Introduction to Plunger Lift

David Cosby, P.E.
Shale Tec LLC
How does plunger lift work
Why is artificial lift required
When is plunger lift required
Applications and benefits
Installation and operation
Safety
HOW DOES PLUNGER LIFT WORK
How Does Plunger Lift Work

Bottom Hole Spring
Plunger
Lubricator / Catcher
Arrival Sensor
Pressure Transducers
Control Valve(s)
Gas Flow Meter
Well Head Controller
How Does Plunger Lift Work

**Stage** | **Control Valve** | **Gas Flow** | **Plunger** | **Casing Pressure**
---|---|---|---|---
Fall (Gas, Liquid) | CLOSED | NONE | FALLING | INCREASE
Pressure Build | CLOSED | NONE | BOTTOM | INCREASE
Rise | OPEN | FLOW | RISING | DECREASE
Production | OPEN | FLOW | SURFACE | DECREASE

**PLUNGER FALL VELOCITY**
SPE 80891 – Determining how different plunger manufacturer features affect plunger fall velocity

**LIQUID LOAD** = \( CP - TP \)

**LIFT PRESSURE** = \( CP - LP \)

**FOSS and GAUL**
SPE 120636 – Modified Foss and Gaul model accurately predicts plunger rise velocity

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How Does Plunger Lift Work

Video courtesy of PCS Ferguson

Production Control Services (PCS) and Ferguson Beauregard are now PCS Ferguson
How Does Plunger Lift Work

DOWNWARD FORCE
- Liquid Load (CP-TP)
- Line Pressure Restrictions

PLUNGER EFFICIENCY
- Best – Brush or Pad
- Worst – Bar Stock

UPWARD FORCE
- Lift Pressure (CP – LP)

Time to Surface (min)

Depth to Bottom Hole Spring

Scale, Paraffin
- Hydrates
- Sand
- Motor valve trim size
- Choke (even if open!)
- Hold down assembly
- Orifice plate

SLOW
- 500 fpm

GOOD
- 1000 fpm

FAST
- 20 min

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WHY IS ARTIFICIAL LIFT REQUIRED
Why Is Artificial Lift Required

DECREASING GAS FLOW RATE
Why Is Artificial Lift Required

Production Control Services (PCS) and Ferguson Beauregard are now PCS Ferguson
Why Is Artificial Lift Required

Line Pressure
- Liquid
- Scale / Paraffin
- Chokes
- Control Valve Trim
- Orifice Plate
- Multiple 90 degree elbows

LOW Backpressure
- Produces

LOW FBHP
- Ensures

MOST Production

FLOWING BOTTOM HOLE PRESSURE
Why Is Artificial Lift Required

Flowing Pressure (Psi)

Flow Rate (Mscf / D)

Inflow Performance Relationship

\[ Q_{sc} = C \left( P_r^2 - P_{wf}^2 \right)^n \]

- 60 psi
- 138 ft of water
- 2 3/8 Tubing

46 % of AOF
79 % of AOF

ABSOLUTE OPEN FLOW!

- 42 mcf /d
- $52,920/yr
- $3.5 / mcf

“Gas Well Deliquification” by Lea, Nickens, Wells
“Natural Gas Engineering Handbook” by Guo, Ghalambor

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Why Is Artificial Lift Required

DAILY PRODUCTION

LOST PRODUCTION

NATURAL DECLINE CURVE

CASING PRESSURE

LIQUID LOADED DECLINE CURVE

LOST PRODUCTION

480 – 350 = 130 mcf/d
130 mcf/d X 30 days X 12 months = 46,800 mcf
46,800 mcf X $ 3.50 / mcf = $ 163,800 / year
$ 163,800 / yr X 100 wells = $ 16.38 Million / yr

Flow Rate (mcf) vs. Pressure (psi) graph with annotations.
PLUNGER LIFT
WELL
REQUIREMENTS
Plunger Lift Well Requirements

IS LIQUID IN THE TUBING?

Production
Liquid Loading
Casing Pressure

Line Pressure
Plunger Lift Installed

Production
Erratic Production

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Plunger Lift Well Requirements

**IS LIQUID IN THE TUBING?**

Provided by Echometer and PLTech LLC

**Turner Unloading Rate for Well Producing Water**

- 4-1/2 OD: 3.958 ID
- 3-1/2: 2.992
- 2-7/8: 2.441
- 2-3/8: 1.995
- 2-1/16: 1.751

- What's happening at bottom of well?

- Coleman Critical Flow Rate is 20% lower than Turner

- SPE 120625 “Guidelines for the Proper Application of Critical Velocity Calculations” by Sutton, Cox, Lea, Rowlan

- SPE 94081 “A Systematic Approach to Predicting Liquid Loading in Gas Wells” by Gua, Ghalambor, Xu.
Plunger Lift Well Requirements

Video courtesy of Marathon

Liquid Loading
Unstable Slug Flow
2-in Tubing

[Image of liquid loading in a tube]
IS GAS VOLUME SUFFICIENT?

NO PACKER
400 SCF / BBL / 1,000 FT OF LIFT

Example:
400 scf X 10 bbls X 7500 ft / 1000 ft
30,000 scf or 30 mcf
Compare actual to required

Measure actual flow with clear tubing!

WITH PACKER
Higher GLR required.
Typically 2X No Packer.

IF PACKER ALREADY INSTALLED
Remove packer OR ....

Inject gas into casing if needed

Bottom Hole Spring
Perforated Tubing
Packer
Optional Standing Valve
**IS GAS PRESSURE SUFFICIENT?**

**LIFT PRESSURE**
Lift Pressure > = 2X Liquid Load

**LOAD FACTOR**
Liquid Load / Lift Pressure < = 0.5

**FOSS AND GAUL**

\[
CP_{\text{req'd}} = CP_{\text{min}} \times \left\{ \frac{(A_{\text{ann}} + A_{\text{tbg}})}{A_{\text{ann}}} \right\}
\]

\[
CP_{\text{min}} = \{SLP + P_p + P_c FV\} \times \{1 + D/K\}
\]

- **CP** = Casing Pressure; **SLP** = Sales Line Pressure
- **A_{\text{ann}}** = Area Annulus; **A_{\text{tbg}}** = Area Tubing
- **P_p** = Pressure req’d to lift just the plunger
- **P_c** = Pressure req’d to lift 1 bbl of fluid and overcome friction
- **FV** = Fluid Volume above the Plunger
- **K** = Constant accounting for gas friction
- **D** = Depth of the Plunger

**OTHER CONSIDERATIONS**

- Packer ?
- No holes in tubing
- Same ID from BHS to Lubricator
- End of tubing location
- Control valve trim size
- Orifice plate trim size
- Flow meter properly sized
- Pipeline pressure surge restrictions
- Dump valves appropriate for surges
- Clean / dry gas supply available
- Knowledgeable operator(s) ! ! !

**Plunger Lift Well Requirements**

<table>
<thead>
<tr>
<th>Tubing</th>
<th>K</th>
<th>Pc</th>
</tr>
</thead>
<tbody>
<tr>
<td>2 3/8</td>
<td>33,500</td>
<td>165</td>
</tr>
<tr>
<td>2 7/8</td>
<td>45,000</td>
<td>102</td>
</tr>
<tr>
<td>3</td>
<td>57,600</td>
<td>67</td>
</tr>
</tbody>
</table>
APPLICATIONS AND BENEFITS
# Applications and Benefits

## TYPICAL APPLICATIONS

### GAS WELLS
- ✔ Removal of liquids
- ✔ Reduction of emissions
- ✔ Keeps tubing free of paraffin, salt & scale

### OIL WELLS
- ✔ Produce from high GLR wells
- ✔ Conserve formation pressure
- ✔ Control paraffin and hydrates

### LOW GAS TO LIQUID RATIO WELLS
- ✔ 2 Stage plunger lift
- ✔ Plunger assisted gas lift
- ✔ Gas assisted plunger lift

## TYPICAL BENEFITS

### STABILIZES AND IMPROVES PRODUCTION
- ✔ 20% improvement is common
- ✔ Keeps tubing clear of debris
- ✔ Can produce wells to depletion
- ✔ Produces with a low casing pressure

### ECONOMICAL
- ✔ Low initial investment
- ✔ Low operating, repair and maintenance costs
- ✔ Reduces chemical cost, venting and swabbing
- ✔ Rig not required for installation
- ✔ Cost of system is unaffected by well depth

### GOOD FOR THE ENVIRONMENT
- ✔ Reduces methane emissions and lost gas
- ✔ Operates on solar energy

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**Primary Purpose**

Removal of liquid from gas wells so that gas can flow freely to the surface
# Applications and Benefits

<table>
<thead>
<tr>
<th>TWO STAGE PLUNGER LIFT</th>
<th>GAS ASSISTED PLUNGER LIFT</th>
<th>PLUNGER ASSISTED GAS LIFT</th>
</tr>
</thead>
<tbody>
<tr>
<td>✓ Low GLR, marginal wells</td>
<td>✓ Low GLR wells</td>
<td>✓ Low GLR wells</td>
</tr>
<tr>
<td>✓ 200 scf / bbl / 1000 ft</td>
<td>✓ Gas injected to annulus 400 scf / bbl / 1000 ft</td>
<td>✓ Add plunger to intermittent gas lift wells</td>
</tr>
<tr>
<td>✓ Two or more plungers in the same well</td>
<td>✓ Short shut-in times</td>
<td>✓ Reduces injected gas requirements (30 % range)</td>
</tr>
<tr>
<td>✓ Ideal for wells with packers</td>
<td>✓ +/- 250 Bbls / day possible</td>
<td>✓ Eliminates fall back</td>
</tr>
<tr>
<td>✓ Can be used with injection gas</td>
<td>✓ Plunger seal is important</td>
<td>✓ Increases production</td>
</tr>
</tbody>
</table>

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Benefits with Telemetry

STABILIZE AND IMPROVE PRODUCTION
✓ Allows skilled operator to control many wells
✓ Optimize production using real time data and trends
✓ Rapid and more accurate troubleshooting

ECONOMICAL
✓ Identify & resolve problems before profits are lost
✓ Reduce windshield time
✓ Reduce equipment repair and maintenance
✓ Reduce unplanned well downtime

SAFETY
✓ Remote, real time knowledge of well site parameters
✓ Remote shut-in of wells when necessary
✓ Less drive time (fuel, insurance, maintenance)
COST ITEMS
✓ Check tubing
  ✓ Drift, broach, pressure check
✓ Set bottom hole spring
✓ Re-configure well head tree
✓ Install lubricator
✓ Install control (motor) valve
✓ Install pressure transducers

$15,000 to $25,000

COST ITEMS
✓ Establish communication with flow meter and “office”
✓ Install plunger lift controller
✓ Route clean, dry gas to solenoid
✓ Install plunger
✓ Swab well if necessary
✓ Establish controller settings

$ 4 / mcf

Maintain wells natural decline curve. Don’t wait till production is lost!

<table>
<thead>
<tr>
<th>Flow Rate</th>
<th>10 % Change</th>
<th>15 % Change</th>
<th>20 % Change</th>
<th>25 % Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>100 Mcf/d</td>
<td>$ 1,200 / mo</td>
<td>$ 1,800 / mo</td>
<td>$ 2,400 / mo</td>
<td>$ 3,000 / mo</td>
</tr>
<tr>
<td>200 Mcf/d</td>
<td>$ 2,400 / mo</td>
<td>$ 3,600 / mo</td>
<td>$ 4,800 / mo</td>
<td>$ 6,000 / mo</td>
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<tr>
<td>300 Mcf/d</td>
<td>$ 3,600 / mo</td>
<td>$ 5,400 / mo</td>
<td>$ 7,200 / mo</td>
<td>$ 9,000 / mo</td>
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<tr>
<td>400 Mcf/d</td>
<td>$ 4,800 / mo</td>
<td>$ 7,200 / mo</td>
<td>$ 9,600 / mo</td>
<td>$ 12,000 / mo</td>
</tr>
<tr>
<td>500 Mcf/d</td>
<td>$ 6,000 / mo</td>
<td>$ 9,000 / mo</td>
<td>$ 12,000 / mo</td>
<td>$ 15,000 / mo</td>
</tr>
</tbody>
</table>
INSTALLATION AND OPERATION CONSIDERATIONS
Installation Considerations

- Establish a standardized installation process!
- Dual master valve
- Dual outlet lubricator
- Platform to reach lubricator
- Pressure transducer type, locations
- Pressure gauge type, locations
- Solenoid supply - clean / dry gas!
- Control valve type. Trim size, materials.
- Ball valve model number & locations
- Hammer union locations
- Flow meter communication - trench or radio?
- Communications with office - spread spectrum radio or cell phone data radio
- Controller location and attachment method
- Lightening suppression
- Emergency shut off
- Sand cut probe

WELL HEAD
- Well head ID compatible with tubing ID
- Remove unnecessary WH components
  - Minimize height of wellhead tree
- Eliminate gaps and ID inconsistencies
- Sleeve wellhead if necessary
  - Maintain same ID – BHS to Lubricator

Standardize Installation!
Installation Considerations

Minimize Restrictions!

- Scale, Paraffin – Drift and broach tubing
- Bottom hole spring holddown – size, debris
- Motor valve trim – full port opening
- Orifice plate at flow meter
- Well head – Sleeve if needed
- Chokes

Flow Area

<table>
<thead>
<tr>
<th>Diameter</th>
<th>Area</th>
<th>% Difference</th>
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<tbody>
<tr>
<td>7/8 inch</td>
<td>0.601 inch²</td>
<td>0 %</td>
</tr>
<tr>
<td>1 inch</td>
<td>0.785 inch²</td>
<td>30.6 %</td>
</tr>
<tr>
<td>1 ¼ inch</td>
<td>1.227 inch²</td>
<td>104.2 %</td>
</tr>
<tr>
<td>1 ½ inch</td>
<td>1.767 inch²</td>
<td>194.0 %</td>
</tr>
</tbody>
</table>
Installation Considerations

End of Tubing Location - Vertical Well

Tubing too high

Tubing too low or water column too high

Tubing set correctly

Liquid column pressuring lower zones

Clear water column and restart plunger

Tubing as low as possible and still surface plunger
### Key Considerations:
- What is the tubing ID?
- How is BHS attached to tubing?
- What is the seating nipple ID?
- What is the tubing deviation at the anchor point?
- Is a SV and pressure relief spring required?
- If vertical, where is the end of tubing relative to the perf’s?

### Bottom Hole Spring Location - Deviation

45 to 50 degree typical

SPE 147225 – Analysis of Plunger Lift Applications in the Marcellus Shale

<table>
<thead>
<tr>
<th>MD</th>
<th>TVD</th>
<th>EW</th>
<th>NS</th>
<th>DIP</th>
<th>AZM</th>
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<tbody>
<tr>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
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<tr>
<td>96</td>
<td>96</td>
<td>-0.33</td>
<td>-0.07</td>
<td>0.4</td>
<td>257.4</td>
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<tr>
<td>158</td>
<td>158</td>
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<td>-0.47</td>
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<td>188</td>
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<td>-1.5</td>
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<td>7382</td>
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<tr>
<td>7413</td>
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<td>12.8</td>
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<td>7445</td>
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<td>47.8</td>
<td>12.2</td>
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<td>51</td>
<td>12</td>
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<tr>
<td>7508</td>
<td>7296.46</td>
<td>829.35</td>
<td>-359.3</td>
<td>54.8</td>
<td>11.3</td>
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<tr>
<td>7539</td>
<td>7313.41</td>
<td>834.27</td>
<td>-333.82</td>
<td>58.9</td>
<td>10.6</td>
</tr>
</tbody>
</table>

**Tubing Details:** (02/15/2008)

- 229 jts 2 3/8" 4.7 lb/ft, J-55, FBN tbg
- F Nipple @ 7432.9
- 1 jt 2 3/8" 4.7 lb/ft, J-55, FBN tbg
- Notched Collar w/ ceramic disk
- EOT @ 7465 ft.

**Current**

- MD = 742 ft
- KB = 763 ft
- API# 42-251-32044

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**Installation Considerations**

**Bottom Hole Spring Location – Horizontal Well**

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Standing Valve

Installation Considerations

Standing Valve

Line Pressure

Daily Production

Standing Valve

26% Production Increase

Horizontal wells – may need specialized SV if set at high deviation
All wells with EOT above perfs
All wells when TP/CP equalize

Flow Rate

CP

TP

Detail Well History

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Installation Considerations

Plunger Selection

Use the right plunger for the well conditions.

Replace worn plungers BEFORE production declines.

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### Open Conditions
(After fall time elapses)

- Time = set point
- Tubing pressure = set point
- Casing pressure = set point
- Tubing/Casing = set point
- Tubing – Line = set point
- Lift pressure = set point
- Lift pressure = Foss and Gaul
  = % of Foss and Gaul
- Load Factor = set point

Open at minimum pressure required to surface plunger at desired plunger velocity

### Close Conditions
(After plunger surfaces)

- Time = set point
- Tubing pressure = set point
- Casing pressure = set point
- Flow Rate = Critical flow
  = % of critical

Maximize production while allowing the designed quantity of liquid to enter tubing on every cycle

### Algorithm Selection

- Operate at the maximum number of cycles to generate the lowest average flowing bottom hole pressure

- Load Factor = Liquid Load / Lift Pressure

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## Operation Considerations

### Preventative Maintenance

**Method**
- Who? What? When? How to track?

**Typical “checks”**
- Plunger
  - When to replace? How do you know?
- Lubricator
  - Spring, catcher, connection to WH
- Bottom hole spring
  - Debris, spring, seal
- Motor valve
  - Trim, gas supply if utilized
- Battery / Solar panel
- Valves - grease
- Arrival sensor & cable – no misses!
- Tubing – no obstructions, no holes
- Flow meter calibration

### Other

**Organizational structure**
- In house optimizers?
- Field operator responsibilities?

**Training**
- Who? How often? Track learning!
- Basic plunger lift principles
- Plunger lift equipment
- Optimization of wells
- Troubleshooting
- Controller settings
- Problem solving process

**Initial well lineout**
- Who?

**Remote monitor and optimize**
- In house? 3rd Party?
Arrive at site safely!

- In 2011, more than 2 out of every 5 fatal workplace incidents were transportation accidents.

- Four primary causes of O&G related transportation accidents:
  - Ignoring the speed limit
  - Using a cell phone while driving
    
    About 80% of people involved in traffic accidents are distracted.
  - Not wearing a seat belt
    
    63% of people killed in traffic accidents were not wearing seat belts.
  - Lack of rest
    
    Tired drivers involved in 4,000 road crashes in Texas in 2010.
Job Safety Analysis (www.osha.gov)
- Identify the sequence of steps to complete the job
- Identify hazards or potential hazards for each step
- Identify every possible source of energy (electrical, mechanical, pressure, height, etc)
- Determine necessary actions to eliminate, control, or minimize hazards
- Each safe job procedure or action must correspond to the job steps & identified hazards

Hydrogen Sulfide (H_2S)
- 1 ppm Can be smelled
- 10 ppm 8-hour exposure permitted
- 200 ppm Numbs smell rapidly and burns eyes, throat
- 500 ppm Loss of reasoning and balance. Respiratory disturbance in 2 – 15 minutes
- 700 ppm Loss of consciousness quickly.
- 1,000 ppm Unconsciousness occurs at once.

Appropriate Training!
- Hard Hat, Steel Toe Boots
- Flame retardant clothing
- Safety glasses
- H2S monitor

What Is Hydrogen Sulfide?
Hydrogen sulfide is a naturally occurring gas that is produced along with natural gas and crude oil. It can be fatal if breathed!
Serious Injuries

- Pressure traps (hydrates, sand, scale)
- Lubricator cap off, pressure trap under plunger
- Open master valve, hammer unions not secure
- Installing well head with underrated equipment
- **High plunger velocity – especially when venting to tanks**
- Compressed lubricator springs
- Removing cap, cracking open control valve
- Pressure gauges are not always right
Injury

- An ice plug in the lubricator released and struck a worker in the head

Contributing factors (partial list):

- Ice build up in the lubricator assembly
- Poor procedures in identifying potential hazards
- Lack of operator training in safe work practices for the use of this equipment
- Removing lubricator cap with contained pressure
- Ice build up in the spring housing
- Paraffin, wax, sand and hydrates build up in the tubing string
- Poorly designed springs or stops
- No methanol injection or heat trace to keep ice and hydrates from forming
- Fast Plunger Arrivals
  - Plungers traveling “Dry” with little or no fluid
  - Changes in line pressure, causing fast arrivals
  - Change in plunger style used in well
HYDRATES, PARAFFIN, SAND PREVENT PLUNGER FROM FALLING TO BOTTOM OF THE WELL

ICE / SAND BUILD-UP IN SPRING HOUSING

HYDRATE
ICE LIKE CRYSTALLINE SOLID FORMED FROM A MIXTURE OF WATER AND NATURAL GAS AT LOW TEMPERATURES AND HIGH PRESSURES

PLUNGER HELD AT SURFACE, FLOW REGIME CHANGED CAUSING FORMATION OF HYDRATES

ICE / SAND BUILD-UP IN SPRING HOUSING

TOP FLOW LINE NOT TIED IN CAN RESULT IN PRESSURE TRAP

Have a Plan Be Safe!
Linkedin Group

“Plunger Lifted Gas Wells”
**Fluid Volume in Tubing (Barrels)**

- \( FV = 0.002242 \times (CP-TP) \times (ID^2)/SG \)
- \( CP = \) Casing Pressure; \( TP = \) Tubing Pressure
- \( ID = \) Tubing Inner Diameter (inches)
- \( SG = \) Specific Gravity (1.0 for water)

**Fluid Height in Tubing (Feet)**

- \( FH = (CP-TP) / (0.433 \text{ psi/ft} \times SG) \)
- 0.433 psi/ft = Pressure gradient of water
- \( SG = \) Specific Gravity (1.0 for water)
- Typically, fluid column is 20% liquid, 80% gaseous liquid (foam). Divide results by 20% to obtain height of the gaseous liquid column
## Tubing Fluid Height and Volume

### 2 3/8” tubing (1.995” ID)

<table>
<thead>
<tr>
<th>CP-TP (psi)</th>
<th>Liquid Volume (bbls ; SG = 1)</th>
<th>Liquid Height (solid column)</th>
<th>Liquid Height (80% gaseous)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>0.089</td>
<td>23 ft</td>
<td>115 ft</td>
</tr>
<tr>
<td>20</td>
<td>0.178</td>
<td>46 ft</td>
<td>231 ft</td>
</tr>
<tr>
<td>30</td>
<td>0.268</td>
<td>69 ft</td>
<td>346 ft</td>
</tr>
<tr>
<td>40</td>
<td>0.357</td>
<td>92 ft</td>
<td>462 ft</td>
</tr>
<tr>
<td>50</td>
<td>0.446</td>
<td>115 ft</td>
<td>577 ft</td>
</tr>
<tr>
<td>60</td>
<td>0.535</td>
<td>138 ft</td>
<td>692 ft</td>
</tr>
<tr>
<td>70</td>
<td>0.625</td>
<td>161 ft</td>
<td>808 ft</td>
</tr>
<tr>
<td>80</td>
<td>0.714</td>
<td>185 ft</td>
<td>923 ft</td>
</tr>
<tr>
<td>90</td>
<td>0.803</td>
<td>208 ft</td>
<td>1039 ft</td>
</tr>
<tr>
<td>100</td>
<td>0.892</td>
<td>231 ft</td>
<td>1154 ft</td>
</tr>
<tr>
<td>125</td>
<td>1.115</td>
<td>288 ft</td>
<td>1443 ft</td>
</tr>
<tr>
<td>150</td>
<td>1.338</td>
<td>346 ft</td>
<td>1732 ft</td>
</tr>
<tr>
<td>175</td>
<td>1.562</td>
<td>404 ft</td>
<td>2020 ft</td>
</tr>
<tr>
<td>200</td>
<td>3.569</td>
<td>923 ft</td>
<td>4618 ft</td>
</tr>
</tbody>
</table>

### 2 7/8” tubing (2.441” ID)

<table>
<thead>
<tr>
<th>CP-TP (psi)</th>
<th>Liquid Volume (bbls ; SG = 1)</th>
<th>Liquid Height (solid column)</th>
<th>Liquid Height (80% gaseous)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>0.133</td>
<td>23 ft</td>
<td>115 ft</td>
</tr>
<tr>
<td>20</td>
<td>0.267</td>
<td>46 ft</td>
<td>231 ft</td>
</tr>
<tr>
<td>30</td>
<td>0.400</td>
<td>69 ft</td>
<td>346 ft</td>
</tr>
<tr>
<td>40</td>
<td>0.534</td>
<td>92 ft</td>
<td>462 ft</td>
</tr>
<tr>
<td>50</td>
<td>0.668</td>
<td>115 ft</td>
<td>577 ft</td>
</tr>
<tr>
<td>60</td>
<td>0.801</td>
<td>138 ft</td>
<td>693 ft</td>
</tr>
<tr>
<td>70</td>
<td>0.925</td>
<td>162 ft</td>
<td>808 ft</td>
</tr>
<tr>
<td>80</td>
<td>1.068</td>
<td>185 ft</td>
<td>924 ft</td>
</tr>
<tr>
<td>90</td>
<td>1.202</td>
<td>208 ft</td>
<td>1039 ft</td>
</tr>
<tr>
<td>100</td>
<td>1.336</td>
<td>231 ft</td>
<td>1154 ft</td>
</tr>
<tr>
<td>125</td>
<td>1.670</td>
<td>289 ft</td>
<td>1443 ft</td>
</tr>
<tr>
<td>150</td>
<td>2.003</td>
<td>346 ft</td>
<td>1732 ft</td>
</tr>
<tr>
<td>175</td>
<td>2.338</td>
<td>404 ft</td>
<td>2020 ft</td>
</tr>
<tr>
<td>200</td>
<td>5.343</td>
<td>923 ft</td>
<td>4616 ft</td>
</tr>
</tbody>
</table>
Sufficient Gas Volume

- No Packer
  - 400 scf / bbl / 1000 ft of lift
- Packer
  - 2,000 scf / bbl / 1000 ft of lift

Sufficient Gas Pressure

- Casing Pressure at least 1.5 X line pressure
- Lift Pressure at least 2 X greater than fluid load
- See Foss and Gaul requirements
Foss and Gaul (CP Required to Lift Plunger)

- $\text{CP}_{\text{req'd}} = \text{CP}_{\text{min}} \times \left( \frac{A_{\text{ann}} + A_{\text{tbg}}}{A_{\text{ann}}} \right)$
- $\text{CP}_{\text{min}} = \{\text{SLP} + P_p + P_c FV\} \times \{1 + D/K\}$

- CP = Casing Pressure; SLP = Sales Line Pressure
- $A_{\text{ann}} = \text{Area Annulus}; A_{\text{tbg}} = \text{Area Tubing}$
- $P_p = \text{Pressure required to lift just the plunger}$
- $P_c = \text{Pressure Required to lift 1 bbl of fluid and overcome friction}$
- FV = Fluid Volume above the Plunger
- $K = \text{Constant accounting for gas friction below the plunger}$
- $D = \text{Depth of the Plunger}$

<table>
<thead>
<tr>
<th>Tubing</th>
<th>K</th>
<th>$P_c$</th>
</tr>
</thead>
<tbody>
<tr>
<td>2 3/8</td>
<td>33,500</td>
<td>165</td>
</tr>
<tr>
<td>2 7/8</td>
<td>45,000</td>
<td>102</td>
</tr>
<tr>
<td>3</td>
<td>57,600</td>
<td>67</td>
</tr>
</tbody>
</table>
Critical Flow Rate (Coleman, $P_f$ Less Than 1,000 psi)

- $CV_{\text{water}} = 4.434 \times \left\{ \frac{\left( 67 - 0.0031P_f \right)^{1/4}}{(0.0031P_f)^{1/2}} \right\}$
- $CV_{\text{condensate}} = 3.369 \times \left\{ \frac{\left( 45 - 0.0031P_f \right)^{1/4}}{(0.0031P_f)^{1/2}} \right\}$
- $FR = CV \times \pi \times (ID/2)^2 \times \left( \frac{1 \text{ ft}}{144 \text{ in}^2} \right) \times 86,400 \text{ sec/day}$

$CV$ = Critical Velocity (ft/sec)

$FR$ = Flow Rate (scf/d)

$P_f$ = Flowing Pressure

$ID$ = Tubing Inner Diameter

Turner ($P_f$ Greater Than 1,000 psi)

- Turner = Coleman + 20%
Standard Cubic Foot

\[
SCF = ACF \times \frac{P_f}{P_s} \times \frac{T_s}{T_f}
\]

- **SCF** = Standard Cubic Foot of gas
  - Volume of gas contained in 1ft\(^3\) at 60\(^\circ\)F and 14.7 psi
- **ACF** = Actual or Measured Cubic Foot
- **\(P_f\)** = Flowing pressure (psi); **\(P_s\)** = 14.7 psi
- **\(T_f\)** = Flowing temperature (\(^\circ\)R)
- **\(T_s\)** = Standard temperature (516.67\(^\circ\)R)
- \(^\circ\)R = \(^\circ\)F + 459.67
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