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Study of Identifying Liquid Loading in Gas Wells and Deliquification Techniques

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***Abstract*:- The minimum gas rate for unloading liquids from a gas well has been the subject of much interest, especially in old gas producing fields with declining reservoir pressures. For low-pressure gas wells, liquid accumulation in the tubing is a critical factor that could lead to premature well abandonment and a huge detrimental difference in the economic viability of the well. Some notable correlations that exist for predicting the critical rate required for liquid unloading in gas wells. However, these correlations offer divergent views on the critical rates needed for liquid unloading and for some correlations in particular, at low wellhead pressures. The best result oriented among these models is used to predict liquid loading.**

Keywords: Liquid Loading, De-liquification, Critical Rate, Gas Well

1. INTRODUCTION
LIQUID LOADING IN GAS WELLS

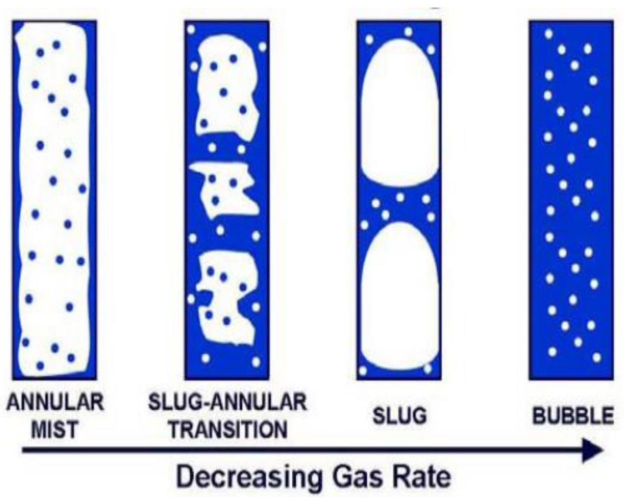

Figure 1: Flow regimes of a naturally flowing gas well as it progresses through different stages of liquid loading

Liquid loading is the most common cause of production impairment in gas well and can lead to erratic slug flow and decreased production from the well. The well may eventually die if the liquids are not removed continuously or well may produce at the rate less than the well potential. Hence it is necessary to identify the cause of liquid loading and suitable remedial actions are needed to be taken.

To understand the effects of liquids in a gas well, it is necessary to understand how the liquid and gas phases interact under flowing conditions. Multiphase flow in a vertical conduit is usually represented by four basic flow regimes as shown in Figure 1. At any given time in a well's history, one or more of these regimes will be present. A flow regime is determined by the velocity of the gas and liquid phases and the relative amounts of gas and liquid at any given point in the flow stream.

- **Bubble Flow**: The tubing is almost completely filled with liquid. Free gas is present as small bubbles, rising in the liquid. Liquid contacts the wall surface and the bubbles serve only to reduce the density.
- **Slug Flow:** Gas bubbles expand as they rise and coalesce into larger bubbles, then slugs. Liquid phase is still the continuous phase. The liquid film around the slugs may fall downward. Both gas and liquid significantly affects the pressure gradient.
- **Slug-Annular Transition:** The flow changes from continuous liquid to continuous gas phase. Some liquid may be entrained as droplets in the gas. Gas dominates the pressure gradient, but liquid is still significant.

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- **Annular-Mist Flow:** The gas phase is continuous and most of the liquid is entrained in the gas as a mist. The pipe wall is coated with a thin film of liquid, but pressure gradient is determined predominately from the gas flow.

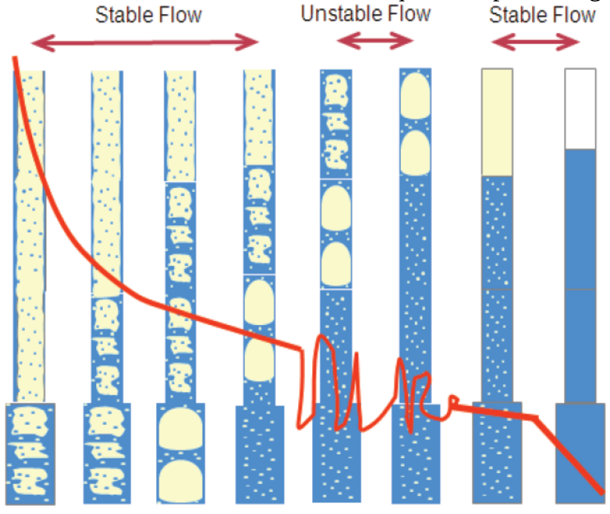

Figure 2: Decreasing Gas rate with decreasing reservoir Pressure

Lee, Nickens and Wells suggest that a well may go through several flow regimes including bubble flow, slug flow, slug-annular transition flow and annular-mist flow during the course of its life. Figure 2 shows the progression of a typical gas well from initial production to end of life.

Initially the well has sufficient gas rate i.e., gas rate is above the critical unloading rate. At this stage, the flow regime in the production tubing is usually mist flow. As the time progresses and gas production decreases, typical of normal production decline, the flow pattern progresses from mist flow to bubble flow until a static equilibrium fluid condition is built in the tubing. During the transition from mist to bubble flow the bottom hole backpressure in the wellbore continuously increases, resulting in reduced gas flow rate. The static fluid height in the tubing, associated with the bubble flow regime, will eventually stop or decrease the gas production if no corrective action is taken, resulting in a premature dead well and significant unrecovered gas reserves.

Liquid Loading: Inability of the well to lift the fluid associated with the gas production to the surface, as observed when the flow pattern progresses from mist flow to bubble flow is termed as liquid loading. We consider the well to be liquid loaded when the fraction by volume of liquids present in the gas flow path is higher than would be present in the mist flow situation. Almost all the gas wells produce some water and / or hydrocarbon condensate which may be due to the reservoir pressure dropping below the dew point or as a consequence of fluid coning. The overall result of liquid loading is an increase in back-pressure on the reservoir and reduction in gas production, which causes the well to die if no intervention is implemented.

Liquid Loading is not always readily identifiable because as loading occurs, the well may still produce for a significant amount of time. Turner, Hubbard and Dukler & Coleman et al described the liquid droplet transport model in vertical gas flow, which led to introduction of the term “minimum critical flow rate” or “critical velocity”- defined as the minimum gas flow velocity needed to lift liquid droplets out of the well. Gas rates below the critical rates results in droplet falling and accumulating downhole leading to decreased production and eventual well ceasure.

2. LIQUID DROPLET TRANSPORT MODEL AND CRITICAL VELOCITY

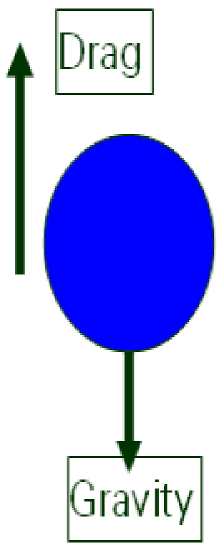

Figure 3 Illustration for Turner droplet model

The onset of liquid loading in gas well can be calculated based on Liquid droplet transport model. The droplet model for “critical velocity” or “critical rate” is based on the fact that in mist flow, two forces act on liquid droplet – the drag force and the gravity force. With decreasing reservoir pressure, the drag force declines and once it balances with the gravity forces, a liquid particle would “float” (not move) in the gas stream. From this point onwards the well starts to liquid load.

Turner et al. developed a simple correlation to predict the so-called critical velocity in near vertical gas wells assuming the droplet model. In this model, the droplet weight (the gravity force) acts downward and the drag force from the gas acts upward (Figure 3 shows a schematic illustrating Turner’s theory). When the drag is equal to the weight, the gas velocity is at “critical”. Theoretically, at the critical velocity the droplet would be suspended in the gas stream, moving neither upward nor downward. Below the critical velocity, the droplet falls and liquids accumulate in the wellbore.

Equation 1 gives the formulae for critical velocity, equation 2 for critical flow rate based on droplet model:

$$v_{gc} = k\frac{\sigma^{\frac{1}{4}}(\rho_l - \rho_g)^{\frac{1}{4}}}{\rho_g^{\frac{1}{2}}}$$ .... Equation 1

$$Q_{gc} = \frac{3.06PAv_{gc}}{(T+460)z}$$ …………… Equation 2

SYMBOL	NOTATION	UNIT
V_{gc}	Critical gas velocity	(ft/s)
K	Constant : 1.92 (Turner) 1.59 (Coleman)	
σ	Surface tension liquid to gas	(dyne/cm)
ρ_g	Density of gas	(lb/ft3)
ρ_l	Density of liquid	(lb/ft3)
Q_{gc}	Critical gas rate	(MMscf/d)
V_{gc}	Critical gas velocity	(ft/S)
A	Cross sectional area	(ft^2)
T	Temperature	(F)
P	Pressure	(psi)
Z	Compressibility factor	

For tubing head pressure greater than 800psi value of k = 1.92 (Turner value) is used and for tubing head pressure less than 800psi value of k = 1.59 (Coleman value) is used.

Strictly speaking, the above equations (1 & 2) are only valid for a vertical well in mist flow regime. However, with various modifications they can also be applied with sufficient accuracy for non-vertical wells – effectively the critical velocity is divided by cosine of degree of deviation to modify it for non-vertical wells.

3. IDENTIFICATION OF LIQUID LOADING IN GAS WELLS

Liquid loading will not always lead to non-production. If a well is loaded, it still may produce for long time. If liquid loading is recognized and reduced, higher producing rates are achieved. Symptoms indicating liquid loading include the following:

- ❖ Sharp drops in liquid decline curve

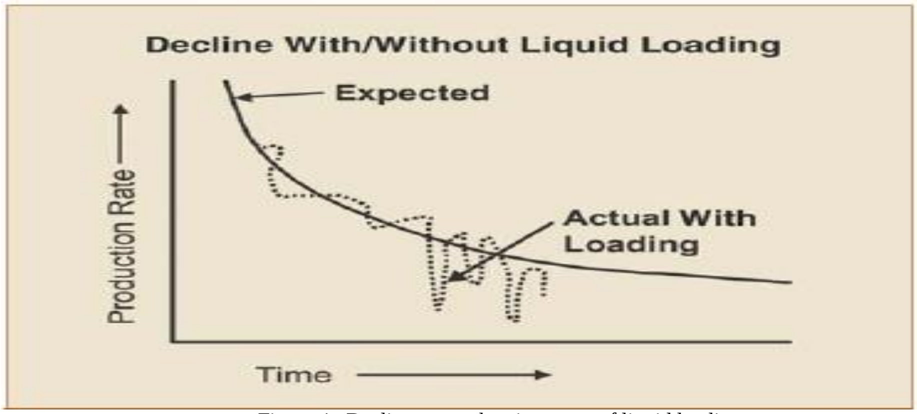

Figure 4 : Decline curve showing onset of liquid loading

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- One of the most common methods to detect liquid loading is to measure the gas flow rate through an orifice over time. Typically, when a well produces liquids without loading problems, the liquids are produced in the gas stream as small droplets (mist flow) and have little effect on orifice pressure drop. However, when liquid slug passes through orifice the relative high density of liquid slug causes a pressure spike. A pressure spike on a plot of orifice pressure drop usually indicates that liquids are beginning to accumulate in the wellbore and /or the flow line and are being produced erratically as some of the liquids reach the surface as slugs.

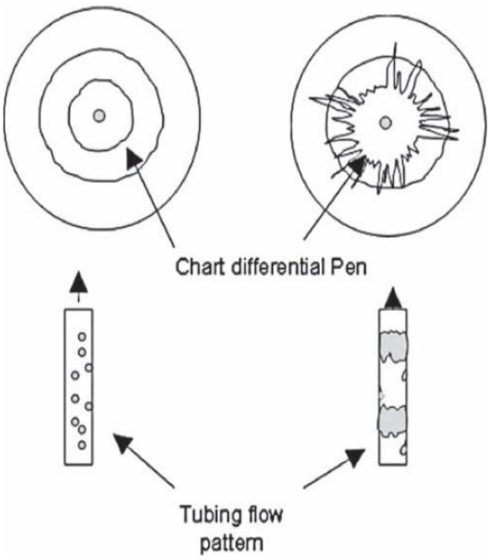

Figure 5: Effect of flow regime on orifice pressure drop – Mist flow (L) vs. Slug flow (R) in the tubing

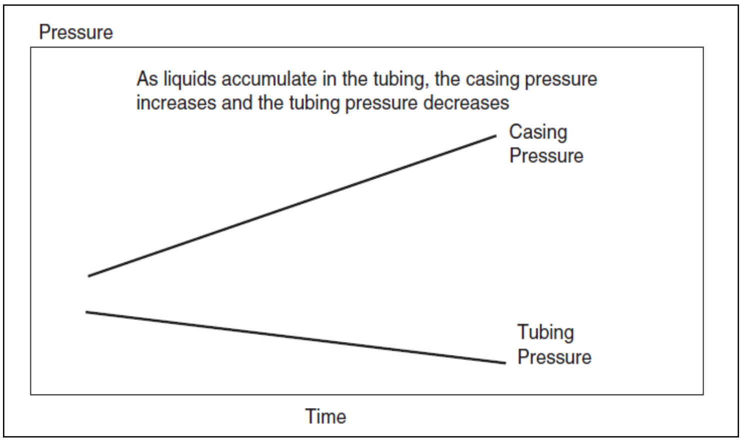

Figure 6: Casing and Tubing pressure indicator

- Increasing difference between the tubing and casing flowing pressure (i.e., $P_{cf} – P_{tf}$) with time, measurable without packer's present

- Sharp changes in gradient on a flowing-pressure survey

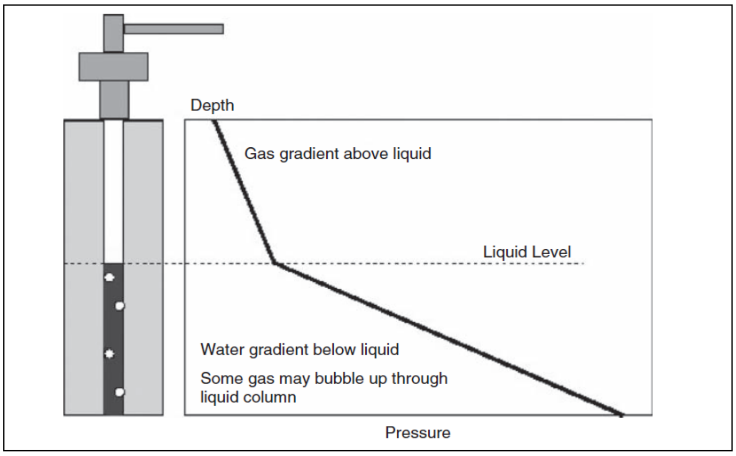

Figure 7: Pressure Survey schematic

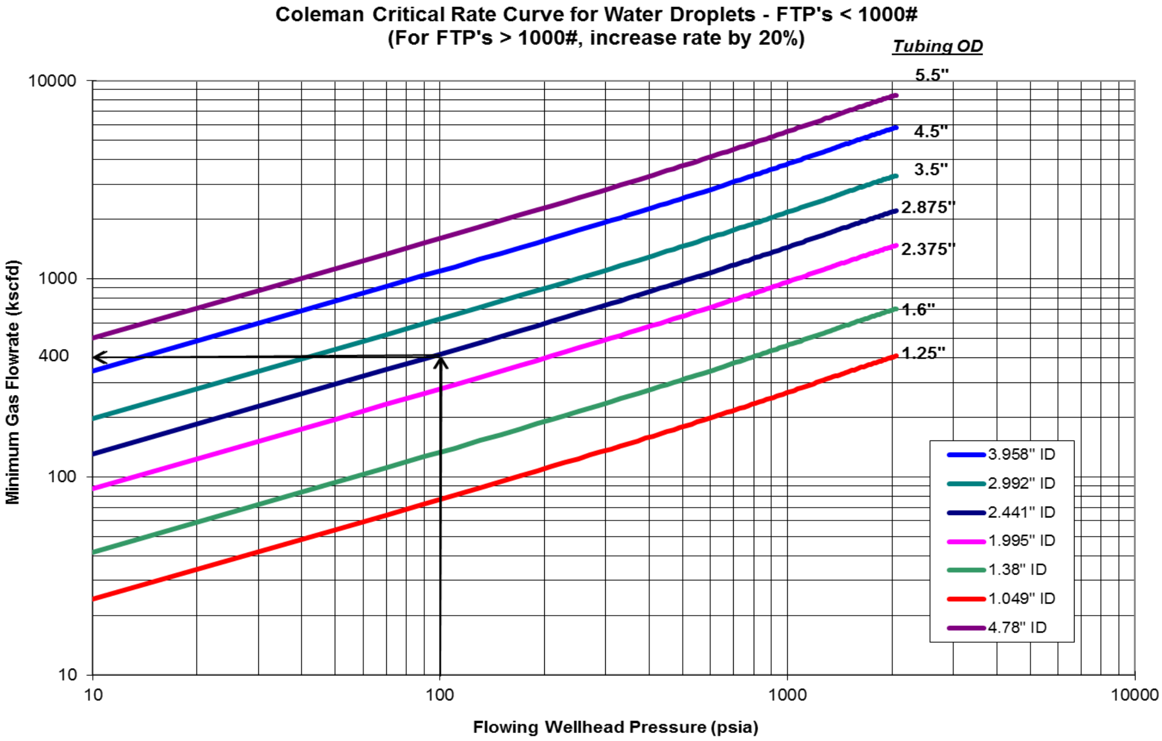

Figure 8: Critical Rate Cure

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Tabulation 1: CRITICAL VELOCITY RATES

		qg, m3/D			
Pwh, psi	KSC	1.25"	1.5"	2 7/8"	3 1/2"
50	4	1478	2056	7839	11777
100	7	2089	2905	11079	16645
150	11	2557	3556	13560	20373
200	14	2951	4103	15648	23509
250	18	3297	4585	17483	26267
300	21	3609	5019	19140	28756
350	25	3896	5418	20660	31039
400	28	4162	5788	22072	33161
450	32	4412	6135	23395	35149
500	35	4647	6463	24645	37026
600	42	5084	7070	26961	40507
700	49	5484	7627	29083	43695

4. DE-LIQUEFYING TECHNIQUES:

Liquid loading may be present, but what solutions are best to alleviate the problem? No universal solution exists. In principle all artificial lift technologies that are already used in oil wells can be seen as gas well de-liquification technologies. However, there are various circumstances that need to be considered when planning to install artificial lift technology in gas wells. The main factors influencing the successful application of gas well deliquification technologies are the accurate knowledge or estimation of the gas and liquid production rates and the composition of the produced liquid. This is very often a challenging task, as in liquid loaded wells not all liquids are being produced to surface. As some artificial lift technologies have a narrow operating range, it is crucial to overcome the problem of information on liquid rates so that de-liquification technologies can be designed properly.

Other crucial factors in the design of artificial lift technology are:

- ❖ Well configuration (information about casing and tubing, inclination, depth, ability to work over the well, knowledge if annular flow is possible, subsurface safety valve requirement)
- ❖ Flowing well conditions (flowing and static bottom hole pressure, flowing and static bottom hole temperature, surface pressure, gas gravity, presence of CO_2 and H_2S, flowing gradient and critical rates)
- ❖ Infrastructure (onshore or offshore well, power availability and high pressure gas availability)

All these factors have a significant impact on the design and applicability of deliquification technologies and can be the deciding factor between success or failure of a certain artificial lift method in a gas well. In general, all existing deliquification technologies can be put into one of the following four categories:

- ❖ Surveillance
- ❖ Mechanical
- ❖ Chemical
- ❖ Gas Lift

4.1 Surveillance:

Surveillance is general method which can be tried in every well for deliquification, but have limited time usage i.e., a point will be reached in the life of well when these methods will not bring the well back to life. Surveillance can be broadly classified into two broad categories:

- ❖ Cycling &
- ❖ Venting

4.1.1 Cycling:

Cycling a well requires exact monitoring of a well's fundamental data (production rate, wellhead temperature, wellhead pressure and if possible downhole data). The aim is to shut a gas well that suffers liquid loading in at an appropriate time, to let it build up pressure and then open it up again. During the shut-in time two changes happen to the well: The hydrostatic liquid column (partly) drains away back into the reservoir (what can be observed by increasing wellhead pressure) and the well builds up pressure in the near-wellbore region being "charged" from the reservoir. When opening up the well, this increased pressure might lift some of the liquids that obstruct gas production for a short period of time and hence gain the well some time until a

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liquid column of sufficient height has built up again to impact gas production -at which time the well should be shut-in already. Trials are needed in order to find the optimum shut-in time as well as the durations of flow period and shut-in-period. If the optimum timing is found, this method can be very effective - as experience has shown - up to double gas production. However, changes in well parameters have to be observed and reacted upon with different shut-in and production times.

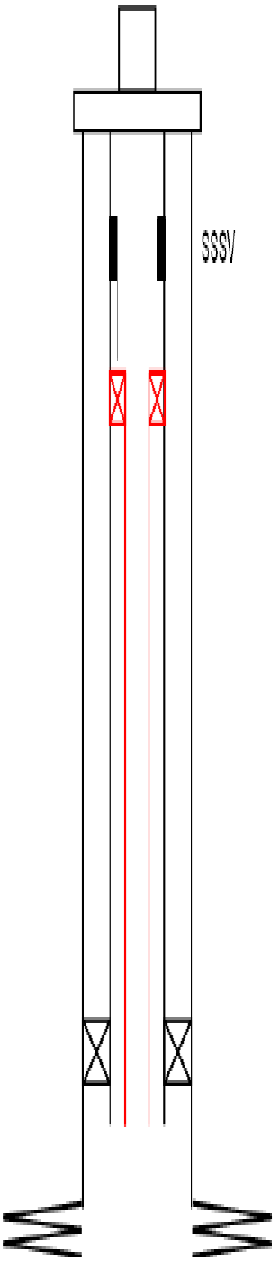

Figure 10: Velocity string schematic

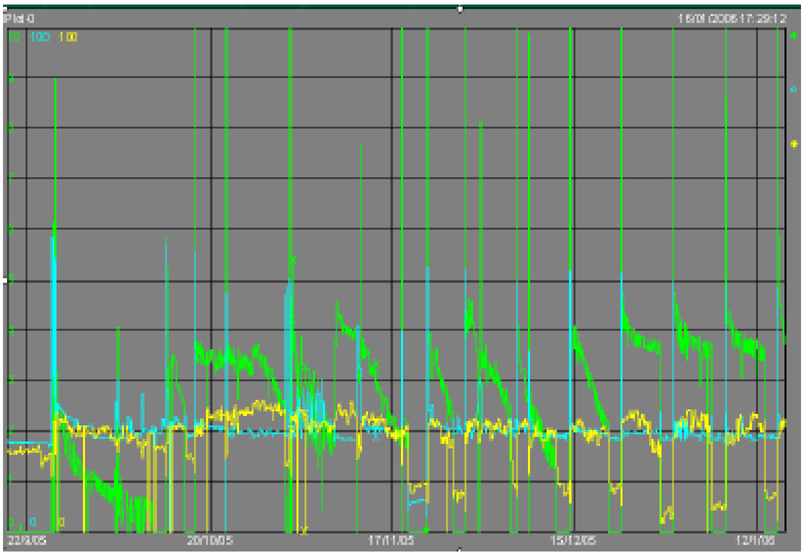

Figure 9: Cycling Wells

Figure 9 show an example of how cycling a well has more than doubled gas production in one offshore gas well. The green line shows the gas production rate, yellow symbolizes the wellhead temperature and blue the wellhead pressure.

Cycling can be tried in all wells, regardless of environment and completion. However, in wells that are heavily impaired by liquid loading (dead wells) other methods have to be used to bring these wells back to life before trying to improve their performance with cycling. However, a point will be reached in the life of a well, where cycling will not have any positive effect in which case artificial lift methods have to be used. Typical cycling times range from hours to several days' shut-in period and hours up to several weeks' production periods.

4.1.2 Venting:

In order to try to bring dead gas wells back to life, one option is to achieve maximum pressure drawdown by opening a well up to atmosphere. The main effect that is achieved by venting is the removal of any backpressure on wellheads. This "extra" pressure drop might lead to success in bringing a gas well back to life, however on a regular basis it is environmentally not acceptable. The same effect of venting can be achieved by temporarily tying a gas well into a low-pressure-system or by reducing backpressure with the aid of a compressor. Moreover, another environmentally acceptable option is to vent a well into a de-pressurized vessel, so that all produced fluids and the gas are contained in the vessel.

Venting is a method applicable in all types of wells and is independent of the completion type and well location. However, in order to "vent" in an environmental friendly way, temporary lines might have to be installed to direct the well contents to a vessel or a low pressure system.

As wells decline further, venting might have to become a more frequent operation and a point will be reached, where venting will not bring a liquid loaded well back to life.

In such a case, artificial lift methods have to be used to recover all reserves associated with a gas well.

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4.2 Mechanical:

Mechanical gas well de-liquefaction technologies cover a wide span of methods.

4.2.1 Swab Cup:

Instead of venting a dead well to atmosphere, it can also be tried to mechanically remove fluid that causes backpressure on the formation. The intervention tool used for this type of operation is a "swab cup", which is attached to a wire line. During this wire line intervention, the swab cup is lowered a certain depth into to fluid column, where care has to be taken that on the way up, the tensile strength of the wire is not exceeded. Therefore, accurate knowledge of the fluid level is crucial. Once the swab cup has reached the desired depth it is pulled out of the wellbore again and in theory should remove most of the liquids that are located above it due to the fact that it should expand and form a seal. In practice, there is always a certain degree of fallback due to the fact that the seal cannot be completely tight.

The operation might have to be repeated several times. Care has to be taken due to the fact that when enough liquid is removed from the gas well, it might start to flow.

In very weak wells, swabbing might have to be employed as a continuous deliquification method. However, if this is the case, other methods of artificial lift are more efficient.

4.2.2 Sizing production string to eliminate liquid loading:

The onset of liquid loading is related to certain critical rate. The critical rate above which a gas well should produce to avoid liquid loading is related to the cross-sectional area of the flow conduit, which in turn is proportional to the square of the radius of the flow conduit. This in fact translates that a reduction of pipe diameter by a factor of 2 (half the pipe size) would in fact drive down the critical rate required to keep a gas well unloaded by a factor of 4. This idea is the basic principle behind the velocity strings: as the gas production declines, a smaller conduit is installed to keep the gas well unloaded. Figure 10 shows the schematic for a velocity string installation, where it becomes obvious that in wells with sub-surface safety valve (SSSV) the velocity string has to be hung below the SSSV.

While installing velocity string in dead wells with a fluid column present, it should be taken into consideration that the same amount of liquid in a smaller flow diameter occupies "more height", which means that hydrostatic pressure on the formation from the same volume of fluid in the wellbore will be higher. Under such circumstances production has to be started with another method like bull heading nitrogen into the well and displacing some of the liquid into the formation, which reduces the hydrostatic head. Other methods to bring such a well back on production are coiled tubing gas lifting or venting.

There is mixed track record of velocity string installation in industry. Design of velocity string is crucial, as they might act as choke on gas well if designed to small and might have negligible effect if designed too large.

4.2.3 Tubing Extension:

Some gas wells have a particularly long liner section, in which high gas rates would be necessary to keep this section of the well loaded. However, especially in declining gas wells these rates might not be achieved and the wells would suffer production impairment by liquid loading. To overcome this issue, the tubing can be extended into liner, which has the same effect of a velocity string as described earlier. Figure 11shows a simplified schematic of a tubing extension:

Prior to extending the tubing it is necessary to get information about the well condition and possibility of sand production. High sand production might restrict the installation of tubing extension so as to avoid cementation of tubing which might be caused by well's sand production.

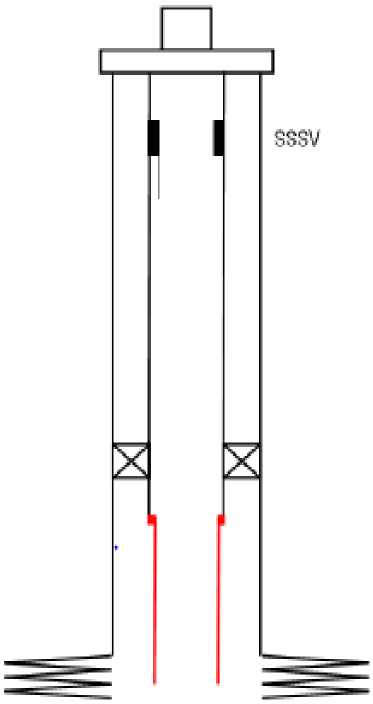

Figure 11: Tubing extension schematic

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4.2.4 Plunger Lift:

Plunger lift operation is one of the most widely and successfully used gas well de-liquification technology. The operation can be best described by looking at the schematic shown in Figure 12.

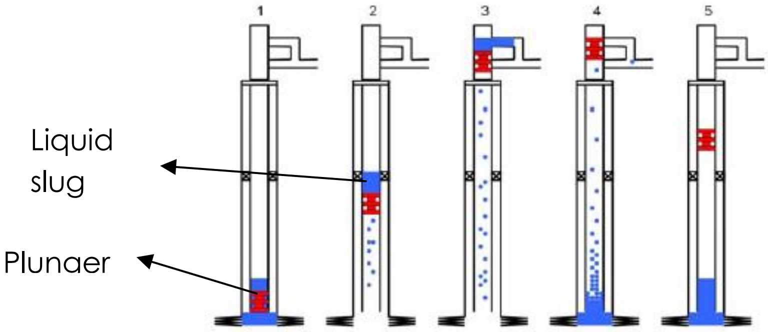

Figure12: Schematic of a Plunger Lift operation

A plunger is a piston that is driven by the well's own energy. It is a device that lifts liquid out of a well during intermittent production. At schematic 1 the well is closed, the pressure in the tubing-casing annulus builds up. Once enough pressure has built, the well is opened (see sketch 2), and the plunger lifts the fluid that has accumulated above it to surface. Fall-back of liquids is prevented by the gas turbulence in the clearance area between tubing and plunger. The plunger is pushed to surface by the well's own energy that has built-up during the shut-in period. Once the plunger arrives at surface (sketch 3), it is held in a lubricator. The gas is produced until the well starts loading up with liquid (sketch 4), at which time the well is shut-in and the plunger is released (sketch 5). The plunger falls to the bottom of the well and bypasses the liquid. Once sufficient pressure has built up again, the cycle starts again

Plunger system works well for gas wells with liquid loading problems as long as long as the well has sufficient GLR and pressure to lift the plunger and liquid slugs.

Advantages of Plunger lift system are:

- ❖ It works well with larger tubing so that there is no need to downsizing the tubing,
- ❖ Plunger lift can produce the well up to depletion and maintain normal Decline curve,
- ❖ Decreased average BHP, resulting in higher production, and
- ❖ Provides good hydrate and paraffin control

Although one of the most successfully used techniques for gas well deliquification, its use is limited in wells having large deviation, wells with non-uniform tubing size and wells having SSSV. Figure 13, can be used to estimate whether the well conditions are sufficient to support a plunger system:

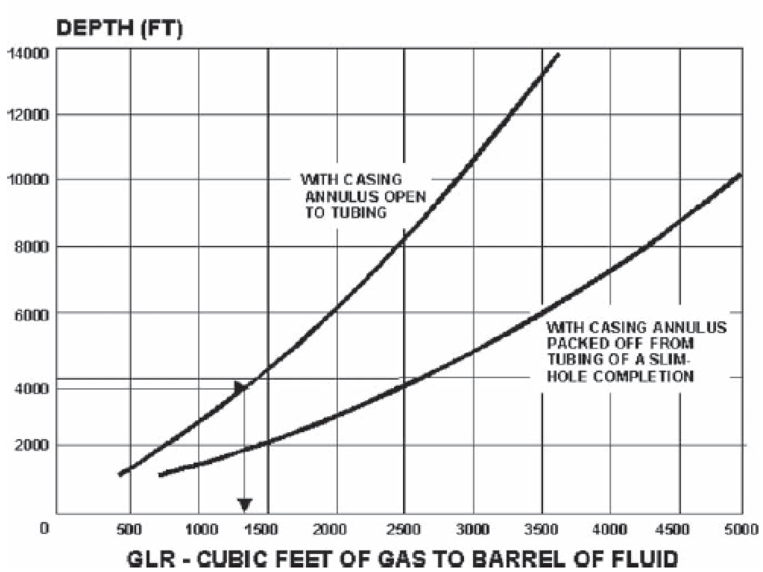

Figure 13: Gas needed for Plunger lift with / without a packer in the well

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4.2.5 Compression:

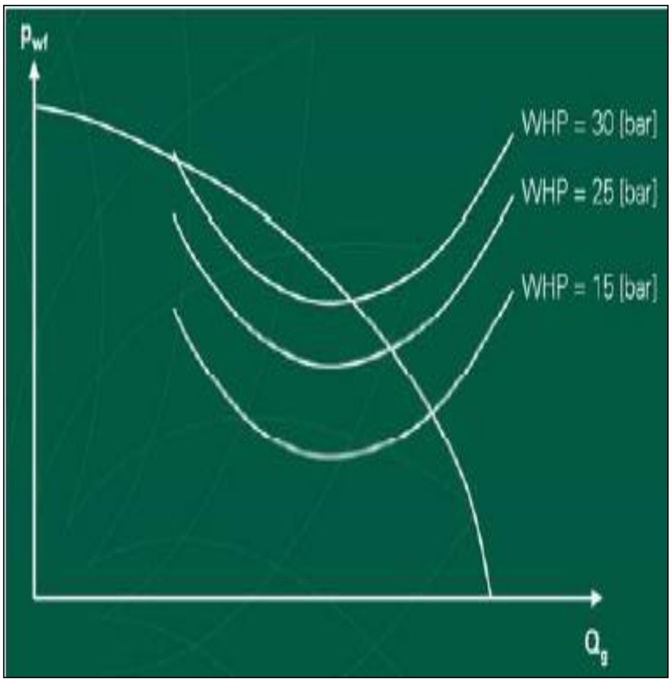

Figure 14: Effect of compression

Compression is vital to deliquification as it results in lowering of wellhead pressure and increased gas velocity. Compression lowers wellhead pressure, which in turn leads to a lower bottom hole flowing pressure and increased drawdown. Lowering of bottom hole producing pressure and wellhead pressures, with compression, can result in substantial production and reserves increases. This increase ranges from a few percent to many times the current production.

However, the method suffers from following limitations:

❖ This uplift requires investment for the compressor and associated equipment as well as operating costs for the maintenance and power to continue running the compressor.

❖ Also the reservoir limitation such as sand breakthrough ,increased water coning with increasing drawdown, puts a restriction on the lower THP limit allowable by compressor application.

However, many times compression can be the most economical way to keep wells deliquified, providing higher production rates at lower pressures. Figure 14 shows a schematic of the beneficial effect of wellhead pressure reduction by compressor application. The IPR stays fixed, the VLPs “move down” with decreasing wellhead pressure and the intersection shows higher production rates.

4.2.6 Jet Pump:

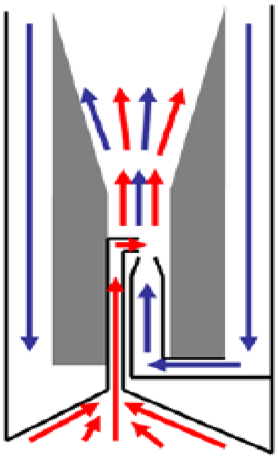

Fig 15: Jet pump schematic

By helping to generate a significant pressure drawdown in a wellbore, jet pumps make use of the Bernoulli-Principle. Power fluid has to be used and circulated down to the pump, which is then accelerated in a nozzle. At the point where the power fluid leaves the nozzle, a local, lower pressure region is generated, which draws the wellbore contents into this area. The combined stream of wellbore content (gas and liquid) and power fluid is then produced up the well to surface. Figure 15 shows the schematic of a jet pump, where the blue arrows symbolize the power fluid and the red arrows the wellbore contents. A jet pump can be a very effective deliquification tool however the operating range is quite narrow, which leads to the necessity of nozzle change-outs if well conditions change.

Jet pumps are actively being looked at to be deployed as gas well deliquification technologies in days to come.

4.2.7 Electrical Submersible Pump:

An Electric Submersible Pump is a multi-stage centrifugal pump driven by an electric motor. Wellbore fluids and gas are drawn past the motor exerting cooling action into the pump. The cooling of the motor is crucial to increase longevity of the ESP system.

Impellors impart kinetic energy to the fluid and diffusers direct the flow into next impellor and convert kinetic energy into potential energy (head). The number of stages determines how much head is produced; head and flow rate are interlinked. The power required to drive a pump is directly related to the density of the fluid. Due to the fact that an ESP needs fluid to be cooled, it cannot handle excessive amounts of free gas, traditional pumps can handle only up to 30 [%] of free gas. Recent developments in ESP technology, where big gas bubbles are “chopped up” at the pump intake so that between the smaller gas bubbles there is also some amount of liquid exerting cooling action on the pump have pushed this “free gas limit” into the 50 to 70 [%] envelope. Although ESPs are not the prime technology in gas well deliquification they can be very well used in gas wells with excessive water production. Moreover, ways to direct only the liquid to the ESP intake exist which let the gas bypass around the pump.

ESPs can be used in various environments however they do not have a big history for gas well deliquification applications.

4.2.8 Progressive Cavity Pumps:

A progressive cavity pump consists of a rotor and a stator. A motor drives the rotor, which is an eccentric screw that turns in an elastomeric stator. This progresses the cavity, which is filled with reservoir fluids along the pump and leads to production of the well.

In Gas Well Deliquification PCPs were trialed in onshore gas wells. However, experience has shown that the elastomer gets damaged if too much free gas is in the pump. At the moment it is being investigated what exactly caused the elastomer to fail and how to avoid it in future trials. Due to this, PCPs have found no application in Gas Well Deliquification.

4.3 Chemical:

The use of surfactants or foam for de-watering liquid loaded gas wells is by changing the liquid into a bubble film the surface area exposure is increased, the density is decreased, the surface tension is decreased and the net impact on the critical velocity calculations is usually a reduction by a factor of 2.5 to 3 and in some cases even higher. The best applications for this technology usually occur in higher GLR applications where the agitation necessary exists and in higher water cut applications where the surfactant acts mostly on water. Normally wells with GLR of 1000 to 10000 scf/bbl, which will allow for the necessary agitation, and the higher water cut is the most likely candidate for foam application. A lower limit of 50% water cut is usually a practical limitation, below this the chemical costs can get quite high and foaming may be impossible. A high condensate production particularly can be an issue as the condensate can act as a natural defoamer. In the case the other produced fluid is oil then many times oil can be lifted in conjunction with the foamed water, however in limited quantities.

There are numerous ways to apply surfactants to a liquid loaded gas well.

- liquid batch injection
- liquid continuous injection
- drop of “soap sticks”

However, the method suffers from following limitations:

- It is crucial for each application type that the surfactant concentration is correct. Too low concentrations are unlikely to have a beneficial effect on unloading the liquid, too high concentrations might lead to foam-locking a well. Hence determining the correct concentration is a critical factor for foam application in gas well deliquification.
- Different surfactant should be tested on a sample of wellbore fluid to determine the most effective foamer using Bureau of mines testing procedures or other testing procedure. Hence the same field may require different foamer application for effective deliquification.
- Foaming is more difficult and expensive for hydrocarbon with water percentages less than 80%. Also economics of continued use needs to be evaluated.

4.4 Gas Lift:

Gas lift can be principally grouped into different types of application:

- “Conventional” gas lift
- Gas Lift for kick-off
- Continuous gas circulation

The principle of all applications in gas wells is the same, although the applications vary. All applications have in common that it is tried to lift the liquid out of a gas well by keeping the velocity in the tubing above the “critical velocity” for liquid loading. Hence the combined rate of back produced gas lift gas and produced gas should be above the “critical rate”.

- *“Conventional” Gas Lift:*

“Conventional” gas lift, as used in various oil wells delivers gas through gas lift valves into the tubing. A number of unloading valves help to kick production off once a well has been shut in or has killed itself due to various reasons.

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❖ *Gas Lift for Kick-Off:*

Gas lift for kick-off can be deployed temporarily by use of a coiled tubing unit and if often used to lift liquid loaded gas wells on (especially after well interventions).

❖ *Continuous Gas Circulation:*

Continuous gas circulation aims to keep the tubing velocities above the critical rate at all times by continuously circulating gas through an injection string to the pay zone. The gas circulation rate can be adjusted based on the well production conditions.

Gas lift applications for gas wells are not yet widely used. The issue with gas lifting a gas well is that maximum drawdown cannot be achieved due to the fact that gas has to be injected in the near wellbore area and the injection pressure at that point has to be higher than the naturally occurring pressure at that point would be. Moreover, in flow loops flow regimes have been observed, where gas and liquid separate in the tubing and gas is produced up the tubing while liquid falls back on the low-side of the tubing. However, potential applications of gas lift might be combined with other artificial lift methods to get the best out of every method.

5. DISCUSSION:

- ❖ Recognize liquid loading from well symptoms, critical velocity, and/or Nodal analysis.
- ❖ Surfactants, laboratory tested for specific well conditions may be tried with little initial cost. Economics of continued use needs to be evaluated.
- ❖ Use of smaller-diameter tubing can be very effective for higher ranges of flow and can be a long-term solution. Smaller tubing may eventually have to be downsized to continue flow. However, small tubing (approximately 1-in. diameter or less) can be very difficult to unload.
- ❖ Plunger lift may be preferred over smaller tubing for lower rates, because the plunger works well with existing larger tubing and may perform to depletion of the reservoir. The two-piece plunger shows advantages in some wells.
- ❖ Use of compression to lower wellhead pressures helps almost any method of producing gas wells, but economics must be considered.
- ❖ Jet hydraulic pumps are easy to install, produce high rates, and have low servicing costs. However, they do not achieve low producing BHPs, and initial cost is a consideration. High power requirements may be experienced.
- ❖ Gas lift, by adding gas to the tubing to raise the velocity above critical, is viable if high-pressure gas is available.

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