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Analysis of Liquid Loading and Sandness in Gas Wells A1, A2 and Their Correction with The Plunger Lift Method in Field B

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Abstract

The inability of the gas to lift liquid to the surface causes liquid to accumulate in the downhole, commonly called as liquid loading, and sand deposits at the bottom of the well are produced and are caused to be swept away by the gas flow. If a well has liquid loading and sandiness problem, production will decrease and eventually stop. For this reason, it is necessary to carry out a predictive analysis of the well and methods to overcome the problem of liquid loading and sandiness. Liquid loading is not always easy to identify, because when loading occurs the well may still be producing significant amounts. The commonly used method in the petroleum world to identify liquid loading is the "Turner et al" method. While the method to overcome liquid loading is the plunger lift method. The plunger lifting system uses gas pressure buildup in the well to lift the accumulated liquid column out of the well. The researcher conducted a liquid loading analysis on well A1 and well A2. From the results of the study, it was identified that well A1 did not experiencing liquid loading, because the calculation results showed that the well's critical gas flow rate was 3.3 MMSCFPD which was less than the actual gas flow rate of 5 MMSCFPD. Well A2 is experiencing liquid loading, because the results of the calculation of the well's critical gas flow rate are 3.6 MMSCFPD, while the actual gas flow rate in the field is 3MMSCFPD. After removal of fluid and sand from the bottom of the well, the production rate of the A2 gas well increased to 5 MMSCFPD.

INTRODUCTION

In general, what is often experienced by gas wells is the accumulation of liquid and sand at the bottom of the wellbore, which is one of the problems in the production of gas wells. Gas wells usually produce natural gas, which produces liquids, both in the form of water and condensate (hydrocarbons), which is formed from gas vapor. When the velocity of gas flow in the well decreases due to a decrease in reservoir pressure, the carrying capacity of the gas decreases (Guo et al., 2005). Liquid and sand grains that accumulate in the well result in a liquid column or fluid column. The higher the liquid column, the higher the pressure loss in the tubing. This situation will result in a sharp decrease in gas. This is because the reservoir pressure does not provide enough energy to lift the gas to the surface because it is hampered by the accumulation of liquid in the well. This event is usually referred to as liquid loading.

When liquid loading occurs, the reservoir pressure decreases along with production, the gas flow rate will decrease, and the velocity will no longer be able to carry liquid to the surface, so that it accumulates at the bottom of the well, providing back pressure. If the reservoir pressure is the same as the back pressure due to the liquid pool, then the well will die. The accumulation of liquid and sand at the bottom of the well will also cause liquid saturation around the wellbore to increase so that the effective permeability of the gas will decrease and reduce the gas production rate, which will cause a decrease in gas flow velocity so that the liquid loading conditions get worse (KJ et al., 2017).

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In this study, an analysis of the occurrence of liquid loading and sand deposition at the bottom of the well and its countermeasures was carried out in gas wells A1 and gas wells A2 in field B. Researchers used the Turner et al. method to identify the occurrence of liquid loading and the plunger lift method to handle it. Where the plunger lifts with a valve is placed in the tubing assembly. At the bottom of the tubing is an opening through which gas and liquid can pass into the tubing. When the plunger is placed at the bottom of the tubing, the tubing is closed, and all production flows through the annulus.

The objectives of this research proposal are analyzing liquid loading and sandiness in wells A1 and wells A2 and countermeasures for liquid loading and sandiness using the plunger lift method and then calculate the critical gas flow rate in the liquid loading well after the plunger lift is carried out. The formulation of the problem in this study focused on identifying liquid loading with the Turner et al. method, then handling liquid loading and sandiness with a plunger lift.

Liquid Sources and Sand Grains

As is known, the problem that usually occurs in gas wells is liquid loading. Therefore, it is important to know the source of the liquid. This liquid may be free water, water condensate, or hydrocarbon condensate. The liquid produced together with gas has several sources depending on the conditions and type of reservoir from which the gas is produced:

a. Water due to water coning from the aquifer zone below the productive zone.
b. Water or condensate that enters the wellbore is in the vapor phase and condenses into a liquid.
c. Condensate hydrocarbons
d. Production of water from other zones
e. Free-formation water is co-produced with the gas.
f. Sand is carried by the flow of gas into the well.
g. Unconsolidated formation

Liquid Loading Prediction

Liquid loading is not always easy to identify because when loading occurs, the well may still be producing significant amounts. The most widely used and generally accepted approach to predicting liquid loading is to evaluate the “critical flow rate” which is defined as the minimum flow velocity required to lift the liquid out of the well. The gas rate below the critical flow rate causes liquid droplets to fall and accumulate downhole, which causes a decrease in well production, and eventually the well dies. The most preferred and widely used empirical expression in the petroleum world is the (Turner et al., 1969) method (Liu et al., 2017)

Turner, Hubbard, and Dukler proposed 2 models to predict gas well fluids. Firstly, the movement of the liquid along the pipe wall, and secondly, the liquid droplets entrapped in the gas core at high velocity. Turner used field data to validate each of the models and concluded that the entrained droplet model could better predict the minimum level required to lift liquid from the gas well (Turner et al., 1969).

The theoretical equation for the speed to lift the liquid droplet:

Vt = (〖1,593〗 ^(1/4) (〖ρl- ρg)〗 ^(1/4))/ 〖ρg〗 ^(1/2) ft/sec (1)

For liquids in the form of condensate:

v_(c cond)= 4.043 〖(45-00031P)〗 ^(1/4)/((〖00031P)〗 ^(1/2)) ft/sec (2)

For liquids in the form of water:

V_(c water)=5.321 〖(67-00031P)〗 ^(1/4)/〖00031P〗 ^(1/2) ft/sec (3)

V_(c gas)=5.62 〖(67-00031P)〗 ^(1/4)/〖00031P〗 ^(1/2) ft/sec (4)

The reason why the Turner method is the most popular is because all the parameters needed in the equation can be easily obtained at the wellhead, which is a convenience for field operators. In this way, operators can avoid the difficulty of obtaining bottomhole data and thereby reduce operational costs. In practice, when the "theoretical" Turner correlation is applied to a particular gas well, the coefficients are generally necessary to adjust the equation to be more appropriate in the particular field. This shows that in the Turner method, there is also inherent uncertainty in the global world of the application of the Turner method. Turner et al. explained that the reversal of liquid droplets is especially for the beginning of liquid loading because it is more compatible with the field data used. This assumption is also the most significant theoretician of the convention Turner correlation (Hashmi et al., 2016).

Critical Rate

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The critical oil flow rate is also a parameter that influences liquid loading. To maintain the reservoir pressure of a well is to produce the well below the critical flow rate (Musnal, 2014).

The minimum gas flow rate to avoid liquid loading is calculated by the equation:

$$Q_{gc}=\frac{3.06PAV_g}{(T+460)Z} \quad (5)$$

$$A = \frac{\pi\, dt^2}{4 \times 144} \quad (6)$$

Where:

T = Surface temperature, °F

Vg = Gas velocity. ft/sec

Z = gas compressibility factor, fraction

P = Flow pressure at the wellhead, psi

A = Channel area, ft^2

dt = ID of the tubing, inches

Liquid Loading Countermeasures Methods

In this writing, the author uses the plunger lift method to overcome the problem of liquid loading and sandiness of gas wells A1 and A2 in field B. Plunger lift is one of the most widely used and successful gas well pusher lifting technologies. The plunger is a piston driven by the energy of the well itself. The plunger lift system uses the build-up of gas pressure in the well to lift a column of accumulated liquid out of the well. Basically, the plunger lift system uses a plunger that moves up and down in the tubing to lift the liquid (Park et al., 2009)

The plunger is a piston type device with a valve located in the tubing assembly. At the bottom of the tubing is a place where gas and liquid can pass into the tubing. When the plunger is placed at the bottom of the tubing, the tubing is closed, and the entire production passes through the annulus. During the tubing closing period, the plunger is at the bottom of the spring assembly, gas pressure accumulates in the annulus, and liquid accumulates at the bottom of the tube. After a certain period of time, the pressure accumulates in the annulus. The casing rises, and the energy is stored in the annulus to move the plunger and the liquid above the plunger to the surface. A valve (motor valve) is used to control the plunger flow rate cycle (set by time) (Gasbarri, 1996).

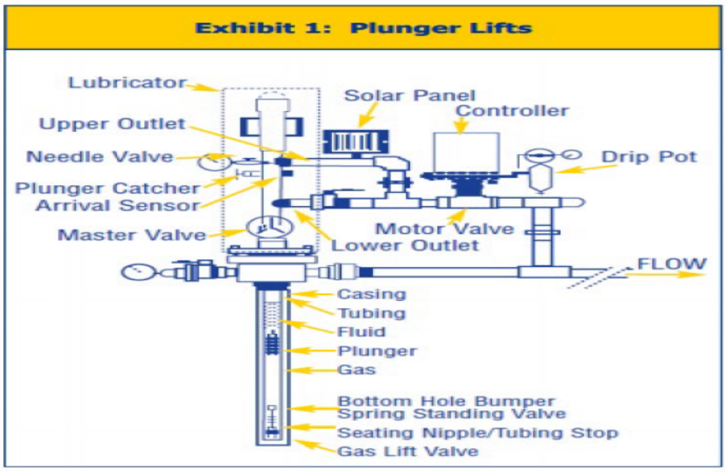

Figure 1. Installing a plunger lift on a gas well (Gasbarri, 1996)

Typical operating steps of a plunger lift system:

The plunger rests on the bottom hole bumper spring located at the bottom of the well. The well is closed on the surface by an automatic controller to reverse the decline in gas production. When the plunger is lifted to the surface, gas and liquid accumulated above the plunger flow up and down the outlet. The plunger is caught in the grease, located opposite the top grease outlet. The gas that lifts the plunger flows through the outlet from the bottom of the well. Once the gas flow is stabilized, the controller automatically releases the plunger, dropping it back down the pipe.

Repeat cycle

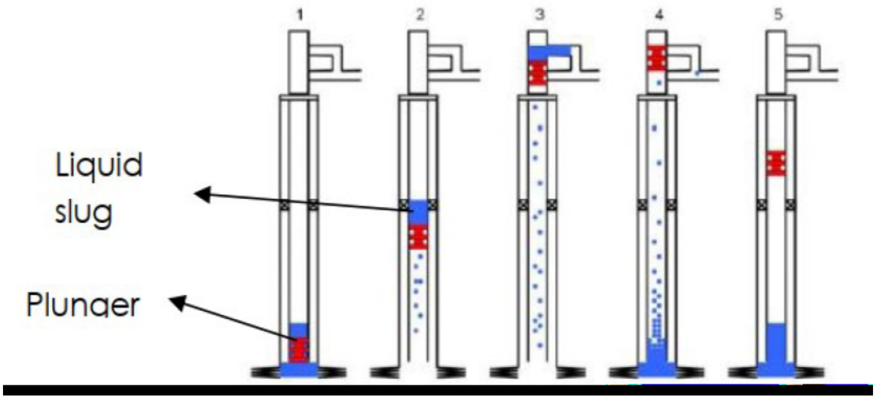

Figure 2. Schematic Operation of Plunger Lift (Gasbarri & Wiggins, 2001)

In scheme 1, the well is closed, and the pressure inside the casing annulus-tubing is formed. In sketch 2, the well is opened, and the plunger lifts the fluid that has accumulated above it to the surface. The fallback of the liquid is prevented by gas turbulence in the area between the pipe and the plunger. The plunger is pushed to the surface by the well's own energy that has built up during the shut-off period. After the plunger arrives at the surface (sketch 3), gas begins to be produced until the well is filled with liquid (sketch 4). In sketch 5 the well is again closed, and the plunger is released. The plunger falls into the well and passes through the liquid. One more pressure is enough, and the cycle starts again (Musnal, 2014)

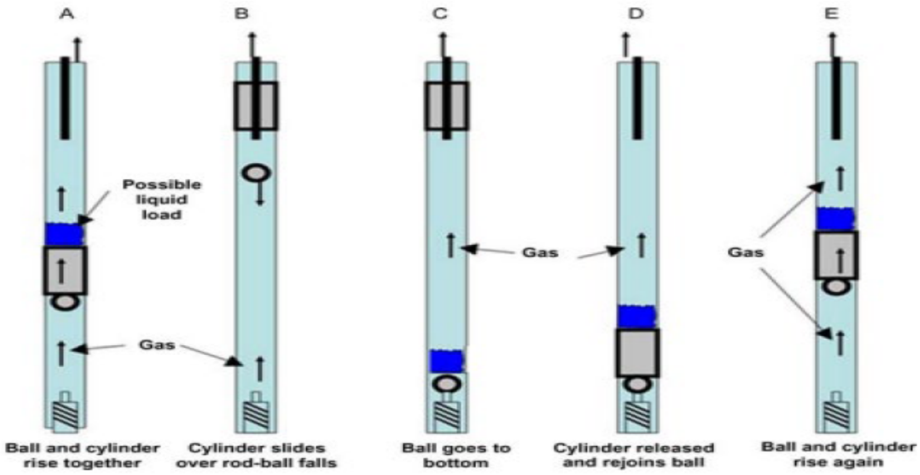

Figure 3 Continuous Plunger Cycle (Gasbarri & Wiggins, 2001)

Based on Figure 3. it can be seen how the cycle occurs in the plunger. Starting from the fall of the plunger to lift the fluid and then up and then down again to bring the fluid back up. This activity continues to be carried out in order to reduce liquid accumulation in gas production wells.

METHODS

Data source

Retrieval of some data from wells as study wells in this case can be carried out based on consultation with the field coordinator in the field of gas production.

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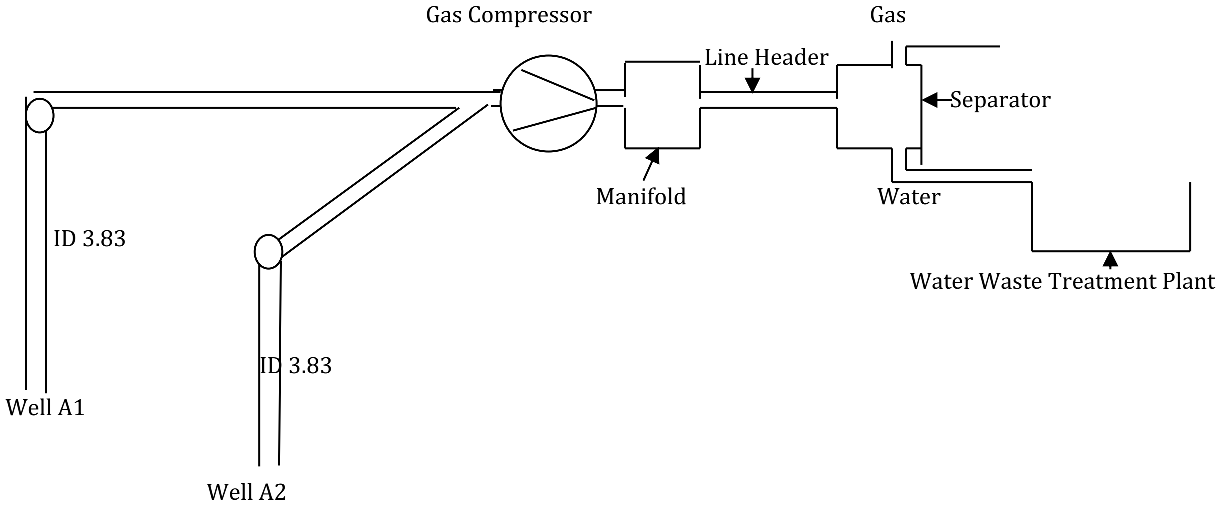

Figure 4. Field sketch B

Table 1 Properties of Gas Wells A1 and A2

Variable	Well A1	Well A2	Unit
Gas Rate	5	3	MMScf/day
Liquid Gradient	0.45	0.45	psi/ft
ID of Prod Tubing	1.995	1.995	in
OD of the Prod Tubing	2.375	2.375	in
ID of Casing	3.83	3.83	in
Depth to Plunger (D)	4500	4500	ft
Tubing Head Pressure (Pwh)	540	650	psi
Pressure in Reservoir	1200	1200	psi
Gas compressibility factor in average tubing (Z)	0.88	0.88	
Average Temperature (Tavg)	98	105	F^0
Plunger Weight (Wp)	20	20	lbf
Plunger Falling Velocity in Gas (Vfg)	500	500	ft/min
Plunger Falling Velocity in Liquid (Vfl)	200	200	ft/min
Plunger Rising Velocity (Vr)	1200	1200	ft/min
Slug Volume	2	2	bbl

Data Processing Analysis

The research was carried out on well A1 and well A2 in field B. This is qualitative research with literature studies related to liquid loading analysis, sandiness, and countermeasures, namely by collecting field data information on well data, production data in the form of literature books, journals, theses, as well as a final project and other modules related to liquid loading and plunger lift.

Calculation and Data Analysis

Turner method is used for calculating the critical flow rate. If the critical flow rate is below the actual flow rate in the field, then liquid loading occurs, and if the critical gas flow rate is above the actual field flow rate, then liquid loading does not occur in the well.

Critical Gas Flow Rate Calculation Procedure

Prepare Data:

1. Specific gravity of gases
2. Pipe diameter, d (inch)
3. Temperature, (°F)
4. Pressure at the wellhead, Pwh (psi)
5. Tubing Size

Calculate Vcg

Vc gas= 5.62 〖(67-00031P)〗^(1/4)/〖(00031P)〗^(1/2) ft/sec

Where:

Vcg = critical gas velocity, ft/sec

P = Pressure at the wellhead, Psi

Calculate the area of the channel.

A = π /4 d^2

Calculate the Critical flow rate.

Qgc = (3.06P Vg Pwh)/TZ

Where:

T = Surface temperature, °F

Vg = Gas velocity, ft/sec

Z = gas compressibility factor, fraction

Pwh(P) = Flow pressure at the wellhead, Psi

dt = tube ID

Overcoming Liquid Loading

The plunger lift system is a method to increase the production of gas that drops due to liquid loading. It is a cost-effective alternative because it does not require an external energy source. The plunger works to reduce the fallback of liquid slug when they rise with the gas pressure above it (Garg, 2004). Plunger lift is a liquid loading solution that uses the energy of a gas reservoir to generate liquid that collects in the bottom hole.

The plunger is a type of piston that moves freely in the tubing string and fits according to the inner diameter of the pipe. The plunger moves up when the well pressure is sufficient to lift it and then moves back down due to the force of gravity. Plunger installations operate as a cyclic cycle as well pressure builds up during closure and flows when pressure is sufficient to lift. During the closing period, the plunger is at the bottom of the spring assembly, gas pressure accumulates in the annulus, and liquid accumulates at the bottom of the tubing. Pressure accumulates in the annulus. Depends on different parameters such as closure period, reservoir pressure, and reservoir rock permeability. Plunger lift is a low-cost, high-efficiency artificial lift method for gas wells especially used for wells that have high gas-liquid ratio (GLR) ((Marques De Jesus Junior et al., 2018).

RESULTS AND DISCUSSION

This study discusses the problems that occur in gas production wells, namely liquid loading, and sandiness. This term refers to the production process that occurs in gas wells which also produces liquid and sand to the surface. This liquid production makes the flow rate of gas well production slowly decrease due to the accumulation of liquid and sand and even makes gas wells uneconomical to produce. Therefore, in the following, we will discuss the analysis of liquid loading and sand in the gas production wells A1 and A2 and their countermeasures using the plunger lift method.

Well A1 produces 5 MMSCFD gas, and Well A2 produces 3 MMSCFD gas. This well continues to produce, and in 2017 there has been a decline in production until now. The decrease in gas production is seen in the production of liquid and sand. This must be followed up immediately because the decline in gas production is getting bigger. For this reason, it is necessary to carry out calculations and analyses on liquid loading and

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sand in the A1 and A2 wells. The handling of liquid loading and sandiness can be done by using a plunger lift, an artificial lift tool that works to lift liquid and sand from the bottom of the well.

To determine whether liquid loading occurs, it can be determined by analyzing the critical flow rate in the well. This method was then further developed to obtain an analysis that indeed showed that there was indeed liquid loading, as can be seen from the results of the calculations below,

Well A1:

With P = 540 psia, T = 105 oF, SG gas = 0.9 we get z = 0.88

A= π /4 d^2=0.08 〖ft〗^2

Q_gc= (3.06pV_(c gas) A)/Tz=2.7 MMSCFD

Pwh 540 psia

Tubing 3.5

Tubing ID 3.83

Twh 98 F

SGgas 0.9

gas velocity 12.35 ft/s

z factor 0.88

A 0.08001 ft2

Qg 3.3 MMSCFPD

It was found that the critical gas flow rate was 3.3 MMSCFPD, while the actual gas flow rate was at

well A1 of 5 MMSCFPD, based on the results of this calculation on Well A1 liquid loading does not occur, because the critical flow rate is smaller than the actual flow in the field.

Well A2:

Pwh 650psi 650psi

3.5 Inch Tubing

Tubing ID 3.83inch

Twh 105 oF F

SGgas 0.9

gas velocity 11.24 ft/s

z factor 0.88

A 0.080 ft2

Qg 3.6 MMSCFPD

With P = 650 psia, T = 105 oF, SG gas = 0.9, z = 0.88

A= π /4 d^2=0.08 〖ft〗^2

Q_gc= (3.06pV_(c gas) A)/Tz=3,6 MMSCFD

The critical gas flow rate is 3.6 MMSCFD, while the gas flow rate in well A2 is 3 MMSCFD. Based on the results of this calculation, liquid loading occurs in well A2, because the critical flow rate is greater than the actual flow in the field. To overcome liquid loading in the Well A2, an artificial lift is used, which in this study uses a plunger lift. The workings of the plunger lift have been described in the previous chapter, where liquid loading and sand can be lifted together. The sand that is produced often damages the compressor engine, thus disrupting the rate of gas production. The use of a plunger in gas wells is considered effective even though the liquid removal to the surface is still low. The movement speed of the plunger, both during the lifting and falling process, is slower than the normal lifting parameters. This is due to the fact that the pressure in the well is low, causing the plunger speed to slow down, which results when the plunger falls, the plunger speed slows down.

After overcoming liquid loading and sandiness using a plunger lift on the A2 gas well, based on observations, the gas production rate increased from 3 MMSCPD to 4 MMSCFPD, and the gas production rate increased due to increased gas velocity.

Table 2 Results of Gas Well A1 and A2

Variable	Well A1	Well A2 (before) Plunger Lift	Well A2 (After) Plunger Lift
Gas Rate, MMScf/day	5	3	4
Velocity gas, ft/s	12.35	11.24	12.38
ID of Prod Tubing, inch	1.995	1.995	1.995
OD of the Prod Tubing, inch	2.375	2.375	2.375
ID of Casing, inch	3.83	3.83	3.83
Depth to Plunger (D), ft	4500	4500	4500
Tubing Head Pressure (Pwh), Psi	348	650	600
Pressure in Reservoir, Psi	1200	1200	1200
Gas compressibility factor in average tubing (Z)	0.88	0.88	0.88
Average Temperature (Tavg), F^0	105	90	90
Plunger Weight (Wp), lbf	20	20	20
Plunger Falling Velocity in Gas, ft/min	500	500	500
Plunger Falling Velocity in Liquid, ft/min	200	200	200
Plunger Rising Velocity (Vr), ft/min	1200	1200	1200
Slug Volume, bbl	2	2	2

The sand problem can be proven by the frequent occurrence of compressor damage because sand is also produced with the gas fluid, for liquid loading and sand at the same time it can be overcome with a plunger lift, and to prevent sand deposition at the bottom of the well, it must be overcome by installing slotted screens and gravel packs such as picture below.

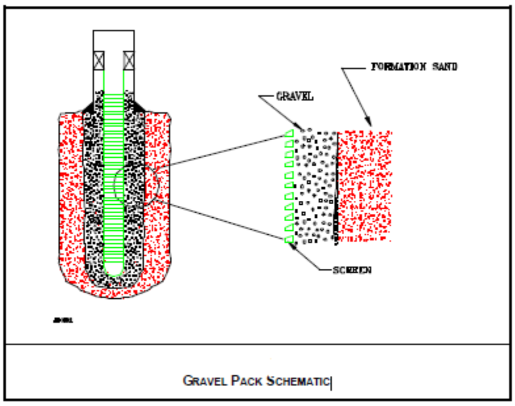

Figure 6. Schematic Gravel Pack and Slotted Screen (Penberthy Jr & Shaughnessy, 1992)

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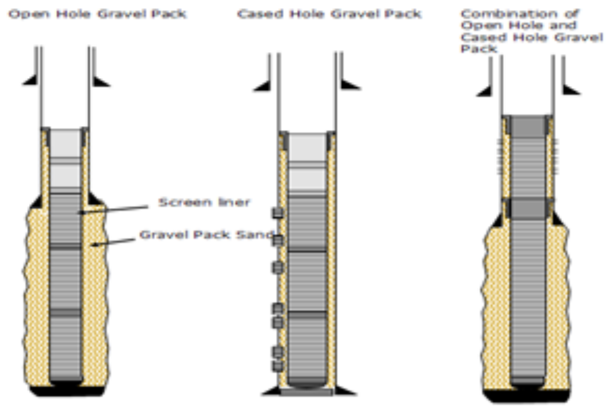

Figure 7. Open Hole, Cased Hole, and Gravel Pack Combination

CONCLUSIONS

Based on the results of the research that has been carried out, several conclusions can be drawn as follows:

1. Based on the calculation results of the critical flow rate in gas well A1 of 3.3 MMSCFPD, and the actual flow rate of 5 MMSCFPD, it means that in well A1 there is no liquid loading. In well A2 the critical flow rate is 3.6 MMSCFPD, and the actual flow rate in the field is 3 MMSCFPD. In well A2 there is liquid loading and sandiness. Sandiness is characterized by frequent damage to the gas separator.
2. Countermeasures for liquid loading and sandiness in well A2 using the plunger lift method. The results of this countermeasure can increase gas production to 4 MMSCFPD with a critical gas flow rate of 3.7 MMSCFPD.

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