SELECTION OF ARTIFICIAL LIFT METHODS FOR DELIQUIFICATION OF GAS WELLS

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INTRODUCTION

As production drops in gas wells, the lower gas velocity allows more liquids to accumulate in the well.. The additional pressure on the perforations from the accumulating liquids either will reduce the flow of gas or stop it entirely.

There are a number of methods that have been developed to artificially remove these accumulated liquids so gas can flow at a higher rate. A summary list of the most popular methods includes the following:

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

Since there are these and other methods to choose from, there is a problem in selecting which method to choose. This paper contains guidelines to assist Production Operators, who are seeking to deliquify gas wells, with the selection of artificial lift methods to solve this problem. It is recognized that there are other methods such as a diagphragm pump that is under development and special devices such as tubing collar mixing devices, a vortex device to swirl the flow at the bottom of the tubing, and a device with several special configurations in the tubing to recombine the gas and liquids. Other methods also exist.

SCREENING

Table 1 is a simplified tool for screening methods of artificial lift that might be used for deliquifying gas wells. Not all considerations can be put into such a simplified screen tool. Here are some additional comments for each method to clarify some points.

ESP systems

This system has low efficiency below a production rate of about 400 bpd. As such, ESP's are normally used for higher production rate wells and not normally used for gas wells. There is an ESP system designed and configured to inject large/small volumes of water below a packer into an injection zone and allow gas to flow out of the well with no liquids and no water disposal expense. Good electrical power is required. Sand, high temperatures, and some types of corrosion reduce run ESP lives. Gas must be separated from the intake liquid for most ESP systems to work effectively. Small ESP systems are used extensively for dewatering coal bed methane wells.

PCP system

PCP's can handle some solids if they are run slower. They should not run in a pumped off condition or the stator elastomers may be damaged by high temperature. They are somewhat depth limited (4000 -5000 feet of depth begins to bring on problems). They can produce large volumes from shallow depths and smaller volumes at deeper depths, as is typical for lift systems.

BEAM PUMPING SYSTEM

Beam pumping systems typically pump liquids up the tubing and gas flows up the annulus. Gas must be separated from the pump intake preferably by setting the intake below the perforations; but if needed, by using a gas separator. This is a common deliquification system. For slim holes in shallower wells, coiled tubing has been used as rods and as the flow path. To handle any sand, special provisions must be made. At 10,000' only a few barrels per day of fluid can be produced.

HYDRAULICALLY POWERED PUMPS

Reciprocating and jet pumps can be powered with water or oil. A small jet pump can be installed in one inch coiled tubing (CT) and pumped out. The CT can be landed in 2 3/8's or 2 7/8's production tubing. This is not as popular as initially thought because the efficiency is poor, the power requirements are high, and the bottom-hole production pressure cannot be brought to very low levels. Some small amounts of solids and gas can be tolerated using the jet pump. The reciprocating pump has a low tolerance for solids.

Gaslift

Gaslift is commonly used for low to high rates of fluid production. If enough gas is injected to maintain the gas velocity above the critical velocity, then liquid loading will not occur. This is one way to visualize this application for gas wells. Pressurized gas is required to operate the system. Solids are tolerated. See Figure 1 for a chart to determine the critical rate such that if the gas rate is kept above the critical velocity, no liquid loading is predicted.

Plunger lift

Plunger lift is very common and works well even in deep wells. Some pressure and a significant gas to liquid ratio are required. New controllers help reduce operator time. The newer two-piece plunger and/or the free cycle plungers can obtain low well flowing pressures when they can be applied. Solids are in general not tolerated in plunger lift systems.

Compression to lower wellhead pressure

Wellhead compression can be used to lower the pressure and increase the gas production rate. It may bring the gas rate to above critical so no liquid loading will occur. Also lower pressures help to keep the liquids in the vapor state, so it may be considered a lift method in and of itself. For most types of compressors to lower the wellhead pressure, a liquid removal system must be maintained before the compressor suction. Compression is sometimes used to add gas to the annulus for plunger systems as well as to lower the well head pressure.

Foam using surfactants

Soap sticks are common launched manually or automatically down the tubing. For deeper wells they may not reach bottom. Periodic batch treating down the annulus is common if no packer is present. Use of a capillary ¼" tubing lubricated down the tubing will allow chemicals to reach bottom even when a packer is present. Lab tests should be made to determine if the chemicals proposed will foam the wellbore liquids, resulting in a lower effective density of liquids and a lower interfacial tension between liquids and gas.

Velocity string

Installing a smaller string of coiled tubing (any smaller ID tubing) can increase the gas velocity above critical and maintain unloaded flow for a period of time. Later a smaller string may have to be used to continue. Determining critical velocity or using a Nodal Analysis program are tools to determine if a velocity string could solve liquid loading problems. Small strings approaching 1" diameter are difficult to unload if a large slug of liquid is introduced into the string. Care must be taken to avoid adding excess friction to the system with a smaller flow passageway.

Injection of water

Some systems are designed (beam and ESP primarily) to pump water below a packer into an underlying injection zone, if such an injection zone is present. No surface disposal of water is required and gas flows freely up the well to the surface.

FEASIBILITY OF LIFTING METHODS

Figures 2 & 3 show depth/rate envelopes for the major lift methods. The charts comprise one form of feasibility analysis.

1. 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 ^{o}F up to 400 ^{o}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 coals. High solids concentrations may cause the unit to fail if they are allowed to be pumped, although special sand resistant units can be used.

2. 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 4500 bpd. With elastomeric stators, the maximum temperature is about 150 ^oF. They can be used up to about 250 ^oF 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.

3. Beam Pump

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. Figure 1 illustrates that they can pump to up to 5000 bpd at shallow depths but the maximum production rate is greatly reduced at greater depth. Less than 1000 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 and low horsepower may be sufficient.

4. Hydraulically Operated Pumps

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 ^oF 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.

5. 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 ^oF are typical and can reach up to 400 ^oF with precautions. For gas well operation, typical rates are a few 100 bpd or less.

6. Velocity String

A velocity string can be used to 10,000' or deeper. ID's 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.

7. 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.

8. 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 1 and ½ times the line pressure. 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 very low liquid production rate, but in some cases can produce up to 300 bpd. Usually no outside energy is needed to operate the system.

9. Foaming the Liquids

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.

10. Injection Systems

Use these systems only if 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 use.

ECONOMICS

Initial Costs

See Tables 2-11 for a summary of initial costs for the various systems of lift considered. There are many variations of what the costs may be as a function of depth, rate, and well conditions.

Operating Costs

Power efficiency may be defined as: $\eta = \dfrac{0.00000736(bpd)(Lift)\gamma}{kW/.746}$ 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.

kW = .00000736 x 20 x 4000 x 1.0 x 0.746/ η = 0.4356/η

Assume electrical costs of $0.08/ (kW-hr)
$/year = 0.4356 x 0.08 x 365 x 24 / η = 305 / η
$/year ≈ 300/$\eta$ for low rate case of 20 bpd
$/year ≈ 3000/$\eta$ for high rate case of 200 bpd

Below are electrical costs to operate the systems. Other costs such as maintenance, water disposal, replacement of failed equipment, pumper expense, and other routine costs are not included.

1. ESP's
   $/year ≈ 3000/$\eta$ for 200 bpd
   Assume η= 42%
   $/year = $7142.00

2. PCP's
   $/year ≈ 3000/$\eta$ for 200 bpd
   Assume η= 62%
   $/year = $4838.00/year

3. Beam Pump
   $/year ≈ 3000/$\eta$ for 200 bpd
   Assume η= 50%
   $/year = $6000.00/year

   $/year ≈ 300/$\eta$ for 20 bpd
   Assume η= 50%
   $/year = $600.00/year

4. Hydraulic Pump
   a) Jet Pump:
   $/year ≈ 3000/$\eta$ for 200 bpd
   Assume η= 20%
   $/year = $15,000/year
   b) Recip Pump:
   $/year ≈ 3000/$\eta$ for 200 bpd
   Assume η= 50%
   $/year = $6000.00/year

5. Gaslift
   $/year ≈ 3000/$\eta$ for 200 bpd
   Assume η= 20% for entire system
   $/year = $15,000/year

6. Velocity string
   N/A

7. Compression
   Just for an estimate, assume 200 Mscf/D delivered by a recip compressor with 83% efficiency with suction near zero and discharge at 50-60 psi with CR to 4.0

8. Plunger

N/A if feasible for operation with no outside compression etc.

$$hp \approx 0.223M(CR^{0.2} - 1.0)$$

Hp = 0.223x200($4^{0.2}$-1) = 14.25 or 10.6 kW

Cost/Year = 0.08 x 10.6 x 365 x 24 = $7449/year

9. Foaming

N/A for most systems

10. Injection Systems

$/year ≈ 3000/η for 200 bpd

Assume η= 40%

$/year = $7,500/year… could be much less if gravity helps do the injection

SELECTION FROM FLOW CHARTS

Figure 4 shows a selection or branching selection chart to pick the best method of artificial lift for a gas field in East Texas. Note that this chart is older and was developed before the time that plunger lift controllers had reached the development stage that they have now. As such, plungers today might have a much more important place on the chart. Also this is, of course, for a particular field and as such could be different for a field with different producing conditions.

SUMMARY

Selection of the artificial lift method to deliquify gas wells has been discussed using a screening matrix, feasibility criteria, economics with initial costs and energy costs, and a flow or selection chart. There are many criteria such as availability, familiarity, comparison to similar fields, and even using a more complete financial analysis such as present value or other methods. The discussion is provided hoping portions of the discussion will assist operators.

REFERENCES

1. Lea, J. F., "Solving Gas- Well Liquid-Loading Problems", Journal of Petroleum Technology, April, 2004, pp 30-74.
2. *Gas Well Deliquification*, by J. Lea, H. Nickens, and M. Wells, 1st Edition, Gulf Professional Publishing- Elsevier, 2003.

Table 1
Screening Matrix For Lift Methods Designed To Lift Liquids Off Gas Wells

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

Characteristic	ESP	PCP	Beam	Hydraulic	Gas-Lift	Plunger	Compress	Foam	Vel String	Inject
Well Conditions										
Deep	+	+/-	+/-	+/-	+/-	++	+	+	+	+/-
Shallow	+	+	+	+	+	++	+	+	++	+
Deviated	+/-	+/-	+/-	+/-	+	+	+	+	++	+
Small casing	-	+/-	+/-	-	+/-	+/-	+	+	+	+
Dual completion	--	-	-	-	+/-	-	+/-	+/-	+/-	+
Production Characteristics										
High production	++	+/-	-	+/-	+/-	--	+/-	-	++	+
Low production	-	+/-	+	+/-	+/-	++	++	++	+/-	+
High BHP	+	+	+	+	++	+/-	+/-	++	++	-
Low BHP	+/-	+/-	++	+/-	-	+	+	+	+/-	+
High GOR	-	+/-	--	-	++	++	++	+	++	+
Low GOR	+	+	+	+	-	-	--	--	-	+
Sandy	-	+/-	-	-	+/-	--	-	+	+	--
Sour	+/-	+/-	+/-	+/-	+/-	+	-	+	+	+/-

Characteristic	ESP	PCP	Beam	Hydraulic	Gas-Lift	Plunger	Compress	Foam	Vel String	Inject
Viscous	-	+/-	-	-	-	--	-	--	--	--
Corrosive	-	-	-	-	+/-	+	-	+	+	+/-
Location										
Onshore	+	+	+	+	+	++	+	+	+	+
Offshore	+/-	+/-	-	-	++	+	+/-	+/-	++	--
Sub-sea	+/-	-	-	-	+/-	-	-	-	+	--
Developed	+/-	+/-	-	-	+/-	++	-	++	++	++
Remote	+/-	+/-	+/-	-	+/-	++	+/-	+	++	+/-
Access to Power										
Good power	+	+	+	+	+/-	+	+/-	+	++	+/-
Poor power	-	-	+/-	-	+	+	+/-	+	++	+/-
No access to electrical power	--	--	+/-	--	+	+	+/-	+	++	+/-
Access to Spare Parts										
Ready access to spare parts	+	+	+	+	+	+	+	+	+	+
Poor access to spare parts	+/-	-	-	-	-	+/-	+/-	+	+	+

Characteristic	ESP	PCP	Beam	Hydraulic	Gas-Lift	Plunger	Compress	Foam	Vel String	Inject
Staff										
Trained engineers	+	+	+	+	+	+	+	+	+	+
No engineers	-	-	+/-	-	+/-	+/-	+/-	+/-	+/-	+/-
Trained operators	+	+	+	+	+	+	+	+	+	+
Untrained operators	-	-	+/-	-	+/-	-	-	+/-	+/-	+
Good access to service staff	+	+	+	+	+	+	+	+	+	+
Poor access to service staff	-	-	+/-	-	+/-	-	-	+/-	+	+
Budget Support										
Adequate capital budget	+	+	+	+	+	+	+	+	+	+
Limited capital budget	-	-	+/-	-	+/-	-	-	+/-	+/-	+/-
Adequate operating budget	+	+	+	+	+	+	+	+	+	+
Limited operating budget	-	-	+/-	-	+/-	+/-	-	+/-	+/-	+/-

Table 2
ESP System Initial Cost

DESCRIPTION	SIZE	TYPE	Cost	Operating Cost	COMMENTS
Motor	77 HP	2130V	$33,435		
Pump	340 Stage		$24,659		
Protector	FSB-3	400 Series	$8,732		
Cable	CPNR	Galv	$48,681		
Motor Lead Cable	40'	Monel	$1,327		
Starter Box	2400V		$15,753		
Vent Box			$547		
Wellhead			$1,028		5 1/2" x 2 3/8"
					x 4 Roun Cable
SERVICE					
Pulling Unit			$3,000		
Electricians			$1,500		
Electricity				.05 per KWH	

Table 3
PCP's: Example Initial Cost

Electric PC System to Produce 100 BPD From 3500 Ft. w/ 5-1/2" Casing and 2-3/8" Tubing.

Item #	Qty	Description	Net Sales Price	Extended Price
1	*1*	*Drivehead with Pinned Stuffing Box*	*$ 8,282.00*	*$ 8,282.00*
2	*1*	*20 Hp, Explosion Proof Electric Motor, 1200 RPM*	*$ 1,499.00*	*$ 1,499.00*
3	*1*	*Polished Rod - 1 1/4" x 22' Spray Metal*	*$ 150.00*	*$ 150.00*
4	*1*	*Sheaves, Belts and Bushings*	*$ 750.00*	*$ 750.00*
5	*140*	*7/8" D Sucker Rod w/ SH Class T Coupling (per Rod)*	*$ 42.22*	*$ 5,910.80*
6	*140*	*7/8" x 2" Spin-Thru Rod Guides 2 Per Rod*	*$ 27.00*	*$ 3,780.00*
7	*1*	*Rotor w/ 7/8" Pin*	*$ 1,939.00*	*$ 1,939.00*
8	*1*	*Stator, High Nitril Elastomer, High Speed*	*$ 2,956.00*	*$ 2,956.00*
9	*1*	*2-7/8" Slotted Tag Bar*	*$ 89.00*	*$ 89.00*
10	*1*	*2-7/8" x 4' Handling Sub*	*$ 75.00*	*$ 75.00*
11	*1*	*2-7/8" x 2-3/8" Change Over Collar*	*$ 81.50*	*$ 81.50*
12	*1*	*2-3/8" x 4' Handling Sub*	*$ 71.00*	*$ 71.00*
13	*1*	*Support System*	*$ 250.00*	*$ 250.00*
14	*1*	*Pumping Tee, Nipple, Bushing, etc.*	*$ 295.00*	*$ 295.00*
15	*1*	*20 Hp, VSD*	*$ 6,125.00*	*$ 6,125.00*
16	*1*	*2-7/8" x 5-1/2" No-Turn Tool*	*$ 1,495.00*	*$ 1,495.00*
			Price	***$ 33,748.30***

Table 4
Beam Pump System Initial Cost

DESCRIPTION	SIZE	TYPE	Cost	Operating Cost	COMMENTS
Pumping Unit	160 D	Lufkin	$35,000		
Engine/Motor	30/40HP		$1,500		
Starter Box					
Sucker Rods	3/4	D	$1.43/ft		
Sucker Rods	7/8	D	$1.80/ft		
Downhole Pump	1 1/2"		$1,200		
SERVICE					
Contract Truck/Crane			$1,500		
Lease Service			$1,000		
Electricians			$1,000		
Pulling Unit			$2,000		$200hr x 10hr

Table 5
Hydraulic Pump Initial System Cost
About $40,000 for skid mounted jet pump installation

	Beam	PCP	Jet
Initial Investment (materials/rods, etc)	$28K	$24K	$46K
Downtime/rig cost for installation/repair	$29K	$53K	$16K
Expected failures/year	3	6	2
Failure cost/year	$50K	$203K	$2K
Total First year Cost	$113K	$286K	$70K
Total Second Year Cost	$56K	$209K	$8K

Table 6
Gaslift System Initial Cost

DESCRIPTION	SIZE	TYPE	Cost	Operating Cost	COMMENTS
Coil Tubing	1 1/4"		$1.00/ft		
Gas Lift Valve	1 1/4"		$15,000		6 valves per well/avg, $2500/vlv
Tree Hanger	1 1/4"		$5,000		
SERVICE					
Coil Tubing Unit			$10,000		Installation costs
Water truck			$1,000		Installation costs
Roustabout work			$1,000		Installation costs for flowline
					& meter-run

Table 7
Velocity String Initial Cost

EQUIP DESCRIPTION	SIZE	TYPE	Cost	Operating Cost	COMMENTS
Coil Tubing	1 1/2"		$1.00/ft		
Tree Hanger			$5,000		
SERVICE					
Coil Tubing Unit			$10,000		Installation costs
Lease Crew			$1,000		Installation costs
					of flowline

Table 8
Compression Initial Cost

Medium Pressure Compressors
30HP-370 $13,400.00 (electric)
40HP-390 $15,900.00 (electric)
50HP-5120 $18,500.00 (electric)
80HP-24120 $27,000.00 (electric)

Compressor costs per se. are approximately:

Cost:	Rate:	η	Pdisc	Psuc	CR
Recip: $40k	200 Mcfd	83%	50-60	0	3.5-4.0
Screw: $30k	150 Mcfd	60%	5-30	16"Hg	15
Vane: $20K	120-150 Mcfd	60%	30	30	3
L-ring: $12-15K	150 Mcfd	60%	5psi	5	22-30 psi

Table 9

(a) Flow Through Plunger Initial Cost

DESCRIPTION	SIZE	TYPE	Cost	Operating Cost	COMMENTS
Plunger	2 7/8"		$1,000	$2,000	Replace plunger 2x year.
Controller			$1,700		
Lubricator	2 7/8"		$2,200		
Motor Valve	2"		$1,150		
Bumper Spring	2 7/8"		$646		
Collar Stop	2 7/8"		$250		
Connections	2"		$600		
TOTAL			$7,546		
SERVICE					
Swab Rig			$2,000		Swab rig, 2 days. Run gauge ring,
Reconfigure tree/flowline			$1,000		, set collar stop and swab well in.
					Remove tree, install lubricator
TOTAL			$3,000		and hookup flowling.

(b) Conventional Plunger Initial Cost

DESCRIPTION	SIZE	TYPE	Cost	Operating Cost	COMMENTS
Plunger	2 7/8"		$860	$1,720	Replace plunger 2x year.
Controller			$1,550		
Lubricator	2 7/8"		$1,132		
Motor Valve	2"		$466		
Bumper Spring	2 7/8"		$600		
Collar Stop	2 7/8"		$250		
Connections	2"		$600		
TOTAL			$5,458		
SERVICE					
Swab Rig			$2,000		set collar stop and swab well in.
Reconfigure tree/flowline			$1,000		set collar stop and swab well in.
					Remove tree, install lubricator
TOTAL			$3,000		and hookup flowline.

Table 10
Foaming: Capillary Tube System Estimate

DESCRIPTION	SIZE	TYPE	Cost	Operating Cost	COMMENTS
Capillary Tubing	1/4"	2205	$1.40/ft		
Mandrel / Double Check	1/4"	SS			No charge. Price included in tubing
Wellhead Packoff	2 3/8" & 2 7/8"				No charge. Price included in tubing
Backpressure Valve	1/4"	SS	$1,200		
Chemical Pump			$1,600		
Various Connections			$200		
Chemical (Surfactant)			$6.14/Gal	$xgal/dy	

Table 11
Injection Systems

For bypass seating nipple to work with beam pumping system, the downhole hardware is about $8000. However a back pressure regulator may be needed for the surface. Also the recompletion costs can easily be triple the hardware costs for this system. There are other variations of the injection systems. A total cost of $40,000 is easily possible.

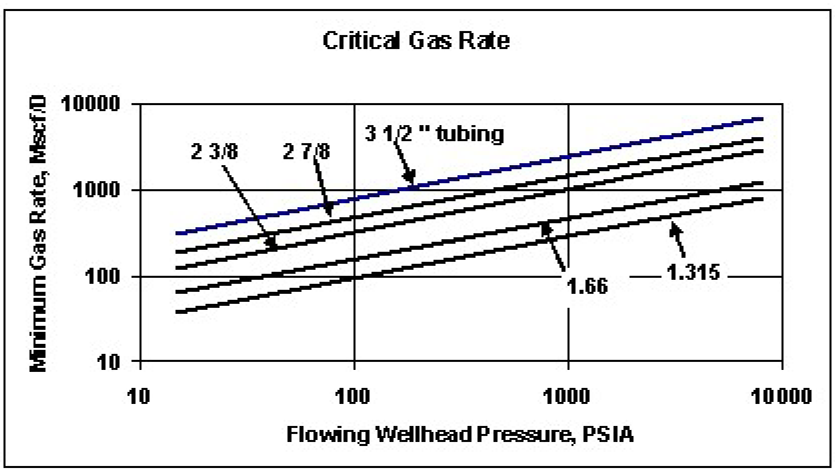

Figure 1 - Critical Gas Rate Required vs. Wellhead Pressure (Coleman et al., see Reference 1)

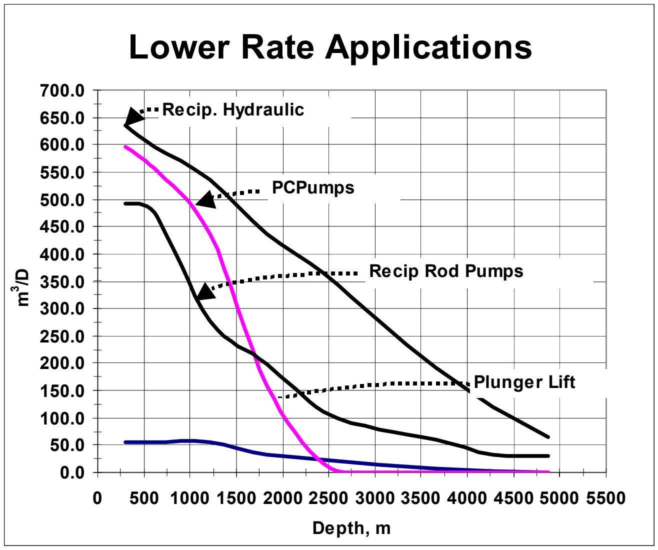

Figure 2 - Low Rate Applications

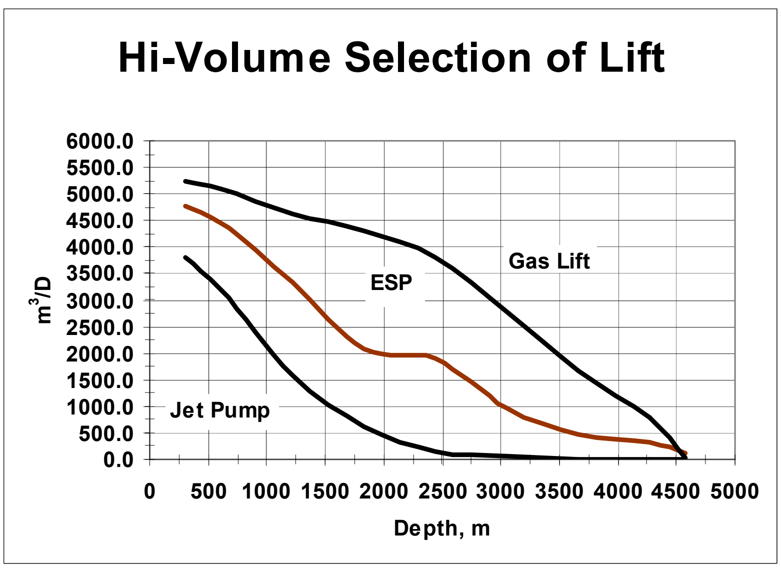

Figure 3 - High Rate Applications

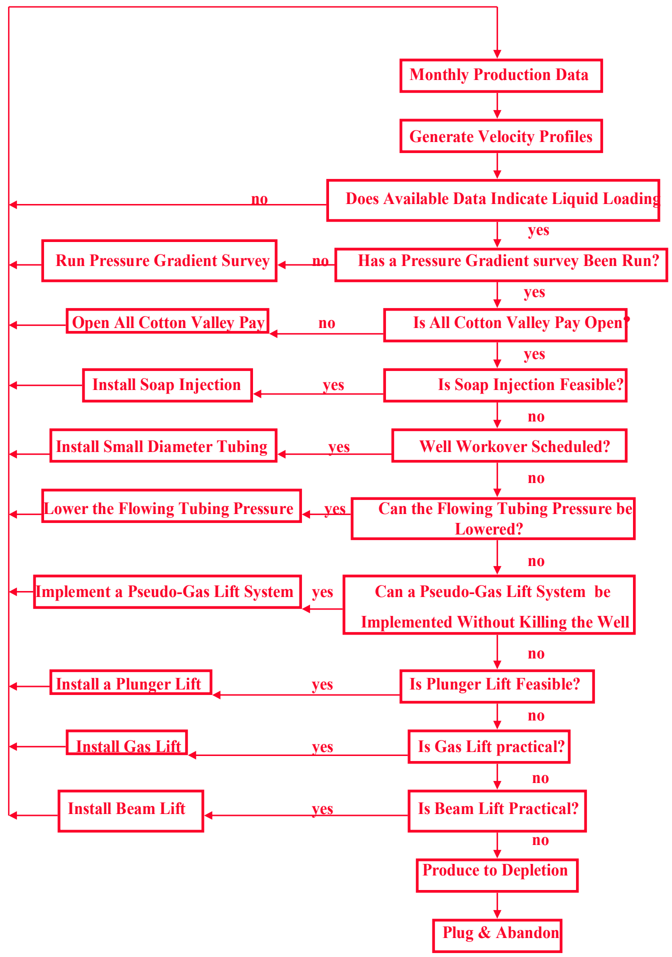

Figure 4 - An Older Selection Chart Developed for AL Selection for Gas Wells in East Texas

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

↓

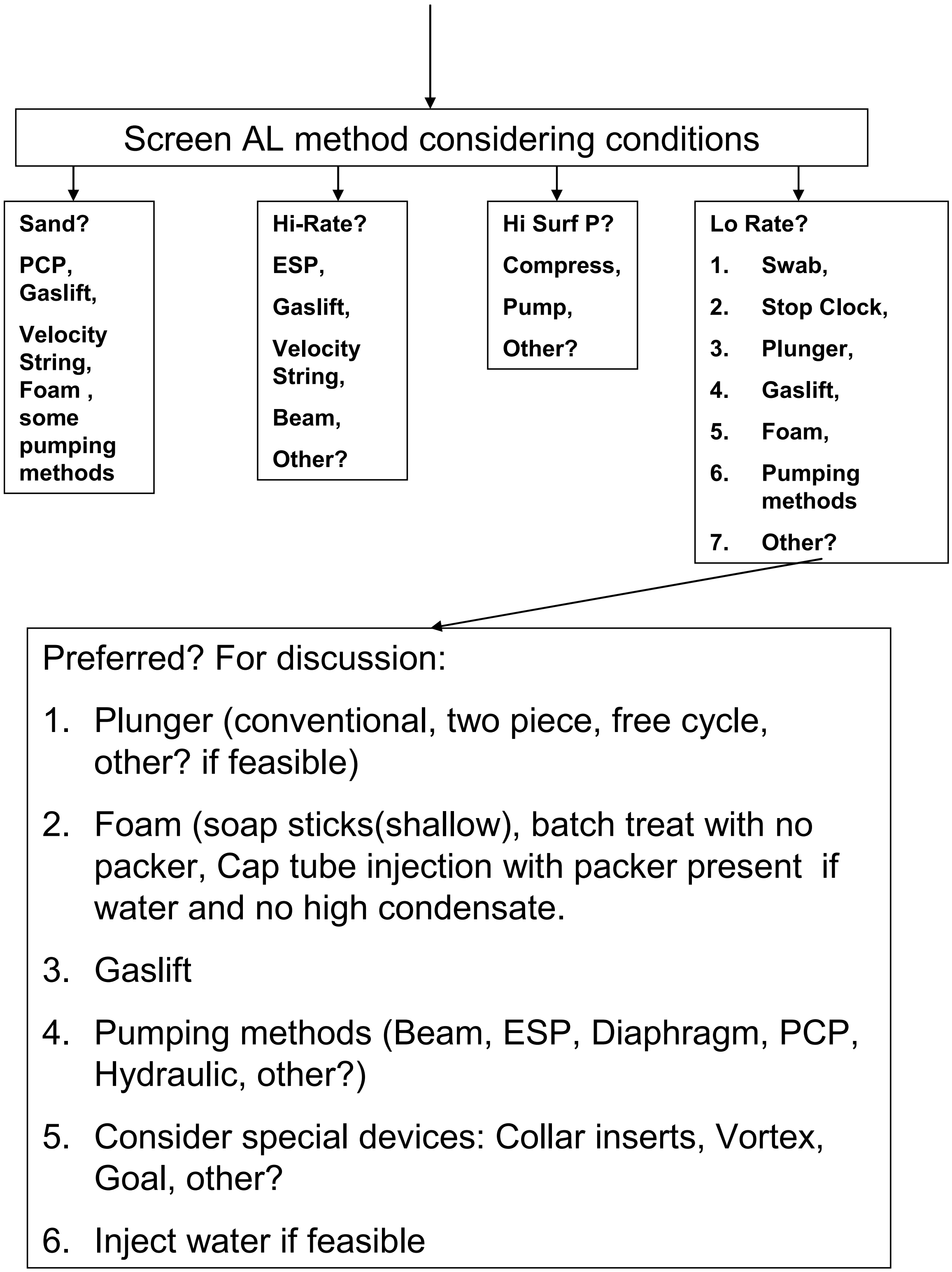

Figure 5 - A Simple AL Selection Chart for Consideration or Discussion When Selecting AL for Deliquification of Gas Wells