Influence of the top pressure on water removal from a vertical tube in a two-phase flow regime

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Abstract. The purpose of this work is to highlight the effects of wellhead pressure on the removal of water from its bottom. Tests were therefore carried out in a simulation laboratory on a test section represented by a vertical tube 600 mm long and 37 mm in diameter. It was therefore a question of working on a two-phase flow with air as gas and water as liquid. The velocity of the air injected into the tube was calculated taking into account the top and bottom pressures of the vertical tube. Related measurements and calculations were carried out and conclusions were drawn on the impact of the tube top pressure on the removal of water from the tube bottom, all by analogy to vertical gas extraction wells.

1 Introduction

The objective of this study is to simulate in a two-phase flow environment the conditions for a removal of water from the bottom of vertical a vertical annulus which can represent a gas well.

In their initial phase, at the beginning of exploitation, gas wells benefit from the natural flow, the energy of which is high enough to allow effective production. For wells that already have a long production period, the natural energy of the reservoir becomes insufficient to overcome the weight of the column of fluid inside the well and to deliver the fluid to the surface.

Some analyzes [1, 2] based on data from exploitation reports show that in the Urengoy Cenomanian gas field 37% of the total stock of existing gas wells have an operating flow rate which does not allow sustainable recovery of fluids from the bottom of the well, and 13% slightly exceeds the required minimum, which leads to estimate that in the near future the stable operation and productivity of the wells will be ensured with difficulty. From the other side, the impact of self-preserving wells on total daily production is very high. At the same time, the share of gas production from self-preserving wells is 26% of the total production volume, and from wells that will become self-preserving in the near future -13% [3]. In Yamburg Cenomanian gas field it was found that 7.4% of gas some treatment units producing wells will tend to self-stalling after their flow rate has decreased by a range of 0-25 thous. m^3/day; another 10.8% of wells will cease to carry fluid when the flow rate decreases by 25-50 thous. m3/day [4].

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According to the above forecasts, the number of self-damping wells of the Urengoy oil and gas condensate field will be about 500 by 2030, or 72% of the entire well stock of the Cenomanian deposit of the Urengoyskoye oil and gas condensate field [1].

For the Yambourg deposit, from 2001 to 2021 there was a rise in the gas-water contact level of more than 25 meters [5].

This problem is also relevant for many other fields, such as the Orenburgskoye, Medvezhye, Vyngapurovskoye, Vuktylskoye, etc. At the same time, the accumulation of fluid at the bottomhole and the retirement of wells from the operating stock do not allow achieving high hydrocarbon recovery from the reservoirs.

In order to limit, as much as possible, the effects water influx caused by the reduction in the reservoir pressure and resulting in large losses of gas reserves and significant complications in the exploitation of the well, it therefore becomes necessary to resort to technical resolutions of water removal from gas well downhole.

It is under these conditions that artificial lifting methods can be used to maintain the well in an economically profitable state of productivity.

Gas production can be stimulated by the injection of artificial gas which at the same time can be beneficial in removing accumulated liquids from the bottom of the well. The effective operation of a flowing gas extraction well is also profoundly influenced by the gas injection pressure.

The experiments carried out so far as well as the well-stocked literature which results from them demonstrate the importance of the question regarding the wellhead pressure and the resulting energy loss [6]–[11].

2 Experimental set up and procedure

Figure 1(a) shows the setup set up for this study in the Mining Machinery and Equipment Laboratory of RUDN University. The test section supported by a vertical mount corresponds to a transparent quartz glass tube 37 mm in internal diameter and 600 mm in length.

Air and water were used as working fluids.

The water supply was provided by the university's water pipe network to supply the water pump. The injected gas (air) was produced at the required pressure by a compressor and the gas flow was measured by a differential manometer. The two fluids were injected into the test section (quartz glass tube) through their respective inlets located at the base of the tube without prior mixing of said fluids. The connections of the water and gas pipes have been made by a tee-connection mechanism as shown in Figure 1(b).

When entering from the base into the test section, the initial massive water was transformed by a nozzle into fine dispersed droplets [3]. At the top of the test tube there was installed a valve which served to regulate head pressure. The water having been removed by the top was channeled by a pipe towards a reservoir tank. A hydroaccumulator was connected to the water pump in order to supply the latter, while a water meter installed after the pump allowed the volume of water injected to be determined.

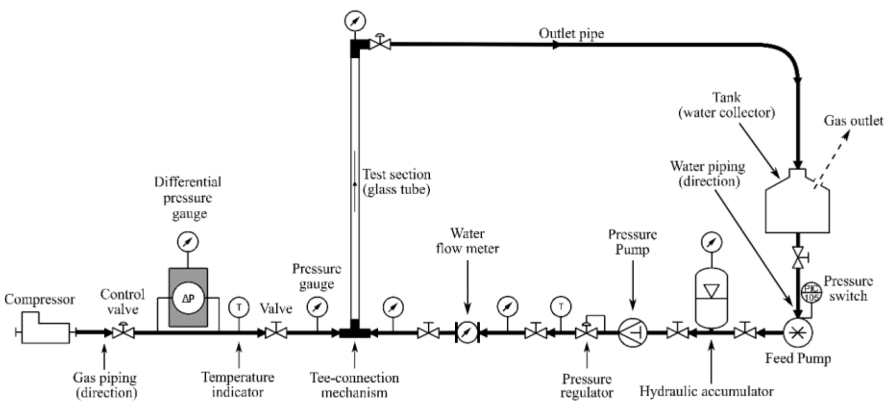
The gas (air) injected into the pipe by the air compressor, and landing on the t-connection mechanism, penetrated the test section in order to raise the injected water from the bottom of the tube to its top in order to reroute the latter to the water collector.

Water and air flow rates were changed by adjusting the pressure regulator at the outlet of the pressure pump and the control valve at the inlet of the differential manometer.

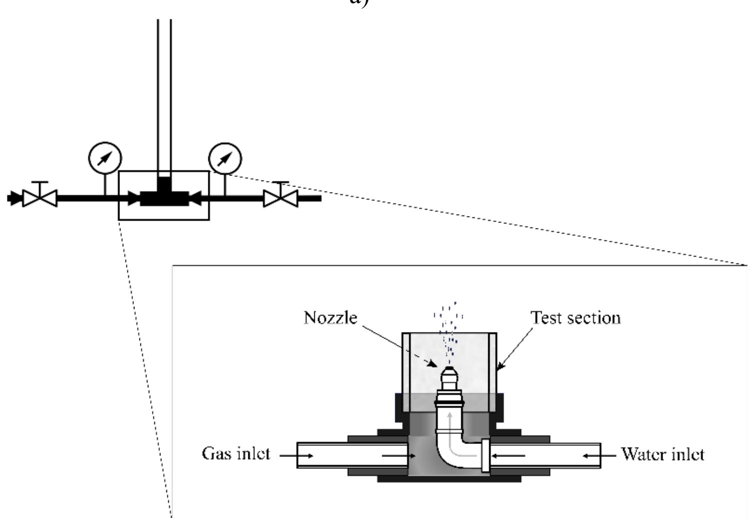
The pumped water was injected into the test section through a nozzle whose 1.9 mm hole allowed the velocity of the injected water to increase considerably from 0.024 to 54.827 m/s in the form of fine droplets.

This involved on the one hand measuring the gas and water pressures respectively at the inlet of the glass tube, as well as the pressure at the outlet (representing the pressure at the wellhead), and on the other hand measure the volume of water injected and removed by a precise volume of gas.

Apart from the wellhead pressure, the operating conditions of a gas-lift well are specified by other parameters such as the properties of the fluids (crude oil and injected gas), the average pressure of the reservoir, the geometry of the well, the size and depth of the gas valve, the rate of gas injected. Thus, during the experiments, the settings of the installation (dimensions and angle of inclination of the test section) were not modified, nor the characteristics of the fluids (pressure and flow rate of the gas injected, nor the flow rate gas).



a)



b)

Fig. 1. Schematic of the vertical test section (a) and the tee-connection mechanism (b).

The operating conditions of a gas-lift well are specified by the following parameters:

- Fluid properties (crude oil and injected gas).
- Average reservoir pressure.

- Well geometry.
- Wellhead pressure.
- Gas-lift valve size.
- Gas-lift valve depth.
- Injected gas rate.

During the experiments, the installation settings were not changed, neither the injected gas pressure, the gas flow rate, the tubing size.

3 Results and interpretation

A graph was made that plotted gas pressure drops in the system versus volumetric gas flow (Figure 2). In this figure it can be seen that the volumetric gas flow is proportional to the square of the pressure drop, which indicates that the regime is turbulent. The Reynolds number varies between 77119.66 and 27268.83.

In order to calculate the superficial gas velocity, it was necessary to define a coordinate system having the vertical test section as its axis [12]. The positive direction for this coordinate system along the tube is the same as that of force of gravity, which is opposite to fluid injection, ie from top to bottom of the tube.

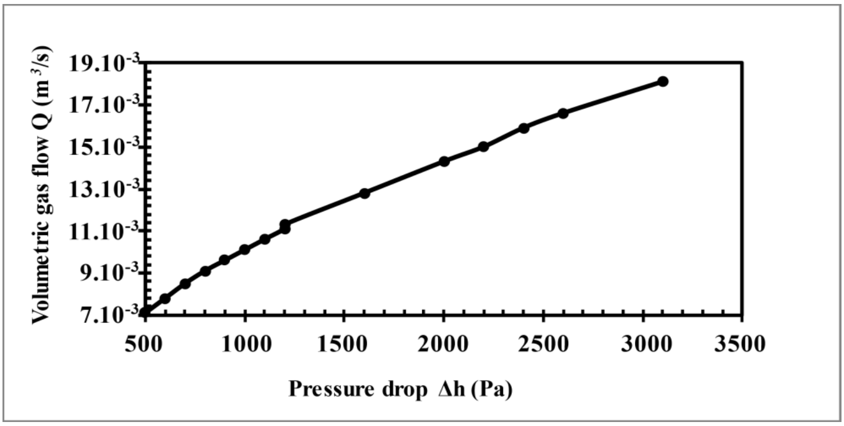


Fig. 2. Volumetric gas flow variation with pressure drops.

For one-dimensional steady flow, the continuity equation is:

$$\frac{d(\rho v)}{dx} = 0 \tag{1}$$

Where, p is the density of air, (kg/m^3); v is the superficial velocity, (m/s); x is tube coordinates, (m).

Knowing that the gas flows from the bottom to the top of the tube considered as a production well, the equation of motion will be:

$$\frac{dP}{dx} = \rho g - \rho v \frac{dv}{dx} + \lambda v^2 \frac{\rho}{2D} \tag{2}$$

Where, P is the pressure of fluid, (Pa); g is acceleration of gravity, (m/s^2); λ is friction coefficient; D is the interior diameter of vertical tube, (m).

The gravity term, which is the first term on the right side of equation (2) reflects the gravity of the gas over the pressure gradient. The second term is called the acceleration term, while the third term is the friction term.

Considering that the equation of state of gas is:

$$\rho = \frac{PM}{ZRT} \tag{3}$$

Where, Z is the deviation factor or compression factor; R is universal gas constant, (J/mol·K); T is thermodynamic temperature, (K); M is gas molar mass, (kg/mol), we can get from equation (1):

$$\rho v = C \tag{4}$$

Where, C is constant, independent of tube coordinates. The physical meaning of C is the mass flow rate of the vertical tube. If we combine equations (3) and (4), we obtain:

$$v = \frac{CZRT}{PM} \tag{5}$$

By merging the equations (2), (3) and (5), we obtain the differential equation of the pressure P, which makes it possible to calculate the pressure at the top of the tube:

$$\frac{dP}{dx} = g\frac{PM}{RTZ} - \frac{C^2RT}{M}\frac{d}{dx}\left(\frac{Z}{P}\right) + \frac{\lambda C^2RT}{2D}\frac{Z}{PM} \tag{6}$$

From equation (6), an ordinary differential equation on the pressure P is obtained by:

$$\frac{dP}{dx} = g\frac{PM}{RTZ} - \frac{C^2RT}{M}\frac{d}{dx}Z\left(\frac{1}{P}\right) + \frac{\lambda C^2RT}{2D}\frac{Z}{PM} \tag{7}$$

i.e

$$\left(1 - \frac{C^2RT}{MP^2}Z\right)\frac{dP}{dx} = g\frac{PM}{RTZ} + \frac{\lambda C^2RT}{2D}\frac{Z}{PM} \tag{8}$$

Backward finite difference method is applied to solve equation (8). To get the difference format of equation (8), the above segment has been divided into micro-segments as:

$$\left(1 - \frac{C^2RT}{MP^2}Z\right)\frac{P_{k+1} - P_k}{\Delta_x} = g\frac{P_kM}{RTZ} + \frac{\lambda C^2RT}{2D}\frac{Z}{PM} \tag{9}$$

Rearranging (9) yields:

$$P_{k+1} = P_k + \left(\Delta_x g\frac{P_kM}{RTZ} + \frac{\Delta_x\lambda C^2RT}{2D}\frac{Z}{PM}\right)\Big/\left(1 - \frac{C^2RT}{MP_k^2}Z\right) \tag{10}$$

Thus, when combining on the one hand equalities (3), (4), (5) in (10), and considering on the other hand the top pressure of the tube P_k as P_t, and the bottom pressure of the tube P_{k+1} as P_b, we get respectively:

$$P_{k+1} = P_k + \left(\Delta_x g\rho + \frac{\Delta_x \lambda \rho v^2}{2D}\right) \Big/ \left(1 - \frac{\rho v^2}{P_k}\right) \tag{11}$$

And

$$P_b = P_t + \left(\Delta_x g\rho + \frac{\Delta_x \lambda \rho v^2}{2D}\right) \Big/ \left(1 - \frac{\rho v^2}{P_t}\right) \tag{12}$$

From equation (12) we get the superficial velocity of gas which integrates top and bottom tube pressures.

$$v_{sg} = \sqrt{\frac{2DP_t(P_b - P_t - \Delta_x g\rho)}{P_t(\Delta_x \lambda \rho) + 2D\rho(P_b - P_t)}} \tag{13}$$

On the one hand, Figure 3(a) represents on the abscissa the tube top pressure P_t which is maintained static at 994.10^2 Pa and the values of the tube bottom pressure P_b ranging from 1000.10^2 to 995.10^2 Pa and on the ordinate the values of the superficial gas velocity according to formula (13).

On the other hand, by analogy with Figure 3(a), Figure 3(b) represents the tube top pressure P_t being maintained static at 1496.10^2 Pa and the values of the tube bottom pressure P_b ranging from 1500.10^2 to 1497.10^2 Pa.

In both cases, the top pressure being fixed, the superficial gas velocity varied according to the tube bottom pressure.

In the case with the higher top pressure P_t at 1496.10^2 Pa and despite less significant pressure differences between P_t and P_b, lower gas velocities were observed, resulting in a lower rise in water as well as shown in Figure 3(c-d).

In order to determine the respective average velocities of gas and liquid, the void fraction a had to be calculated. In the literature, many correlations have been proposed to estimate the void fraction of a two-phase flow in vertical tubes. Among them, the Nicklin's correlation has been selected [13]–[15], considering factors such as pipe characteristics, flow direction, pipe inclination and the fluids involved.

The following formulas were therefore considered to calculate the average gas and liquid velocities.

$$v_g = \frac{v_{sg}}{\alpha} \tag{14}$$

$$v_l = \frac{v_{sl}}{1 - \alpha} \tag{15}$$

$$\alpha = \frac{v_{sg}}{C_0(v_{sg} + v_{sl}) + v_{gu}} \tag{16}$$

$$v_{gu} = 0.35\sqrt{gD} \tag{17}$$

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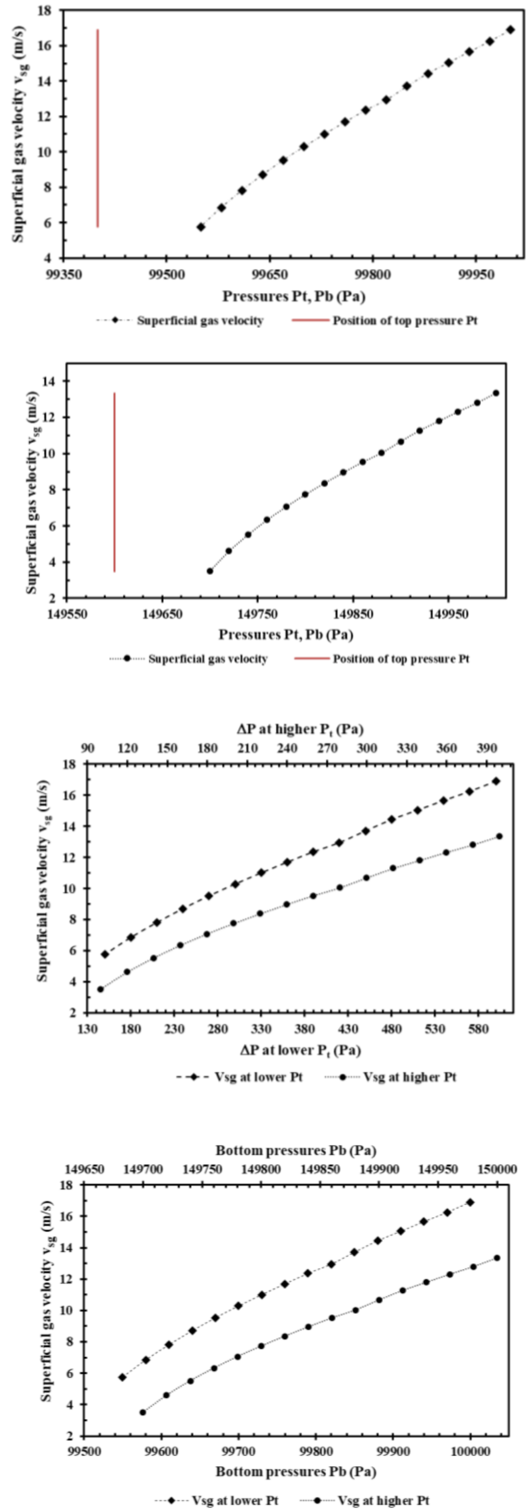

Fig. 3. Superficial gas velocity at two different values of the top pressure P_t.

Where v_g is the average gas velocity, (m/s); v_l is the average liquid velocity, (m/s); α is the void fraction, dimensionless; C_0 is the two-phase distribution parameter, dimensionless; v_{gu} is the gas phase drift velocity, (m/s).

Under the conditions with the tube top pressure equal to 994.10^2 Pa, we obtained average gas velocities ranging from 72,913 to 86,284 m/s, and from 59,528 to 68,182 m/s for the liquid phase.

With the tube top pressure equal to 1496.10^2 Pa, the average velocities were between 70,210 and 82,019 m/s for the gas and 57,709 and 65,482 m/s for the liquid phase.

The velocity of the injected gas being inversely proportional to the rise time of water from the tube bottom to the top of the latter, the water rise time was then between 30 and 44 seconds for the wellhead pressure being 994.10^2 Pa and from 41 to 62 seconds for the wellhead pressure being 1496.10^2 Pa, from higher to lower gas velocities in both conditions.

Figure 4 represents the increasing pressure difference between the top and bottom levels and water removal duration which is going upward as velocity decreases.

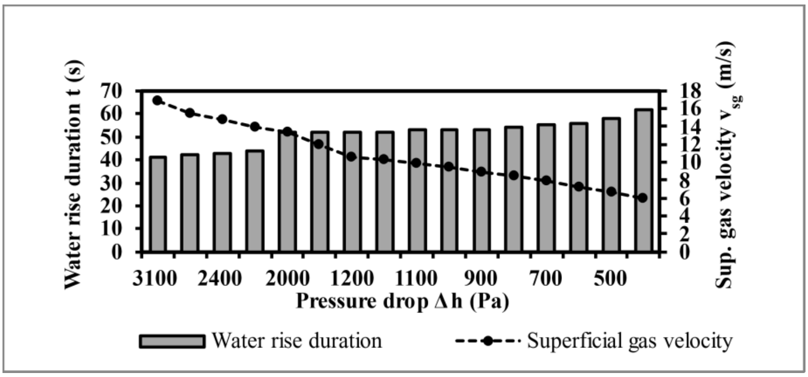

Fig. 4. Duration of lifted water vs gas velocity.

Figure 5 indicates that at a lower head pressure of 994.10^2 Pa, the volume of water removed from the tube is higher than that removed at a higher head pressure (1496.10^2 Pa).

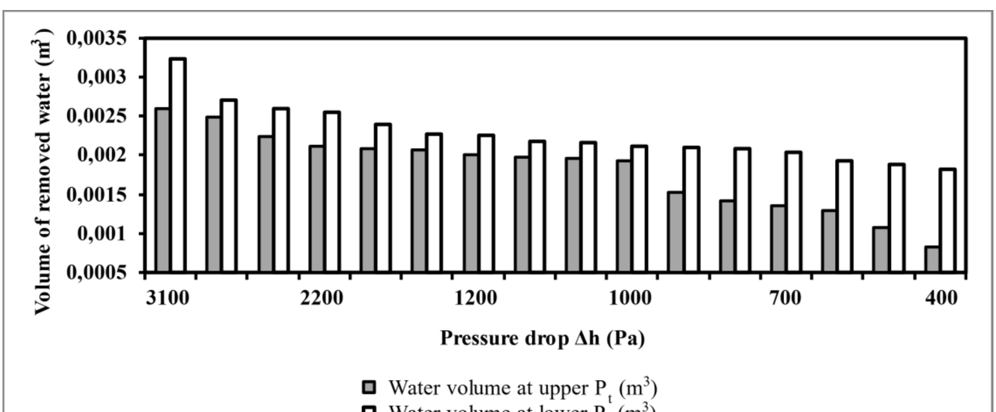

Fig. 5. Volume of water removed from the pipe.

In terms of the ratio, Figure 6 represents the fact that, for the largest gas flow injected into the glass tube at lower head pressure, there was 93.6% water volume removed on the total of water injected into the tube. At higher head pressure, the removed water ratio was 83.5%, a difference of 10.1%.

At lower head pressure, for the smallest gas flow injected into the tube, the water evacuation ratio of the glass tube is 50.6%. Only 26.9% of water volume was removed at higher head pressure for the smaller gas flow injected into the tube. The ratio difference is 23.7%.

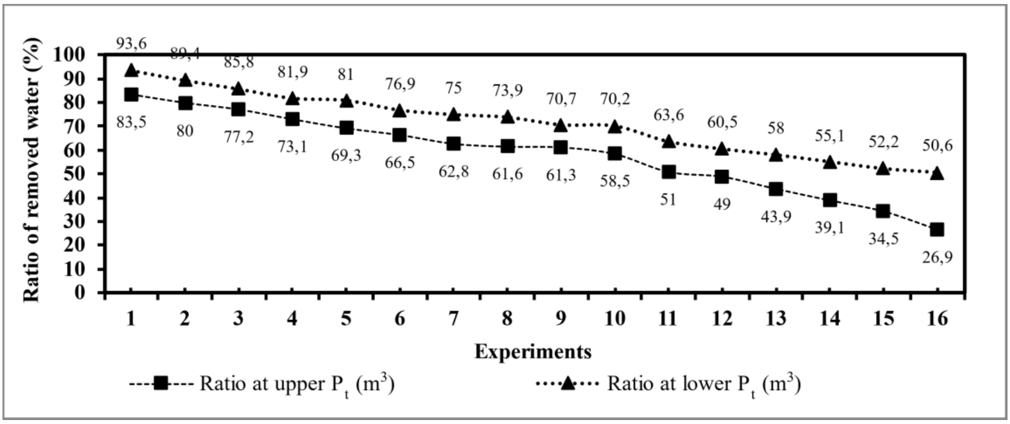

Fig. 6. Ratio of water removed from the vertical tube.

4 Conclusion

The work highlighted the effects of wellhead pressure on the removal of water from its bottomhole. The simulation tests carried out in a two-phase medium on a vertical test section 600 mm long and 37 mm internal diameter made it possible to deduce that with a lower tube top pressure of around 994.10^2 Pa the rate of water removed from the tube was 10.1%. higher than with a higher tube top pressure measured at 1496.10^2 Pa.

It should be noted that the formula developed for the superficial velocity of the injected air, taking into account the top and bottom pressures of the tube, allowed to put in evidence the impact of the two pressures on the gas ascent, and from to on the removal of water from the tube.

The drop in gas velocity, thus leading to an increase in the duration of the rise of the water in the tube, put the accent on the top pressure of the tube.

The comparison in the two conditions of tube top pressure of the gas and liquid velocities, the durations of water rise, the rate of water removal, demonstrates the impact of the tube top pressure on water removal, and the importance of maintaining low pressure for better efficiency during this type of water removal operation.

By analogy to what has been presented in this work, for operations related to gas extraction, of which the removal of water from gas wells is a part, a minimum wellhead pressure would therefore allow a more effective alleviation from the bottom of the well and thereby, an increase in the productivity of the gas well.

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