Introduction to Plunger Lift

David Cosby, P.E.
Ferguson Beauregard
PRIMARY PURPOSE
Remove liquid from a well so that gas can flow freely to the surface.

- How does plunger lift work
- Why is artificial lift required
- When is plunger lift needed
- Benefits, limitations, economics
- Key components
- Optimizing and Troubleshooting
- Safety
HOW DOES PLUNGER LIFT WORK
How Does Plunger Lift Work

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

**STEP 1. PLUNGER FALL MODE**

- Tubing Valve Closed
- No gas flow
- Plunger is falling
- Casing pressure is building
- Liquid is not entering tubing (most wells)

**LIQUID LOAD = (CP – TP)**
STEP 2. PRESSURE BUILD MODE

- Tubing Valve Closed
  - No gas flow
  - Plunger is on the bottom
  - Casing pressure is building
  - Liquid is not entering tubing (most wells)

LIFT PRESSURE = (CP - LP)
How Does Plunger Lift Work

STEP 3. PLUNGER RISE MODE

- Tubing Valve Open
  - Well is flowing
  - Plunger is pushing liquid to the surface
  - Casing pressure is declining
  - Liquid is entering the tubing
How Does Plunger Lift Work

**STEP 4. PRODUCTION MODE**

- Tubing Valve Open
  - Well is flowing
  - Plunger held at surface by gas flow rate
  - Casing pressure is declining
  - Liquid is entering the tubing
How Does Plunger Lift Work

VIDEO
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)

**FAST**
- 1000 fpm
- GOOD 500 fpm
- SLOW

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

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

RULE OF THUMB

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WHY IS ARTIFICIAL LIFT REQUIRED
Why Is Artificial Lift Required

MIST FLOW

TRANSITION FLOW

SLUG FLOW

BUBBLE FLOW

LIQUID LOADED

DECREASING GAS FLOW RATE

Water Droplets

Gas Bubbles
Why Is Artificial Lift Required

VIDEO
Why Is Artificial Lift Required

**BACKPRESSURE**
- High Line Pressure
- **LIQUID LOADING**
- Scale / Paraffin Build-Up
- Chokes
- Motor Valve Trim Size
- Multiple 90 degree elbows
- Small Orifice Plates

**FLOWING BOTTOM HOLE PRESSURE**
- HIGH = LESS PRODUCTION
- LOW = MORE PRODUCTION

**RESERVOIR PRESSURE**

Over 90% of the gas wells in the US are liquid loaded (Marathon study)

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Why Is Artificial Lift Required

How Much More?

![Graph showing IPR curves for Well 1 and Well 2. The graph indicates that without artificial lift, the flow rates are significantly affected, with Well 1 needing lift to maintain flow at 100 Mcf/d and Well 2 needing lift to maintain flow at 20 Mcf/d.](image-url)

Flowing Pressure, PSIA

Rate, MCFD

100 psi

Well 1

Well 2

IPR CURVE

ABSOLUTE OPEN FLOW!
Why Is Artificial Lift Required

GAS PRODUCTION

LIQUID LOADING RANGE

PRODUCTION DECLINE CURVE

OIL PRODUCTION

MISSED OPPORTUNITY

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WHEN IS PLUNGER LIFT REQUIRED
When Is Plunger Lift Required

- Free Flowing Well
- Foaming Agent
- Velocity Strings
- Plunger Lift
- Compression
- Gas Assist or Lift
- Beam Pump
- High Cap X
- Pulling Unit; Short Term Fix
- Monthly Chemical Expense
- Not Environment Friendly
- Swab or Intermit Well

Liquid Loading

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When Is Plunger Lift Required

IS LIQUID IN THE TUBING?
(Over 90% of US Gas Wells)

IS GAS VOLUME SUFFICIENT?

IS GAS PRESSURE SUFFICIENT?

LIFT PRESSURE = (CP - LP)
LIQUID LOAD = (CP – TP)

ERRATIC PRODUCTION

DECLINE CURVE ANALYSIS

CRITICAL FLOW RATE

400 SCF / BBL / 1,000 FT OF LIFT

Note: Requires open annulus, med-low line pressure, med-shallow depth

LIFT PRESSURE ≥ 2X LIQUID LOAD

LIQUID LOAD / LIFT PRESSURE ≤ 0.5
LOAD FACTOR
When Is Plunger Lift Required

- Erratic Production!
- Line Pressure
- Daily Production
- Plunger Lift Installed
When Is Plunger Lift Required

- **DAILY PRODUCTION**
- **DECLINE CURVE**
- **LIQUID LOADING**
- **CASING PRESSURE**
When Is Plunger Lift Required

Empirical Study using wells with over 1,000 psi flowing tubing pressure

Predicted critical flow rate is 20% greater than Coleman
Empirical Study using wells with flowing tubing pressure less than 1,000 psi

Predicted critical flow rate is 20% less than Turner

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

SPE Paper “A Systematic Approach to Predicting Liquid Loading in Gas Wells” by Gua, Ghalambor, Xu.
When Is Plunger Lift Required

VIDEO

Liquid Loading Unstable Slug Flow 2-in Tubing
<table>
<thead>
<tr>
<th>WELL DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth to BH Spring</td>
</tr>
<tr>
<td>Gas Production</td>
</tr>
<tr>
<td>Liquid Production</td>
</tr>
<tr>
<td>Pressures (Closed)</td>
</tr>
<tr>
<td>TP</td>
</tr>
<tr>
<td>CP</td>
</tr>
<tr>
<td>LP</td>
</tr>
<tr>
<td>Pressures (Open)</td>
</tr>
<tr>
<td>TP = LP = 150 psi</td>
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</table>

<table>
<thead>
<tr>
<th>IS GAS VOLUME SUFFICIENT?</th>
</tr>
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<tbody>
<tr>
<td>(400 scf / bbl / 1,000 ft of lift)</td>
</tr>
<tr>
<td>Rule of Thumb</td>
</tr>
<tr>
<td>400 scf X 10 bbls X 7500/1000</td>
</tr>
<tr>
<td>= 30,000 scf or 30 Mscf/d</td>
</tr>
<tr>
<td>Actual Volume is 200 Mcf/d</td>
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<tr>
<td>YES</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>IS FLUID IN THE TUBING?</th>
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<tbody>
<tr>
<td>Turner Critical Flow Rate</td>
</tr>
<tr>
<td>Coleman Critical Flow Rate</td>
</tr>
<tr>
<td>Actual Flow Rate is 200 Mcf/d</td>
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<tr>
<td>YES</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>IS GAS PRESSURE SUFFICIENT?</th>
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<tr>
<td>Liquid Load = CP – TP = 75 psi</td>
</tr>
<tr>
<td>Lift Pressure = CP – LP = 250 psi</td>
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<tr>
<td>Lift Pressure &gt; 2 X Liquid Load</td>
</tr>
<tr>
<td>Load Factor = 75 / 250 = 0.3 (&lt; 0.5)</td>
</tr>
<tr>
<td>YES</td>
</tr>
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</table>
BENEFITS

LIMITATIONS

ECONOMICS
**Benefits** (No Telemetry)

- **Stabilizes and improves production**
  - 10% to 20% production improvement is common
  - Keeps tubing clear of debris (Paraffin, scale, hydrates, etc)
  - Long term solution – produce well to depletion
  - Effective with vertical, directional, s-shaped and horizontal wells
  - Produces with a low casing pressure

- **Economical**
  - Low capital investment (Payback typically less than 60 days)
  - Low annual operating cost (Typically less than $1,500 per year)
  - Reduces chemical cost
  - Reduces venting and swabbing
  - Reduces gas lift energy requirements by 30% to 70%

- **Good for the environment**
  - Reduces methane emissions and lost gas (less venting)
  - Operates on solar energy
**Benefits (With Telemetry)**

- **Stabilizes and improves production**
  - Allows skilled operator to control many wells
  - Optimize production using real time data and trends
  - Rapid and more accurate troubleshooting

- **Economical**
  - Allows identification and resolution of problems before profits are impacted
  - Enables reduction in windshield time (fuel, time, vehicle maintenance, safety, etc)
  - Enables reduction in equipment repair and maintenance
  - Enables reduction in unplanned well downtime

- **Safety**
  - Remote knowledge of key well site parameters
  - Remote shut-in of wells when necessary
  - Less drive time possible
Limitations

- **Liquid / Gas Content**
  - Up to 100 BBLS / D
  - 400 scf / BBL / 1000 Ft of Lift
  - Lift pressure at least 2X Liquid Load
  - Insufficient gas volume or pressure

- **Flow Stream Content**
  - High sand production, extreme paraffin content, excessive hydrates, low gravity crude oil

- **Mechanical Configuration**
  - End of tubing set too high or low
  - Flow line restrictions
  - Holes in tubing
  - Variations in tubing ID (Spring to Spring)
  - Difficult to operate with small tubing ID
  - Packer requires higher Gas to Liquid ratio
  - Bottom hole spring set at less than 50 degree deviation
Economics

- **Typical Costs**
  - Capital and set-up ($4,000 to $15,000)
  - Annual maintenance ($1,500)
- **Revenue ($4.00 / Mcf)**

<table>
<thead>
<tr>
<th>Flow Rate</th>
<th>10 % Increase</th>
<th>15 % Increase</th>
<th>20 % Increase</th>
<th>25 % Increase</th>
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<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>
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<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>
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<tr>
<td>400 Mcf/d</td>
<td>$4,800 / mo</td>
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<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>
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</table>
Key Components

- Bottom Hole Spring
- Plunger
- Arrival Sensor
- Lubricator / Catcher
- Pressure Transducers
- Motor Valve(s)
- Gas Flow Meter
- Well Head Controller
FUNCTION:
• Provides stop for the plunger
• Absorbs plunger impact
• Prevents damage to the plunger
• Protects the profile nipple
• Allows standing valve and pressure relief valve
• Holds liquid in the tubing

1) Standard bottom hole spring assembly with single cup hold down
2) Bottom hole spring assembly with single cup hold down and standing valve
3) Bottom hole spring assembly with tubing stop
4) Bottom hole spring assembly with collar stop
5) Bottom hole spring assembly with collet latch
Tubing too high. Liquid column pressuring lower zone, preventing gas to flow freely.

Standing Valve!

Tubing too low, or water column too high. Clear water column and restart plunger.

Tubing as low as possible and still surface plunger. Prevent backpressure on entry zones
**Key Components**

**SPRING LOCATION**

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<tr>
<th>MD</th>
<th>TVD</th>
<th>EW</th>
<th>NS</th>
<th>DIP</th>
<th>AZM</th>
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<tr>
<td>219</td>
<td>218.98</td>
<td>-1.08</td>
<td>-1.5</td>
<td>1.5</td>
<td>169.5</td>
</tr>
</tbody>
</table>

**Key Considerations:**

1. What is the tubing ID?
2. What are we anchoring to down hole?
3. If seating nipple, what is the ID (F, X, XN)?
4. What is the tubing deviation at the anchor point? 
   *(Prefer less than 50 degree)*
5. Is a standing value and pressure relief spring required?
6. If vertical, where is the end of tubing relative to the perf’s?

**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.
Key Components

STANDING VALVE

Line Pressure

Daily Production

Standing Valve

26% Production Increase
FUNCTION:
- Interface between liquid and gas
- Push liquid to the surface
- Fall quickly to the bottom
- Clean debris from tubing ID
- Detectable by arrival sensor

1) Cleanout plunger
2) Fiber seal (brush) plunger
3) Dual row pad plunger
4) Continuous flow plunger (Rod req’d)
5) Continuous flow plunger (No rod)

Key Considerations:
1. Use the correct plunger for the well!
   - Particulates?
   - Match fall speed to casing pressure build
   - Seal effectiveness?
2. When to replace the plunger?
Key Components

PLUNGERS

Use the right plunger for the well conditions

Replace worn plungers BEFORE production declines

Continuous Flow Plunger

Flow Rate

Line Pressure

Flow Rate

Line Pressure

Continuous Flow Plunger

Flow Rate

Line Pressure

Continuous Flow Plunger

Flow Rate

Line Pressure
Key Components

LUBRICATOR / CATCHER

FUNCTION:
• Absorb plunger impact
• Catch plunger at surface
• Ports for valves, transducers, arrival sensor

OPTIONS:
• Manual or auto catcher
• Single or dual outlet
• Threaded or flanged
• Cold weather certification
ARRIVAL SENSOR

FUNCTION:
• Signal controller when plunger is at the surface

MOTOR VALVE

FUNCTION:
• Open and close the well as instructed by the controller

REQUIREMENTS:
• Adequate pressure rating
• Pressure opening
• Large trim size (Prefer same as pipe)

OPTIONS
• Trim kit material
• Threaded or flanged
• Straight or right angle

LATCH VALVE
(Solenoid Valve)

FUNCTION:
• Converts electrical signal to pneumatic signal to open or close the motor valve.

NOTE:
• Opening in solenoid valve is very small. Debris can easily clog, causing Motor Valve to remain open or closed.
CONTROLLERS

FUNCTION:
- Signals well to open or close
- Collect, displays, transmits data
- Provide means to adjust plunger cycles
- May calculate gas flow rate
- May e-mail and text alarm conditions
- Simple to complex controls

Key Considerations:
1. Telemetry benefits desired?
2. Self adjusting benefits desired?
3. Algorithm selection considered?
4. Keypad at well site desired?
5. Well optimization support desired?
6. Standardize with EFM?
OPTIMIZE AND TROUBLESHOOT
Optimize And Troubleshoot

PRE-INSTALLATION

1. Well Data Sheet complete?
2. Is well a plunger lift candidate?
   o Liquid in the tubing?
   o Sufficient gas volume and pressure?
     o Check with clear tubing!
   o Minimal restrictions?
     o Packer, choke, trim size, orifice plate, line pressure, etc
   o Evidence of holes in tubing or blockage?
   o Sand? H₂S? CO₂?
   o Same ID spring to spring
     o Well head sleeve required?
3. Review prior 90 day production
4. Production target known?
5. Review well bore diagram.
   o Packer? Obstructions? Seating nipple locations? Type? ID?
6. Plumbing configuration known?
   o By –pass loop around motor valve
   o Dual Master Valves?
7. Bottom Hole Spring location
8. Preventative Maintenance Plan
9. Safety ! ! ! !
   o Trained Operators?
• **FOCUS ON PRODUCTION!**
• Use reliable hardware
• Minimize restrictions
• Use algorithms that address well variations
• On each cycle, review
  • Fluid in Tubing
  • Lift Pressure
  • Plunger Velocity
  • Gas Produced
• Troubleshoot – Use DATA!

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**IPR CURVE**

- Max Cycles
- Lowest BHP
- Smallest Liquid Loads
- Most Production

---

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# Plunger Lift Cycle Report

<table>
<thead>
<tr>
<th>Cycle #</th>
<th>AT CLOSE</th>
<th>AT OPEN</th>
<th>RUN DATA</th>
<th>PRODUCTION DATA</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Pressures (psi)</td>
<td>Pressures (psi)</td>
<td>Plunger Rise</td>
<td>Gas (Mscf)</td>
</tr>
<tr>
<td></td>
<td>CP</td>
<td>TP</td>
<td>SLP</td>
<td>CP-TP</td>
</tr>
<tr>
<td>3460</td>
<td>314</td>
<td>253</td>
<td>135</td>
<td>61</td>
</tr>
<tr>
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<td>316</td>
<td>253</td>
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<td>60</td>
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<td>3479</td>
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<td>253</td>
<td>135</td>
<td>60</td>
</tr>
</tbody>
</table>

- **Cycle #**
- **Liquid Load (CP – TP)**
- **Actual Lift Pressure (CP – LP)**
- **Calc Req’d Lift Pressure**
- **Close Time**
- **Plunger Velocity**
- **Production Data**

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Optimize And Troubleshoot

Detail Well History

- Casing Pressure
- Lift Pressure
- Flow Rate
- Line Pressure
- Liquid Load
- Tubing Pressure

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Optimize And Troubleshoot

Detail Well History

- Well Opens
- Head Gas Produced
- Plunger Arrives
- Lateral Leg Unloads
- Well Closes

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SAFETY
**Safety**

- **Arrive at site safely**
  - Avoid driving distractions. Drive courteously!

- **Job Safety Analysis** ([www.osha.gov](http://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
  - Determine necessary actions to eliminate, control, or minimize hazards!
  - Each safe job procedure or action must correspond to the job steps and identified hazards

- **Wear appropriate Personal Protective Equipment**!
• **Injury**
  – A technician was seriously injured when an unsuspected ice plug in the wellhead lubricator released and struck the worker in the head resulting in a fractured skull and permanent eye loss.

• **Contributing factors (partial list):**
  – Ice build up in the lubricator assembly
  – The ice build up in the lubricator was caused by produced water freezing in the assembly and no method of thawing the wellhead was available at this particular work site.
  – Poor procedures in identifying potential hazards.
  – Lack of operator training in safe work practices for the use of this equipment.
• Noted sources of potential injury and equipment failure:
  – Removing lubricator cap with contained pressure above or below ice plugs, sand bridges etc.
  – Ice build up in the spring housing
  – Paraffin, wax, sand and hydrates build up in the tubing string
  – Poorly designed springs or stops
  – 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
  – No methanol injection or heat trace to keep ice and hydrates from forming
Noted sources of potential injury and equipment failure:

- Restricted flow path if the plunger is being held at surface causing a pressure drop and creating the environment for the formation of hydrates
- Unexpected changes in flow regimes caused by cycling a plunger – sand production due to higher drawdown effect on the reservoir
- High pressure and volumes of gas and fluid affecting surface equipment due to the cyclic nature of plunger operations impact of the plunger at surface
Be Safe by Design!

What is your process?
ADDENDUM
# WELL DATA SHEET

## WELL LOCATION / OPERATOR DATA

<table>
<thead>
<tr>
<th>Well Name</th>
<th>State</th>
<th>Field</th>
</tr>
</thead>
<tbody>
<tr>
<td>County / Parish</td>
<td>API #</td>
<td>Formation</td>
</tr>
<tr>
<td>Operator Engineer Contact</td>
<td>Address</td>
<td>Mobile</td>
</tr>
<tr>
<td>Field Contact</td>
<td>E-mail</td>
<td>Mobile</td>
</tr>
</tbody>
</table>

## WELL DATA

### WELL TYPE

<table>
<thead>
<tr>
<th>Gas</th>
<th>Oil</th>
<th>Sweet</th>
<th>Sour</th>
<th>Ranged</th>
<th>Threaded</th>
<th>How</th>
<th>Pump</th>
<th>Gas Lift</th>
<th>Intermit</th>
<th>Vent</th>
<th>Shut-In</th>
<th>T/A</th>
</tr>
</thead>
</table>

### WELLHEAD

### WELL STATUS

### WELL FORM

<table>
<thead>
<tr>
<th>Vertical</th>
<th>Horizontal</th>
<th>Directional</th>
<th>Other</th>
<th>Twy/No</th>
<th>Depth</th>
</tr>
</thead>
</table>

### Packer

### SEATING NIPPLE

### WELL DEPTH

<table>
<thead>
<tr>
<th>TD (MD)</th>
<th>TVD</th>
<th>Kick-Off</th>
<th>GL</th>
<th>RB</th>
<th>ID Depth</th>
</tr>
</thead>
</table>

### ATTACHMENTS

<table>
<thead>
<tr>
<th>Well Bore Survey</th>
<th>Schematic</th>
<th>Swab Report</th>
<th>BHP Test</th>
</tr>
</thead>
</table>

## TUBING / CASING / PERFORATIONS

<table>
<thead>
<tr>
<th>Size Wt / Grade Depth</th>
<th>Tubing</th>
<th>Casing</th>
<th>ZONE</th>
<th>Top Perf Depth</th>
<th>Bottom Perf Depth</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>1</td>
<td>2</td>
<td>3</td>
<td>4</td>
<td>5</td>
</tr>
</tbody>
</table>

## PRODUCTION DATA

### Production (24 hr flow)

<table>
<thead>
<tr>
<th>Oil</th>
<th>Gas</th>
<th>Water</th>
<th>90 Day Production Chart Awaill</th>
</tr>
</thead>
</table>

### Pressures

<table>
<thead>
<tr>
<th>Tubing Flowing</th>
<th>Casing Flowing</th>
<th>Casing Static</th>
<th>Sales Line</th>
</tr>
</thead>
</table>

## RESERVOIR DATA

### API Gravity

<table>
<thead>
<tr>
<th>Oil / Condensate</th>
<th>Tubing</th>
</tr>
</thead>
</table>

### Gas Gravity

<table>
<thead>
<tr>
<th>Gas Gravity</th>
</tr>
</thead>
</table>

### Water Gravity

<table>
<thead>
<tr>
<th>Water Gravity</th>
</tr>
</thead>
</table>

### Shut-in Pressures (24 Hour)

<table>
<thead>
<tr>
<th>Light</th>
<th>Sand</th>
<th>Paraffin</th>
<th>Salt</th>
<th>Scale</th>
<th>Iron Sulfide</th>
<th>Chlorides</th>
<th>% or PPM</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Moderate</th>
<th>H₂S</th>
<th>CO₂</th>
</tr>
</thead>
</table>

## EQUIPMENT ON SITE

<table>
<thead>
<tr>
<th>Lubricator Type / Mgr</th>
<th>SEADA Software</th>
</tr>
</thead>
<tbody>
<tr>
<td>Plunger Type / Mgr</td>
<td>Tank Qty / Size</td>
</tr>
<tr>
<td>Controller Model / Mgr</td>
<td>Chem Pump Model</td>
</tr>
<tr>
<td>Flow Meter Model / Mgr</td>
<td>Standing Valve</td>
</tr>
</tbody>
</table>

## OPERATOR EXPECTATIONS

## COMMENTS / PICTURES

---

Ferguson-Beauregard

February 20 – 22, 2012

2012 Gas Well Deliquification Workshop
Denver, Colorado
• Fluid Volume in Tubing (Barrels)
  o \( FV = 0.002242 \times (CP-TP) \times (ID^2)/SG \)
  o \( CP=\) Casing Pressure; \( TP=\) Tubing Pressure
  o \( ID=\) Tubing Inner Diameter (inches)
  o \( SG = \) Specific Gravity (1.0 for water)

• Fluid Height in Tubing (Feet)
  o \( FH = (CP-TP) / (0.433 \text{ psi/ft} \times SG) \)
  o 0.433 psi/ft = Pressure gradient of water
  o \( SG = \) Specific Gravity (1.0 for water)
  o Typically, fluid column is 20 % liquid, 80 % gaseous liquid (foam). Divide results by 20% to obtain height of the gaseous liquid column.
CP = Casing Pressure
TP = Tubing Pressure
ID = Tubing Inner Diameter (inches)
SG = Specific Gravity = 1.0 for Water
LH = Liquid Height in Tubing (Feet)
LV = Liquid Volume in Tubing (Bbls)
Water pressure gradient = 0.433 psi / ft

LIQUID HEIGHT IN TUBING
LH = (CP-TP) / (0.433 psi/ft X SG)
LH = (500-100) / (0.433 psi/ft X SG)
LH = 923.78 ft

LIQUID VOLUME IN TUBING (BBLS)
LV = 0.002242 X (CP-TP) X (ID²)/SG
LV = 0.002242 X (500-100) X (ID²)/SG
LV = 0.8968 X (ID²)
LV = 15.84 Bbls (2 3/8 tbg)
LV = 5.34 Bbls (2 7/8 tbg)
Foss and Gaul (CP Required to Lift Plunger)

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

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

<table>
<thead>
<tr>
<th>Tubing</th>
<th>K</th>
<th>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>
- 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 1ft³ at 60⁰F and 14.7 psi
  - ACF = Actual or Measured Cubic Foot
  - P_f = Flowing pressure (psi); P_s = 14.7 psi
  - T_f = Flowing temperature (⁰R)
  - T_s = Standard temperature (516.67⁰R)
  - ⁰R = ⁰F + 459.67
• **Critical Flow Rate (Coleman, \(P_f\) Less Than 1,000 psi)**
  - \(CV_{\text{water}} = 4.434 \times \frac{\{(67 - 0.0031P_f)^{1/4}\}}{\{(0.0031P_f)^{1/2}\}}\)
  - \(CV_{\text{condensate}} = 3.369 \times \frac{\{(45 - 0.0031P_f)^{1/4}\}}{\{(0.0031P_f)^{1/2}\}}\)
  - \(FR = CV \times \pi \times (\text{ID}/2)^2 \times \left(\frac{1 \text{ ft}}{144 \text{ in}^2}\right) \times 86,400 \text{ sec/day}\)
  - \(CV = \text{Critical Velocity (ft/sec)}\)
  - \(FR = \text{Flow Rate (scf/d)}\)
  - \(P_f = \text{Flowing Pressure}\)
  - \(ID = \text{Tubing Inner Diameter}\)

• **Turner (\(P_f\) Greater Than 1,000 psi)**
  - Turner = Coleman + 20%
Rules of Thumb

• **Gas Volume Required**
  - No Packer
    - 400 scf per bbl per 1000 ft of lift
  - Packer
    - 2,000 scf per bbl per 1000 ft of lift

• **Casing Pressure at least 1.5 X line pressure**
  - CP ≥ 1.5 X SLP

• **Lift Pressure at least 2 X greater than fluid load**
  - (CP – SLP) ≥ 2 X (CP – TP)
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