Gas Well Deliquification Workshop

Sheraton Denver Hotel

Denver, Colorado

February 29 to March 2; 2016

Introduction to Plunger Lift

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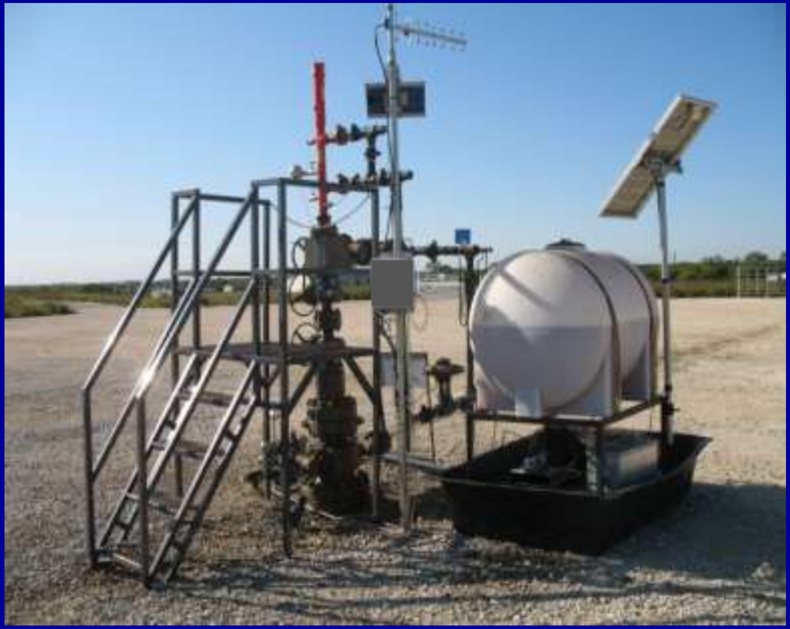
Shale Tec LLC



Introduction to Plunger Lift

How does plunger lift work

Why is artificial lift required

Plunger lift well requirements

Applications, benefits, limitations

Primary Purpose

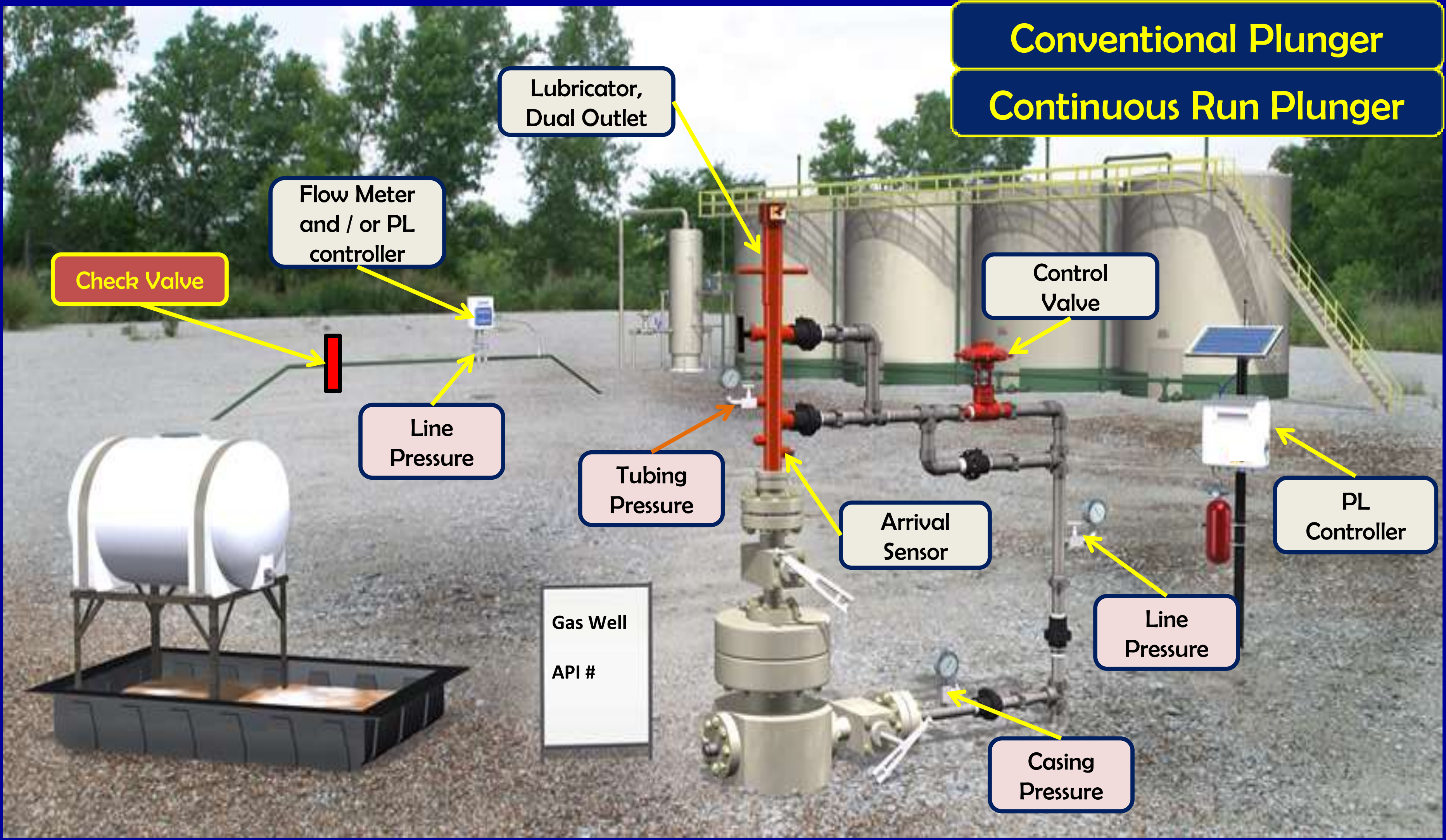
Removal of liquid from gas wells so that gas can flow freely to the surface

HOW DOES PLUNGER LIFT WORK

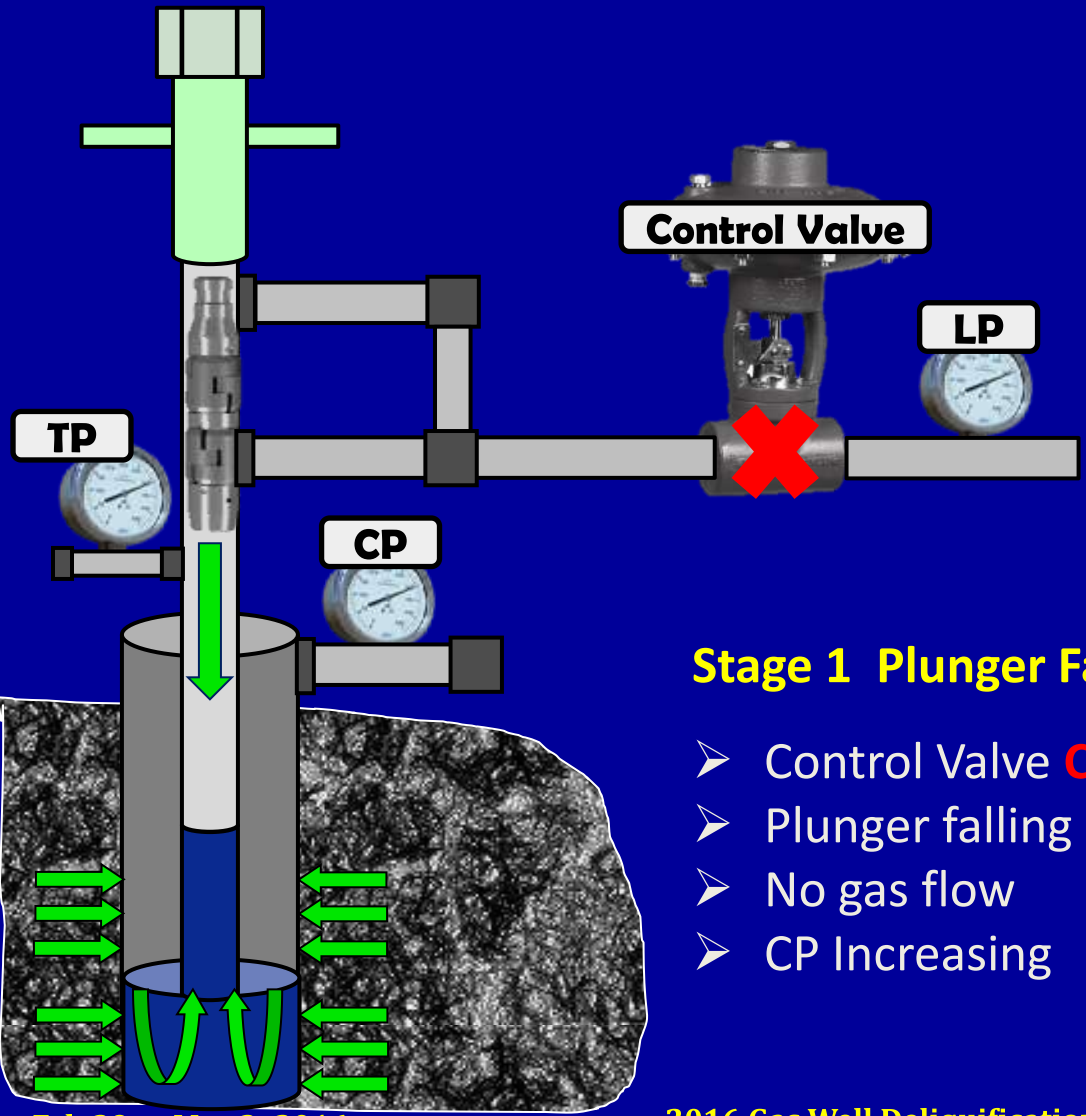
How Does Plunger Lift Work

- Bottom Hole Spring
- Plunger
- Arrival Sensor
- Lubricator with Catcher
- Pressure Transducers
- Control Valve(s)
- Gas Flow Meter
- Well Head Controller

How Does Plunger Lift Work



How Does Plunger Lift Work



Conventional Plunger

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

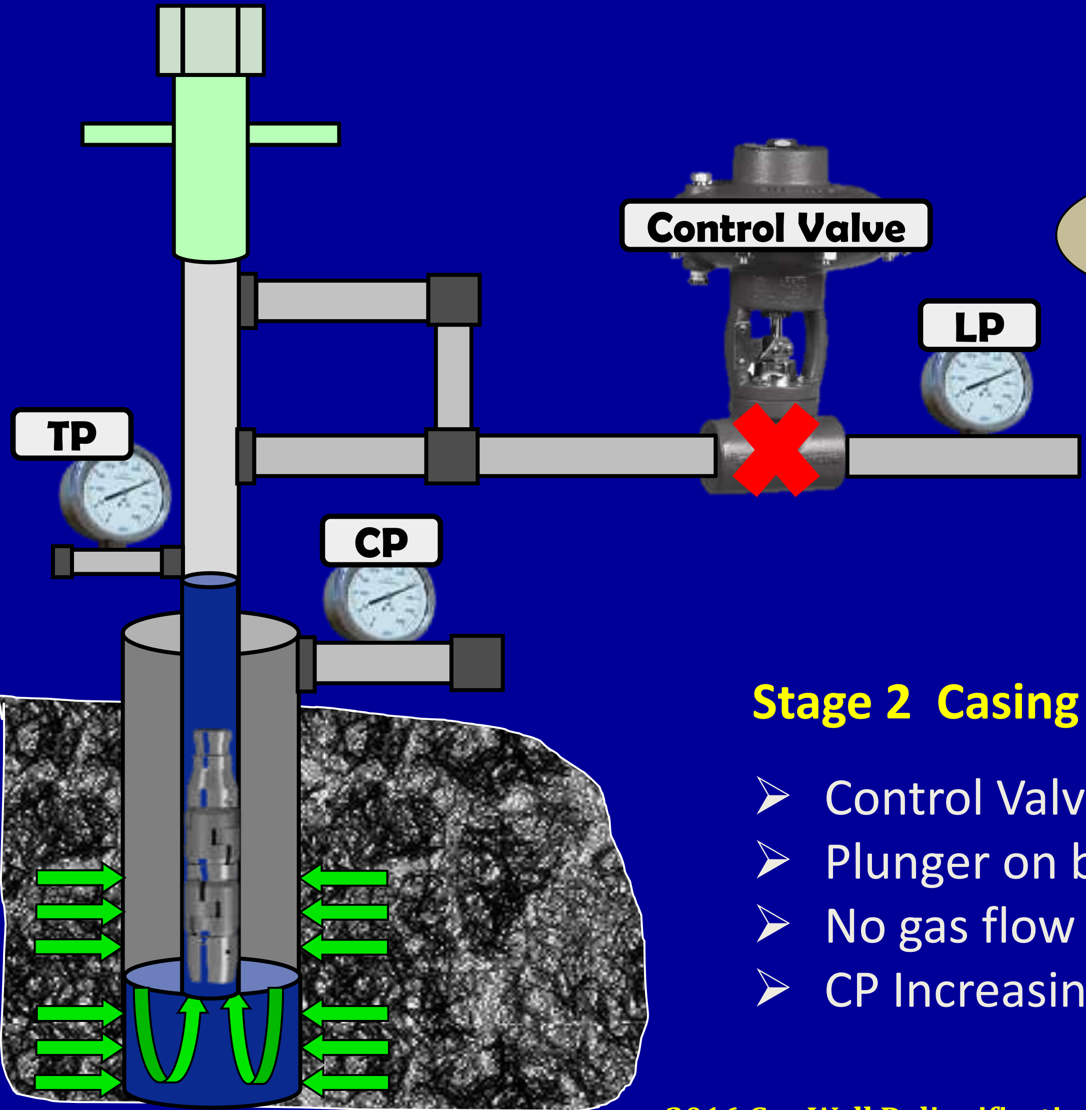
4 Stages

Casing normally closed during plunger lift operations

Stage 1 Plunger Fall (Gas, Liquid)

- Control Valve **Closed**
- Plunger falling (through gas, then gaseous liquid)
- No gas flow
- CP Increasing

How Does Plunger Lift Work



Conventional Plunger

Just before well opens

LIQUID LOAD = (CP – TP)

LIFT PRESSURE = (CP- LP)

LIQUID LEVEL MEASUREMENT

SPE 120643 – Acoustic Liquid Level Testing of Gas Wells

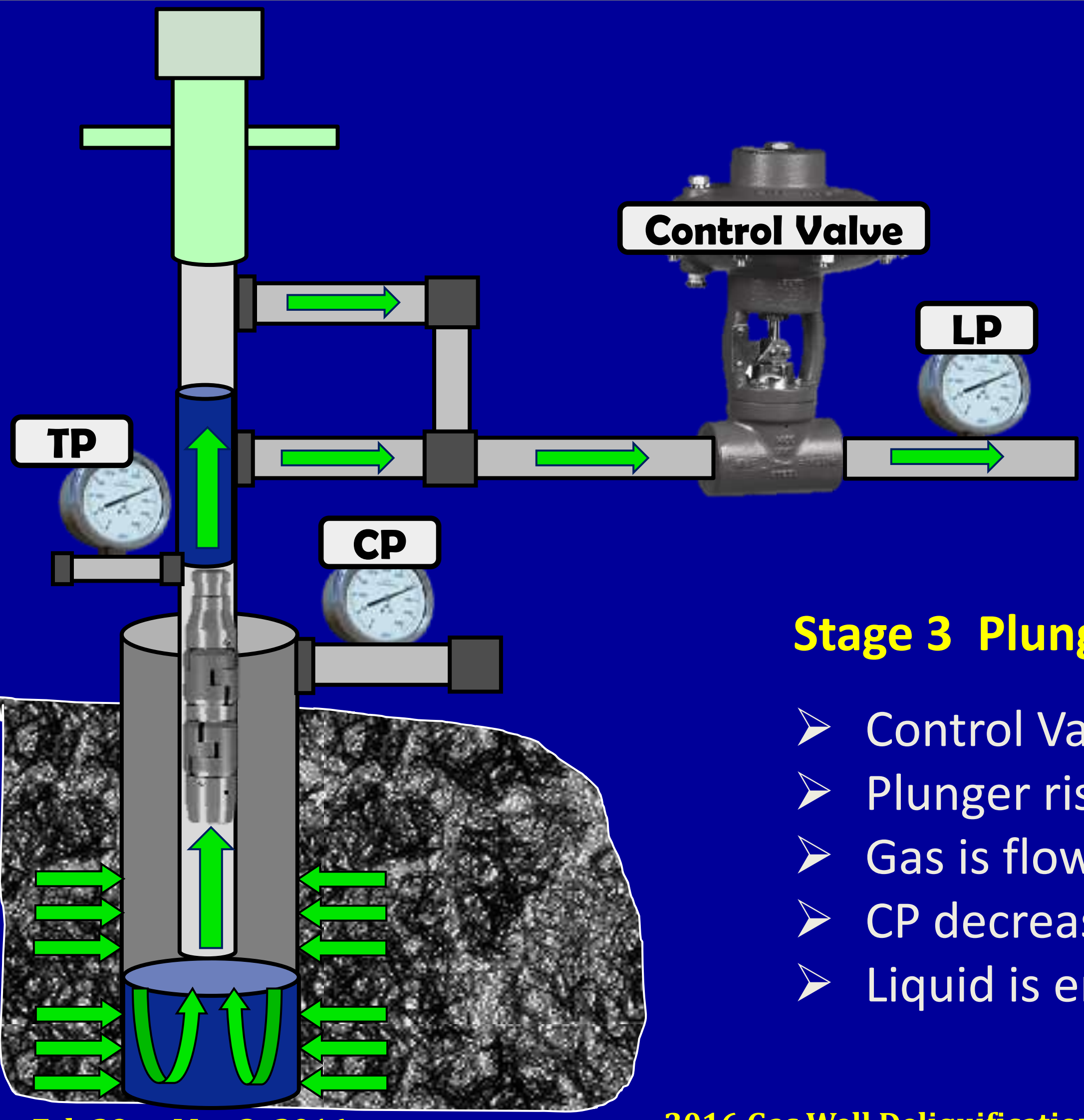
FOSS and GAUL Required Pressure

SPE 120636 – Modified Foss and Gaul model accurately predicts plunger rise velocity

Stage 2 Casing Pressure Build

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

How Does Plunger Lift Work



Conventional Plunger

Plunger Rise Velocity Guideline
500 to 1000 fpm

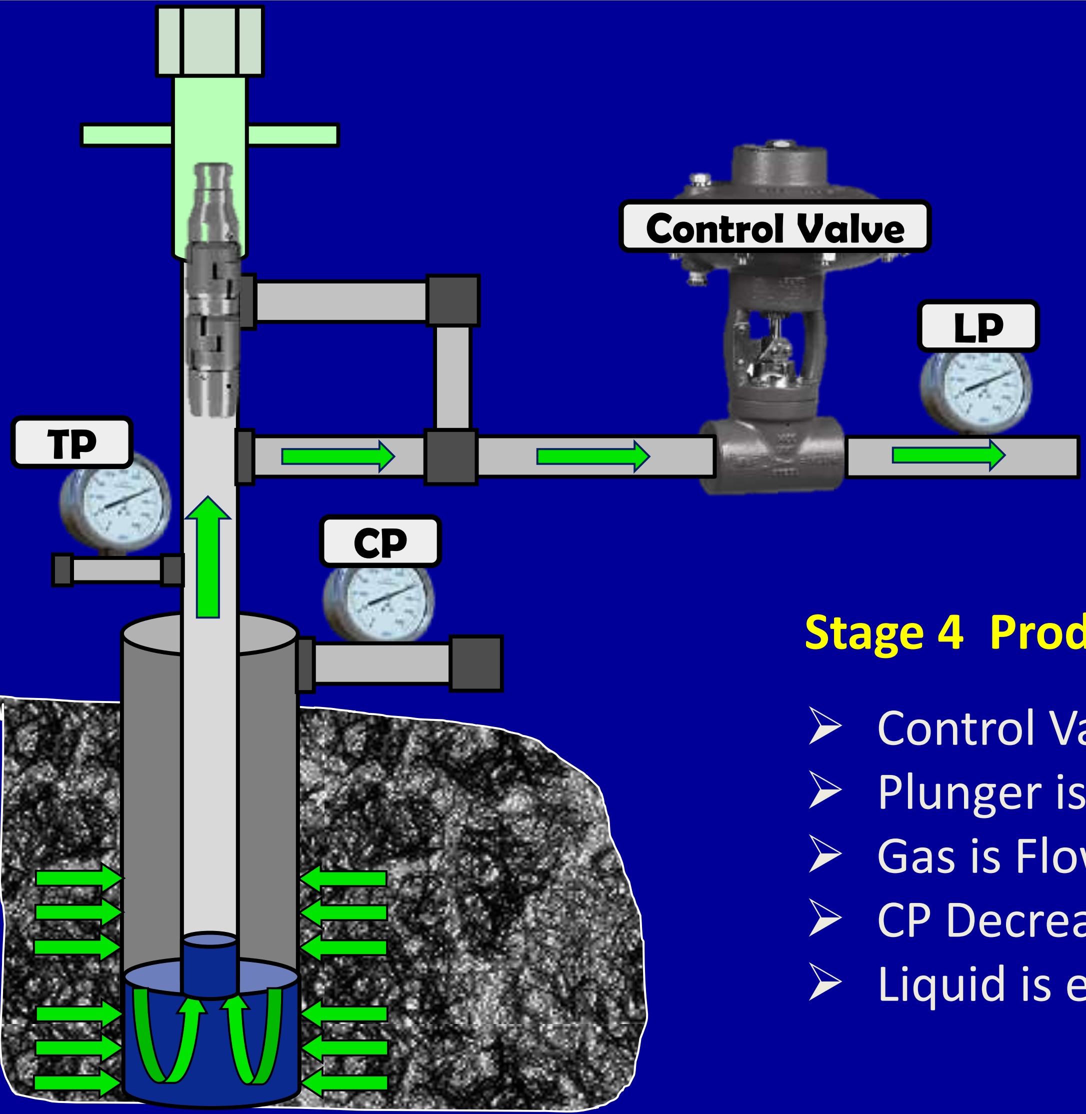
"Fast enough to avoid stalling, slow enough to avoid damage"

Stage 3 Plunger Rise

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

How Does Plunger Lift Work

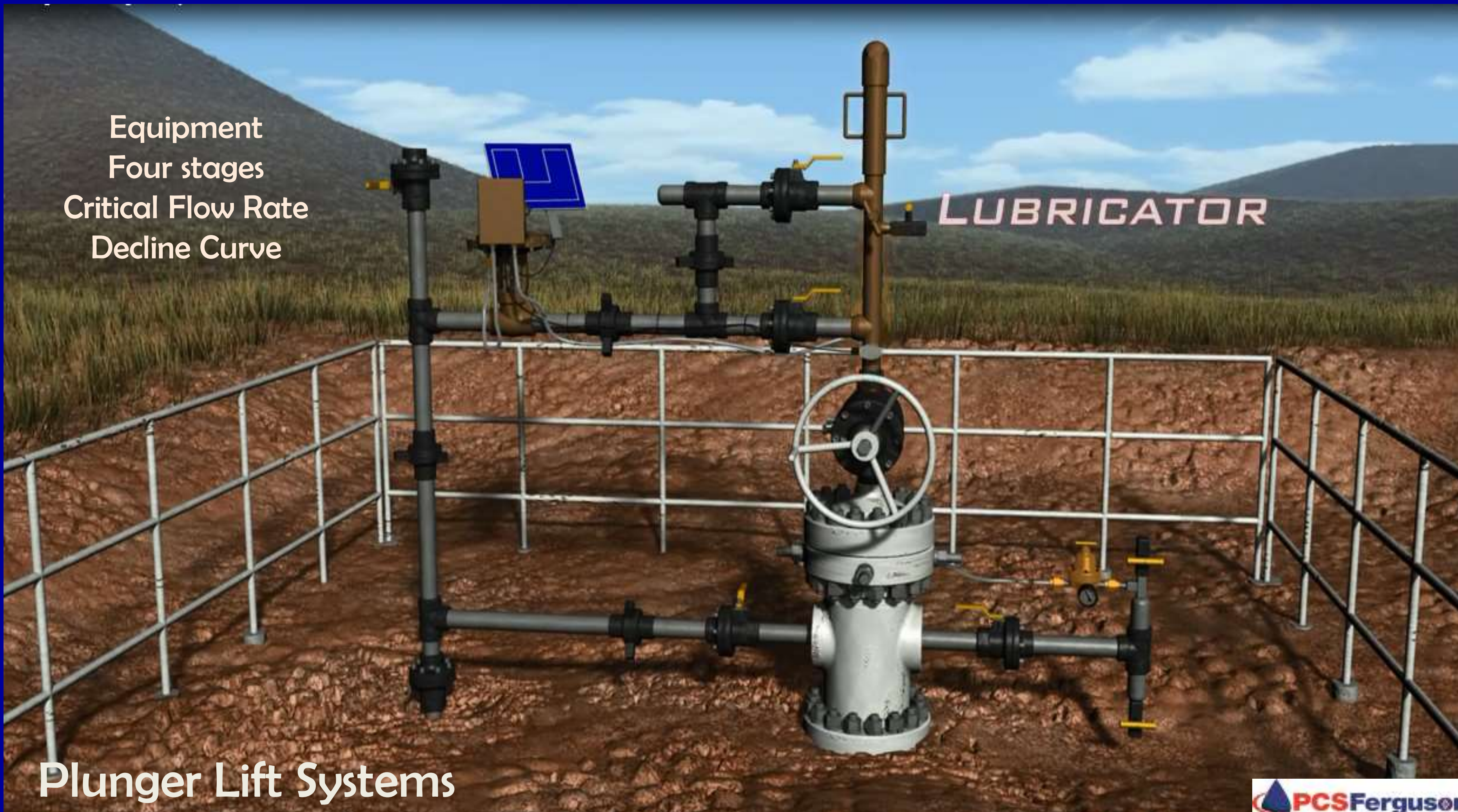
Conventional Plunger



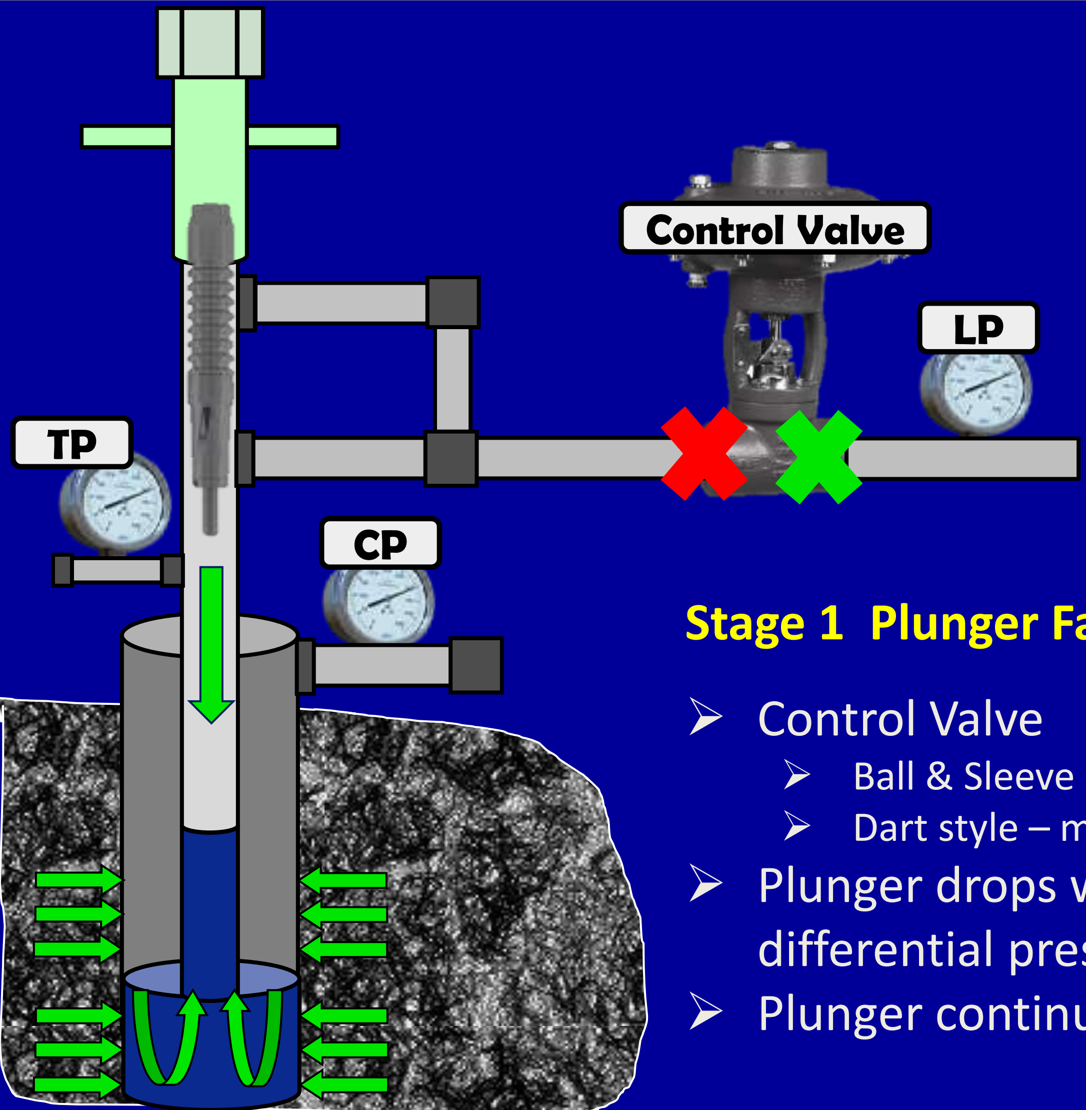
Stage 4 Production (After Flow)

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

How Does Plunger Lift Work



How Does Plunger Lift Work



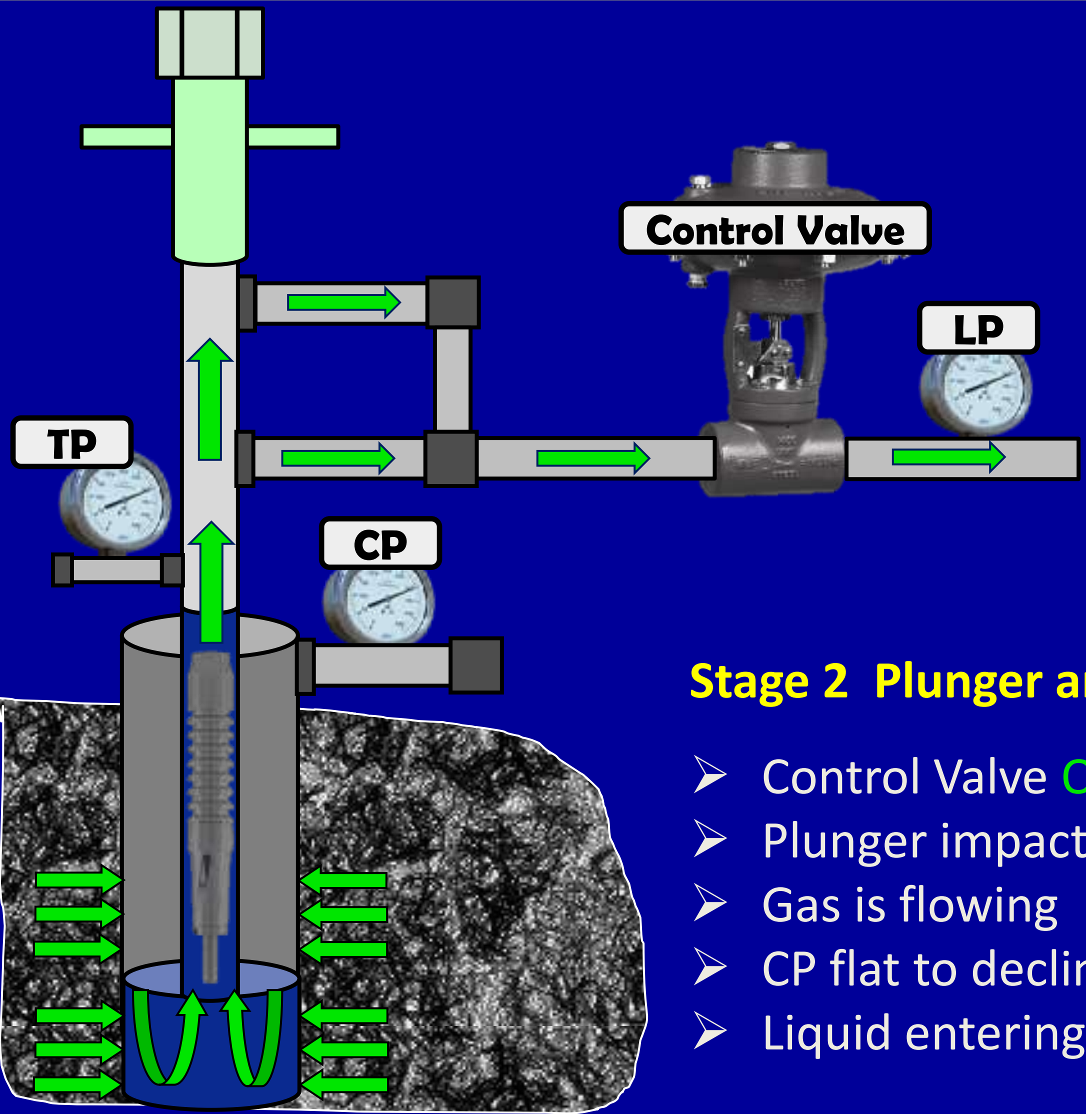
Continuous Run Plunger

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

Stage 1 Plunger Fall Mode (Gas, Liquid)

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

How Does Plunger Lift Work

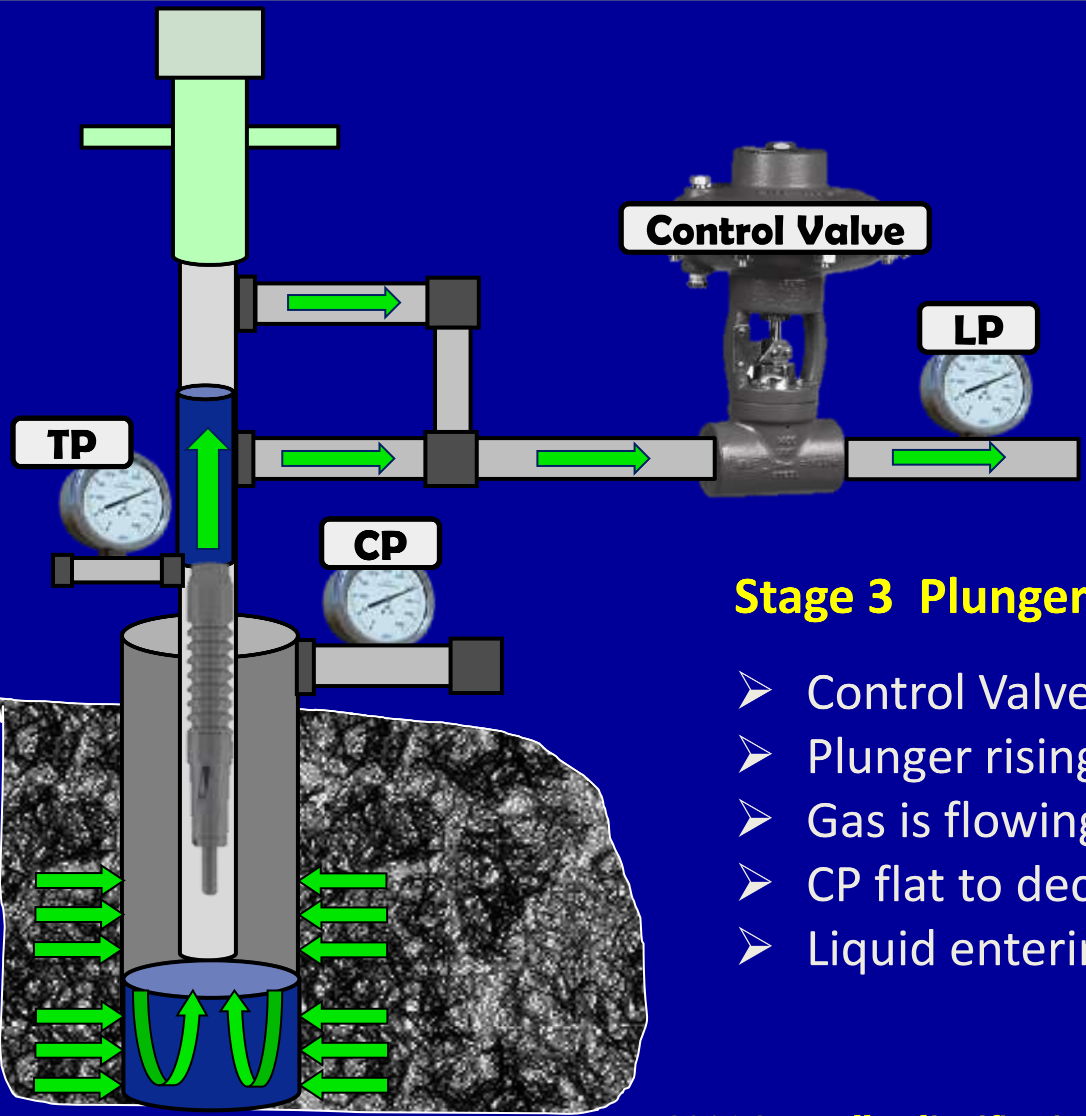


Continuous Run Plunger

Stage 2 Plunger arrives at bottom hole spring

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

How Does Plunger Lift Work



Continuous Run Plunger

"Fast enough to avoid stalling, slow enough to avoid damage"

Stage 3 Plunger Rise

- Control Valve Open
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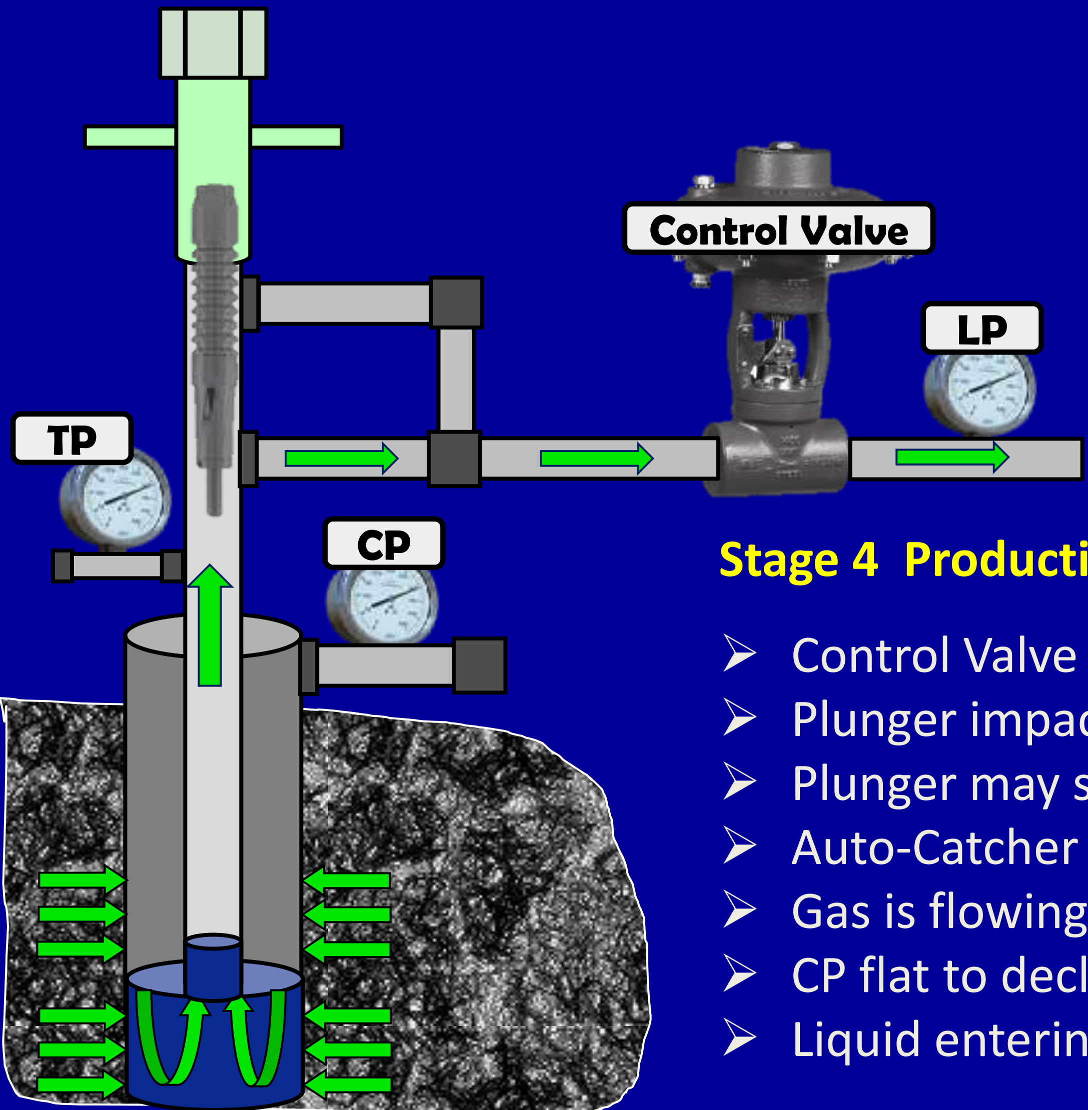


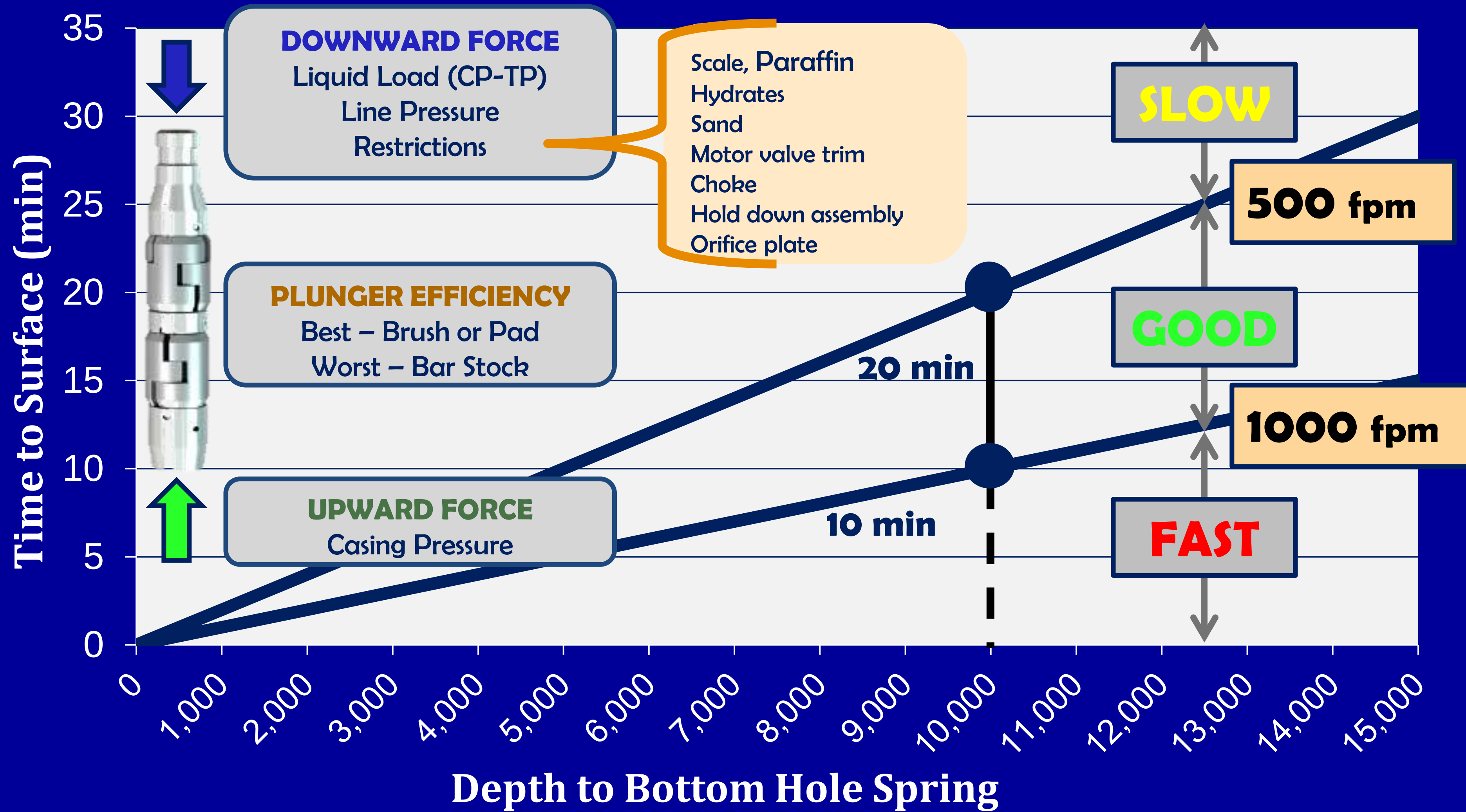
Continuous Run Plunger

Stage 4 Production (After Flow)

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

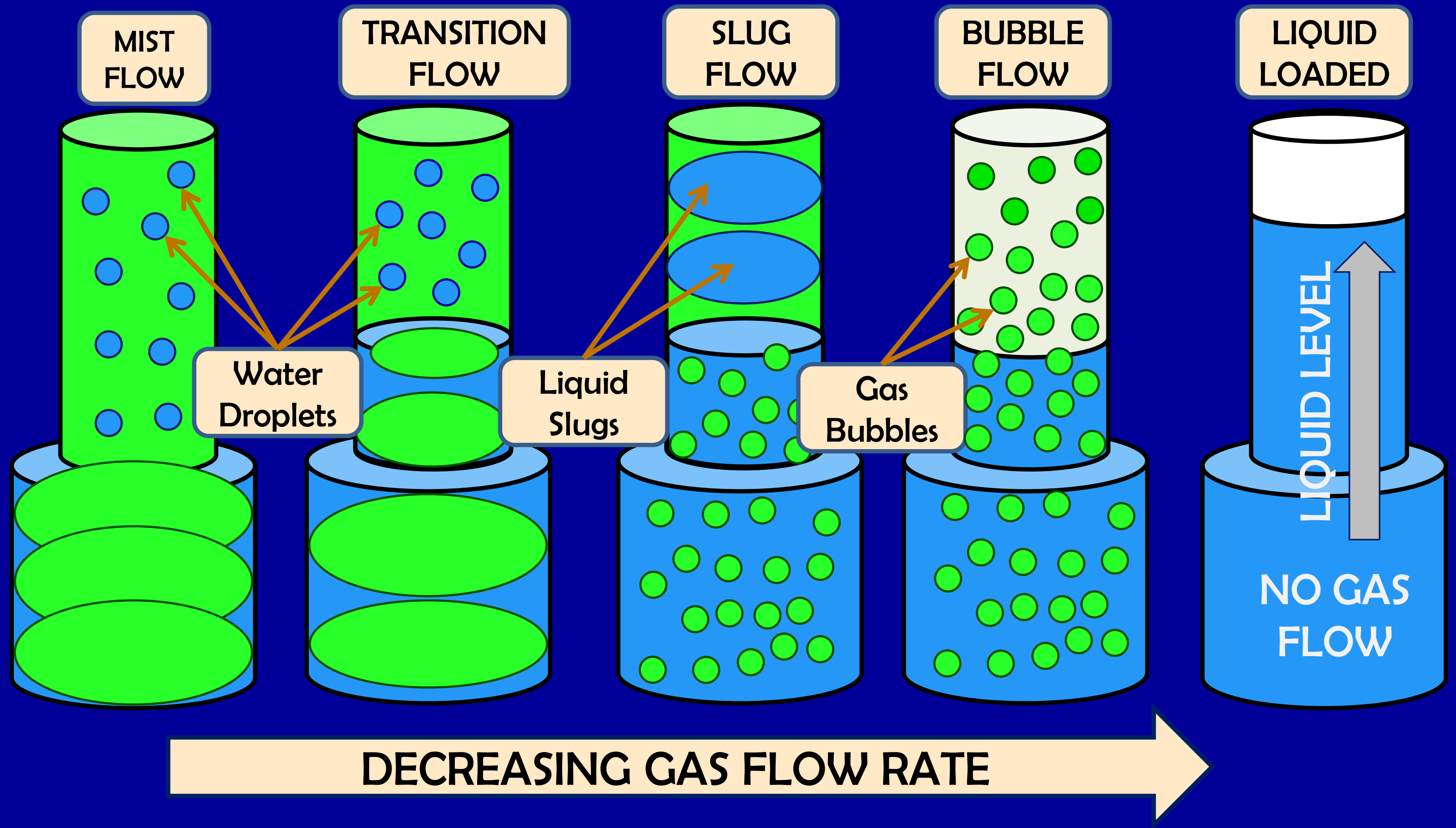
How Does Plunger Lift Work

How Does Plunger Lift Work



WHY IS ARTIFICIAL LIFT REQUIRED

Why Is Artificial Lift Required



Why Is Artificial Lift Required

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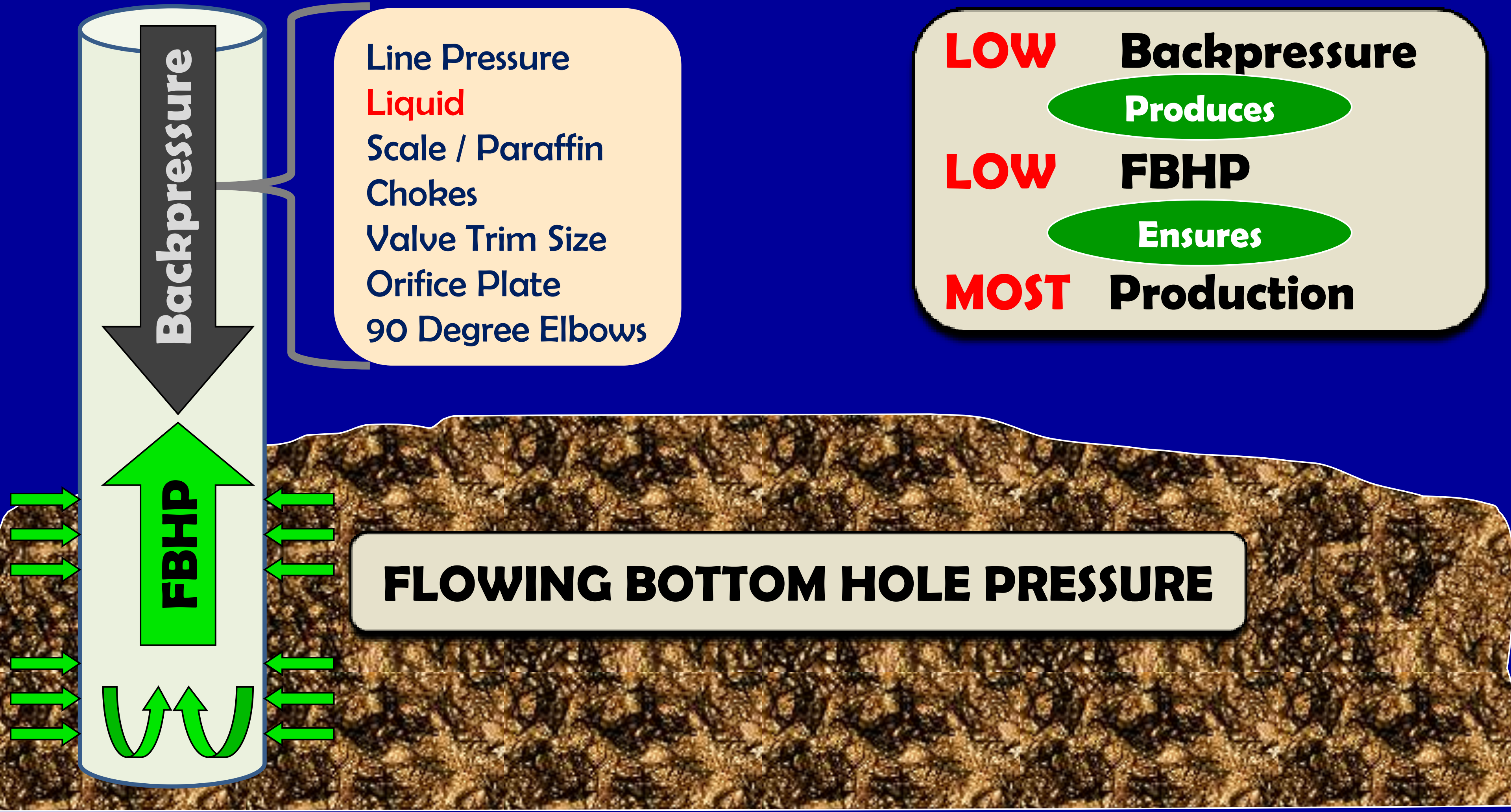

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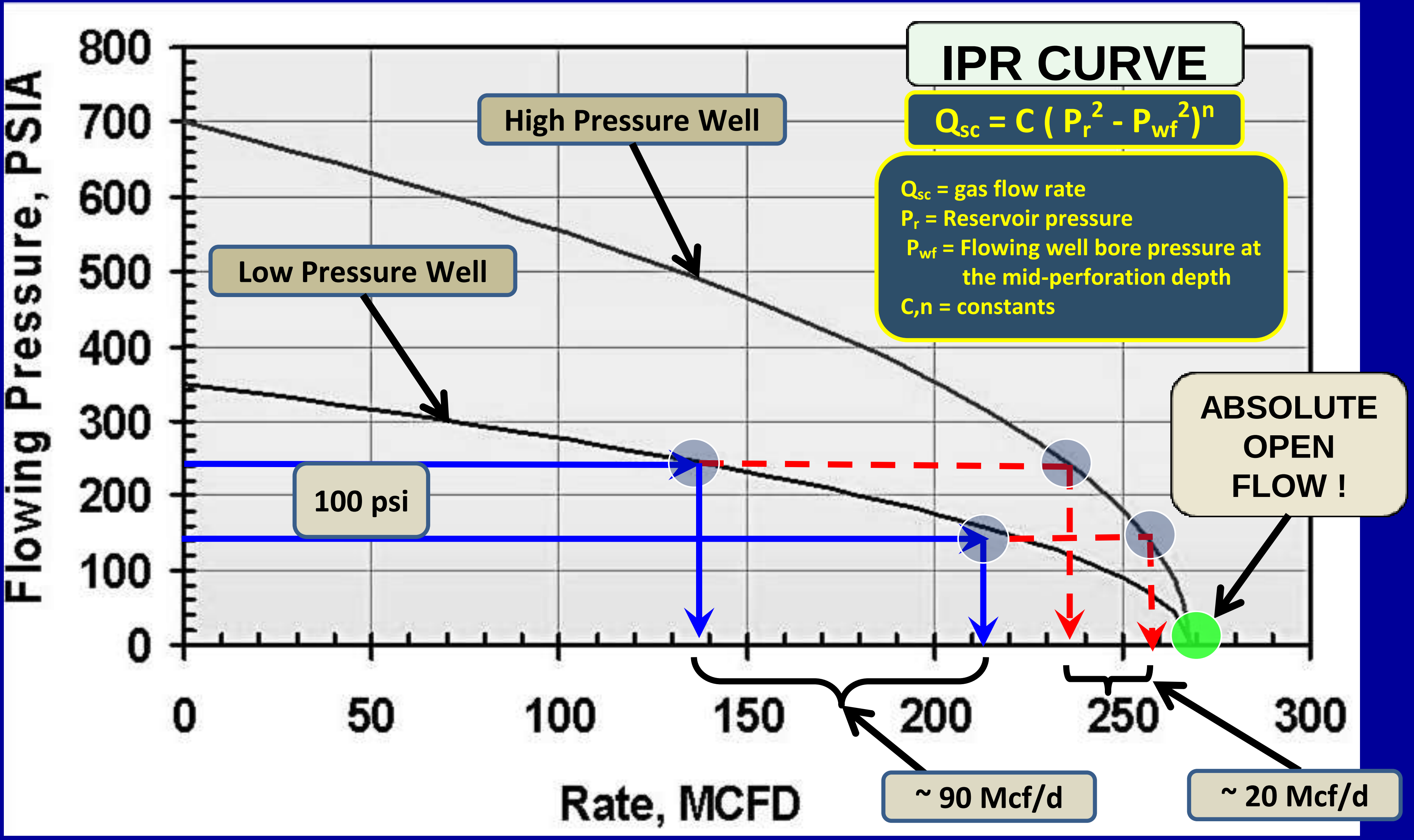

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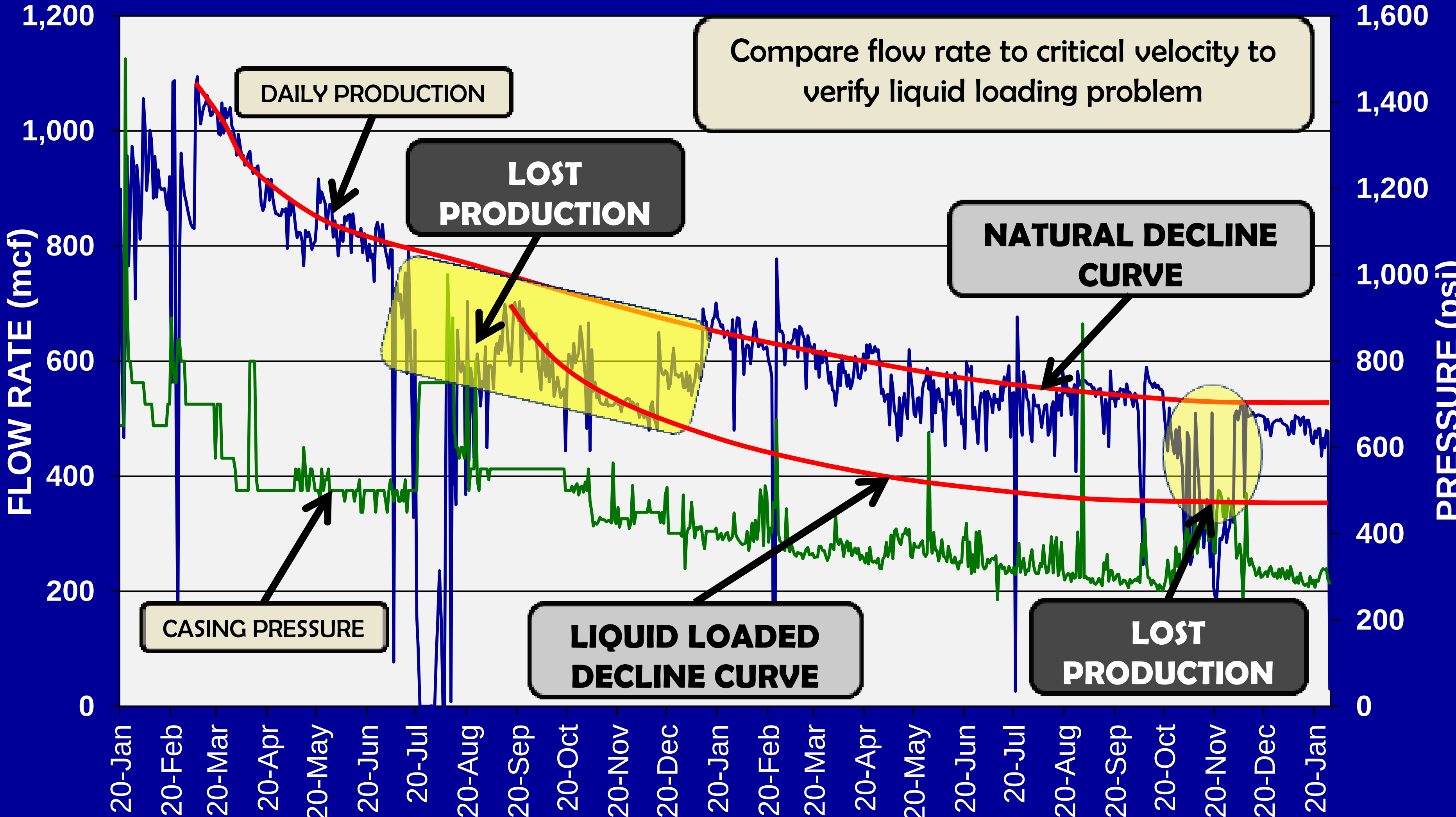


Artificial Lift Types

ESP

Beam Pump

Plunger Assisted Gas Lift

Gas Assisted Plunger Lift

2 Stage Plunger Lift

Plunger Lift

Compression → High Cap X

Velocity Strings → Often, only Short Term Solution

Foaming Agent → Monthly Chemical Expense

Swab or Intermit Well → Not Environment Friendly

Free Flowing Well

Liquid Loading

Artificial Lift Type Considerations:

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

PLUNGER LIFT WELL REQUIREMENTS

Plunger Lift Well Requirements

IS LIQUID IN THE TUBING ?

(Over 90% of US Gas Wells)

- ERRATIC PRODUCTION
- DECLINE CURVE ANALYSIS
- CRITICAL FLOW RATE

YES

IS GAS VOLUME SUFFICIENT ?

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

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

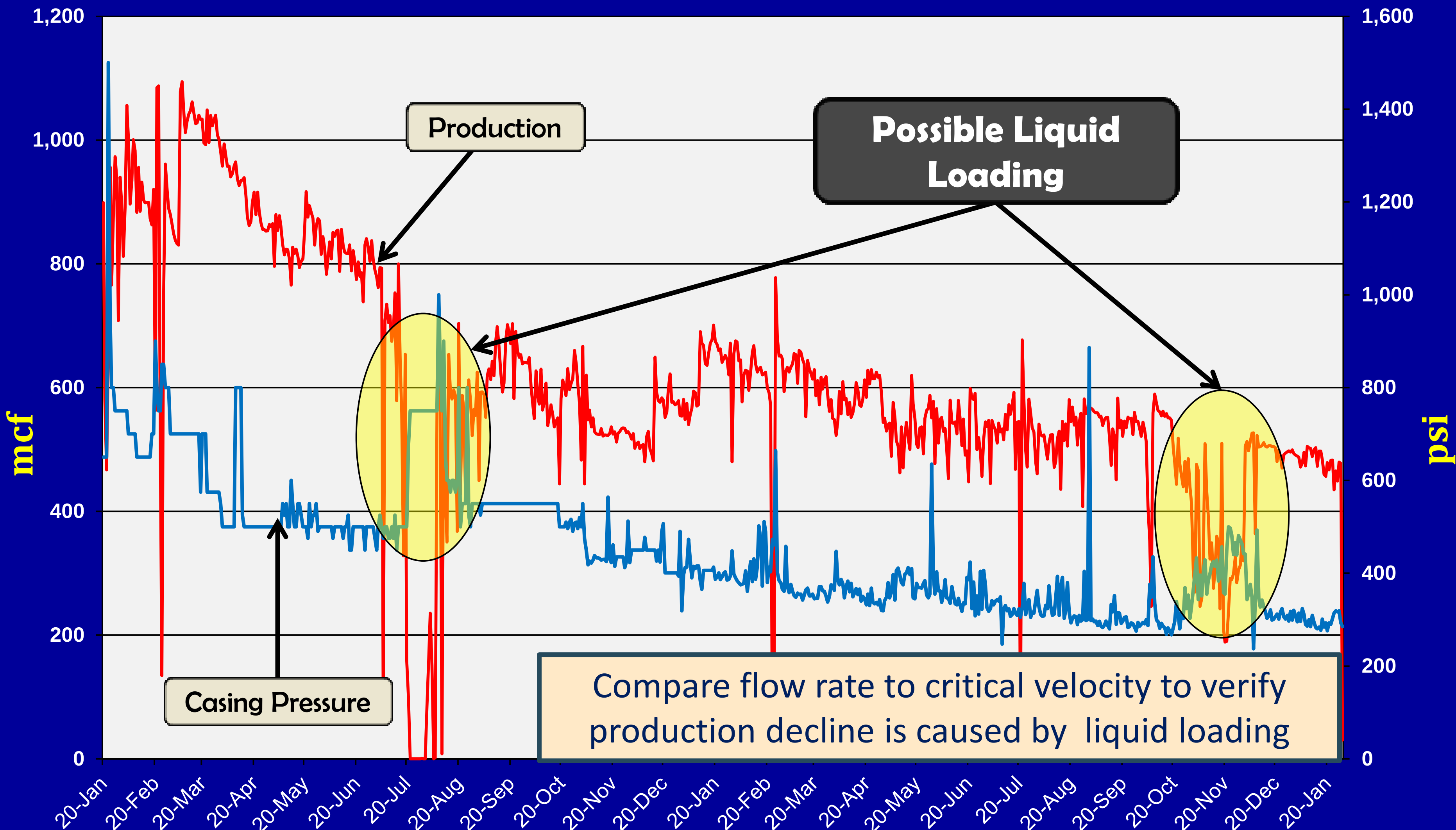
YES

IS GAS PRESSURE SUFFICIENT ?

- LIFT PRESSURE >/= 2X LIQUID LOAD

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

Is Liquid in the Tubing?



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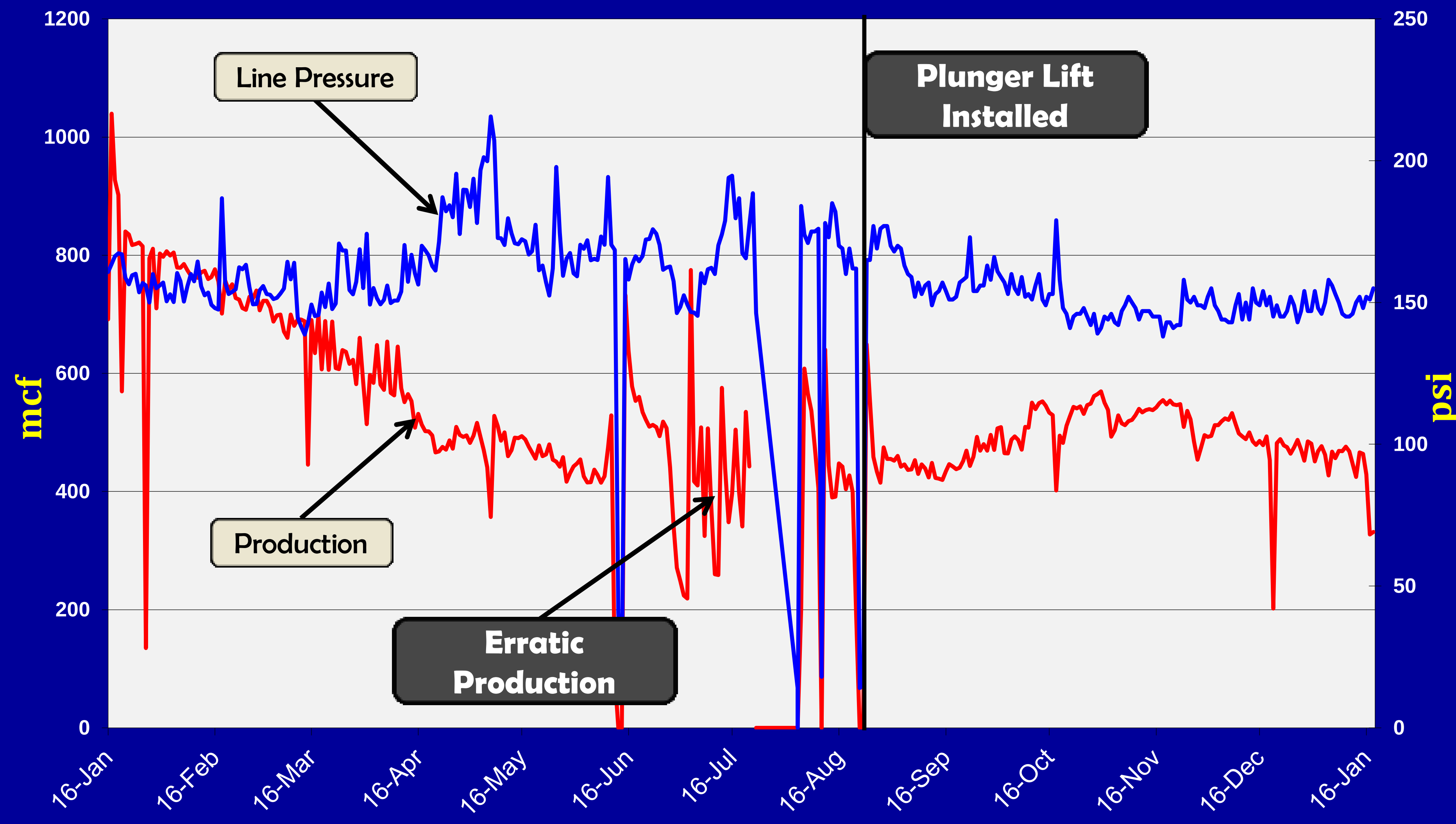

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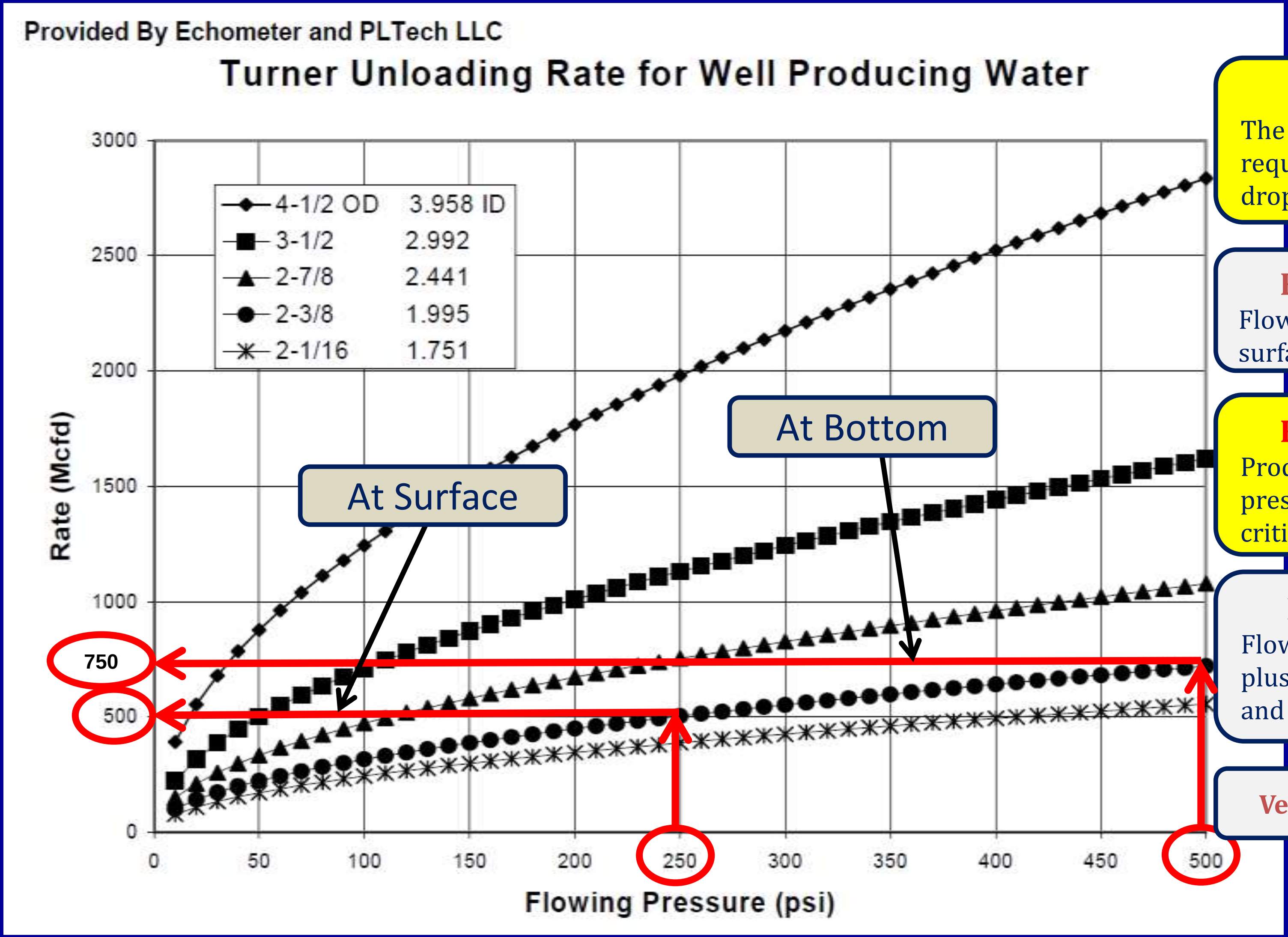


Critical Velocity
The minimum gas velocity required to move water droplets upward.

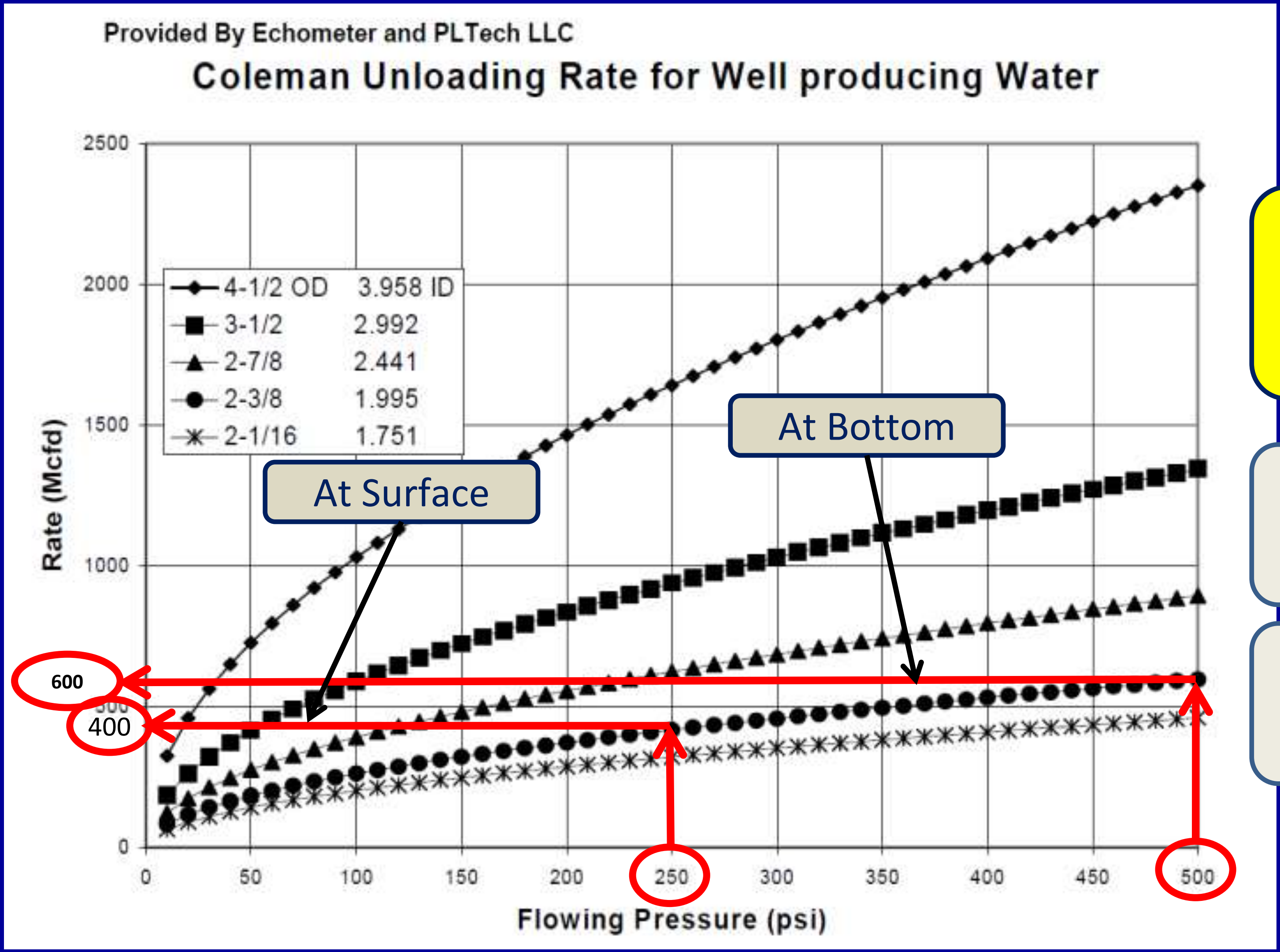
Flowing Pressure
Flowing tubing pressure for surface critical flow rate

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

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

Vertical portion of well!

Is Liquid in the Tubing?



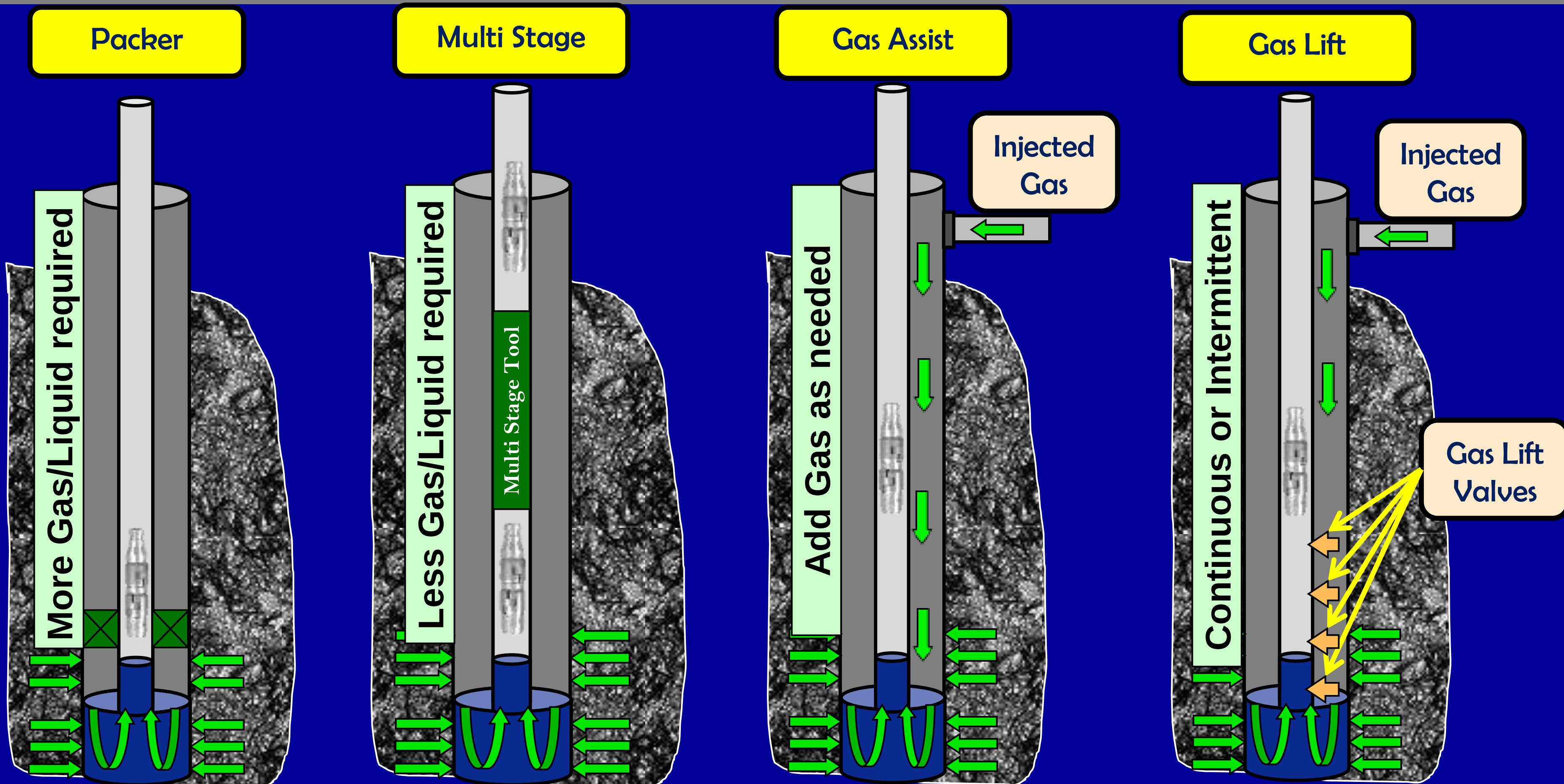
Predicted critical flow rate is 20% less than Turner

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

SPE 94081-PA "A Systematic Approach to Predicting Liquid Loading in Gas Wells" by Gua, Ghalambor, Xu.

Is Liquid in the Tubing?

Is Gas Volume Sufficient?



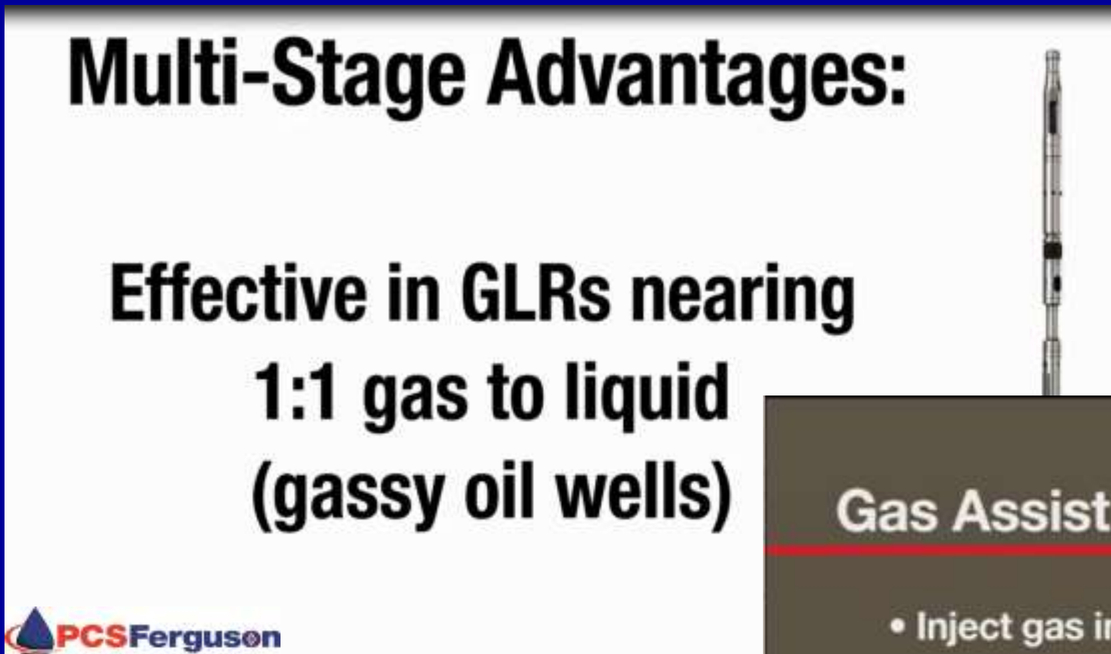
NO PACKER
400 SCF / BBL / 1,000 FT

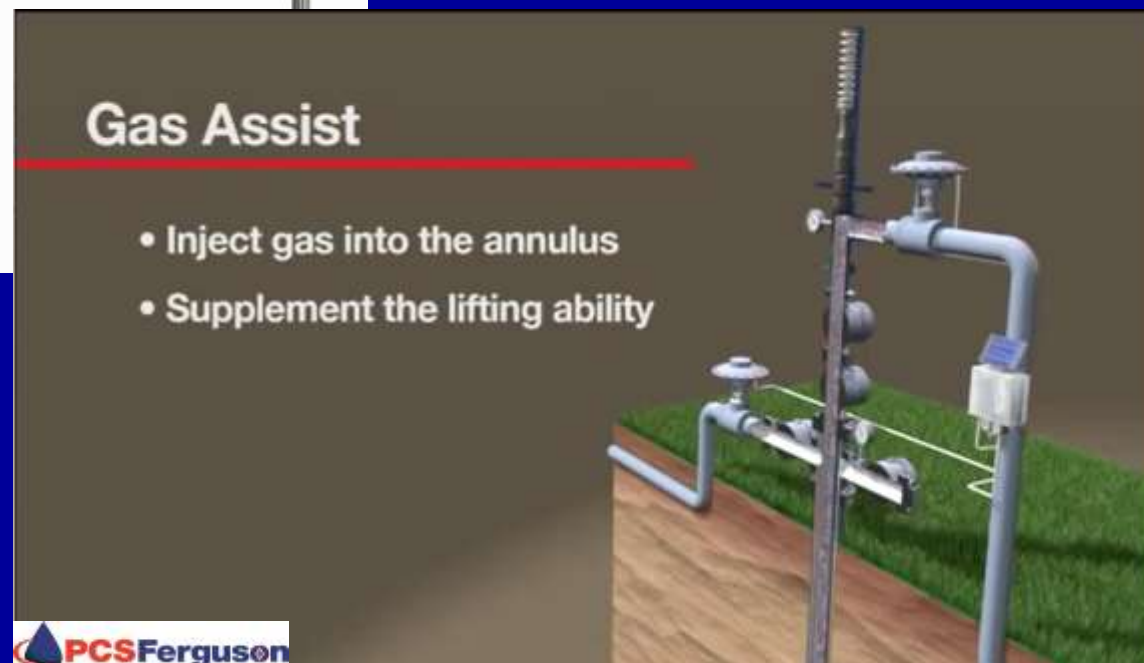
200 SCF / BBL / 1,000 FT

Inject to 400 SCF / BBL / 1,000 FT
250 + bbls/day possible

Reduce injected gas
by up to 30 %

Multi Stage Plunger Lift





Is Gas Pressure Sufficient?

Right before well opens

LIFT PRESSURE

Lift Pressure = CP – LP

LIQUID LOAD

Liquid Load = CP – TP

LOAD FACTOR

Liquid Load / Lift Pressure < or = 0.5

LIFT FACTOR

Lift Pressure / Liquid Load > or = 2.0

Lift Pressure > or = 2 X Liquid Load

FOSS and GAUL EQUATION

Predicts the casing pressure required to surface the plunger and liquid column

Lift Pressure$_{req'd}$ = CP$_{req'd}$ – LP

Foss and Gaul Equation

- $CP_{req'd} = CP_{min} \times \{(A_{ann} + A_{tbg}) / A_{ann}\}$
- $CP_{min} = \{SLP + P_p + P_c FV\} \times \{1 + D/K\}$
- CP = Casing Pressure; SLP = Sales Line Pressure
- A_{ann} = Area Annulus; A_{tbg} = Area Tubing
- P_p = Pressure required to lift just the plunger
- P_c = Pressure Required to lift 1 bbl of fluid and overcome friction
- FV = Fluid Volume above the Plunger
- K = Constant accounting for gas friction below the plunger
- D = Depth of the Plunger

Other Considerations

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

APPLICATIONS, BENEFITS, LIMITATIONS, ECONOMICS

Applications

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

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

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

Benefits

No Telemetry

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

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

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

With Telemetry

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

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

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

Benefits

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

Limitations

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

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

Economics

COST ITEMS

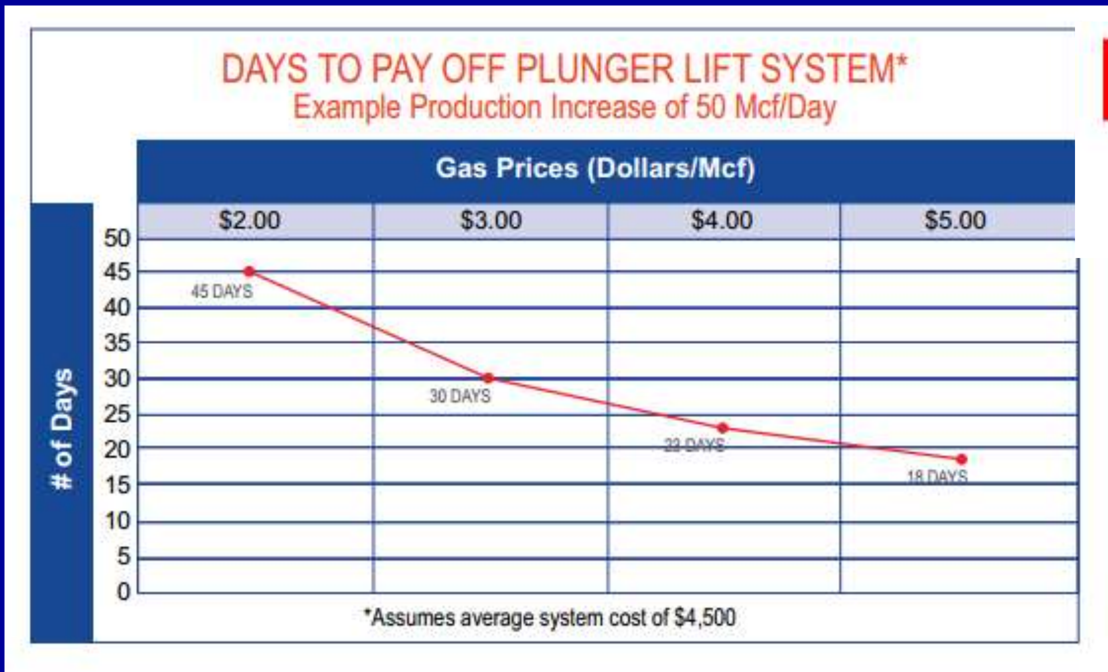
- ✓ Check tubing
  - ✓ Drift, broach, pressure check
- ✓ Set bottom hole spring
- ✓ Re-configure well head tree
- ✓ Install lubricator
- ✓ Install control (motor) valve
- ✓ Install pressure transducers

COST ITEMS

- ✓ Establish communication with flow meter and “office”
- ✓ Install plunger lift controller
- ✓ Route clean, dry gas to solenoid
- ✓ Install plunger
- ✓ Swab well if necessary
- ✓ Establish controller settings

Maintain wells natural decline curve. Don’t wait till production is lost!

Economics



The investment in a PCS Ferguson Plunger Lift system typically runs between $2,500 and $10,000. A plunger lift system could increase production by 100 Mcf/day or more.

PCS Ferguson Plunger Lift Equipment Catalogue - 2016

Guidelines & Recommended Practices
Use of Plunger Lift for Deliquifying Gas Wells

Introduction

This paper discusses the considerations, applications, costs and best practices for use of Plunger Lift systems, particularly Tubing Plungers.

$ 15,000 to $ 25,000

Use the Natural Decline Curve to estimate production increases

"World Oil" 1998

"It has been Conoco's experience, with more than 200 plunger lift systems in the San Juan basin, that the plunger operator is the single most important factor in keeping a plunger system operating efficiently. If an operator knows certain principles of plunger operation and gas well mechanics, he can effectively maintain and trouble-shoot the system. His goal will be to optimize the system, keep a good maintenance schedule and attempt to flow the well against the lowest pressures possible. If an operator does not understand these principles, a system will loss efficiency due to poor maintenance. An operator who does not understand basic principles may try to "just keep the plunger running," and he may be frustrated when the system does not work well."

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

Linkedin Group

“Plunger Lifted Gas Wells”

ADDENDUM

Tubing Fluid Height and Volume

Fluid Volume in Tubing (Barrels)

- $FV = 0.002242 \times (CP - TP) \times (ID^2)/SG$
- CP=Casing Pressure; TP=Tubing Pressure
- ID=Tubing Inner Diameter (inches)
- SG = Specific Gravity (1.0 for water)

Fluid Height in Tubing (Feet)

- FH = (CP-TP) / (0.433 psi/ft X SG)
- 0.433 psi/ft = Pressure gradient of water
- SG = Specific Gravity (1.0 for water)
- Typically, fluid column is 20 % liquid, 80 % gaseous liquid (foam). Divide results by 20% to obtain height of the gaseous liquid column

Tubing Fluid Height and Volume

2 3/8" tubing (1.995" ID)

CP-TP (psi)	Liquid Volume (bbls ; SG = 1)	Liquid Height (solid column)	Liquid Height (80% gaseous)
10	0.089	23 ft	115 ft
20	0.178	46 ft	231 ft
30	0.268	69 ft	346 ft
40	0.357	92 ft	462 ft
50	0.446	115 ft	577 ft
60	0.535	138 ft	692 ft
70	0.625	161 ft	808 ft
80	0.714	185 ft	923 ft
90	0.803	208 ft	1039 ft
100	0.892	231 ft	1154 ft
125	1.115	288 ft	1443 ft
150	1.338	346 ft	1732 ft
175	1.562	404 ft	2020 ft
200	3.569	923 ft	4618 ft

2 7/8" tubing (2.441" ID)

CP-TP (psi)	Liquid Volume (bbls ; SG = 1)	Liquid Height (solid column)	Liquid Height (80% gaseous)
10	0.133	23 ft	115 ft
20	0.267	46 ft	231 ft
30	0.400	69 ft	346 ft
40	0.534	92 ft	462 ft
50	0.668	115 ft	577 ft
60	0.801	138 ft	693 ft
70	0.925	162 ft	808 ft
80	1.068	185 ft	924 ft
90	1.202	208 ft	1039 ft
100	1.336	231 ft	1154 ft
125	1.670	289 ft	1443 ft
150	2.003	346 ft	1732 ft
175	2.338	404 ft	2020 ft
200	5.343	923 ft	4616 ft

Sufficient Volume and Pressure

Sufficient Gas Volume

- No Packer
  - 400 scf / bbl / 1000 ft of lift
- Packer
  - 2,000 scf / bbl / 1000 ft of lift

Sufficient Gas Pressure

- Casing Pressure at least 1.5 X line pressure
- Lift Pressure at least 2 X greater than fluid load
- See Foss and Gaul requirements

Casing Pressure Required

Foss and Gaul (CP Required to Lift Plunger)

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

Tubing	K	Pc
2 3/8	33,500	165
2 7/8	45,000	102
3	57,600	67

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

Critical Flow Rate

Critical Flow Rate (Coleman, P_f Less Than 1,000 psi)

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

Turner (P_f Greater Than 1,000 psi)

- Turner = Coleman + 20%

Standard Cubic Foot

$$SCF = ACF \times P_f/P_s \times T_s/T_f$$

- SCF = Standard Cubic Foot of gas
  - Volume of gas contained in $1 ft^3$ at $60^{\circ}F$ and 14.7 psi
- ACF = Actual or Measured Cubic Foot
- P_f = Flowing pressure (psi); P_s = 14.7 psi
- T_f = Flowing temperature ($^{\circ}R$)
- T_s = Standard temperature ($516.67^{\circ}R$)
- $^{\circ}R = {^{\circ}F} + 459.67$

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