Deliquification vs. Artificial Lift

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Deliquification vs. Artificial Lift

- Introduction
- Deliquification methods that evolved from Artificial Lift
- Gas-specific deliquification methods
- Conclusion

Introduction

- In the last 50-100 years, gas has gone from being a waste product that hindered oil production to a primary, sought after product
- Current gas prices are causing operators to rethink the terms “economic limit” and “abandonment pressure”
- Operators are reaching original abandonment pressure while the field is still very profitable
- What do they have to do differently to remain profitable down to very low reservoir pressures?
- The biggest difference is “Deliquification”

Working Definitions

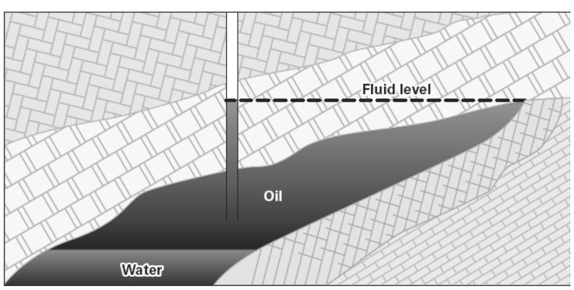
- Artificial Lift: application of external energy to lift a commercial product from reservoir depths to the surface
- Deliquification: application of energy to remove an interfering liquid to enhance gas production
- The key difference is that it matters where and in what condition artificially-lifted oil ends up, but water just needs to be gone
  - Evaporation is a reasonable deliquification method, but it would be an artificial-lift failure
  - Pump discharge below a packer is reasonable deliquification but not good for artificial lift

Net Positive Suction Head (NPSH)

- Net Positive Suction Head is the amount of external pressure at the inlet to a pump.
- The *Required* NPSH (NPSH-r) is the amount of external pressure required to ensure the pump operates full of liquid.
- The *Available* NPSH (NPSH-a) is the amount of external pressure available at the pump suction.
- It generally doesn't matter if the NPSH comes from an actual hydrostatic head or an applied pressure (as long as the pump sees continuous-phase liquid).
- NPSH-r is very dependent upon fluid properties (mainly the boiling point, gas solubility, and vapor pressure)

NPSH in Oil Fields

- When the completions are downstructure, the oil will try to "seek its own level"
- Often, several hundred feet of fluid will sit above the pump inlet without harming reservoir performance

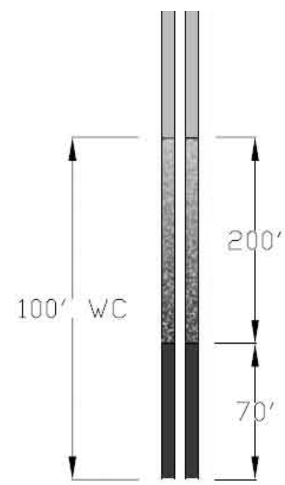


NPSH in Gas Fields

- Any fluid above the perfs will add to the backpressure on the formation
- Backpressure is a significant factor in production rate, but it is not simple:
  - Many wells have a "pressure window" that maximizes production
  - The window is defined by the sum of all sources of restriction to flow (e.g., friction, fluid interference within reservoir, and condensation)
  - Going outside of this pressure window will reduce gas rate
  - The pressure window moves with time
- There is never a clear relationship between NPSH-a and backpressure

Finding Fluid Level

- The environment downhole is tumultuous and no condition exists for more than a few seconds
- Liquid Water exerts 0.43 psi/ft
- Methane at 100 psig and 110°F exerts 0.00012 psi/ft
- A froth of gas and water is somewhere between
- A pressure bomb or surface reading can only see effective height
- A fluid shot will give you its best return and will usually be somewhere within the froth (generally will pick a height in the midst of the froth and overstate backpressure)



Where do you go to get more NPSH?

- Change technology:
  - A rod pump needs less NPSH than a jet pump
  - A progressing-cavity pump needs less than a rod pump
- Downhole equipment:
  - Gas separators
  - Mechanical devices to trip traveling valves
  - Vent piping, holes in tubing or pump
- Remove pressure drops (screens, tail pipes, standing valves). CAUTION:
  - Each of these devices has a reason for being there
  - Removing them is not without risks

Rat Hole

- Defined: space within the wellbore below the producing strata.
- Functions:
  - Collect fill and other wellbore trash
  - Raise NPSH-a without adding hydrostatic head on the formation
- Downside of placing pump in the rat hole:
  - Can concentrate solids in the pump suction
  - Harder to remove pump heat in the small volume of liquids around the pump

Technologies that evolved from Artificial Lift

- Pump-off control
- Stroking pumps
- Progressing cavity pumps (PCP)
- Electric submersible pumps (ESP)
- Gas lift
- Jet pumps
- Surfactants

Pump-off Control

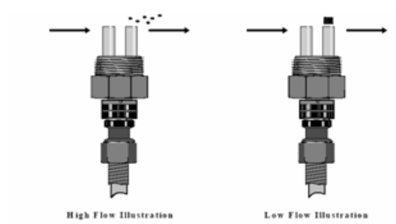
- Inflow to gas wells is never very constant
- Pump-capacity requirements will change many times per day
- Using periodic fluid level shots will result in pumps running at the wrong speed most of the time
- Gross-level surface indications (e.g., flow rate, tubing-casing differential, etc.) happen too late to support needed changes (i.e., by the time you see the problem it is either over or has gotten much worse)

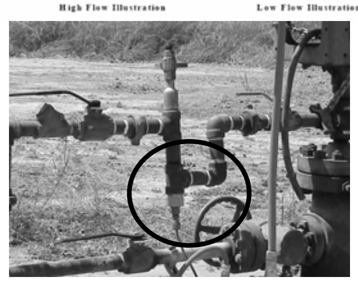
Pump-off control example

- Well makes 5 bbl/day and 25 MCF/d
- Rod Pump
  - 1-1/2 pump inside 2-3/8 tubing
  - 40-inch stroke
  - 4 strokes/min
  - Pump capacity 44 bbl/day
- Running on stop clock, 30 min on, 4.5 hours off
- Problem
  - The well **averages** 5 bbl/day
  - As hydrostatic head changes during the cycles the flow rate fluctuates wildly and pump is always gas locked
- Stop/start control works better in oil than in gas wells

Pump-off Control

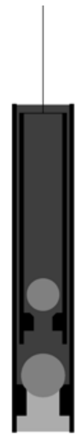
- Oil & Gas Instruments, Inc.
  - Two probes
  - Upstream probe just an RTD
  - Downstream has RTD and heating element
  - Flow past the probes carries some of the heat away
  - If the heated probe gets hotter, then the fluid has less liquid and element sends signal to slow the pump down
  - If it gets cooler then it sends signal to speed the pump up
- Setting the device in a dip helps prevent false negatives





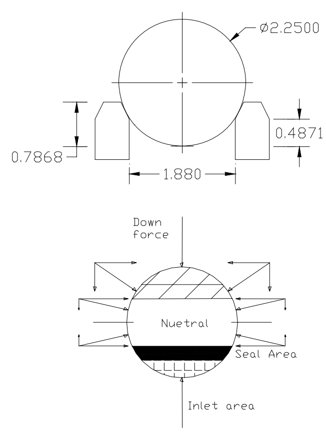
Rod Pump

- Simple chamber with two valves
  - Chamber empties on downstroke
  - Chamber fills on upstroke
- With the pump liquid-filled, very little plunger movement is required to start pumping



Rod Pump

- Effective area of ball above seal is 57% of net surface
- Residual pressure in barrel is based on:
  - Pump leakage
  - Amount of gas in pump
  - Boiling point of liquid
- NPSH-r is:
  - Almost 43% higher than residual pressure
  - Typically 75-100 ft

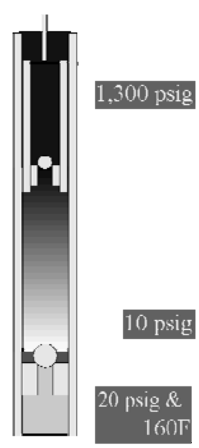


Rod Pump
Produced Gas Lock

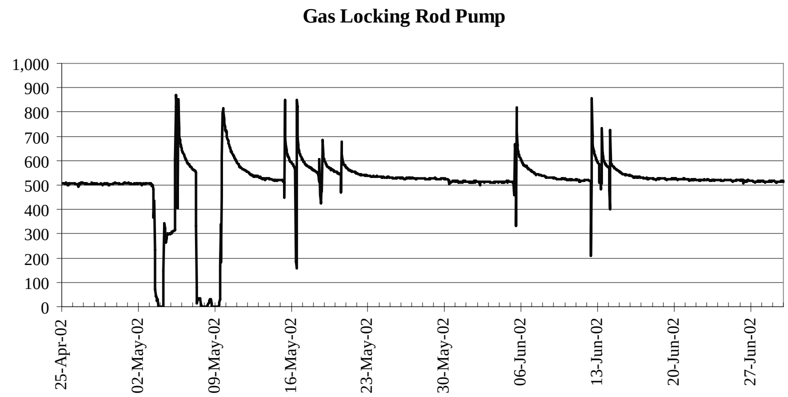
- If the pump is liquid-filled, very little rod movement required to open traveling valve.
- If the pump has considerable dissolved or free gas:
  - It must compress the gas to above discharge hydrostatic head before the traveling valve will open.
  - At 3,000 ft depth with 20 psig bottom-hole pressure the gas must compress to over 40 ratios.
  - The pump will travel up and down without pumping until
    - Leakage past the plunger fills the barrel with enough liquid to open the traveling valve, or
    - Bottom-hole pressure rises enough to open standing valve

Rod Pump
Steam Lock

- At low pressures, water boils at low temps (e.g., at 15” Hg, water boils at 160F)
- Compressing steam raises its temp (e.g., 40 ratios would raise temp from 160F to 1,300F)
- Leakage past barrel adds liquid to barrel
- Eventually a steam lock will develop enough pressure to open traveling valve and cool everything off.



Rod Pump
What does a Gas Lock look like?



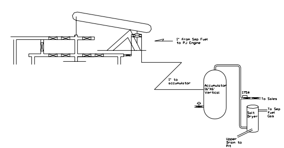
Effect of backpressure on rod pumping

- Assume:
  - Flowing Casing pressure 0 psig
  - Pump set up for 20 bbl/day
  - Pump set depth 3,000 ft

	Zero MCF/d		1.0 MCF/d	
	0 psig	200 psig	0 psig	200 psig
Pump disch at 3,000 ft	1,311	1,511	41	1,248
dP across Plunger	1,280	1,480	38	1,245
Slippage (gal/day)	7.9	9.1	0.04	7.3
Time to break gas lock	4 hours	3.5 hours	5 days	4 hours

Beam Units on Very Low Line-Pressure Gas Wells

- Need energy for control gas and blowcase
- One solution is a beam compressor
  - Unit fits on walking beam
  - Will move ≈50 MCF/d
  - Maintain accumulator vessel around 150 psig
  - Pipe fuel and control gas from accumulator
  - Any excess production goes to sales



Shorten Stroke Length

- Sometimes you just can't slow a pump down enough to match inflow with outflow
- A solution is to go to a much smaller pump with a shorter stroke length
- If you can't economically reduce the height of the wellhead, you can raise the pump

Progressing Cavity Pump (PCP)

- Rotor has a profile with a slight pitch.
- Each revolution causes the liquid in the cavities to move up the pump barrel.
- PCP's are positive displacement pumps and can develop very high discharge pressures
- Pumps turn fairly slowly (60-300 rpm):
  - Very resistant to damage from solids in a slurry.
  - Not resistant to damage from running dry.

PCP

- Can be a significant mechanical load on wellhead
- Slow speed required for high solids
- Maintain fluid level to prevent heat rise due to compression of gas
- Heat of compression:

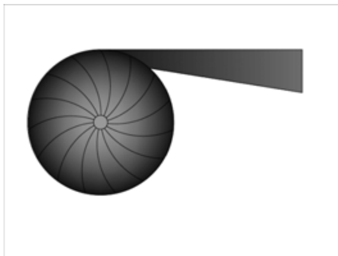
BHP (psia)	BHT	1000 ft	2000 ft	3000 ft	5000 ft
15	100°F	809°F	1,018°F	1,160°F	1,362°F
50	100°F	494°F	651°F	758°F	910°F
100	100°F	350°F	483°F	574°F	703°F

PCP

- NPSH-r is about 60 ft
- Failure to meet NPSH-r results in:
  - Excessive heat of compression
  - Overheated stator
  - Stuck pump
- Pump can only run dry for a few minutes
  - New pump-off controls act very quickly on reduced flow to slow pump down
  - Controls will not stop pump if flow stops
  - Oversized stators have not really worked well in no-flow conditions

Electric Submersible Pump (ESP)

- Multi-stage centrifugal pump
- The impellor slings water from the eye at the center to the volute at outside edge to trade decreasing pressure for increasing velocity
- The volute has an increasing cross section to trade decreasing velocity for increasing pressure
- Each stage discharges into next stage



ESP

- NPSH-r typically 150 ft
- Without adequate NPSH:
  - The first stage will cavitate.
  - The surface of the first-stage impellor will lose efficiency.
  - Subsequent stages will cavitate.
- Sometimes you can intermit the pump to align capacity with well performance:
  - Stopping pump will empty tubing back into formation
  - A standing valve can prevent emptying, but allows solids to settle out.
  - Settling solids can seize the pump and or/seal the standing valve.
  - A hole in the tubing above standing valve will let the pump backflush, but it steals capacity.
- Sand screens, standing valves, and filters decrease NPSH-a.

Gas Lift

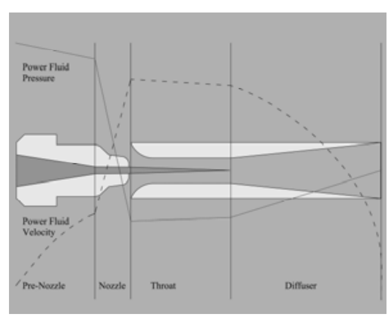
- High pressure/high velocity gas is injected into annulus above a packer through gas-lift valves in tubing
- Combination of:
  - Liquid absorbing gas reducing density (80% of benefit)
  - Velocity effects (20% of benefit)
- Very popular in oil operations
  - Oil can absorb a large quantity of gas
  - Absorbed gas is easily recovered
  - Small footprint (one compressor can serve a number of wells)
  - Gas lift can't be said to have an NPSH-r

Gas Lift in Gas operations

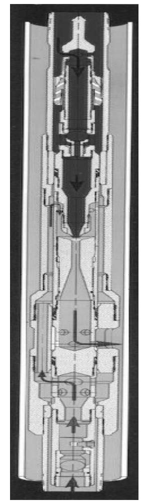
- Every operator tries it sometime, somewhere
- Gas lifting water:
  - Oil can absorb up to 15% of its mass
  - Water can absorb 0.15% of its mass
  - Gas lifting water takes about 5 times the energy required for a given liquid volume
- "Po Boy Gas Lift"
  - Gas lift without a packer or gas lift valves
  - Inject high pressure gas down annulus and hope that it comes back up the tubing instead of into the formation
  - It has been tried many times
    - It seldom increases liquid production at all
    - Both gas and liquid production usually increase when it is turned off

Jet Pump

- Have been used in oil fields for over 50 years
- Convert pressure to velocity
- Traditional Oil Field Pump:
  - Seats in a packer
  - Power liquid usually down tubing
  - Well production and Power Fluid exhaust up backside

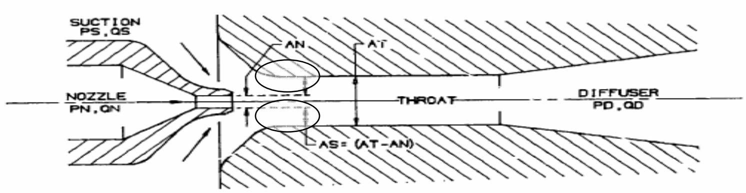


Jet Pump



- Traditional pumps are rarely effective in gas wells because:
  - All well and power fluids must go through pump
  - Ports and nozzles are too small for flow rates
- Gas as Power fluid
  - Shape of the throat is wrong for efficient ejector operation
  - Could be done with a very large pump and a redesigned throat (more of a “downhole compressor” than a water pump)
- Tubing Pumps:
  - Two tubing strings (either dual or concentric)
  - Power water down inner or side string
  - Well liquid and exhausted power liquid up tubing/tubing annulus (or main tubing)
  - Gas production up casing/tubing annulus

Jet Pump



- NPSH-r varies by nozzle/throat combination, but it is seldom less than 460 ft (200 psig)
- Cavitation damage occurs in the entrance to the throat
- When the pump cavitates it stops pumping immediately

Surfactant

- Soaps, foamers, and other surfactants are designed to foam and:
  - Introduce voids that lighten the liquid column
  - Reduce the surface tension of the liquid drops to minimize their size/weight
- All soaps have to be activated by agitation
- Care must be exercised to ensure that the soaps are activated downhole
  - Unactivated liquid soap will often activate and foam in the production/measurement equipment
  - Foaming in the gathering system will tend to increase the condensation surface and increase water problems
  - Liquid soap is “gummy” and can increase skin

Deliquification Techniques

- Velocity String
- Tubing-flow controller
- Plunger
- Vortex tool
- Evaporation

Velocity String

- Critical Flow—R.G. Turner et al published a JPT paper in November, 1969 coining the term "Critical Flow"
  - Showed liquid volume that reached surface to be a function of gas velocity which is a function of interfacial tension and fluid density
  - Virtually all data taken above 1,300 psig
- Many other researchers have built on this concept with new interpretations of Turner's data and some new data sets
- It is certain that at some increasing velocity, liquid volume transported to the surface will begin to increase
- The magnitude of that number and the method of determining it will continue to be a source of heated academic debate

Critical Flow

- For a particular well:
  - Tubing set-depth = 3,000 ft (2-3/8" 4.7 lbm/ft J-55)
  - Flowing wellhead Pressure = 4 psig
  - Flowing wellhead temperature = 80°F
  - Flowing bottom-hole temperature = 105°F
  - Production (just up tubing) = 130 MCF/d, 5 bbl/MMCF
- Critical Flow
  - Turner = 158 MSCF/d (loading)
  - Coleman = 132 MSCF/d (onset of loading)
- Flowing bottom-hole pressure
  - Gray Correlation = 55 psig
  - Orkiszewski Correlation = 308 psig
  - Cullender-Smith Dry Gas Correlation= 30 psig
  - Duns-Ros Correlation = 135 psig
- Measured flowing bottom-hole pressure = 8 psig (no sign of loading there)
- Take anyone's "correlations" with healthy skepticism and a complete understanding of their underlying assumptions

Velocity String

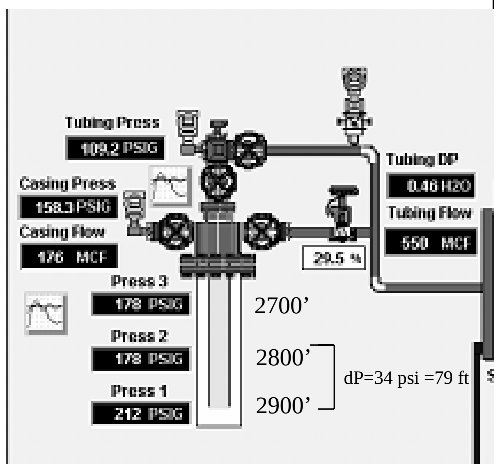
- A “velocity string” is a string of tubing that is intended to force normal gas flow rate to have a velocity greater than the “critical velocity”
- Higher velocity equates to higher friction drop
- Wells with velocity strings are very unforgiving:
  - If rate increases, friction will rapidly raise FBHP
  - If rate decreases slightly, you can drop below the actual critical rate and load up
  - A cold section in the wellbore can condense water vapor and upset the balance on a near-critical well
  - Aggressive velocity strings preclude both plungers and swabbing
- It is not a good idea to fully open the casing with a velocity string
  - Flow in the velocity string will drop to very near zero
  - The well is nearly assured of loading up and can be difficult to restart

Tubing-Flow Controller

- If you’re using a velocity string and the tubing/casing differential pressure is “excessive” then you can alleviate high friction drop by allowing some casing flow:
  - Must monitor tubing flow to make sure you stay above critical
  - Must throttle casing flow carefully to ensure that you don’t upset the tubing flow too much
- Most installations use:
  - Orifice meter on the tubing
  - Pneumatic control valve on casing
- This rarely works probably due to:
  - Relatively large dP caused by the meter
  - Sluggishness of the pneumatic valve

Tubing-Flow Controller

- You can use:
  - Pitot tube measurement
  - Electric V-Ball flow control
- This makes the system much more responsive
- Several wells have seen sustained performance improvements with this configuration



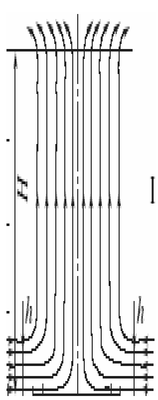
Plungers

- A plunger operates like a pipeline pig
  - Differential pressure across the plunger moves it up the wellbore
  - Any solids or liquids it encounters are pushed in front of it
- Differential pressure determines how much liquid a given well can lift
  - Disregarding friction, 10 psid can move:
    - No more than 2.5 gallons per trip in 2-3/8
    - No more than 4.4 gallons per trip in 2-7/8
  - To move 5 bbl/day with 10 psid in 2-3/8 requires at least four trips per hour (closer to 6 with a safety factor)

Plungers

- The various types of plungers are differentiated by:
  - Fall rate
  - Quality of seal
  - Efforts to clean pipe
- There is a narrow window in reservoir pressure where plungers are the best choice:
  - Early in life, there tends to be enough FBHP that the well doesn't need assistance
  - Late in life the pressure required to lift a plunger plus a load of water is greater than the pressure available

Vortex Tools



- People have been studying rotational flow since the 1800's
- Simply put,
  - They want to know how nature gets from this
  - To this
- The Coriolis effect doesn't have the horsepower to transfer enough energy fast enough to explain it

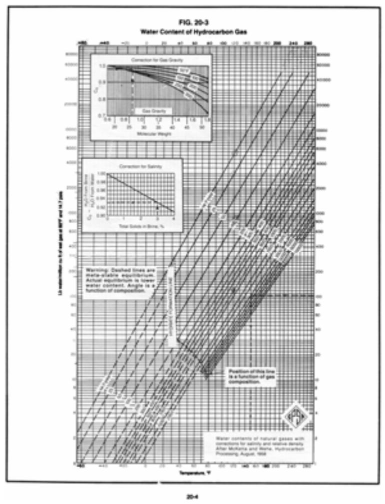
Vortex Tools

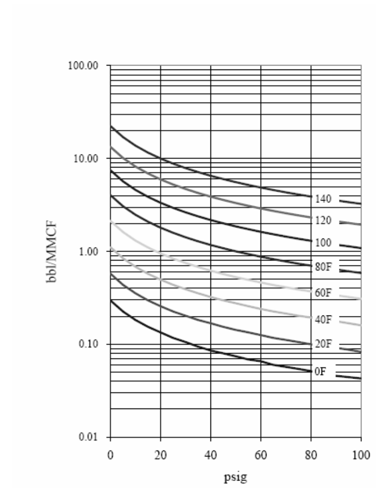
- Hurricanes last for weeks
- Tornadoes last for hours
- If a man-made vortex can be controlled to last for 10-15 minutes it could be valuable
  - Typical critical velocity often 50 ft/sec
  - 10 minutes at 50 ft/sec = 30,000 ft
- Vortex tools have been shown to lower critical velocity by about 30%
- Vortex tools tend to sling liquids to the outside of the pipe while minimizing the gas/liquid interfacial tension

Evaporation

- Whenever there is a coherent gas/liquid interface, liquid will evaporate until the gas at the surface of the liquid is at 100% relative humidity
- Water vapor is <u>not</u>:
  - Fine spray (101-200 micron)
  - Mist (51-100 micron)
  - An aerosol (1-50 micron)
- A water vapor molecule is 0.00038 microns
- Separator mist extractors are usually rated at about 20 microns
- As wellhead pressures diminish, the amount of water that gas can carry as "humidity" increases dramatically

Evaporation





Evaporation

- At low pressures evaporation is often adequate by itself
- If you are relying on evaporation, then critical flow is irrelevant:
  - Water vapor will move as a gas
  - The gas doesn't have to drag the water drops along
  - You want the gas to move as slowly as possible to minimize friction
  - It can be a good idea to remove the tubing altogether
- Separators will not accumulate liquid except what condenses due to vessel temperature being lower than dew point
- The water will condense in the piping as distilled water

Phase-Change Scale

- Produced water is usually at least 10,000 mg/l TDS
  - Flashing a barrel of water deposits 3.5 pounds of solids somewhere
  - NaCl turns into salt blocks (eventually soluble in hot water)
  - Bicarbonate (HCO_3) turns into Nahcolite ($NaHCO_3$) that is granite hard and barely soluble in strong acid

Accelerating Evaporation

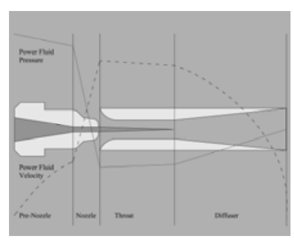
- Change thermodynamic conditions:
  - Raise temperature
  - Lower Pressure
- You can usually change pressure more economically than you can change temperature so your options are:
  - Reduce gathering-system pressure
    - Pipe becomes much less efficient
    - Pneumatic wellsite equipment may not work anymore
    - Very difficult to shift liquid from vessels
  - Wellsite compression is less efficient than central compression, but it avoids the other problems

Typical Wellsite Compressor Types

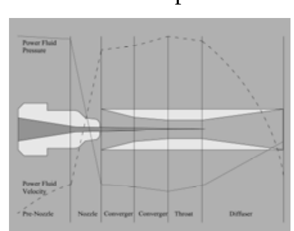
	Eff	Limit	Max Ratios	Typical Use
Liquid Ring	50-60%	Boiling point of liquid	4-6	Vacuum to slight positive pressure
Dry Screw	60 - 72%	Disch temp	5	Control air
Centrifugal	65 - 75%	Disch temp	5/stage	Plant Inlet (no oil in gas)
Flooded Screw	70 - 82%	Max suction Press	10-20	Varying suction
Reciprocating	78 - 88%	Rod load or disch temp	4.5/stage	Varying discharge

Eductors/Ejectors

- From the family of thermocompressors that includes Air Ejectors, Evacuators, Sand Blasters, Jet Pumps, and Eductors
- High pressure gas entrains and compresses suction gas and the combined stream is left at an intermediate pressure
- Up to 10 compression ratios are possible, limited by:
  - Power gas mass flow rate (fixed by nozzle size and upstream pressure and temperature)
  - Suction gas mass flow rate
  - Suction pressure and temperature
  - Discharge pressure
- Efficiency 40-70%



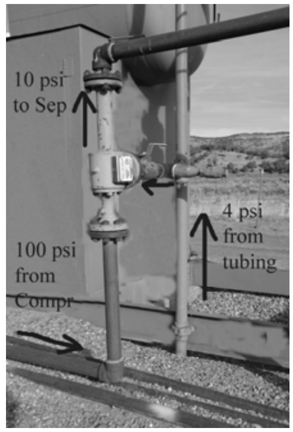
Jet Pump



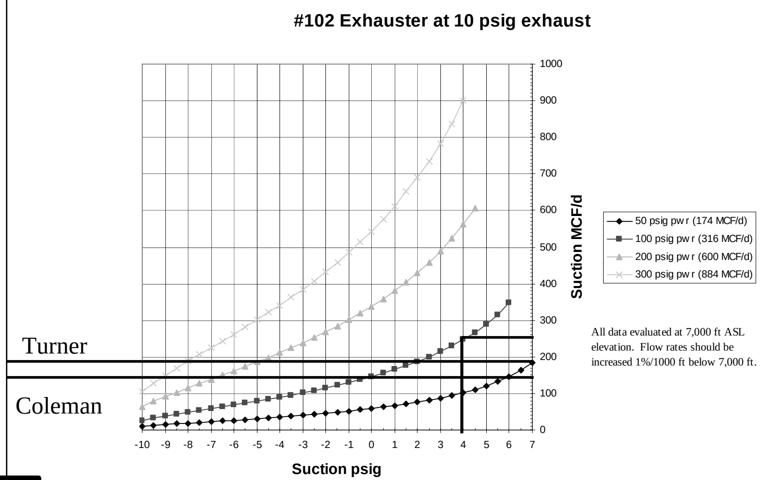
Ejector

Eductor Application

- Everything sucks
  - Compressor sucks on tubing/casing annulus
  - Eductor sucks on tubing to maintain liquid level very near end of tubing
- Small amount of hp
  - 32 hp for power gas
  - 14 hp used in eductor
  - ε=44%



Ejector Well



Conclusion

- Deliquification is different from Artificial Lift and it requires different:
  - Tools
  - Mind set
  - Staffing levels
- No technology is set-and-forget:
  - Be prepared for any given technology to work or fail to work on any given well (regardless of “similar” wells in the same field)
  - Expect to spend considerable field and engineering effort to “get it right” only to find that as pressures change it doesn’t work any more
- There is no “silver bullet” for deliquification