

# **Guidelines & Recommended Practices**

## **Use of Plunger Lift for Deliquifying Gas Wells**

### **Introduction**

This paper discusses the considerations, applications, costs and best practices for use of Plunger Lift systems, particularly Tubing Plungers.

Plunger Lift is a method of artificial lift that uses the well's own energy, either pressure or gas rate, to effectively lift fluids to the surface. The plunger creates a seal to the tubing wall to reduce the amount of gas/liquid slippage and lift the fluid to surface as completely as possible.

An optimized plunger lift well is achieved when the well is operating at the maximum number of cycles possible with the energy available and at the lowest average flowing bottom hole pressure.

### **Plunger Lift is a Very Economical Artificial Lift Method:**

- Low initial investment (CAPEX)
- Low operating, repair and maintenance cost (OPEX and R&M)
- Rig not required for installation
- Cost of system is unaffected by well depth

### **Applications for Plunger Lift:**

- Primarily used for dewatering gas wells
- Superior artificial lift method for gassy wells
- Keeps tubing cleaned of paraffin deposits
- Keeps tubing free of salt/scale

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# Practical Considerations for Tubing Plungers

## I. Well Depth and Type

### A. Depth

1. There are no practical depth limits for tubing plungers. The primary issues associated with depth include fall and rise times. Deepest known tubing plunger lift well is approximately 26,000 ft. Success is more dependent upon other factors, such as differential pressure (downhole/surface), fluid rate and gas rate.

### B. Horizontal

1. Consideration needs to be given to the distance between the EOT and where the bumper spring is landed. When plunger lift downhole components are set at deviation greater than 60 – 65°, the ability to retrieve or set is limited by wireline capabilities.
2. The effectiveness of a standing valve in a horizontal well may also be questionable. For landing a standing valve at high deviation, a specialized standing valve may be required.
3. When the dogleg severity exceeds 3° per 100 ft of depth, the length and type of the plunger needs to be considered. The more severe the dogleg, the shorter the plunger.

### C. S-shaped

1. Historical data has shown that plungers can be run as long as the deviation is not greater than 20 - 35°. While tubing plungers have been used successfully in wells with even higher deviations, the issue is plunger fall.
2. Success is also dependent upon plunger style.

### D. Packer/Slim Hole Completions

1. If a packer is present, the system requires a higher GLR to cycle a plunger to surface. Typically, the GLR needs to double for a conventional system operation.
2. Continuous flow plungers are applicable if the necessary gas velocity is available.

3. In the case that sufficient velocities are unable to support continuous or conventional plungers a “staged” plunger system may be more applicable.

## **II. Tubing/Wellhead Size**

### **A. Tubing Size**

1. Tubing plungers may range in size from 1.25" – 4.5" OD. An OD of 5.5" is possible. Mass and control (stopping) at the surface are issues with larger OD plungers. Smaller OD plungers are commonly used in coiled tubing.
2. Tapered tubing: If a well has tapered tubing, it may be necessary to use two plunger stages, with different sized plungers operating in each section of tubing. If possible, it is recommended that the tubing string be replaced with a consistent string size to maximize efficiency.

### **B. Wellhead Size**

1. The wellhead ID should be compatible with the tubing ID so the plunger can be installed and retrieved.
2. Wellhead components that are not necessary should be removed to eliminate gaps and inconsistent IDs, and to minimize the height of the plunger tree/lubricator.
3. If the wellhead ID does not match the tubing size, a wellhead sleeving operation is recommended to ensure the plunger arrives to the lubricator regularly.
4. Threaded connections are commonly used. However, flanged connections may offer improved strength.

## **III. Tubing Integrity**

- A. For ideal tubing plunger performance, the tubing should be free of leaks and internal tubing weld beads (coil tubing). There should be no obstructions and no significant amount of tubing wear.
- B. The tubing ID to plunger OD ratio should be no less than 90% and will be much more efficient when as close to 95% as possible. This ratio must be carefully controlled to ensure the plunger can fall easily, and can also lift the liquid slug to surface with minimal fallback.

- C. If tubing integrity issues are suspected, consider conducting further tests (fluid levels, pressure tests, slick line evaluations, etc.) and taking the necessary corrective action (broach or replace tubing).

#### **IV. Pressures**

- A. Producing surface pressure (line/tubing). Generally, flowing surface pressures of less than 1000 psi are preferred. The lower the better. Along with lower pressure comes high gas velocity and potential for higher plunger impacts at surface. Optimization is very important.
- B. Shut-in wellhead pressure. Match the pressure rating of the lubricator and associated equipment to the pressure rating of the wellhead.

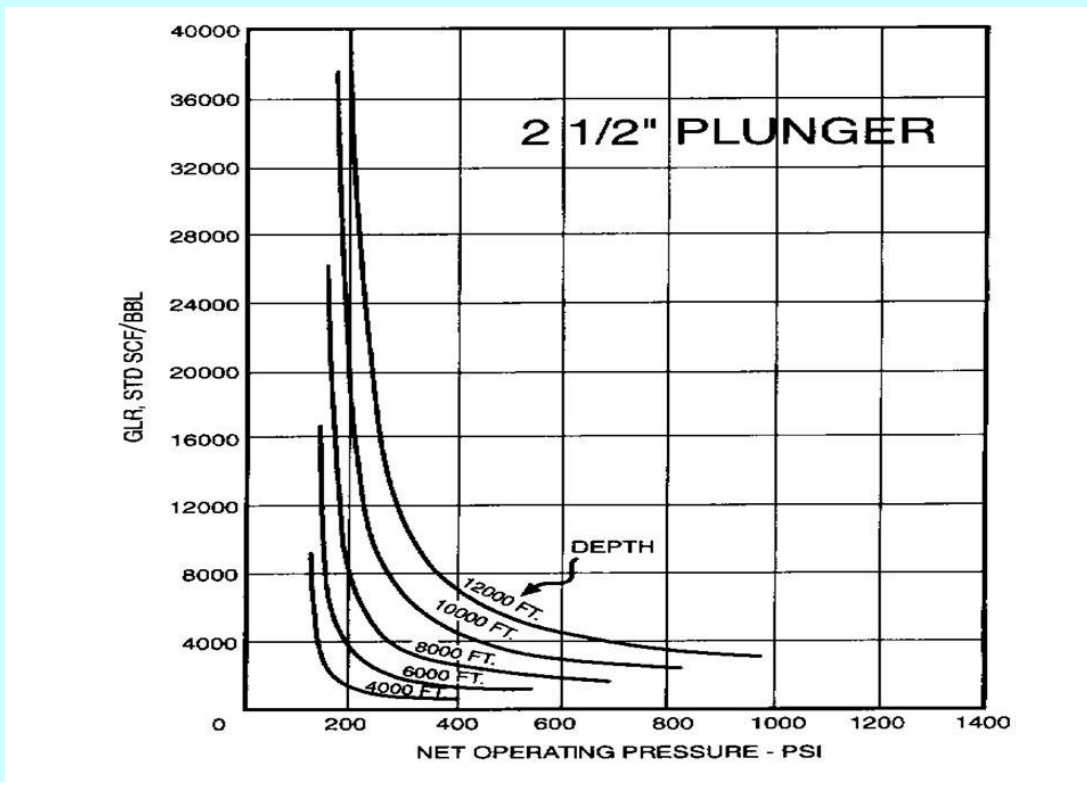
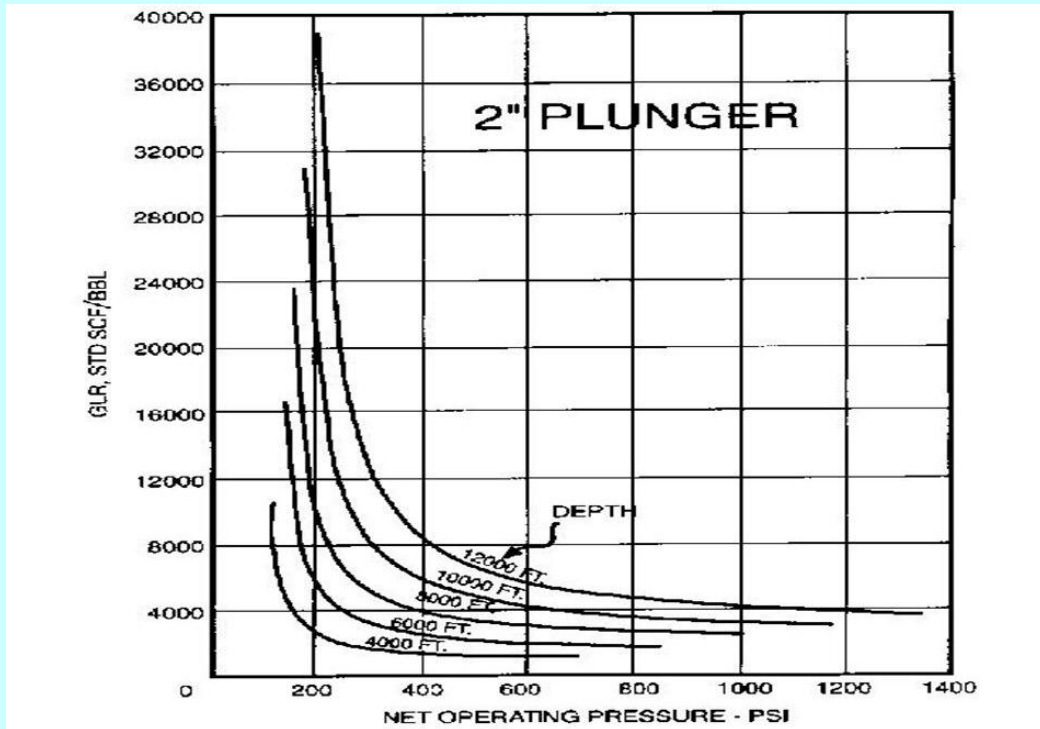
*NOTE: These recommendations are for packerless wells.*

#### **V. Temperature**

- A. Environmental temperature at the surface dictates proper equipment material specification, specifically when choosing a lubricator.
- B. Downhole equipment material selections should be based on reservoir characteristics.

#### **VI. Gas/Liquid Rate**

- A. Utilizing surface critical rate alone may not result in maximized productivity. Downhole critical rate must also be considered.
- B. Change (reduction) in produced liquids is a key indicator of liquid loading.
- C. Maximum liquid rate in barrels per day depends on tubing size, e.g. (based on approximately 5000 ft, 100 psi surface pressure, 1000 psi build-up in fall time, casing size 1 size above tubing collar OD, and the well producing below critical rate)
  - 1. 1.500" – 35 B/D
  - 2. 2.0625" – 50 B/D
  - 3. 2.375" – 110 B/D
  - 4. 2.875" – 165 B/D
  - 5. 3.500" – 200 B/D
- D. Use a GLR vs. depth table



Figures 1 and 2 – GLR Requirements by Plunger OD

## **VII. Sand, Corrosion, Erosion, H<sub>2</sub>S, CO<sub>2</sub>, etc.**

- A. Proper selection of plunger types and materials, and surface equipment can improve effectiveness.
  - 1. Sand and coal fines (can deal with small amounts)
    - a) Use a bar stock or a brush plunger (expect accelerated wear).
    - b) Consider using a sand screen.
    - c) Some spiral plungers have proven effective.
    - d) Padded plungers should be avoided.
    - e) Standing valves should be avoided due to plugging issues.
    - f) Dual outlet lubricators may help with preventing plunger sticking issues.
  - 2. H<sub>2</sub>S and CO<sub>2</sub>
    - a) Compatible metallurgy is required. A metallurgy study may be necessary.
    - b) For standard operations with less than 1% corrosive gas, the industry standard is 4130 or 4140 materials as conditions warrant.

## **VIII. Paraffin**

- A. Use bar stock plungers.
- B. Padded plungers may be used depending upon cycle frequency.

## **IX. Chemical treatments for foaming, corrosion, scale, paraffin, hydrates, salt, etc. can be used in conjunction with plungers**

- A. Chemical can be injected down the back side for packer-less completion.
- B. Injection down the tubing can prevent proper plunger lift operations and possibly reduce the effectiveness of the chemical itself.
- C. Introduction of chemical can have an effect on the performance of the plunger fall and rise speeds.

## **X. Power Requirements**

- A. Power is only required for wellhead measurement, control, and communication system.
  - 1. Normally this is provided by d-cell batteries or a solar power system.
  - 2. Lack of daylight and weather conditions will increase the power requirements.
  - 3. Cycle frequency can tax the electrical system requirements



## Equipment Requirements

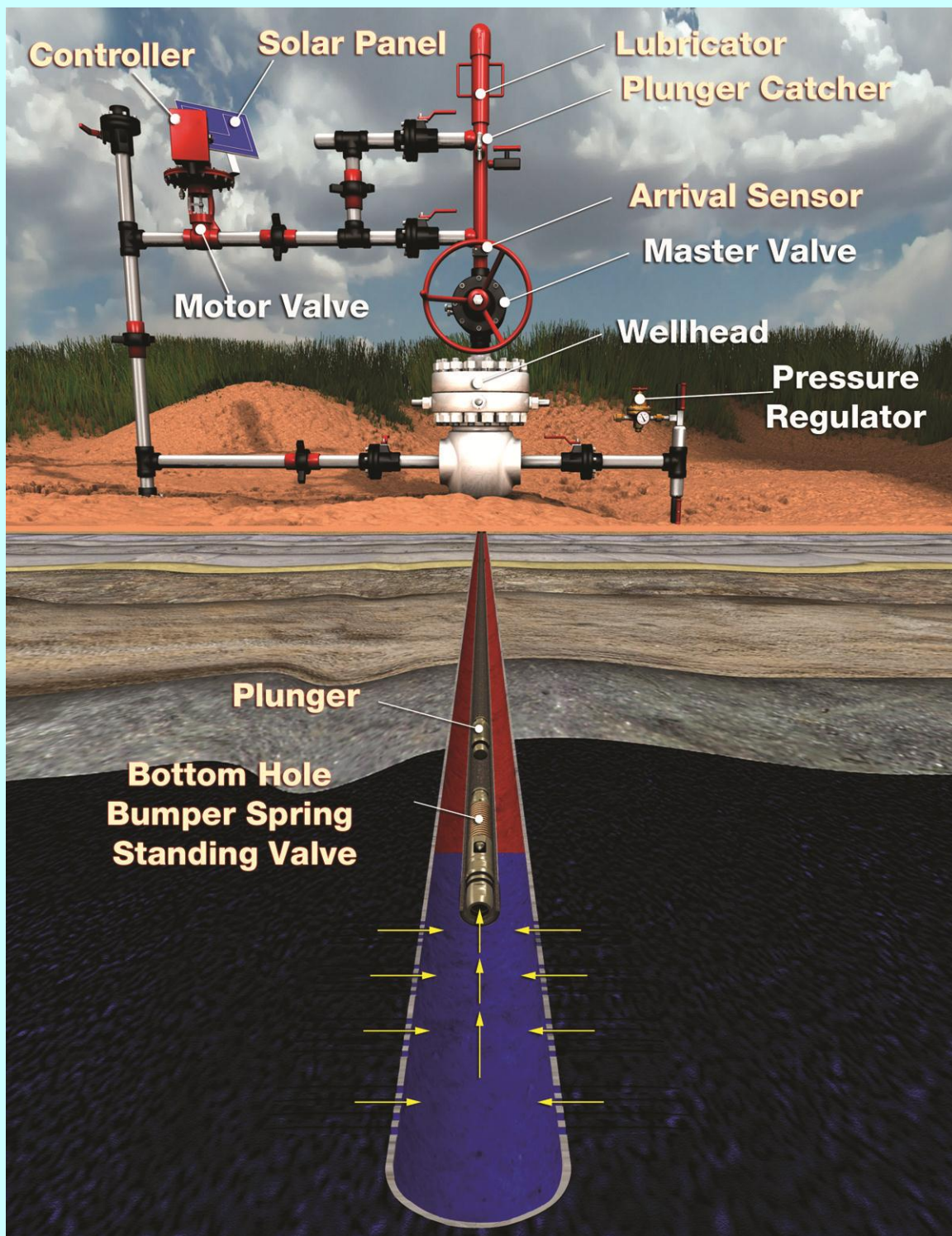


Figure 3 – Basic Plunger Components

## **I. Surface Equipment/Wellhead**

### **A. Lubricator**

1. Normally matched to the existing wellhead equipment pressure specification.
2. Pressure rating, material, and connection type should be met according to specific end user requirements.
3. Flowing through the well head tee and wing valve is not recommended. Replace the well head tee and wing valve with lubricator assembly if possible.
4. Plunger catcher
  - a) Component of the lubricator that catches and holds the plunger upon arrival.
  - b) The standard catcher is a manual type.
  - c) An “auto” type catch can also be used. Benefits of an auto-catch are:
    - (1) Increased production due to plunger not allowed to prematurely fall.
    - (2) Reduced back pressure due to the plunger being held out of the flow path.
    - (3) Reduced wear and possible equipment breakage due to dry trips (both downhole and lubricator).
    - (4) Aids in optimization of system.
    - (5) Stops plunger rattling in the lubricator reducing chance of premature wear inside the lubricator.
    - (6) Holds continuous or fast fall style plungers until the well is ready to cycle.
5. Dual Outlets
  - a) Dual outlets are recommended to prevent freezing, increasing plunger life, increases production by reducing back pressure on the tubing.
  - b) Both outlets should be full open. If the plunger fails to consistently trip the sensor, the bottom outlet should

be controlled so you can close it during the open time. Once the plunger arrives, the bottom outlet should be returned to full open.

#### 6. Lubricator Spring

- a) Resides in the top of the lubricator. Cushions the plunger on arrival and protects equipment from breakage due to fast or dry runs.
- b) Should always be used.
- c) Should be selected based on environmental conditions.
- d) Design should allow for liquids drainage from cap.

#### 7. Arrival Sensor

- a) Use of a plunger sensor is highly recommended. Optimization is limited without knowing when the plunger arrives.
- b) Adds a level of safety by allowing the controls to react to extreme plunger arrival times.

#### B. Motor Valve

- 1. Full port opening is recommended.

#### C. Well Head Chokes

- 1. Should be removed if possible or carefully selected for maximum flow.

### II. Other Surface Equipment/Facilities

#### A. Separation/Measurement

- 1. Reviewed and sized for instantaneous gas and fluid production that is associated with intermittent lift

#### A. Compression

1. Single well compression and plunger lift can be used together if properly sized and configured for intermittent gas and fluid flow.
  - a) Crucial components for optimization are dumps, valves and controllers, suction control valves, recirculating valves, speed controllers

## **II. Down Hole Equipment**

### **A. Bottom Hole Assemblies**

1. Most consist of a seating nipple or tubing stop near the end of the tubing (to keep the plunger and spring in the tubing), and a spring (to absorb the shock of the plunger when falling). It is also fairly common to include a standing valve (to capture produced liquids) in the BHA.
2. Standing valves should be considered on all wells
  - a) When the end of tubing is above the perforations.
  - b) When the GLR is high enough that fluids will fall out of the end of tubing.
3. Standing valves with pressure relief will reduce the risk of wireline intervention or swabbing. It is not recommended to notch a standing valve.
4. There are options where a seating nipple is not available but the preferred hold down/stop will be set in a seating nipple.
5. Bumper springs attached to a hold down is preferred. Other options are however available.

### **B. Tubing**

1. A single continuous string of tubing with a single nipple located near or at the end of tubing.
2. Nipples/profiles/SSSV/side pocket gas lift mandrels add complexity.

### **C. Plungers**

## 1. Conventional plungers

- a) Conventional plungers are used in wells that require additional energy build-up in order to lift accumulated liquid and plunger. This build-up occurs while the well is shut in at the surface.
- b) Available in a variety of types and should be discussed with vendors for specific applications.
  - (1) Padded – Expand/contract to tubing ID
  - (2) Solid/Bar Stock - Constant OD
  - (3) Brush – Flexible fiber material
  - (4) Typically a minimum of 10 ft/s is required.

## 2. Continuous flow /bypass plungers.

- a) Continuous flow/bypass plungers are typically applied at or near critical velocity and require little to no shut-in, these type plungers open to allow gas passage on the downward travel.
- b) Continuous flow/bypass plunger typically operate at gas velocities greater than 9 ft/s (calculated at the bottom of the tubing) this can be tool specific and should be discussed with vendors.
- c) Also come in a variety of types
  - (1) Ball and sleeve
  - (2) One-piece designs
  - (3) Typically a minimum of 10 ft/s is required

### Decline vs. Plunger Type

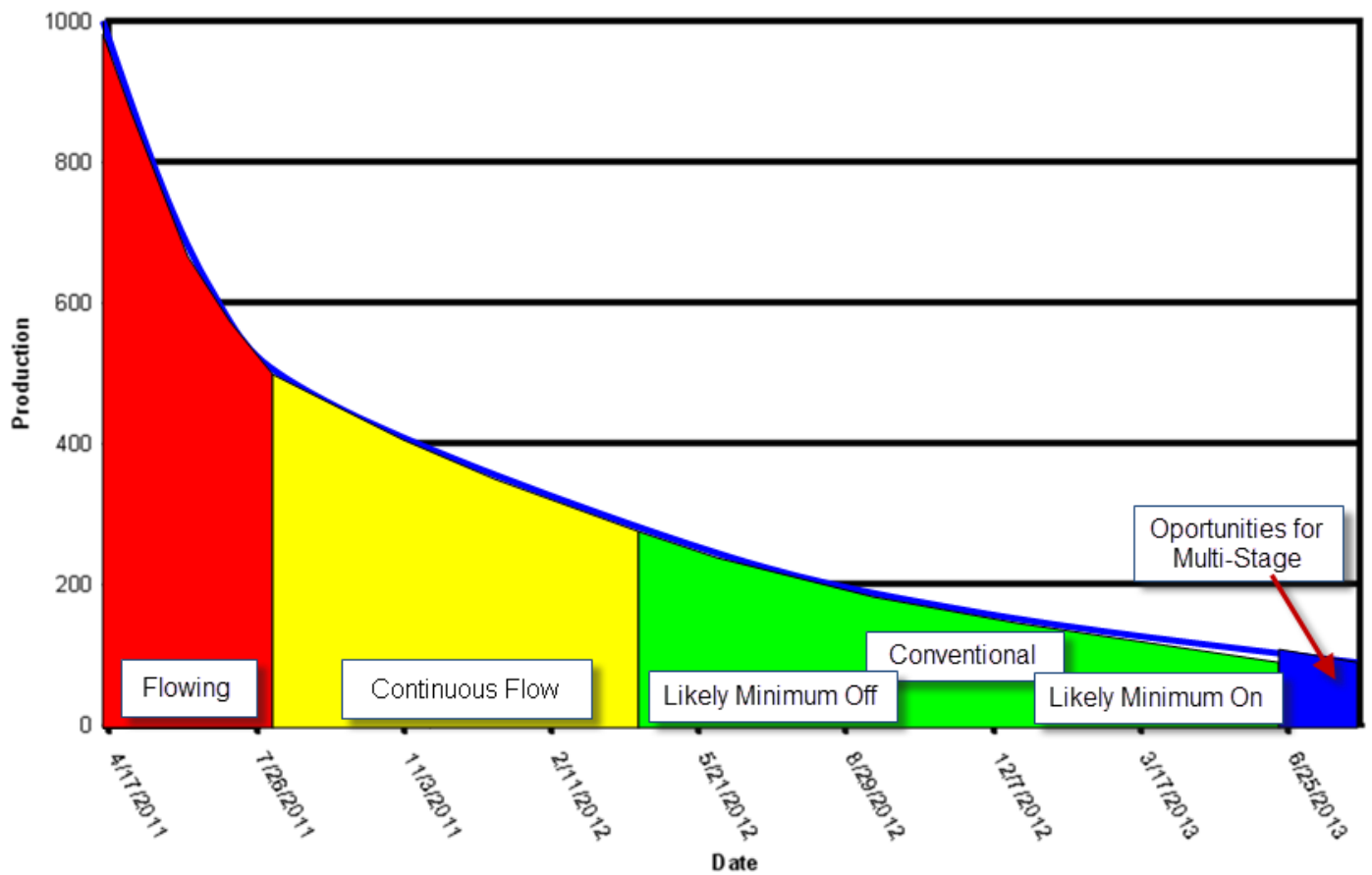


Figure 4 – Sample Decline vs. Plunger Type Graph  
(Dependent upon velocity available through the tubing string)



## Cost Guidelines for Tubing Plungers

### I. CAPEX (Capital Expense)

- A. Typical CAPEX expectations should be in the range of \$15-25K for initial installation depending on metallurgy, automation requirements, and surface hardware requirements. There will be some required surface modifications, slickline work and possibly some automation system changes that have associated costs.
- B. The following cost items should be considered in determining the true cost for a plunger installation. These costs should be considered when preparing a justification for the project. **The following are possible considerations; not all elements may be required:**
  - 1. Rig costs if required can be the largest cost component.
    - a) Tubing replacement (if needed)
    - b) Seating nipple (if required)
    - c) Packer removal or communication to annulus
  - 2. Control system + power source:
    - a) Arrival sensor + timer
    - b) Pressure measurement
    - c) Programmable plunger controller
    - d) SCADA (supervisory control and data acquisition) system
    - e) Radio
    - f) Antenna
  - 3. Wireline for installation
  - 4. Labor for wellhead reconfiguration and facility modifications
  - 5. Swabbing to kick off well (if necessary)
  - 6. Production deferment (typical one-day installation)
  - 7. Initial vendor surveillance/technical support
  - 8. Safety consideration
  - 9. Surface equipment
  - 10. Downhole equipment

11. Facility modifications
12. Flow rate measurements (gas, liquid)

## II. OPEX (Operating Expense) and R&M (Repair & Maintenance)

- A. These costs will normally average less than \$2K per year.
  1. Typically plungers will need to be replaced 2-3 times per year.
  2. The control valve internal components need replacement once every 2 or 3 years depending on the solid production.
  3. The lubricator and bottom hole assembly also require some maintenance.
- B. The following OPEX and R&M costs should be considered with planning and justifying a plunger installation. **The following are possible considerations; not all elements may be required:**
  1. Training
  2. Lineout
  3. Downhole equipment replacement
  4. Downhole maintenance
  5. Surface equipment replacement
  6. Surface equipment maintenance
  7. SCADA/Surveillance – in-house or vendor
  8. Troubleshooting
  9. Operational wire line work
  10. Swabbing (rare)
  11. Downhole wire line repairs
  12. Possible rig costs (rare)



## **Life Expectancy Guidelines for Tubing Plungers**

### **I. Normal Operating Life**

- A. If a tubing plunger is operated properly, the following service lives may be expected:
  - 1. Plunger: six months to a year (brush plungers tend to be shorter lived)
  - 2. Downhole equipment: one to five years.
  - 3. Surface equipment: three to five years.
- B. As mentioned previously, plunger change outs will be required and surface maintenance is advised. Beyond that, the plunger system will continue to operate until the well depletes below an economical point or, in the case of a water drive, until the GLR has changed enough that the well is no longer a plunger lift candidate.
- C. The plunger's life itself is normally relative to mileage travelled and conditions that the plungers operate in. A plunger that rarely travels will typically last longer than one that cycles frequently.
- D. The plunger's position in the wellhead during afterflow may also have an effect. The plunger "bobbles" in the lubricator, which may also cause wear.

### **II. Early System Failure**

- A. Typically there is less than 1% due to failure of the plunger system itself if there is close vendor surveillance after the installation.
- B. There may be up to 5% failures due to incorrect or changing information on well conditions.
- C. Failure rate may be higher if the installation is performed by untrained staff.
- D. With good automation, infant mortality is rare as the system will catch arrivals outside of the equipment specifications. It is still wise to watch the first arrivals to ensure that the automation equipment is working correctly.

## Recommended Practices for Installation, Operation and Maintenance of Tubing Plunger Systems

### I. Plunger Lift Installation Procedure

#### A. Slick Line Installation

1. Rig up slick line unit
2. Run in hole (RIH) w/ 1.5" blind box or gauge ring and tag fill at (PBTD) and ensure that perforations (Top Perforations – Bottom Perforation) are clear.
3. RIH w/ drift gauge ring to top of nipple at (nipple depth or suggested lifting depth).
4. RIH w/ broach to (nipple depth or suggested lifting depth)
5. RIH w/ running tool (Bottom Hole and Bumper spring) and set at (suggested lifting depth).
6. Drop and chase plunger. DO NOT PUSH.
7. Occasionally tag to find out how much time plunger takes to get to bottom. Only drop if fluid is noted.
8. Rig down slick line unit

## **II. Operating Best Practices**

- A. Train operators in liquid loading principles and plunger lift operation.
  - 1. Basic understanding of gas well liquid loading
  - 2. Firm understanding of plunger lift.
  - 3. Firm understanding of controller operation.
  - 4. Train and abide by safe operating principles.
  - 5. Ensure knowledge of common terminology (see glossary).
- B. Develop and implement a consistent optimization strategy.
- C. Communicate strategy with clearly defined division of responsibility.
- D. It is recommended that an operator should be on location for a plunger arrival as frequent as possible, at a minimum every 6 months. The frequency should be increased for wells with stand alone control and no remote measurement or surveillance.
- E. A periodic use of high resolution equipment such as acoustic measurement can be useful.

## **III. Maintenance Best Practices**

- A. As a minimum, plungers should be replaced every 6 months. While there are rare exceptions where plungers last longer, the potential costs related to extending the plunger longevity will not outweigh the minimum investment of replacing the plunger. Ideally, each plunger should be inspected on a frequency related to its distance travelled, wear pattern, erosion and corrosion. A good starting point would be to inspect based on vendor recommended mileage.
- B. The lubricator requires thorough inspection at the time of plunger replacement. Vendors will provide guidelines. At a minimum, the lubricator spring and catch assembly (auto or manual) should be functional. O-rings should be inspected and replaced as needed.
- C. Test plunger catcher function.
- D. Control valve leak test should be performed; fuel gas supply should be checked, and full travel on the control valve (open and

shut) should be tested. Ensure that fuel gas is suitable for operation of valve (non-sour).

- E. Wiring to transducers and arrival sensor should be inspected. Verify measurement is accurate.
- F. Drain all supply drip-pots.
- G. Confirm orifice plate size and ensure that it is properly sized.
- H. Check dump valve function.
- I. Bottom hole bumper springs needs to be inspected at minimum every 2 years. Exceptions should be made for high risk applications and the frequency of inspection increased.
- J. Standalone controllers should have an inspection of solar panel (clean and facing the sun), battery date and wiring. Inspect power supply level. In the case of an automated system a scheduled maintenance plan should be in place.
- K. The tubing must be maintained with good ID integrity, or it must be replaced.

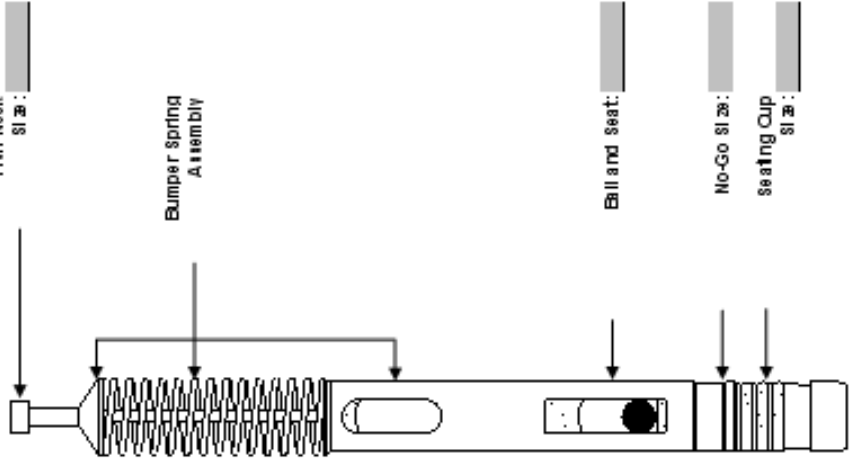
### Figure 5 - Sample Plunger Maintenance and Inspection Form

Bottom Hole Assembly

Company \_\_\_\_\_  
Area \_\_\_\_\_  
Well \_\_\_\_\_

Contact \_\_\_\_\_  
Date \_\_\_\_\_

**Bottom Hole Assembly**



Fish Neck size: \_\_\_\_\_

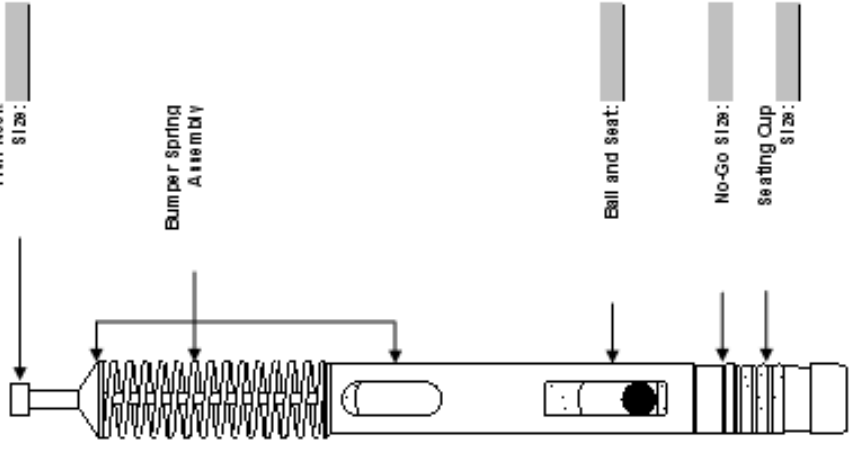
Bumper Spring Assembly

Ball and Seat: \_\_\_\_\_

No-Go size: \_\_\_\_\_

Seating Cup size: \_\_\_\_\_

**Bottom Hole Assembly Super Flow**



Fish Neck size: \_\_\_\_\_

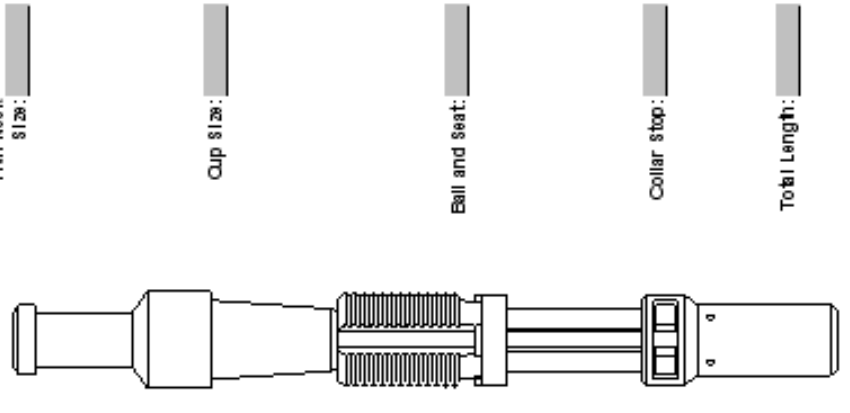
Bumper Spring Assembly

Ball and Seat: \_\_\_\_\_

No-Go size: \_\_\_\_\_

Seating Cup size: \_\_\_\_\_

**Tubing stop / Seal Assembly**



Fish Neck size: \_\_\_\_\_

Cup size: \_\_\_\_\_

Ball and seat: \_\_\_\_\_

Collar stop: \_\_\_\_\_

Total Length: \_\_\_\_\_

Figure 6 – Example Bottom Hole Bumper Spring Inspection Sheet

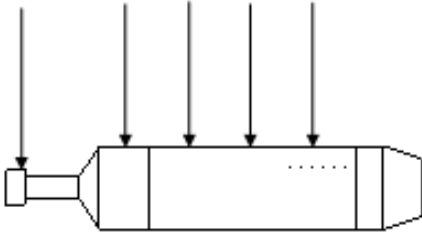
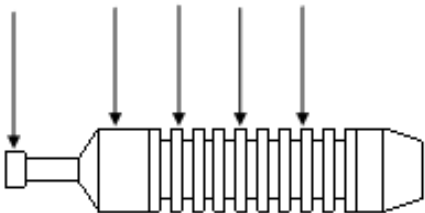
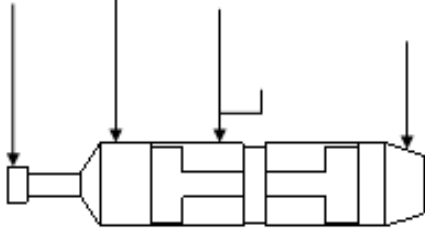
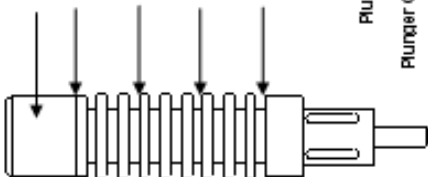
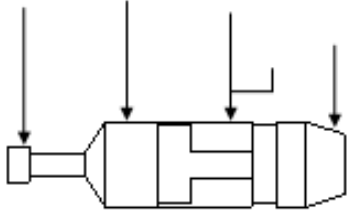
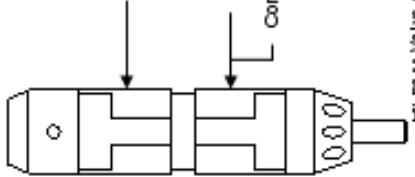
Plunger Specifications	
Company Area Well	Contact _____ Date _____
<b>Brush Plunger</b>  Risk Neck Size: _____ Size: _____ Size: _____ Size: _____ Size: _____ Plunger Size: _____ Plunger Condition: _____	<b>Solid Plunger</b>  Risk Neck Size: _____ Size: _____ Size: _____ Size: _____ Size: _____ Plunger Size: _____ Plunger Condition: _____
<b>Dual T-Pad Plunger</b>  Risk Neck Size: _____ Size: _____ Open: _____ Compressed: _____ Note Cone Condition: _____ Plunger Size: _____ Plunger Condition: _____	<b>Rapid-Ro Plunger</b>  Risk Neck Size: _____ Size: _____ Size: _____ Size: _____ Size: _____ Plunger Size: _____ Plunger Condition: _____ Bypass Valve Condition: _____
<b>Single T-Pad Plunger</b>  Risk Neck Size: _____ Size: _____ Open: _____ Compressed: _____ Note Cone Condition: _____ Plunger Size: _____ Plunger Condition: _____	<b>Dual Continuous Row Plunger</b>  Size: _____ Open: _____ Compressed: _____ Bypass Valve Condition: _____ Plunger Size: _____ Plunger Condition: _____

Figure 7 – Example Plunger Inspection Sheet

## **IV. Environmental & Safety Best Practices**

### **A. Hydrates**

1. A hydrate safety strategy should be in place.
2. If there is any possibility of a hydrate, venting should NOT be considered.

### **B. Venting**

1. Venting is NOT recommended.
2. Piped in lubricator during venting is required.
3. Velocities in venting can be very dangerous.

### **C. Removing Plungers from Lubricators**

1. Plunger tree blow-down procedures should be followed. Ensure all pressure has been bled and LOTO procedures have been applied to master valve and control valve.
2. Never look into the lubricator.
3. When pulling the plunger use vendor recommended tools.
4. Dropping plungers on master valves should be avoided.
5. Using well pressure to extract a plunger from a lubricator is never recommended.
6. Work at heights policy should be followed.
7. Stuck plunger across master valves must be addressed by local control policies.

### **D. Extended Shut-Ins and High Velocity Arrivals**

1. Your monitoring system should identify extreme speed arrivals and have shut-down set points.
2. It is recommended that an operator be on location to control the first arrival after an extended shut in period.
3. When a well has been shut in for an extended period, there is a risk of all fluids being pushed out of the tubing and a high velocity arrival occurring.



## **Recommended Practices for Optimization of Tubing Plunger Systems**

An optimized plunger lift well is a well that is operating at the maximum number of cycles necessary to generate the lowest average flowing bottom hole pressure with the available reservoir energy.

Wells should be identified as either Minimum On or Minimum Off (referring to the sales and shut-in times).

### **Minimum On Well**

Well shuts in immediately after plunger arrival and has little or no afterflow. Additional build up pressure is needed after the plunger reaches bottom to ensure a successful arrival on the next cycle. This type of well is optimized by improving the efficiency of plunger seal and conditions to ensure plunger arrival.

### **Minimum Off Well**

Well shut-in time does not exceed the minimum off time. Well typically produces afterflow. This type of well is optimized by modifying afterflow time.

The key to optimization is that the well should always be one or the other, occasionally both but never neither.

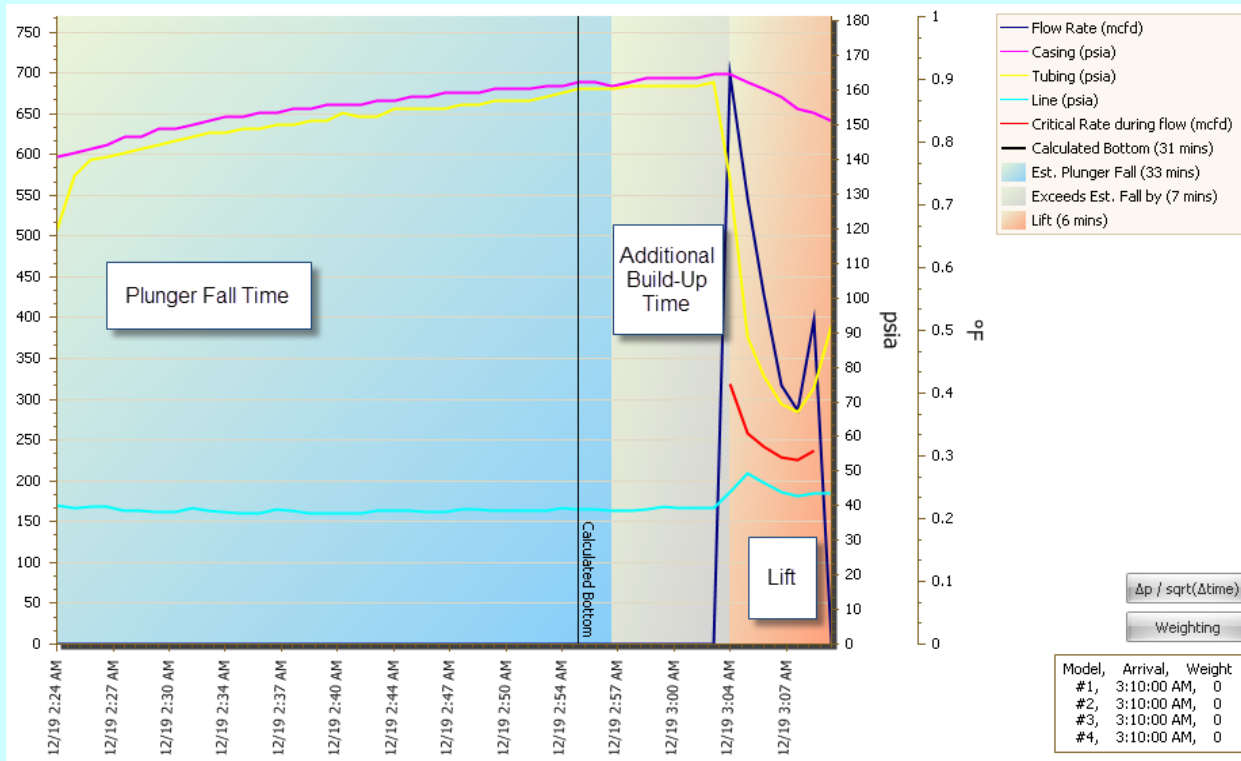


Figure 8 - Minimum On Well (Individual Cycle)  
Well shuts in on arrival optimization to build up pressure conditions.

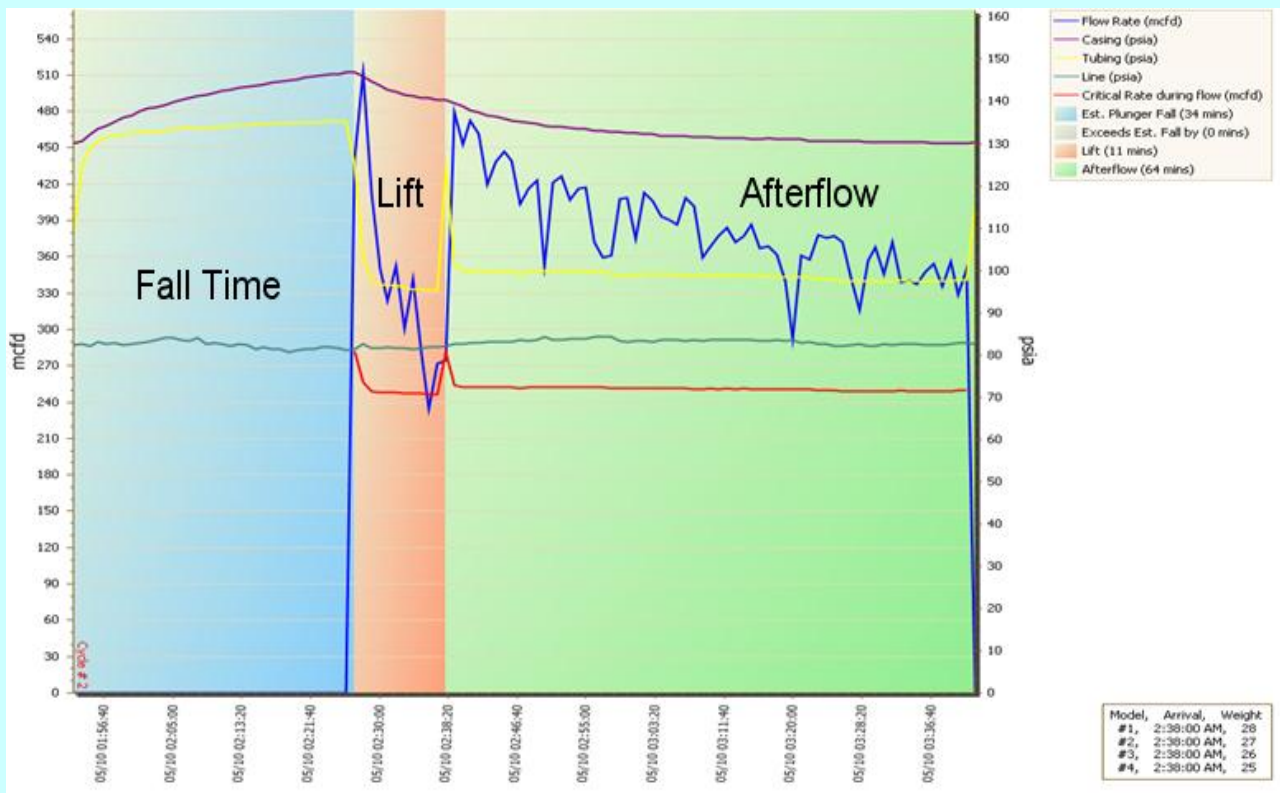


Figure 9 - Minimum Off Well (Individual Cycle)  
Lift cycle begins as plunger reaches bottom. Production is optimized using afterflow period.

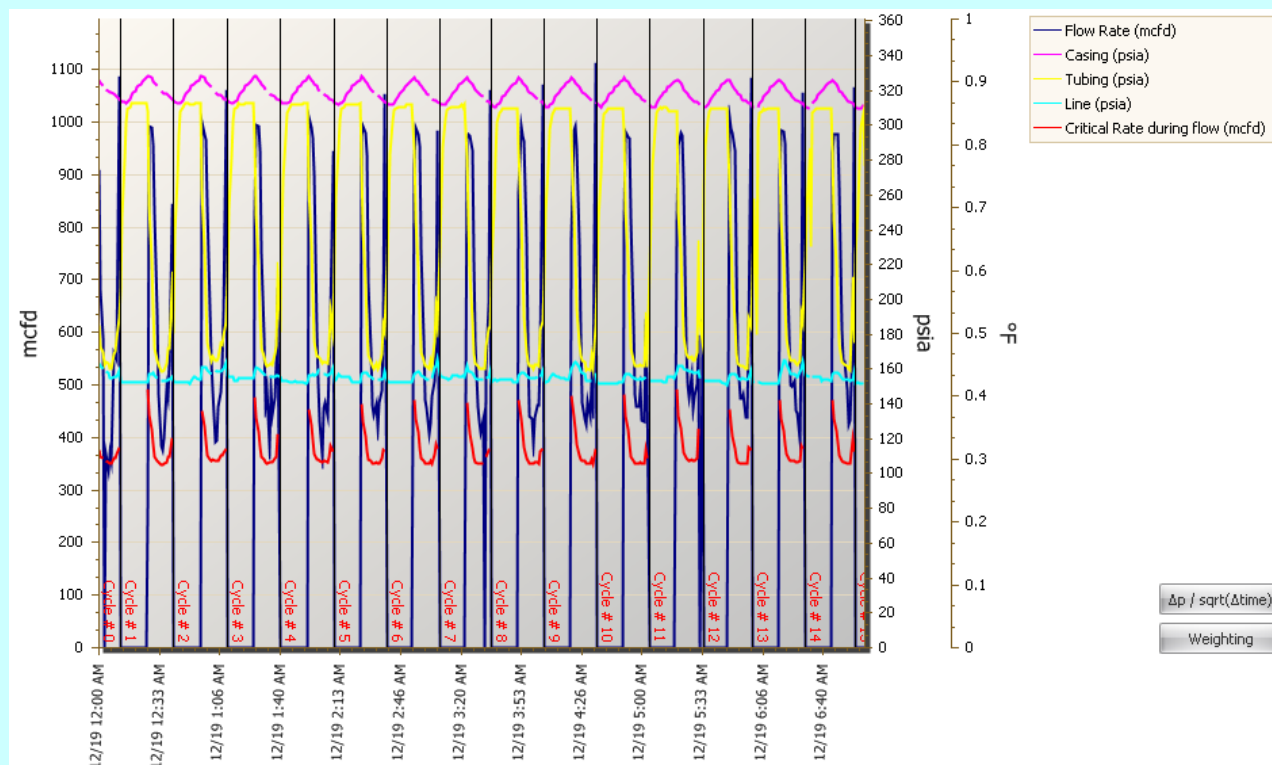


Figure 10 - Both (Multiple Cycles). Well cycles many times per day but there is very little afterflow or additional shut in time (see Figure 10a).

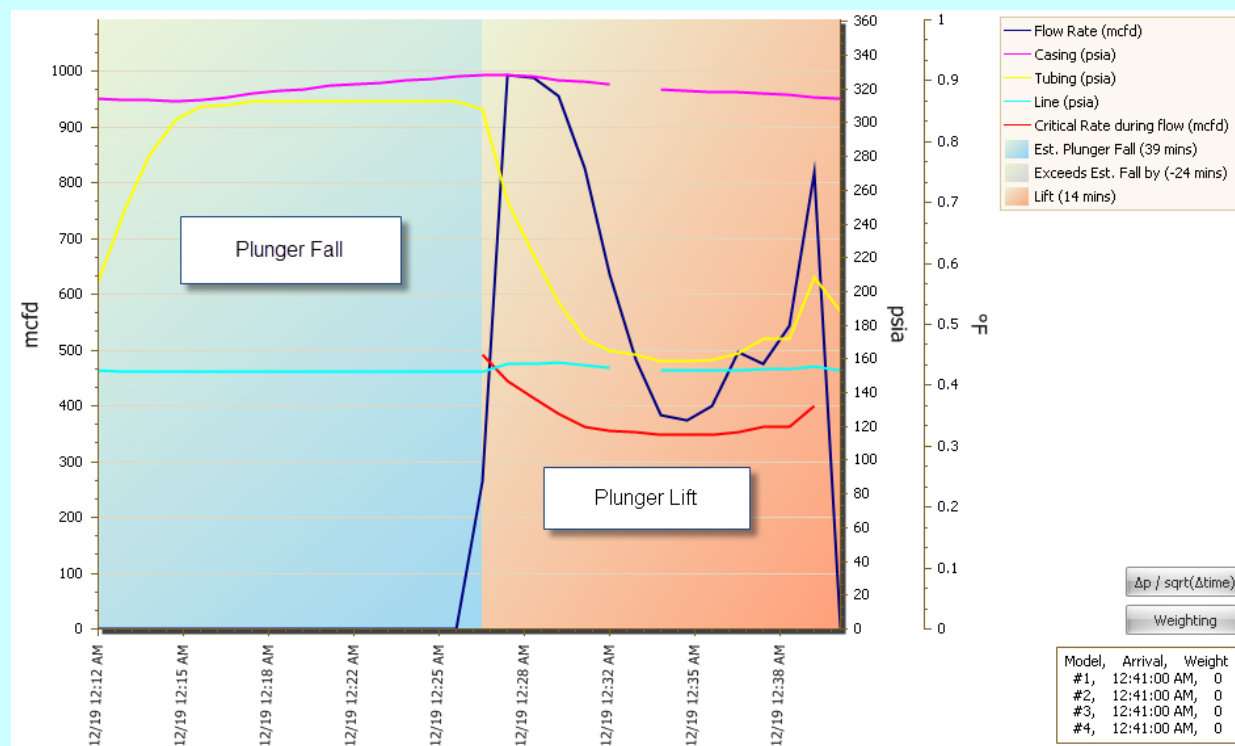


Figure 10a – Individual cycle is efficient. As well, depletes it will become a Minimum On well unless the surface pressure is reduced.

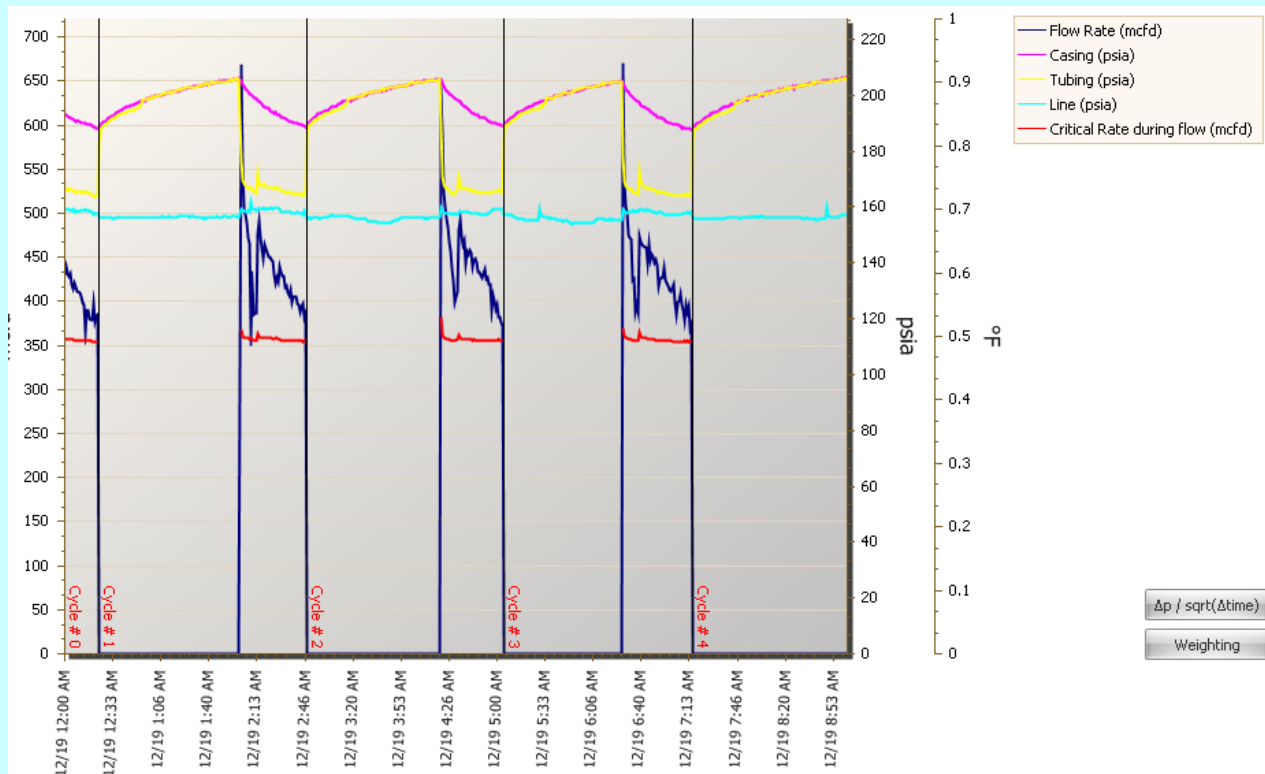


Figure 11 - Neither (Multiple Cycles). This situation should be avoided. Extended afterflow requires extended build up in order to avoid slow or missed arrivals.

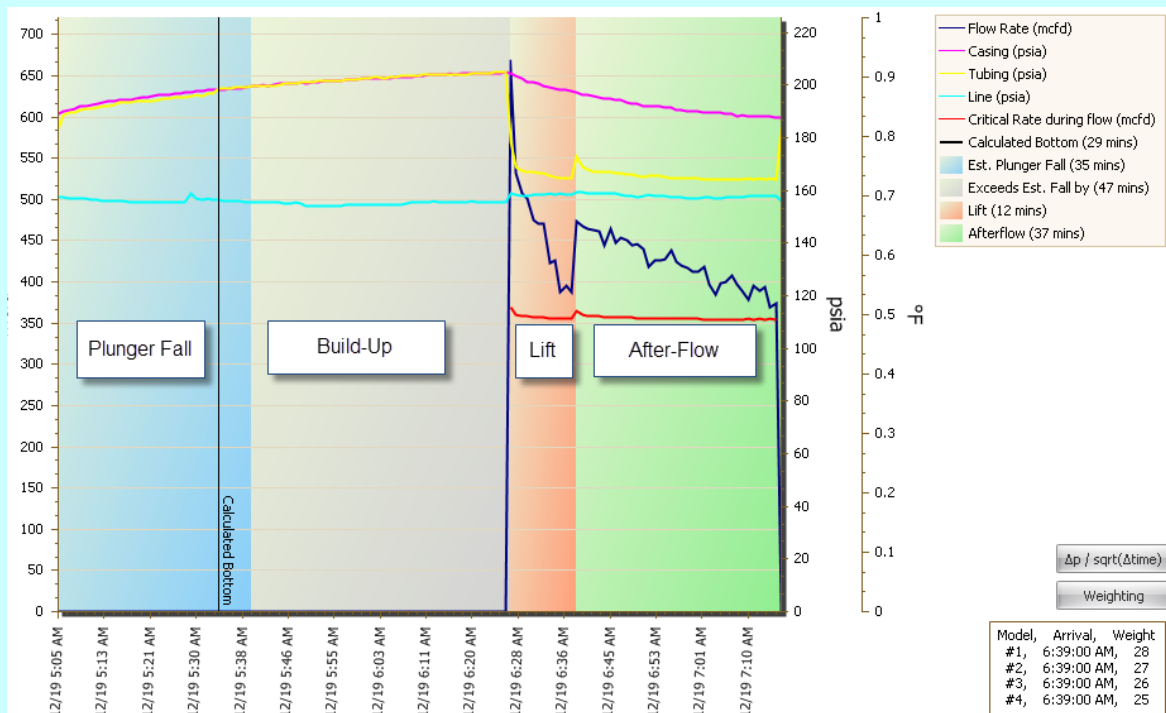


Figure 11a - Plunger reaches bottom and another 45 minutes of build-up is required to achieve 600-700 ft/min arrival. This is due to fluid build-up during >30 minute afterflow.

***If you are NOT at Minimum Off,  
there should be little or no afterflow.***

At a minimum, the plunger needs to arrive during every cycle and at a velocity that doesn't cause damage. The plunger needs to travel fast enough to avoid stalling out and slow enough to avoid damage.

Most vendors recommend an average rise velocity of between 500-1000 ft/min and will provide specific guidance for the proper plunger selection.

### **Continuous Flow Plunger Lift**

Continuous flow plunger lift should be installed before a well starts to load. This allows production to remain on the decline curve. As the well continues to deplete and available flowing energy decreases, a transition will occur to a quick drop then to conventional and then possibly a staged plunger system.

During continuous flow plunger lift, the optimization changes are generally related to changes in afterflow time or off conditions. These off conditions are most effective if they relate to:

- too low flow rate
- Turner with a multiplier
- too high differential pressure between casing and tubing

During this phase, cycles are determined by not exceeding a maximum specified arrival velocity. As the afterflow time decreases in order to maintain that velocity, a shut-in time period will be required. At this point, a slower falling plunger should be used to improve seal, and an adjustment should be made to the shut in time to ensure the plunger reaches bottom (also known as a "quick drop").

The method for optimization of quick drop is very similar to conventional plungers. Using a quick drop strategy, the plunger falls fast to allow for a short build up time. (NOTE: There **must** be fluid over the bumper spring to ensure that that fall speed does not result in damage.) Changes are made to afterflow time or conditions until afterflow is minimized and more shut-in time is required than the minimum fall for a conventional plunger.

### **Transitioning to Conventional Plunger Lift**

Once a conventional plunger can be installed, then the optimization loop begins again as a Minimum Off well with optimization on afterflow until the afterflow is reduced to a minimum when the well transitions to a Minimum On well.

Optimization of a Minimum On well is focused on maintaining the necessary plunger velocity by increasing or decreasing the build-up conditions. This is done by optimizing shut in time or an on pressure condition such as Casing pressure vs. Line pressure, Load Factor, or a Foss & Gaul calculation.

## **Control and Surveillance of Tubing Plunger Lift Systems**

### **Plunger Lift Controllers**

A plunger lift controller (or RTU) is used to control the shut in, unloading and afterflow period of a plunger system. It does this by operating one or more surface control valves to shut in and flow the well.

Different controllers use various set points and well data to determine the length of these periods. Controllers can be one of two types:

1. Manually set devices: such as timers or differential pressure controls
2. Self-adjusting systems: such as an electronic smart controller operating based on time, pressure and or plunger velocity

The choice is dependent upon each well's anticipated mode of plunger lift operation gathering system metrics, existing communications and support infrastructure.

### **SCADA/Automation Systems**

SCADA and Automation provide significant benefits to plunger lift operation. SCADA provides a remote look at producing conditions, including wellhead and electronic flow measurement (EFM). Automation algorithms attempt to make adjustments to set points without manual intervention, though manual interventions can be made to optimize production. Problem wells are identified by exception reporting and trending.

***Simple on/off controllers are not effective for optimization of a plunger system.***

## Common Myths

**“Tubing should always be landed above perforations.”**

This needs to be carefully evaluated. The end of tubing should actually be as low as possible and still effectively operate the plunger.

**“If I wait, I will get a second slug of fluid under the plunger.”**

A slug that arrives after the plunger is identified as “intermittent slug flow.” It is not an effective means of deliquification nor as efficient as a plunger at liquid removal.

**“Casing pressure requirement is 1.5 times line pressure.”**

This is not always true and can be misleading. A better predictive method will include a load size.

**“P plungers won’t work in larger tubing, such as 2 7/8”, 3 1/2”, 4 1/2”, etc.”**

Plunger lift application is not dependent upon tubing size. It is well specific and will work if the well meets the GLR and pressure requirements.

**“If I run my well on the edge, the risk of an upset is not worth it.”**

With today’s modern controls, the risk of upset can be mitigated. The increase in production could well be worth the additional effort.

**“I don’t want to cycle my quick drop so often the plunger wears out.”**

Incremental production increases will outweigh the value of saving trips.

**“P plungers wear out tubing.”**

A plunger is 10-20” long and travels the entire length of the tubing. A section of the tubing only has contact with the plunger twice per plunger cycle (once on the trip down, and once on the trip up). While wear is possible, it is very difficult to document and will take a long time to occur.

**“Certain plungers fall at certain speeds consistently.”**

The pressure environment, the fluid and gas properties, and tubing condition all have a dramatic impact on plunger fall velocity.

**“Average plunger velocity throughout the well is consistent.”**

P plungers typically accelerate as they near the surface. This is especially true in low gathering system applications.

**“Low pressure/low rate wells can’t hurt anything.”**

If a low rate well produces to a low pressure gathering system this can equate to extreme near surface velocities.

**“We don’t use bypass plungers because they break equipment.”**

If you use the correct plunger for the well’s conditions and operate the plunger as recommended (obeying maximum travel speed limitations and fluid build-up requirements), bypass and continuous flow plungers can be run effectively and without issue.

### **Topics Still Up for Discussion**

Plungers and Soap Combination



## **Glossary of Typical Plunger Lift Expressions**

This guide should be considered a quick reference for terms used in the document that may not be familiar to a new user. It is not intended to be all-inclusive of artificial lift, plunger lift or other well terminology.

### **Afterflow**

*Also known as: Sales Delay, Delay Timer, Post Flow*

The period after a plunger arrives to surface when the well continues to flow. During this time, the well is allowed to produce until a load of fluid is developed at the bottom of the tubing.

### **Build-up Time**

The time period allowed for the well to continue to build pressure after the plunger fall time has elapsed. This is normally an optimization period where the pressure build-up is balanced with the necessary requirement of energy to ensure a plunger arrival.

### **Lift**

*Also known as: Travel Time, Minimum A-On Time, Plunger Arrival Time, WOP (Waiting on Piston/Plunger), Open Time, Head Gas, Tubing On Time, A-On Time, Plunger Arriving*

The minimum amount of time the motor valve will remain open after the completion of the build-up time as controlled by a timer in the RTU. During this time, the RTU monitors for a plunger arrival and measures the time for this arrival to occur. Leading to the next state (afterflow), in the case of a non-arrival, it may also lead to a vent Valve operation or to an extended build-up timer.

### **Plunger Cycle**

The period that begins with the sales valve closing, the plunger falling to bottom, a build-up period (if necessary), a lift time and an afterflow time (if necessary). As the afterflow time ends, a new plunger cycle begins.

### **Plunger Fall Time**

*Also known as: Fall Time, Minimum Off Time, Drop, Plunger Drop Time, Open Time Delay, Close Valve Timer*

The minimum amount of time the controller will stay closed at the beginning of a cycle to allow for the plunger to reach bottom as controlled by a timer in the RTU

**Sales Valve**

*Also known as: Main Valve, Main Sales Valve, Flow Valve, Production Valve, A-Valve*

Typically the pneumatic or electric valve which will be used to start and stop flow during a plunger operation. This valve will be placed downstream of the wellhead and will actuate open or closed as determined by the RTU.

**Arrival Sensor**

*Also known as: Sensor, Plunger Arrival Sensor, Plunger Sensor, Plunger Detector, Piston Detector, MSO, Plunger Arrival Switch, Beagle™, Trip-Mate™, 3DSO™, etc.*

An magnetic relay that closes when the plunger arrives completing a circuit which the RTU detects as a “plunger arrival.”

**Vent Valve**

*Also known as: By-Pass Valve, Blow Valve, Tank Valve, B-Valve*

Typically applied to the pneumatic or electric valve which will be used during the plunger cycle to relieve the wellhead pressure from line pressure down to atmosphere or near atmospheric pressure by diverting the gas to a tank, pit or other low pressure system.