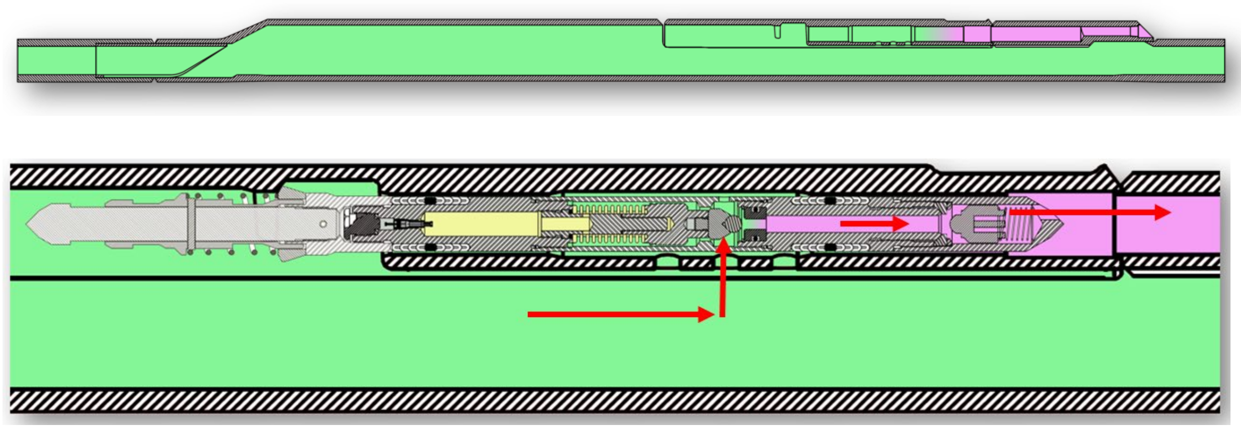


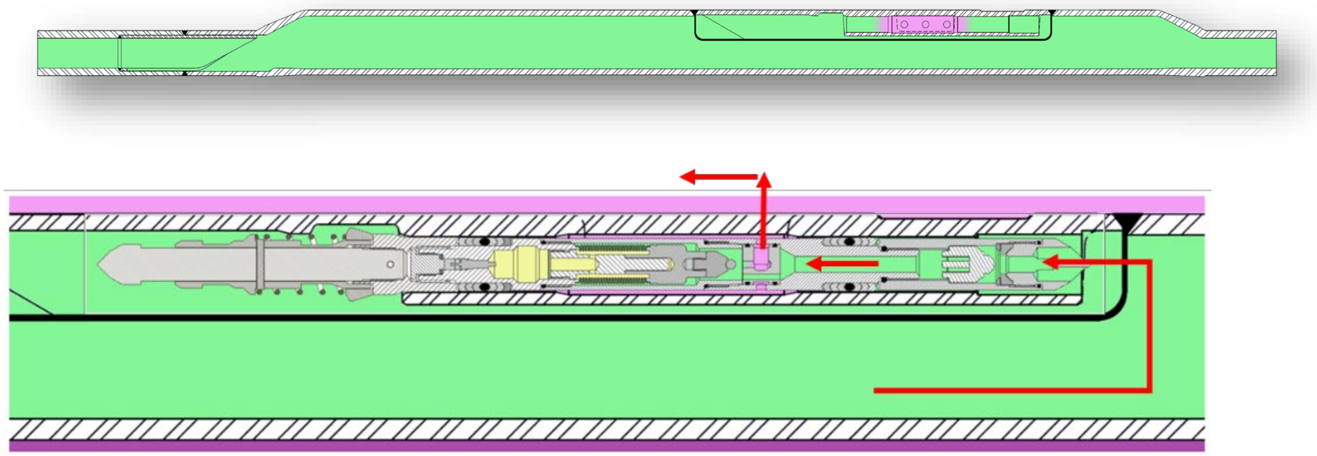
There are a few different configurations of sidepocket mandrels. The below diagram shows the flow paths both a standard and EC sidepocket configuration.



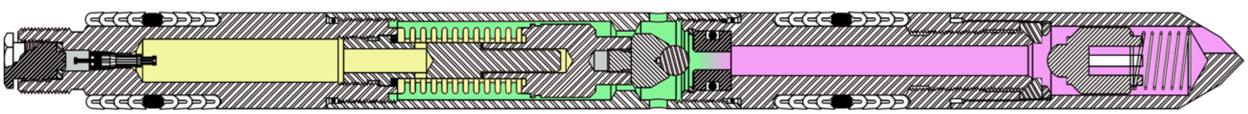
To set up the EC mandrel for annular flow, a standard retrievable valve is installed initially (tubing injection). When the operator wants to switch from annular flow to tubing flow, the valves would be swapped out via wireline and replaced with reverse flow retrievable valves. Below is a diagram showing the flow path of the injection gas.



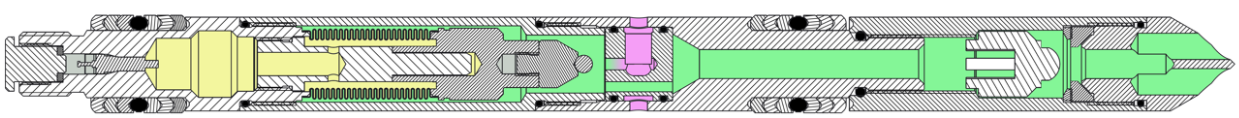
Below is a diagram showing the flow path of injection gas through a reverse flow retrievable valve installed in a standard sidepocket mandrel (non EC).



Standard configuration retrievable IPO valve (Injection Pressure Operated):



Reverse flow configuration retrievable IPO valve:



Advantages of the sidepocket: This style of mandrel is an attractive option as the flow path can be switched from annular to tubing flow later in the life of the well without requiring a costly workover where the tubing needs to be pulled. Workover costs and downtime are greatly reduced compared to a using a workover rig to replace a conventional system. As mentioned previously, the sidepockets are also full drift. A disadvantage of the sidepocket systems is they typically more compared to a conventional system (depending on the metallurgy and qualifications required). An experienced wireline or gas lift technician are recommended when completing wireline work on wells with sidepockets.

HYBRID SYSTEMS

Another configuration option for both annular and tubing flow is a hybrid system. This method combines conventional fluid mandrels with a conventional tubing flow gas lift mandrels on one tubing string. This allows the operator to switch from annular flow to tubing flow by changing the injection path at the wellhead. The check valves installed in each system are in place to ensure cross flow does not occur. Advantages include not having a workover or wireline to switch from annular to tubing flow. Disadvantages are there will be a large number of mandrels in the well.

HIGH PRESSURE GAS LIFT CASING FLOW SCENARIO (NO TUBING)

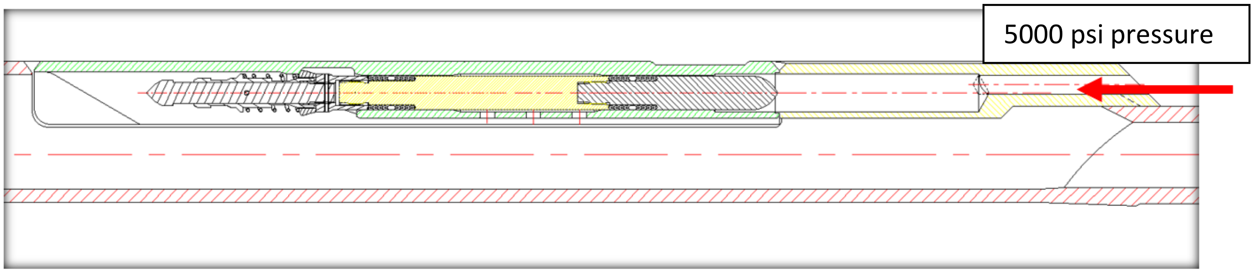
A single point, high pressure injection system is currently being explored, which would further increase production compared to an annular flow system as there would be less friction loss and no tubing restriction.

The picture to the right is an example of a system that uses a 1 ¼" coil tubing externally to casing as the injection string. It is a permanent installation where the coil tubing is cemented in place.

Dual 1 1/2" 10K high pressure check valves, and an orifice are part of the assembly. In this particular application, approximately 3000-4000 psi injection pressure is required.

FEA STUDY

It was discovered that on occasion when there is a large enough pressure differential across the mandrel, the valves could come out of the pockets in the EC style mandrels. A Finite Element Analysis study was conducted to evaluate the stress, strain, and radial deformation. The study found that the material selection in the latch assembly makes a large difference in keeping the valve and latch from deforming. A common material used in the industry for latches is 316 stainless steel which has a 27 ksi yield strength. When 5000 psi of pressure applied to the valve in the pocket, the yield strength and plastic strain of 316 SS can be exceeded, resulting in deformation of certain components, this could cause the latch and valve components to bend and displace the valve from the pocket.



Various metallurgies and scenarios were examined to come up with a solution that reduces the possibility of valves from coming out of the pockets. The outcome was to use 17-4 PH Stainless steel 105 ksi yield strength materials on the entire latch combined with an oversized 17-4 PH SS latch ring. The oversized latch ring allows more surface area and radial contact between the latch ring and shoulder.

CONCLUSION

Annular flow gas lift systems are increasing in popularity and are a viable high volume artificial lift type. There are different configurations and options available that have various advantages and disadvantages (see summary table below). The sidepocket and the hybrid conventional systems both offer annular and tubing flow optionality without the need for costly workovers.

It is important to ensure the correct materials are used, as mentioned in the FEA study summarized in this paper for the EC style mandrels.

Mandrel:	Type	Valve	Cost	Flow Path	Advantages	Disadvantages
Fluid mandrels	Conventional	Tubing	Low	Annular	Low cost, dual check valve capable	Require a rig to change over to tubing flow or swap valves, tighter clearance
Internal Mounted	Conventional	Tubing	Low	Annular	Can use larger diameter valves, will fit in smaller casing sizes	Require a rig to change over to tubing flow or swap valves. No ID drift
Standard Sidepocket	Sidepocket	Wireline	High	Tubing & Annular	Flexability - swap valves with wireline. Convert to tubing flow without a rig	Higher initial cost
EC Sidepocket	Sidepocket	Wireline	High	Tubing & Annular	Flexability - swap valves with wireline. Convert to tubing flow without a rig	Higher initial cost
Hybrid	Conventional	Tubing	Moderate	Tubing & Annular	Convert to tubing flow without a rig. Dual check valve capable	Larger number of mandrels in the well. Bottom valves could be open and exposed