# A LIFE OF THE WELL ARTIFICIAL LIFT STRATEGY FOR UNCONVENTIONAL WELLS

**Jay Miller Sales Manager**
**Production Lift Companies Inc.**
**Artificial Lift & Production Congress**
**January 29, 2019**


# Unconventional Wells

# History

- The Permian Basin Was An Oil Basin
- Unconventional Wells Have Gas and Sand
  - Horizontal Completions Cause Slugging
  - High Flow Rates
  - High Bottom Hole Pressures
  - Not Easily Pumped
- Historical Artificial Lift Choices
  - Electric Submersible Pumps
  - Rod Pump
  - Gas Lift

# Outline

- Current AL Strategy.
- Where does artificial lift begin?
- Back Pressure.
- Gas?
- Completion Design.
- The Hot 90.
- What’s the best AL method for high rate wells?
- One Completion for the life of the well.
- Extend Well Life.

- Flowback.
- Put the well on an ESP.
- Remove the ESP and put the well on gas Lift.
- Remove the gas lift and put the well on Rod Pump.
- Expensive and shortens the life of the well.

# Current Artificial Lift Strategy

# Not an Artificial Lift Strategy

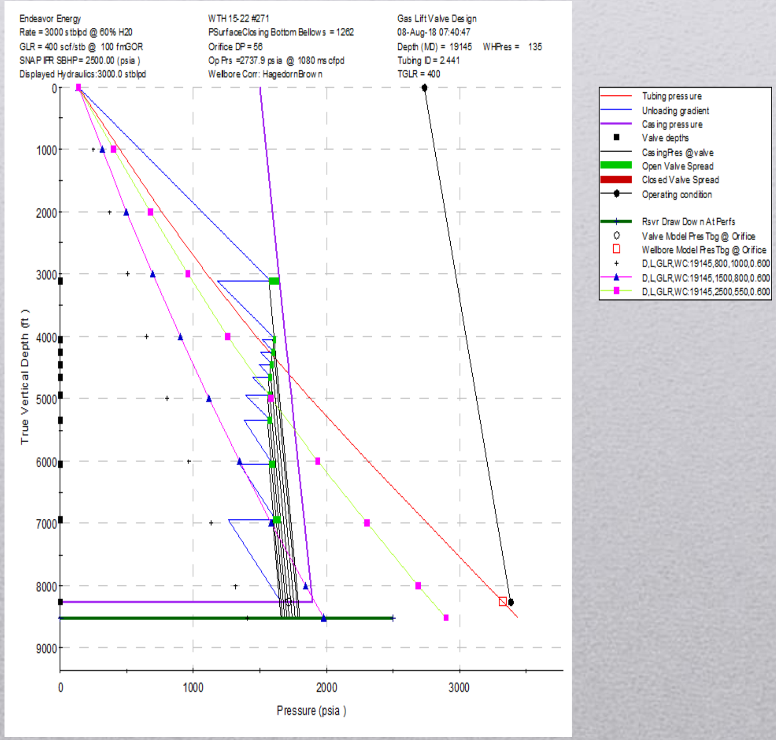
- Artificial Lift Starts at the wellhead.
- Not enough attention is paid to streamline surface facilities and flowlines.
- Not doing so can cost as much as 25% to 30% of available productivity.
- High Back Pressure wastes BHP and reduces the amount of total fluid recovered over the life of the well.

# Where Does Artificial Lift Begin?

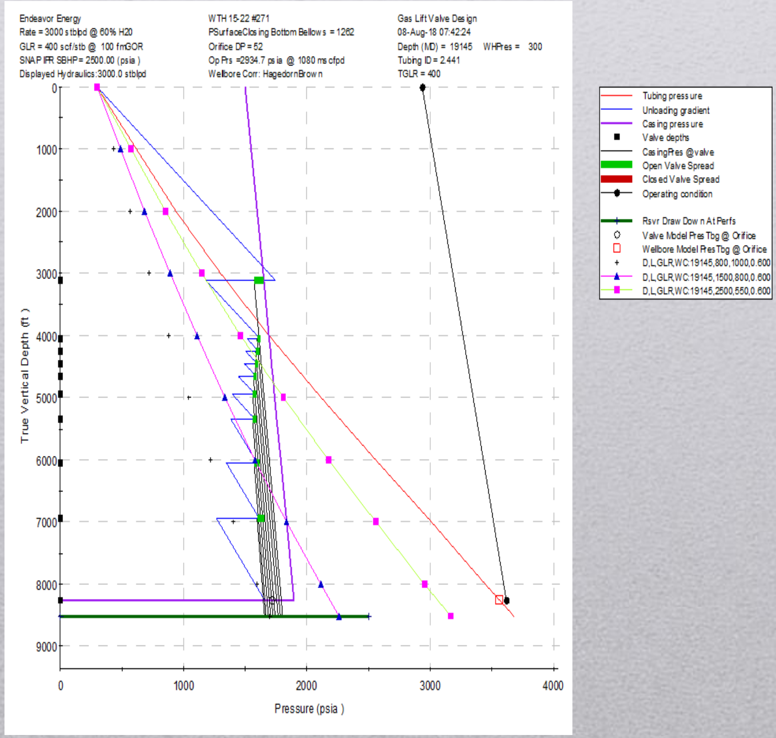
- High Back Pressure holds the well back.
- High Back Pressure wastes a well's stored energy.
- You don't have to have high back pressure.

# Back Pressure is Bad

## 135 PSI Back Pressure




## 300 PSI Back Pressure



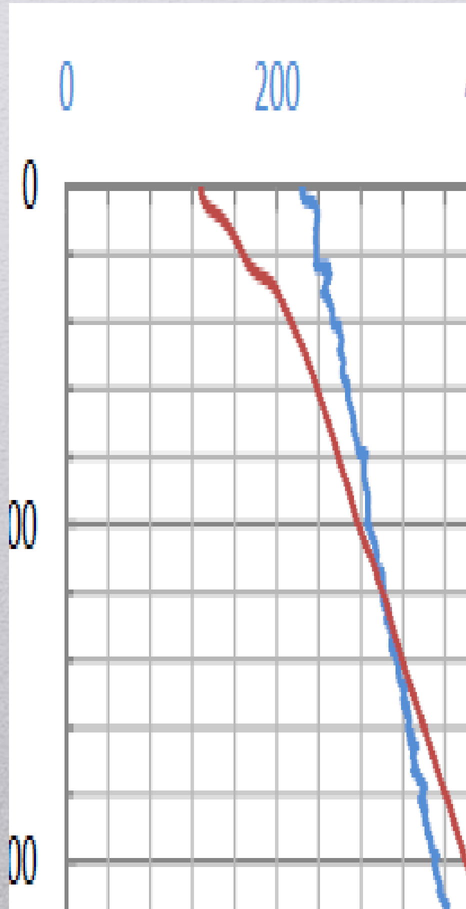

# Back Pressure Comparison

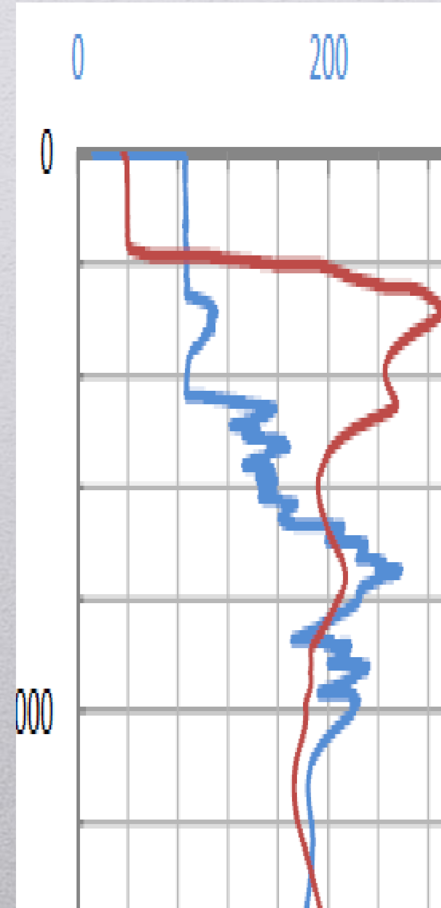
- Typical Casing design is a 5 ½' long string or 7" with a 4 ½" liner.
- Both have proven to be mechanically sound and are widely used in Unconventional wells.
- To enable the best available artificial lift strategy, production engineers need to be involved in the casing design.
- A few simple and inexpensive changes can greatly improve overall well performance and reliability.

# Completion Design in Unconventional wells

- Gas changes everything in Unconventional wells.
- One of the most overlooked changes is what gas does when the pressure lowers below 300 psi.
- Gas breaks out of fluid exponentially below 300PSI.
- Gas takes up space in the tubing raising the back pressure on the well.
- Increasing the tubing size will give the gas more room to expand.
- 7” casing for the 1st 1000’ allows you to run 3.5” or 4.5” tubing.

# Optimized Casing/Tubing Design




# Exponential Gas Breakout Below 300 PSI

- Plan For Exponential Gas Breakout < 300 PSI.
- Change Casing Plan to accommodate Larger Tubing
- Streamline Surface Facilities
- Back Pressure Hurts Production

# Completion Strategy

- Operators are trying to get the most fluid out of these wells in the first 90 days.
- The go to method has been ESPs.
- ESPs while delivering very high production rates are not designed for the gas and sand they will produce in unconventional wells.
- Jet Pumps can produce the high rates and sand, but not the gas.
- Gas Lift can produce high amounts of sand and gas.

# High Rate Production The Hot 90.

- ESPs produce high rates, but gas and sand ruins them.
- ESPs in 5 1/2” casing heat up and burn up.
- Jet Pumps can handle the sand, but gas cause cavitation and wear to the throat of the pump.
- Gas Lift is ideal and high rate designs can compete with ESPs an Jet Pumps.

# What is the best Artificial Lift Method for the first 90 days?

# NEW ARTIFICIAL LIFT STRATEGY STARTS AT THE WELLHEAD!

- Flow-back.
- High Rate Gas Lift.
  - Conventional Gas Lift Equipment.
    - Standard Gas Lift Equipment.
    - Plunger Assisted Gas Lift.
    - Multi-Stage Plunger Lift.
    - Gas Lift Assisted Gas Lift.
  - Annular with Side Pocket Mandrels.
    - Conventional Gas Lift With Side Pocket Mandrels.
    - Gas Lift Assist Gas Lift with Side Pocket Mandrels.
    - Plunger Lift With Side Pocket Mandrels.

- Annular Lift
  - Very High Rates Up to 10,000 BPD.
  - Dangerous to casing.
  - Requires special equipment to transition to other lift methods.
- Conventional High Rate
  - Up to 4000 BPD 2/7/8” x 5 ½.”
  - Casing is protected.
  - Easy transition to other artificial lift methods.

# High Rate Gas Lift

# Annular Flow Gas Lift

## Conventional Annular

- Uses an internally mounted GLV.
- No slickline or wireline access.
- Tubing must be pulled to change to conventional flow Gas Lift.

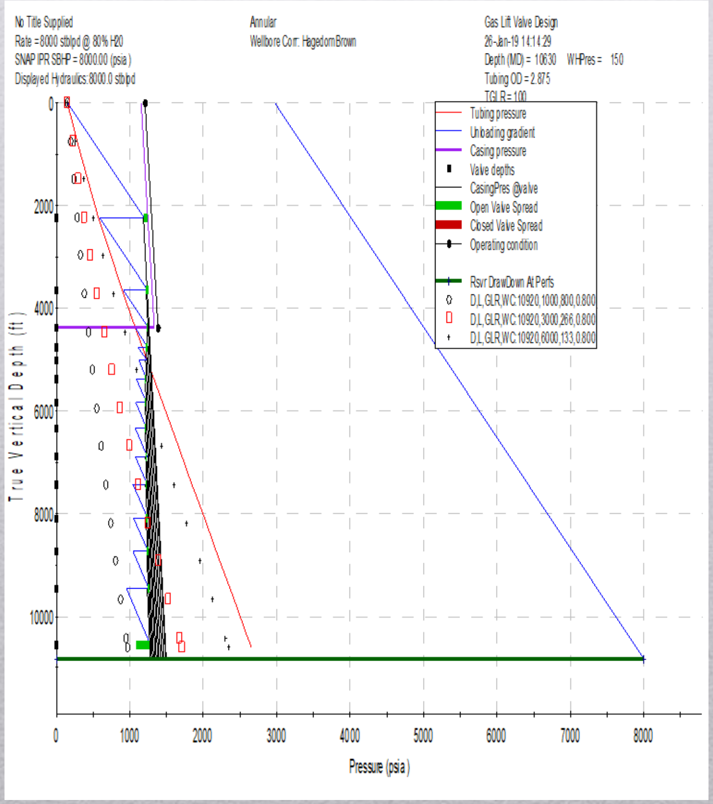
## Side Pocket Mandrels

- Can be changed to conventional flow gas lift with slickline.
- Allows slickline and wireline access.
- Requires a special plunger for GAPL.

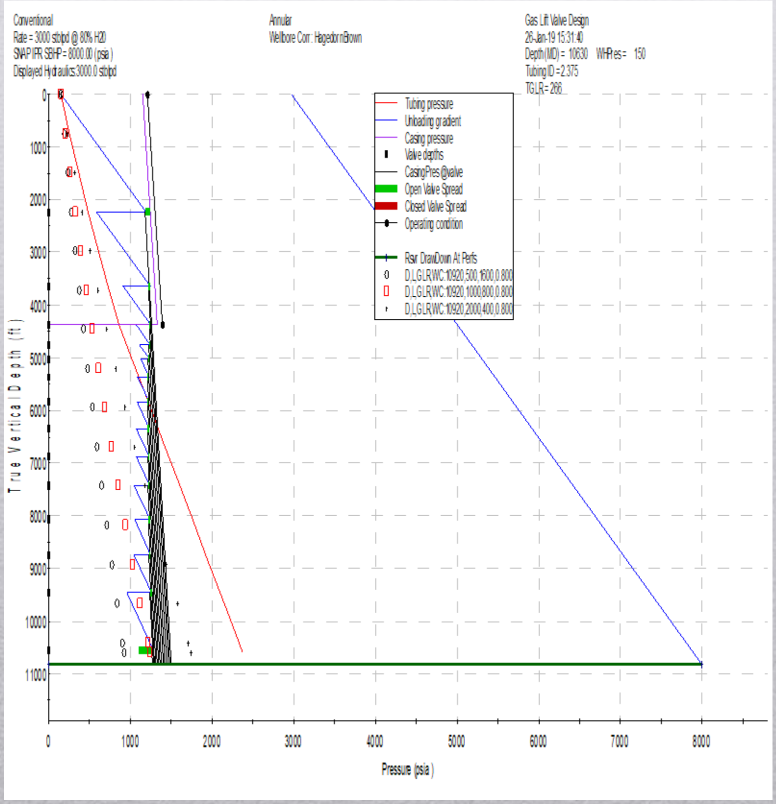
- **Annular Flow Gas Lift can weaken the casing to the point that casing failure can occur.**
- **Completion teams must work with production teams to run blast joints across from the gas lift mandrels to protect the casing.**

# Annular Flow Gas Lift

## Annular Flow Gas Lift




## Conventional Flow Gas Lift




# No need to pull the tubing

# Total Well Approach

- Install one completion that will last for the life of the well.
- Flow-back to High Rate Gas Lift.
- Mid rate gas lift.
- High rate PAGL 500 BPD.
- Plunger Lift.
- Low Rate GAPL 200 BPD.
- Staged Plunger Lift.

# GAS LIFT

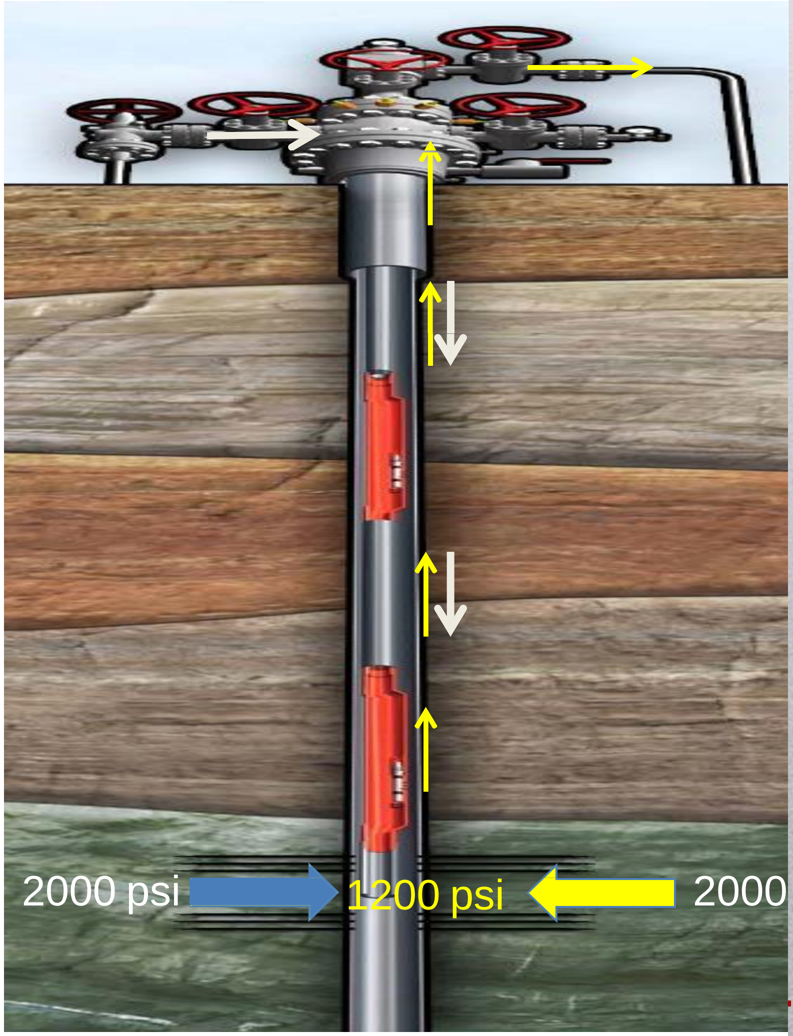
- High Liquid Production Rates
- High Bottom Hole Pressure
- Good Option Above 500 BPD
- Below 500 BPD-Less Efficient
- Below 200 BPD-Inefficient
- Transition To PAGL

# GAS LIFT

A method that artificially reduces wellbore pressure so that the formation can produce desired fluids.

This is accomplished by injecting high pressure gas from the casing into the tubing at the deepest point possible.

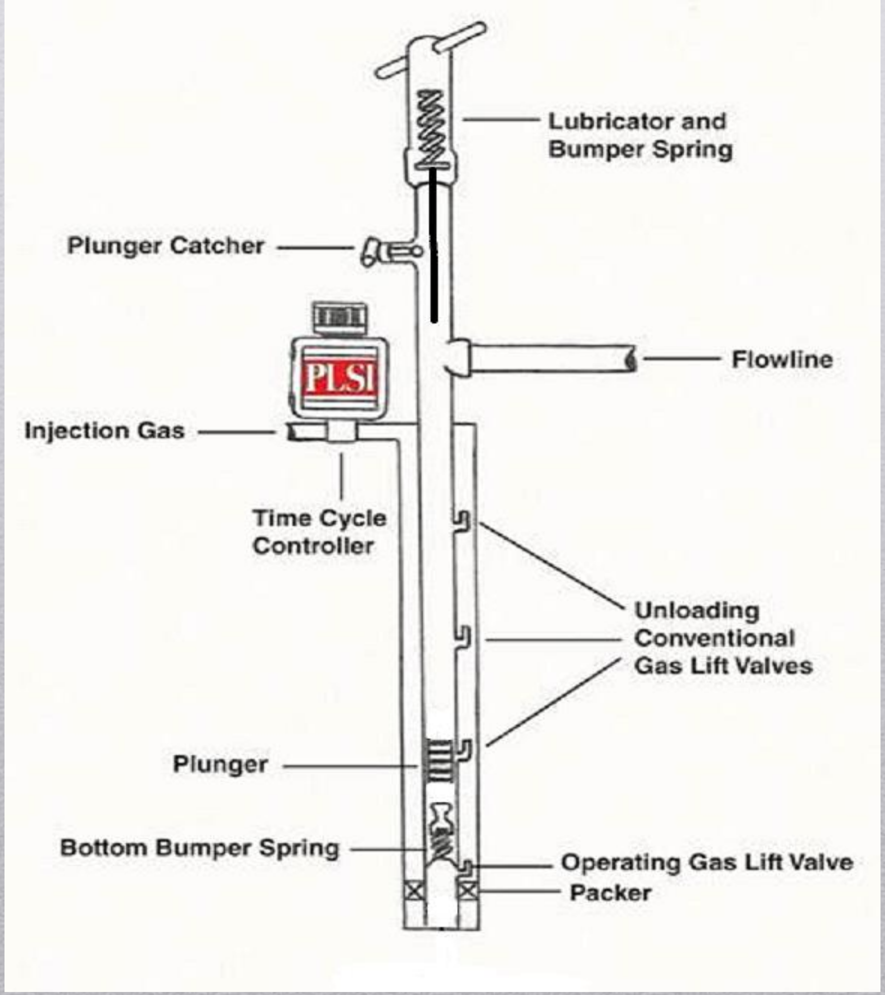
This in turn lightens the fluid column in the tubing above the formation, reducing the pressure in the wellbore, and causing fluid flow.



# PLUNGER-ASSISTED GAS LIFT

- Hybrid System-Plunger Assists Gas Lift.
- Continuous Gas Lift-Free Cycle Plunger.
- Reduces Over Injection/Liquid Slippage.
- Bypass Plungers-Valved & Two Piece.
- Begin to Reduce Gas Injection Rate.
- May Eliminate Injection Gas.

# PLUNGER-ASSISTED GAS LIFT



# BYPASS PLUNGERS

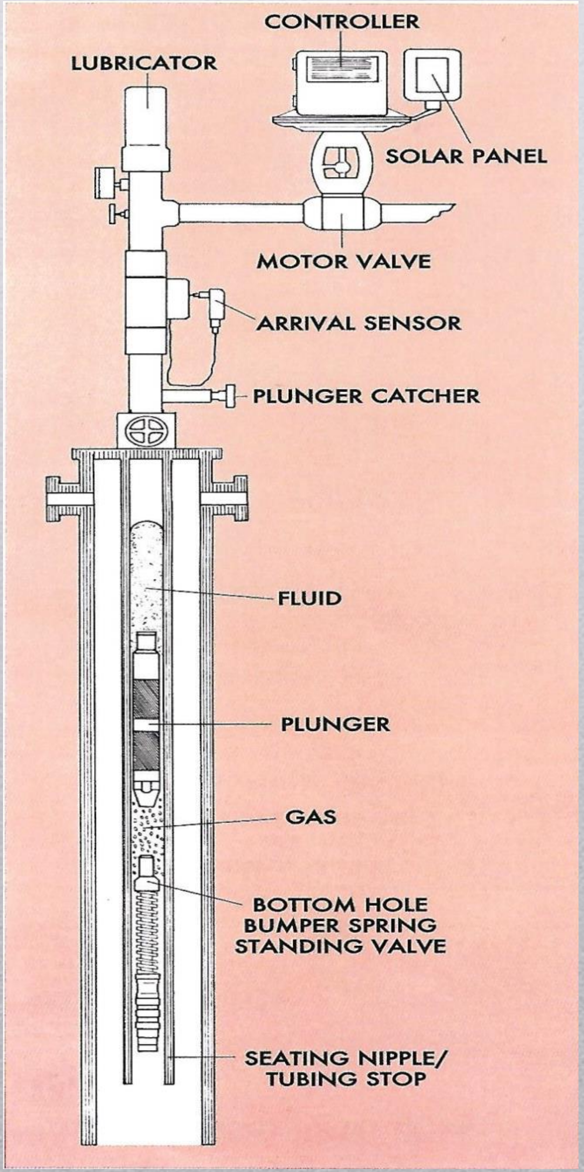
In a **“Free Cycling”** well the plunger falls to bottom against the flowrate without shutting in the well. An internal bypass in the plunger allows gas and fluids to flow through. The plunger can have an internal valve or be two pieces. The plunger engages a shift rod at the surface to either shift the valve open or separate the ball and sleeve. The valve closes when it hits the spring assembly on bottom. The sleeve reconnects with the ball on bottom to reseal.

# PLUNGER LIFT

- Well Is Produced With No Outside Energy Source.
- Plungers Transition From Bypass To Conventional.
- As Rates Decline Plunger Seal Becomes Critical.
- The Most Economical Form or Artificial Lift.
- If Plunger Will No Longer Surface-Stage Lift.

# PLUNGER LIFT

The plunger travels the entire length on each cycle, pushing produced fluid to surface.  Gas and pressure from the well is the power source. Gas under the plunger expands to force both plunger and fluid to surface.

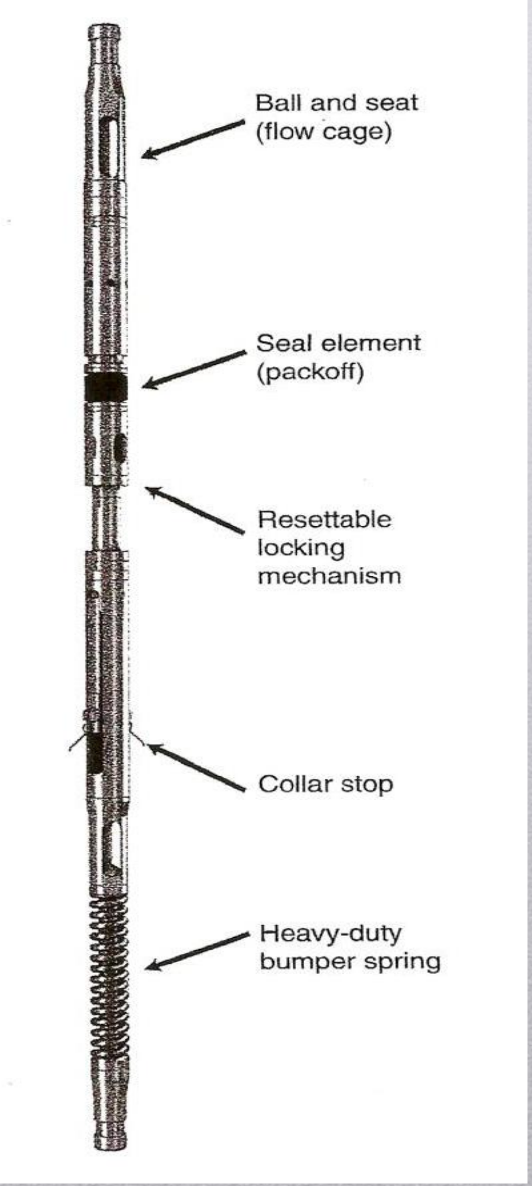


# MULTI-STAGE PLUNGER LIFT

- Stages the lift process in the tubing string
- Uses the energy source under each plunger
- Lifts smaller liquid loads more frequently
- Requires an additional plunger and stage
- Transfers liquid to surface in stages

# MULTI-STAGE PLUNGER LIFT

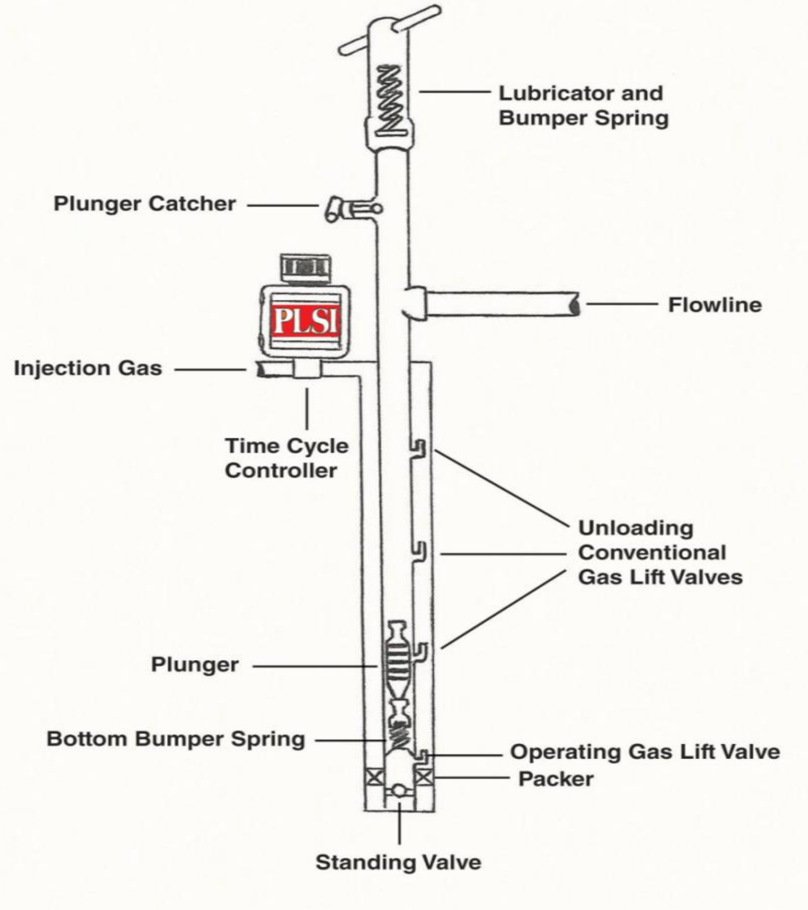
Staging tool is set up hole roughly 20-70% of the way down, but above the standing fluid level. Staging tool incorporates a pack-off and standing valve. Plungers run in the upper and lower portions. The lower plunger carries fluid up hole to the staging tool. The upper plunger carries fluid from the tool to surface. Pressure and gas requirements are cut in half.



# GAS-ASSISTED PLUNGER LIFT

- Hybrid Intermittent Gas Lift-Plunger Lift Operation.
- Takes Advantage of Existing Gas Lift Infrastructure.
- Inject Minimum Amount of Gas to Surface Plunger.
- Lower BHP Will Require a Standing Valve.
- Essentially a Low Cost Pump.

# GAS-ASSISTED PLUNGER LIFT




PLUNGER IN AN INTERMITTENT GAS LIFT INSTALLATION

# SUMMARY

- Determine Long Term Production Strategy.
- Several Overall Long Term Cost Savings.
- No Need to Pull Well Between Phases.
- No Need to Kill Well For Servicing.
- Will Not Need to Electrify The Field.
- Chemical Treatment Down Casing.
- Additional Training Needed.