GAS LIFT
Continuing Problems and Possible Solutions

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ALRDC Gas Lift Workshop
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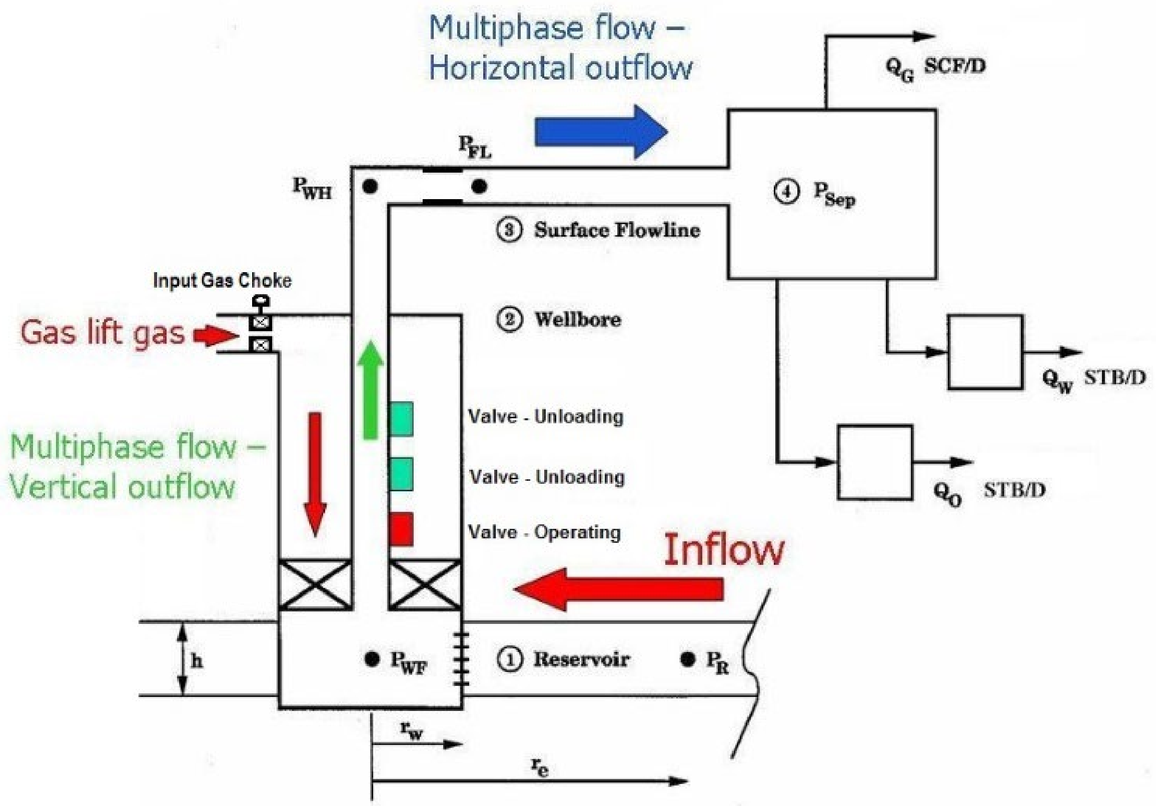
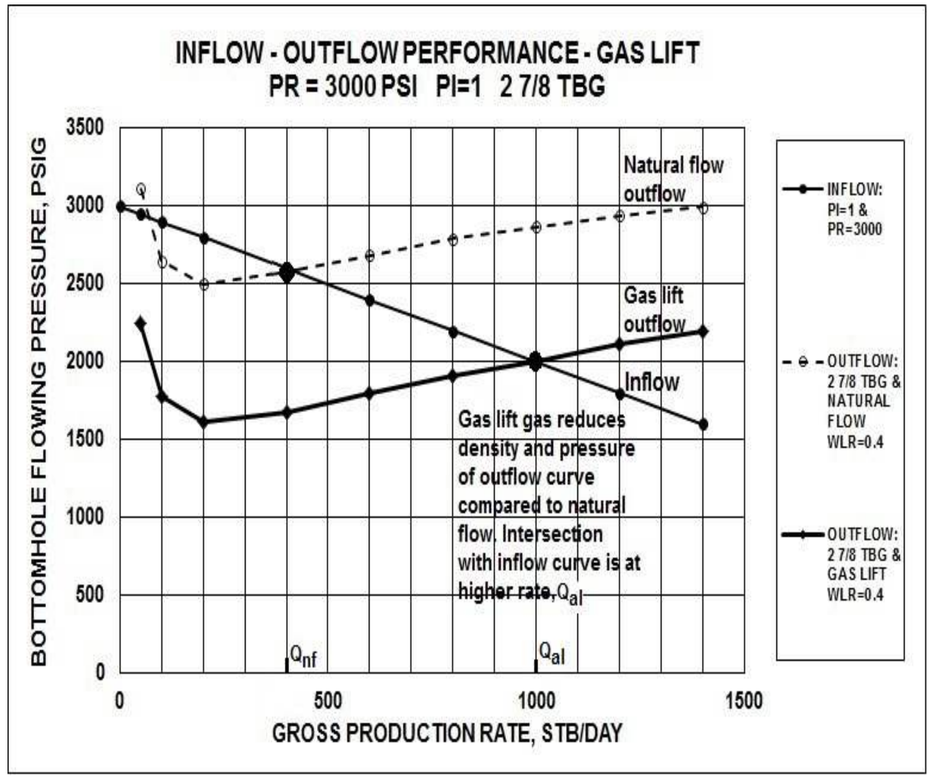
Gas Lift - Gas Well Or Oil Well Higher Rate Than Natural Flow

RESERVOIR PRESSURE DRIVES FLUID TO SURFACE FACILITY; GAS LIFT GAS REDUCES DENSITY

- RESERVOIR PRESSURE AND PI FOR INFLOW
- TUBING OUTFLOW ALTERED WITH GAS LIFT GAS REDUCING DENSITY
- FLOWLINE OUTFLOW
- SEPARATOR PRESSURE
- REDUCED PRESSURE OF TUBING OUTFLOW GIVES INTERSECTION AT HIGHER ARTIFICIAL LIFT RATE, Qal





Gas Lift History

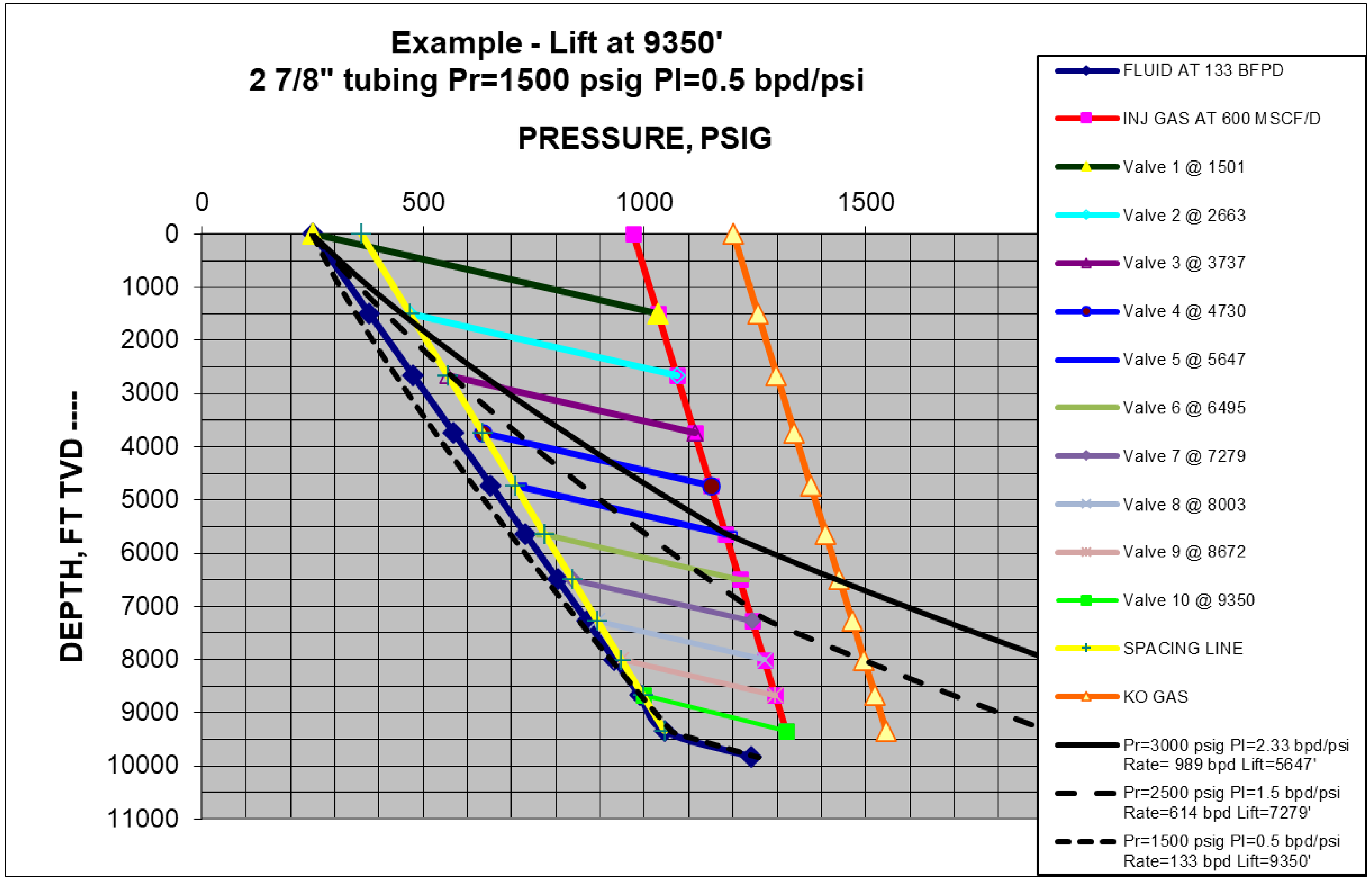
- Gas lift distribution manifolds
- Intermitter valves at manifold
- Intermitter control devices – gear driven
- Automation by trial and error with time cycle adjustment

Gas Lift for Life
Tubing and Valve/Mandrel Configuration

- NATURAL FLOW INITIALLY
- CONTINUOUS GAS LIFT
  – ANNULUS FLOW
  – TUBING FLOW
- INTERMITTENT GAS LIFT
- INTERMITTENT GAS LIFT WITH PLUNGERS

Gas Lift Problems
Valve Pressure

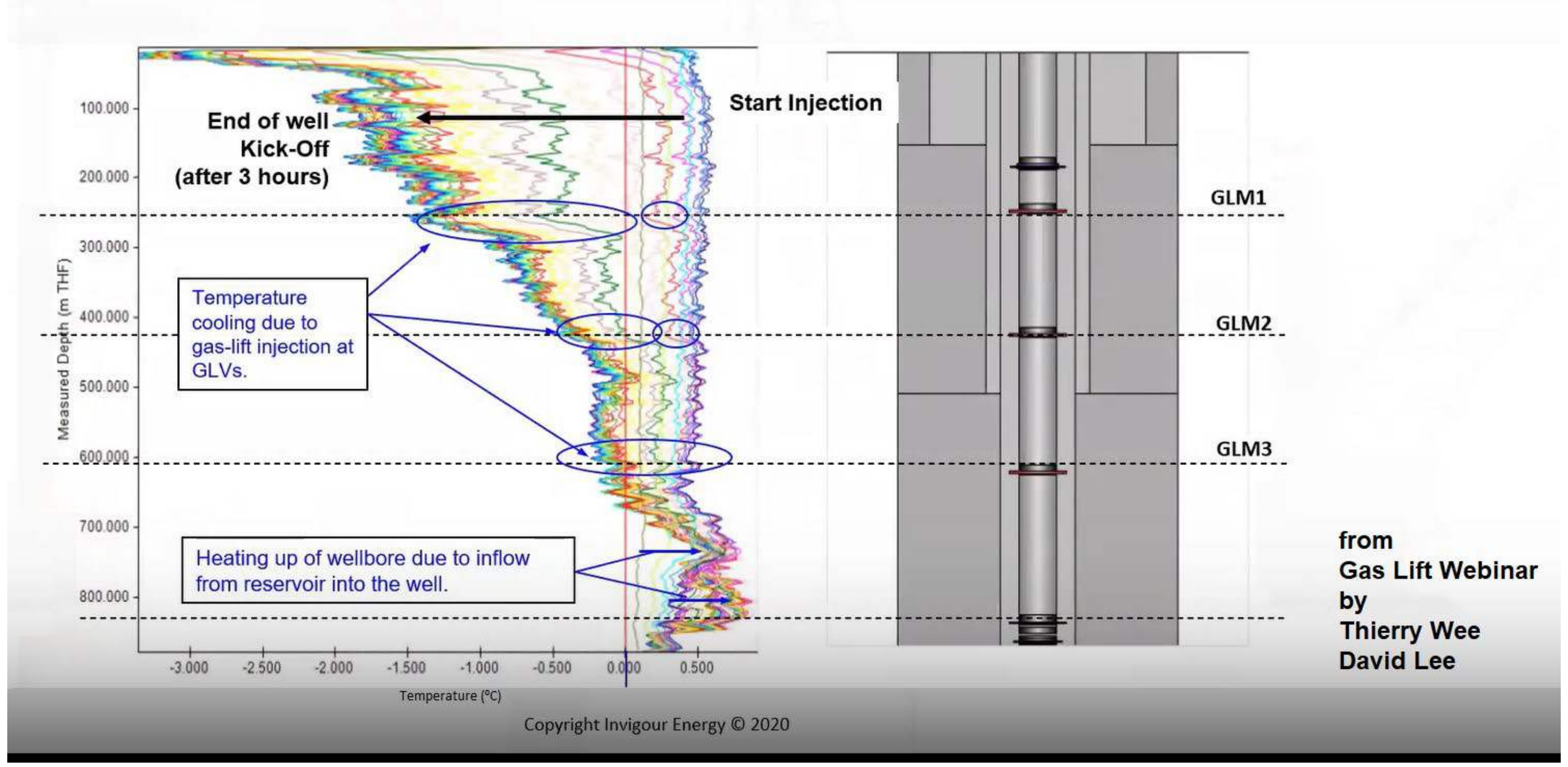
- PRESSURE BASED ON COMPUTER CALCULATION
- NO VALIDATION FROM FLOWING SURVEY
- HIGH FLOW, HIGH PRESSURE INTIALLY
- DECLINES TO MID AND LOW RATES WITH TIME
- ESTIMATES BASED ON RESERVOIR PRESSURE AND PRODUCTIVITY CHANGE
- NEED IMPROVED DATA GATHERING IN FLOWING WELLS PRIOR TO GAS LIFT DESIGN



West Texas data

Gas Lift Problems
Valve Temperature

- GOES FROM STATIC TO FLOWING TEMP
- MUST PICK AN UNLOADING TEMP
- WELLBORE HEATS WITH RESERVOIR FLUID FLOW
- NEED WELL DATA FROM DIST TEMP SURVEY
- NOT EVERY WELL, JUST THE INITIAL WELLS
- NOTE THAT A PLATFORM HAS WARM ZONE HOTTER THAN GEOTHERMAL



from
Gas Lift Webinar
by
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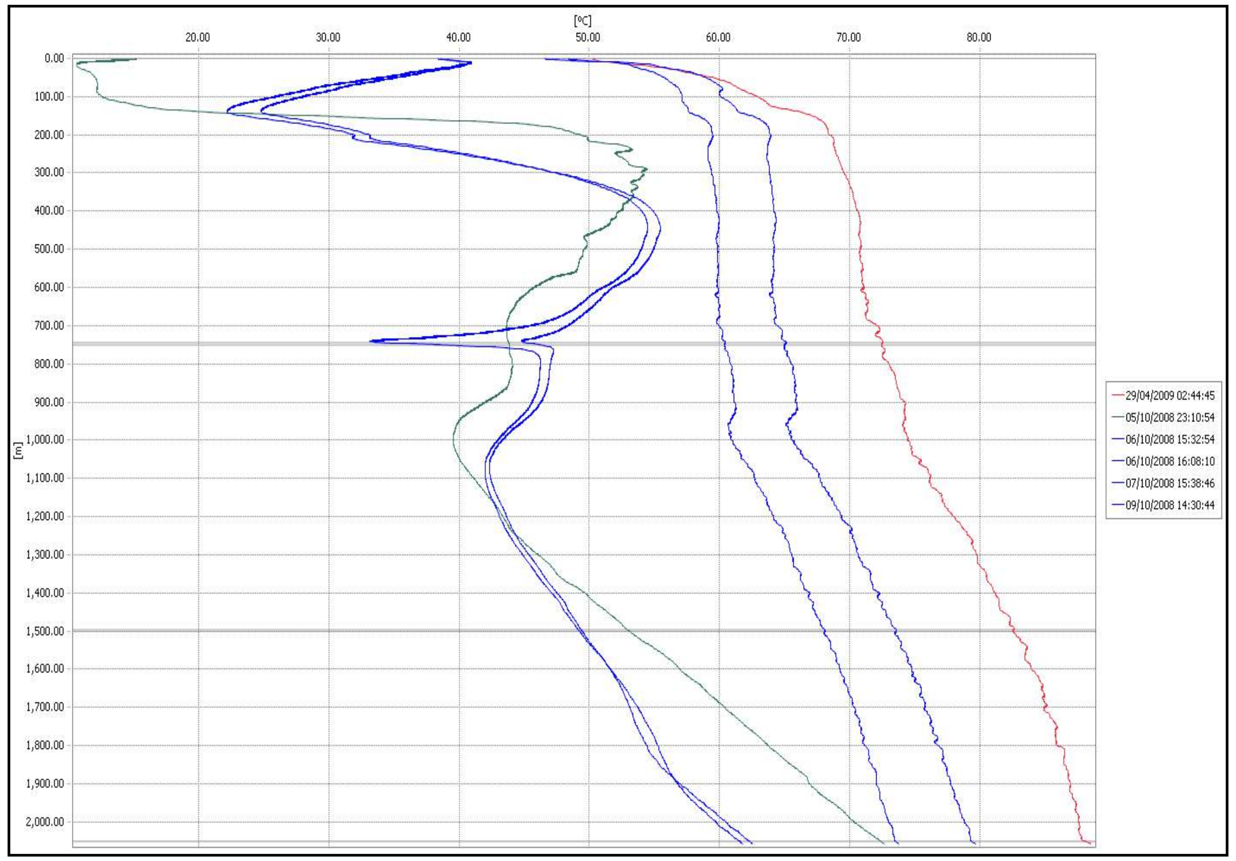
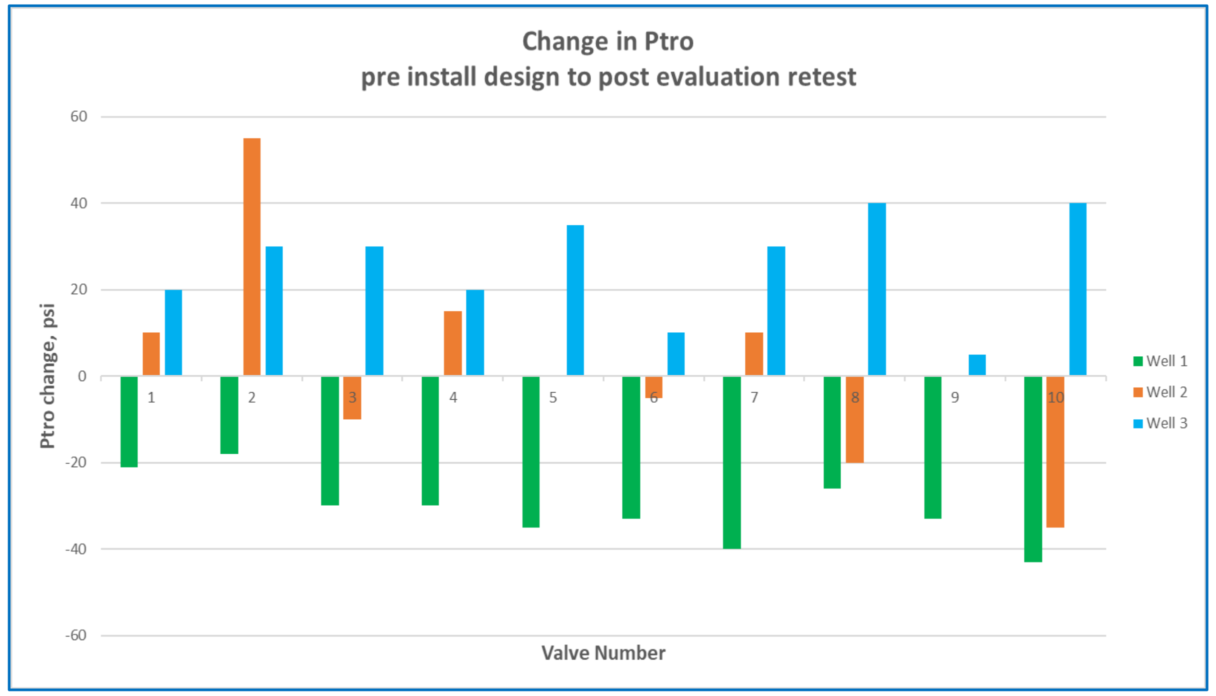
David Lee

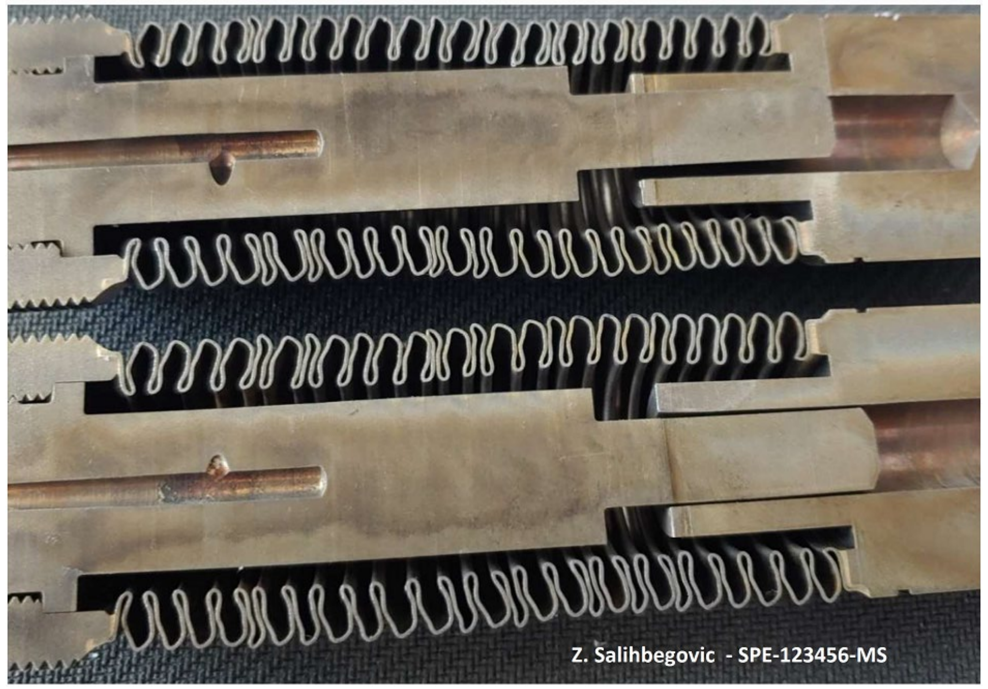


North Sea data

Gas Lift Problems
Valve Bellows Manufacturing Quality and Performance

- BELLOWS COMMON TO MOST VALVES
- MANUFACTURING MIGHT AFFECT BELLOWS BEHAVIOR
- HYDROSTATIC FORMING MAY AFFECT PERFORMANCE
- AGING PROCEDURE MIGHT HAVE TO BE STANDARDIZED
- THIS VALVE DATA SHOWS VARIATION IN THREE STRINGS OF VALVES
- AFFECTS VALVE UNLOADING AND PERFORMANCE
- ZLATKO SALIHBEGOVIC WILL DISCUSS BELLOWS IN HIS PRESENTATION





Valve	Well 1			Well 2			Well 3		
	Design Ptro	Retest Ptro	Diff	Design Ptro	Retest Ptro	Diff	Design Ptro	Retest Ptro	Diff
1	1065	1044	-21	1120	1130	10	1110	1130	20
2	1065	1047	-18	1130	1185	55	1115	1145	30
3	1065	1035	-30	1140	1130	-10	1115	1145	30
4	1065	1035	-30	1145	1160	15	1115	1135	20
5	1065	1030	-35	1145	1145	0	1110	1145	35
6	1065	1032	-33	1150	1145	-5	1110	1120	10
7	1065	1025	-40	1150	1160	10	1105	1135	30
8	1065	1039	-26	1150	1130	-20	1100	1140	40
9	1065	1032	-33	1145	1145	0	1095	1100	5
10	1065	1022	-43	1140	1105	-35	1080	1120	40

Gas Lift Problems
Valve Erosion While Unloading

Practices are applied during the workover to install the packer, tubing, mandrels, and valves:

a) Circulate the wellbore to remove any drilling mud before perforating, running other completion equipment, and installing the gas lift valves.

b) Use a casing scraper to remove debris that adheres to the casing wall and burrs created when packers were set; circulate the casing clean.

c) Use filtered completion and workover fluids and leave filtered fluid in the tubing-casing annulus. Unfiltered fluids are a source of solids that can either cut out or plug the gas lift valves.

Unloading the control (kill) fluid from the tubing and annulus is initiated after the well is secured:

a) Displace with unloading rates not exceeding 1 barrel per minute (BPM).

b) Control injection rate to attain a 50 psig casing pressure increase in 10 minute increments.

c) Continue until the casing pressure reaches 400 psig, increase gas rate to achieve a 100 psig increase in 10 minute increments.

d) Monitor for an injection gas pressure drop and the return of aerated fluid.

e) Confirm casing pressure decline as injection point transfers to deeper valves.

f) Use acoustic fluid level tools in the casing annulus to confirm depth of injection.

Gas Lift Problems
Valve Erosion While Unloading

Gas rates equal to 1 bbl/min (1 BPM)				
Kick Off Pressure	Gas Vol Factor SG=0.7	Gas Rate = 1 BPM SG=0.7	Gas Vol Factor SG=0.8	Gas Rate = 1 BPM SG=0.8
psig	ft3/scf	thou scf/d	ft3/scf	thou scf/d
800	0.0168	481	0.0158	512
1000	0.0130	622	0.0121	668
1050	0.0123	657	0.0113	716
1200	0.0105	770	0.0096	842
1400	0.0087	929	0.0079	1023
1600	0.0075	1078	0.0066	1225
1800	0.0065	1244	0.0058	1394
2000	0.0058	1394	0.0051	1585
2200	0.0052	1555	0.0047	1720
2400	0.0048	1685	0.0043	1880
2600	0.0045	1797	0.0041	1972
2800	0.0042	1925	0.0039	2073
3000	0.0040	2021	0.0037	2185

SG=Injection gas specific gravity   Gas Temp = 100°F

Gas Lift Problems
Surface Control the Solution?
Compiled by Ali Hernandez – Happy Birthday, Ali, on June 23

ELECTRONIC

Silverwell (DIAL): Not wireline retrievable, not a retrofit option, limited pressure rating, faulty cable connections (surface and subsurface splice), combination of 6 orifices (multiple source of failure), commercially available

Precise DHS (Oura): Not wireline retrievable, not a retrofit option, pressure rating 7500 psi, infinite orifice size from 0 to 24/64 inch, commercially available

PTC (E-Lift): Wireline retrievable, not a retrofit option, pressure rating 10000 psi, infinite orifice size, association with Emerson (extensive cable splicing experience), will use 19G2 specification check valves, commercially available by 2023

WiGL (one way): Wireline retrievable, retrofit option, surface to valve communication only, requires battery

WiGL (two ways): Wireline retrievable, retrofit option, surface to valve and valve to surface communication, requires battery and turbine

SageRider EGL: Development, not installed, has single cable, fewer stations

HYDRAULIC

Innovex (LiftSmart): Not wireline retrievable, difficult to move the point of injection upward, commercially available

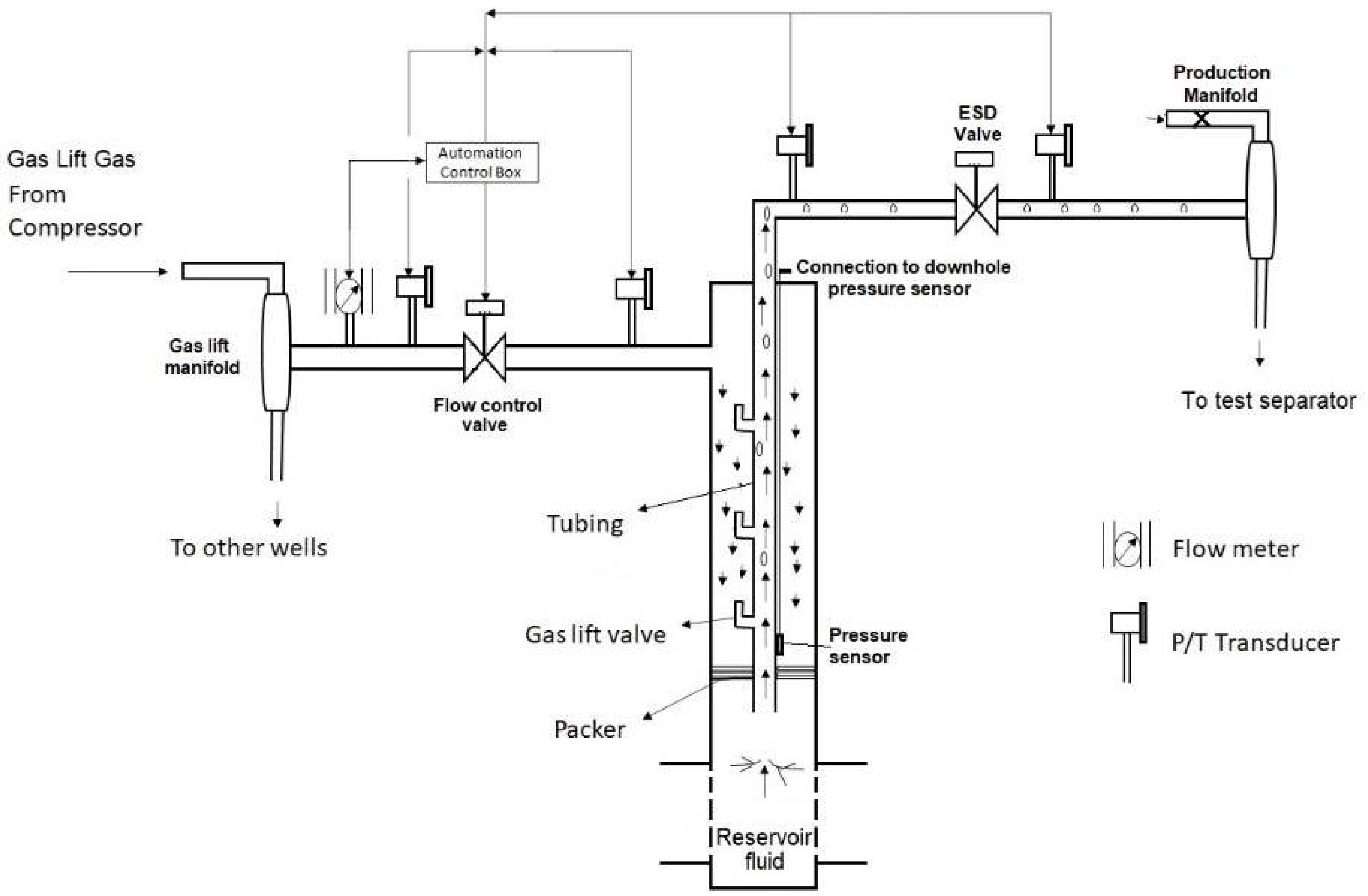
PTC (HPO valve): Wireline retrievable, difficult to move the point of injection upward, will use 19G2 specification check valves

Automation
Hardware and Software

- PRESSURE/TEMPERATURE/FLOW SENSORS BOTH SURFACE AND SUBSURFACE
- DATA LINKED TO SOFTWARE THAT CAN DIRECT CHANGES TO IMPROVE PRODUCTION AND/OR MAINTAIN STEADY FLOW
- SOFTWARE CONTROLS DEVICES
  - VARIABLE SPEED DRIVES
  - INPUT CONTROL OF GAS LIFT GAS
  - PLUNGER CYCLES
- SOFTWARE CONTROL OF TESTING
  - SERIES TESTING WITH CHANGED INPUT (GAS LIFT GAS OR VARIABLE SPEED)
  - OPTIMIZE PRODUCTION AND INPUTS
- SMART INSTRUMENTATION
  - LINKED TO SOFTWARE WHICH USES REAL TIME DATA FROM SENSORS
- STAFF TRAINED TO BECOME HARDWARE/SOFTWARE SPECIALISTS IN ADDITION TO PRODUCTION SPECIALISTS
- FAILURE DATA BASE TO AID REDESIGN

Gas Lift Automation
API Gas Lift Handbook Addendum

- Introduction
- Automation Objectives and Practices
  - General
  - Automation Practices
  - Automation Systems
  - Automation Data Usage
- Gas Lift Automation Hardware and Software
  - General
  - Automation Hardware
  - Automation Database Information
- Section Summary



Gas Lift Design Guidelines

RESERVOIR PRESSURE DRIVES LOW DENSITY FLUID TO SURFACE FACILITY

- **DESIGN GAS LIFT COMPRESSORS FOR HIGH INJECTION PRESSURE AND MORE THAN PREDICTED CAPACITY**
  - **INJECTION PRESSURE NEAR 1400 PSI**
  - **CONSIDER VERY HIGH INJECTION PRESSURE FOR SINGLE POINT LIFT OR FOR ANNULUS FLOW**
- **DESIGN SUFFICIENT LOW PRESSURE CAPACITY IN GATHERING SYSTEM**
  - **REDUCES GAS LIFT GAS INJECTION RATES**
  - **INCREASES PRODUCTION RATES**
- **INSTALL BOTH SURFACE AND DOWNHOLE PRESSURE/TEMPERATURE SENSORS**
  - **USE FLOWING BHP MEASUREMENT TO CONTROL INJECTION GAS**
  - **USE SURFACE MEASUREMENT TO CONTROL SURGING BY ADJUSTING INJECTION GAS RATE**
- **TROUBLE SHOOTING GUIDES FOLLOW – REVIEW AT YOUR LEISURE – NOT NOW**

GAS LIFT FUTURE

QUESTIONS FOR YOU

- WHAT IS YOUR LEVEL OF AUTOMATION
  - HARDWARE
  - SOFTWARE
- WHERE IS YOUR STAFF IN EXPERIENCE AND TRAINING WITH REGARD TO AUTOMATION
- ARE YOU EXPERIMENTING WITH SURFACE CONTROLLED GAS LIFT TO EVALUATE COST VS BENEFIT
- DO YOU HAVE WELLBORE FLOWING DATA TO ENABLE A BETTER DESIGN
- QUESTIONS?

Troubleshooting Quick Matrix

Trouble shooting steps	Action 1	Action 2	Action 3	Action 4	Action 5
1. Test well to establish a trend; retest well when gas lift performance decline suspected	Check instrumentation and meters to assure quality of test.	Check both lift gas and production wellhead valves to insure full open position.	Check production choke to assure full open.	Use sonic or infrared devices to detect partially plugged pipe or leaks at valves.	Fix instrument, plugging, or valve leaks, then retest well.
2. Well retest is off trend – review wellhead area	Inspect wellhead area for cold temperature or water condensation (sweating) at tubing spool as indicator of leaking tubing hanger seal. If leaking, wellhead maintenance team should inject sealant at hanger seal.	Inspect lift gas control valve choke. If cold and reduced lift gas rate, inject methanol to dissolve hydrate.	Compare casing pressure to design surface close pressure of each unloading valve; estimate depth of lift of current operating valve. Use in Prosper simulation.	Compare to Prosper simulation at well test rate, wellhead flowing pressure, downhole gauge pressure (DHPG). Adjust lift depth estimate until Prosper run and well test match.	Change lift gas rate if Prosper simulation indicates deep lift will restore production rate. Retest well at reduced lift gas rate of 50%, increment lift gas rate to 70%, 90%, 110% lift gas.

GAS LIFT WORKSHOP 2022

Troubleshooting Quick Matrix

Trouble shooting steps	Action 1	Action 2	Action 3	Action 4	Action 5
3. Apply non-wellbore intervention diagnostic tool – CO_2 tracer →	Run CO_2 tracer survey under normal flowing conditions for the well.	Measure the gas lift injection rate accurately.	Inject quickly into the lift gas stream the calculated weight of CO_2.	Record casing/tubing pressure and temperature for the duration of the survey.	Note well-flow interruptions or events affecting well performance during the survey.
4. Evaluate well condition from CO_2 tracer survey →	Implement revisions to lift gas rate or valve design.	Repeat CO_2 tracer survey and revisions until well is lifting at orifice.			
5. Evaluate well condition from acoustic (sonic) surveys →	Obtain fluid level data in casing as the deepest point of fluid (kill) displacement from casing annulus; may not be the current depth of lift gas injection.	Obtain acoustic data in tubing to interpret valve depths and anomalous behavior.			

Troubleshooting
Quick Matrix

Trouble shooting steps	Action 1	Action 2	Action 3	Action 4	Action 5
6. Apply wellbore intervention diagnostic tools – flowing pressure and temperature surveys ➡	Use best practices to minimize wireline risk and obtain quality flowing data.	Two stops for each mandrel: approximately 15 ft above and 15 ft below.	Bottom mandrel to perforations: 5 or more stops to obtain reservoir fluid gradient.	Perforations: 100 ft stops to locate water contacts.	Duration of stops: 5 minutes if flow is steady; longer time if the well is surging.
7. Use distributed temperature surveys with fiber optic cable ➡	Cables inserted using wireline methods, or strapped to the tubing during initial completion.	Identify point(s) of gas passage with Joule-Thomson cooling due to gas expansion.	Observe pre-unloading, unloading, and producing profile.		
8. Use visual tubing/casing pressure diagnostic tools ➡	Use DCS data capture for real time collection and analysis; use wellhead tubing and casing pressure recorders if DCS not installed.	Review data for evidence of surging (slugging or heading); take following corrective steps.	Compare casing pressure to design surface close for each valve to estimate lift depth.		

Troubleshooting Quick Matrix

Trouble shooting steps	Action 1	Action 2	Action 3	Action 4	Action 5
9. Wells not taking lift gas →	Compressor pressure low: set discharge to higher pressure.	Excessive wellhead backpressure: lower compressor suction pressure.	Hydrate at choke or regulator: depressure both sides, inject methanol.	Valve design temperature too low: well takes gas, and then stops as well heats. Confirm, replace valves.	Closed or plugged valves/chokes: check surface valves with sonic or infrared tools.
→	Casing pressure less than surface close pressure: pull valves and replace.	Solids plugging at gas lift valve: get sample with wireline, flush with solvent			
10. Wells circulating gas →	Solids plugging keeps valve open: raise tubing by 500 psi pressure with jumper from casing; bleed tubing quickly to dislodge solids (rock the well).	Erosion damage during unloading: confirm with CO_2 tracer; pull and replace valve.	Leak in tubing, mandrel, or packer: confirm location with CO_2 tracer, remediate.	Valve design temperature too high; valve cannot close: confirm circulation with CO_2 tracer; pull and replace valves.	Surface close pressure too low, valves set too low: confirm circulation with CO_2 tracer; pull and replace valves.

2022 GAS LIFT WORKSHOP

Troubleshooting
Quick Matrix

Trouble shooting steps	Action 1	Action 2	Action 3	Action 4	Action 5
11. Leakage detection and correction ➡	Flowline leak: shut line at separator; use sonic or infrared tool to find leak.	Wellhead leak: check JT cooling at tubing hanger; inject wellhead sealant.	Leak in tubing/casing: apply tubing to casing integrity test; remediate.		
12. Solids plugging ➡	Hydrate plugging at choke, regulator valve, or low point where liquid accumulates: use methanol injection.	Paraffin/wax: chemical dispersant mixed with lift gas; wireline scraping in tubing; hot fluid in flowline.	Asphaltenes: chemical dispersant; xylene solvent to remove; wireline scraping in tubing	Salt: fresh water flush with lift gas.	Scale: chemical dispersant or solvent.
➡	Corrosion: chemical inhibitor program.	Reservoir rock particles: production rate control; sand screens.			

Troubleshooting Quick Matrix

Trouble shooting steps	Action 1	Action 2	Action 3	Action 4	Action 5
13. Well flow instability	Compressor surging: adjust suction, discharge, and recycle settings.	Distribution piping constraint: locate surging wells on map to find under size distribution line.	Input choke port (or regulator valve) size: match to orifice port to eliminate casing pulsing.	Operating gas lift valve or orifice port: select port to pass current required rate; replacement required for future condition.	Multiple lift points (multi-pointing): replace valves with smaller ports.
	Instability in tubing: use Prosper to estimate lift gas rate to achieve 4 to 6 ft/sec velocity.	Wellhead restrictions: avoid use of production choke.			
14. Well underperformance (shallow lift)	Facility pressure constraint: reset compressor discharge to higher pressure.	Excessive wellhead backpressure: eliminate choke and small ported surface safety valve; clean solids from flowline.	Mandrel spacing too wide: pull tubing and reset mandrel spacing; punch hole in tubing and insert packoff with valve.	Incorrect pressure setting: pull and replace valves.	Poor valve quality from manufacturing, assembly, or installation: change to supplier adhering to API 19G2 specs.

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