

PLUNGER ASSISTED ANNULUS FLOW

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ABSTRACT

The Appalachian Basin, specifically the Marcellus and Utica shales, are known for their initial low water-to-gas ratios and appealing high gas rates. This, however, leaves operators with establishing phase of life flow paths as the well declines. Installing production tubing too early leaves the asset producing at a constrained rate due to frictional losses downhole. These constraints have been observed to be as much as 30% - 40% depending on flowing conditions. Installing production tubing too late; leaves the asset vulnerable to slug flow and deviation from natural decline impacting cash flows. Utilizing a Production Engineer to run nodal analysis to understand exact timing of tubing install can be unrealistic and logistically challenging for procuring material and resources for large-scale tubing programs.

Through engineering efforts along with automation of field devices, an evolution of previously deployed plunger lift optimization efforts traditionally leveraged for optimization of depleted wells and assets resulted in the successful implementation of a unique artificial lift technique called Plunger Assisted Annulus Flow (PAAF). PAAF is targeted to be installed in combination with the installation of production tubing which is approximately 30% above the calculated Turner critical rate in 5-1/2" production casing. PAAF allows for bottom hole pressure to be drawn down until the full well stream can be diverted up tubing without any constraints. This is achieved by simultaneously flowing the annulus and tubing while cycling a continuous-style plunger in the tubing. Each plunger cycle is initiated when flow rates drop below annulus critical rate and is needed to help evacuate fluid hold up that starts to occur in the annulus.

PAAF allows Production Engineers to focus on evolving their business, provide a smooth decline to aid in more accurate forecast generation, and support more predictable cashflows in volatile market conditions.

INTRODUCTION

This paper focuses on efficient management of liquid loading while maximizing productivity in the Marcellus and Utica Shale. Liquid loading remains a persistent challenge in gas and gas-condensate wells, particularly as reservoir pressure declines and gas velocities fall below critical thresholds required for continuous liquid removal. Accumulated liquids in the wellbore increase bottomhole pressure, restrict gas flow, and can lead to premature production decline or well shut-in. Conventional mitigation strategies—such as velocity strings, surfactants, and artificial lift—are often effective but may be constrained by well geometry, operating costs, or mechanical limitations.

Traditional artificial lift and deliquification techniques, including plunger lift, surfactant injection, and mechanical lift systems, are typically deployed later in a well's productive life once natural energy is insufficient to sustain stable flow. While effective at restoring

production, there is a growing need for intermediate solutions that extend casing-flow operations and delay full conversion to tubing-based flow / lift systems.

By combining flow regimes, PAAF can improve liquid evacuation efficiency without requiring major deferment in rates or large capital investments. Despite its increasing field application, the mechanisms governing annular liquid mobilization under plunger operation are not yet fully characterized, and performance outcomes can vary widely depending on well conditions, and operating parameters.

This paper examines the role of PAAF in gas wells requiring a transition from annular flow to tubing flow. The study focuses on underlying flow behavior, operational considerations, and production impacts observed in field applications. Through analysis of production data and operational performance, the paper aims to provide practical guidance for identifying suitable candidate wells and maximizing the effective cross-sectional flow path to enhance overall productivity during phase of life flow path changes.

CANDIDATE WELL

Successful application of PAAF depends on identifying wells where annular liquid loading limits production but sufficient reservoir energy remains to support plunger operation. Candidate wells are typically gas or gas-condensate producers operating in annular-flow configurations that are approaching the limits of stable flow but have not yet fully transitioned to tubing flow or conventional artificial lift. Figure 1 illustrates a Marcellus well entering a liquid loading state while flowing up the annulus. A phase of life flow path change is required to maintain critical gas velocity and preserve production on natural decline.

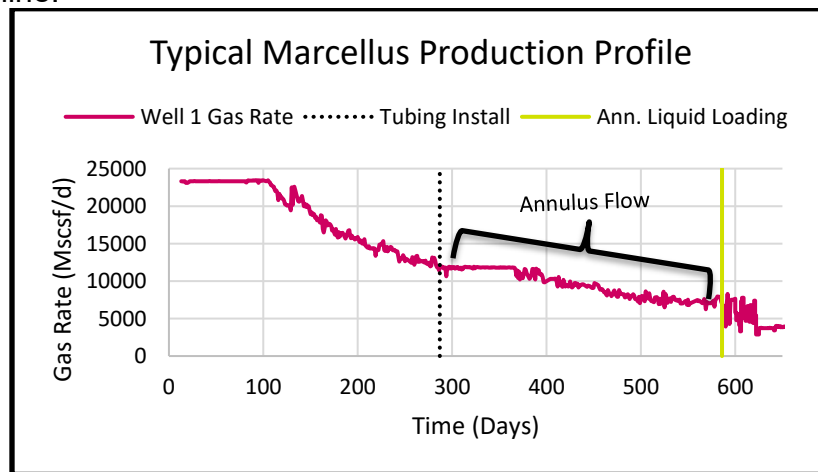


Figure 1 – Example Marcellus PAAF Candidate

Flow Regime and Production Indicators

Flow regime evolution in Marcellus and Utica shale gas wells closely follows the rapid decline characteristics associated with unconventional reservoirs. Wells typically enter production at high gas rates with elevated reservoir pressure, allowing stable casing flow during early life. In this phase, gas velocities are sufficient to maintain mist or

annular flow regimes, effectively transporting liquids to surface while maximizing cross-sectional flow area and minimizing frictional losses. Production follows a period of “flat time” until flowing pressure reaches static vessel pressure. Subsequently a steep but predictable early-time decline driven by reservoir depletion ensues leading to lower downhole velocities.

As drawdown increases and reservoir pressure declines, gas velocity decreases due to the larger flow area. In Marcellus and Utica wells, this transition often occurs earlier than in conventional reservoirs because of high initial production rates followed by rapid pressure depletion. Early indicators of casing flow degradation include increasing casing pressure, subtle liquid fallback, and deviations from expected decline trends despite unchanged choke or surface operating conditions. Gas and water rates may begin to fluctuate and become more variable.

With continued depletion, production tubing typically 2-7/8” or 2-3/8” is installed followed by a phase of life change in flow path. As can be seen above in Figure 1, once tubing is installed the flow path changes from casing flow to annulus flow. The well will once again follow natural decline until annular gas velocity falls below critical thresholds required for continuous liquid removal and the onset of liquid loading in the annulus. In Marcellus and Utica developments, this phase frequently represents the inflection point where continued annulus flow becomes unsustainable without intervention, yet full conversion to tubing flow or late-life artificial lift may be premature and/or result in avoidable production deferment.

As illustrated in Figure 2, the inflow and outflow performance relationships for a representative Marcellus well define the maximum achievable production rate for a given wellbore configuration, with the intersection of the curves indicating the operating point under existing flow conditions. In the tubing-flow configuration shown, the outflow performance results in a production curtailment of approximately 3.15 MMscf/d or 43% relative to outflow of the annulus flow configuration. This loss in deliverability reflects the transitional phase of the well’s life where annulus-flow efficiency has deteriorated, yet full conversion to tubing flow is not operationally optimal.

PAAF is most effective when applied during this phase-of-life transition—after annular flow performance begins to degrade but before tubing-flow conversion or late-life artificial lift is required. Given the relatively low capital intensity of implementation, operators may also elect to implement PAAF concurrent with tubing installation to limit the effects of full annulus flow through the b-Section. By reestablishing liquid mobility and stabilizing flow regimes within the annulus, while simultaneously leveraging tubing flow during plunger cycling, PAAF increases the effective cross-sectional flow area and shifts the outflow curve toward higher deliverability. The objective of PAAF is to maintain critical gas velocity, reduce liquid holdup, and preserve natural decline behavior while extending the productive annulus/tubing-flow window.

Proper identification of this Marcellus- and Utica-specific transition enables operators to recover curtailed production, delay tubing conversion, reduce operating costs, and maximize ultimate recovery while minimizing deviation from base decline expectations.

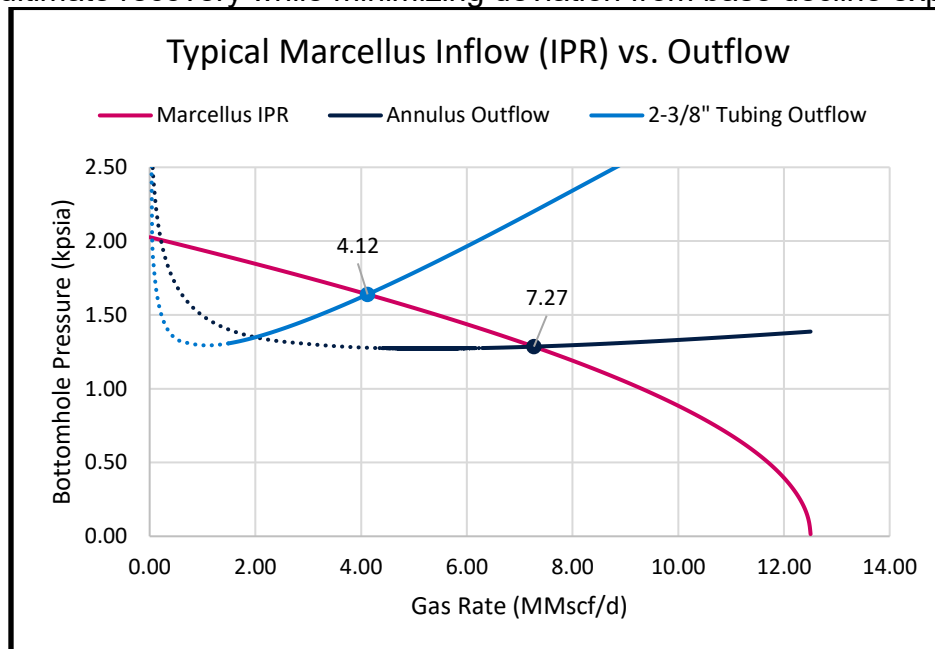


Figure 2 – Marcellus Nodal Analysis

Wellbore Configuration

The effectiveness of PAAF is strongly influenced by wellbore configuration, as flow geometry governs gas velocity, liquid holdup, and pressure losses throughout the production system. In Marcellus and Utica wells, PAAF is commonly applied in wells originally produced on casing flow that later undergo a phase-of-life configuration change with the installation of production tubing.

Early in the life of a Marcellus or Utica well, production typically occurs through the casing to maximize effective cross-sectional flow area and minimize frictional losses. As reservoir pressure declines and gas velocity approaches Turner Critical Rate, production tubing—most commonly 2-7/8" or 2-3/8" is installed. End of tubing is typically placed between 40° Inclination and 80° Inclination with a profile nipple between 30° Inclination and 65° Inclination. For purposes of this paper EOT was set at 80° Inclination and the profile nipple at 65° Inclination. This configuration gives the operator flexibility in where the downhole plunger lift equipment can be set without compromising the seal.

In a PAAF configuration, the annulus acts as the primary production flow path under natural flow conditions, while the tubing provides a reduced-area conduit that can sustain higher gas velocities during unloading events, i.e., lift cycle. The interaction between annular flow and tubing flow during these cycles effectively increases the productive cross-sectional area of the wellbore allowing fluid to "U-tube" between the annulus to the tubing where there is a mechanical means to evacuate the fluid.

Not all wellbore configurations are suitable for PAAF. Wells with minimal annular clearance, severe tubing eccentricity, damaged casing, mechanical integrity issues, or wells constructed with packers may experience reduced effectiveness or operational challenges. Additionally, wells that have already fully transitioned to tubing-dominated flow with persistent low reservoir energy may not benefit from annular flow enhancement.

Exclusion Criteria

While PAAF can effectively extend annular-flow performance and delay tubing-flow conversion, not all wells are suitable candidates. The following exclusion criteria identify conditions under which PAAF is unlikely to provide sustained benefit or may introduce unacceptable operational risk.

Mechanical Integrity Constraints

Wells with known casing damage, collapsed tubing, excessive corrosion, or compromised well integrity should be excluded from PAAF consideration. Mechanical restrictions can impede plunger travel, create unsafe operating conditions, or limit effective annular flow, reducing both reliability and performance.

Excessive Solids or Debris

High sand, scale, paraffin, or debris of like can interfere with plunger movement and increase the risk of the plunger sticking or surface equipment damage. Wells exhibiting sustained solids production may experience frequent plunger failures and increased nonproductive time, making PAAF operationally impractical. This compounded with any mechanical integrity issues could exacerbate erosion both from the b-section of the wellhead and / or downstream piping. Special consideration should be given to the flow path diameter in conjunction with solid production. A detailed discussion of erosional velocity evaluation methodology is present later in this paper.

Surface Facility Limitations

Surface infrastructure that cannot accommodate cyclic flow behavior, pressure fluctuations, or transient liquid production may preclude PAAF implementation. Wells lacking adequate pressure monitoring, automated control capability, or liquid-handling capacity should be excluded unless facility upgrades are feasible. Flowline, separator, and compression systems must also tolerate transient flow conditions. Undersized flowlines or separators may experience excessive backpressure during unloading events, negating the benefits of annular liquid mobilization. Compression systems that cannot accommodate variable inlet rates or pressure fluctuations may result in shut down events or at a minimum less than modeled uplift.

DEPLOYMENT

Effective PAAF implementation requires appropriate downhole and surface equipment to accommodate plunger travel and flow path transitions. Key considerations include end of tubing placement, BHA depth, and surface control systems capable of managing cyclic flow behavior. The wellbore must also be free of excessive restrictions, scale, or

solids that could impede plunger movement or restrict annular flow. It is recommended that a formal Management of Change (MOC) be conducted to evaluate both surface and subsurface conditions to ensure equipment limitations, spec breaks, and design criteria are adhered to.

Mechanical

Targeted mechanical modifications to the existing wellhead and surface piping are made to enable independent control of both tubing and annulus flow paths while maintaining compatibility with conventional plunger-lift equipment. In most legacy casing-flow wells, the original surface configuration was not designed to accommodate dual-flow-path control, necessitating reorientation and installation of additional surface hardware. In future applications, these modifications are implemented concurrent with tubing installation, allowing PAAF to be deployed without requiring additional downtime.

As shown in Figure 3, modifications begin at the plunger-lift lubricator. In the legacy configuration, downstream piping orientation often prevents straightforward installation of a tubing flow control valve. To resolve this constraint, the lubricator is rotated approximately 90 degrees such that the outlet ports are aligned perpendicular to the b-section. This reorientation allows direct installation of a dedicated tubing flow control valve downstream of the lubricator while preserving proper plunger travel, arrival detection, and catcher functionality if applicable.

Downstream of the casing b-section valve, additional piping is installed to accommodate an automated choke dedicated to annulus flow control. This automated annulus choke enables precise regulation of annular backpressure and flow rate independent of the tubing flow path, which is critical for maintaining critical gas velocity and managing liquid loading during PAAF operation. The annulus choke is integrated with the plunger control system to allow coordinated adjustments during buildup and unloading cycles.

Both the tubing and annulus flow paths are tied together downstream of their respective control valves. As illustrated in Figure 3, the combined flow streams are directed into a single buried production flowline leading to the downstream separation and measurement facilities. This commingled configuration simplifies facility integration while preserving the ability to independently manage each flow path upstream of the tie-in.

Multiple isolation valves are installed both upstream and downstream of the automated tubing and annulus control valves. These isolation points provide operational flexibility, allowing the operator to selectively flow the well via annulus-only, tubing-only, or combined flow configurations. This design also eliminates the need for future surface modifications as the well continues to decline and transitions out of the PAAF operating window.

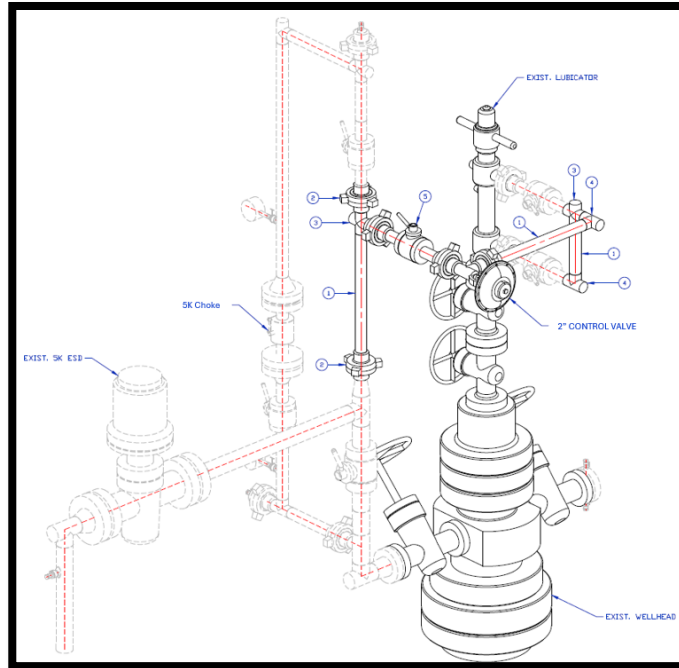


Figure 3 – Surface Wellhead Configuration for PAAF

Special consideration must be given to the b-section diameter and associated erosional limitations at specified flowing pressures. The case studies referenced in this paper had a b-section diameter of 1.45" & 2.9" flowing into a 900 psi(g) system. Specification of b-section valves are API 6A DD floating gate valve. Utilizing API RP 14E, and a 200 C-factor with 50 bbl/d produced fluid, erosional limitation in the annulus is 7.51 MMscf/d and 30.05 MMscf/d respectively. This can be illustrated in Figure 3 below.

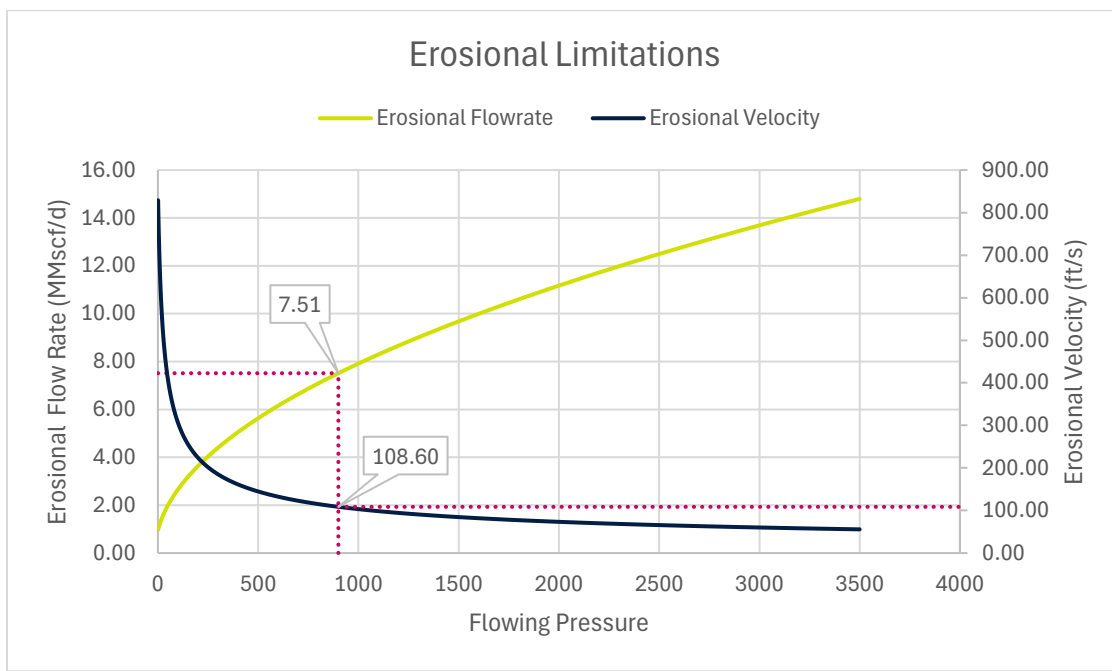


Figure 4 – Calculated erosional velocity & rate through 1.45” b-section at 900 psi(g)

Standard surface plunger-lift equipment remains an integral component of the PAAF configuration. Required components include a pressure-rated lubricator, plunger arrival sensor, and plunger

Automation / Electrical

Surface automation and electrical modifications were required to support independent control and monitoring of tubing and annulus production streams while maintaining coordinated operation with the plunger lift control system. Existing installations were not originally designed to support simultaneous control and monitoring of dual flow paths, resulting in limited instrumentation and control capability for managing cyclic flow behavior. Implementation of PAAF therefore required additional sensing and automated control functionality to accurately regulate dual-flow paths and monitor performance throughout cyclic operation.

Both the annulus and tubing flow control valves were equipped with electric actuators providing modulating control capability, allowing automated regulation of flow during all stages of the plunger cycle. This configuration differs from conventional plunger-lift installations, where tubing flow is typically controlled using with block valves that simply open or close during plunger cycles. In contrast, PAAF operation requires continuous modulation of both flow paths to manage flow conditions and maintain stable operating performance as production characteristics change. These actuators are integrated with the facility control system, enabling remote positioning, feedback monitoring, and coordinated control adjustments without requiring manual intervention.

Due to limited available cabling between the wellhead and facility control system, instrumentation deployment required minimizing conductor usage while preserving full operational functionality. The tubing valve actuator was therefore installed with Modbus digital communication capability, allowing both control commands and position feedback to be transmitted over a reduced wiring footprint. This approach enabled incorporation of additional automation functionality without requiring cable replacement or installation of new communication infrastructure.

Traditional wellhead installations commonly include only tubing and casing pressure transmitters located upstream of their respective control valves. While sufficient for conventional production monitoring, these measurements alone are inadequate when both annulus and tubing are produced simultaneously. Estimating individual flow contributions requires measurement of upstream pressures and downstream flowline conditions in conjunction with control valve characteristics.

To support this requirement, an additional pressure transmitter was installed downstream of the tubing and annulus control valves on the production flowline. Using valve position together with casing, tubing, and flowline pressures, annulus flow is calculated across the annulus control valve utilizing valve Cv relationships. Tubing flow

is then determined as the difference between total measured production rate and the calculated annulus flow. These values are used within the control system for operational optimization during plunger cycles.

Subsurface

Proper subsurface design is critical to successful PAAF deployment and must account for end-of-tubing (EOT) depth, placement of the plunger lift BHA, and plunger selection based on anticipated downhole flow velocities and fluid behavior.

In Marcellus and Utica shale applications, commonly used 2-3/8", L-80 production tubing set at approximately 80 degrees of inclination has proven to be an optimal configuration for extending productive well life. This setting depth positions the EOT within the liquid column as reservoir pressure declines, reducing the need for future well intervention as fluid levels change over time. The tubing is intentionally not set on a packer, allowing casing pressure to be accurately measured and utilized for plunger optimization, flow diagnostics, and evaluation of annular performance. This configuration enables simultaneous production through both the annulus and tubing, which is fundamental to the PAAF operating concept.

The tubing string is equipped with a mule shoe at the EOT, followed by a 3-ft pup joint, a ceramic disc sub, a full joint of tubing, and an XN or no-go profile. The ceramic disc serves as a temporary pressure barrier during tubing installation and is intentionally burst following installation operations. A single profile nipple is installed in the tubing string at approximately 65 degrees of inclination. Placement of the profile nipple deeper than this inclination can introduce challenges during BHA deployment, including the risk of the assembly surfacing during setting operations. Conversely, placement shallower than 65 degrees increases the height of the fluid column below the profile nipple resulting in sustained higher BHP.

During PAAF operation, downhole gas velocities at the EOT can reach values as high as 20 ft/s, depending on reservoir conditions and operating parameters. These velocities, combined with rapid fluid level equalization between the annulus and tubing, make plunger selection a critical factor in maintaining stable operation and preserving natural decline behavior. Early PAAF deployments utilized fast-fall barstock plungers with fall velocities of approximately 300 ft/min in gas. More recent applications have transitioned to ball-and-sleeve style plungers. A detailed discussion of plunger selection evolution and performance is presented later in this paper.

HOW IT WORKS

To maintain plunger-assisted annulus flow (PAAF) as a cost-effective deliquification and artificial lift strategy, the system is designed to operate without the addition of dedicated surface separation or metering equipment for individual flow paths. Instead, tubing and annulus flow rates are inferred using a calculated approach that leverages existing surface measurement infrastructure.

Total production is measured at the gas processing unit (GPU), where a single custody-quality meter captures combined flow from both the tubing and annulus. Annular flow rate is then calculated based on the flow coefficient (Cv) of the annulus control valve and the corresponding stem travel of the valve. Tubing flow rate is subsequently determined by subtracting the calculated annular flow rate from the total metered production rate. This methodology enables real-time estimation of total flow, tubing flow, and annulus flow without incremental capital investment in additional meters or separation equipment.

Calculated flow values are transmitted to the SCADA system, providing operators with enhanced visibility into flow-path performance and enabling data-driven optimization of PAAF operating parameters. This approach supports continuous monitoring of annulus gas velocity relative to critical thresholds while ensuring effective liquid evacuation via tubing flow during plunger cycles.

The primary objective of PAAF is to maintain annular flow rates above critical velocity to prevent liquid loading, while intermittently flowing the tubing to remove accumulated liquids using conventional plunger methods. The operating cycle is structured to balance annular flow stability with tubing-based liquid removal, preserving natural decline behavior and maximizing productive well life.

The following sections describe each phase of the PAAF operating cycle in detail, including the control logic, triggering conditions, and transition criteria used to optimize performance under varying well conditions.

Fall Time

During the fall time phase of the cycle, control signals are issued to both the tubing and annulus flow-control valves to establish the conditions required for plunger descent and pressure buildup in preparation for the subsequent lift cycle. At the initiation of fall time, the tubing flow-control valve is commanded to a fully closed position, while the annulus control valve is positioned at approximately 43% open.

Maintaining the tubing valve in a fully closed position allows the plunger to free-fall to the BHA while enabling tubing pressure to rebuild to levels sufficient to support the next lift event. Concurrently, the annulus valve is held at a fixed minimum opening of approximately 43%, permitting controlled annular flow to continue during fall time. This valve position represents the minimum opening at which annular flow rate can be reliably calculated based on (Cv) and stem travel.

Holding the annulus valve at this minimum position during fall time eliminates delays in flow-rate calculation when transitioning between operating phases, specifically from lift time to afterflow. Rather than requiring the valve to travel from a fully closed position to the minimum measurable opening at the onset of afterflow, the valve remains pre-positioned, allowing annular flow measurement to resume immediately upon phase transition. This improves data continuity, enhances SCADA-based flow estimation accuracy, and reduces control system latency.

Upon completion of the programmed fall-time interval, the control logic transitions the well into the lift-time phase.

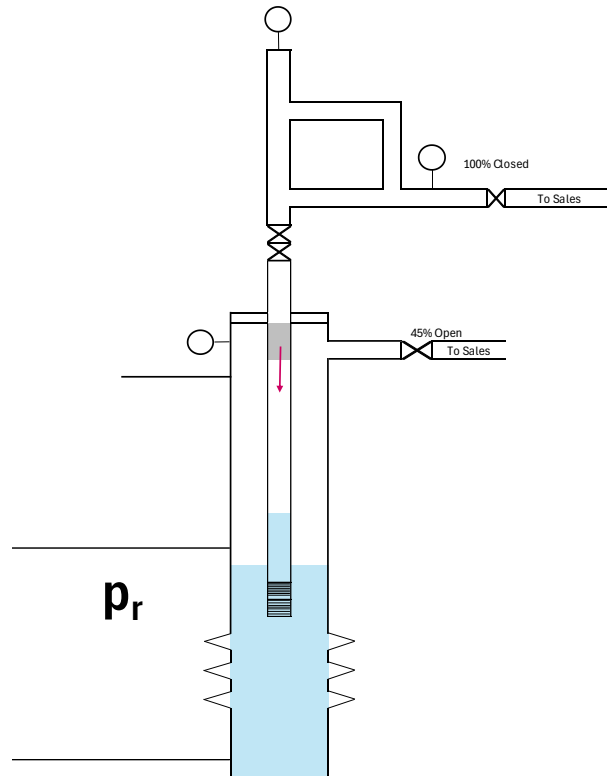


Figure 5 – Well configuration during fall time

Lift Time

The lift time phase initiates the active liquid evacuation portion of the PAAF cycle. Upon entering lift time, a control command is issued to open the tubing flow-control valve, while the annulus control valve remains fixed at approximately 43% open, consistent with the measurement and control strategy described previously in fall time. This configuration allows continued annular flow measurement while prioritizing controlled flow through the tubing to lift the plunger and associated liquid load.

As illustrated in Figure 6, opening the tubing flow path establishes an upward pressure gradient that drives the plunger from the bottomhole assembly toward surface through the tubing string, while annular flow is partially restricted to preserve sufficient pressure support. Computational fluid dynamics (CFD) modeling performed by plunger vendors indicates that downhole gas velocities should be maintained below approximately 60 ft/s to prevent exceeding the hold-down force of the plunger lift BHA. Exceeding this threshold may result in unseating the BHA and allowing it to travel freely within the tubing, negatively impacting reliability and well control.

To manage this risk, the tubing valve is not opened fully during lift time. Instead, tubing flow is regulated to a user-defined maximum flowrate setpoint that limits downhole

velocities to acceptable levels while still providing sufficient lift energy. In the field case studies presented in this paper, maximum tubing flow rates were conservatively constrained to 5.0–6.0 MMscf/d. Although conservative, these limits were effective in maintaining stable plunger operation under the higher velocities and elevated water–gas ratios (WGR) characteristic of the PAAF operating window.

The well remains in lift time until either plunger arrival is detected at surface or the programmed lift fail-time setpoint is reached. Due to higher well productivity, increased liquid loading, and elevated gas velocities relative to conventional plunger-lift applications, target lift velocities—averaged over the full tubing length—are typically set between 250 and 500 ft/min. Corresponding fail-time settings range from approximately 101.3 minutes at the lower velocity limit to 57.4 minutes at the upper limit.

If a plunger arrival is not detected within the prescribed fail-time window, the control system commands the tubing valve to fully close, terminating the lift attempt. The well then transitions back into the fall time phase, allowing additional pressure buildup prior to initiating a subsequent lift cycle.

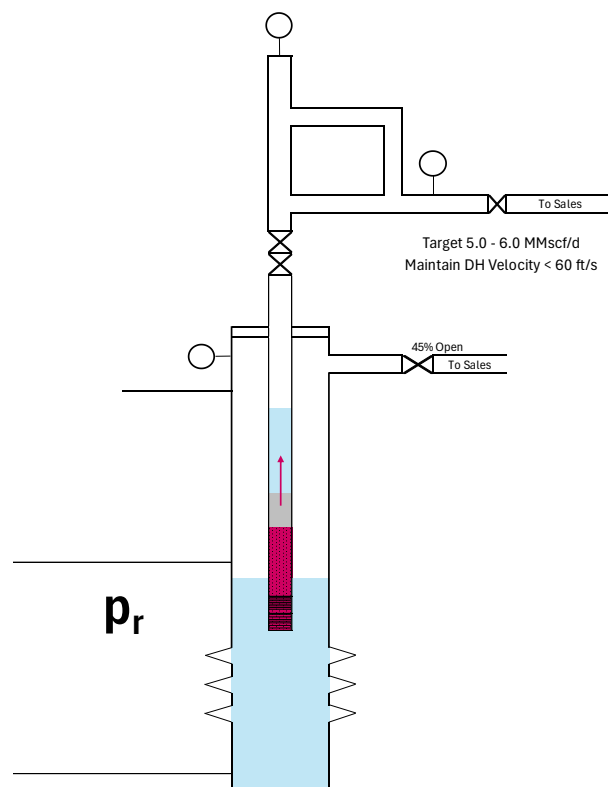


Figure 6 – Lift Time Configuration to Control Plunger Velocity

Afterflow

Upon detection of plunger arrival at surface, the control system transitions the well into the afterflow phase for a minimum of 5 minutes before evaluating close triggers. At this point, an afterflow timer is initiated and both the tubing and annulus flow-control valves are commanded open. The objective of this phase is to maximize stabilized production

following liquid evacuation while maintaining annular & tubing flow above critical velocity and within erosional limits.

As illustrated in Figure 7, both the tubing and annulus flow paths are directed to sales, allowing simultaneous production through each conduit. Two independent flowrate setpoints are utilized during afterflow: a maximum allowable tubing flow rate and a maximum allowable annulus flow rate.

At the onset of afterflow, the annulus control valve opens to 100% not to exceed the maximum allowable annulus flow rate. Logic deployed on the candidate wells analyzed in this paper utilized a maximum annulus flow rate of 13.0 MMscf/d. This allows annulus velocities to remain under 200 ft/sec. as a safe guard should the inputs for the erosional velocity calculation be inaccurate. Annular flow is then regulated based on two primary constraints:

Erosional velocity limits through the casing b-section, calculated in accordance with API RP 14E;

$$V_e = \frac{C}{\sqrt{\rho_m}}$$

Where:

V_e = erosional velocity limit (ft/s)

C = empirical constant (typically 100–125 for continuous service; lower values used for solids production)

ρ_m = mixture density (lb/ft³)

Turner critical gas velocity requirements to prevent liquid fallback in the annulus & tubing;

$$V_c = C_T \frac{\sigma^{1/4} (\rho_L - \rho_g)^{1/4}}{\rho_g^{1/2}}$$

Where:

V_c = critical gas velocity (ft/s)

C_T = 1.593 (field units)

σ = surface tension (dynes/cm)

ρ_L = liquid density (lb/ft³)

ρ_g = gas density (lb/ft³)

Total well production is metered at the GPU, annular flow rate is calculated using the annulus valve flow coefficient (C_v), and tubing flow rate is then determined by subtracting calculated annular flow from the total metered production rate. This inferred measurement methodology enables continuous monitoring of both flow paths without additional surface metering infrastructure.

If the calculated annular flow rate exceeds the allowable erosional velocity limit derived from API RP 14E, the annulus control valve is automatically throttled to reduce flow to within acceptable limits. Concurrently, tubing flow is controlled to remain above calculated critical rate while not exceeding the predefined maximum allowable tubing flow setpoint. In the case studies presented herein, maximum tubing flow during

afterflow was limited to 5.0–6.0 MMscf/d; however, the tubing valve remained mechanically at 100% open, with effective rate control governed by system backpressure and annular regulation.

If calculated tubing flow rate declines below the corresponding critical rate threshold, the annulus valve will begin to close to increase annular velocity and preserve sufficient gas velocity for continued liquid transport.

The well remains in afterflow for a minimum of five minutes prior to evaluation of close triggers. Two primary close triggers are utilized:

Timer-Based Transition

If the afterflow setpoint is approached (e.g., a 20-minute afterflow duration), the annulus control valve begins closing approximately five minutes prior to expiration of the timer. For example, at 15 minutes into a 20-minute afterflow cycle, the annulus valve is gradually reduced to approximately 45% open in preparation for the next fall phase. During this five-minute transition window, the tubing continues to flow at the established rate. This preferential tubing flow serves to evacuate any fluid accumulated in the tubing during afterflow and mitigates the risk of “U-tubing,” where fluid migrates from the annulus into the tubing and creates an excessive liquid column prior to the next lift cycle.

Critical-Rate Trigger

A second close trigger is based on annular critical velocity. Using the Turner critical-rate correlation above, the calculated annular flow rate is continuously compared to the required critical rate for liquid transport. If the calculated annular rate falls below the Turner critical threshold for more than five consecutive minutes (close-trigger delay), the afterflow phase is terminated and the well transitions into fall time. This logic ensures that annular flow does not persist under subcritical conditions that would promote liquid loading.

As shown in Figure 7, the afterflow configuration represents the period of maximum combined deliverability, where both tubing and annulus contribute to production under controlled conditions. Proper management of erosional velocity limits, critical-rate thresholds, and timed transitions is essential to preserving annular stability while preparing the system for the next plunger cycle.

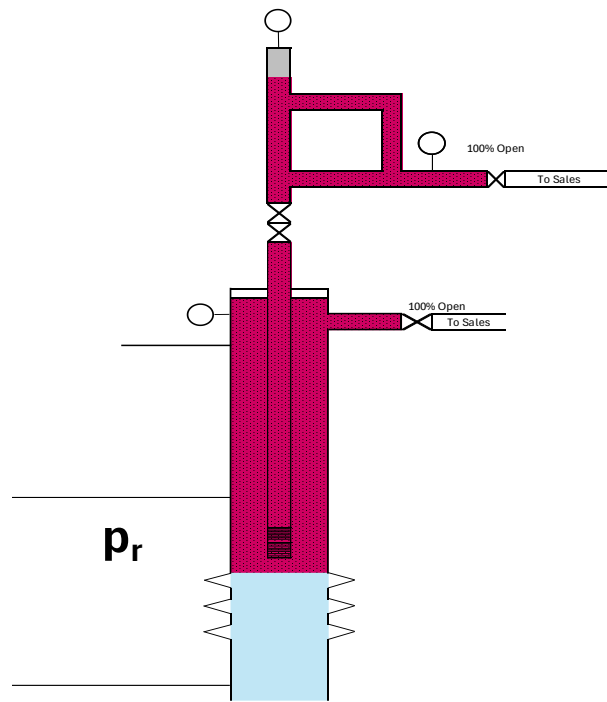


Figure 7 – Afterflow Configuration to Maximize Well Deliverability

CHALLENGES / EVOLUTION

PAAF has proven to be an effective transitional deliquification strategy in high gas-liquid ratio (GLR) unconventional wells. However, as with most emerging technologies, implementation has not been without technical and operational challenges. These challenges are particularly pronounced when adapting existing equipment and processes for applications beyond their original design intent. PAAF is no exception, and early deployments required iterative refinement to address issues encountered.

Initial test wells revealed key challenges, including elevated solids production affecting plunger travel reliability, variability in downhole velocities requiring changes in plunger selection to ensure target rates were maintained, and limitations in the methodology used to calculate independent tubing and annulus flow rates.

As PAAF expands from pilot implementations to broader field deployment, continued evolution remains essential to ensure reliability, scalability, and repeatability. Standardization of operating parameters, control logic, and surface / subsurface configurations has become a priority to minimize variability between installations. Lessons learned from early deployments have informed best practices and future evolution is focused on increasing system autonomy through enhanced control algorithms.

Plunger Selection

Early PAAF applications utilized a fast-fall barstock plunger to validate operational logic, surface control integration, and dual-flow-path functionality. The primary objective

during initial deployment was to confirm that the control system properly transitioned between fall, lift, and afterflow phases while maintaining annular critical velocity. While the barstock plunger provided reliable baseline functionality, subsequent field performance indicated higher downhole velocities and rapid fluid equalization required a more application-specific plunger design.

Following the initial proof-of-concept phase, a more aggressive plunger was introduced to reduce fall time and mitigate fluid “U-tubing” from the annulus into the tubing between cycles. As shown in Figure 8, Trial Well #1 exhibited downhole gas velocities exceeding 20 ft/s at approximately 900 psi(g) static pressure. These velocities exceed commonly accepted industry minimum thresholds to successfully cycle a ball and sleeve plunger under comparable conditions.

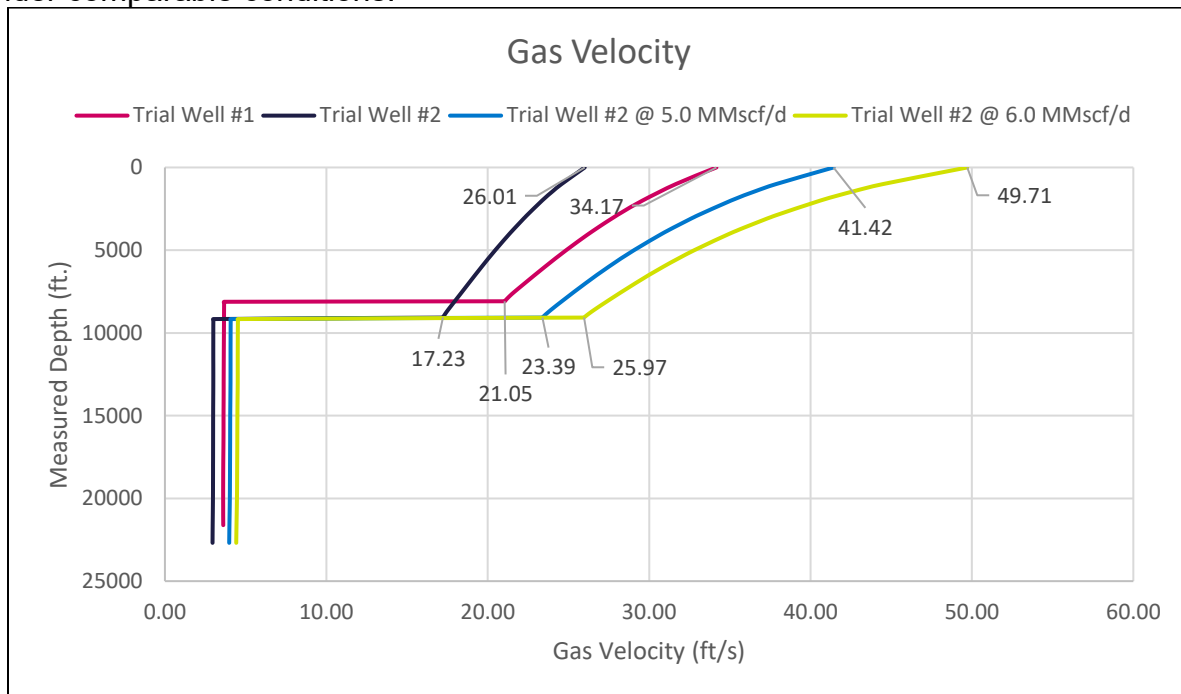


Figure 8 – Velocity Profile for PAAF well at ~900 psi(g) static

In Trial Well #2, a ball-and-sleeve plunger was deployed as the initial plunger selection. However, plunger arrivals were erratic and lacked repeatability, resulting in performance deviation from forecast. Velocity modeling (Figure 8) indicated limited gas expansion during lift time, reducing the differential forces required to maintain engagement between the ball and sleeve components. Insufficient expansion contributed to separation during ascent, producing inconsistent arrival behavior and reduced unloading efficiency.

To address these issues, two corrective actions were implemented:

Increase Maximum Allowable Tubing Flow

Post-analysis modeling indicated that increasing maximum tubing flow during lift time would improve gas expansion between the end of tubing (EOT) and surface (Figure 8).

The maximum allowable tubing flow rate was increased to 6.0 MMscf/d, resulting in an increase in calculated gas velocity from EOT to surface of approximately 14.96 ft/s ($\approx 170\%$ increase).

The intent of this modification was to increase dynamic lift energy and maintain seating force between the ball and sleeve during ascent, thereby reducing “yo-yoing” behavior and improving plunger stability within the tubing string. Following implementation, arrival repeatability improved and deviation from forecast was reduced.

Plunger Design Modification – Sleeve with Ball Retainer

To further enhance mechanical integrity during lift, the sleeve design was modified to include an internal ball-retainer mechanism. As shown in Figure 9, the 9-in. sleeve incorporates a retention clip that prevents premature separation of the ball during lift. Once the sleeve seats onto the ball, separation requires an internal force within the sleeve assembly rather than relying solely on differential pressure.



Figure 9 – 9” Sleeve with Ball Retainer

In addition to the mechanical retainer modification, the original stainless-steel ball was replaced with a tungsten ball. Field observations indicated that the stainless-steel ball became magnetized over time, which contributed to delayed or inconsistent separation from the sleeve upon surfacing. This magnetic attraction negatively impacted fall-time consistency and led to fast arrivals. The use of a tungsten ball eliminated magnetization effects, improved separation repeatability at surface, and enhanced overall cycle stability as can be seen in Figure 10.

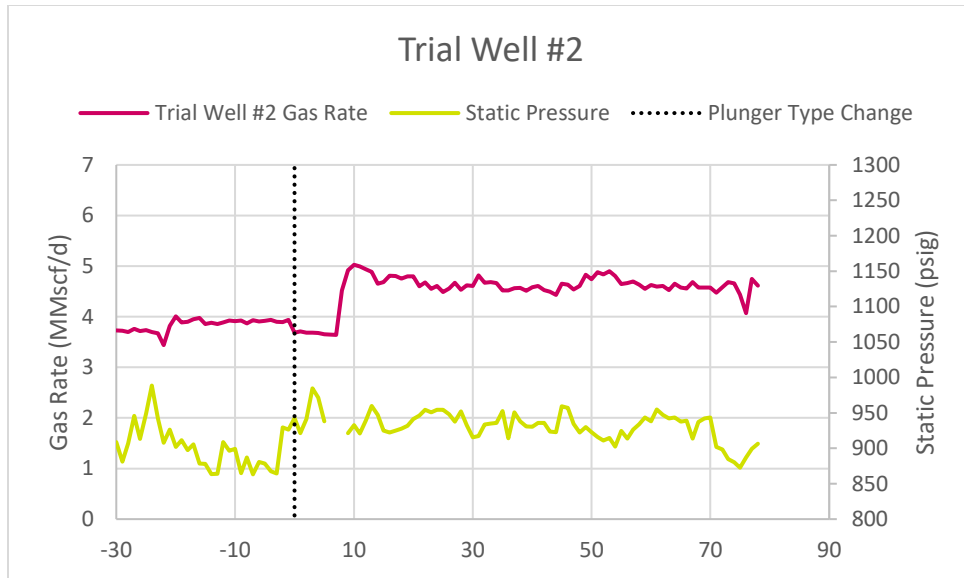


Figure 10 – Production Profile After Plunger Type Change

Together, the retainer-equipped sleeve and tungsten ball configuration ensured consistent engagement during ascent and reliable separation upon impact with the lubricator rod. These modifications significantly improved lift reliability and reduced erratic plunger behavior observed in earlier trials.

Solids Production

Following implementation of the ball-and-sleeve configuration in Trial Well #1, intermittent fast arrivals began to occur. Although not consistently observed every cycle, the behavior was prevalent over a 24-hour period. A plunger inspection revealed that the sleeve had experienced significant sand packing (Figure 11), resulting in slower-than-calculated fall times.



Figure 11 – Sleeve packed with Sand

Due to the quantity of sand observed within the sleeve, a decision was made to pull and inspect the bottomhole assembly (BHA). Inspection revealed damage to the 2-3/8-in. BHA fish neck (Figure 12) along with recovery of wellbore debris and plug fragments (Figure 13).



Figure 12 – 2-3/8” BHA Fishneck Damaged



Figure 13 – Wellbore debris / plug parts

Although the well was more than 1,000 days from first sales, the increase in downhole velocities associated with this phase-of-life transition was sufficient to mobilize residual debris from the lateral into the tubing. While no catastrophic failure occurred, this event highlighted an important operational risk: debris accumulation around or within the BHA could result in plugging off the BHA or prevent retrieval via slickline. In such a scenario, intervention requiring tubing pull would be necessary to re-establish communication with the lateral.

These findings underscore the importance of considering solids mobilization risk when implementing PAAF in mature unconventional wells experiencing increased velocity regimes.

Measurement and Data Integrity

Under PAAF operation, total well production is metered at the GPU while produced fluid is allocated to each well based on its total percent of gas production. Annular flow rate is calculated using the annulus control valve flow coefficient (C_v) in conjunction with valve position, while tubing flow rate is determined by subtracting the calculated annular flow from the total metered production rate. The C_v -based calculation assumes single-phase gas flow; however, the actual flowstream contains gas, produced liquids, and entrained solids. As a result, inherent variance in the calculated annular rate should be expected. This variance can introduce error into derived parameters, including Turner critical rate and API RP 14E erosional velocity calculations. Because tubing and

annulus rates are inferred rather than independently metered, overall system accuracy is directly dependent on the quality and reliability of the input data.

Field implementation identified pressure measurement integrity as a primary source of calculation variability, particularly tubing and flowline pressure data. Errors in pressure inputs directly propagate into calculated annular rate and, by extension, tubing rate estimation.

In northeastern operating environments, sustained sub-freezing winter conditions introduced additional complexity. Frozen PITs resulted in intermittent or inaccurate pressure readings, negatively impacting flow calculations and control logic performance. Although mitigation strategies—including insulation, heat tracing (snake wrap), and protective enclosures—were implemented to reduce freezing risk, extreme weather conditions occasionally compromised data quality.

Inaccurate pressure data can result in miscalculated annular flow rates, leading to inappropriate valve adjustments, unstable control responses, or premature phase transitions within the PAAF cycle. The experience gained through these early deployments reinforced a key operational principle: successful PAAF performance is not solely dependent on mechanical configuration and control logic, but equally on data integrity. Reliable pressure measurement and flow estimation are essential to maintaining annular critical velocity, enforcing erosional limits, and ensuring repeatable cycle performance across large well populations.

Evolution

The most impactful area for continued evolution of PAAF lies in measurement accuracy and data resolution. Independent measurement of tubing and annulus flow would significantly increase confidence in flow-path allocation, ensure adherence to erosional velocity and critical-rate thresholds, and further optimize control parameters. Although multiphase measurement technologies have been evaluated, most available solutions are either impractical for this application or economically inconsistent with one of PAAF's primary advantages, which is its low capital cost.

Given that annular flow is calculated using a Cv-based methodology that assumes single-phase gas flow, inherent variance is expected in a multiphase environment containing gas, produced liquids, and entrained solids. This variance can introduce uncertainty into calculated critical-rate and erosional-velocity thresholds. To mitigate this risk, additional mechanical safeguards may be incorporated. Implementation of non-destructive testing (NDT) protocols on surface piping could be utilized to monitor wall thickness and verify that calculated erosional limits are not being exceeded. In addition, periodic removal and manufacturer inspection of wellhead valves could provide confirmation of valve integrity and erosion performance. These proactive measures help offset uncertainty introduced by Cv-based calculations outside of a true single-phase environment.

Discrete measurement is valuable not only for gas production allocation but also for water production analysis. Under the current configuration, water production is measured as a combined volume downstream of the commingled flow paths and is not allocated between tubing and annulus based on actual gas contribution. Independent water-rate measurement for each flow path would provide improved insight into plunger efficiency, annular liquid transport behavior, and optimization of plunger-state setpoints, including afterflow duration, fall time, and lift parameters.

Improved data fidelity would enable transition from static setpoint control toward adaptive optimization. With more accurate and higher-resolution measurements, PAAF operating parameters could be dynamically adjusted in response to changing reservoir pressure, fluid loading behavior, and velocity constraints. This shift would allow the system to maintain critical thresholds more precisely while maximizing deliverability within mechanical and erosional limits.

Looking forward, integration of edge computing and advanced analytics represents the logical progression for PAAF evolution. Migrating control logic from centralized supervisory systems to edge devices on site would enable higher-frequency data acquisition and real-time calculations, including bottomhole pressure estimation, nodal analysis, velocity monitoring, among others. This architecture would reduce latency in valve control and improve responsiveness to transient conditions.

Coupling edge deployment with advanced analytical tools or machine-learning algorithms would further enhance system autonomy. As previously discussed, data anomalies such as pressure degradation or sensor malfunction can significantly impact calculated flow rates and control stability. Automated anomaly detection could identify these conditions in real time and alert engineers prior to measurable production decline or equipment failure. Over time, such systems could transition from reactive alerting to predictive optimization, further reducing manual intervention while preserving operational safeguards.

The long-term objective of PAAF evolution is increased autonomy, improved measurement confidence, and scalable optimization across broad unconventional asset portfolios. Continued advancement in data integrity, control architecture, and analytical integration will expand the operational envelope of PAAF while maintaining its economic advantages.

CONCLUSIONS

Plunger-Assisted Annulus Flow (PAAF) provides a cost-effective transitional deliquification strategy designed to bridge the gap between early-life casing flow and full tubing-flow conversion in Marcellus and Utica shale gas wells. Rather than prematurely shifting to tubing flow or abandoning annular production as reservoir pressure declines—often resulting in 30–40% deferred volumes—PAAF leverages controlled dual-flow-path operation to maintain critical annular velocity while intermittently evacuating liquids through tubing via plunger cycling.

Successful implementation of PAAF requires coordinated surface and subsurface design. Subsurface configuration—including tubing size, end-of-tubing (EOT) placement, profile nipple depth, and plunger selection—directly influences downhole velocities, BHA stability, and fluid equalization behavior. Surface modifications must allow independent control of tubing and annulus flow paths, including installation of a dedicated tubing flow-control valve, automated annulus choke, and integration with standard plunger-lift equipment. The ability to commingle both flow paths downstream while maintaining upstream control flexibility is essential to long-term operational viability and scalable deployment.

Control logic governing the fall, lift, and afterflow phases is critical to maintaining system stability. During lift time, tubing flow is regulated to limit downhole velocities below BHA hold-down thresholds while delivering sufficient energy to surface the plunger and associated liquid load. During afterflow, simultaneous production from tubing and annulus maximizes deliverability while annular flow is constrained by both API RP 14E erosional velocity limits and Turner critical-velocity requirements. Transition triggers based on timer logic and critical-rate comparison ensure that annular flow does not persist under subcritical conditions that would promote renewed liquid loading.

Field applications demonstrate that PAAF can recover curtailed production associated with annular liquid loading while preserving natural decline behavior. In representative Marcellus wells evaluated in this study, production losses identified through inflow/outflow analysis were mitigated through controlled PAAF implementation. By maximizing effective cross-sectional flow area and maintaining annular gas velocity above critical thresholds, PAAF extends the productive casing/annulus-flow window without requiring immediate tubing-flow conversion.

Importantly, PAAF is operationally attractive due to its low capital cost compared to traditional artificial lift systems such as gas lift or electric submersible pumps (ESPs). Typical implementation costs range from \$25,000 to \$40,000 per well, depending on the extent of wellhead modifications required and the size and configuration of b-section casing valves. The method requires minimal additional downhole equipment beyond standard plunger-lift components and does not necessitate gas lift mandrels, compression upgrades, or high-capital electrical infrastructure. Surface modifications are modular and adaptable to existing wellhead configurations, further reducing installation complexity and capital exposure. This low mechanical footprint, combined with the ability to utilize existing wellbore geometry and reservoir energy, makes PAAF a cost-effective and scalable solution for transitional-phase shale gas wells.

Beyond its technical and economic advantages, PAAF provides meaningful operational flexibility. By extending the annulus-flow operating window, PAAF reduces the need to precisely forecast the optimal date for tubing-flow conversion on a well-by-well basis. This allows Production Engineers to focus on broader asset optimization and business evolution rather than reactive timing decisions. The ability to defer immediate tubing conversion supports the development of structured, large-scale tubing programs,

improving capital planning, resource allocation, and execution efficiency across the asset base.

PAAF is most effective when deployed during the transitional phase of well life—after annular flow efficiency begins to deteriorate but before reservoir energy declines to levels insufficient to support plunger-assisted cycling. Proper candidate selection, mechanical configuration, and control parameter optimization are essential to sustaining performance and ensuring equipment integrity.

Overall, PAAF represents a flexible, economically efficient artificial lift strategy that enhances production stability, reduces volume deferment, delays more capital-intensive lift interventions, and maximizes recovery in high-decline unconventional gas reservoirs. Continued refinement of velocity constraints, plunger selection, and automated control strategies will take PAAF from a conceptual strategy to a scalable and repeatable phase of life artificial lift technique.

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