Deliquification of Gas Well with Plunger Lift
Major Concepts

• Plunger lift is one of the top 2 ways to lift liquid loaded gas wells.

• Limited by GLR
  – Old rule 300 scf/bbl/1000 feet requires ideal conditions.
  – Better Rule Greater than 1000 scf/bbl/1000 feet or 700 m3/m3/1000m

• The higher the surface pressure, the more build pressure and GLR you need especially above 250-300 psi (1600-2100 kPa).

• Solids are not plungers friends – the more sand/scale etc. the more likely there will be problems.

• Deviation can be handled but there are limitations
  – Must be below 60 Degrees if more than 3 degrees per 100 feet the length of plunger must be limited.
Reference Definition

- Conventional Plunger Lift – A plunger that requires shut in time for the plunger to fall to bottom. Well builds pressure during shut in time.

- Continuous Flow Plunger Lift – Typically bypass plungers with a valve system that allows fall against flow. Also known as Velocity Plunger Lift as it requires the gas velocity to lift the plunger rather than a build pressure.
Liquid Loading - Loss of Gas Velocity Over Time

Decreasing Gas Rate with Decreasing Reservoir Pressure

Initial Production

Stable Flow

Unstable Flow

Stable Flow

Highest Velocity

Gas Velocity

Lowest Velocity

Well Dead

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**What Causes it - Liquid Loading: Turner Equation**

**Gravity**

**Gas Flow**

**Water Droplet**

Drag from flowing gas is tending to lift water droplet which is reacting to **GRAVITY** and trying to remain at bottom of a well.

**Turner Equation:** Calculates Flow Velocity that keeps “Liquid Drop” Stationary in flow stream; Calculate Critical Velocity necessary to maintain Drag Force.

**VELOCITY OF FLOW IN THE TUBULAR CONFIGURATION THAT WILL CAUSE DROPLET TO REMAIN STATIONARY**

\[ V_c = 1.593 \frac{\sigma^{1/4}(\rho_{\text{Liquid}} - \rho_{\text{Gas}})^{1/4}}{\rho_{\text{Gas}}^{1/2}} \]

Turner Equation
Turner Equations
... Determine Critical Flow Rate for Liquid Loading of Gas Wells

Critical Velocity for API Tubing (OD/ID)

Flow Rate (MSCFD)

Pressure (Psi)

- 1.90/1.61
- 2 1/16"/1.75
- 2 3/8"/1.995
- 2 7/8"/2.441
- 3.5"/2.867
So Why do People Use Plungers?
Plunger Lift Systems Applications

• Unload wells that continue to load up with produced wellbore fluids.

• Reduce fallback in wells being produced by intermittent gas lift.

• Enhance production in high gas/liquid ratio wells.

• Clean tubing ID in wells experiencing paraffin problems.
Plunger Lift System Advantages

- Requires no outside energy source; uses well’s energy to lift
- Dewatering gas wells
- Rig not required for installation
- Easy maintenance
- Keeps well cleaned of paraffin deposits
- Low-cost artificial lift method
- Handles gassy wells
- Good in deviated wells
- Can produce well to depletion
Plunger Lift System Limitations

- Specific GLRs to drive system
  - Around 700-1000 m3/m3/1000m
- Low-volume potential (30 m3/day of fluid)
- Major Solid Production
So Let’s Talk Evaluation of a Good Candidate
Things needed for a good plunger candidate

• Completion
  – Ideally a consistent ID string of Tubing with the end of tubing into the perforations.
  • Too high may leave fluid back on perforations possible solution flow tube.
  • Sumped makes getting gas to the plunger difficult may require perforating tubing.
  • Rule of thumb say 1/3 into perforations
  – Better with no packer to use annulus for pressure storage
Things needed for a good plunger candidate

Production Capability within range of plunger application

- Flowing Wellhead
  - Pressure < 1600 kPa or 250 psi
    - No Packer: need greater than 0.5 E3/m3/100m or 500 scf/bbl/1000 ft
    - Packer: need greater than 1 E3/m3/1000m or 1000 scf/bbl/1000 ft
- Flowing Wellhead
  - Pressure > 1600 kPa or 250 psi
    - No Packer: need greater than 1 E3/m3/1000m or 1000 scf/bbl/1000 ft
    - Packer: need greater than 2 E3/m3/1000m or 2000 scf/bbl/1000 ft
Things needed for a good plunger candidate

- Production Capability within range of plunger application

- These production rates should be evaluated with a decline analysis to ensure liquid loading issues and potential uplift.
Things needed for a good plunger candidate

- Ability to achieve gas velocity by either
  - The wells natural flow rates
    - If a well can flow at over 3 m/s (10 ft/s) velocity but not over critical it can seal a plunger (see next slide)
  - Building Pressure
    - If a well can’t flow over 3 m/s (10 Ft/s) velocity it will require some shut in time to build pressure and achieve a seal.
Things needed for a good plunger candidate

- Ability to achieve gas velocity by either
  - The wells natural flow rates
Things needed for a good plunger candidate

• Ability to achieve gas velocity by either
  – Building Pressure

• Quick Tests
  – Line Pressure X 1.5 = Necessary Casing Pressure Build
  – Load Factor (Below)

(Casing-Tubing)/(Casing-Line)=Load Factor

Load Factor needs to be Less than 50%

Example

SI well Casing pressure = 400 psi
Tubing Pressure = 200 psi
Line pressure = 100 psi

(400-200)/(400-100)=66% (no arrival)

Tubing Pressure = 300 psi

(400-300)/(400-100)=33% (should get an arrival)
Things needed for a good plunger candidate

- Ability to achieve gas velocity by either
  - Building Pressure
  - Foss and Gaul (the hard way)

\[ P_{cmin} = \left[ (P_p + P_{lp} + (P_{lw} + P_{lf}) \times L) \times (1 + (D/K)) \right] \]

- \( P_{cmin} \) = Minimum Pressure Necessary to Cycle Plunger
- \( P_p \) = Pressure to lift weight of plunger.
- \( P_{lp} \) = Flow-line pressure.
- \( P_{lw} \) = Pressure to lift weight of liquid per barrel.
- \( P_{lf} \) = Liquid frictional pressure loss per barrel.
- \( L \) = Load size, bbls
- \( D \) = Depth of tubing, ft
- \( K \) = Constant to show relationship between tubing size and pressure loses due to friction.
Things needed for a good plunger candidate

• Consistent Wellhead Size with Tubing Size
  – Ideally 2 3/8” Tubing matched up with 2 1/16” Wellhead etc.

• Surface Facilities capable of High instantaneous rates and shut in periods

• Minimal Sand and Solid Production
Things your service company needs to provide Initially

- Installation, line out and optimization.
- Equipment inspection, replacement, and scheduled optimization.
- Complete Evaluations with solid technical expertise for candidate selection assistance.
- Equipment material suitable for the conditions.
- Availability for training, service, and technical assistance on the customers time line
Plunger Lift Equipment Overview
Bumper Springs/Standing Valve

- Free fall set from surface
- Ball and seat option
- Wireline retrievable
- H₂S service available
Collar Stop and Tubing Stop

- Type A tubing stop
- Type F collar stop
- Used when tubing is open ended
- Wireline set
- Wireline retrievable
Downhole Profile
Surface Hookup
Conventional Plungers
Conventional Plungers

**Description:**

- **Pad Plungers**
  - Metal/metal seal
  - High efficiency, even after cycling for months

- **Brush Plungers**
  - Fiber seal
  - Initially efficient seal

- **Solid-Ring Plungers**
  - Turbulent seal
  - Least-efficient seal

**Applications:**

- **Pad Plungers**
  - Very low solid movement (sand, scale)
  - Maximum seal necessary to move fluid

- **Brush Plungers**
  - Sand movement
  - Some cases necessary for efficiency

- **Solid-Ring Plungers**
  - Scales application
  - Dry-trip potential
  - Poor monitoring in field (no moving parts)
Life of a Plunger Well

A-Well Flowing Above Critical

B-Well flowing just below critical (High Speed Spiral Continuous Flow)

C-Well flowing below 5 m/s Padded Continuous Flow

D-Well flowing below 3 m/s Conventional

E-Low Reservoir pressure and inflow Seal very Important, consideration for Staging Plungerlift
**High-Speed Continuous-Flow Plungers**

**Description:**
- Solid-ring seal
- Large amount of flow through center for maximum falling velocity
- Trip rod at surface to separate ball from sleeve, or open valve to allow flow through.
- 1.24-in² cross-sectional bypass (compared to 0.60-in² on padded bypass)

**Applications:**
- Wells that have just fallen below critical velocity but still have +5 m/s velocity available
- Single-well compression (low suction pressures, high velocity, no downtime necessary)
- Very Wet Wells (more trips than possible with conventional plungers)
- Excellent range of usage on low line-pressure wells

*RapidFlo™*
Where does this happen?
Padded/Brush Continuous-Flow Plungers

Description:

- Bypass-type plungers (allow flow through the plunger) with pad seal
- May have internal trip rod or trip rod in lubricator to trip valve
- 0.60-in$^2$ cross-sectional bypass (compared to 1.24-in$^2$ on high-speed bypass)

Applications:

- 3-5 m/s velocities for continuous flow
- High fluid producers with quick build times for quick trip application
- Can be run at slightly higher line pressures than high speed plungers because of increased seal at lower velocities
Where does this happen?
Example of Application

Well successfully operating a conventional 2 3/8” Pad x Pad Plunger to 350 psi line pressure however there appeared to be additional gas production possible if well unloaded continually.
Progressive Plunger Lift
What is it?

- By adding an additional plunger in the tubing string and “staging” the transfer of fluid the well is produced in a more efficient manner.

- The system includes from bottom to surface

  1. A typical bottom hole bumper spring
  2. A solid ring plunger for the bottom stage
  3. An ILA-Intermediate Landing Assembly (see right) made up of two bumper springs (one facing up/one down) a sealing component, a check valve and a tubing stop.
  4. Another plunger for the upper stage (usually a double pad)
  5. A Lubricator to receive the upper plunger.
Where is it Used (What makes a Good Candidate)

- Primarily used in wells that have GLR’s below what is necessary to lift a conventional plunger.
- Generally wells that barely make the required gas for lifting a plunger from bottom with the required fluid loads.
- Wells that shut in on arrival due to significant inflow of fluid during lift cycle.
- Field Trials indicate that it decreases lift gas by 1-3 Mcf per Barrel.
- Also used in wells which are depleted to the point that they no longer can lift using available casing pressure builds.
- Wells that have previously been considered Rod Pump Candidates.
Progressive Plunger System

Results

• More Cycles with less fluid per cycle resulting in more total production.

• Well can keep up with fluid as it is delivered from the formation.

• Casing Pressure is reduced therefore reducing back pressure and increasing inflow.

• Well does not need to vent (all gas is produced down sales line)

• Cycle’s are more regular
Lubricators

- Cushions plunger upon arrival into wellhead to prevent damage

- Single or dual outlet
- Catcher option
- Sensor mount
- Threaded outlets
- Spring-loaded cap and striker pad
Accessories - Common between competitors

- Motor valves
- Sensor switch
- Solar panels
- Strap-on sensors
- Drip pot w/ regulators
- Control pilots
  - Pressure reducing
  - Differential control
- Gas filters
Controllers

Computerized means of opening and closing motor valve based on programmed responses or sets of parameters (sequence of events)

Controller options:

- On/Off
- On/Off with Arrival Recognition
- Self adjusting on Arrival time only
- Pressure Based
- Complete Automated Systems
History of Plunger Lift Control

Evolution of plunger lift control
- Time cycle control
  » On time -- off time
- Time cycle with plunger arrival recognition
  » On time -- sales time -- off time
- Auto-adjust time cycle
  » Adjust time settings by reacting to failure
  » Plunger traveling -- too fast, too slow, none
- Pressure based Stand Alone control
  » Operates on the pressure build of the well and on current operating conditions optimizing every cycle based on the wells capability and the systems capacity.
- Pressure based Auto-Adjust w/ Communications
  » Central based communications provide-pressure based control as well as adjustable settings from a central Host.
Different System’s

• Time Static Control – Changes are made only by operations, an optimization opportunity is recognized and changes are made directly to sales time or off time.

• Auto-Adjust – Changes are made based on previous plunger arrival time. Fast Arrivals = Less Off time, more sales time. Slow arrivals = More Off time, less sales time.

• Pressure Control
  – Steady Pressures – Well cycles based on pre-set pressure conditions, well optimizes based on live well conditions. Changes to set pressures are made by operations.
CEO II Controller (Simple On/Off High Low)

• This controller can be used as our On/Off Controller with On, Off, Sales, Plunger Fall and Shut-In settings.

• Also used as a High/Low Controller

• The upgrade for this controller also has an Auto-Tune Feature (Next Slide)
CEO II+ Auto Tune Option

Figure 18: Auto Tune Adjustments

*At least one second
Normal Plunger Cycle

- Off Time or Shut In Time
  - Solenoid opens Control Valve
  - Well continues Shut In, Builds Pressure

- A-On Time
  - Plunger Arrives

- Sales or After-Flow Time
  - Plunger Arrives

- Plunger Fall Time
  - Solenoid Closes Control Valve

- Normal Plunger Cycle
  - Normal Plunger Cycle
  - Normal Plunger Cycle
  - Normal Plunger Cycle

- Normal Plunger Cycle
  - Normal Plunger Cycle
  - Normal Plunger Cycle
  - Normal Plunger Cycle
Pressure Based Control

Controller Information

- 6 Analog Inputs (1-5V or 4-20 mA) Currently used for Tubing, Casing, Line, and Differential pressure as well as Temperature which can be used for optimization

- Digital Inputs (Plunger Arrival switch, Murphy switch, tank float switch etc.)

- Digital Outputs (3 currently used on pulse valve operation)

- Certified to Class 1 Div 2 Class A,B,C,D or non-hazardous location

- Communicates using RS-232 and 485 protocols
On Pressure Limit Control

Commonly Used Operating Parameters for Plunger Lift Well Control
Using Flow and Pressure-operated Control System

Initiate on cycle for plunger lift when:

1. Tubing pressure > or = on pressure limit
   (looks for tubing pressure to exceed a set point)

2. Casing pressure > or = on pressure limit
   (looks for casing pressure to exceed a set point)

3. Tubing – line > or = on pressure limit
   (looks for tubing pressure to build to a set point above line pressure)

4. Casing – line > or = on pressure limit
   (looks for casing pressure to build to a set point above line pressure)

5. Foss and Gaul Calculations
   (looks for casing to reach a calculated value)
Off Pressure Limit Control

Initiate off cycle for plunger lift when:

1. Plunger has arrived (used on oil wells)
2. Casing pressure $\leq$ off pressure limit (looks for casing to fall below a set pressure)
3. HW $\leq$ off pressure limit (looks for flow rate to fall below a set differential in inches of water)
4. Flow Rate (Sometimes a calculated Turner Rate)
5. Casing-tubing $\geq$ off pressure limit (looks for differential between casing and tubing to increase)
6. Casing To Tubing Sway looks for the casing and tubing pressure to start moving apart from each other.
7. Casing to Line $\geq$ off pressure limit (looks for differential between casing and line pressure to increase)
Foss and Gaul Calculation

- A calculation in the controller to consistently perform a Foss and Gaul calculation establishing the proper moment to kick the well off.
  - This calculation is a relationship accounting for fluid load, surface pressure, casing size, tubing size, frictions and depth.
  - This calculation allows the opportunity to completely compensate for changing line pressure as well as changes in inflow.
In order to completely optimize a casing-communicated well that produces minimal fluid loads it is sometimes necessary to flow the well below critical velocity until fluid begins to accumulate to a point to where a significant load has been achieved.
Casing-Tubing Sway

1. Identify Point where Casing and Tubing get as close to each other as possible.

2. Identify when they start to move apart from each other.

3. Allow the pressures to move a set amount apart to ensure that the well can not unload on it’s own again.

4. Shut in once the minimal point plus the allowed sway has been met.
Pressure based communicated devices

 Controllers can be configured in the field or from the central host
New Technology for Analyzing Plunger Lift
Plunger Falling Through Gas & Liquid

200 Ft/min
Gas

39 Ft/min
Liquid

Plunger Hits Liquid

Plunger on Bottom

Zoom in on Axis From 40.554 to 13 mins
Count Collars for Fall Velocity & Depth
Plunger Depth and Fall Velocity

Normally, Velocity Decreases as Plunger Falls Deeper into Well

- Begin - 250 ft/min
- End - 131 ft/min

Collar # C227
Depth to Plunger: 7309.40 ft
Plunger Fall Velocity: 131.43 ft/min
Elapsed Time: 47.459 mins

Depth to Plunger: 7313.12 ft
Bottom of Tubing: 7773.00 ft

Normally, Velocity Decreases as Plunger Falls Deeper into Well
Evaluation

1. Establish decline curve (if well has ever flowed above critical).

2. Use the decline curve and any available pressure (casing, flowing gradients) to ensure that liquid loading is a problem.

3. Apply quick tests to establish if the well is a candidate using rule’s of thumb’s (spreadsheet).
Evaluation

4. Establish velocity (either calculate or use graphs)
   - Use available velocity to establish whether well is a high speed continuous flow application (+15 ft/s or 5m/s), pad bypass application (10-15 ft/s or 3-5 m/s).
   - If velocity is not available begin Foss and Gaul Calculations for Conventional Plunger lift (see next).


6. If well does not qualify for plungerlift review other forms of artificial lift and compression.
Evaluation - Using Decline Curve and Pressure Data to Establish Loading.
Evaluation—Using Decline Curve and Pressure Data to Establish Loading.

Well Parameters

1) Flowing Casing pressure (if no packer present)

2) Flowing Gradient Data and Flowing Bottom Hole pressure.

3) LGR before liquid loading and after.

What the parameters mean

1. Casing/Tubing differential usually indicates fluid in the tubing if the well is lower than the friction point.

2. Flowing gradient data can be used to figure out flow regimes and flowing bottom hole pressure can be used both in IPR calculation and liquid level calculation.

3. The LGR number can help establish what should be expected if the well was unloaded as well as the amount of fluid that needs to be moved to get the well unloaded.
Evaluation—Using Decline Curve and Pressure Data to Establish Loading.

4) Daily fluid and gas production. Daily Fluid can give indication to erratic fluid entry as well as well unloading itself. These numbers need to be matched to daily gas to establish which of the two it is.

5) Minute by minute gas production. Gives indication whether the well is sweeping the chart or is consistently flowing. Used to indicate flow regime.

6) Operator Input. Most important factor, Operator can tell you what the well does and how it reacts and what needs to be done to keep the well unloaded.
### Quick Calculations to see if a well is a plunger candidate

<table>
<thead>
<tr>
<th>Flowing Wellhead Pressure</th>
<th>No Packer requirement</th>
<th>Packer requirement</th>
</tr>
</thead>
<tbody>
<tr>
<td><code>&lt;1600 kPa or 250 psi</code></td>
<td>greater than 0.5 E³/m³/100m or 500 scf/bbl/1000 ft</td>
<td>greater than 1 E³/m³/1000m or 1000 scf/bbl/1000 ft</td>
</tr>
<tr>
<td><code>&gt;1600 kPa or 250 psi</code></td>
<td>greater than 1 E³/m³/1000m or 1000 scf/bbl/1000 ft</td>
<td>greater than 2 E³/m³/1000m or 2000 scf/bbl/1000 ft</td>
</tr>
</tbody>
</table>
Pressures to see if a well will lift a plunger.

Load Factor

\[(\text{Casing-Tubing})/(\text{Casing-Line})=\text{Load Factor}\]

Load Factor needs to be Less than 50%

Example

SI well Casing pressure = 400 psi

Tubing Pressure = 200 psi

Line pressure = 100 psi

\[(400-200)/(400-100)=66\% \text{ (no arrival)}\]

Tubing Pressure = 300 psi

\[(400-300)/(400-100)=33\% \text{ (should get an arrival)}\]
Velocity Calculation

Velocity Equation from Turner (simplified)

\[ v_{crit} \ (ft/s) = \frac{5.62(67 - 0.0031P)^{1/4}}{(0.0031P)^{1/2}} \]

\[ V \ (mcf/d) = \frac{3.06\pi P v_{crit} \ (D/12)^{1/2}}{4(T + 460)Z} \]

- P = pressure (psi)
- D = wellbore diameter (inches)
- T = temperature (Deg F)
- Z = Z factor (dimensionless)
Velocity Using Graphs 2 3/8”

2 3/8” Tubing 0–1000 psi

- Critical Flow Rate

Flow Rate (Mcf/day)

Pressure (psi)
Velocity Using Graphs 2 3/8” (Metric)

2 3/8” Tubing 0-7000 kPa

Flow Rate (E3m3/day) vs. Pressure (kPa)
Plot Result—Choose appropriate correlation

Pressure and Temperature vs Depth Analysis for (Untitled)
Sensitivity To: Well and riser flow correlation

Coordinates: X = 170, Y = 2145.53, T = 68

<table>
<thead>
<tr>
<th>Gas</th>
<th>Condensate</th>
<th>Water</th>
</tr>
</thead>
<tbody>
<tr>
<td>Rate (MMSCF/day)</td>
<td>Rate (STB/day)</td>
<td>Rate (STB/MMSCF)</td>
</tr>
<tr>
<td>0.250</td>
<td>6,000</td>
<td>6,000</td>
</tr>
<tr>
<td>0.250</td>
<td>6,000</td>
<td>6,000</td>
</tr>
<tr>
<td>0.250</td>
<td>5,000</td>
<td>5,000</td>
</tr>
</tbody>
</table>
Results

Turner unloading velocity and in-situ gas velocity vs Depth Analysis for (Untitled)

<table>
<thead>
<tr>
<th>Gas Rate (MMSCF/day)</th>
<th>Condensate Rate (STB/day)</th>
<th>Water Rate (STB/day)</th>
<th>WGR</th>
<th>GSR</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.200</td>
<td>2.000</td>
<td>0.000</td>
<td>40.000</td>
<td>40.000</td>
</tr>
</tbody>
</table>
Foss and Gaul Minimum Plunger Cycling Pressure Equation

\[ P_{\text{cmin}} = [(P_p + P_{lp} + (P_{lw} + P_{lf}) \times L) \times (1 + (D/K))] \]

- \( P_{\text{cmin}} \) = Minimum Pressure Necessary to Cycle Plunger
- \( P_p \) = Pressure to lift weight of plunger.
- \( P_{lp} \) = Flow-line pressure.
- \( P_{lw} \) = Pressure to lift weight of liquid per barrel.
- \( P_{lf} \) = Liquid frictional pressure loss per barrel.
- \( L \) = Load size, bbls
- \( D \) = Depth of tubing, ft
- \( K \) = Constant to show relationship between tubing size and pressure loses due to friction.
### Weatherford Plunger Analysis Worksheet

#### General Information

- **Well Name:** [Redacted]
- **Field Name:** [Redacted]
- **Compan y Name:** [Redacted]
- **Date:** April 14, 2007

#### Foes and Goal Calculation Results

<table>
<thead>
<tr>
<th>Metric</th>
<th>Unit</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Maximum Casing Pressure to Cycle Plunger</td>
<td>psi</td>
<td>1800</td>
</tr>
<tr>
<td>Average Casing Pressure</td>
<td>psi</td>
<td>945</td>
</tr>
<tr>
<td>Minimum Casing Pressure</td>
<td>psi</td>
<td>491</td>
</tr>
<tr>
<td>NetSize</td>
<td>psi</td>
<td>6.6</td>
</tr>
<tr>
<td>Additional Casing Pressure Necessary</td>
<td>psi</td>
<td>0.59</td>
</tr>
<tr>
<td>No. of Cycles necessary to lift fluid</td>
<td></td>
<td>25</td>
</tr>
<tr>
<td>Actual #Cycles</td>
<td></td>
<td>16.90</td>
</tr>
<tr>
<td>Actual #Cycles</td>
<td></td>
<td>16.90</td>
</tr>
<tr>
<td>Gas used to cycle plunger</td>
<td>psi/1000</td>
<td>0.4</td>
</tr>
</tbody>
</table>

#### Critical Flow Calculations (Turner & Coleman)

<table>
<thead>
<tr>
<th>Metric</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current critical velocity (surplus)</td>
<td>0.55</td>
</tr>
<tr>
<td>Current critical velocity of BH (outlet)</td>
<td>0.4</td>
</tr>
<tr>
<td>Critical velocity at BH (unbalanced)</td>
<td>5.1</td>
</tr>
<tr>
<td>Current critical flow rate (surplus)</td>
<td>0.83</td>
</tr>
</tbody>
</table>

#### Continuous Flow Calculations

<table>
<thead>
<tr>
<th>Metric</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Current velocity (surplus)</td>
<td>0.91</td>
</tr>
<tr>
<td>Current velocity (outlet)</td>
<td>0.6</td>
</tr>
<tr>
<td>Velocity Unleaded (Surplus)</td>
<td>5.14</td>
</tr>
<tr>
<td>Minimum fluid in cycles at outlet</td>
<td>3.0</td>
</tr>
<tr>
<td>Efficiency</td>
<td>66.7</td>
</tr>
<tr>
<td>Maximum fluid in cycles at outlet</td>
<td>9.3</td>
</tr>
<tr>
<td>Upwards time at efficiency</td>
<td>11.1</td>
</tr>
<tr>
<td>Type of Plunger</td>
<td>Rapid Flo Plunger</td>
</tr>
</tbody>
</table>

---

**Notes:**
- [Redacted] details for certain calculations.
- [Redacted] some values for specific parameters.
Foss and Gaul Calculation

Parameters Example

2 3/8” Tubing set at 10000 ft with packer less completion in 4.5” casing

Produced with a LGR of 50 bbls/MMcf until it reach critical velocity.

Currently producing @ average of 20 Mcf/day however decline curve says well should produce @ 100 Mcf/day. Current fluid around 1 bbl/day mix oil and water.

Flowing to 100 psi line pressure Casing pressure fluctuates between 130 unloaded up to 360 loaded.

1 Hour SI when unloaded. Builds from 130 to 300 psi.

Example Results

Decline shows the well should be doing 100 Mcf/day using the LGR from over critical we should be making 5 bbls/fluidday with that 100 along with some extra for the time below critical.

Foss and Gaul tells us that we can unload ½ bbl per cycle with a build up of 300 psi and we should be able to run 20 times a day initially to clean up and level out at around 10 runs a day once near wellbore is cleaned up.
Example Completion Parameter

Completion

2 3/8” Tubing to 10000 ft (3115 m) in 4.5” Casing

100 ft (31.1m) of perforations, tubing hung 30 ft (9.3 m) into perforations

No Packer

Wellhead 2 1/16”

Perforations clear (no sand)

Tubing gauged @ 1.901” (48.92 mm)

Good Completion for Plungerlift
Example #1 Decline Curve

Production vs Time Example #1

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Example #1 Decline Curve Analyzed

Production vs Time Example #1

Liquid Loading Point
Example Well #1 parameters

**Imperial**

Production Data (Current) Average

200 Mcf/day w/ 4 bbls of water and 4 bbls of oil per day. LGR of 40 bbls/MMcf producing to 100 psi line pressure.

Production Data (past)

500 Mcf/day w/ 12.5 bbls of water and 12.5 bbls of oil per day. LGR of 50 bbls/MMcf

Decline shows well should be at 250 Mcf/day w/ 6 bbls Water and 6 bbls oil.

Well will build from 150 psi to 400 on casing in 1 hour when unloaded. Tubing pressure to 300 psi

Operator must unload well when line swings and production drops. Well normally has around 300-400 psi on casing.

**Metric**

Production Data (Current) Average

5.6 E3m3/day w/ 0.6 m3 of water and 0.6 m3 of oil per day. LGR of 0.2 m3/E3m3 producing to 690 kPa line pressure.

Production Data (past)

14 E3m3/day w/ 2 m3 of water and 2 m3 of oil per day. LGR of 0.29 m3/E3m3.

Decline shows well should be at 7 E3m3/day w/ 1 m3 of water and 1 of oil.

Well will build from 1034 kPa to 2800 kpa on casing in one hour when unloaded. Tubing pressure builds to 2068 kPa

Operator must unload well when line swings and production drops.
Quick Calculations

• Flowing WHP below 250 psi (200000 scf/8 bbls/10 *1000 feet) = 2500 which is greater than the 500 minimum

• Load Factor (400-300)/(400-100)=33% which is less than 50% so a good pressure build.

Flowing WHP below 1600 kPa (7E3m3/2m3/3115m) = 1.12 which is greater than the 0.5 rule.

Load factor (2800-2068)/(2800-690)=33% which is less then 50% so a good pressure build.
Example #1 Velocity

Velocity calculation = 17 ft/s

Velocity Calculation 5 m/s