Sustaining Production in Water Producing gas Wells

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Abstract

At an advanced stage of natural gas production, water production from gas wells often results in production problems. If not properly addressed the production of water can lead to the premature abandonment of wells associated with an avoidable loss of asset value.

To identify the state of the art and identify best practice in liquid unloading of water producing gas wells, the German Scientific Society of Petroleum, Natural Gas and Coal (DGMK) initiated an extensive study, which was carried out by Clausthal University of Technology in 2005. This paper documents part of the findings of the joint industry project: the commonly used methods to improve the dewatering of gas wells, the requirements for an implementation, typical ranges of application, industry experiences, elements of a screening and selection process and areas of further research needs.

Introduction

The production of natural gas is always associated also with the production of liquid. In the initial stages, the produced liquids usually are water or hydrocarbon condensates, thus liquids, which are in the vapour phase under in-situ conditions, and are formed in the process of the cooling of the production stream as it rises from the reservoir to the surface. In an advanced production stage of a well, the production of free water is often observed in addition to this production of condensate.

Condensate unloading typically does not represent a problem. Only for very advanced production stages with extremely low rates (and pressures) are problems of liquid unloading observed. The production of free reservoir water, however, can cause problems already very early in the life of a well, eventually leading to the loss of the well.

The much lower energy density of natural gas compared with crude oil significantly limits the economic flexibilities for the employment of artificial aids for lifting the liquids. Liquid production must therefore rely substantially on using the natural reservoir energy.

This report describes the commonly used methods for liquid unloading from natural gas wells, their ranges of applicability and the experiences of the industry.

Pipe flow

The optimization of liquid unloading by selection and application of the best method under the given conditions requires a good understanding of the flow processes taking place in the borehole.
For small liquid-gas-ratios (WGV) the liquid is transported to the surface by the flowing gas in
the form of mist or droplets. For high gas velocities, the velocity of the droplets is
approximately equal to the gas velocity. As drag forces between gas and liquid decrease as
a result of decreasing well rates and gas velocities, which are associated with advancing
reservoir depletion, the velocities of the liquid droplets decrease relative to the gas velocity.
As the gas velocity decreases a critical velocity is reached where the rate of rise of the liquid
droplets becomes zero. The well „dies“. For wells, producing under gas expansion drive, this
is a realistic scenario in an advanced stage of production. Safeguarding liquid unloading
under these conditions reduces to ensuring a gas velocity in the tubing, which is larger than
the critical gas velocity or critical gas rate.

After Turner (Lea et al., 2003) the critical gas rate (under in-situ conditions) is given by

\[
Q_c = (1,166) \cdot 520,1 \cdot D^2 \cdot \left[ \left( \frac{\rho_l \cdot z \cdot T - 348.3 \cdot \gamma_g \cdot p}{348.3 \cdot \gamma_g^2} \right) \cdot \frac{\rho^2 \cdot \sigma_l}{T^3 \cdot z^3} \right]^{1/4}
\]  

(1)

where

- \( Q_c \) = critical gas rate, Nm\(^3\)/h
- \( T \) = in-situ temperature, °K
- \( D \) = pipe diameter, in.
- \( \gamma_g \) = relative gas density (air =1)
- \( \rho_l \) = liquid density, kg/m\(^3\)
- \( \rho \) = in-situ pressure, bar
- \( z \) = gas deviation factor
- \( \sigma_l \) = surface tension liquid-gas, dyn/cm

According to equation (1) the critical gas rate may be reduced, and thus the unloading
conditions for liquid improved, by:

- reduction of the pipe diameter, e.g. installation of a velocity string
- reduction „of the liquid density“, e.g. foaming of the liquid by use of surfactants
- lowering of pressure, e.g. use of compressors
- increase of temperature
- reduction of surface tension, e.g. use of surfactants.

With rising liquid-gas-ratio the pipe wall is being wetted by the flowing liquid droplets. Liquid
unloading now requires a rising film at the pipe wall in addition to rising droplets in the gas
core. With a further rise of the liquid-gas-ratio, the thickness of the liquid film increases. Film
roughness and instability increase with increasing tendency for liquid fall back and liquid
bridging across the pipe. For even higher liquid-gas-ratios, the gas filled spaces between the
liquid bridges become more stable assuming the form of regular gas slugs moving through
the rising liquid. For natural gas wells this is usually the end of the natural unloading of liquid.

To optimize liquid unloading for high liquid-gas-ratios requires the use of complex multiphase
models for the determination of tolerable pressure losses. These models define the pressure
loss as a function of the flow regime. Application of the procedures shows that the
optimization of liquid unloading means in particular to provide for a favorable flow regime and
to preclude the occurrence of heading.

Practical experience has shown that the flow regime map of Gould et al. (1974) is well suited
to predict the prevailing flow regime in gas wells, Reinicke et al. (1987), Rist (1996).

Figure 2 shows the production performance of an approx. 4500 m deep Rotliegendes well
with the initial and final conditions of this well depicted in the flow regime diagram after Gould
et al. (1974) in Figure 1.
The leading parameters for the determination of the flow regime according to Gould et al. are the gas and the liquid velocity numbers, defined in metric units by

\[ N_{gv} = 3178 \cdot \frac{v_{sg}}{\rho_l} \cdot \sqrt{\frac{\rho_l}{\sigma_l}} \quad \text{and} \quad N_{lv} = 3178 \cdot \frac{v_{sl}}{\rho_l} \cdot \sqrt{\frac{\rho_l}{\sigma_l}} \]  

(2)

where
- \( v_{sg} = \frac{q_g}{A} \) = apparent gas velocity, m/s
- \( v_{sl} = \frac{q_l}{A} \) = apparent liquid velocity, m/s
- \( \rho_l \) = liquid density, kg/m³
- \( \sigma_l \) = surface tension liquid-gas, dyn/cm
- \( q_g = B_g Q_g \) = gas rate under in-situ conditions
- \( q_l \) = liquid rate under in-situ conditions
- \( A \) = tubing cross section
- \( B_g \) = gas formation volume factor
- \( Q_g \) = gas rate under standard conditions
According to equation (2) improvements of the flow regime are achievable by:
- reduction of tubing diameter
- decrease in pressure
- rise in temperature
- reduction of surface tension

while reductions in liquid density should lead to less favorable flow conditions according to equation (2).

For low velocities $v_m$, the pressure gradient equation

$$\frac{dp}{dL} = \left(\frac{dp}{dL}\right)_{\text{gravity}} + \left(\frac{dp}{dL}\right)_{\text{friction}} + \left(\frac{dp}{dL}\right)_{\text{acceleration}}$$

$$= \frac{g}{g_c} \cdot \rho_m \cdot \sin \theta + \frac{2 \cdot f_m \cdot \rho_f \cdot v_m^2}{g_c \cdot D} + \frac{\rho \cdot v_m \cdot dv_m}{g_c \cdot dL}$$

is dominated by the gravity term, which is governed by the two-phase density $\rho_m$ given by

$$\rho_m = \rho_l \cdot H_l + \rho_g \cdot (1 - H_l)$$

where $p$ = pressure, $L$ = distance in direction of flow, $g$ = acceleration due to gravity, $g_c$ = conversion factor, $f_m$ = Moody friction factor, $v_m$ = two-phase velocity, $H_l$ = liquid hold up

According to equation (3) a reduction of the pressure loss can be achieved in particular by reducing the two-phase density.

If the natural energy stored in the reservoir does no longer suffice to unload the liquid, artificial lift may be implemented to lift the liquid to the surface, as for the production of oil.

**Process for the examination of a liquid-loaded well**

For the examination of a liquid-loaded well the process documented in the following is proposed, see also Lea et al. (2005).

Use of the process documented in Figure 3 requires that the observed productivity problems are caused by liquid loading. Indicators for "liquid loading" are
- production rate below the critical rate according to Turner (the rule of thumb documented in the literature for the critical rate is 900 Mcf/d (approx. 1,000 m$^3$/h)
- flow regime diagram after Gould suggests slug flow
- observed severe slugging or heading
- dramatic decrease of the production rate for gas and/or water
- increasing differences between tubing and annular pressure in the case of completions without packers.
Fig. 3: Process for the examination of a liquid-loaded well

The necessary information required for a comprehensive examination consists of drilling history, production data, wellbore diagram, completion log, CBL/VDL or comparable logs necessary to evaluate cementation quality, gas and liquid samples/analyses as well as samples and analyses of deposits and scale if these represent a problem, test data as well as data from production control surveys if available. These data form a good basis for analyses in order to determine the cause of the loading problems, e.g.

- sub-critical velocity possibly in connection with water traps
- increasing water-gas-ratios due to coning/cusping
- increasing water-gas ratio due to (selective) water encroachment into the reservoir
- production of reservoir water from water-bearing formations via poor cementation.

If selective water encroachment is the problem, water influx from the formation may be reduced by:

- draw down management, if the influx is due to coning/cusping and if the management is economically meaningful
- setting a mechanical plug in the wellbore, if water influx is through the deeper perforation intervals and if there is good cementation between the intervals
- repair of the cementation, if the water production results from a leaky cementation.
Problems in the dewatering of wells are always caused by insufficient gas velocities and gas relative volume. If the completion is maintained, higher velocities are achievable, by opening up additional formations, if such formations exist, or by re-perforation to remove skin damage or last not least by stimulation.

Only if these possibilities are exhausted, further measures should be considered. These measures include

- improvement of the unloading conditions for liquids, if remaining reservoir energy is sufficient. Conditions may be improved by decreasing wellbore pressure, by installation of a velocity string, by use of surfactants and by use of plungers,

- supply of energy to lift the liquids. Energy may be supplied by installation of gas lift, by using sucker rod pumps, by electrical submersible pumps and progressing cavity pumps.

In designing these measures use should be made of a ‘NODAL’, Beggs (1991), or ‘system network analysis’.

**Method screening and industrial experience**

A procedure for a first screening of the methods which are available to unload gas wells is shown in Table 1, see also Lea et al. (2005). It should be used in combination with the empirical values of the industry. These are shown in Table 2.

**Table 2:** Industry experience with methods to improve liquid unloading

<table>
<thead>
<tr>
<th>Condition before</th>
<th>Data sets</th>
<th>Velocity String</th>
<th>Surfactants</th>
<th>Plunger Lift</th>
<th>Gaslift</th>
<th>Chamber Lift</th>
<th>Sucker Rod</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas rate, m³/h</td>
<td>51</td>
<td>0 - 12.530</td>
<td>&lt; 0.1 - 89</td>
<td>18 - 388</td>
<td>6 - 12.390</td>
<td>20 - 146</td>
<td>44 - 1.378</td>
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<tr>
<td>Water rate, m³/d</td>
<td>40</td>
<td>0 - 2.360</td>
<td>&lt; 0.1 - 11</td>
<td>0.8 - 12</td>
<td>0.4 - 159</td>
<td>&lt; 0.1</td>
<td></td>
</tr>
<tr>
<td>Water-gas-ratio, cm³/m³</td>
<td>23</td>
<td>3 - 1.403</td>
<td>1 - 1.500</td>
<td>0.3 - 4.577</td>
<td>2.041 - 2.712</td>
<td>1.555 - 5.116</td>
<td>950 - 1.687</td>
</tr>
<tr>
<td>Perforation depth, m a.H.</td>
<td>20</td>
<td>1.204 - 6.268</td>
<td>905 - 4.577</td>
<td>19 - 34</td>
<td>3 - 14</td>
<td>3 - 5</td>
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<tr>
<td>Wellhead flowing pressure, bar</td>
<td>3</td>
<td>7 - 117</td>
<td>7 - 117</td>
<td>3 - 34</td>
<td>0.3 - 14</td>
<td>3 - 5</td>
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<table>
<thead>
<tr>
<th>Average values for condition before / after measure</th>
<th>Velocity String</th>
<th>Surfactants</th>
<th>Plunger Lift</th>
<th>Gaslift</th>
<th>Chamber Lift</th>
<th>Sucker Rod</th>
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<tr>
<td>Gas rate, m³/h</td>
<td>790 / 1.046</td>
<td>428 / 1.012</td>
<td>92 / 145</td>
<td>0.129 / 1.324</td>
<td>62 / 120</td>
<td>412 / 560</td>
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<tr>
<td>Water rate, m³/d</td>
<td>5.6 / 2.5</td>
<td>1.1 / 3.6</td>
<td>2.7 / 1.4</td>
<td>28 / 41</td>
<td>&lt; 0.1 / 0.14</td>
<td>6 / 6.4</td>
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<tr>
<td>Water-gas-ratio, cm³/m³</td>
<td>164 / 80</td>
<td>183 / 134</td>
<td>1.13 / 445</td>
<td>573 / 1.114</td>
<td>23 / 62</td>
<td>1.000 / 1.401</td>
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<tr>
<td>Perforation depth, m a.H.</td>
<td>3.472</td>
<td>2.776</td>
<td>2.324</td>
<td>2.433</td>
<td>1.207</td>
<td>1.679</td>
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<td>Wellhead flowing pressure, bar</td>
<td>44 / 53</td>
<td>29 / 24</td>
<td>14 / 16</td>
<td>5 / 10</td>
<td>4 / 4</td>
<td>35 / 34</td>
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<tr>
<th>Installation cost</th>
<th>Europa, k €</th>
<th>USA, M USD</th>
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<tr>
<td>Success rate, %</td>
<td>100 - 150</td>
<td>100 - 150</td>
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<td>Installation cost</td>
<td>25 - 115</td>
<td>10 - 20</td>
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<tr>
<td>Average rate increase for successful measures, m³/h</td>
<td>330</td>
<td>635</td>
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1) continuous injection of surfactants
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<tr>
<th>Screening of Suitable Methods</th>
<th>Velocity Siting</th>
<th>Compression</th>
<th>Foam</th>
<th>Plunger</th>
<th>Gas-Lift</th>
<th>Sucker Rod</th>
<th>Hydr TP</th>
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<th>ESP</th>
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<td>deep (&gt;3000m)</td>
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<td>shallow (&lt;3000m)</td>
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<tr>
<td>Diameter small</td>
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<td>EOT-to-Perf.Distance &gt;100m</td>
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<td>Small casing (&lt; 4.5&quot;)</td>
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<td>high (&gt; 135 °C)</td>
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<td>++</td>
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<td>low (&lt; 65 °C)</td>
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<tr>
<td>Water/condensate high (&gt;1,5)</td>
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<td>+</td>
<td>+</td>
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<td>Sand, scale</td>
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</table>

Legend: Green = Method suited, Yellow = Validate Suitability, Orange = Method should not be used.
The data in Table 2 are based on approximately 130 data sets. These data sets were either provided by the companies participating in the project or were taken from the literature: Adam and Marsili (1992), Boswell and Hacksma (1997), Burgstaller (2004), Ganahl (1987), Green and Korzekwa (1984), Hendersen (1984), Hutlas and Granberry (1972), Lea et al. (2003), Libson and Henry (1984), Reinicke et al. (2006), Schwall (1989), Stephenson and Rouen (2000), Vosika (1983), Wesson (1993) - SPE 12590, size Texas August (1983), SPE 18870; as well as the reports of the Gas Well De-Liquification Workshop Denver Colorado, February 28 - March 2 2005: Bakker et al. (2005), Bolding (2005), Chrisler (2005), Gates (2005), Hughes et al. (2005), Lea et al. (2005), Lestz et al. (2005), Schlumberger (2005), Williams (2005), Wittfeld C. (2005).

Despite the size of the data basis, caution is advised in using the data. Publications are usually written with a certain bias. Caution is appropriate in particular when using the success rates derived from the reviewed publications. They are at best indications.

According to Table 2 the costs associated with the implementation of the various methods differ significantly. The differences from method to method are expected and understandable. The significant differences between European and American cost should be investigated further. Only for plunger lift installations are the costs reported for Central Europe similar to those in North America.

Evaluation of the data reported in Table 2 warrants the following conclusion:

- **Average** pre-treatment rates are all, in some cases significantly below 1,000 m$^3$/h,
- Velocity string and gaslift are typically applied for ‘higher’ gas rates. In some instances pre-treatment gas rates for velocity string and gaslift are well above 10,000 m$^3$/h,
- Surfactants and pumps are usually applied for ‘medium’ gas rates up to 2,500 m$^3$/h,
- Plunger lift and chamber lift are typically applied for ‘low’ gas rates below 300 m$^3$/h down to the 10 m$^3$/h range
- The lowest relative rate increases compared to the pre-treatment rate have been achieved for velocity string and gaslift (approx. 50%). For all other methods reported rate increases are approx. 100% and more.
- The smallest success rates are achieved for batch (stick) surfactant treatments and sucker rod pumping (approx. 50 - 60%) followed by gaslift (approx. 75%).

The foregoing statements are not statements in an absolute sense as can be seen from Figure 4, which displays all the data reported in Table 2 in cross plots ‘water rate’ versus ‘gas rate’ and ‘depth’ versus ‘gas rate’.

**Planning of measures for improved unloading and well design**

As is obvious from the presented results there is neither a method, which is applicable under all conditions nor are there clearly defined ranges of applicability for the individual methods. The optimal method is dependent on many factors. Only when they are considered in an integrated fashion can the economic optimum for a given set operating and environmental condition be identified. The most important of these factors are shown in Table 3 below.
**Fig. 4:** Water rate and depth as a function of gas rate

**Table 3:** Requirement for the implementation of liquid unloading methods

<table>
<thead>
<tr>
<th>Method</th>
<th>Reservoir Energy</th>
<th>Power</th>
<th>Other Infrastructure</th>
<th>Training Need</th>
<th>Note</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure Decrease</td>
<td>y</td>
<td></td>
<td></td>
<td>M</td>
<td>Increase velocity above critical velocity</td>
</tr>
<tr>
<td>Velocity String</td>
<td>y ^1)</td>
<td>L</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Surfactant</td>
<td>y</td>
<td>H</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>Plunger</td>
<td>y</td>
<td>M-H</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gaslift</td>
<td></td>
<td></td>
<td></td>
<td>M</td>
<td>Supply of energy to lift fluid</td>
</tr>
<tr>
<td>Sucker Rod Pump</td>
<td>y</td>
<td></td>
<td></td>
<td>M</td>
<td></td>
</tr>
<tr>
<td>ESP</td>
<td>y</td>
<td>L</td>
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<td></td>
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<tr>
<td>PCP</td>
<td>y</td>
<td>M</td>
<td></td>
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</tbody>
</table>

^1) y = yes  
^2) L = low, M = medium, H = high
The typical industry approach to improve liquid unloading is expressed in a simplified way as follows.

- At the first signs of liquid loading, reduced the cross section to flow, e.g. by ‘snubbing’ a velocity string,
- if liquid rate is very high (> 50 m$^3$/d), evaluate gaslift versus pumps,
- For smaller liquid rates, too large for the use of plungers (10 - 50 m$^3$/d, dependent on the cross section to flow), use surfactants:
  - sticks in wells of shallow depth,
  - liquid batch applications in wells without packer,
  - capillary injection in wells with packer.
Surfactant use requires that there is little condensate and no H$_2$S.
- Otherwise, install plungers in 50 - 250 m$^3$/h wells, if there is little risk of the plungers getting stuck:
  - conventional plungers,
  - two-piece plungers,
  - multi-stage.
- Monitor the well and lower of well head pressure as required.

When designing wells and completions for improved liquid unloading, consideration should be given to

- cased hole completions
- monobore completions
- for traditional completions: an end-of-tubing (EOT) immediately above or in the upper third of the perforated interval
- for existing wells with large distance between EOT and perforations: a siphon string to bridge the larger diameter interval between EOT and perforations
- sizing of the tubing cross section to meet the initial rate requirements with the possibility of a later reduction in cross section by installing a velocity string
- employing of pipe straightening when running a coiled tubing as velocity string to reach down to the perforated interval or immediately above

**Outlook**

The large discoveries in Germany have been made. For years already, production replacement and reserves replenishment relies on reservoir management. In this context the production of gas wells with liquid loading problems becomes more and more important. Further improvements in depletion require a better understanding of the methods and conditions of applicability, a reduction in installation and operating costs, and increases in the rate of implementation success. The example of RAG, which operates wells with production rates below 100 m$^3$/h and wellhead flowing pressures in the single digit bar range, shows, that money can also be made with low productivity wells.

Despite world-wide high efforts to improve the technology for unloading natural gas wells, questions, which are worthwhile of being addresses scientifically, remain.

Many correlations exist to determine the two phase pressure loss, necessary to design wells and completions for liquid unloading. The deviations of the pressure losses, predicted by the individual correlations under conditions critical for a system design, are significant for some correlations. The popular software tools to predict pressure loss typically contain many of the
known correlation, do, however, give little guidance as to which correlation is best suited under which conditions. Investigations to determine the correlation, which are best suited to describe liquid unloading of natural gas wells appear desirable.

Wittfield (2005) reports approx. 150 batch surfactant applications. Only approx. 50 of these applications were classified successful, more than 60 applications were unsuccessful. No classification was possible for the remaining approx. 90 treatments. Further investigations into the effectiveness of surfactants, e.g. as a function of reservoir brine, inhibitors, corrosion products are desirable. These investigations should include determinations of foam density and surface tension as a function of the surfactant concentration under in-situ conditions. Results for this dependency are available in the open literature only for laboratory conditions.

Only few data sets could be collected on the use of pumps to unload natural gas wells. All applications known for Central Europe were unsuccessful and abandoned shortly after implementation. Investigations of the causes of failure and improvements in technology and in success rate appear appropriate. The investigations should include investigations to the effectiveness of scale inhibitors and investigations into the applicability of e.g. multi-phase pumps for horizontal transport.

References


