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LIQUID LOADING IN WELLBORES AND ITS EFFECT ON CLEANUP PERIOD AND WELL PRODUCTIVITY IN TIGHT GAS SAND RESERVOIRS

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ABSTRACT

Tight gas reservoirs normally have production problems due to very low matrix permeability and significant damage during well drilling, completion, stimulation and production. Therefore they might not flow gas to surface at optimum rates without advanced production improvement techniques.

After well stimulation and fracturing operations, invaded liquids such as filtrate will flow from the reservoir into the wellbore, as gas is produced during well cleanup. In addition, there might be production of condensate with gas. The produced liquids when loaded and re-circulated downhole in wellbores, can significantly reduce the gas production rate and well productivity in tight gas formations.

This paper presents assessments of tight gas reservoir productivity issues related to liquid loading in wellbores using numerical simulation of multiphase flow in deviated and horizontal wells. A field example of production logging in a horizontal well is used to verify reliability of the numerical simulation model outputs. Well production performance modelling is also performed to quantitatively evaluate water loading in a typical tight gas well, and test the water unloading techniques that can improve the well productivity.

The results indicate the effect of downhole liquid loading on well productivity in tight gas reservoirs. It also shows how well cleanup is sped up with the improved well productivity when downhole circulating liquids are lifted using the proposed methods.

KEYWORDS

Tight rock gas reservoir, liquid loading in wellbore, well productivity, production improvement.

INTRODUCTION

In gas producing wells, different downhole flow regimes might be present in a wellbore depending on gas and liquids velocities, and their relative amounts in the wellbore (Guo and Ghalambor, 2005). Under multiphase flow conditions, the light phase moves with a velocity different than the heavier one by a magnitude known as slippage velocity (Kappa Engineering Team, 2005). In a deviated wellbore, the lighter phase flows at the top side of the wellbore, and water as the heaver phase stays at the bottom side. The typical velocity profiles in horizontal wells in different deviations are shown in Figure 1. The density difference of coexisting fluids, the hold-up of liquid (Y_L: the ratio of a given pipe cross section occupied by liquid), and well deviation can control the slippage velocity and flow regimes in multiphase flow in oil and gas wells.

The basic flow regimes that usually represent multiphase flow in a gas well are shown in Figure 2. During progression of a typical gas well from initial production to end of life, one or more of these regimes might be encountered (Lea et al, 2008). In initial conditions, gas flow rate is high and the flow regime is in mist flow, and therefore the produced gas can carry the wellbore liquids to the surface. Then as the reservoir pressure drops, the gas velocity in the wells is declined, causing the carrying capacity of gas to decrease. When the gas velocity is less than a critical level, liquids begin to accumulate and be loaded in the wellbore. The liquid loading can gradually change the downhole flow regimes in a wellbore to annular flow and later to slug flow. Eventually, the well will undergo bubbly flow regime, with no economical production rates (Guo and Ghalambor, 2005).

Liquid loading is a common problem in gas wells, and can be in the form of liquid water and/or condensate. The liquids are loaded in the wellbore and cannot be lifted when the flow rate is less than the minimum gas flow rate and gas velocity is not high enough. As a result, the well's productivity is affected due to the additional drop of pressure in the wellbore where the circulating liquids are present in the wellbore. The liquid circulation makes the well downhole operating conditions unstable.

The carrying capacity of the gas to lift liquid in gas wells depends on the tubular sizes, pressure losses across the wellbore, the surface pressure, the amount of liquids being produced with the gas, wellbore deviation, and the gas composition (Lea et al, 2008; Veeken et al, 2009). A

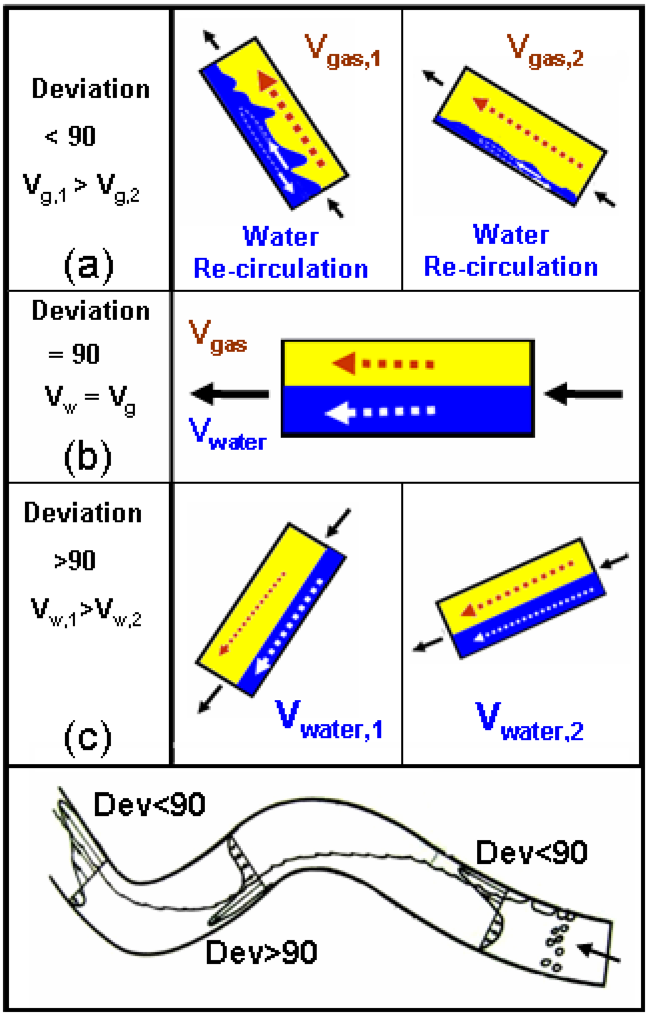

Figure 1. Typical flow regimes in deviated horizontal wells.

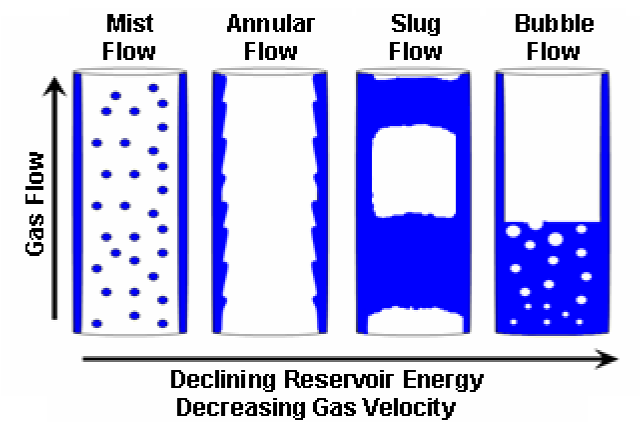

Figure 2. Flow regime changes with decline of reservoir pressure and gas velocity.

sharp decline in the gas production rate can indicate that the liquid column is building up in the well and an additional energy is required to lift the liquids out (Guo and Ghalambor, 2005). If a corrective action is not taken after a liquid loading problem starts, the well production rate will continue to decline and eventually log off (Lea et al, 2008). To reduce liquid loading and modify flow regimes in gas wells, different methods can be employed such as: flowing at a high velocity by use of optimum tubing diameter; creating a lower wellhead pressure using pump; using gas lift to take the liquids out of the well; and using surfactants. Foaming the liquids to reduce water density is also another technique to enable the gas to lift liquids from the well (Lea et al, 2008).

When reservoir energy is low and natural gas flow rate is not high enough to lift the wellbore liquids to the surface, the liquids are loaded in the wellbore and create problems for well productivity. This study aims to evaluate the water loading problem as one the factors that can control productivity of tight gas wells.

CLEANUP IN TIGHT GAS RESERVOIRS

Tight gas reservoirs normally have production problems due to a very low matrix permeability and significant damage during well drilling, completion, stimulation and production. Therefore they might not flow gas to the surface at optimum rates without advanced production improvement techniques (Brant and Brent, 2005).

After well stimulation and fracturing operations, invaded liquids such as filtrate will flow from the reservoir into the wellbore as gas is produced during well cleanup. In addition, there might be production of condensate with gas. The produced liquids when loaded and re-circulated downhole in the wellbore, can significantly reduce the gas production rate and well productivity from tight gas formations. As a field example of tight gas cleanup after stimulation (Shaoul and Koning, 2009), a total of around 2,000 barrels water leaked off into the formation during the fracturing operations, and around 700 barrels of water was produced back during the 35-day cleanup period. In this time period, gas flow rate reduced from 3.5 MMSCFD to 1.5 MMSCFD.

A commercial reservoir simulation software was used to build a reservoir simulation model of a multiple hydraulic fractured tight gas reservoir and study water and gas production behavior during the well cleanup period in case of an efficient stimulation operation. The 3-Dimentional view of the model with hydraulic fractures across the horizontal wellbore in well XX-01 and the model input data are shown in Figure 3 and Table 1 respectively. In the multiple hydraulic fractured tight gas reservoir model, first water was injected for two days to have water invasion, and then the well was put on production to water production behavior as gas is produced.

Dimensionless production rates (Q_d: ratio of production rate to the initial production rate) of water and gas were plotted, as presented in Figure 4. The observations indicated that the very low permeability in the tight gas

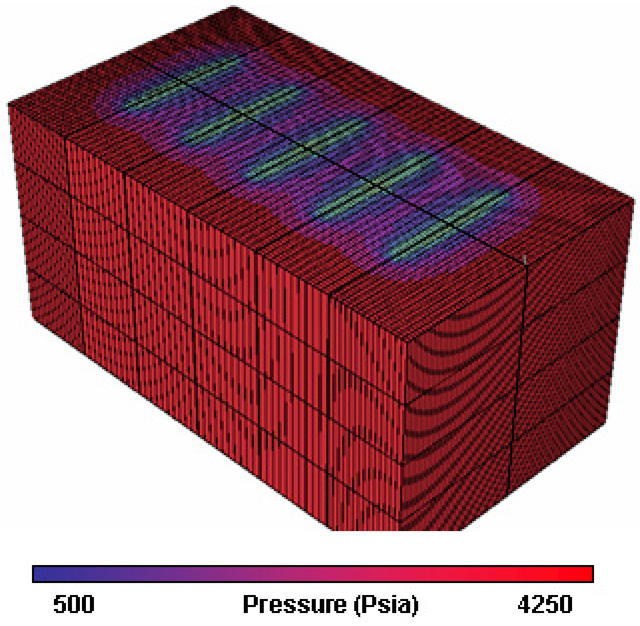

Figure 3. The 3-D view of the tight gas simulation model, with 5 hydraulic fractures perpendicular to the horizontal leg.

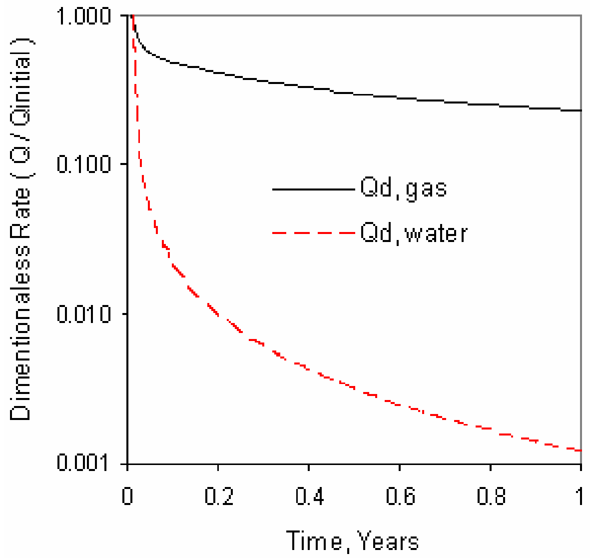

Figure 4. A typical gas and water production behavior during cleanup of the stimulated tight gas reservoir.

reservoir made the cleanup period last for a relatively long period of time. The effect of relative permeability and capillary pressure curves is also an important consideration, since they can have significant impact on the amounts of produced water from an invaded zone. The cleanup of invaded liquids might take a few months or even up to one year, depending on reservoir permeability. Knowing that the gas production rate and driving energy normally declines in tight gas reservoirs sharply, the presence of produced liquids in gas flow in such wells especially in deviated sections may cause the well to face a liquid loading problem and not produce to its maximum gas deliverability potential.

Table 1. Input parameters in reservoir simulation model of well XX-01.

Porosity	%	5
Permeability	md	0.002
Reservoir thickness	ft	60
Reservoir pressure	psia	4,250
Horizontal well length	ft	4,000
No. of hydraulic fractures	-	5
Fracture half length	ft	710
Initial gas production rate	MMSCFD	12
Gas production rate after one year	MMSCFD	3

FILED EXAMPLE OF WATER LOADING

A production logging tool with water hold-up measurements sensors was run in the horizontal well YY-01 to evaluate the well's production performance. There was no water production reported at the surface of this well. Figure 5 shows the well trajectory in a vertically zoomed scale (Figs 5a and 5b), the water hold-up (Y_w) data across the horizontal leg (Fig. 5c), and also water hold-up measurement sensor positions on the production logging tool (Fig. 5d). The four water hold-up sensors were mounted on caliper arms to record water hold-up data during the production logging: a probe at the top side of wellbore (probe 1), two probes around middle (probes 2 and 3), and one at the bottom side of the wellbore (probe 4).

As can be seen in Figure 5c, from point A to point D, wellbore deviation varies between 89 and 92 degrees, and no significant water loading was detected by hold-up sensors. From point D to point E where deviation changes to 85, significant amounts of water were detected by production logging water hold-up sensors. In this interval, the bottom probes 3 and 4 read almost 100% water (Y_w=1), whereas top probes 1 and 2 read mainly hydrocarbon (Y_w=0).

The results indicate that there is re-circulation of water downhole and the well faces a water loading problem, although no water was coming to the surface at the time of logging. In low productivity gas wells—especially when they are deviated or horizontal—evaluating production performance using production logs can help detect possible liquid loading, which in such cases can provide an option for improving well productivity.

NUMERICAL SIMULATION OF LIQUID LOADING

Multi-phase flow is a very complex physical phenomenon, in which different phases travel with different speeds depending on the difference between density of phases, hold-up of each phase, and the wellbore deviation. In multiphase flow, the liquid-gas contact line is not stable due to the presence of a disturbed interfaces (e.g. surface waves on a falling film, or large, highly deformable drops or bubbles) and since there is transition between different gas-liquid flow regimes. The difficult physical laws and mathematical treatment of phenomena occurring in the presence of the two phases (the interface dynamics, drag, etc.) are still largely undeveloped, causing some uncertainties in results of simulation models (Ghorai, 2008). In this study, the numerical simulation approach was used to qualitatively model water loading in a gas well.

A series of simulation runs were carried out using a commercial computational fluids dynamics (CFD) simulation software, which solved continuity and momentum equations for a deviated horizontal wellbore with two phase flow of gas-water. The input data into the model are presented in Table 2. The data similar to well YY-01 were input to have a model that is calibrated with an actual case and therefore have appropriate selection of equations in the software. Figure 6 shows qualitative results from the simulation model of 20 MMSCFD gas flow with 0.99 gas fraction. The results indicate water loading in deviations below 90 degrees. Section B-C with deviation of 89.5° showed very small amounts of water loaded in the lower side of the wellbore. In section D-E with deviation of 85°, significant amounts of water loading was observed in wellbore. The results from the simulation were approximately in agreement with observations in well YY-01 water loading conditions, confirming the reliability of the model in terms of water loading prediction. This model was used as the base model, to perform sensitivity analysis.

Figures 7a and 7b show water loading when the gas flow rate is reduced to 4 MMSCFD and 1 MMSCFD, which indicates the well will have more severe water loading problem in lower gas flow rates. Based on simulation results, in addition to the sharp decline of drive energy and gas flow rate with time in tight gas sand reservoirs, when there is water re-circulation downhole in wellbore, the loading of the considerable amounts of water can cause more deterioration of well productivity with passage of time. Therefore in addition to the declining production rate, liquid loading can cause further reductions in productivity of tight gas wells.

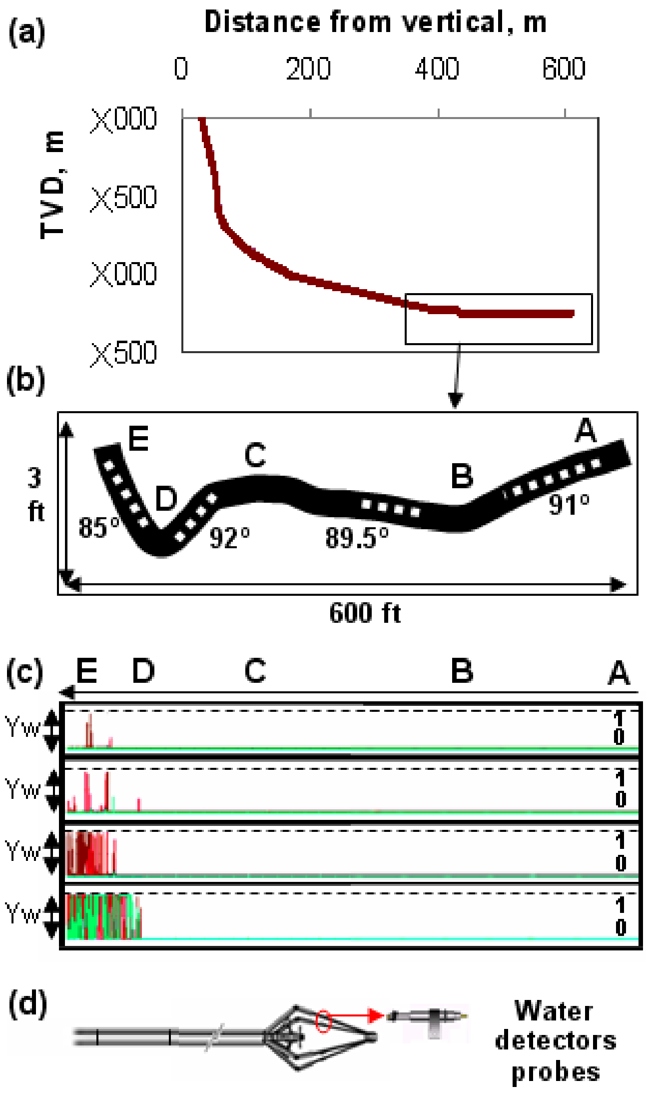

Figure 5. Production logging tool water holdup readings in the horizontal well YY-01.

PRODUCTIVITY IMPROVEMENT BY WATER UNLOADING

Well production performance modelling was performed using a commercial multiphase flow simulator software to evaluate water loading in the typical tight gas well ZZ-01, and to test the water unloading techniques and improve the well productivity. Table 3 shows model input data. First, several cases were run as sensitivity analysis

Table 2. Input data to the CFD simulation model of fluid flow in wellbore, based on well YY-01 data.

Horizontal well length in the model	ft	600
Wellbore ID	Inches	6.2
Operating pressure	psia	5,000
Downhole gas density	kg/m³	140
Downhole gas viscosity	cp	0.0204
Downhole water density	kg/m³	1,006
Downhole water viscosity	cp	0.3
Primary fluid in wellbore	-	Water
No. of cells in the model	-	236,000
No. of nodes in the model	-	248,000
No of iterations in each simulation run	-	5,000

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in order to select appropriate models and equations for flow regime and critical unloading velocity options in the software. Due to a low gas production rate, some models were insensitive to the changes in well parameters, some were too sensitive, and some gave unrealistic results. After sensitivity analyses were completed, finally the Hagedorn and Brown flow model and the Coleman critical unloading velocity were selected in the base model, as they provided more reasonable results in the sensitivity analysis runs.

Figure 8 shows inflow performance relationship (IPR) and tubing performance relationship (TPR) curves, and the liquid loading (LL) line that resulted from the well performance modelling results. The well operating point, which is the intersection of IPR and TPR curves, shows that the well can produce with a flow rate of 2.55 MMSCFD. The liquid loading line indicates that a minimum gas flow rate to avoid water loading is around 2.65 MMSCFD. In other words, the well has a water loading problem under these well and reservoir conditions.

Different water unloading techniques were considered to improve the wells productivity. Figure 9 shows the use of a water foaming system in which water density is reduced from 1 gr/cc to 0.8 gr/cc. Using the system, the line showing the minimum gas flow rate to avoid water loading was moved from 2.55 MMSCFD [LL1] to 2.52 MMSCFD [LL2], which means water can be unloaded using the technique. The water unloading might result in slight productivity improvement at this stage, however the main objective is removing the water from the wellbore to improve well productivity in the long term. The liquid loading predication results also indicate that if the mud had been selected as oil-based mud instead of water-based mud, the well would not have faced the liquid loading problem since oil has less density than water.

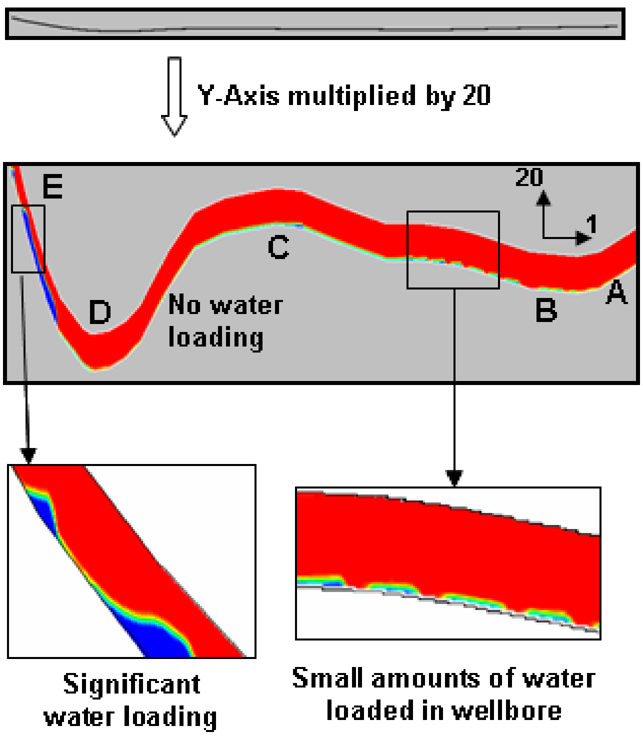

Figure 6. Preliminary model qualitative simulation results in case of 20 MMSCFD gas flow rate. Water loading results approximately calibrated with well YY-01 water loading (Y-Axis multiplied by 20 to better visualise the simulation results).

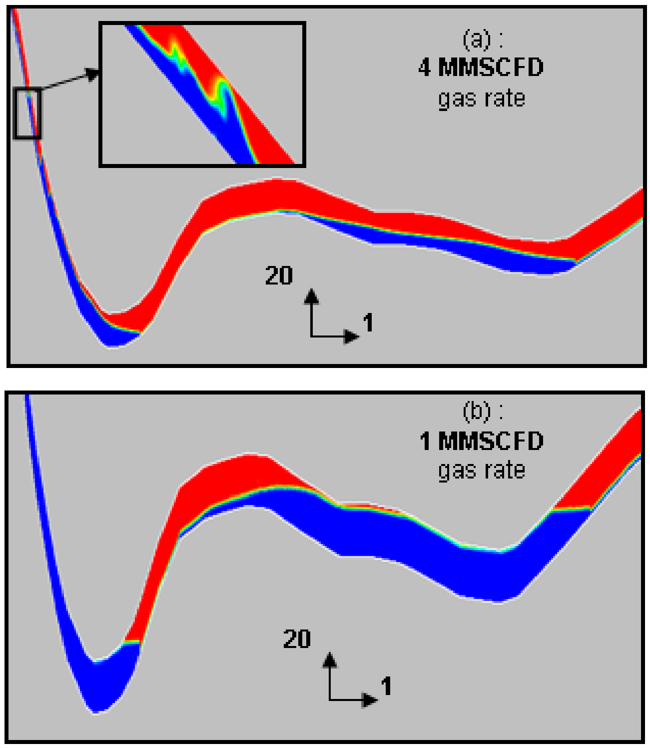

Figure 7. Sensitivity analysis to evaluate effect of gas flow rate on water loading in well YY-01 (Y-Axis multiplied by 20 to better visualise the simulation results).

Table 3. Input data used for well performance modelling of well ZZ-01 in the stimulated tight gas reservoir.

Porosity	%	7
Permeability	md	0.01
Skin	-	-3
Reservoir pressure	psia	5,000
Reservoir thickness	ft	300
Horizontal well length	ft	1,000
Initial gas production rate	MMSCFD	12
Tubing ID	inch	4
Initial water gas ratio	STB/ MMSCF	20
Gas S.G. (air=1)	-	0.65
Water density	Kg/m^3	1,000

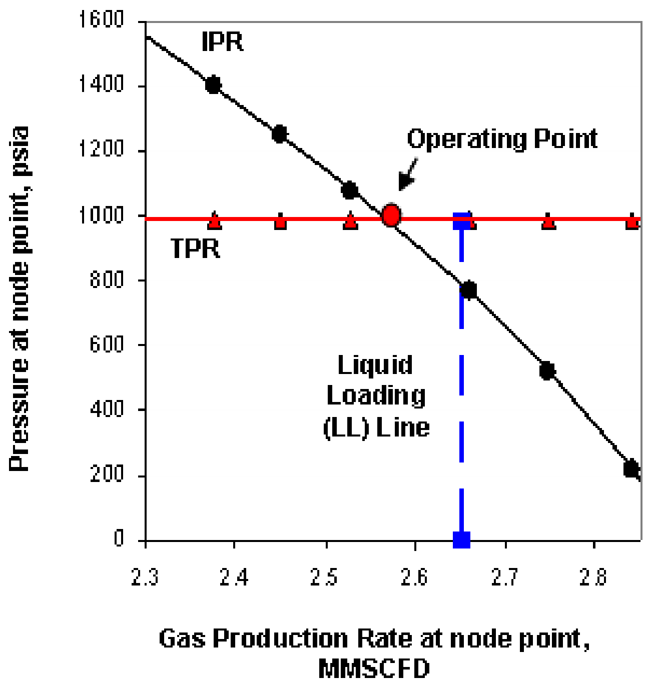

Figure 8. Well performance modelling results of water loading in well ZZ-01.

Figure 10 shows use of tubing size optimisation for water unloading. In this case, a 2.8-inch coiled tubing is run inside 4-inch ID well tubing. As a result of the reduction in area in the wellbore and an increase in gas velocity, the minimum gas flow rate to avoid water loading is reduced from 2.55 MMSCFD [LL1] to 1.32 MMSCFD [LL2]. In other words, successful removal of water from the wellbore and a single phase gas production can be achieved using the system; however, it should be noted that due to a reduction in the wellbore flowing area, there is a slight decrease in the gas production rate using the method. When using the coiled tubing system, gas injection into the coiled tubing can also be considered to enhance the process of water lifting to the surface and to unload the well from circulating liquids downhole.

DISCUSSION

Water loading can be an important factor in controlling the productivity of tight gas reservoirs, especially in late time when the reservoir driving energy and gas flow rate declines. Based on the simulation and modelling study, to have optimum productivity in tight gas reservoirs it is important to minimise the amounts of water or other liquids to be invaded into the reservoir matrix and fracture during drilling and well completion. The tight gas strategy is recommended to be focussed on under-balanced drilling to reduce the damage to near wellbore region by liquid

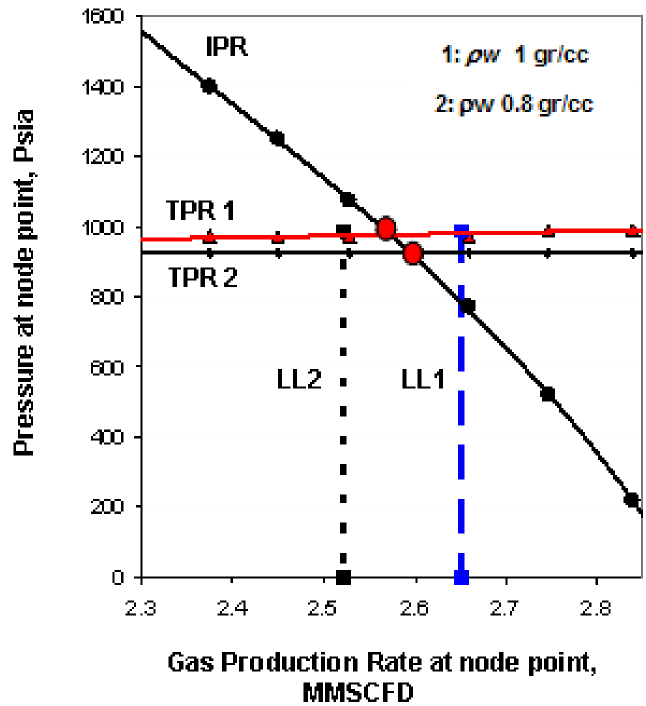

Figure 9. Well performance modelling results of water unloading in well ZZ-01 for reduced liquid density.

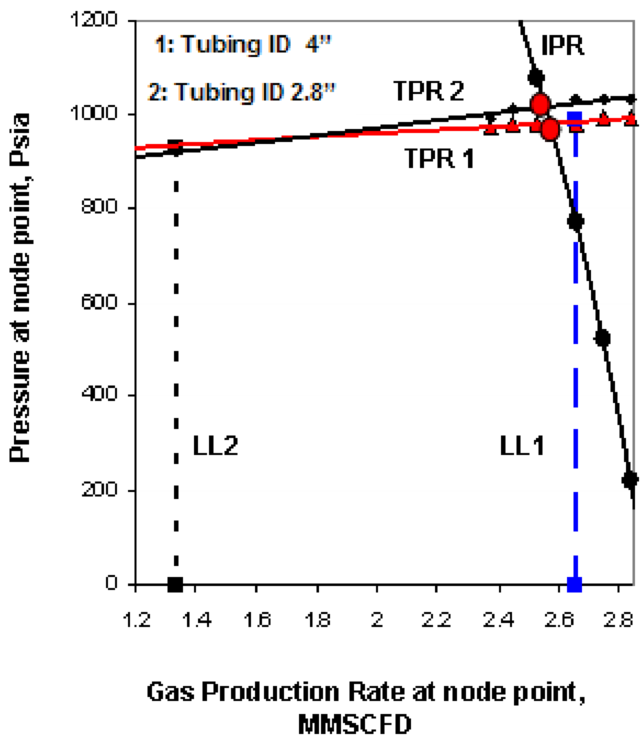

Figure 10. Well performance modelling results of water unloading in well ZZ-01 for optimised tubing size.

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invasion, and also lessen the significant amounts of water filtrate production during cleanup.

Tubing size optimisation can help in production at optimum gas velocity. During the cleanup period of tight gas wells, a coiled tubing can be temporarily run in the wellbore through the well tubing to lessen the wellbore area and increase gas velocity to lift the circulating liquids downhole. Partially injection of the produced gas to the bottom of the well via the coiled tubing can further improve the water unloading process. After the cleanup process is completed, the coiled tubing can be removed and the well can continue with normal production.

The use of an oil-based mud system can also help reduce the detrimental impact of liquid loading on tight gas wells' productivity. As shown for well ZZ-01, the well could have no liquid loading problem if the invaded liquid was oil (density of 0.8 gr/cc), instead of water filtrate (1 gr/cc filtrate density). Use of the oil-based mud system can also reduce the problems related to shale intervals.

To further reduce damages to formation and avoid any liquid loading, feasibility of drilling using foam or gas needs to be studied for tight gas reservoirs. Theoretically, this approach can help the well to produce to its maximum potential, since near wellbore reservoir region is exposed to the lowest damage and there will be no liquid in the wellbore.

CONCLUSION

According to the simulation modelling results performed in the study for stimulated gas wells in tight sand reservoirs, there might be significant production of filtrate with gas during the cleanup period, which can cause a water loading problem. The very low permeability in the tight gas reservoirs result in a long clean-up period.

A tight gas well might have a water loading problem downhole, although no water may come to the surface. Production logging in tight gas wells can help detect possible liquid loading in the wellbore.

Water loading can have a negative impact on the productivity of gas wells in tight formations, especially in late time when gas flow rate declines. Therefore in addition to the decline of production rate in late time production history of a gas well, the liquid loading can cause a further reduction in a well's productivity.

The use of an oil-based mud system instead of water-based mud during the drilling of tight sand formations can help reduce liquid loading problems in a wellbore, since oil has less density than water.

Tubing size optimisation and the use of foaming agents can help unload re-circulating liquids. As a result, the clean-up period can be sped up and productivity is improved.

NOMENCLATURE

P	Pressure
Y_w	Water hold-up
Y_g	Gas hold-up
Q	Flow rate
ρ_w	Water density
ρ_g	Gas density
μ	Viscosity
V	Velocity
ID	Internal diameter
t	Time
K	Permeability
S	Skin
L	Length
WGR	Water gas ratio
$MMSCFD$	Million standard cubic feet per day

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APPEA