ARTIFICIAL LIFT STRATEGY INTEGRATING GAS LIFT, PAGL, AND PLUNGER LIFT OPTIMIZES LIFE-OF-WELL PRODUCTION IN TIGHT OIL PLAYS

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Long-lateral horizontal well geometries and optimized hydraulic fracturing treatment designs have been critical to maximizing well productivities in U.S. tight oil plays. However, the high initial productivities achieved with longer laterals and complex propped fracture networks can contribute to highly dynamic well conditions with more pronounced natural production declines. From an artificial lift perspective, the dynamic production behavior is often exacerbated by produced fluid streams that contain relatively high ratios of natural gas and water per barrel of oil along with sand and solids content.

Figures 1A-2C show Permian and Bakken data provided by the U.S Energy Information Administration. The decline curve estimates and gas-to-liquid ratios are for new wells drilled or starting production in each respective year through 2020, and 180-day average initial productivities are for new wells starting production through 2023. EIA notes that GORs commonly increase in oil wells over time. In fact, EIA estimate that in 2020 alone it reclassified more than 9,000 U.S. wells from “oil” to “gas” wells as a result of increased GORs.

As these data illustrate, while tight oil plays are becoming more mature as development activity progresses, the production challenges remain as difficult to navigate as ever in these basins. Adapting to and cost-effectively managing a tight oil well’s rapidly changing production profile and depleting natural reservoir pressure can be a major challenge for artificial lift, especially during the first 12-18 months.

However, the combination of gas lift and plunger lift technologies provides a flexible lift solution capable of not only optimizing production at every phase of the well lifecycle over the course of many years, but also adapting relatively easily and quickly as wells transition from the early-, to mid-, to late-life stages.

This paper provides an overview of a “full lifecycle” approach to managing well production from peak IP all the way through to depletion. This flexible and economic approach encompasses interrelated forms of artificial lift:

- Gas lift in early life (maximum flow rates)
- Plunger-assisted gas lift (PAGL) through the mid-life plateau (moderate flow rates)
- Plunger lift and perhaps gas-assisted plunger lift (GAPL) in late life (minimum flow rates)

The fact that gas lift, PAGL/GAPL, and plunger lift all operate relatively indifferently to GOR, water cut, sands/solids, and dogleg severity/inclination only further reinforces their applicability in long-lateral tight oil wells that produce at high rates, but with comparatively rapid declines.

Strategically deploying these artificial lift methods in succession at distinct well life phases enables operators to take full advantage of the relative strengths of each method to collectively span the entire slope of the decline curve, including:

- Gas lift's ability to mimic natural reservoir flow and efficiently handle varied production rates and well characteristics, including high GORs and solid contents.
- PAGL's ability to increase reservoir drawdown, stabilize production, and reduce surging as production diminishes to where gas lift starts to become inefficient.
- Plunger lift's ability to carry accumulated fluids to surface at rates as low as a few bbl/d without an external power/energy source. Increasing GORs as a well matures aligns with the concept of conveying fluids up the tubing string using formation gas to surface a plunger. The plunger also sweeps the tubing of paraffin, scale, asphaltene, etc.
- GAPL's ability to deliquefy loaded wells and produce liquids and gas from mature wells with little to effectively no natural reservoir drive.

THE RIGHT EQUIPMENT

This approach to managing tight oil well production is predicated on having the right surface and downhole equipment in place from day one of production to simplify operational practices and streamline the process of transitioning wells from gas lift, to PAGL, to plunger lift in response to changing production profiles. Specifically, the three key equipment considerations are:

- The design and placement of downhole gas lift valves/manifolds
- The lubricator on the wellhead to receive the plunger at surface
- Automated digital controller for optimizing both gas injection rates and plunger cycles

In all three areas, it is critical to select equipment capable of optimizing well production regardless of the lift type (gas lift, PAGL/GAPL, or plunger lift) without having to interrupt operations or make capital investments to pull tubing or swap out components.

PAGL adds a plunger to a continuous gas lift operation to enhance the carrying capacity of the injected gas and help lift the fluid column to surface. PAGL increases gas lift efficiency to extend the economic application of gas injection further into the decline curve where daily rates are on the order of perhaps 30-50% of IPs. When rates drop low enough that lift gas is no longer needed, the well can switch to plunger lift by gradually eliminating injection without having to pull tubing.

From a gas lift engineering perspective, there are two main system design issues. First, because PAGL uses continuous injection, it requires conventional tubing-retrievable integral mandrels. PAGL is not an option for wells with wireline-retrievable sidepocket mandrels. Second, if an operator intends to use intermittent injection at some point, a gas lift valve should be installed instead of an orifice in the bottom-most station to provide injection control and prevent casing pressure losses after each injection cycle.

Intermittent injection is common in GAPL, which is similar to PAGL, but adds gas injection to supplement plunger lift. An orifice allows casing pressure to bleed down when injection pauses, thereby altering the differential between casing and tubing pressures. To lift fluid again, casing pressure has to rebuild sufficiently to overcome tubing pressure. A gas lift valve eliminates this by maintaining a minimal pressure environment inside the casing.

MAKING THE MOVE

The timing of transitioning a well from gas lift to PAGL, and again from PAGL to plunger lift, is dependent on numerous factors, including erratic production performance and operational inefficiencies such as gas slugging and excessive plunger cycling.

However, deciding when to supplement gas lift with PAGL may be influenced by issues such as paraffin or scale deposition, in which case, having a plunger traversing the well helps keep the inside diameter of the tubing swept clean to smooth out production. In some cases, the primary objective of applying PAGL may not be to increase oil production or decrease gas injection, but to assist production chemicals in controlling paraffin to avoid the need for hot oiling, slickline, and other interventions.

In areas particularly prone to paraffin, it may be beneficial to commence PAGL sooner than what might otherwise be the case. Once paraffin accumulates inside tubing, the plunger's ability to travel up and down the string could become impeded, necessitating a remediation treatment. Plus, regularly cycling production up the hole maintains an average higher temperature inside the tubing, helping prevent paraffin from solidifying into blockages as it cools.

IDEAL LUBRICATOR DESIGN

Although a lubricator and controller can be added to a gas lift well with little production interference, having these components already in place when artificial lift commences makes implementing PAGL a relatively quick and straightforward process. It becomes a matter of determining the best time to drop a plunger – and what type of plunger to use – based on well conditions and gas lift efficiency parameters.

Installing a lubricator as part of the gas lift completion ensures that the wellhead setup is already in place when the time comes to move from gas lift to PAGL and then plunger lift. PCS Ferguson's 10,000-psi Radial Flow Lubricator™ is ideal for the application.

This “drop-in” lubricator design is pressure rated to accommodate high post-flowback rates but contains internal adjustment sleeves to easily modify the flow area to adapt to ‘decreased production rates over time. Engineered for maximum operational adaptability and durability, the Radial Flow Lubricator is one of the crucial pieces of the equipment puzzle for optimizing production from flowback to last oil, and transitioning from gas lift, to PAGL, to plunger lift without having to modify the wellhead.

The fact that the operator doesn’t have to change out downhole or surface equipment when moving from gas lift to PAGL – and again when moving from PAGL to plunger lift – and then plunger lift is a huge advantage contrasted to the scope of operations and deferred production associated with switching to an alternate form of lift that requires activating a workover rig. In fact, the primary piece of surface equipment powering gas lift – the compressor – may be downsized and ultimately removed when a well progresses to plunger lift.

STACK WELL EXAMPLE

As with the lubricator, the right digital controller is fundamental to all aspects of gas lift and plunger lift operations, including PAGL and GAPL. For example, the PCS Ferguson Series 8000™ controller has modules to continuously optimize gas injection and plunger cycling, and incorporates an algorithm that maintains ideal injection rates based on plunger arrival times to sustain peak PAGL performance.

Figure 3 shows a screen capture from the controller on a horizontal well on PAGL in the Oklahoma STACK play. The PAGL algorithm was instrumental in quickly dialing in the best injection rate, and then holding actual rates within the defined target range to ensure the correct number of plunger round trips per day to maximize production at a consistent flowing tubing pressure.

In this application, the optimal rate was identified as 152 Mcf/d, which corresponded to a round-trip plunger cycle of 9 minutes and 12 seconds. Before PAGL, the well was injecting more than 500 Mcf/d of gas. Even though the injection volume was reduced by 70% with PAGL, oil and gas production increased by 15% and 25%, respectively. The ability to reduce injection volumes allowed the operator to replace the reciprocating compressor with a small wellhead unit, lowering LOE by $2,100/month. PAGL cut another $1,000/month in fuel costs by producing sufficient gas to supply injection operations and avoid the need for buy-back supplies.

As this case history illustrates, the simultaneous benefits of reducing compression requirements and eliminating the cost associated with buyback gas can have a significant positive impact on bottom-line profitability and operational footprints exactly when wells need it most: when they mature to the point where the lower flow rates start making economics more marginal.

WOLFCAMP WELL EXAMPLE

As shown in Figure 4, the “win-win” benefits can also positively impact proved, developed producing reserves. In the Permian Basin, a horizontal Wolfcamp well on PAGL was experiencing high plunger velocities that caused erratic production and occasional damage to surface equipment.

This example underscores the importance of understanding a well’s behavior to recognize signs indicating that production has reached the stage where it’s time to move from gas lift to PAGL, or gradually wean a well from injection and move from PAGL to plunger lift.

In this case, the solution was to take the well off gas injection and produce on plunger lift only using the PCS Ferguson Friction Bypass with Taper-Lock™ plunger.

Prior to discontinuing injection, the well had averaged 23 barrels of oil and 432 Mcf of gas at an injection rate of 500 Mcf/d. Daily production increased to 44 barrels of oil and 619 Mcf of gas after transitioning from PAGL to plunger lift. It also eliminated the cost of a wellsite compressor and buyback fuel, saving both CAPEX and OPEX.

Together, gas lift, PAGL, and plunger lift technologies give operators the ability to use the same artificial lift equipment to readily adjust to dynamic conditions at all phases of the tight oil well decline curve and recover more reserves in less time and at lower cost per barrel.

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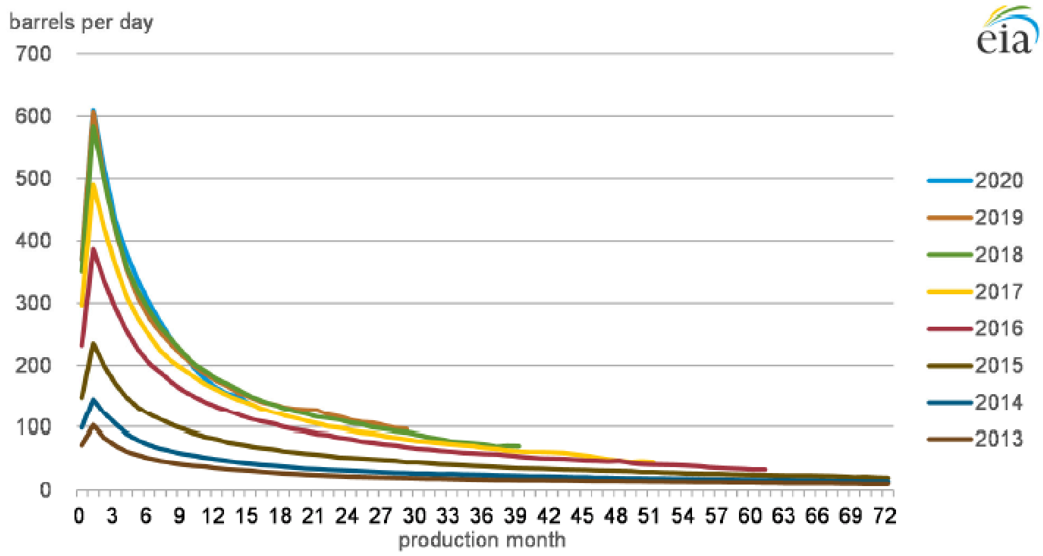
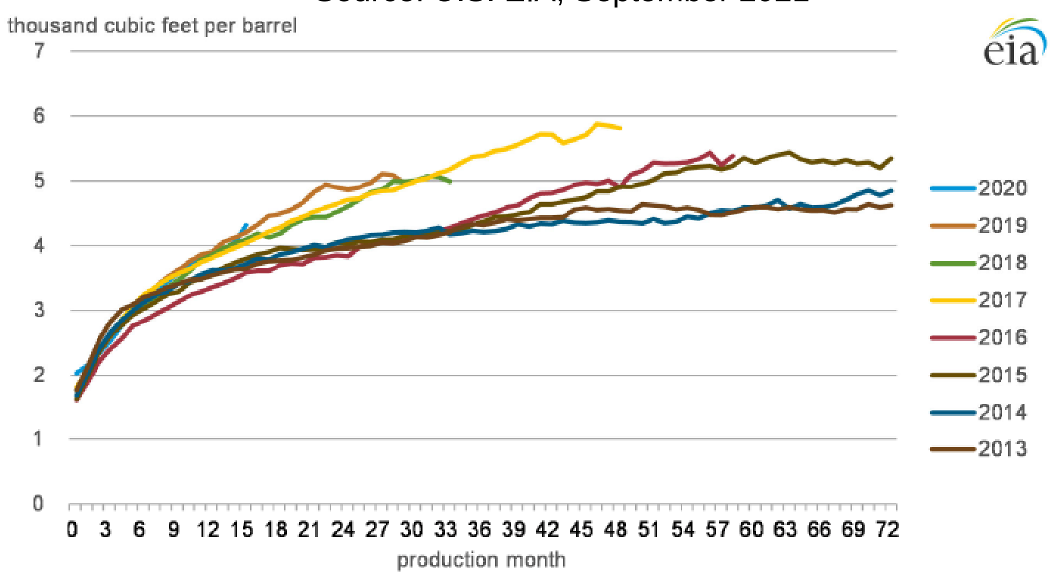
FIGURE 1A
Oil Decline Curves from new Permian Basin Wells
Source: U.S. EIA, September 2021



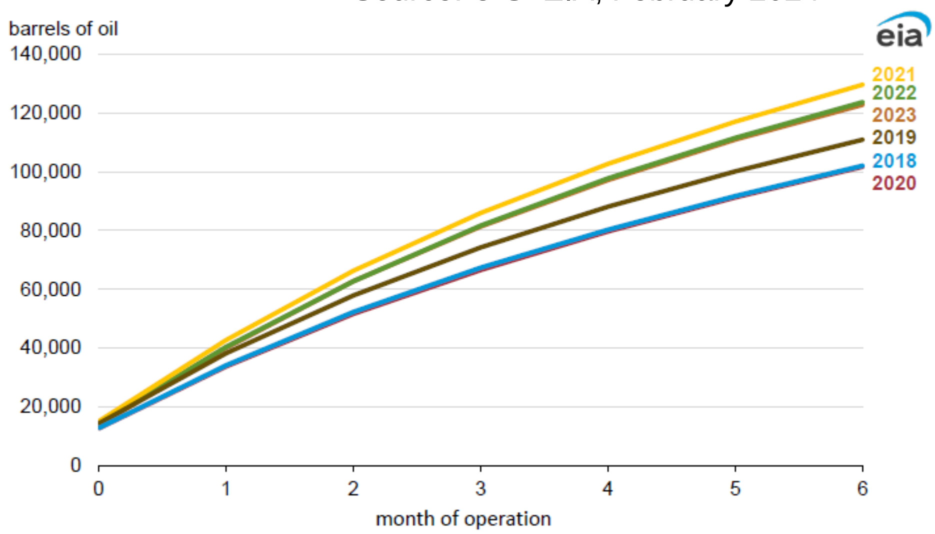
Source: U.S. Energy Information Administration, *Drilling Productivity Report*
Note: Each curve represents average oil production of all wells starting production in a given year.

FIGURE 1B
Vintage Gas-to-Oil Ratios (all Permian Basin Wells)
Source: U.S. EIA, September 2021



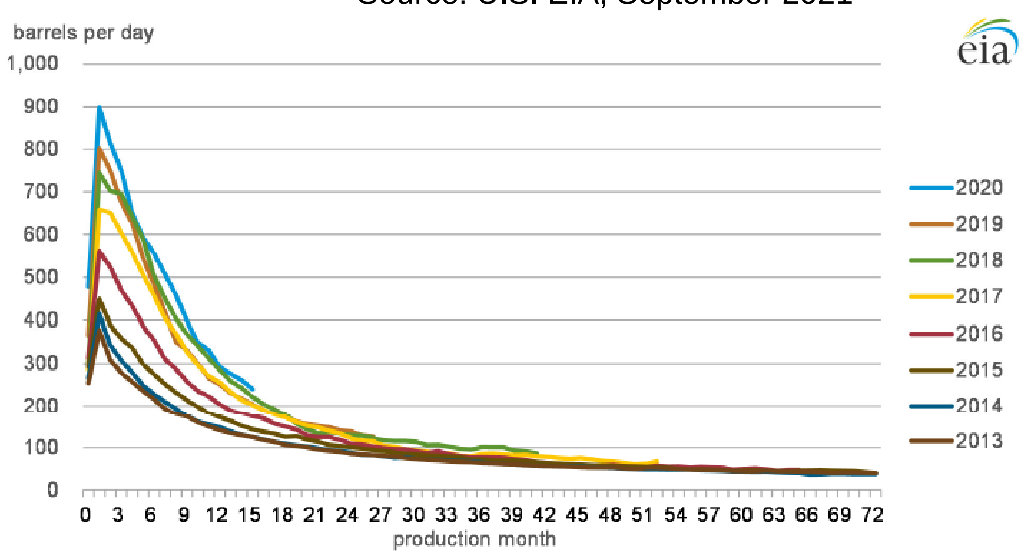
Source: U.S. Energy Information Administration, *Drilling Productivity Report*
Note: Each curve represents average GOR of all wells starting production in a given year.

FIGURE 1C
Permian Wells' First 180 Days of Oil Production
Source: U.S. EIA, February 2024



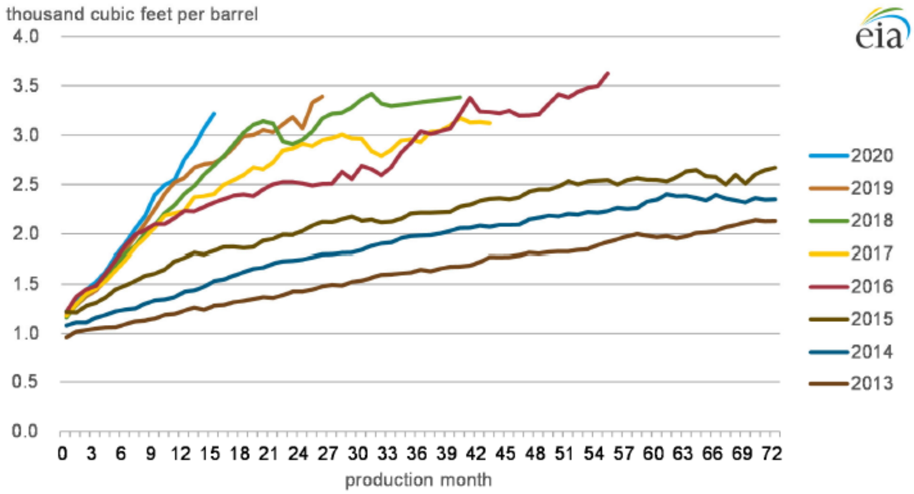
Source: U.S. Energy Information Administration, *Drilling Productivity Report*
Note: Not all wells are reported, and curves are subject to revision.

FIGURE 2A
Oil Decline Curves from new Bakken Wells
Source: U.S. EIA, September 2021



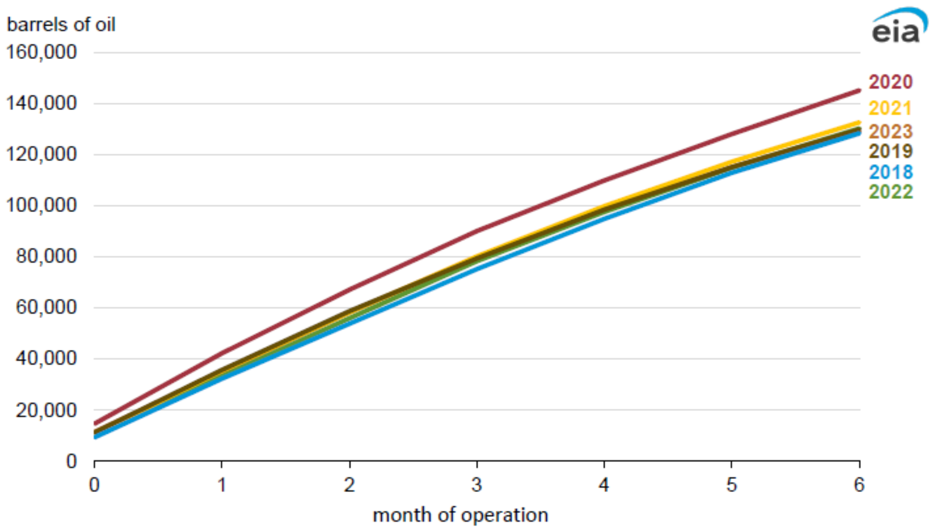
Source: U.S. Energy Information Administration, *Drilling Productivity Report*
Note: Each curve represents average oil production of all wells starting production in a given year.

Figure 2B
Vintage Gas-to-Oil Ratios (all Bakken Wells)
Source: U.S. EIA, September 2021



Source: U.S. Energy Information Administration, *Drilling Productivity Report*
Note: Each curve represents average GOR of all wells starting production in a given year.

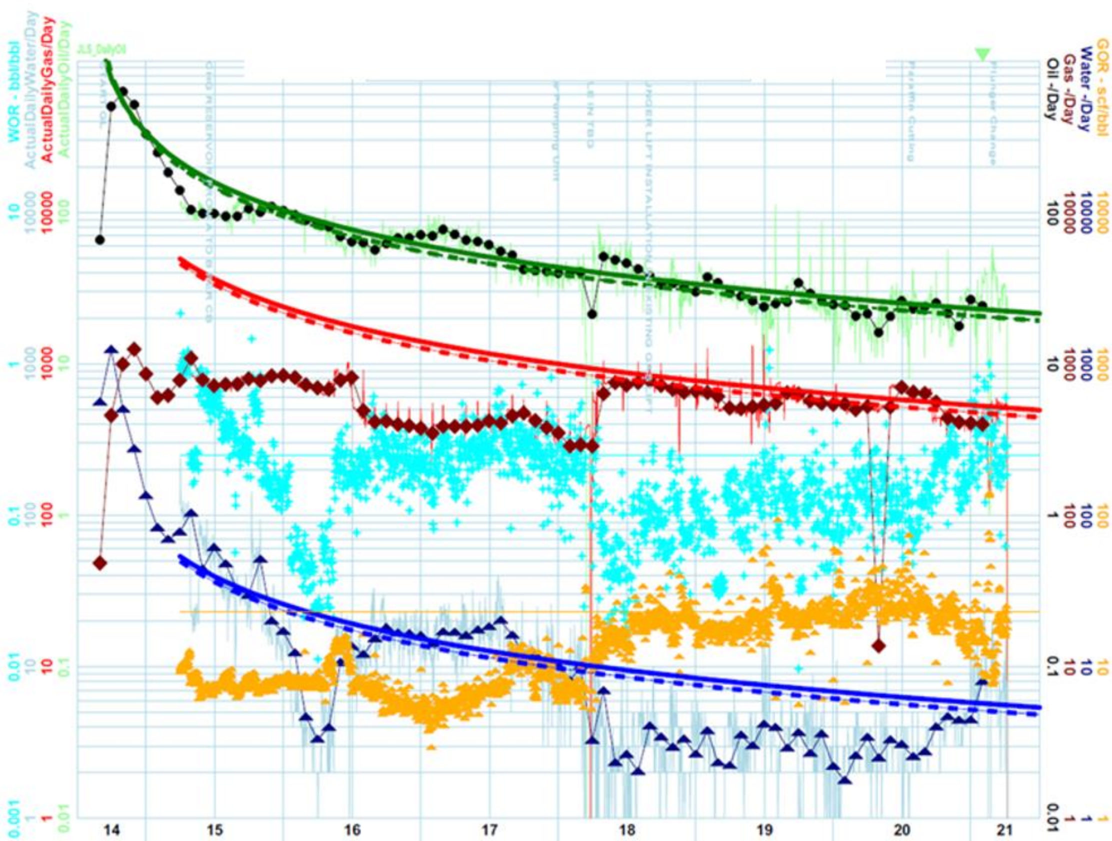
Figure 2C
Bakken Wells' First 180 Days of Oil Production
Source: U.S. EIA, February 2024



Source: U.S. Energy Information Administration, *Drilling Productivity Report*
Note: Not all wells are reported, and curves are subject to revision.

Figure 3
PAGL Optimization in Horizontal STACK Well (Series 8000™ Controller)

Figure 4
PDP Reserves Impact of Transitioning Wolfcamp Well from PAGL to Plunger Lift
(Friction Bypass Plunger with Taper-Lock™)



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