Introduction to Plunger Lift

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Shale Tec LLC
Introduction to Plunger Lift

How does plunger lift work

Why is artificial lift required

Plunger lift well requirements

Applications, benefits, limitations

Primary Purpose

Removal of liquid from gas wells so that gas can flow freely to the surface
HOW DOES PLUNGER LIFT WORK
How Does Plunger Lift Work

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

Flow Meter and / or PL controller

Lubricator, Dual Outlet

Check Valve

Line Pressure

Conventional Plunger

Continuous Run Plunger

Control Valve

PL Controller

Arrival Sensor

Line Pressure

Conventional Plunger

Continuous Run Plunger

Tubing Pressure

Check Valve

Gas Well API #
How Does Plunger Lift Work

Stage 1: Plunger Fall (Gas, Liquid)
- Control Valve **Closed**
- Plunger falling (through gas, then gaseous liquid)
- No gas flow
- CP Increasing

**Conventional Plunger**

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

4 Stages

Casing normally closed during plunger lift operations
How Does Plunger Lift Work

Stage 2 Casing Pressure Build

- Control Valve Closed
- Plunger on bottom
- No gas flow
- CP Increasing

Conventional Plunger

LIQUID LOAD = (CP – TP)

LIFT PRESSURE = (CP - LP)

LIQUID LEVEL MEASUREMENT
SPE 120643 – Acoustic Liquid Level Testing of Gas Wells

FOSS and GAUL Required Pressure
SPE 120636 – Modified Foss and Gaul model accurately predicts plunger rise velocity
How Does Plunger Lift Work

Stage 3 Plunger Rise

- Control Valve Open
- Plunger rising
- Gas is flowing
- CP decreasing
- Liquid is entering the tubing

Conventional Plunger

Plunger Rise Velocity Guideline
500 to 1000 fpm

“Fast enough to avoid stalling, slow enough to avoid damage”
Stage 4 Production (After Flow)

- Control Valve Open
- Plunger is held at surface by gas flow
- Gas is Flowing
- CP Decreasing
- Liquid is entering the tubing
How Does Plunger Lift Work

- Equipment
- Four stages
- Critical Flow Rate
- Decline Curve

Plunger Lift Systems
How Does Plunger Lift Work

**Stage 1  Plunger Fall Mode (Gas, Liquid)**

- **Control Valve**
  - Ball & Sleeve - close for few sec to few minutes
  - Dart style – may or may not need to close valve
- Plunger drops when gravity overcomes upward differential pressure created by flow rate
- Plunger continues to fall with internal valve open

**Continuous Run Plunger**

- Plunger falls against a flow rate
- Requires a strong well
- Typically operates on time
- Monitor Round Trip Time

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Stage 2  Plunger arrives at bottom hole spring

- Control Valve Open
- Plunger impacts BHS, plunger valve closes
- Gas is flowing
- CP flat to declining
- Liquid entering tubing
How Does Plunger Lift Work

Stage 3 Plunger Rise

- Control Valve Open
- Plunger rising
- Gas is flowing
- CP flat to declining
- Liquid entering tubing

Continuous Run Plunger

“Fast enough to avoid stalling, slow enough to avoid damage”
How Does Plunger Lift Work

Stage 4 Production (After Flow)

- Control Valve Open
- Plunger impacts trigger rod, plunger valve opens
- Plunger may start to fall during production stage
- Auto-Catcher will hold plunger at surface
- Gas is flowing
- CP flat to declining
- Liquid entering tubing

Continuous Run Plunger

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How Does Plunger Lift Work

Continuous Flow Plungers
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
- Casing Pressure

Time to Surface (min)
0 5 10 15 20 25 30 35
0 1,000 2,000 3,000 4,000 5,000 6,000 7,000 8,000 9,000 10,000 11,000 12,000 13,000 14,000 15,000

Depth to Bottom Hole Spring

Scale, Paraffin
Hydrates
Sand
Motor valve trim
Choke
Hold down assembly
Orifice plate

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

SLOW
500 fpm

GOOD
1000 fpm

FAST

UPWARD FORCE
- Casing Pressure

10 min

Scale, Paraffin
Hydrates
Sand
Motor valve trim
Choke
Hold down assembly
Orifice plate

How Does Plunger Lift Work

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WHY IS ARTIFICIAL LIFT REQUIRED
DECREASING GAS FLOW RATE

MIST FLOW

TRANSITION FLOW

SLUG FLOW

BUBBLE FLOW

LIQUID LOADED

Water Droplets

Liquid Slugs

Gas Bubbles

Why Is Artificial Lift Required

LIQUID LEVEL

NO GAS FLOW

Water

Gas
Why Is Artificial Lift Required
Why Is Artificial Lift Required

FLOWING BOTTOM HOLE PRESSURE

Low Backpressure
   Produces

Low FBHP
   Ensures

Most Production

Line Pressure
   Liquid

Scale / Paraffin

Chokes

Valve Trim Size

Orifice Plate

90 Degree Elbows

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Why Is Artificial Lift Required

Why Is Artificial Lift Required

IPR CURVE

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

- \( Q_{sc} \) = gas flow rate
- \( P_r \) = Reservoir pressure
- \( P_{wf} \) = Flowing well bore pressure at the mid-perforation depth
- \( C, n \) = constants

**High Pressure Well**

**Low Pressure Well**

ABSOLUTE OPEN FLOW!

Rate, MCFD

Flowing Pressure, PSIA

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Why Is Artificial Lift Required

Compare flow rate to critical velocity to verify liquid loading problem.

**DAILY PRODUCTION**

**LOST PRODUCTION**

**NATURAL DECLINE CURVE**

**LIQUID LOADED DECLINE CURVE**

**CASING PRESSURE**
Artificial Lift Types

Guidelines & Recommended Practices
Selection of Artificial Lift Systems for Deliquifying Gas Wells

Lessons Learned
from Natural Gas STAR Partners

Options for Removing Accumulated Fluid and Improving Flow in Gas Wells

Artificial Lift Types Considerations:
- Operating depth, volume, temperature
- Ability to handle corrosion, gas, solids
- Fluid gravity, build angle, servicing
- Energy source, system efficiency

Free Flowing Well
Swab or Intermittent Well
Foaming Agent
Velocity Strings
Compression
Plunger Lift
2 Stage Plunger Lift
Gas Assisted Plunger Lift
Plunger Assisted Gas Lift
Beam Pump
ESP

Liquid Loading

High Cap X
Monthly Chemical Expense
Not Environment Friendly
Often, only Short Term Solution

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PLUNGER LIFT WELL REQUIREMENTS
**Plunger Lift Well Requirements**

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

**YES**

**IS GAS VOLUME SUFFICIENT?**

**YES**

**IS GAS PRESSURE SUFFICIENT?**

**YES**

**ERRATIC PRODUCTION**

**DECLINE CURVE ANALYSIS**

**CRITICAL FLOW RATE**

**400 SCF / BBL / 1,000 FT OF LIFT**

More if packer is in well.
SCF = Standard Cubic Foot.
Volume of gas contained in 1 ft$^3$ at 60°F and 14.7 psi.

**LIFT PRESSURE >/= 2X LIQUID LOAD**

Lift Pressure = (CP - LP). Liquid Load = (CP - TP).
Foss and Gaul equation is a more precise predictor.

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Is Liquid in the Tubing?

Compare flow rate to critical velocity to verify production decline is caused by liquid loading.
Is Liquid in the Tubing?

Line Pressure

Plunger Lift Installed

Production

Erratic Production

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Is Liquid in the Tubing?

**Critical Velocity**
The minimum gas velocity required to move water droplets upward.

**Flowing Pressure**
Flowing tubing pressure for surface critical flow rate

**Flowing Pressure**
Producing bottom hole pressure for bottom hole critical flow rate

**Producing PBHP**
Flowing casing pressure plus weight of column of gas and liquids in annulus

**Vertical portion of well!**
Is Liquid in the Tubing?

Predicted critical flow rate is 20% less than Turner

SPE 120625-2009 “Guidelines for the Proper Application of Critical Velocity Calculations” by Sutton, Cox, Lea, Rowlan

SPE 94081-PA “A Systematic Approach to Predicting Liquid Loading in Gas Wells” by Gua, Ghalambor, Xu.
Liquid Loading
Unstable Slug Flow
2-in Tubing
Is Gas Volume Sufficient?

**Packer**

- NO PACKER
- 400 SCF / BBL / 1,000 FT

**Multi Stage**

- 200 SCF / BBL / 1,000 FT

**Gas Assist**

- Add Gas as needed
- Inject to 400 SCF / BBL / 1,000 FT
- 250 + bbls/day possible

**Gas Lift**

- Continuous or Intermittent
- Reduce injected gas by up to 30%

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Multi-Stage Advantages:

Effective in GLRs nearing 1:1 gas to liquid (gassy oil wells)

Gas Assist

- Inject gas into the annulus
- Supplement the lifting ability
### Is Gas Pressure Sufficient?

#### Lift Pressure
Lift Pressure = \( CP - LP \)

#### Liquid Load
Liquid Load = \( CP - TP \)

#### Load Factor
Liquid Load / Lift Pressure < or = 0.5

#### Lift Factor
Lift Pressure / Liquid Load > or = 2.0
Lift Pressure > or = 2 \times \) Liquid Load

### FOSS and Gaul Equation
Predicts the casing pressure required to surface the plunger and liquid column

\[
\text{Lift Pressure}_{\text{req'd}} = \text{CP}_{\text{req'd}} - \text{LP}
\]

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

\[
\text{CP}_{\text{min}} = \left\{\text{SLP} + \text{P}_p + \text{P}_c \text{FV}\right\} \times \left\{1 + \frac{D}{K}\right\}
\]

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

- Packer? More gas volume required
- No holes in tubing
- Same ID from BHS to lubricator
- Minimize restrictions!
- Flow meter properly sized
- Pipeline pressure limitations
- Size dump valves for surges
- Clean / dry gas supply available
- Select proper algorithm
- Preventative maintenance plan
- Knowledgeable operator(s) !!!
APPLICATIONS, BENEFITS, LIMITATIONS, ECONOMICS
Applications

GAS WELLS
✓ Removal of liquids
✓ Reduction of emissions
✓ Keeps tubing clear

OIL WELLS
✓ Produce from high GLR wells
✓ Conserve formation pressure
✓ Control paraffin and hydrates

LOW GLR WELLS
✓ 2 Stage plunger lift
✓ Plunger assisted gas lift
✓ Gas assisted plunger lift

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### Benefits

#### No Telemetry

**STABILIZES & IMPROVES PRODUCTION**
- 10% to 20% improvement is common
- Keeps tubing clear of debris
- Long term solution (SPE 18868)
- Produces with a low casing pressure

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

**ECONOMICAL**
- Low capital investment
- Low operating, maintenance costs
- Reduces chemical cost, venting, swabbing
- Rig not required for installation
- Cost of system is unaffected by well depth
- Reduces gas lift energy by 30% to 70%

#### With Telemetry

**STABILIZE AND IMPROVE PRODUCTION**
- Puts data in hands of experts
- Allows skilled operator to control many wells
- Optimize using real time data and trends
- Rapid problem detection & troubleshooting

**ECONOMICAL**
- ID & resolve problems before lost profits
- Reduce windshield time
- Reduce equipment repair and maintenance
- Reduce unplanned well downtime

**SAFETY**
- Remote, real time knowledge of well parameters
- Remote shut-in of wells when necessary
- Less drive time - fuel, insurance, maintenance
## Benefits

<table>
<thead>
<tr>
<th>WELL # 1</th>
<th>PRODUCTION</th>
<th>DOWNTIME</th>
<th>VENTING</th>
<th>REPLACE PLUNGER</th>
</tr>
</thead>
<tbody>
<tr>
<td>BEFORE</td>
<td>148 Mcf / d</td>
<td>22 %</td>
<td>3 X per Wk</td>
<td>Quarterly</td>
</tr>
<tr>
<td>AFTER</td>
<td>186 Mcf / d</td>
<td>8 %</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td></td>
<td>(25.7% Increase)</td>
<td>(63.6% Decrease)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>WELL # 2</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>BEFORE</td>
<td>82 Mcf / d</td>
<td>60 %</td>
<td>Daily</td>
<td>Quarterly</td>
</tr>
<tr>
<td>AFTER</td>
<td>212 Mcf / d</td>
<td>10 %</td>
<td>None</td>
<td>None</td>
</tr>
<tr>
<td></td>
<td>(158 % Increase)</td>
<td>(83.3% Decrease)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
Limitations

- Requires operator training!
- Typical less than 100 bbls/day
- Can move over 200 bbls/day
- Low gas to liquid ratios
- Insufficient gas volume or pressure
- Difficult with small tubing ID
- High sand production
- Extreme paraffin content
- Excessive hydrates
- Low gravity crude oil

- Tubing set to high or low
- Flow line restrictions
- Holes in tubing
- Inconsistent tubing ID
- Packer requires higher GLR
- BHS less than 60 degree deviation
- Greater than 10 deg / 100 ft dog leg
Economics

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

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

Maintain wells natural decline curve. Don’t wait till production is lost!
Use the Natural Decline Curve to estimate production increases.

PCS Ferguson Plunger Lift Equipment Catalogue - 2016

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.

$15,000 to $25,000

Days to Pay Off Plunger Lift System
Example Production Increase of 50 Mcf/Day

Gas Prices (Dollars/Mcf)

<table>
<thead>
<tr>
<th>Price</th>
<th>Days</th>
</tr>
</thead>
<tbody>
<tr>
<td>$2.00</td>
<td>45</td>
</tr>
<tr>
<td>$3.00</td>
<td>40</td>
</tr>
<tr>
<td>$4.00</td>
<td>30</td>
</tr>
<tr>
<td>$5.00</td>
<td>20</td>
</tr>
</tbody>
</table>

*Assumes average system cost of $4,500

The investment in a PCS Ferguson Plunger Lift system typically runs between $2,500 and $10,000. A plunger lift system could increase production by 100 Mcf/day or more.
“It has been Conoco’s experience, with more than 200 plunger lift systems in the San Juan basin, that the plunger operator is the single most important factor in keeping a plunger system operating efficiently. If an operator knows certain principles of plunger operation and gas well mechanics, he can effectively maintain and troubleshoot the system. His goal will be to optimize the system, keep a good maintenance schedule and attempt to flow the well against the lowest pressures possible. If an operator does not understand these principles, a system will loss efficiency due to poor maintenance. An operator who does not understand basic principles may try to “just keep the plunger running,” and he may be frustrated when the system does not work well.”

Dan Phillips, Conoco Inc., Farmington, New Mexico
and Scott Listiak, Conoco Inc, Midland, Texas
Linkedin Group

“Plunger Lifted Gas Wells”

ADDENDUM
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>
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<td>10</td>
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<td>23 ft</td>
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<tr>
<td>20</td>
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<td>46 ft</td>
<td>231 ft</td>
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<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>
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<td>70</td>
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<td>90</td>
<td>1.202</td>
<td>208 ft</td>
<td>1039 ft</td>
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<tr>
<td>100</td>
<td>1.336</td>
<td>231 ft</td>
<td>1154 ft</td>
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<td>125</td>
<td>1.670</td>
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<td>1443 ft</td>
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<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)

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

- \( CP = \) Casing Pressure; \( SLP = \) Sales Line Pressure
- \( A_{ann} = \) Area Annulus; \( A_{tbg} = \) Area Tubing
- \( P_p = \) Pressure required to lift just the plunger
- \( P_c = \) Pressure Required to lift 1 bbl of fluid and overcome friction
- \( FV = \) Fluid Volume above the Plunger
- \( K = \) Constant accounting for gas friction below the plunger
- \( D = \) 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>
Critical Flow Rate (Coleman, $P_f$ Less Than 1,000 psi)

- $C_{V_{\text{water}}} = 4.434 \times [(67 - 0.0031P_f)^{1/4}] / [(0.0031P_f)^{1/2}]$
- $C_{V_{\text{condensate}}} = 3.369 \times [(45 - 0.0031P_f)^{1/4}] / [(0.0031P_f)^{1/2}]$
- $FR = CV \times [\pi \times (ID/2)^2] \times (1 \text{ ft/144 in}^2) \times 86,400 \text{ sec/day}$
- $CV = \text{Critical Velocity (ft/sec)}$
- $FR = \text{Flow Rate (scf/d)}$
- $P_f = \text{Flowing Pressure}$
- $ID = \text{Tubing Inner Diameter}$

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

- Turner = Coleman + 20%
\[ \text{SCF} = \text{ACF} \times \frac{P_f}{P_s} \times \frac{T_s}{T_f} \]

- SCF = Standard Cubic Foot of gas
  - Volume of gas contained in 1 ft\(^3\) 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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