The Lowest OPEX Producer Wins the Production Game

API Luncheon – OKC, February 8, 2018

Jeff Saponja, CEO

HEAL SYSTEMS™

A Schlumberger Joint Venture

Multiple Patents Pending

Agenda

1. Horizontal Well Production Phase Challenges
2. OPEX Reduction Opportunity
3. Importance of Life of Well Slug Flow Mitigation
4. Case Studies
5. Q&A

Horizontal Well
Production Phase Challenges

OPEX Definition

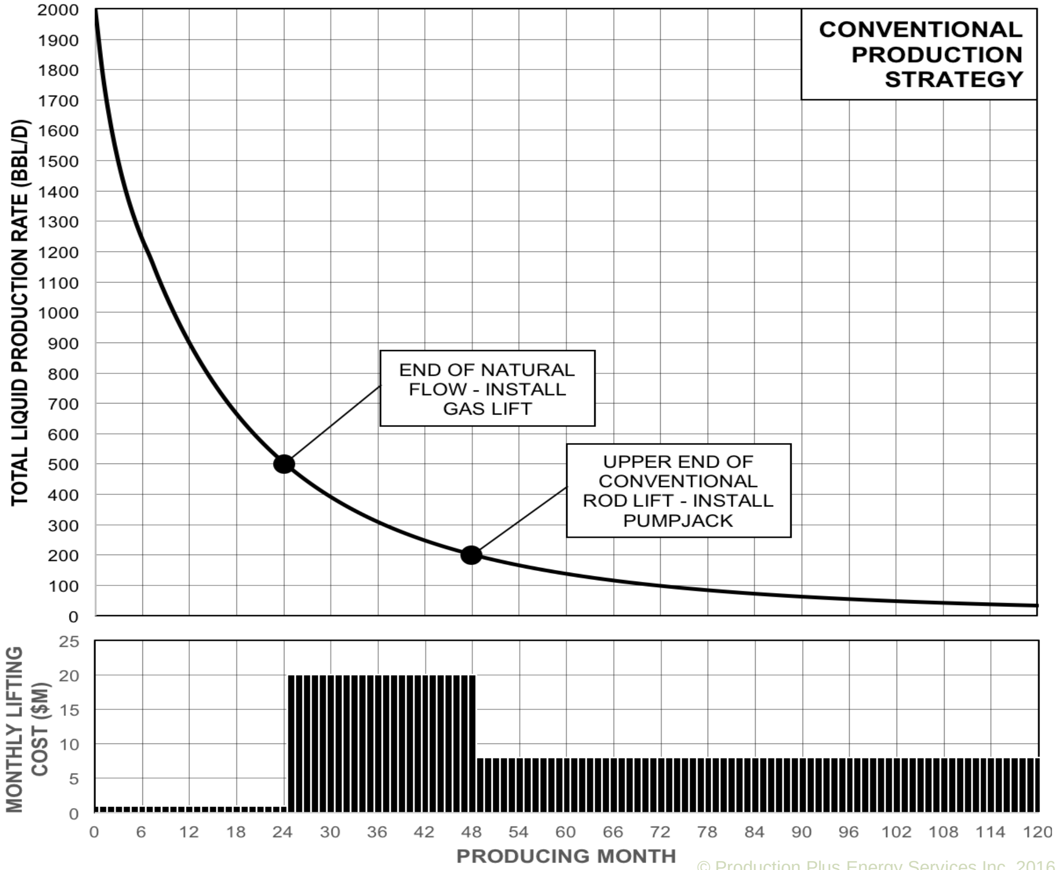
$$\text{OPEX} = \frac{\text{Lifting Cost} \Downarrow}{\text{BBL} \Uparrow}$$

Production Engineer's Predicaments

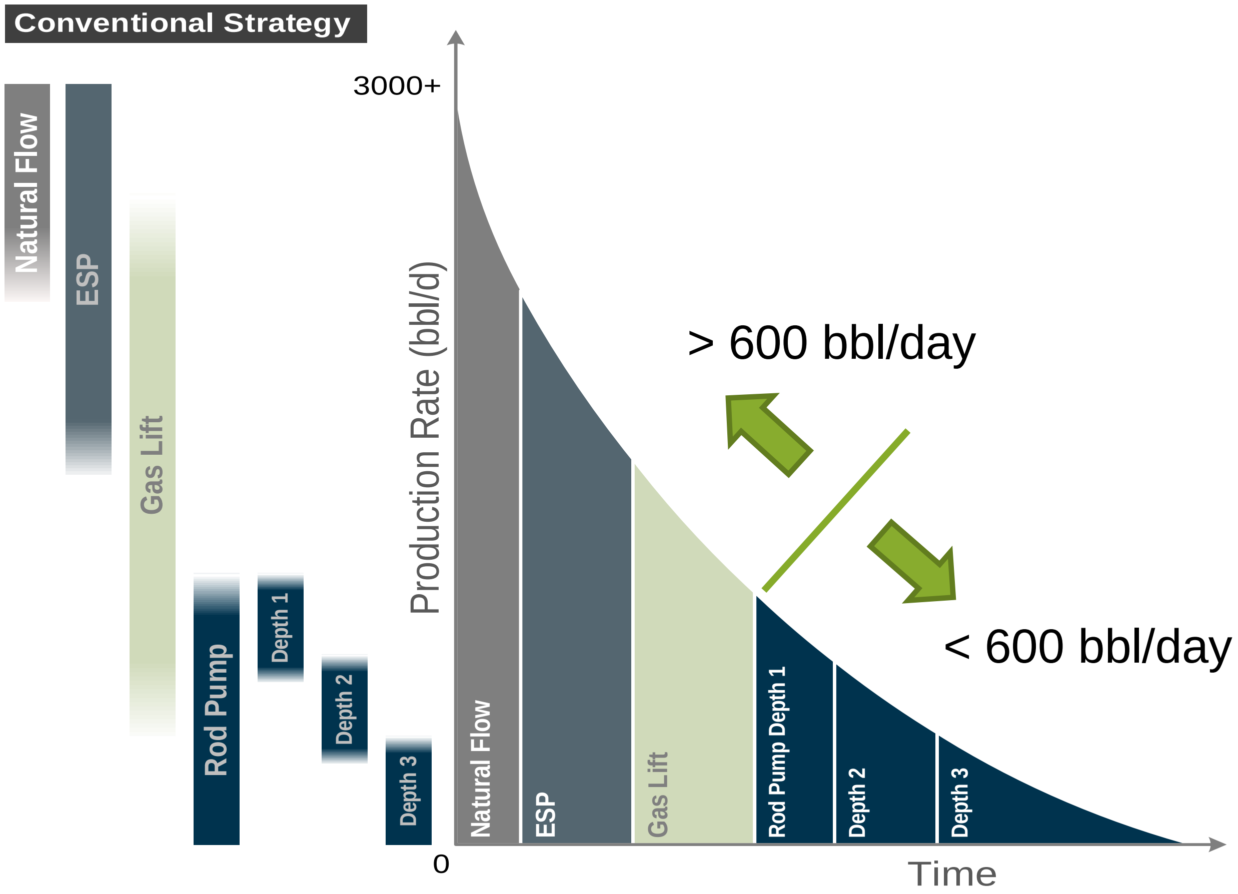
1. No single lift solution for life of well

2. Production rate at the end of natural flow is greater than the top end of rod pumping

3. More drawdown means less reliability of lift system



Common Approach to Production and Lift



Natural Flow Phase Challenges

Challenge	Consequence
Excessive solids	Higher OPEX
Frac proppant flowback events	Higher OPEX
Killing of well transitioning to lifting phase	Higher OPEX
Maximization of flow period	Higher OPEX

> 600 bbl/day Lift Phase Challenges

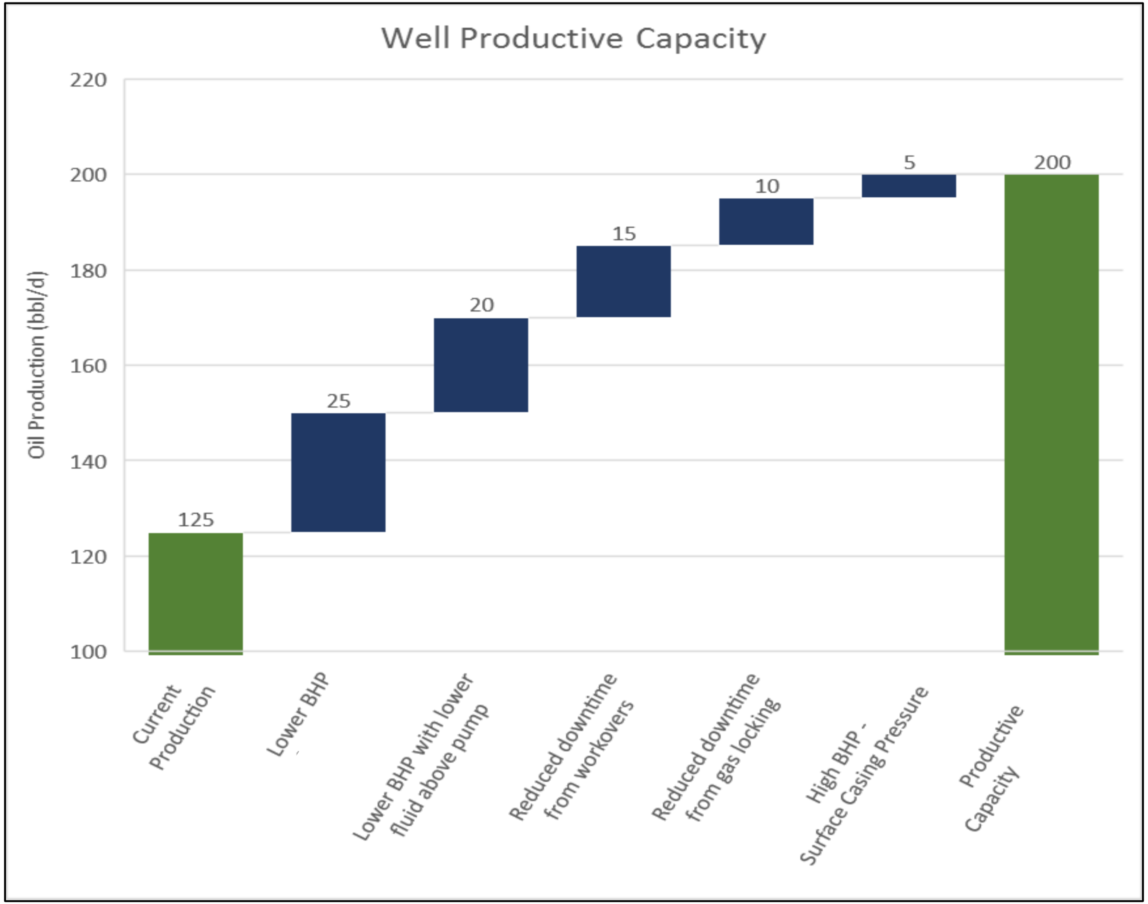
Challenge	Consequence
Pump gas interference	Higher OPEX
Pump solids damage	Higher OPEX
Rate maximization	Higher OPEX
Restrictive casing size	Higher OPEX
Lift system selection	Higher OPEX

< 600 bbl/day Lift Phase Challenges

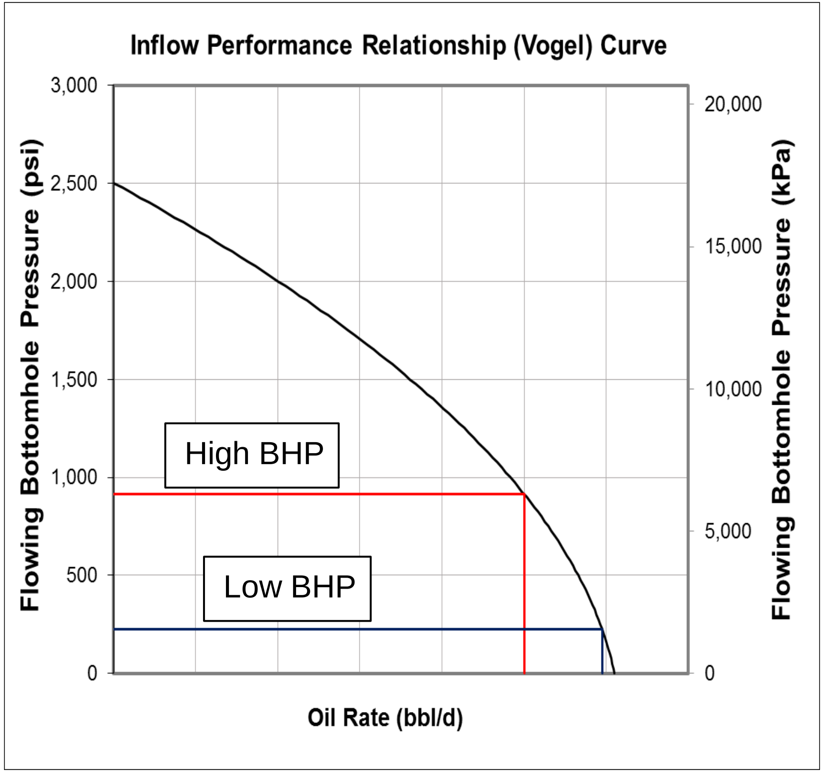
Challenge	Consequence
Pump gas interference	Higher OPEX
Pump solids damage	Higher OPEX
Drawdown maximization	Higher OPEX
High field backpressure	Higher OPEX
Lift System Selection	Higher OPEX

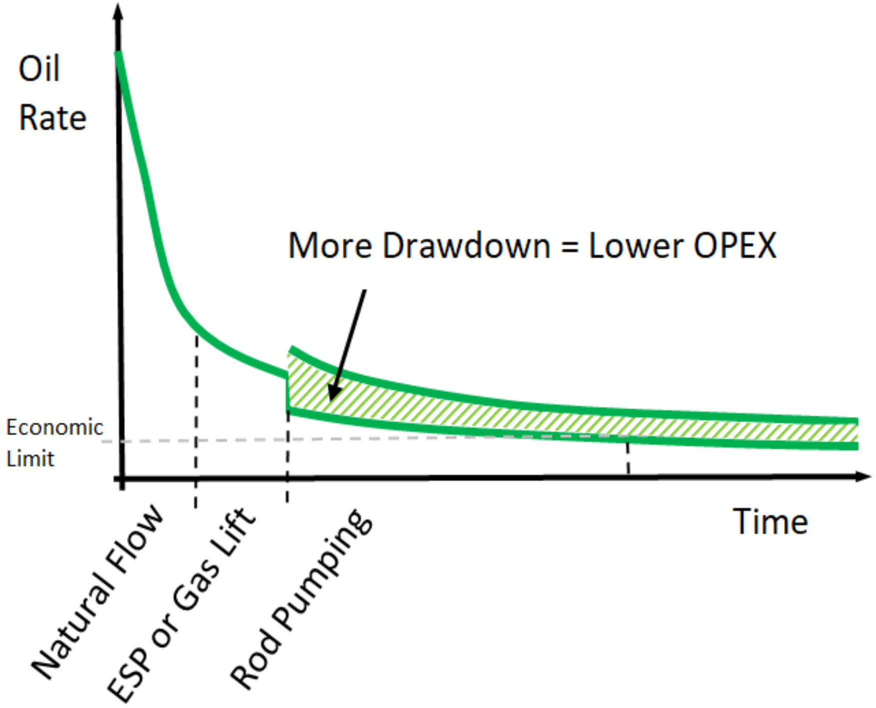
OPEX Reduction Opportunity

Where is the hidden upside in production rate?

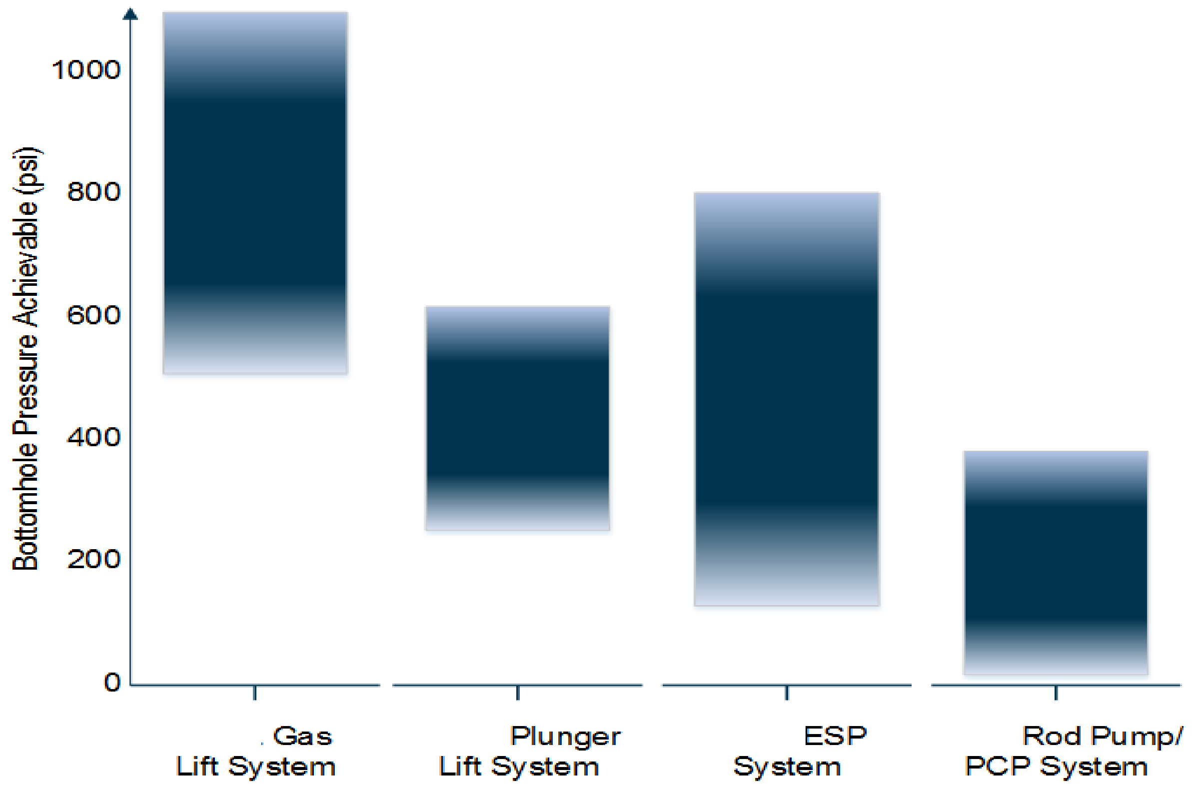


The Importance of Drawdown





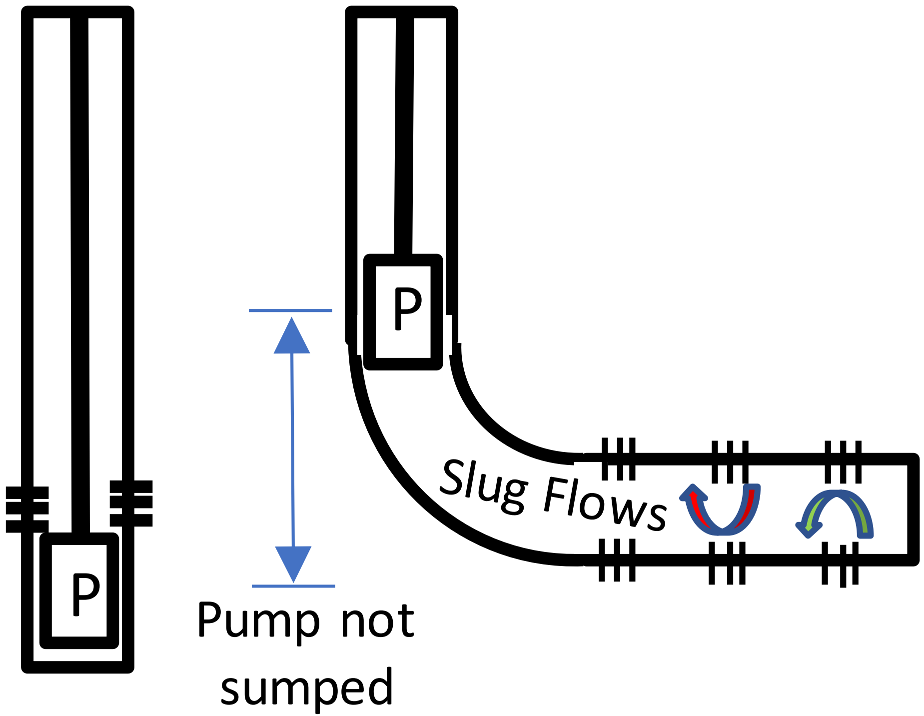
Producing Bottomhole Pressure (BHP) Comparison



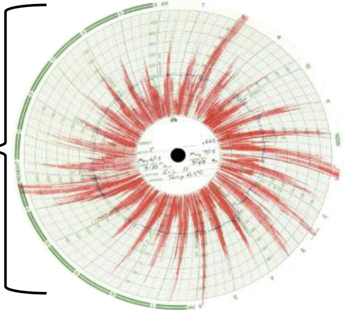
Ideally want lowest OPEX artificial lift method at the appropriate phase of the decline curve

The Importance of Life of Well Slug Flow Mitigation

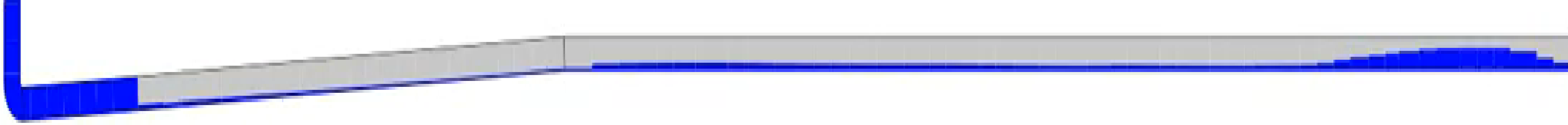
Slug Flow is the Root Cause of Higher OPEX



Why do Horizontal Wells have Slug Flow?



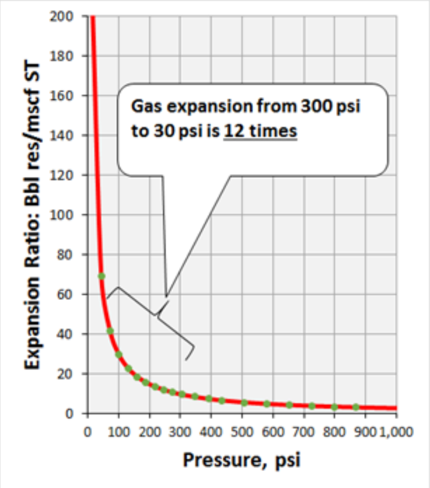
Production
annulus gas rate

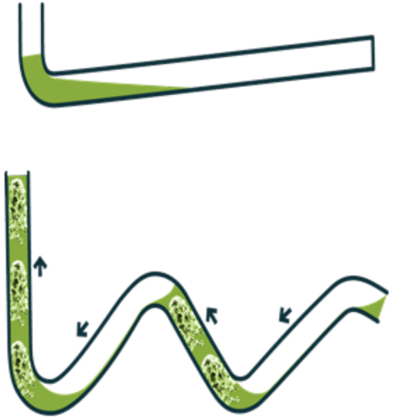


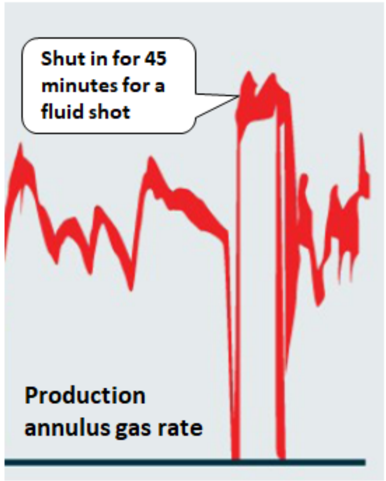
Typical
Pump
Location

Slug Flow Mechanisms

Hydrodynamic	Terrain	Operational
flow regime (GLR, pressure)	well geometry (undulations and toe-up trajectory)	Interruptions, stops / starts







Slug Flow is the Root Cause of Higher OPEX

Slug Flows Cause	OPEX Consequences
Fluctuating gas and liquid rates	• Solids transport in horizontal • High fluid levels and high BHP’s • High pump failure rates • Poor pump efficiency and downhole separation • Reduced run times • Acceptance of gas lifting for life of well
Fluctuating BHP’s	• Frac proppant flow back

Slug Flow Transports Solids Along Horizontal

Solids dunes / beds in horizontal created by slug flow

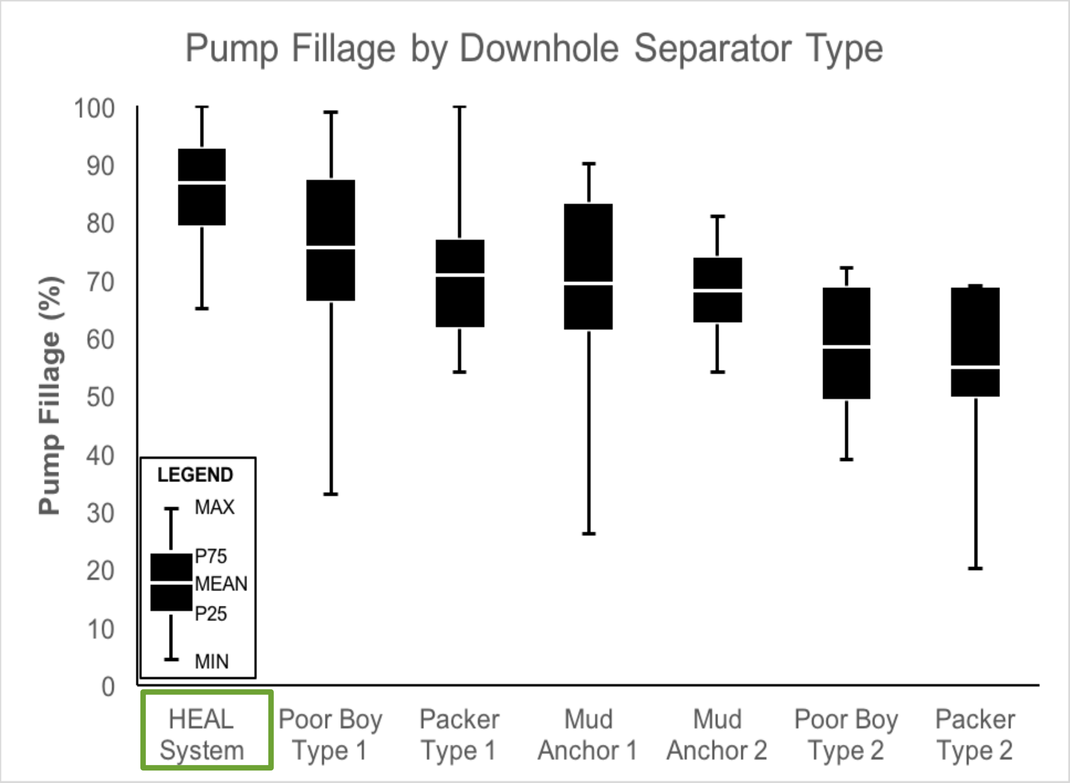
Source: www.evcam.com

Solids are transported in dunes or beds along horizontal due to wave mechanics (saltation) associated with slug flow

Transported solids accumulate at the heel of the horizontal well, where pumps are commonly positioned – high risk of solids damage to pumps

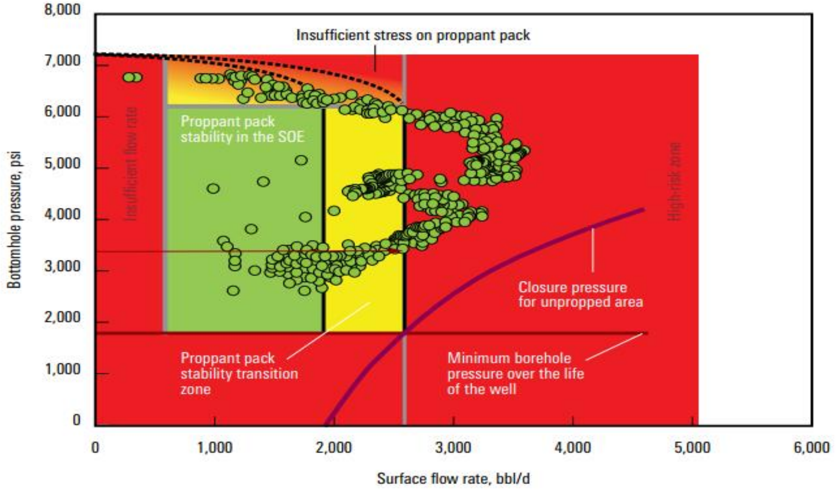
Case Study: Slug Flow Mitigation Improves Separation

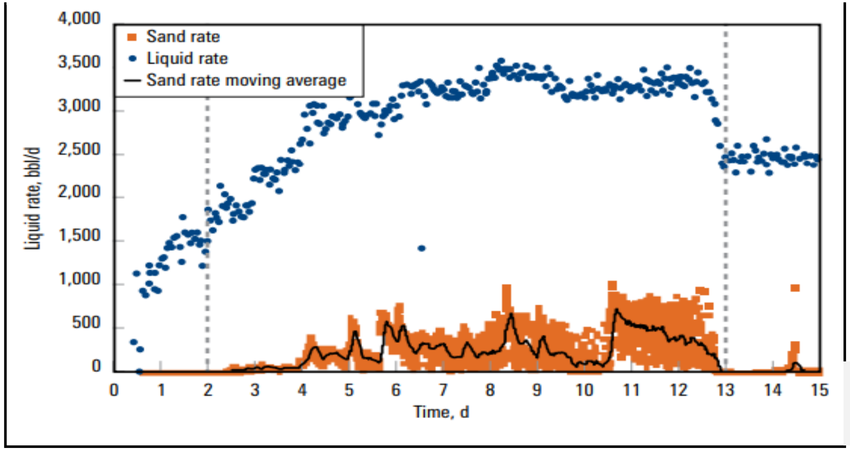
Wolfcamp, Permian



- 23 neighboring wells and 140 readings over seven months
- Slug flow mitigation improves downhole separation, allowing optimal pump fillage
- Additional benefit of lowered BHP
- Less stress on rods by avoiding erratic pump fillage
- Stable fluid level allows for effective pump jack balancing

Slugs Flows Reduce Frac Conductivity

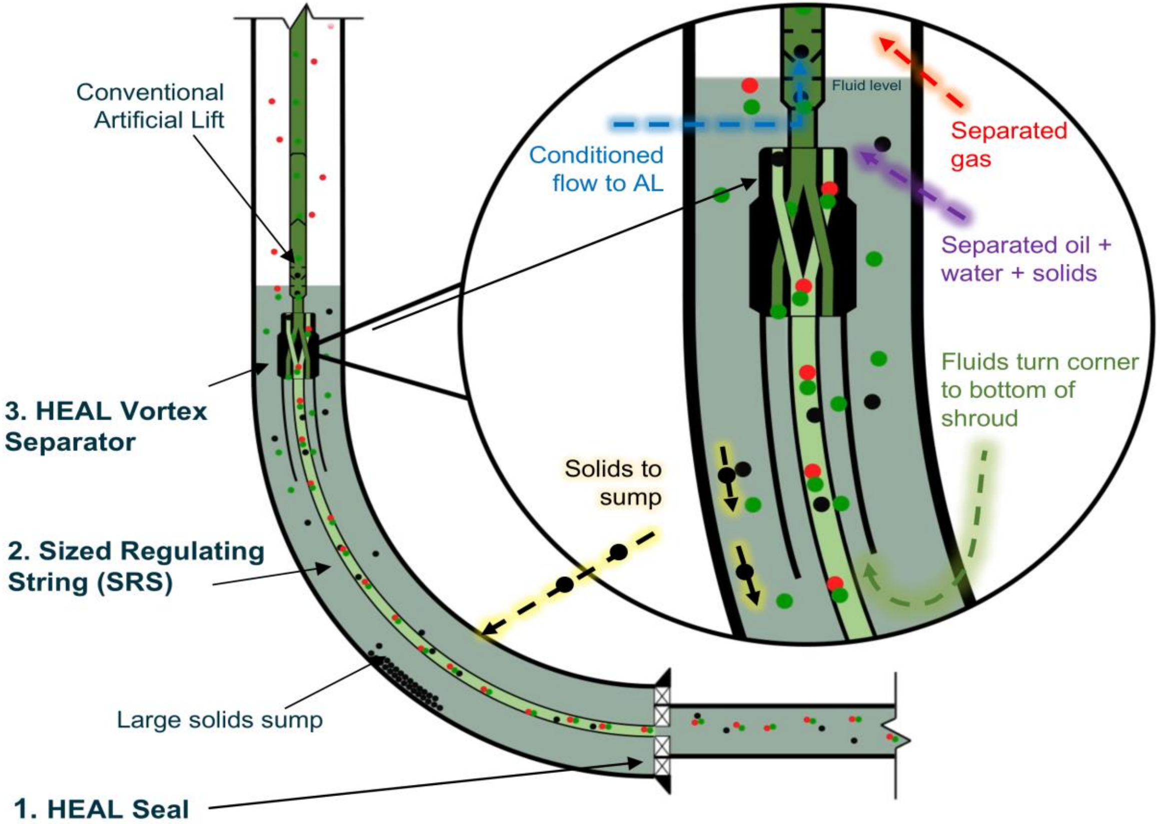




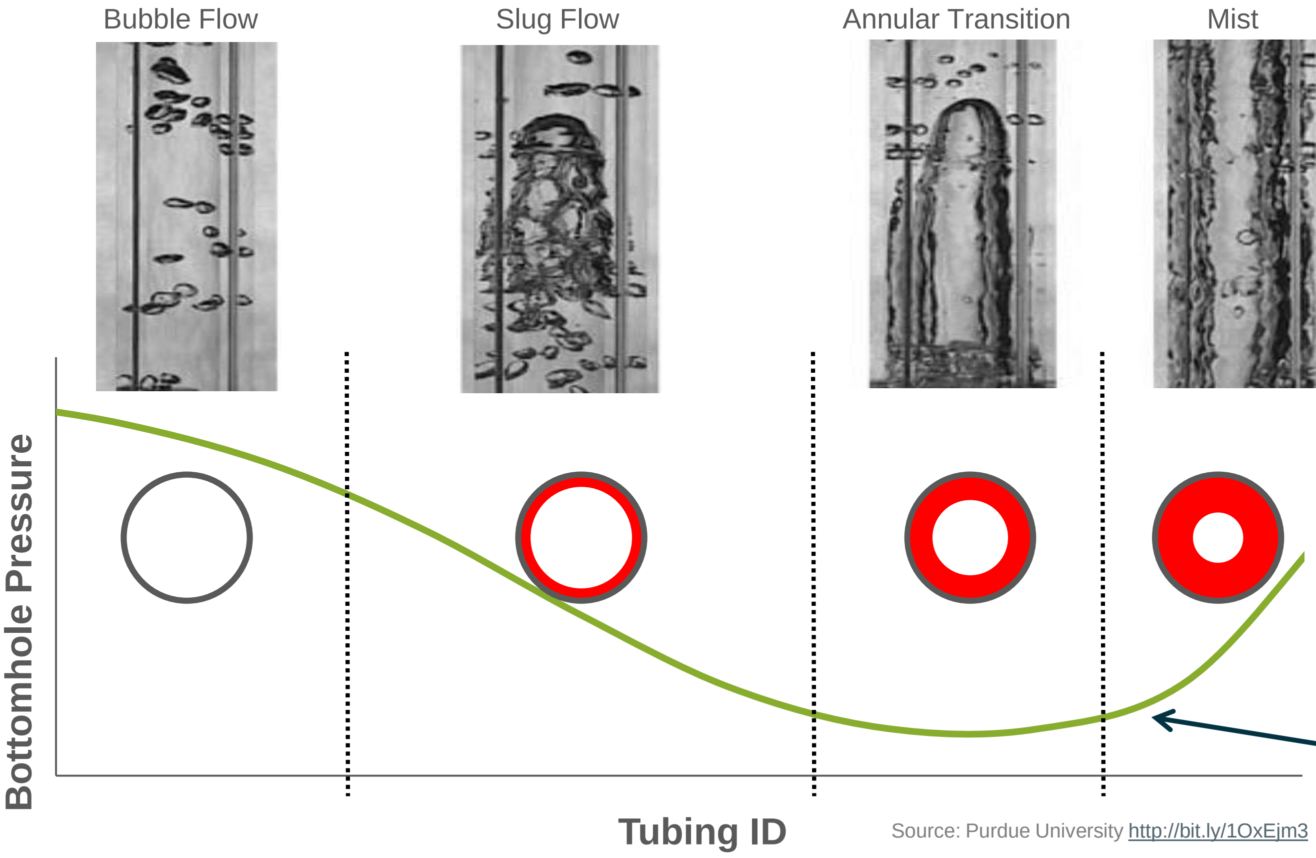
- Maximum pressure to maintain stability of proppant pack
- Maximum flow rate (velocity for sand transport)
- In example, rates were above the level of proppant pack stability
- Evidence that periodic high rates from interruptions and slug flows can reduce proppant conductivity

Source: Schlumberger. 2016. http://bit.ly/2v0aBSP (accessed 26 July 2017).

Slug Flow Mitigation with HEAL System™



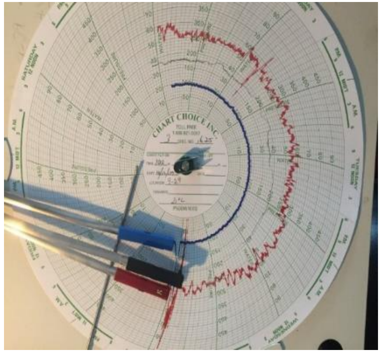
Regulating Flow for Slug Flow Mitigation



Source: Purdue University http://bit.ly/1OxEjm3

SRS is sized for:

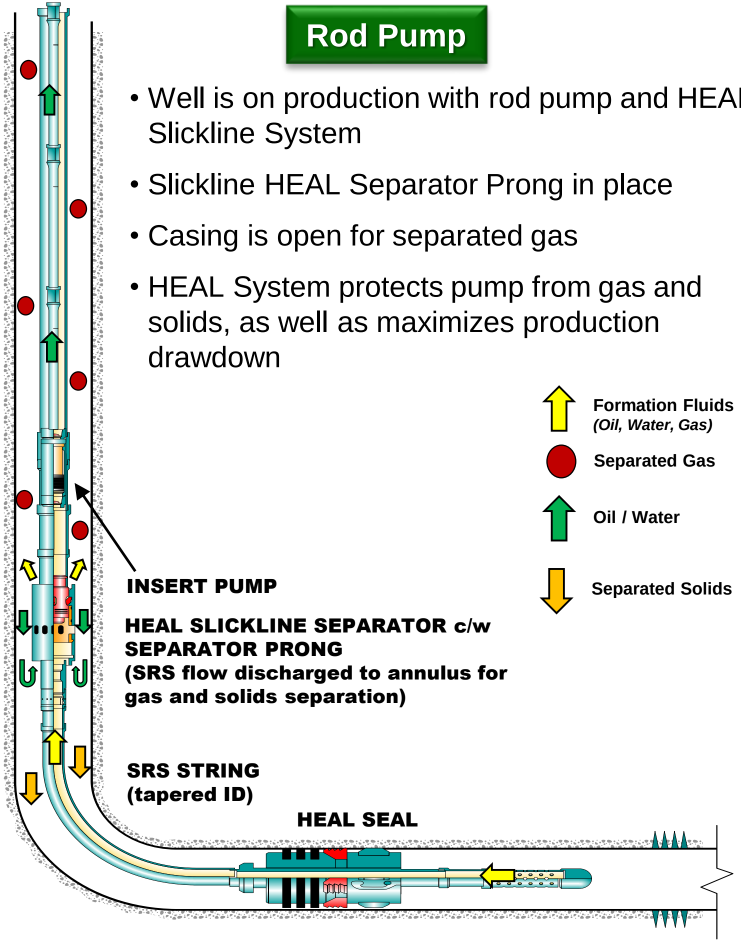
1. Slug flow mitigation
2. Longevity and should not require re-sizing or maintenance



HEAL Slickline System: Offset Well Frac Hit Protection

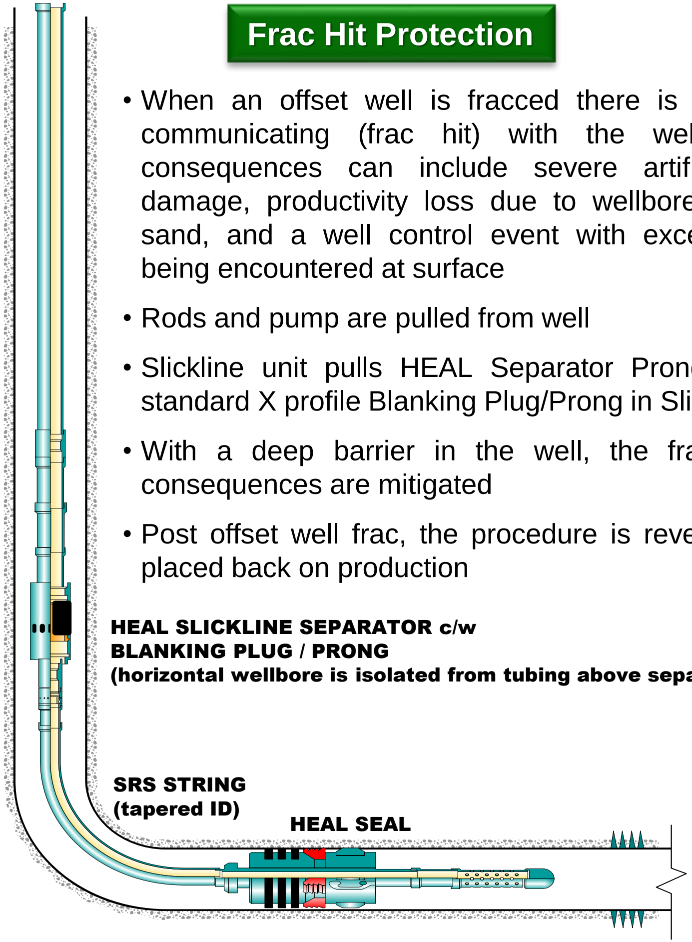
Rod Pump

- Well is on production with rod pump and HEAL Slickline System
- Slickline HEAL Separator Prong in place
- Casing is open for separated gas
- HEAL System protects pump from gas and solids, as well as maximizes production drawdown

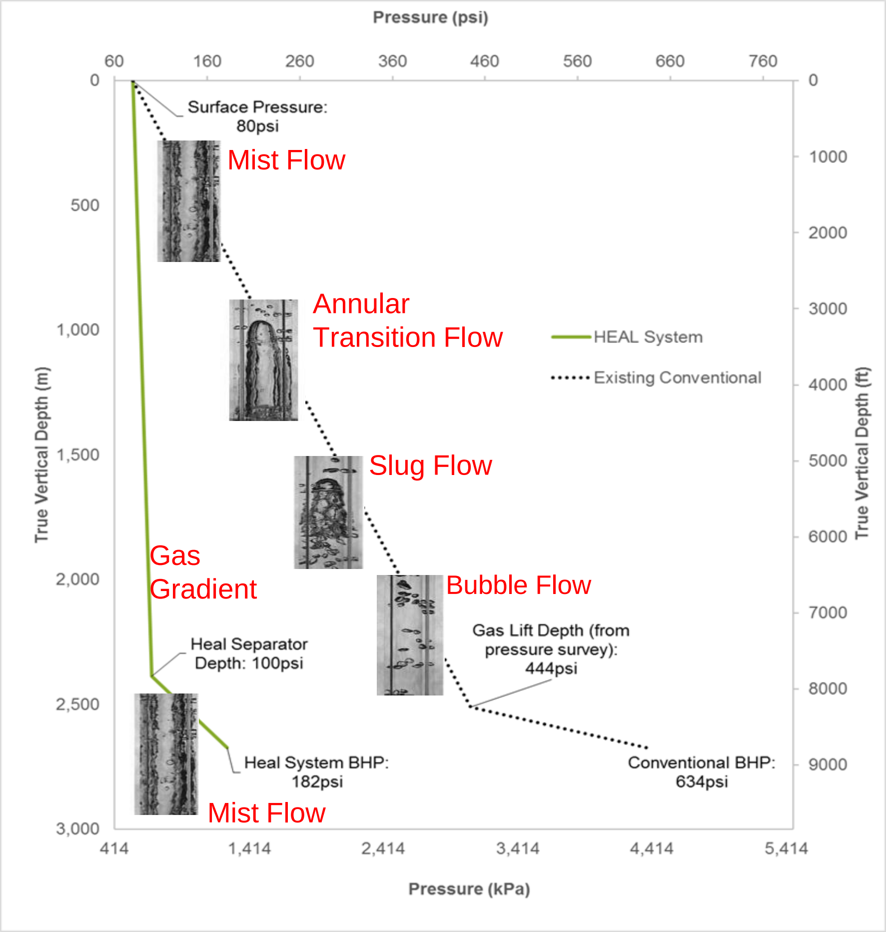


Frac Hit Protection

- When an offset well is fracced there is a risk of a frac communicating (frac hit) with the wellbore. Frac hit consequences can include severe artificial lift system damage, productivity loss due to wellbore filling with frac sand, and a well control event with excessive pressures being encountered at surface
- Rods and pump are pulled from well
- Slickline unit pulls HEAL Separator Prong and installs a standard X profile Blanking Plug/Prong in Slickline Separator
- With a deep barrier in the well, the frac hit risks and consequences are mitigated
- Post offset well frac, the procedure is reversed and well is placed back on production



Gas Lifting Drawdown Limitation

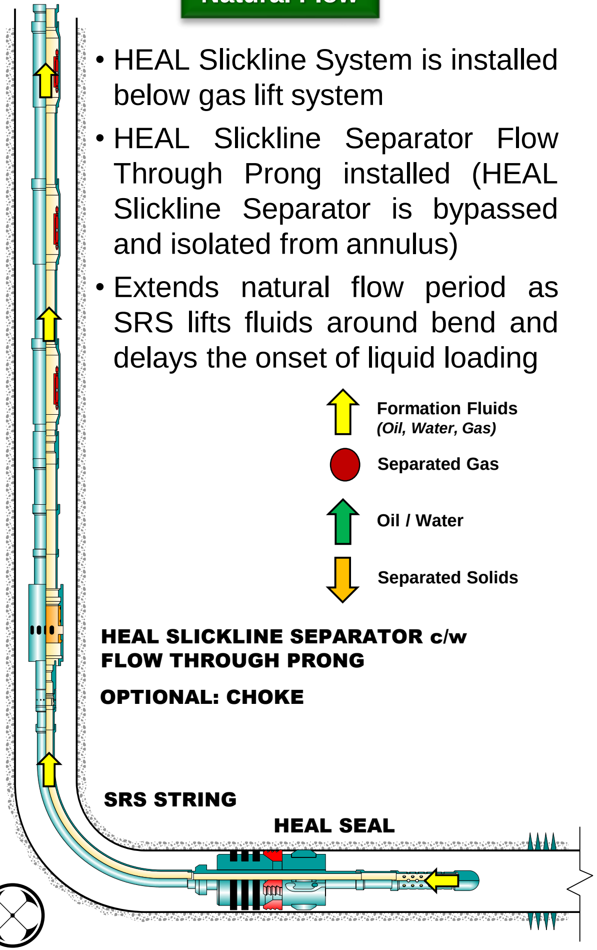


Gas Lifting Limitations:

1. Multiple flow regimes compounding throughout gas lifting interval means drawdown BHP's limited to 600-800 psi
2. Higher OPEX

HEAL Slickline System: Gas Lift and Transition to RP

Natural Flow



- HEAL Slickline System is installed below gas lift system
- HEAL Slickline Separator Flow Through Prong installed (HEAL Slickline Separator is bypassed and isolated from annulus)
- Extends natural flow period as SRS lifts fluids around bend and delays the onset of liquid loading

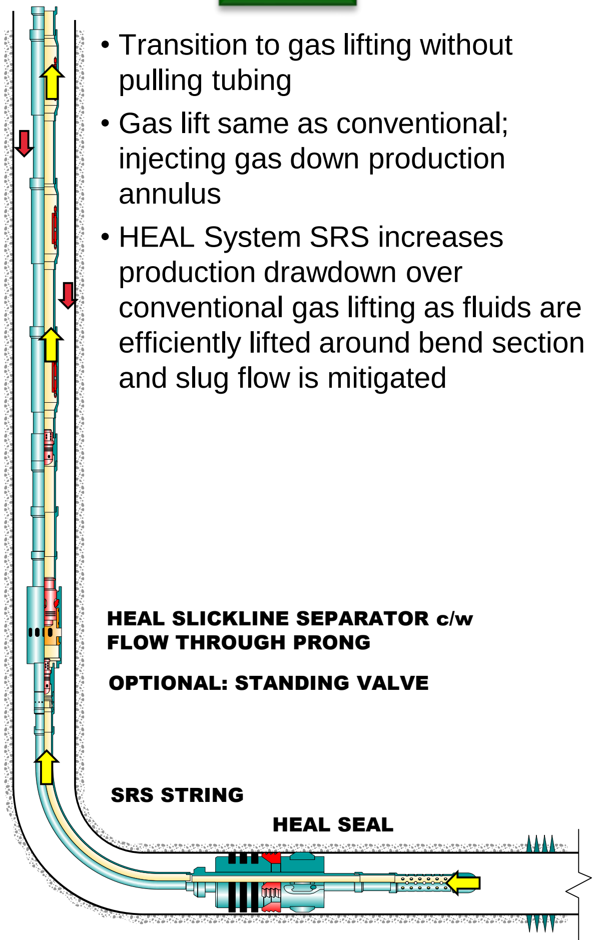
Formation Fluids *(Oil, Water, Gas)*

Separated Gas

Oil / Water

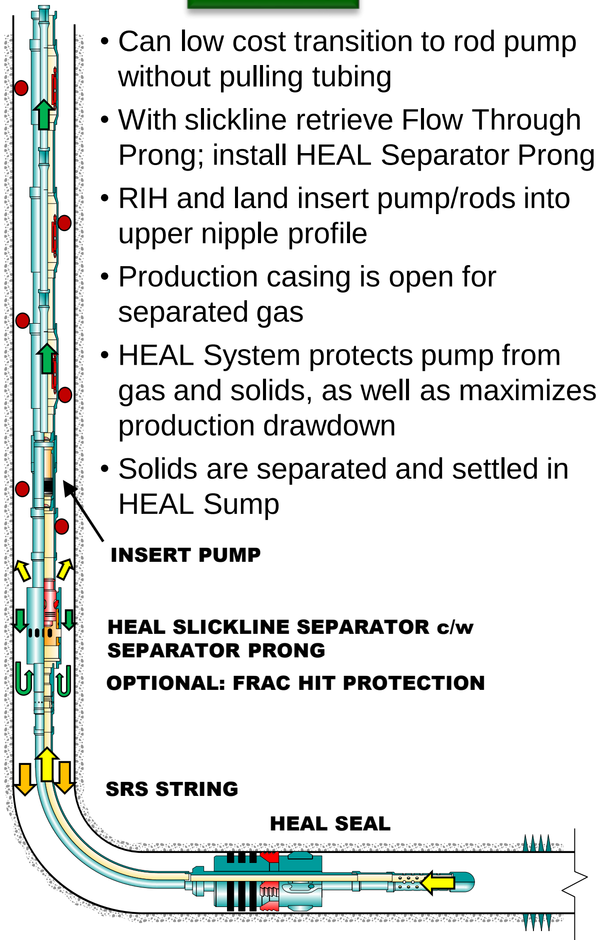
Separated Solids

Gas Lift



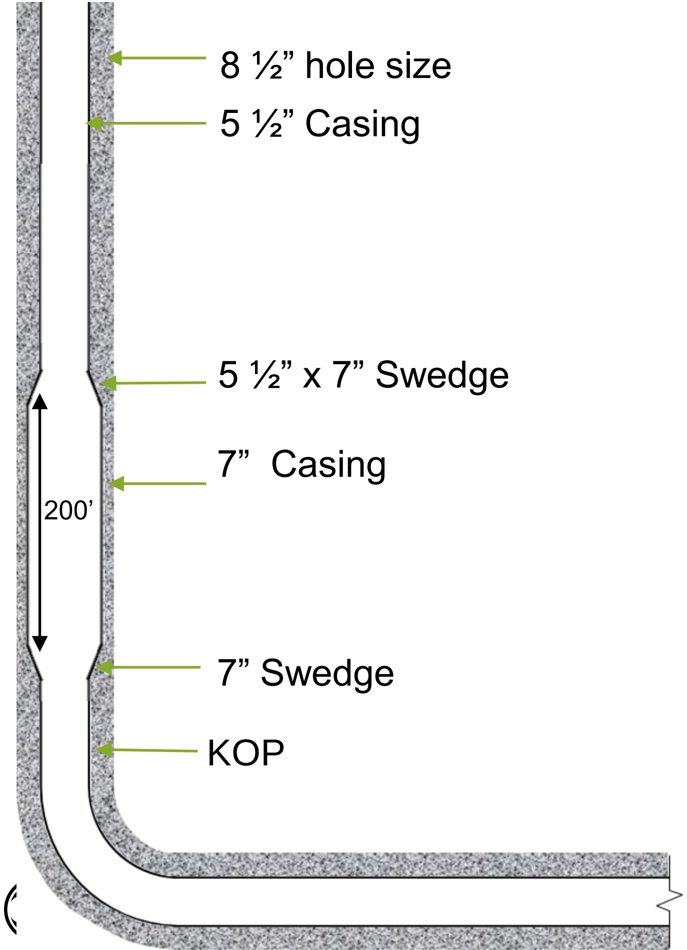
- Transition to gas lifting without pulling tubing
- Gas lift same as conventional; injecting gas down production annulus
- HEAL System SRS increases production drawdown over conventional gas lifting as fluids are efficiently lifted around bend section and slug flow is mitigated

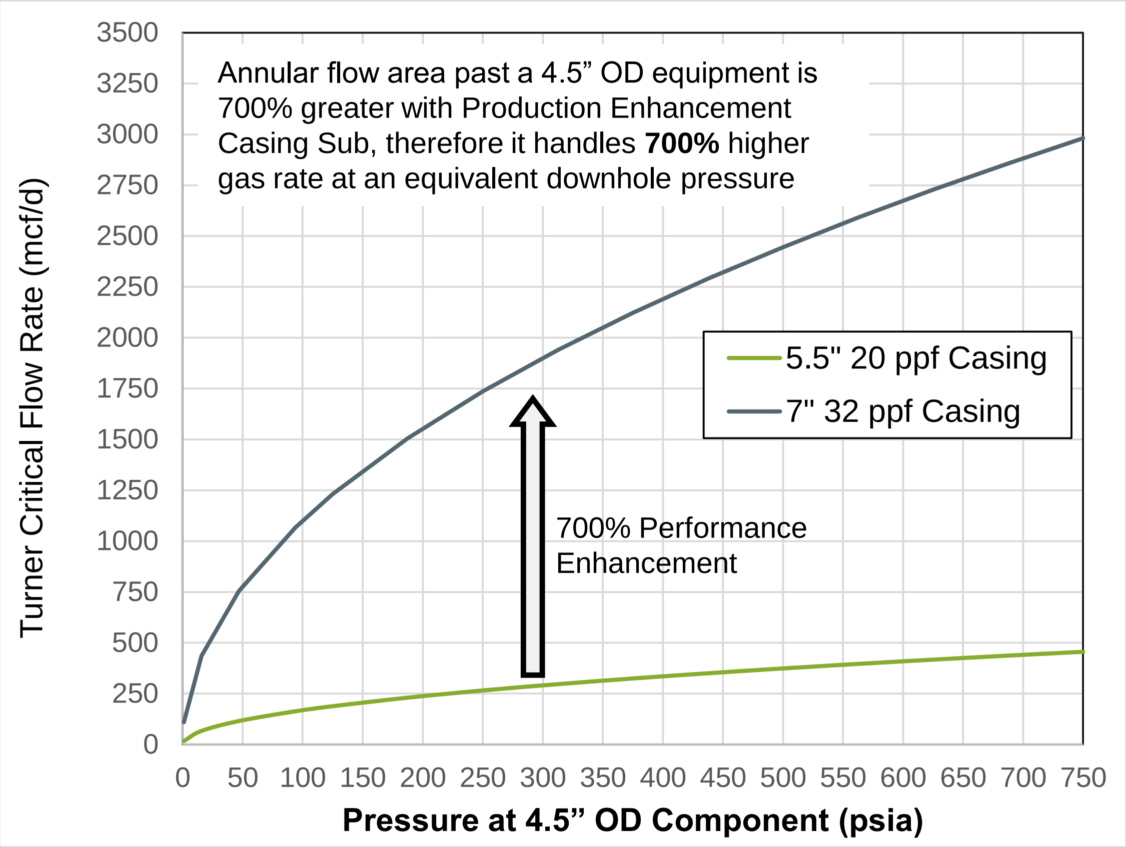
Rod Pump



- Can low cost transition to rod pump without pulling tubing
- With slickline retrieve Flow Through Prong; install HEAL Separator Prong
- RIH and land insert pump/rods into upper nipple profile
- Production casing is open for separated gas
- HEAL System protects pump from gas and solids, as well as maximizes production drawdown
- Solids are separated and settled in HEAL Sump

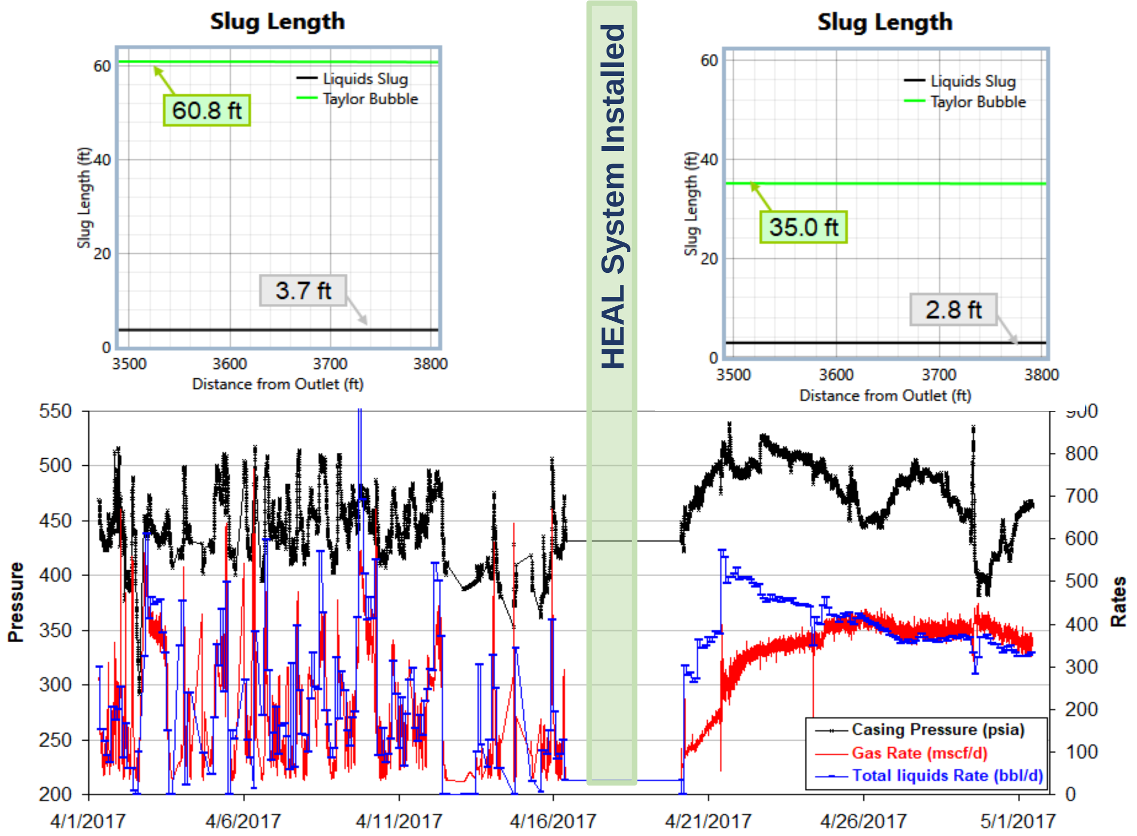
Casing Design with an Enlarged Interval





Case Studies

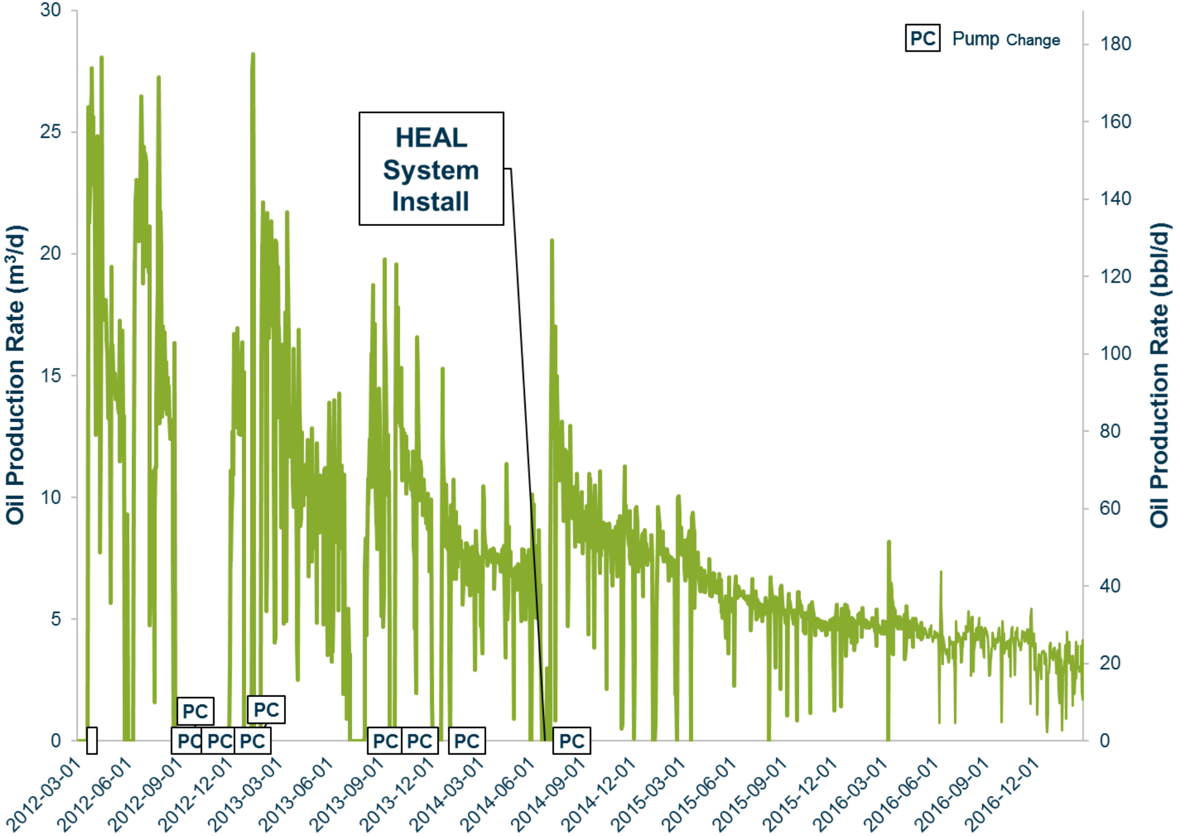
Case Study: Improve Production Performance



Reference:
Nagoo, A. et al. 2017. **“Multiphase Flow Simulation of Horizontal Well Artificial Lift and Life-of-Well Case Histories. HEAL System Modeled in Pipe Fractional Flow.”** Presented at URTEC, San Antonio, Texas 2017. URTEC-2670789-MS.

Case Study: Reduce Operating Expense (Reliability)

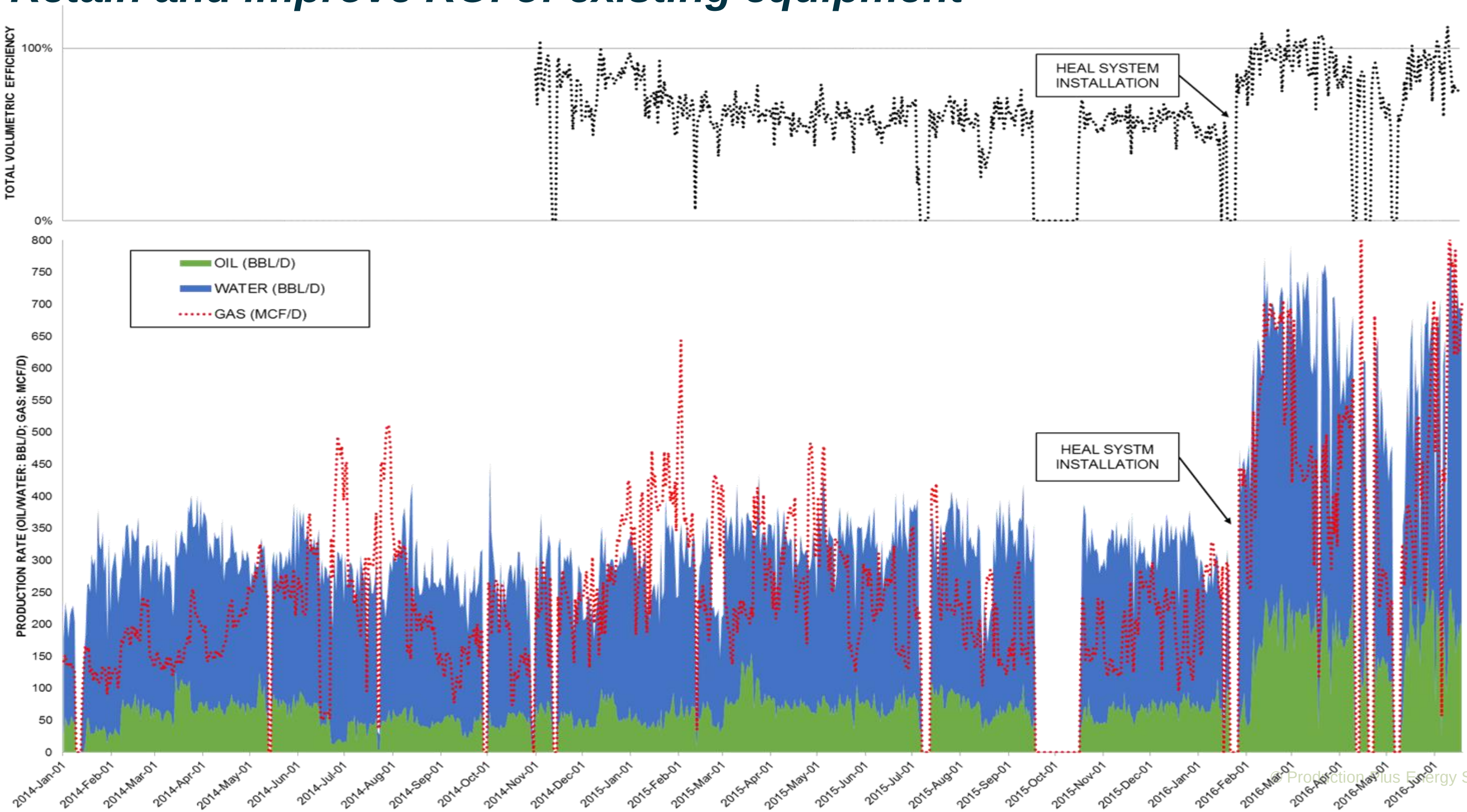
Viking, Canada



- Ran pumps deep to maximize drawdown
  - multiple pump failures
- Ran pumps shallow for reliability
  - poor drawdown, rod breaks from gas interference
- Pre-HEAL
  - 9 pump changes over 2 years costing $600k
- **Post-HEAL**
  - Zero changes in 2.5+ years

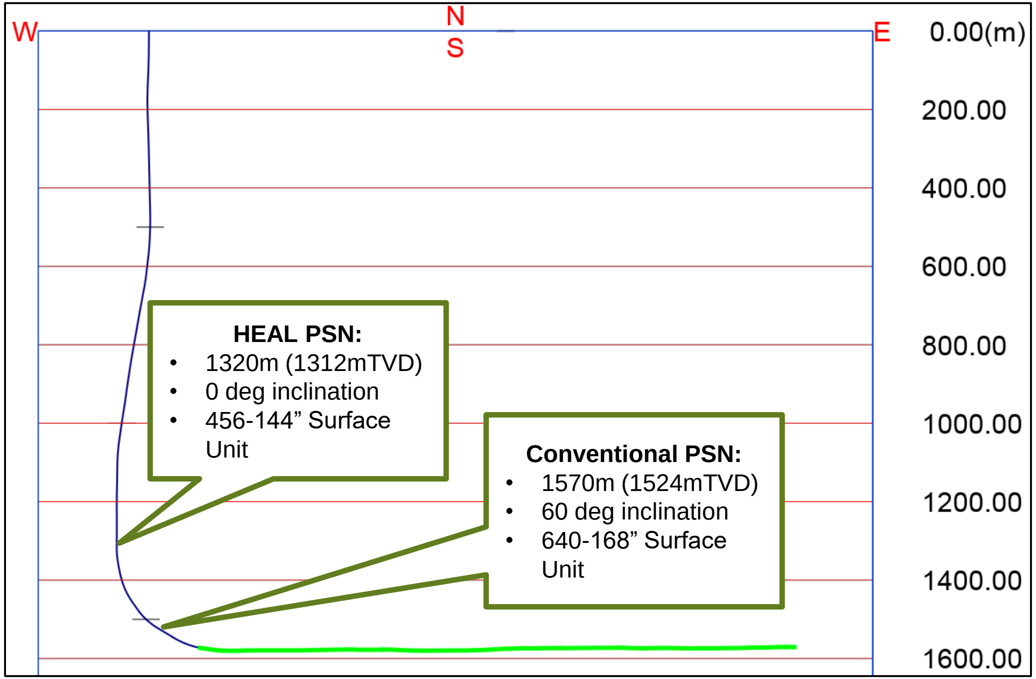
Reduce CAPEX:

Retain and improve ROI of existing equipment



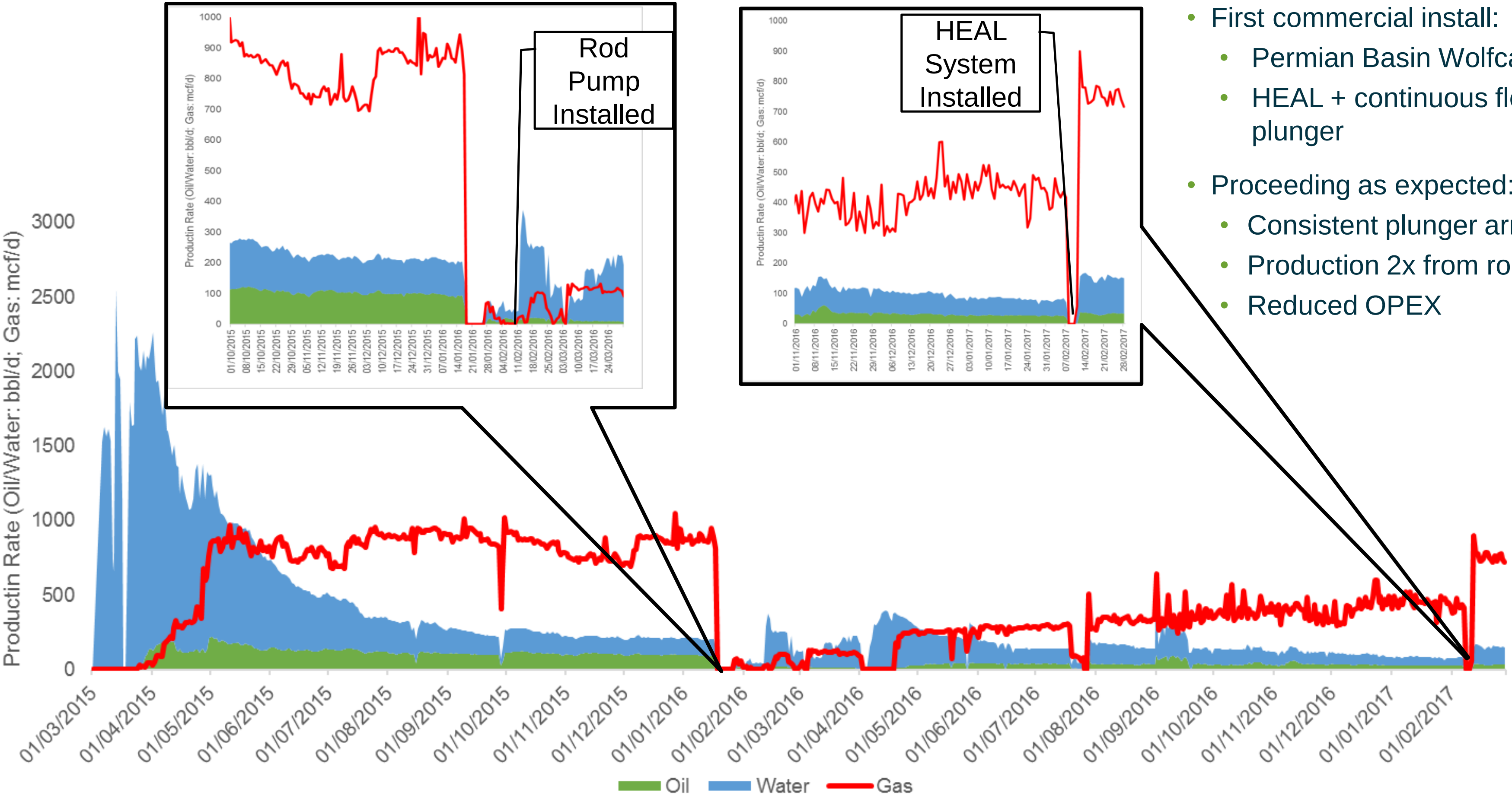
Case Study: Reduce Capital Investment

Cardium, Canada



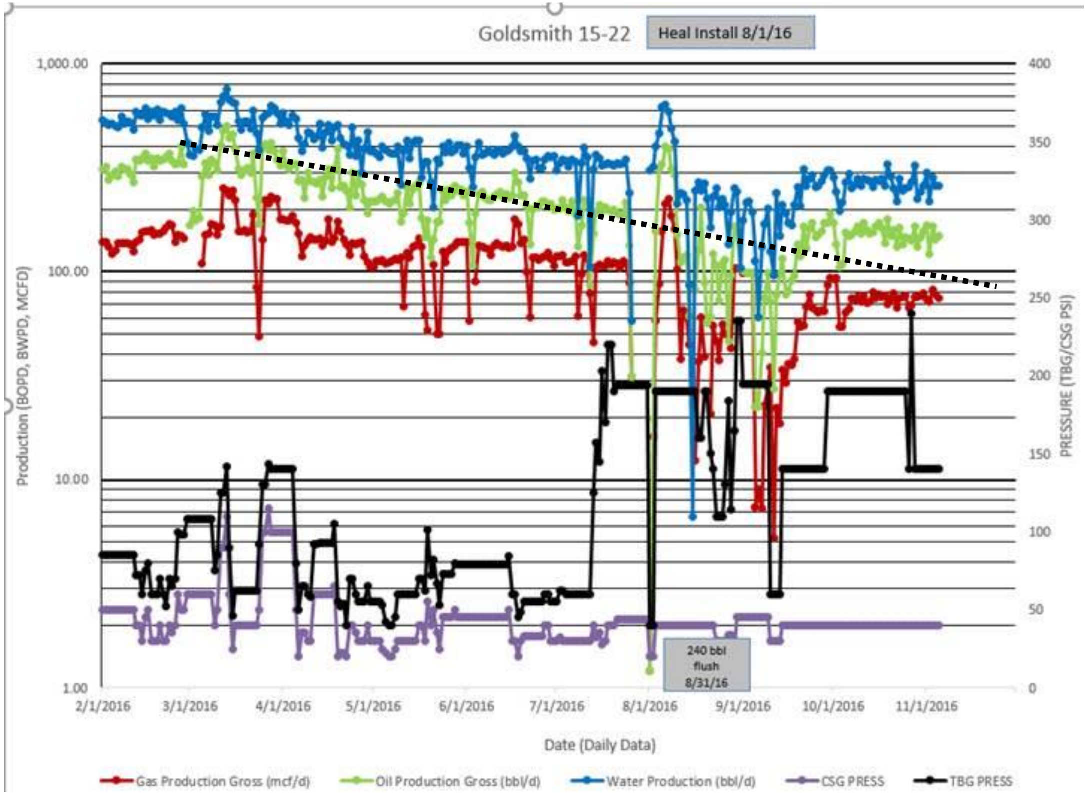
- HEAL System allowed PSN to be raised (212mTVD) from the 60 degree tangent to KOP
- Surface unit savings of **$21k to 29k** (one or sizes smaller)
- 800' less production tubing and rods **($10k)**
- Same or better BHP and production as conventional pump depth
- Improved pump workover frequency and system wear
- No need to conventionally lower pump over time

Reduce OPEX: *Enhance Plunger Lift with HEAL System*



- First commercial install:
  - Permian Basin Wolfcamp
  - HEAL + continuous flow plunger
- Proceeding as expected:
  - Consistent plunger arrivals
  - Production 2x from rod lift
  - Reduced OPEX

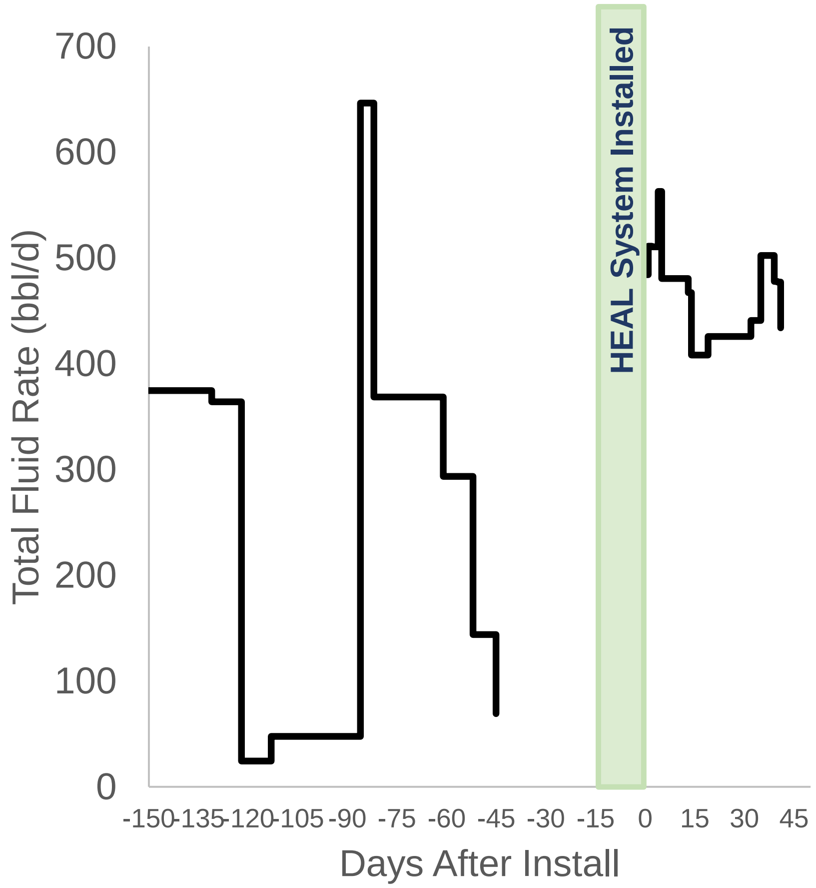
Case Study: Production Enhancement Bakken North Dakota



- Typical Bakken casing configuration results in high pump placement and high BHP's (drawdown limited)
- 30% to 40% increase in production and reserves opportunity
- HEAL System highly suited for such casing configurations for maximizing drawdown
- > 9,200 existing well candidates identified

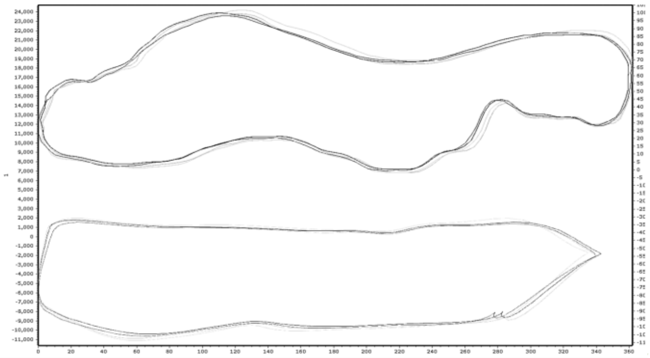
 |

Case Study 6: High-rate Deep Rod Pumping



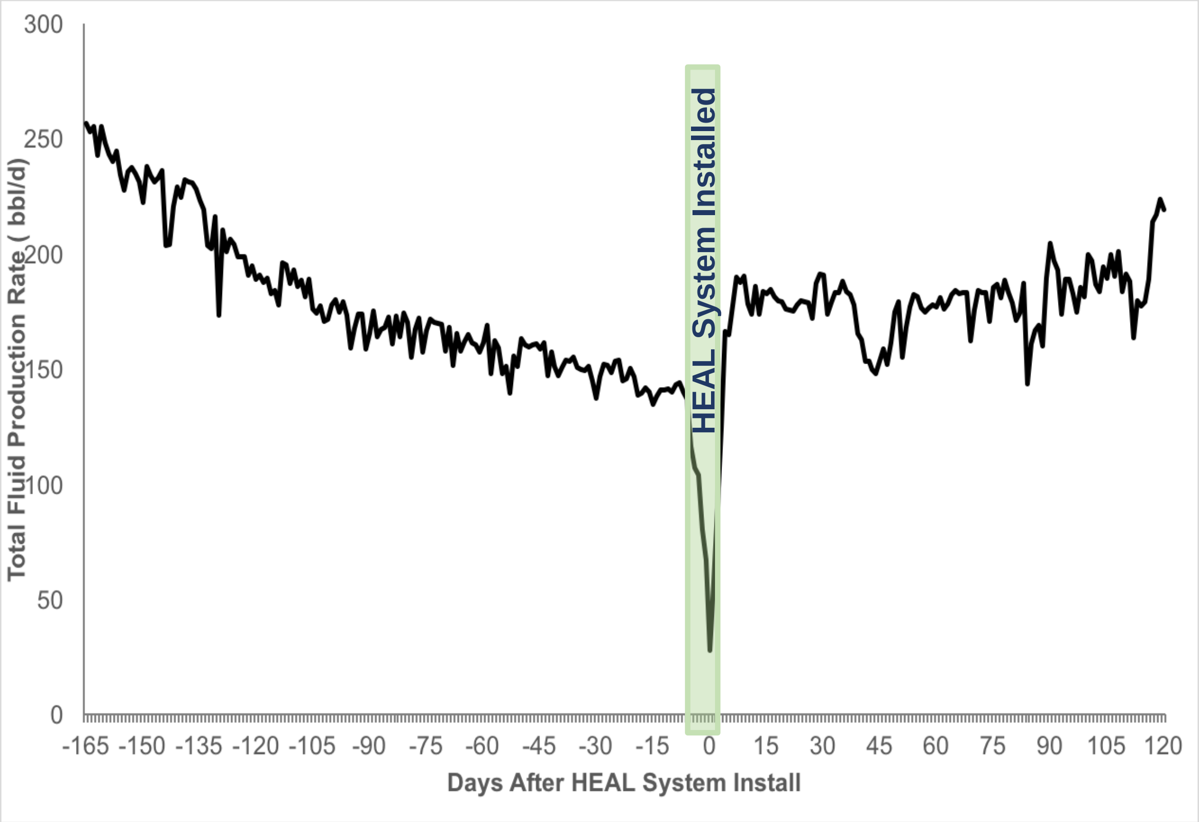
Gas Lift to long stroke pumpjack @ 8,200 ft:

- Inconsistent production with gas lift
- Consistent production after install
- 86% increase in total fluid rate
- > 85% consistent pump fillage
- Reduced operating costs



Case Study: Improve Production Performance

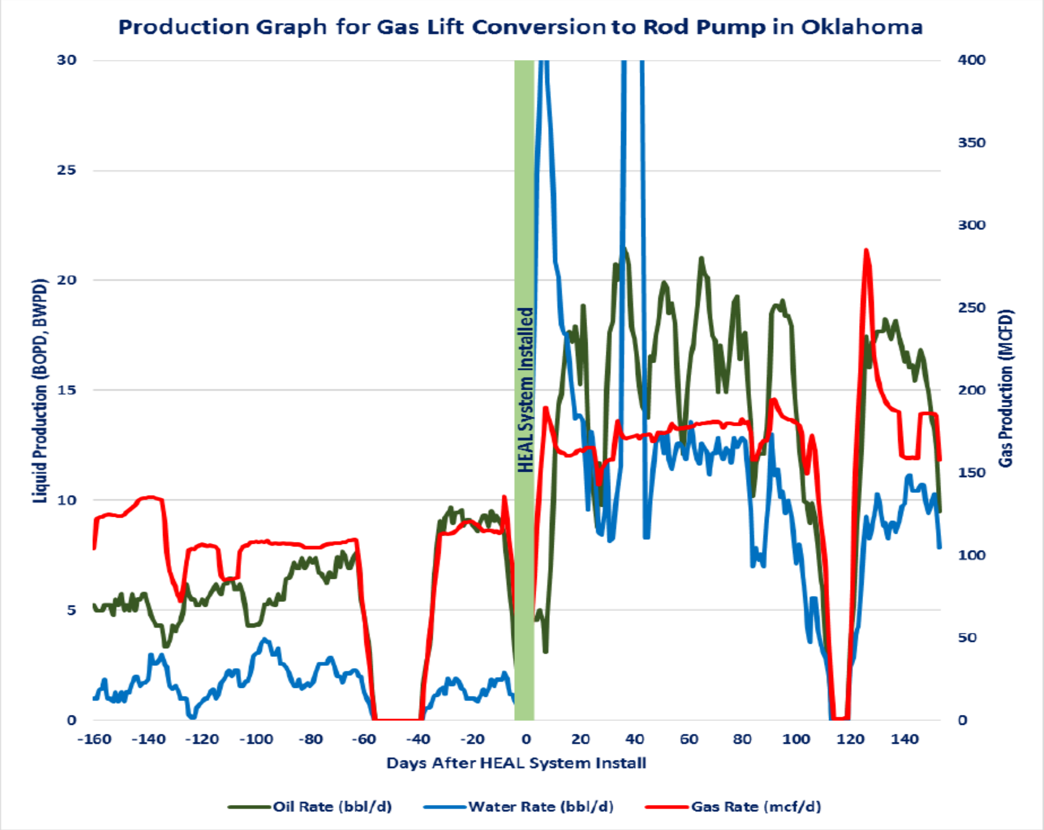
Wolfcamp, Permian Basin



- Gas lift to Rod Pump transition, lower BHP.
- Wolfcamp Formation is challenged by depth, high total fluid rates, high watercuts and severe high GOR gas interference
- Installation in 12 Wolfcamp wells resulted in a sustained **+33% increase** in production
- Lower OPEX and total capital with rod pumping

Case Study: Gas Lift to Rod Pump Transition

Oklahoma

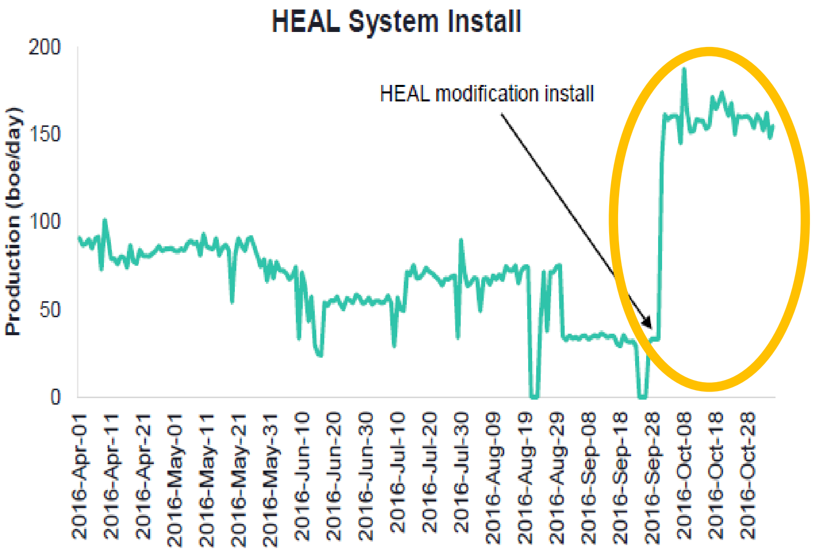


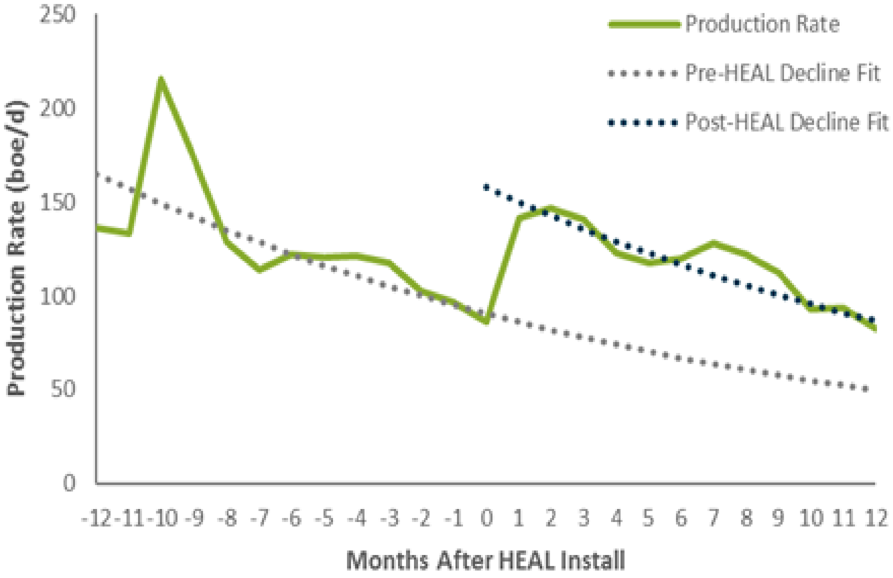
- Gas lifting baseline strategy. Major historic rod pumping challenges: deep, high GOR, some areas have very high initial rates and decline rates
- Increased drawdown objective. Transitioned to rod pumping with Downhole System; installed in 9 wells
- Long term (>12 months) average result is **+100% increase** in production over previous trend
- Implementing larger program to transition from gas lift to rod pumping with Downhole System

Ante Creek – Optimization Initiatives

Ante Creek Optimization Providing Highly Profitable Production Adds

- Optimization initiatives are resulting in excellent capital efficiencies





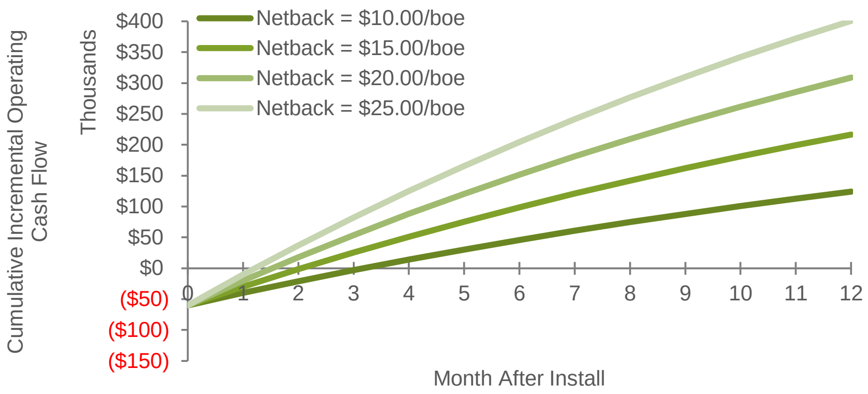
- 300% uplift in Production single well
- Capital Efficiency: ~$1,300/boe/day
- Payout: 1.8 months

- 75% uplift in production averaged on 25 wells
- Capital Efficiency: ~$1,900/boe/day
- Payout: 2.4 months
- Average 6month incremental Production 20,000 bbls
- OPEX Reduction (20%-40%)

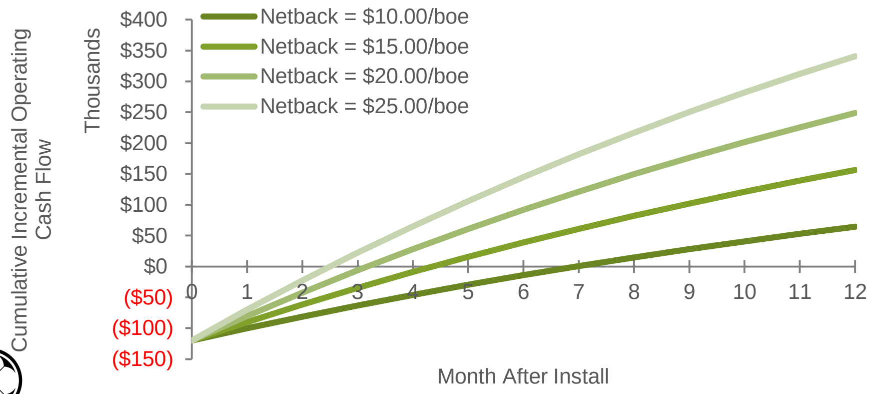
Case Study: Improve Economics

Montney, Canada

HEAL Installed at Transition or Failure



Workover Only for HEAL Install

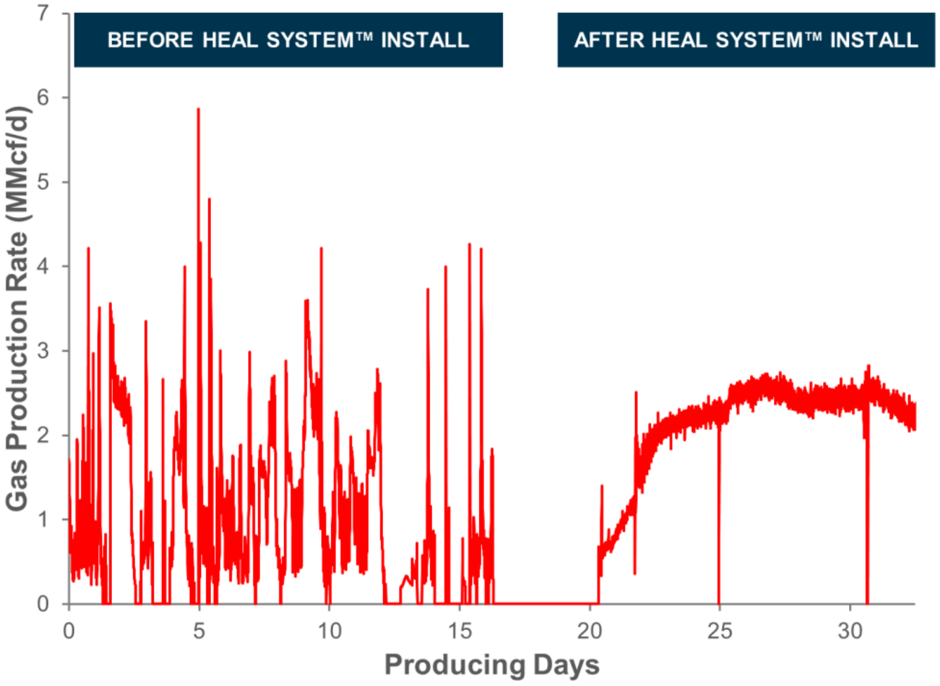


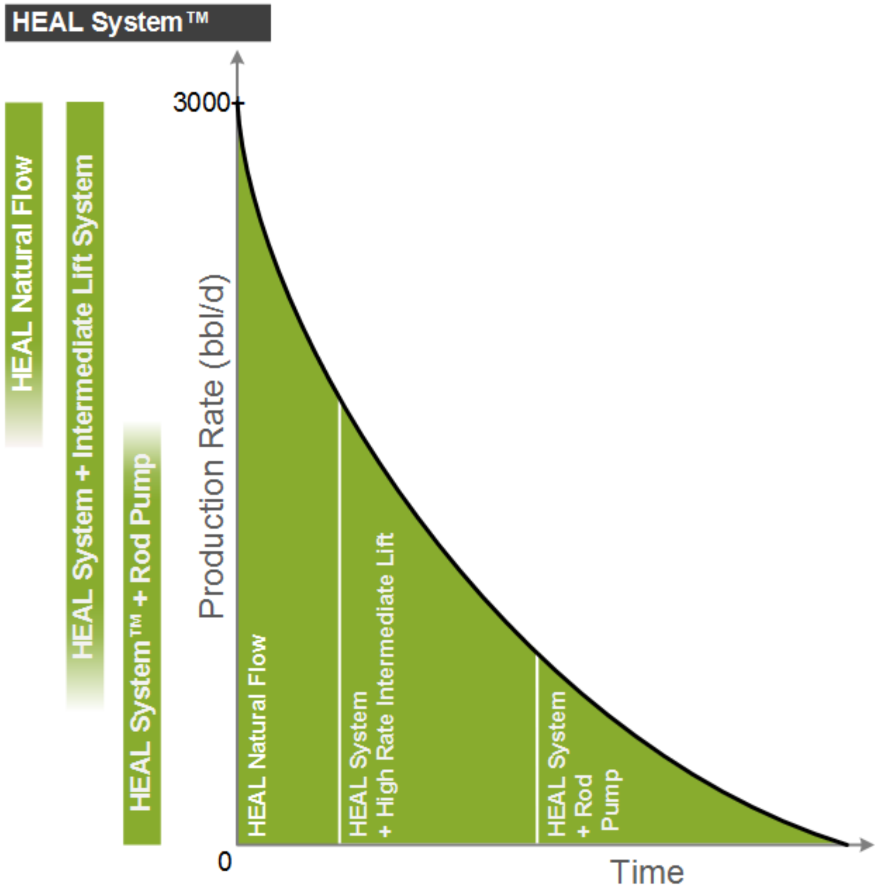
	Total Capex	Incremental Daily Production	Capital Efficiency $/boe/d
HEAL System Cost Only	$60,000	65	$923
HEAL Total Workover Cost	$120,000	65	$1,846
New Drill	$3,500,000 – $4,500,000	300-1100	$4000-15000

	Internal Rate of Return @ Various Netbacks			
	$10/boe	$15/boe	$20/boe	$25/boe
HEAL System Cost Only	328%	535%	737%	937%
HEAL Total Workover Cost	98%	218%	328%	433%
New Drill	20%-75%			

	Payout Period (Months) @ Various Netbacks			
	$10.00/boe	$15.00/boe	$20.00/boe	$25.00/boe
HEAL System Cost Only	3.25	2.25	1.5	1.25
HEAL Total Workover Cost	7	4.25	3	2.5
New Drill	24-48			

Production and Lift Strategy Defined by Slug Flow Mitigation





Thank You API

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