Selection of Deliquification Method

- This presents methods of selection for discussion including:
  - Advantages / Disadvantages
  - Rules of thumb
  - Depth/ Rate capabilities
  - Power consumption
  - Operational considerations and other

_Update of Lea and Dunham Presentation_

Selection of Deliquification Method

- There is no generally accepted method
- There are many factors to consider
- This could be subject of best practice… API or otherwise
- Consideration of some factors can lead to improved selection
- Some (not all) important factors considered here

_Update of Lea and Dunham Presentation_
Some Popular Methods

1. Electrical submersible pumping
2. Progressing cavity pumping
3. Beam pumping
4. Hydraulic pumping
5. Gas lift
6. Velocity strings
7. Compression systems
8. Plungers
9. Foaming
10. Injection systems

Artificial Lift Selection Process

1. Make a Rough Cut with Artificial Lift Screening Criteria
2. Review Feasibility / Functionality of Artificial Lift Methods
3. Evaluate Cost --- CAPEX, OPEX
4. Consider Availability, Use of Reservoir Energy
5. Consider Availability of Required Infrastructure
6. Consider Availability of Required Operator Training
## Artificial Lift Selection

<table>
<thead>
<tr>
<th>Method</th>
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</table>

Increase Rate above Critical with Gaslift, Velocity String, Compression or Foam

Figure 1: Critical gas rate required vs. Wellhead Pressure (Coleman et al., see Reference 1)
Estimate Operating Power Cost from Efficiency Definition

- Operating Costs:
  - Power efficiency may be defined as: as a fraction of the power used to lift liquids divided by the total power supplied.
  - Assume 20hp load for all methods (when applicable), 4000' lift, 20 bpd, sp gr = 1.0 and efficiency as defined below. Assume 200 bpd for high rate lift methods.
  - k\(\text{W} = 0.00000736 \times 20 \times 4000 \times 1.0 \times 0.746 / \eta = 0.4356 / \eta\)
  - Assume electrical costs of $0.08/ (kW-hr)

- $/year = 0.4356 \times 0.08 \times 365 \times 24 / \eta = 305 / \eta$
- $/year \approx 300 / \eta$ for low rate case of 20 bpd
- $/year \approx 3000 / \eta$ for high rate case of 200 bpd

Method:
- ESP 40
- PCP 60
- Beam 50
- Hydraulic Jet 20
- Gas Lift 20
- Velocity Strings -
- Compression 80
- Plungers -
- Foaming -
- Injection Systems -

Screening of Artificial Lift Methods: For discussion: Updating may be required

Artificial Lift Screening for Deliquification of Gas Wells

Legend:
- ++ Very well suited for this situation
- + Well suited for this situation
- +/- May be OK, depending on details
- - Poorly suited for this situation
- -- Very poorly suited for this situation

Table 1: Screening matrix for lift methods designed to lift liquids off gas wells.

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>ESP</th>
<th>PCP</th>
<th>Beam</th>
<th>Hydraulic</th>
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### Production Characteristics

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### Location

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### FIELD EXAMPLES

#### Characteristic

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</table>

#### Selection from Depth-Rate Charts

**High Rate Lift Rate vs: Depth**

![Graph showing lift rate vs depth for different methods](image)

*After Weatherford*
Low Rate Lift Rate vs: Depth

After Weatherford

Inflow / Outflow for Various Lift Methods
Estimates for Discussion Only
Selection from Decision Tree

Examples Presented

Figure 4: An older selection chart developed for AL selection for gas wells in East Texas

Not suggested for use unless studied and altered for your field conditions, but example of selection decision tree.
Selection Chart: For discussion

Check for loading:
- Critical velocity or rate?
- Falls off decline curve and stays there?
- Initiation of slugging?
- Difference between tbg-csg pressure increases with time?
- Other?

Team meeting:
- Establish stable rate (swab?)
- Determine gas rate, condensate rate, water rate
- Some operators check flowing pressure survey

Screen AL method considering conditions

Sand?  PCP, Gaslift, Velocity String, Foam, some pumping methods
Hi-Rate? ESP, Gaslift, Velocity String, Beam, Other?
Hi Surf P? Compress, Pump, Other?
Lo Rate?

Preferred? For discussion:
1. Plunger (conventional, two piece, free cycle, other? if feasible)
2. Foam (soap sticks(shallow), batch treat with no packer, Cap tube injection with packer present if water and no high condensate.
3. Gaslift
4. Pumping methods (Beam, ESP, Diaphragm, PCP, Hydraulic, other?)
5. Consider special devices: Collar inserts, Vortex, Goal, other?
6. Inject water if feasible
Evaluation of Feasibility of Different Artificial Lift Methods

ESP’s

- ESP’s operate from shallow depths to as deep as 10,000’ and deeper.
- They can produce low rates but below about 400 bpd, the efficiency of the system suffers.
- They can produce 20,000 bpd in some cases.
- High temperatures can be a problem with a typical maximum of 275 °F up to 400 °F with special trim.
- They are installed in deviated wells, but the unit must be landed such that it is straight even if the wellbore is deviated.
- Power must be available and is transmitted down a three phase cable to the motor.
- Small disposable units are used for shallow wells such as for coal bed methane to lift water off the coal seams.
- High solids concentrations may cause the unit to fail if they are allowed to be pumped, although special abrasion resistant units can be used.
**ESP’s**

- Recent applications have moved applications to low rates ~ 100-200 bpd.
- Techniques for low rates setting pump below the perforations include use of shroud, recirculation pump, derated motors.
- If you must sit pump above perforations options include rotary separators, Vortex separators, upturned shroud, and other.
- Companies have recently introduced new stages of ~100-200 bpd BEP.

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**PCP’s**

- PCP’s typically operate to 4500’ and in some cases to as deep as 6000’.
- At shallow depths they can produce up to 4,500 bpd.
- With elastomeric stators, the maximum temperature is about 150 °F.
- They can be used up to about 250 °F with special elastomeric materials.
- With rotating rods they can be installed in wells with a deviation of 15°/100’, but if run with ESP motors, deviation is no problem as long as the unit is straight although the wellbore is deviated.
- They can tolerate some sand production, and have high (40-70%) power efficiency.
- New materials may extend temperature limits. There is metal/metal PCP being tried and researched and published on as well.
PCP’s

- There are small rate PCP’s but for small rates it may be difficult to maintain fluid level over pump
- There are ESPCP and ESPCP-TTC options as well

Beam Lift

- These systems have operated to 16,000’ but a depth of 10,000 - 11,000’ is more typical of maximum operating depths with more standard equipment.
- Can pump to up to 5,000 bpd at shallow depths but the maximum production rate is greatly reduced at greater depth.
- Less than 1,000 bpd is more typical for most mid-depth applications.
- They can be used in deviated wells with slow build angles.
- Efficiency is good (45-60%).
- For gas wells with small liquid rates, slender rods, small diameter pumps, and low horsepower may be sufficient.
- If you can’t sit pump below perforations, beam or any pumping system may not be the best choice
Beam Lift

- There are special pumps to help handle sand, some recently appearing from manufacturer... CBM fines and frac sand
- There are special pumps for helping handle gas.
- There are recommendations for gas separators if you must sit above the perforations.

Hydraulics

- Both jet and reciprocating pumps can be run to 15,000’ or below.
- Both can produce up to 10,000 bpd, depending on depths.
- Both can run in 250 °F wells.
- The reciprocating pump cannot tolerate solids.
- Clean pressured power water or oil must be supplied to the pumps to make them operate.
- For gas well de-watering applications, typically a jet pump producing a few hundred or much less barrels per day is more common. The power efficiency is poor and intake pressure is not that low.
Hydraulics

- In general use of reciprocating hydraulics takes large casing size
- Use of jets is inefficient with power
- Depth capability and free pump capability keeps hydraulics a niche player.

Gaslift

- Gaslift can be used to 10,000 ft or more.
- Rates of 10,000 bpd or higher can be achieved.
- Solids can be produced.
- Valves are tubing retrievable.
- High pressure gas is needed.
- For slim holes, valves can be installed on slender tubing or coiled tubing.
- Wellbore temperatures to 250 °F are typical and can reach up to 400 °F with precautions.
- For gas well operation, typical rates are a few 100 bpd or less.
- For gas wells, you can recirculate gas at bottom of tubing with single point injection in some cases.
- With enough gas injected and with velocity over critical, the well will never liquid load.
**Gaslift**

- For most gaslift of gas wells, it is conventional gas lift with packer set. The rate of gas injected brings the total of gas produced and gas injected above the critical rate.

- There are techniques of injecting gas below the packer from SLB and from Weatherford and perhaps others to obtain some lift in extended perforations.

- There is little data to support what gaslift does in terms of bottom hole pressure drawdown for gas wells both with packer and injection below packers. Correlations differ widely. Measurements are in progress.

- In general with low liquids (~100-200 bpd) it is thought low pressures can be achieved with gaslift of gas wells.
- Higher rates are feasible with gaslift but the producing BHP's may not be as low as other methods.

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**Velocity String**

- A velocity string can be used to 10,000' or deeper.
- ID’s down to 1” are used although smaller ID tubing is hard to unload.
- Nodal analysis and critical velocity are used (see below) to help size the installations.
- Many successes are reported, usually for wells making more than several hundred bpd.
- For lower rates, plunger lift might be more applicable.
- String may have to be downsized even more in the future, where plunger could take the well do depletion
Velocity String

- Velocity strings work. There are good case histories especially when downsizing to 1 ½”. They might not last as long as other method (ie plunger) before change have to be made.

Compression

- Compression is used for single wells or for multiple wells.
- Nodal analysis will help predict the expected results to be achieved.
- Lower well head pressure has many beneficial effects.
- Lower pressure keeps water in vapor state so this is artificial lift method in itself
- Biggest percentage gains for low pressure wells
- Lower wellhead pressure improves artificial lift methods in general as well as flowing wells
**Compression**

- Once wells die completely, compression may not restart them without swabbing and other trouble.
- Compression is good combination method with plunger.
- Compression is needed to lower the annulus for pumping wells to achieve best results.

**Plunger Lift**

- If a gas-liquid ratio of 300 - 400 scf/bbl/1000' is present and some buildup pressure is available, the well requires no outside energy to produce when using a plunger.
- Another industry guideline is the well pressure must be 1½ times the line pressure.
- Use Operating Pressure/GLR charts vs Depth>>>
- Plungers can produce from great depths.
- Typically a plunger installation requires that the packer be removed, although free cycle or two piece plungers may operate with the packer in place.
- Plungers usually produce a low liquid production rate, but in some cases can produce up to 300 bpd.
- Usually no outside energy is needed to operate the system.
- Solids are a problem. Brush plunger allows operation with trace sand/solids
Plunger Lift Selection

• There are two kinds of plunger lift:

• Conventional and Continuous Flow

• There are selection criteria for both for discussion
Selection Rules for Conventional and Continuous Plunger

- Conventional plunger: 400 scf/bbl-1000’, 1000 scf/bbl-1000’ with packer, csg operating pressure builds to 1 ½ LP. LF below ~1/2 says plunger will rise when well opened. Foss & Gaul predicts csg operating pressure to lift slug size.

- Continuous Flow Plunger: One technique is to apply when rate is still > 80% of critical rate. Weatherford criteria (Hearn) on following few slides. Other companies may have other selection criteria for various plunger applications.

- Can shift back to conventional plunger when using continuous flow, must use >~20 minutes shut in time.
**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 0.80-in² on padded bypass)

**Applications:**
- Wells that have just fallen below critical velocity but still have +15-ft/s velocity available
- Single-well compression (low suction pressures, high velocity, no downtime necessary)
- High amounts of fluid (more trips than possible with conventional plungers)
- Excellent range of usage on low line-pressure wells

**High-Speed Continuous-Flow Plungers**

**Strengths:**
- No fall time necessary (no shut-in)
- Maximum amount of trips possible (smaller loads of fluid)
- Minimal amount of moving parts (minimal damage at high speeds)
- Simple to operate/optimize

**Limitations:**
- Poor seal
- No changes in OD for pipe ID changes
- +15-ft/s velocity necessary to maintain turbulent seal
- Velocity requirement
- +15-ft/s velocity is over critical at higher operating pressures (+500 PSI).
- Lower velocities result in plunger stalling out and becoming a restriction.
**Padded Continuous-Flow Plungers**

![Image of Padded Continuous-Flow Plungers]

**Padded/Brush Continuous-Flow Plungers**

<table>
<thead>
<tr>
<th>Description:</th>
<th>Applications:</th>
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| ・ 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-in² cross-sectional bypass (compared to 1.24-in² on high-speed bypass)  | ・ 10- to 15-ft/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 |
Padded Continuous-Flow Plungers

**Strengths:**
- Pad seal increases efficiency
- Pad seal allows for lower-velocity application than high-speed plungers
- Usually able to run combination plungers (pad by brush, pad by ring, pad by pad)

**Limitations:**
- Additional moving parts (pads, valve parts); more potential for damage at high speeds and dry drips
- Moving parts increase difficulty of running with sand
- Difficult to optimize because of varying travel times (plunger may sit on bottom, depending on whether fall speed was enough to reset)

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)
Conventional Plungers

**Strengths:** Pad Plungers
- Highly efficient seal as a result of actual contact with tubing walls at all times
- Will adjust for tight spots yet maintain seal at full OD
- Seal enables efficient moving of fluid at lower velocities

**Limitations:** Pad Plungers
- Fall slower than quick-drops and require fall time (fall at rates between 150- and 400-ft/min, depending on gas density and fluid level)
- Require maintenance to avoid breakage
- Moving parts may cause potential for fishing job

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Conventional Plungers

**Strengths:**
- **Brush Plungers**
  - Initial efficiency very high (most available in conventional)
  - Ability to move sand, fibers, allow for sand to be in fibers without sticking plungers
- **Solid Rings**
  - No moving parts, nothing to break, no pads to stick
  - Ability to “chip” at, and move through, scale

**Limitations:**
- **Brush Plungers**
  - Wear very quickly
  - Quick wear results in losses in efficiency
  - Expensive and difficult to rewrap
- **Solid Rings**
  - Poor seal, even initially
  - +15-ft/s velocity must be sustained to maintain turbulent seal
Often foam is used as a first attempt to unload because it is inexpensive to try.

It works much better with water and no condensate but some expensive chemical agents are predicted to foam condensates.

Use soap sticks in shallower wells and use batch treating or capillary tube injection for deeper wells depending on whether or not a packer is present.

Usually if condensate is produced, foam is not used.

Chlorides indicate formation water and lack of chlorides indicate condensation of water in the wellbore.

Typically foaming water reduces the required critical velocity to ½-1/3 of critical rate value without surfactants.
Foam
Foam is usually introduced into the well by:
1. Cap string lubricated down the tubing
2. Soap sticks down the tubing
3. Batch or continuous treatment down backside with packer removed

Some case histories show large production improvements of using cap strings to replace use of soap sticks.

Inject (water)
- Use these systems when only water is produced (no condensate) and if there is an underlying injection zone that will take the produced water.
- Back pressure on the tubing may help inject the water so gas can flow up the annulus.
- Frequency of use in industry is low.
- Western Kansas is area of reported higher use.
- This can be done using various beam pump systems and also using ESP systems for higher rates.