Addendum 3

Bibliography: The following references shall be added

[73] Elmer, W., D. Elmer, L. Harms, "High Pressure Gas-Lift: Is Industry Missing a Potentially Huge Application to Horizontal Wells?", SPE-187443-MS, October 2017, https://doi.org/10.2118/187443-MS
[74] Pronk, B., W. Elmer, L. Harms, W. Nelle, J. Hacksma, "Single Point High Pressure Gas Lift Replaces ESP in Permian Basin Pilot Test", SPE-195180-MS, April 2019, https://doi.org/10.2118/195180-MS
[75] McNeilly, K.; A. Smith, L. K. Harms, W. Nelle, S. Schwin, R. Reynolds, "Learnings From Successful Permian High Pressure Gas Lift Installations", SPE-219552-MS, August 2024, https://doi.org/10.2118/219552-MS
[76] API SPEC 11P *Specification for Packaged Reciprocating Compressors for Oil and Gas Production Services*

19. High Pressure Single Point Injection

19.1 Introduction

High pressure single point injection, Elmer et al[73], is the process of utilizing a gas source to lift production fluids from the end of tubing (EOT) or from a valve/orifice located near the end of the tubing. The completion equipment can be with or without a packer; eliminating the packer provides the option of annulus flow with injection in the tubing, resulting in a high initial production rate comparable to electric submersible pump, Pronk et al[74] and McNeilly et al[75]. Switching to annulus gas injection and producing up the tubing string can then be utilized efficiently for lower production rates with further subsequent conversion to plunger assisted gas lift with conventional mandrels. High pressure gas source options include a gas well, gas processing plant that dehydrates and removes heavy hydrocarbon and nonhydrocarbon components, or compressors that circulate unprocessed production gas. Compressor system configurations consist of "feed" compression units (central, pad or single wellhead) at conventional gas lift pressures of 800-1200 psig providing gas to booster compressors which provide gas lift pressures greater than 5000 psig to multiple wells on pad or a single wellhead. Wellsite multistage compressors which go from low suction up to 5000 psig are also being used. Required pressure to lift from a single point at bottom of the tubing is related to each well's depth (column of fluid which is lifted), reservoir pressure and productivity, which can be changing slowly or rapidly in unconventional plays. Injection gas provided at a pressure higher than the column hydrostatic pressure plus surface backpressure enables high pressure single point injection as an option. Both mechanical and process considerations shall be made when evaluating high pressure single point injection as the injection pressure of 1500 psig to greater than 5000 psig requires appropriate piping, well tubulars, and wellhead plus evaluation of the gas condition related to liquid condensation, hydrates, solids deposition, and corrosion. This section describes the equipment and processes applied to high pressure single point injection.

19.2 Objectives and Practices

19.2.1 General

High pressure single point injection requires prediction of rate and pressure behavior during initial production. Injection pressure required is directly related to reservoir pressure, which determines the height of the column of fluid to lift, and associated wellbore pressure at the bottom of the tubing. The gas column pressure at the surface is transmitted to tubing depth and is sufficient to enter the production fluid column, then mix with, reduce density, and increase the velocity as the production rises to the wellhead. Increased injection gas promotes additional density reduction and increased velocity resulting in lower producing bottom hole pressure and higher production rates; production rate maximum is attained when friction pressure losses become dominant and offset fluid density reduction. Production system components, such as gathering lines, chokes, manifolds and tubulars affecting pressure at the sandface, reservoir pressure and productivity decline are factors that are evaluated using nodal analysis methods to optimize production gains with high pressure single point injection. Well behavior prediction is the basis for selecting well configuration and injection pressure design for the life of the well.

Configuration options range from open-ended tubing run deep in the well to a completion with packer and orifice/valve near the packer, depending on initial rate and decline. Each should be evaluated for surging rate and wellhead pressure that can affect facility separation capacity and compressor operation.

19.2.2 Practices

Implement practices to obtain data for design of gas injection pressure/rate and to simulate both flow and gas condition:

a) Use exploration data for reservoir pressure.

b) Collect rate, wellhead flowing pressure, plus permanent gauge bottomhole pressure data (if available) from initial production wells.

c) Obtain drilling deviation survey to evaluate dog leg severity, angle change, and horizontal wellbore inclination (toe up or toe down).

d) Use computer simulation and calibrate program with test results; simulate tubing/casing size options, materials and coatings, wellhead pressure, tubing flow versus annulus flow, and depth of tubing.

e) Calculate injection gas pressure required for each simulated option.

f) Estimate effect of surging by simulation with transient modelling, using critical velocity calculations, or from observation in initial well behavior.

g) Evaluate compressor design for capability to achieve desired low suction pressure to high discharge pressures capable of single point injection at tubing depth.

h) Investigate wellhead equipment, casing/tubing, and injection gas piping for pressure rating and derating effect of temperature.

i) Capture gas sample for composition analysis.

j) Conduct process evaluation using a compositional model to establish pressure-temperature phase diagram; evaluate liquid condensation at potential injection pressure/temperature points.

k) Use gas process simulation to evaluate hydrate potential and wax or asphaltene deposition.

l) Evaluate erosion/corrosion in upper wellbore and wellhead.

m) Review wellbore completion equipment with single point injection for inclusion/exclusion of gas lift valve, packer, sliding sleeve, and chemical capillary line.

n) Evaluate slickline/wireline accessibility related to placement of completion items at wellbore angles at 60° or higher. Specialized intervention equipment may be required to access higher angles.

19.2.3 Methods

Use the data collected and simulations from each well to select the appropriate method of single point injection at initial and subsequent well life from the following options a) to d):

a) End of tubing circulation with annulus flow and injection in tubing:

   1) Increase gas injection carefully to unload well and to avoid surge of reservoir/proppant sand and to minimize gas/liquid slugging at surface facility. Use choke control on flowing wellhead outlet to mitigate slugging to the facility.

   2) Monitor wellhead pressures and calculate bottom hole pressure (injection pressure less friction loss down injection tubulars plus weight of column of injection gas to the end of tubing), bottomhole pressure (permanent gauge), and capture injection gas rate plus returning production rate for comparison to simulation.

   3) Test well over a range of injection gas rates to develop “optimum” performance and repeat for all wells to develop best performance for the group of wells with the available injection gas. Maximum production rate should occur when injection gas pressure is at a minimum.

   4) Monitor well over a period of time for evidence of pressure and rate surging; increase injection gas flow to stabilize well.

b) End of tubing circulation with tubing flow and injection in annulus:

   1) Apply to wells with lower rate/productivity or when reservoir pressure/rate declines increasing the lifting cost per bbl due to high injection rates. Wellhead piping should be switched to permit tubing flow with annulus injection.

   2) Follow practices in 19.2.3 a) items 1 to 4.

c) Valve/orifice near packer with tubing flow and injection in annulus:

   1) Apply to wells with lower rate and productivity capability.

   2) Choose orifice when production rate is at higher range compared to tubing capacity; size port of orifice for expected injection gas rate and 100-200 psi casing to tubing pressure differential.

   3) Choose valve when production rate is at lower range compared to tubing capacity; set bellows pressure of valve to maintain casing pressure to prevent hydrates at surface choke/regulator.

   4) Consider side pocket mandrel for wireline valve replacement when planning to switch from continuous gas lift (small port valve) to intermittent gas lift (large

port valve or pilot valve).

5) Adhere to unloading guidelines in RP19GLHB Section 12.4 because all annulus fluid passes through the valve/orifice.

d) Valve/orifice near packer with tubing flow and injection in annulus and with plunger installed:

1) Review RP19GLHB Section 17 for recommendations applied to gas well deliquification and discussion of plungers.

2) Install profile nipple above gas lift mandrel with initial completion; shock absorber bumper spring will be set at this depth.

19.3 High Pressure Single Point Injection Equipment

19.3.1 General

High pressure single point injection will have equipment handling gas at pressures from 1500 psig to greater than 5000 psig, depending on reservoir pressure and the height and weight of the fluid to be lifted. RP19GLHB Section 7 “Gas Fundamentals and Facilities” reviews recommendations for gas compressors, dehydrators, meters, and pipelines for standard gas lift pressure less than 1500 psig. Single point injection at higher pressure will require added review and adherence to specifications. Gas dehydration is always recommended to minimize hydrates, water accumulation, and corrosion; this process should be conducted at 800 – 1200 psig to aid gas/glycol separation. High pressure systems for single point injection can use an interstage pressure for dehydration. Field systems that compress production gas to high pressure without dehydration should have an analysis for water and hydrocarbon condensation, hydrate potential, and corrosion. Wellhead, casing/tubing, and gas piping pressure rating is critical for safety; temperature derating should be applied if elevated temperatures are used to minimize hydrates. API specifications, ASME specifications, and GPSA Engineering Data Book[21] guides should be applied. Chemicals for control of corrosion, hydrates, scale, or wax should be evaluated for mixing with high pressure gas and for method of delivery to the affected area of the equipment.

19.3.2 Wellhead, Casing/Tubing, Gas Piping

Review specifications for all gas handling equipment to assure pressure containment and safety:

a) Apply API 6A “Specification for Wellhead and Christmas Tree Equipment”[2] for all sections exposed to high pressure directly or because of seal leaks. Exposed components are master, wing, crown, and production casing valves. Potential seal leaks are at tubing hanger and casing hangers. Use an adjustable choke or regulator valve to slowly lower wellhead pressure or control slugging in addition to slow increase of injection gas during initial unloading. Casing annulus production flow option will require large casing outlet valves (standard flange and valve are small diameter) or multiple flow paths from the annulus. Configure wellhead piping to accommodate casing injection or tubing injection, Figure 19.1.

b) Apply API 5CT “Specification for Casing and Tubing”[3] to evaluate burst and collapse of the exposed tubulars. Evaluate the need for premium connections and/or metallurgy to contain pressure and prevent leakage.

c) Apply ASME B31.3 “Process Piping”[19] specifications to gas piping adjacent the wellhead extending to and including the facility. Apply ASME B31.8 “Gas Transmission and Distribution Piping Systems”[20] specifications to gas piping between facilities.

d) Apply temperature derating to wellheads and casing with installations that use hot gas without aftercooling.

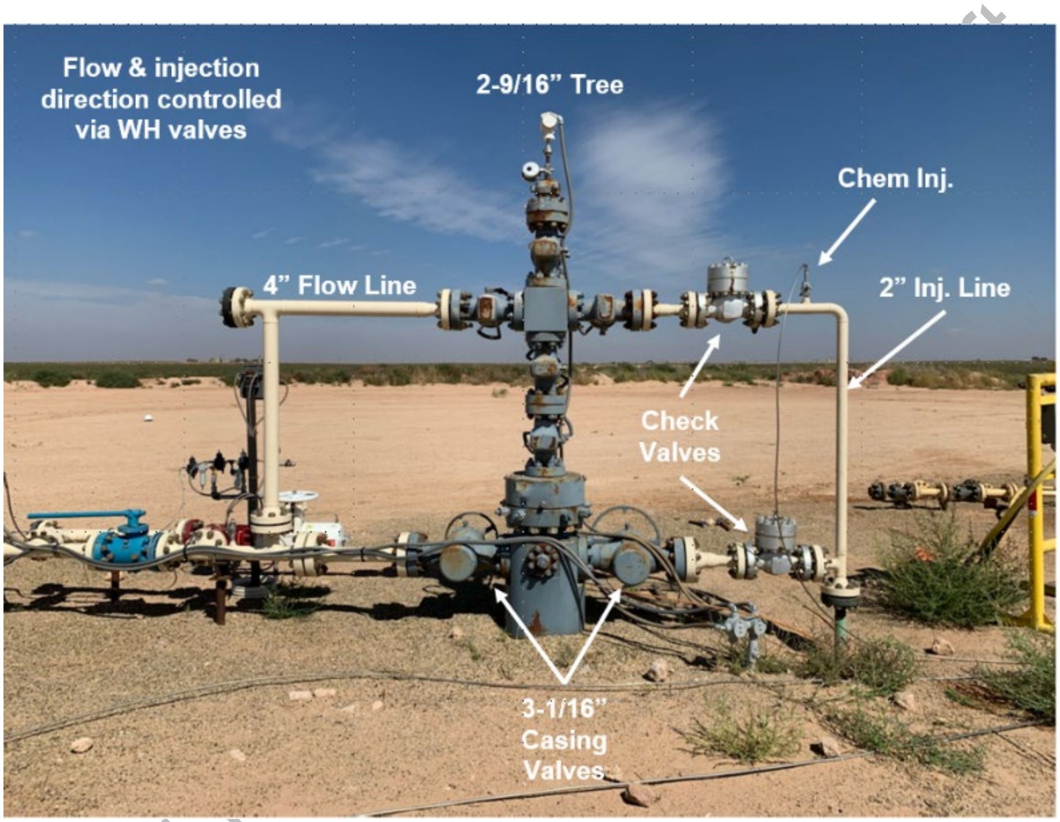

Figure 19.1 – Wellhead and piping example

19.3.3 Compressors

Evaluate compressor systems based on number of wells and physical location; consider large plants (central compression), wellsite installation, or a combination. Use API Spec 11P - Specification for Packaged Reciprocating Compressors for Oil and Gas Production Services[76] as a guide on fundamental compressor design. The following practices in a) to o) will address issues that have proved to be challenging to booster compressors used in high pressure gas lift applications:

a) Limit compression (pressure) ratio to 4 to 1 (discharge absolute pressure/suction absolute pressure) to control discharge temperature from each cylinder. Excess temperature increases maintenance problems and can cause wellhead elastomer seals to fail.

b) Install large separators upstream to accept surging well fluids and to protect compressor skid**.** Evaluate liquid quantities upstream of compressor package and ensure adequate liquid separation exists on-skid or provide additional upstream liquid separation.

c) Install skid mounted reciprocating units that can be easily moved if high pressure injection is temporary; multiple skids can be installed at any location. Driver can be gas engine using produced gas for fuel (propane as backup fuel) or can be electric motor when adequate power is available.

d) Evaluate method of connecting high pressure discharge piping to wellhead; use permanent anchors that prevent piping movement. Apply caution when using temporary frac iron for gas discharge piping; assure containment by anchoring to prevent whipping or movement due to compressor vibration or pulsation. If uncertainty exists on acceptable vibration levels, consider conducting a field vibration study to ensure adequate pipe restraint design and installation.

e) Use installation practices including lubrication and cleaning. Temporary piping should be maintained while in storage and pressure tested to expected working pressure plus a company determined safety factor upon each use, prior to being placed in service. Testing should be to 1.5 times the compressor discharge pressure safety valve (PSV) rating. Temporary piping should be regularly tested and recertified, at least on an annual basis. This recertification process should include a charted hydrotest to full rated pressure and may include additional non-destructive testing.

f) Consider trailer mounted compressor skids for temporary duty. Evaluate temporary piping links or hoses which shall be securely anchored.

g) Evaluate gas condition for liquid condensation; gas with a heavy hydrocarbon content can cause excess condensation and require scrubber discharge to the oil gathering system.

h) Evaluate hydrate potential at inlet screens (witches' hat) and at scrubber dump valves. Figure 7.4 provides hydrate prediction versus pressure and temperature, and a thorough analysis can include gas composition. Use a 20-mesh inlet screen with a surface area of at least 3 times the cross-sectional flow area of the inlet pipe size to the compressor. Remove inlet screen two weeks after compressor startup.

i) Utilize gas coolers that have temperature control systems and louvers.

j) Ensure scrubber float switches are rated for buoyancy in fluids with a specific gravity 0.50 (relative to water) to ensure proper operation with low specific gravity hydrocarbon condensates.

k) Ensure an off-skid gas bypass is provided such that gas can bypass the compressor package when the compressor is not operating or removed from service.

l) Ensure a gas recycle valve is installed when high pressure booster compressor is fed by a single upstream feed compressor package, such that the feed compressor can be started and discharge pressure limit not exceeded until booster compressor can be started and is accepting gas.

m) Ensure that an on-skid fuel gas system is designed to accommodate Joule-Thomson cooling effect from step down of high inlet gas pressure; evaluate hydrate potential.

n) Ensure free liquids are removed and the gas is sweet (< 10 ppm H_2S) if off-skid fuel gas system is utilized.

o) Complete a Hazard and Operability (HAZOP) or Process Hazard Analysis (PHA) study to ensure safe and reliable integration of the compressor into the wellsite or production facility, or both.

19.3.4 Gas Conditioning

Select source from a gas processing plant that has water vapor and heavier hydrocarbon gas removed, if it is available. If production gas is compressed and used as gas lift gas, then install dehydration. For dehydrated or undehydrated gas:

a) Analyze gas composition with samples taken to the chromatograph lab.

b) Use process simulation to establish pressure-temperature phase envelope.

c) Evaluate liquid condensation at various temperatures.

d) Evaluate hydrate dissociation conditions at various pressure/temperature potential operating points.

e) Evaluate solid deposition of wax or asphaltene.

19.3.5 Chemical Injection

Evaluate whether chemical injection for corrosion, hydrates, wax, or scale is compatible with high pressure gas:

a) Work with chemical supplier to conduct lab tests.

b) Evaluate chemical constituents for solids precipitation and compatibility in the operational environment.

c) Evaluate capillary injection line to deliver chemical to affected equipment location.

d) Evaluate spray nozzle for improved mixing if chemical is injected into gas piping. Gas rate changes may affect operation faster than chemical rate changes.

e) Inject chemical at inlet to wellhead, not at injection distribution header.

f) Evaluate effect of liquid content on valve erosion, if a valve is used.

g) Evaluate returning residual chemical content to assure effective application.

19.4 Section Summary

High pressure single point injection is a gas lift option that eliminates unloading valves by using gas pressure from 1500 to greater than 5000 psig to lift from the end of the tubing or from a valve/orifice located near the end of the tubing. This pressure range requires stringent evaluation of the wellhead, casing/tubing, and gas piping for pressure containment and safety. Gas at this pressure is subject to hydrates, condensation, and solids deposition that shall be analyzed to prevent shut down of production caused by these issues. Skid mounted reciprocating compressors are applicable to this method but the number of stages and compression (pressure) ratio per stage shall be designed within operability limits. Reservoir pressure surveillance and management is integral to the surface management of injection options and when changes should be applied.