Addendum 2

Section 3.3 Symbols: The following symbols shall be added to Table 3.1

v_c = critical velocity, ft/sec
ρ_g = gas density, lbm/ft^3
ρ_l = liquid density, lbm/ft^3
σ = surface tension, dynes/cm
Θ = hole angle, degrees from vertical

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Gas Well Deliquification

18.1 Introduction

Gas well deliquification is the process of removing liquid hydrocarbons and water from the wellbore to promote gas and condensate production to the facility. Liquid accumulation in the wellbore can increase flowing pressure gradient causing bottomhole pressure to rise, which reduces drawdown and production rate. The accumulation of liquid across the producing interval can saturate the near well area and can reduce gas relative permeability which impedes gas migration through the pore space or possible damage to permeability from swelling clay. Liquid in the wellbore can be the result of condensation of hydrocarbon or water vapor, water migration through reservoir rock, or water leakage from an adjacent aquifer. Deliquification is accomplished by increasing gas velocity which suspends liquid droplets and forces liquid wall film to rise and exit the wellbore with the gas stream, or by adding chemical foam/surfactant to improve mixing of gas and liquid, or by using mechanical devices to push or lift liquids from the wellbore. This section describes the processes and equipment applied to gas well deliquification.

18.2 Deliquification Objectives and Practices

18.2.1 General

Gas well deliquification requires observation of rate and pressure behavior during production. Liquid loading indicators are surging rate and wellhead pressure. Early identification permits evaluation of practices that can be applied for the removal of liquids (water and/or condensate) from gas wells. Velocity increase above critical velocity is one option to prevent liquid loading via reduced tubing wellhead pressure, or flow area diameter reduction, increased gas circulation, or application of foam chemicals. Physical displacement with plungers or pumps is another option to remove liquid. Selection of a method to enable either option requires consideration of gas and liquid rates, solids content, wellbore deviation, and casing size.

18.2.2 Practices

Implement practices to obtain data and guide operators in making changes to the gas wells:

a) Monitor wells for surging behavior and record rate and wellhead pressure data with online meters and/or test separators.

b) Increase choke size to increase rate and lower wellhead flowing pressure; retest well and record data.

c) Obtain flowing pressure/temperature surveys with wireline to evaluate gradients and liquid holdup.

d) Use computer simulation and calibrate program with test results; simulate changes in tubing size, wellhead pressure, and addition of gas via gas lift or circulation to end of tubing.

e) Evaluate compressors to determine whether suction pressure can be reduced to lower separator and wellhead pressure.

f) Investigate wellhead equipment and tubing for potential plunger installation; valves and tubing should be the same inside diameter; no profile nipples or devices to restrict plunger travel; consider sand, scale, wax, or asphaltene accumulation.

g) Review wellhead crown valve and profile nipple in tubing as potential hanger for coiled tubing velocity string.

h) Review wellbore completion equipment for gas lift valves, packers, sliding sleeves, and chemical capillary lines for use to increase gas circulation and/or to inject foam/surfactant.

i) Evaluate bottom completion for sump (rat hole) area for liquid accumulation for pump installation.

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

18.2.3 Methods

Use the data collected from each well to select the appropriate method of deliquification from the following options:

a) Reduce wellhead tubing pressure:

   1) Increase choke size; schedule a step procedure slowly opening choke to avoid sand surge.

   2) Lower compressor suction pressure at existing compressor stations.

   3) Install wellhead compressor if existing compressors cannot be adjusted.

   4) Install wellhead multiphase pump.

b) Increase velocity with diameter reduction:

   1) Evaluate flowing gradient data for depth of liquid accumulation and to establish end-of-tubing depth.

   2) Replace existing tubing with smaller diameter.

   3) Insert coiled tubing into existing tubing and hang at crown valve or profile nipple; add valves to connect flow to existing flowline.

c) Increase velocity with gas circulation:

   1) Apply gas lift gas to existing valves; depth of injection point should be into liquid accumulation.

   2) Apply gas lift gas to coiled tubing and produce through tubing by coiled tubing annulus.

   3) Apply circulation gas to tubing by casing annulus if gas lift valves and packer are not installed; end of tubing should be into liquid accumulation.

d) Displacement with plungers:

   1) Evaluate suitability of wellhead and tubing relative to constant diameter and absence of restrictions; run wireline tools to establish inside diameter and remove solids deposits.

   2) Choose two-piece or bypass plungers for wells near critical velocity, pad or turbulent plungers for weaker wells, brush plungers to aid sand or wax removal.

   3) Select wellhead lubricator for ease of plunger inspection, safety, and mechanism to hold plunger; select controller for time or pressure control or both; select control regulator valve with full open capacity and streamline wellhead piping to minimize flow restriction.

   4) Reduce gas injection through the addition of a plunger.

e) Displacement with pumps:

1) Evaluate liquid accumulation point in the completion; does sump or rat hole exist and what is the risk of pump placement at that depth; does horizontal completion have a toe up or toe down bore and what undulations exist based on the drilling survey.
2) Remove existing completion and place pump into liquid accumulation with gas flow in the tubing/casing annulus and liquid flow through pump and tubing; gas into the pump will be a constraint if pump is not continuously immersed in liquid.

18.3 Deliquification Equipment

18.3.1 General

Gas well deliquification equipment is associated with the method selected to remove liquids from the wellbore. Surface facility compressors or multiphase pumps are used to reduce wellhead pressure and compressors are also used for gas lift or gas circulation to increase velocity. Wellbore equipment ranges from plungers to gas lift valves to coiled tubing strings to pump assemblies. Pump capacity and cycling of plungers should match reservoir feed plus liquid condensation. Chemical foam injection pumps or soap stick launcher can be installed at wellhead.

18.3.2 Wellhead Pressure Reduction

Implement changes or add equipment to achieve wellhead pressure reduction:

a) Use an adjustable choke or regulator valve to slowly lower wellhead pressure to increase rate and velocity in the wellbore; adhere to a schedule of increasing choke size to avoid sand entry from the reservoir due to surge; automated controllers and actuators on the control valve/choke can aid the procedure.
b) Reduce suction pressure at existing compressors by increasing their throughput capacity via increased speed, or reduction of clearance on reciprocating cylinders. Check proposed operating conditions with compressor OEM software.
c) Install a wellhead compressor with an upstream liquid knockout separator; low compressor suction pressure will reduce wellhead pressure but may require a pump or blowcase at the separator to return liquids to the gathering system. Gas from the well can provide fuel to the engine driver but propane may be needed for supplement when gas from the well is minimal. Electric motor drive is an option.
d) Install a wellhead multiphase pump (MPP) that can push both gas and liquids to the existing facility. Engine driver will need propane as fuel unless an electric motor is used as the driver. MPP can be considered after wellhead choke is fully open and flowback equipment is removed when production fluids are not sand laden. The MPP is used when the wellhead pressure is relatively high so MPP can help to lower the wellhead pressure and sandface pressure accordingly.
e) Reduce wellhead pressure with a jet pump at surface.[61] High pressure gas must be available as the power source fluid and flowline design sizing must be evaluated for the additional total flow of fluids.

18.3.3 Increase Above Critical Velocity

Add wellbore equipment or gas to increase rate to achieve critical velocity:

a) In the area of gas well deliquification, the critical velocity is the gas velocity that will efficiently remove liquids from the well. In 1969, Turner[62,63] published an equation to calculate critical velocity based on a droplet model. The equation (65) presented below is a function of surface tension, liquid density and gas density. McInerney, et al[64] discuss the development of this equation using a combination of a terminal velocity and Weber Number equations.

$$v_c = 1.5934 \left[\frac{\sigma(\rho_l - \rho_g)}{\rho_g^2}\right]^{0.25} \tag{65}$$

Turner utilized a data set consisting of 138 well tests to validate the method and recommended using water liquid properties whenever water was produced. A total of 68% of Turner's data was condensate only liquid production. Despite recommending high values for liquid density and surface tension, Turner recommended increasing the results of Equation (65) by approximately 20%. Coleman, et al[65,66,67,68] reviewed the critical velocity calculation and found Turner's equation to be accurate without the approximate 20% increase. Coleman determined that many gas wells produce condensed water so the use of only water properties in the equation can be justified. Sutton[69] combined the Turner and Coleman data sets and analyzed them using water properties and concluded a more appropriate 10% increase to the equation to provide conservative results. The resulting critical velocity equation has the multiplier increased from 1.5934 to 1.7528.

Water properties that reflect produced water salinity at wellbore pressure and temperature should be used in the evaluation. The actual water specific gravity should be used for the calculations. Note that condensed water does not contain salts and the resulting mixture will be less than formation water salinity.

Turner recommended the evaluation of critical velocity could be made using wellhead conditions. In 2010, Sutton et al[70] showed that the point of liquid loading could occur downhole. Additionally, in 2008, Belfroid et al[71] presented a simple modification to Turner's equation to account for changing wellbore deviation as shown in the following graph:

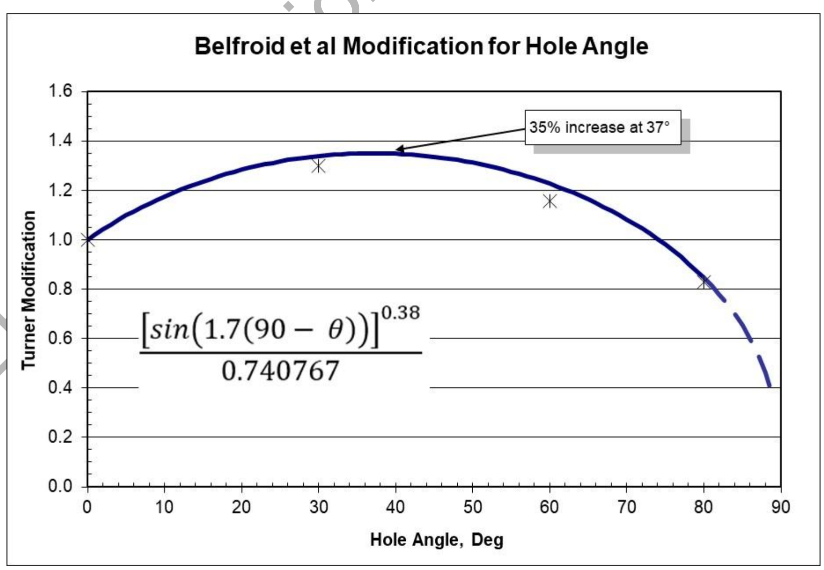

Figure 18.1 – Belfroid et al Modification for Hole Angle

The original Turner equation was meant for application in a vertical well and the Belfroid et al modification extends the application to directional wells. Therefore, the evaluation of critical velocity should be made along the entire wellbore to determine the depth at which liquid loading occurs. This allows for changing wellbore deviation and well geometry with depth. The following equation (66) includes a 10% increase from the original Turner equation along with the Belfroid et al hole angle modification.

$$v_c = 1.7528 \left[\frac{\sigma(\rho_l - \rho_g)}{\rho_g^2}\right]^{0.25} \frac{[sin(1.7(90-\theta))]^{0.38}}{0.740767} \qquad (66)$$

Many other methods of calculating critical velocity have been proposed but the Turner/Coleman method is discussed because it is widely used and effective.

b) Evaluate change of tubing size and consider installation without packer so that end of tubing can be placed within liquid accumulation or in the heel section of a horizontal well.

c) Evaluate coiled tubing installation within existing tubing with flow up coiled tubing or up tubing by coiled tubing annulus (or both). Suspend coiled tubing from new hanger at crown valve with new valves for crown and wing positions; connect wing into existing flowline, or from profile nipple in tubing. End of coiled tubing should be placed in liquid accumulation.

d) Evaluate gas circulation through casing annulus if packer is not installed and end of tubing is within liquid accumulation. Connect compressor to annulus and force gas to circulate but be prepared for large slugs of liquid and gas at the separator facility.

18.3.4 Gas Lift

Add gas lift gas to increase total rate to achieve critical velocity:

a) Apply gas lift gas if completion has valves in tubing string. Use gradient survey data to evaluate whether deepest active valve is within liquid accumulation. If not, then completion should be pulled, and valves respaced to be deeper into bore.

b) Design and install gas lift valves after simulation to determine tubing size and depth to reach liquid accumulation. Options for gas lift installations are shown in Figure 4.6.

c) Design and unload well using guides in Section 11 and Section 12 for continuous lift and Section 13 and Section 14 for intermittent lift.

d) Consider installing a plunger to reduce injection gas rate and to increase liquid rate. A change to conventional tubing retrievable mandrels may be required for successful plunger cycling.

18.3.5 Plungers

Add plungers to displace liquids from wellbore. Plunger lift includes (1) traditional plunger lift method using reservoir energy only, (2) plunger assisted gas lift (PAGL) where continuous gas lift is used with plunger, and (3) gas assisted plunger lift (GAPL) (intermittent gas lift with plunger).

a) Evaluate gas and liquid rate to establish suitability as a plunger lift well. Guides are 400 scf/bbl per 1000' of lift in a completion without packer, ranging to 2000 scf/bbl per 1000' of lift in a completion with a packer or for a horizontal wellbore. Plungers and gas lift can be combined to supply gas required for continuous cycling of the plunger and to provide effective sweep of the liquid column during intermittent lift.

b) Evaluate completion for constant diameter tubing and wellhead valves, and presence/absence of restrictions such as profile nipples or safety valves.

c) Run wireline gauge ring to confirm inside diameter and to find deposits in tubing. Run wireline bar to confirm plunger passage in sections with high dog leg severity.

d) Install tubing or collar stop if a profile or seating nipple is not located near bottom of tubing. Install shock absorber bumper spring and evaluate whether a check valve should be included in assembly. If gas assisted plunger lift is applied, the collar stop should be above the bottom active valve. Reference Section 16 to find the active valve.

e) Install wellhead lubricator and bypass piping, full-open control valve and controller. Revise wellhead piping to streamline exit from well and minimize restrictions.

f) Choose two-piece or bypass plungers for strong continuous flow or PAGL wells, pad or turbulent plungers for intermittent flow or GAPL wells, brush plungers to aid sand or wax removal.

g) Spend considerable time initiating plunger operation and selecting cycle time or pressure differentials to assure plunger travel and liquid removal. Continuous surveillance required to maintain plunger operation.

h) Utilize smart controllers to aid in reducing time to achieve optimum plunger operation. Run smart plunger to detect the plunger descending and ascending process to ensure the controller setting (e.g. after-flow time, shut-in time or off-time) to achieve the best plunger cycles.

i) Run dynamic plunger simulation[72] to design and improve the plunger setting parameters.

18.3.6 Chemical Injection

Evaluate whether chemical injection of foam will improve mixing of liquid and gas. Foam addition may require defoamer chemical operations in the surface facility:

a) Work with chemical supplier to conduct lab tests of wellbore water samples and different concentrations of various chemicals prior to engaging in field tests. Soap sticks may be used to test chemical products for the well.

b) Use existing capillary injection line to test chemical foam products that can improve water removal.

c) Add capillary injection lines strapped to tubing or insert line into wellbore into liquid accumulation or as deep as possible:

d) Consider a through tubing capillary injection line as an alternative after lab tests are conducted. Install injection pack off assembly on crown valve.

e) Implement batch treatments or soap sticks if continuous treatment is not feasible.

18.3.7 Pumps

Consider a pump installation if liquid can be accumulated in a sump or rat hole section of the completion. Pumps can be installed in the heel of the horizontal completion, but gas interference may be a continuing problem. Select pump equipment designed for high gas content wells. Solids filter and gas separator can aid pump operation. Rate variations can be accommodated with variable speed motor drive. Evaluate risk of pump assembly in high gas environment and risk of solids accumulation trapping equipment in wellbore.

a) Rod lift: Install rod lift with molded rod guides through the deviated section; end of tubing with insert pump should be in liquid accumulation and pump capacity matched to rate of inflow.

b) ESP: Install electric submersible motor driving a centrifugal pump for high liquid rate and wells with larger casing. Use variable speed drive to control rate capacity; if pump is in sump or rat hole, a shroud is required to force liquid flow over motor for cooling.

c) Jet pump: Install jet pump for initial evaluation and startup or when a self-contained skid is required before infrastructure development. Highly deviated, casing restricted, and solids producing wells are applications.

d) PCP: Install progressive cavity pump for solids removal at high rate and shallow completions, especially for initial cleanup prior to installation of another lift type.

18.4 Section Summary

Gas well deliquification can be accomplished with gas lift as one option among others such as wellhead pressure reduction with compressors or multiphase pumps, or tubing diameter change, or additional gas circulation to attain critical velocity that suspends droplets and pushes wall film out of the well, or displacement of liquid with plungers or pumps. Identification of liquid loading is accomplished with well testing to observe surging gas rate and wellhead pressure as liquid accumulates and is produced as slugs. Flowing pressure/temperature gradient surveys with wireline can aid in confirming the problem and establishing depths of liquid accumulation.