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Experimental Study of Fluid Flow in Horizontal and Deviated Wells during the Artificial Gas Lift Process

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ABSTRACT

Introduction: One of the main objectives of reservoir engineering studies is to increase the production of hydrocarbon reservoirs with an optimal method. One of the artificial lift methods in wells is the gas lift. This system increases the oil production flow rate by reducing the pressure at the bottom of the well and increasing the pressure at the wellhead. In this method, by injection of high-pressure gas into the well's column, the average density of the well fluid is reduced, and through this, the well is reactivated.
Method: In the current study, the simulation of a gas lift system in the horizontal and inclined wells was investigated. The pressure changes at the end of a simulated pipeline with the ability to change the angle from horizontal to inclined when the continuous fluid is water and the injected fluid in the air is investigated.
Findings: The results obtained from the current study have been investigated by the PIPESIM Software and the GLR parameter sensitivity analysis. The main objective of the current study is to find the optimal flow rate of the injected gas, which is specified after analysis of the figures obtained from the experiment.
Discussion and Conclusion: One of the advantages of conducting this empirical research compared to simulation with PIPESIM Software is that pressure drop fluctuations can be seen along the pipeline in empirical operations, which is not possible in this software.

Introduction

The extraction of crude oil from beneath land or the ocean floor using new technologies is progressing day by day [1]. An oil reservoir's amount is named the Oil in Place [2]. All of the oil in place is not extractable [3]. To extract crude oil from an oil reservoir, it is needed to drill the ground's layers which can be developmental or exploratory [4]. When the natural energy in the reservoir with the oil is not enough to raise it to the surface and cannot bring enough oil to the surface, this energy must be amplified by one of the artificial methods [5].

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Drilling the well and producing oil from the reservoir, more than 90% of the reservoir's oil volume remains beneath the land [6]. Several methods are used to extract these resources, known as the production optimizations methods [7]. These methods are divided into three main categories: reservoir-based, facility-based, and well-based. These methods are known as the long-term (3 to 5 years), mid-term (2 to 3 years), and short-term (6 months to 1 year) methods in terms of the implementation time to achieve more production from oil fields [8]. Also, the implementation costs of these methods are different as the reservoir-based methods are known as the most expensive methods while the well-based methods are known as the cheapest methods [9-11].

In the reservoir-based methods, which mainly include enhanced oil recovery as well as maintaining reservoir pressure through water and gas injection, the main objective is the reservoir itself, and it is tried to amplify the flow of the oil from the reservoir bed to the well's bottom to decrease the amount of remnant oil in the reservoir [12]. The different methods of enhanced oil recovery include the waterflooding methods, thermal methods (periodic stimulation with steam, steam flooding, hot water drive, and in-situ combustion), chemical methods [driving with polymers, surfactants, bases, and polymer core flood), miscible methods (hydrocarbon gas injection, carbon dioxide, and nitrogen injection, as well as the injection of combustion gases in miscible or immiscible methods). These methods lead to oil movement from the injected well to the production wells by physically increasing the reservoir's pressure [13]. Overall, the common objective of all enhanced oil recovery methods is to move the remnant oil in the reservoir upward to the production wells on the reservoir surface [14-16].

The artificial lift methods in the oil fields include Suction Rod Pumps (SRP), Electronic Submersible Pumps (ESP), Progressing Cavity Pumps (PCP), Hydraulic Pumps (HP), and Gas Lifts [17-19]. Gas lift is one of the ways to increase oil recovery from oil fields. In this method, to raise the fluid in the oil well, high-pressure gas is injected into the well column. The density and bottom-hole pressure of the well is reduced during this method [25].

Also, new and innovative artificial lift methods, which are combinations of two artificial methods, are named the hybrid artificial lift method [20]. Currently, a very low percentage of the artificial lift wells in the world are equipped with artificial lift methods; however, regarding the increasing advances in science and technology and the development of these methods, it can be predicted that in the future, a higher percentage of the oil wells will be equipped with such methods [21-23].

In 1996, at Cairo University, Abdolwali and Othman Salamah optimized a gas lift system in the Ramadan Oil Reservoir of the Suez Oil Field in Saudi Arabia and managed to add more than 2,000 barrels per day to the 17,000-barrel per day production in the reservoir.

In 1997, Mirzajanzadeh et al. found out in their investigations that simple parameters relevant to the well such as the production rate and the pressures fluctuate, and these fluctuations are due to the influence of parameters such as the volumetric parameters of porous media and their fluid properties, properties of gas and liquid fluids, etc. Therefore, these parameters and their effects should also be investigated when conducting studies about the well (e.g., artificial lift).

Askar Abbasov, in 2017, in Azerbaijan, conducted some research on the offshore and oily rocks reservoirs and concluded that in the optimal gas injection flow rate, the wellhead pressure fluctuations range is minimum and the frequency at this point is maximum. The well's production is also maximized, while at the points with higher or lower optimal gas flow rate, the pressure fluctuations range is increased, and the frequency is decreased, which is not desirable [24].

Based on what was mentioned, the main objective of the current research is the empirical study of artificial gas lift in horizontal and diversion wells. According to the articles and research, it has been seen that gas lift projects have significantly increased the amount of oil production from the fields and can be considered an effective method. It is expected that the gas lift method will reduce the density and bottom-hole pressure of the oil fields. For this purpose, in this research, the process of gas lifting has been investigated in a laboratory, and the following, PIPESIM software has been used to compare and predict its behavior. Also, in this research, the device used is designed and simulated in laboratory dimensions, which are explained in detail below.

Method

This research was an experimental and applied intervention in which the experimental device was made of a pipeline consisting of four Plexiglas pipes with a total length of 8 meters and an inner diameter of 40 mm, and an outer diameter of 50 mm (4 two-meter pieces). Also, the flanges are machined, and the gaskets are installed to the size of the pipe diameter so that the change in pipe diameter along the pipeline is not noticeable and the flow is not out of a uniform state. This pipeline system can be used to investigate the type of fluid flow and the slugs created in the horizontal and inclined wells.

The device is designed as a cycle in which a pump can return the water from the pipe that flows into the water storage tank to the beginning of the pipe and inject it back into the pipe to maintain a continuous flow of water. Using a pump and a valve installed on the pump outlet, the water flow rate can be changed and adjusted to the desired rate.

First, the water enters a rotameter to measure the flow, and with the aid of an inventor, the pump’s power can be changed until the outlet water flow rate is adjusted. The maximum measurable flow rate by the installed rotameter in the injectable experiment device for the water fluid is 100 l/min.

There is a two-phase nozzle. Inside the pipe, the water flows, through a highly porous disperser made of brass (to prevent rust). Air is injected uniformly into the pipe by a compressor to form a two-phase flow. The volume of the compressor used is 300 liters.

Two rotameters have been installed to measure the injected gas flow rate so that a wider range of gas can be injected into the fluid inside the tube.

The maximum measurable flow rates for the smaller rotameter are 100 l/min, and it is 100 l/min for the bigger rotameter.

Two pressure gauges were installed at the beginning and end of the pipeline to investigate the pressure at the borehole bottom and the wellhead, which was the objective of the current study.

The regulator, a pressure adjuster, is a valve that reduces the inlet pressure of a fluid to the desired rate on its outlet. It is used for liquids and gases and can be an inseparable device with outlet pressure adjustments or a limiter, a sensor in a body, or a separate pressure sensor, controller, or flow valve. Among the other components used in the device of the current study is also a regulator whose duty is to keep the pressure constant. Generally, a regulator is a device that, regarding the internal mechanical systems, can receive high-pressure inlet gas and deliver it with a lower pressure, based on the user's needs. In the current study also, to keep the pressures 2, 4, and 6 constants in the pipeline, this device has been used, which is installed on the back of the device. The device specifications are provided in Table 1.

Table 1. Specifications of the device used in the current study

Device length	**8 meters**
Device diameter	Inner diameter: 40mm, Outer diameter: 50mm
Pipe inclination angle	-10 to 10
Air compressor volume	300 L
Maximum water flow rate	90 l/min
Maximum measurable air flow rate measured by rotameters	Smaller: 100 l/min Bigger: 1000 l/min

As was mentioned, the aim is to find the optimal flow rate of the injected gas for an artificial gas lift. Thus, the current study is aimed to find the optimal gas flow rate (maximum wellhead pressure) for water flow rates and different angles of the pipeline by changing the injected gas flow rate and measuring the wellhead pressure (the pressure at the end of the pipeline).

In the first stage, the pipeline angle is set horizontally as 0 degrees, and the gas is injected at different water flow rates; with the gradual increase in the gas flow rate, the pressures are simultaneously read from the barometer at the end of the pipeline. It is predicted that pressure fluctuations can be seen at the end of the pipeline due to the creation of air slugs inside the pipe. In the next stage, the experiment is repeated by changing the pipeline angle, and like the previous stage, the experiment would be carried out for different flow rates.

PIPESIM is software for system analysis and a precise, fast, and efficient tool to help production. It allows for understanding the addressed reservoir's potential in the oil industry. This software not only investigates the inlet flow model from several reservoirs but also apparently analyzes the trajectory and performance level to produce the main system

The reservoir usually uses PIPESIM, operation, or equipment engineers as an engineering tool for modeling, good performance, system analysis, artificial lift systems design, pipeline facilities and networks, field development plans analysis, and production optimization.

One of the biggest concerns of the engineers is safely designing the wells and pipelines so that the produced fluids safely and cost-effectively reach the processing facility. The foundation of the correct modeling of the production systems is based on three main areas of multiphase flow, fluid properties, and thermal choice modeling, all of which are addressed by the PIPESIM.

The stages resulting from the simulation by the PIPESIM include steps such as defining the source, sync, and pipeline, the pressure and temperature conditions related to the source as well as water flow rate, specifying the pipeline conditions, and defining the fluid properties in this part such as the Watercut and GLR as well as the water and gas viscosity. The fluid can be simulated as the experimental fluid.

Since the experiment system consists of the water and gas fluids, the part related to the multiphase being of the fluid is selected, and the Beggs & Brill correlation is used.

The sensitivity analysis can be done by keeping all parameters constant except the GLR. The system sensitivity can be investigated relative to the change in this input in the P/T profile pane.

The sensitivity and changing of the system at the 0 degrees angle are represented in Fig. 1.

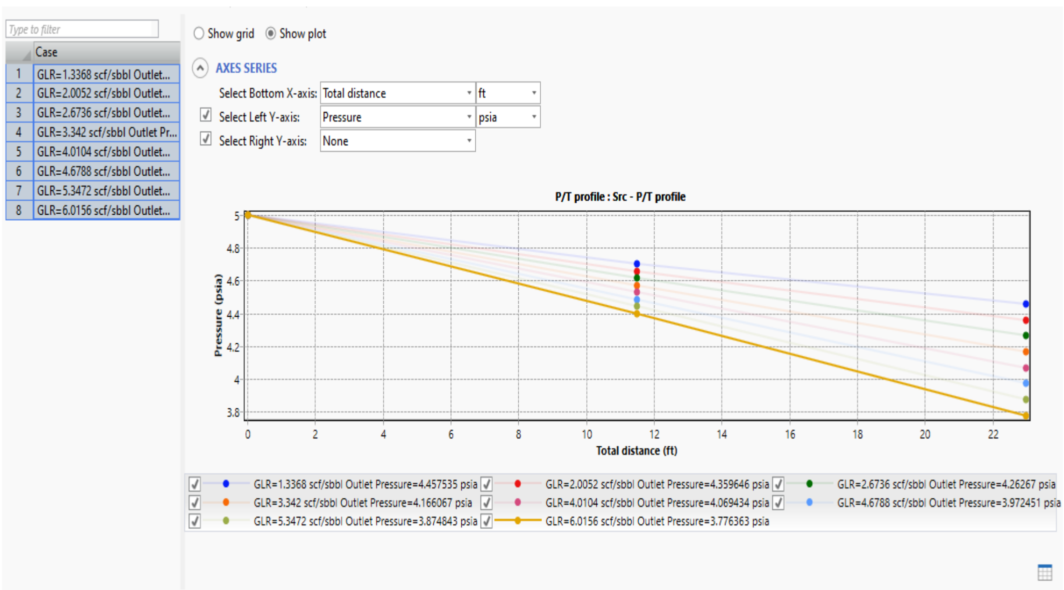

Fig. 1. showing the system sensitivity to changes in GLR at zero degrees angle

The rate of sensitivity and changes in the system in the 3.76 degrees angle relative to the GLR changes is shown in Fig. 2.

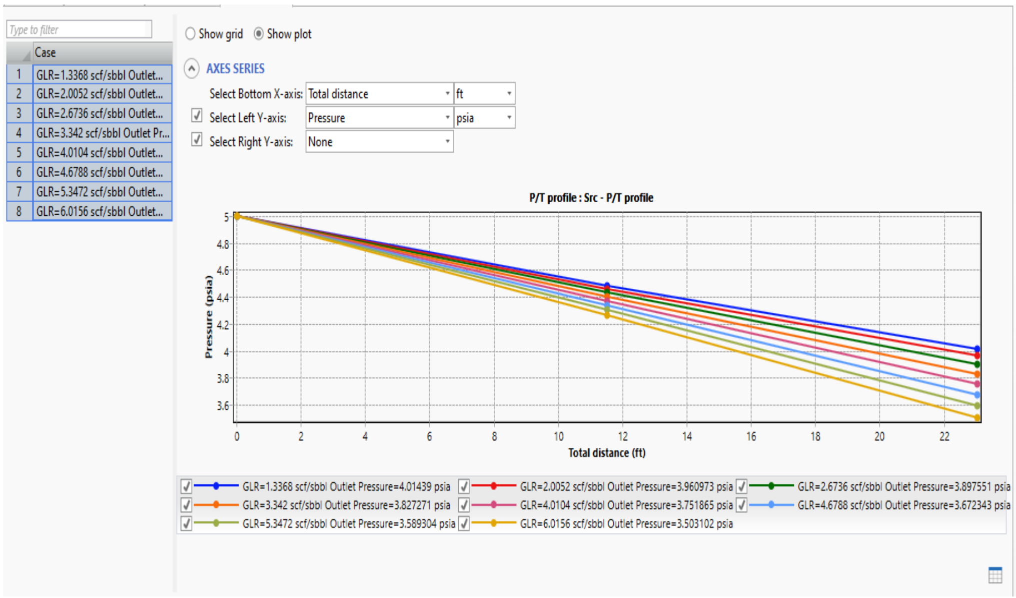

Fig. 2. showing the system sensitivity to changes in GLR at 3.76 degrees angle

The rate of sensitivity and changes in the system in the 9.56 degrees angle relative to the GLR changes is shown in Fig. 3.

Fig. 3. showing the system sensitivity to changes in GLR at 9.56 degrees angle

Findings

In the mode in which the angle of the device pipeline with the horizon is equal to zero degrees, the experiment was conducted in the 60, and 70 l/min water flow rates and different gas flow rates, and the results are presented in the tables and figures in the following.

The results obtained from the 70 l/min water flow rate and the pipeline angle of zero degrees are shown in Table 2 and Fig. 4.

Table 2. The results obtained from the 70 l/min water flow rate and the pipeline angle of zero degrees

Q_{water}= 70 lit/min	
Qg (lit/min)	Pressure (psi)
17	5.25
25	6
33	6.75
42	7.25
50	7.5
58	7.75
67	8.5
75	8.5

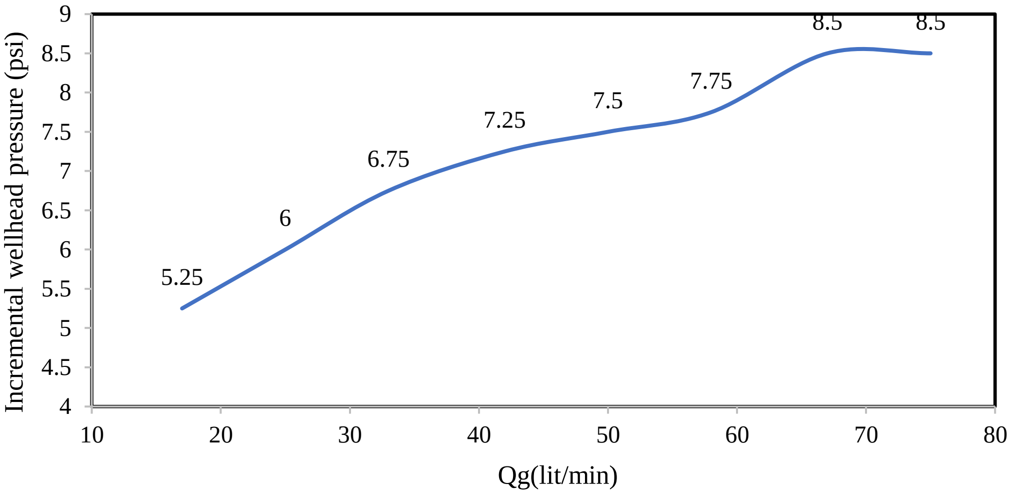

Fig. 4. Graph of wellhead pressure changes per changes in injected gas flow rate

The results obtained from the 60 l/min water flow rate and the pipeline angle of zero degrees are shown in Table 3 and Fig. 5.

Table 3. The results obtained from the 60 l/min water flow rate and the pipeline angle of zero degrees

Q_{water}= 60 lit/min	
Qg (lit/min)	Pressure (psi)
17	4.25
25	4.75
33	5.5
42	5.75
50	6
58	6.5
67	6.5
75	6.5

As you can see in Fig. 6, with the increase in gas flow rate, the pressure gradually increases until it is eventually fixed. In the 70 l/min water flow rate, from the gas flow rate of 67 onwards, the pressure has reached a constant value of 8.5. In Fig. 5 also, from the gas flow rate of 58 onwards, the pressure has reached a constant value of 6.5. It can be concluded that these flow rates are the optimal gas injection flow rates for gas lift operation since due to the increase in gas flow rate, the wellhead pressure is not changed and remains constant. However, it should be noted that if the effective parameters are not considered, it may not be economically viable to continue operations.

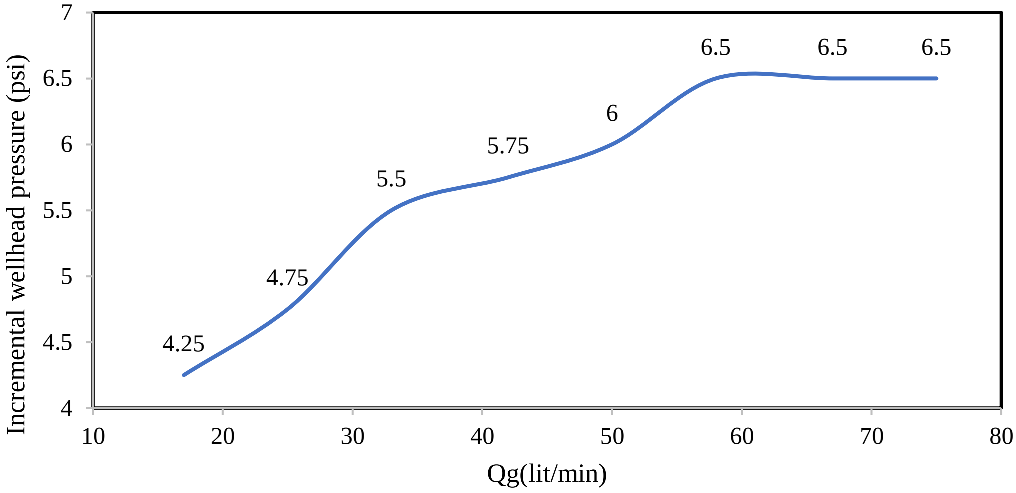

Fig. 5. Graph of wellhead pressure changes per changes in injected gas flow rate for 60 l/min water flow rate and zero degrees angle

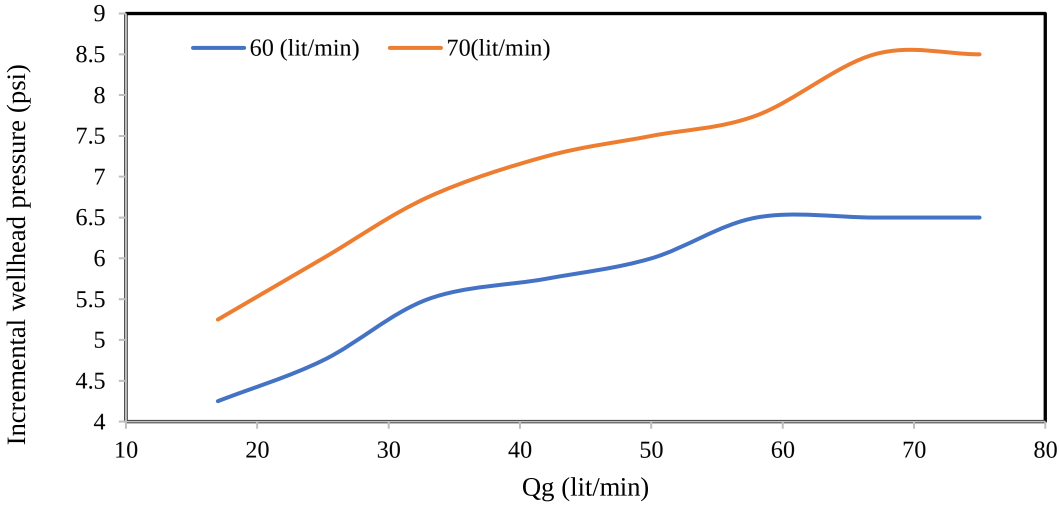

Fig. 6. Graph of wellhead pressure changes per changes in injected gas flow rate for 60 and 70 l/min water flow rate and zero degrees angle

As seen in Fig. 6, the water injection flow rate directly correlates with the wellhead pressure. In other words, with the increase in the water flow rate from 60 to 70 l/min, the pressures measured in different gas flow rates have been increased, and it can be seen that the 70 l/min flow rate figure is above the 60 l/min figure. Thus, it can be concluded that in case the flow rate of the fluid inside the well is increased, the wellhead pressure is also expectedly to increase. After performing the experiment and investigating its results, the pipeline angle was changed by 3.76 degrees with the horizon.

The results obtained from the 70 l/min water flow rate and the pipeline angle of 3.76 degrees are shown in Table 4 and Fig. 7.

Table 4. The results obtained from the 70 l/min water flow rate and the pipeline angle of 3.76 degrees

Q_{water}= 70 lit/min	
Qg (lit/min)	Pressure (psi)
17	5
25	5.75
33	6.5
42	6.5

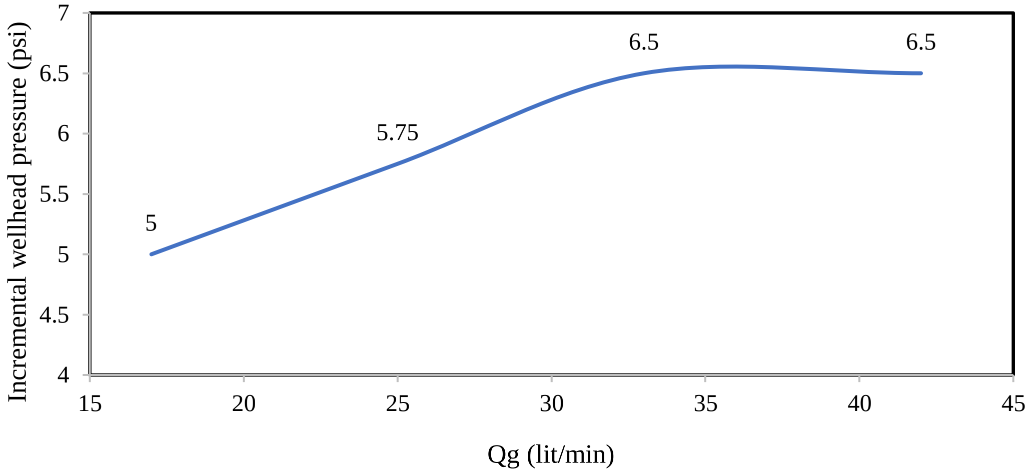

Fig. 7. Graph of wellhead pressure changes per changes in injected gas flow rate for 70 l/min water flow rate and 3.76 degrees angle

The results obtained from the 60 l/min water flow rate and the pipeline angle of 3.76 degrees are shown in Table 5 and Fig. 8.

Table 5. The results obtained from the 60 l/min water flow rate and the pipeline angle of 3.76 degrees

Q_{water}= 60 lit/min	
Qg (lit/min)	Pressure (psi)
17	4
25	4.5
33	5
42	5.25
50	5.5
58	5
67	5

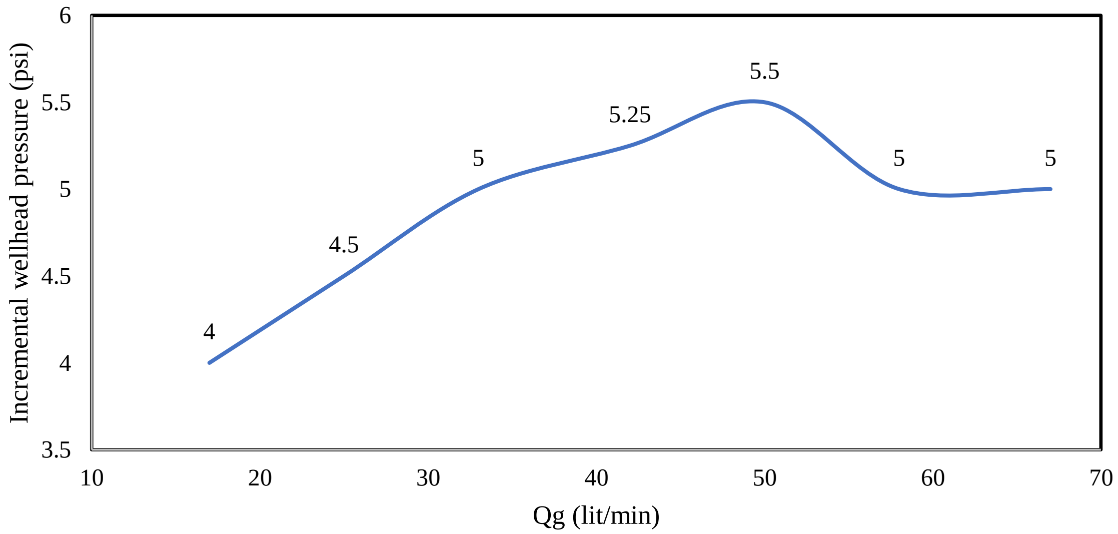

Fig. 8. Graph of wellhead pressure changes per changes in injected gas flow rate for 60 l/min water flow rate and 3.76 degrees angle

The results obtained from the 40 l/min water flow rate and the pipeline angle of 3.76 degrees are shown in Table 6 and Fig. 9.

Table 6. The results obtained from the 40 l/min water flow rate and the pipeline angle of 3.76 degrees

Q_{water} = 40 lit/min	
Qg (lit/min)	Pressure (psi)
17	2
25	2.5
33	2.75
42	3
50	3.25
58	3.25

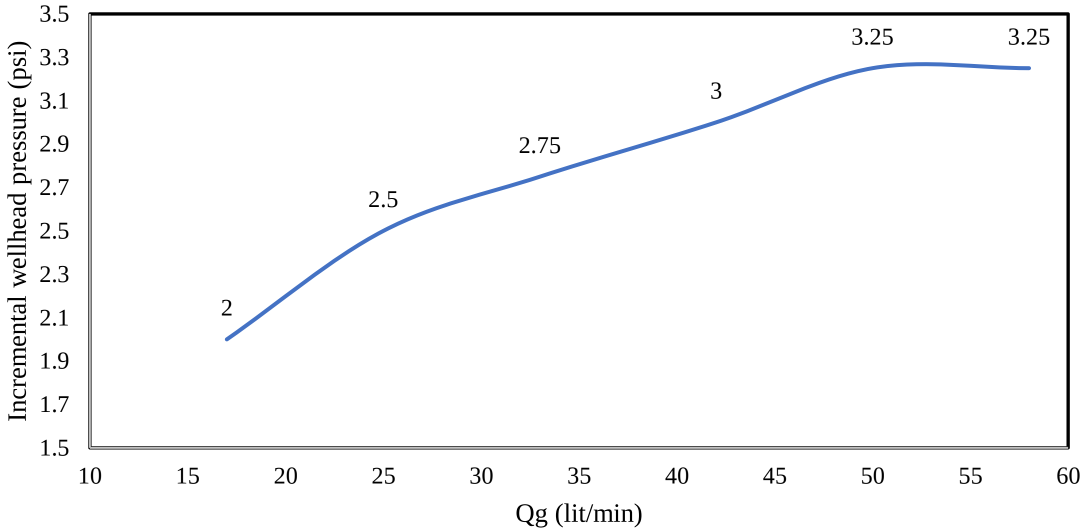

Fig. 9. Graph of wellhead pressure changes per changes in injected gas flow rate for 40 l/min water flow rate and 3.76 degrees angle

The results obtained from the 30 l/min water flow rate and the pipeline angle of 3.76 degrees are shown in Table 7 and Fig. 10.

Table 7. The results obtained from the 30 l/min water flow rate and the pipeline angle of 3.76 degrees

Q_{water} = 30 lit/min	
Qg (lit/min)	Pressure (psi)
17	1.5
25	1.75
33	2
42	2.25
50	2
58	2

In this mode, the pipeline angle is set to 3.76 degrees. Like the previous mode, it can be seen in the results and figures obtained that with the increase in injected gas flow rate, the pressure is gradually increased (in all water fluid flow rates) until it reaches a constant optimal gas flow rate value, even in the cases in which the wellhead pressure drop is seen after the point related to the optimal flow rate. The optimal gas flow rates for 30, 40, 60, and 70 l/min water flow rates are equal to 42, 50, 50, and 33, respectively, and the wellhead pressures at these points are also equal to 2.25, 3.25, 5.5, and 6.5, respectively.

The results obtained from the 70 l/min water flow rate and the pipeline angle of 9.56 degrees are shown in Table 8 and Fig. 11.

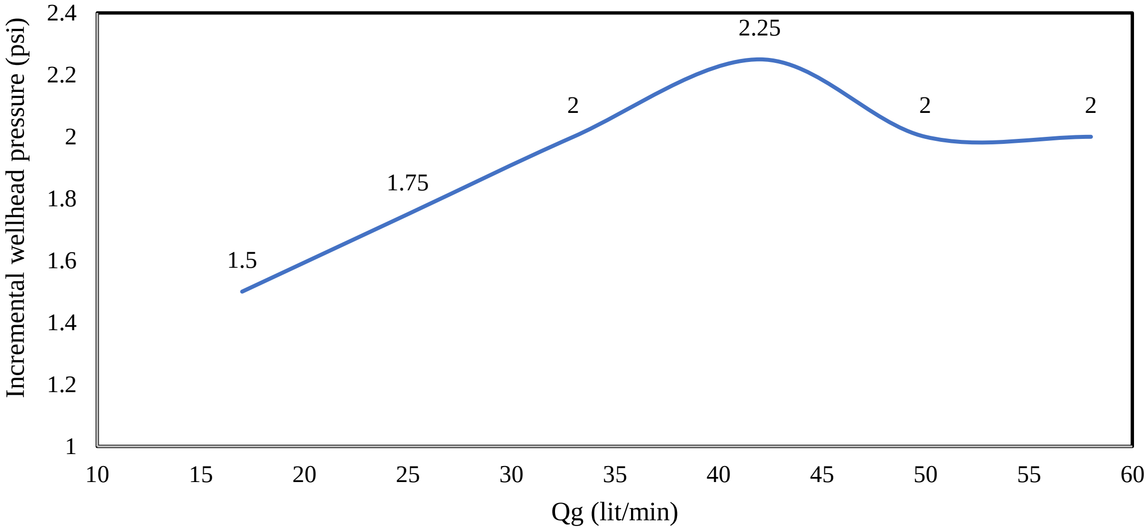

Fig. 10. Graph of wellhead pressure changes per changes in injected gas flow rate for 30 l/min water flow rate and 3.76 degrees angle

Table 8. The results obtained from the 70 l/min water flow rate and the pipeline angle of 9.56 degrees

Q_{water}= 70 lit/min	
Qg (lit/min)	Pressure (psi)
17	5
25	5.25
33	5.75
42	6.25
50	6.5
58	7.25
67	7.5
75	8
83	8
92	8

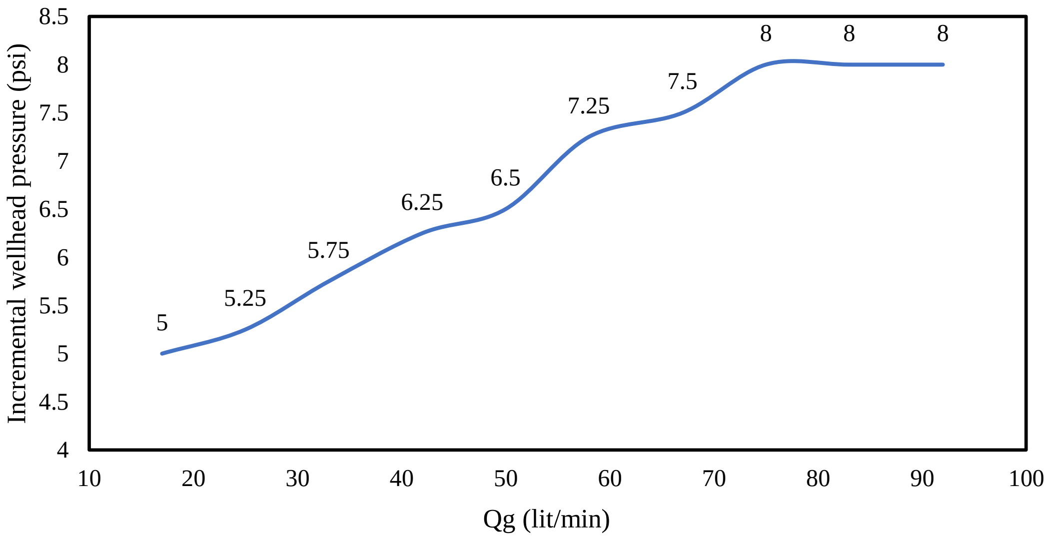

Fig. 11. Graph of wellhead pressure changes per changes in injected gas flow rate for 70l/min water flow rate and 9.56 degrees angle

The results obtained from the 60 l/min water flow rate and the pipeline angle of 9.56 degrees are shown in Table 9 and Fig. 12.

Table 9. The results obtained from the 60 l/min water flow rate and the pipeline angle of 9.56 degrees

Q_{water}= 60 lit/min	
Qg (lit/min)	Pressure (psi)
17	2.8
25	3.1
33	3.6
42	4
50	4.4
58	5
67	4.8
75	5.2
83	6
92	6

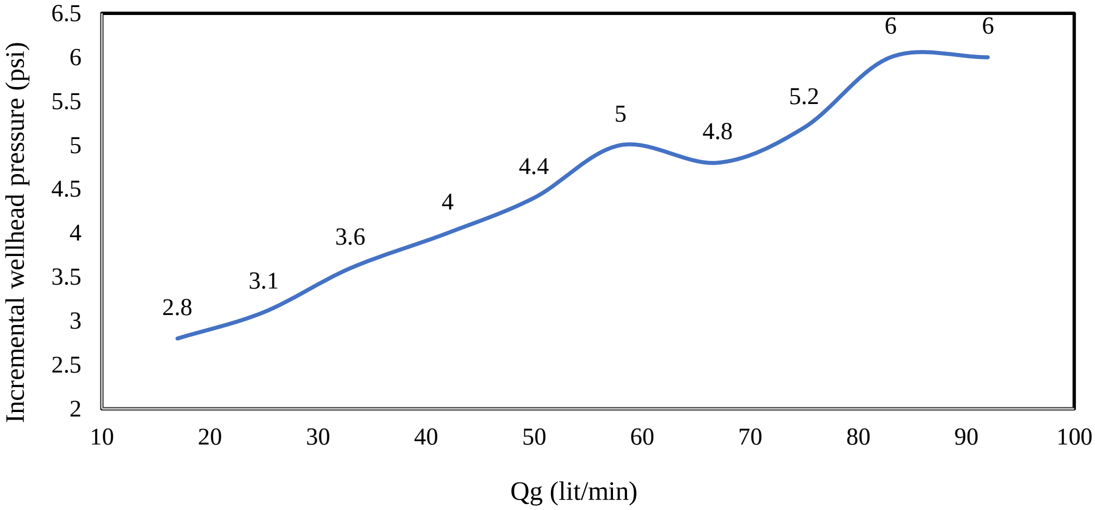

Fig. 12. Graph of wellhead pressure changes per changes in injected gas flow rate for 60 l/min water flow rate and 9.56 degrees angle

The results obtained from the 40 l/min water flow rate and the pipeline angle of 9.56 degrees are shown in Table 10 and Fig. 13.

Table 10. The results obtained from the 40 l/min water flow rate and the pipeline angle of 9.56 degrees

Q_{water}= 40 lit/min	
Qg (lit/min)	Pressure (psi)
17	2
25	2.25
33	2.5
42	2.75
50	3
58	3.75
67	4
75	4.5
83	4

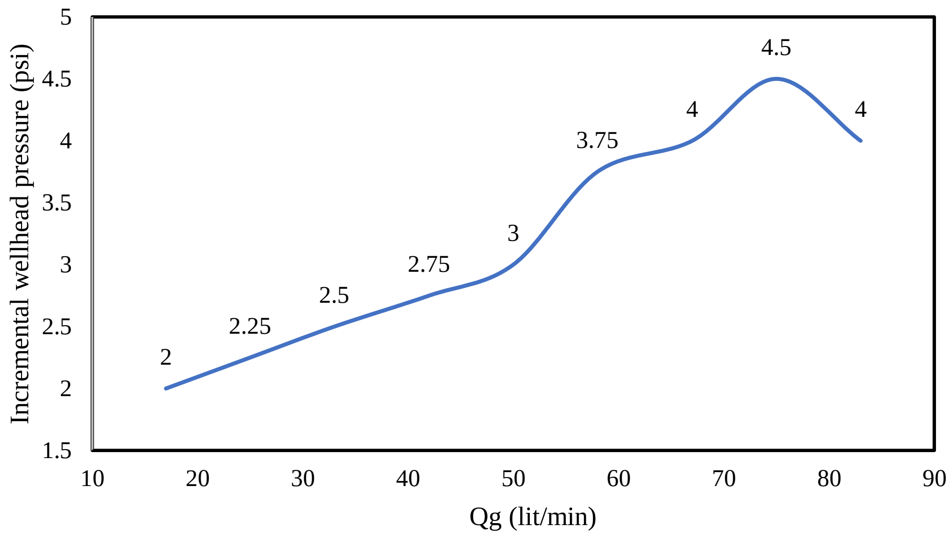

Fig. 13. Graph of wellhead pressure changes per changes in injected gas flow rate for 40 l/min water flow rate and 9.56 degrees angle

The results obtained from the 30 l/min water flow rate and the pipeline angle of 9.56 degrees are shown in Table 11 and Fig. 14.

Table 11. The results obtained from the 30 l/min water flow rate and the pipeline angle of 9.56 degrees

Q_{water}= 30 lit/min	
Qg (lit/min)	Pressure (psi)
17	1.25
25	1.5
33	1.75
42	2.25
50	2.5
58	3
67	2.5
75	2.5
83	2.5

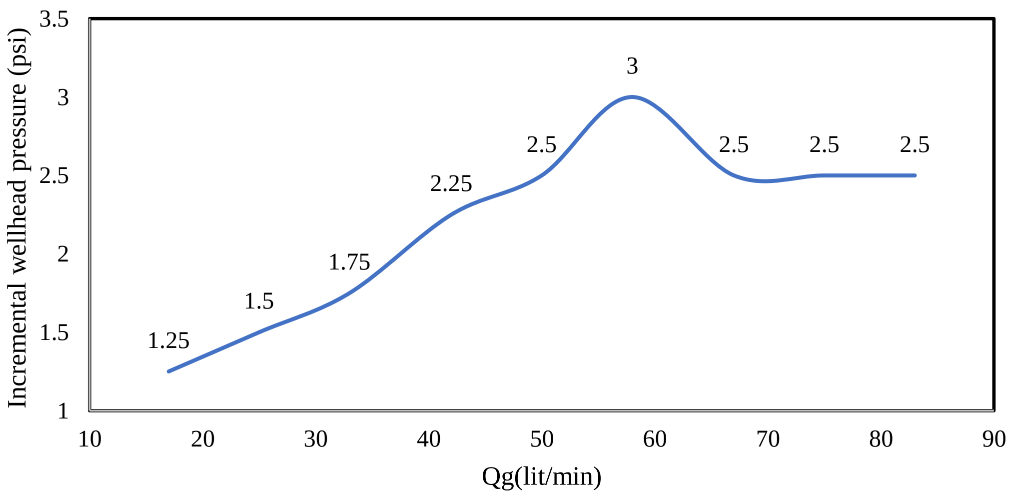

Fig. 14. Graph of wellhead pressure changes per changes in injected gas flow rate for 30 l/min water flow rate and 9.56 degrees angle

It is seen that, like the previous mode, the figures have maintained their increasing trend until reaching the optimal flow rate of injected gas, and after that, the slope has become constant, or a pressure drop has been observed in the flow rates above the optimal flow rate. This trend can be seen for all water flow rates. The injected gas optimal flow rates in the water flow rates of 30, 40, 60, and 70 l/min are equal to 75, 83, 75, and 58, respectively, with pressures of 8, 6, 4.5, and 3.

Conclusions

According to the results obtained, it was observed that in all water flow rates and different angles of the pipeline, with the increase in the injected gas flow rate, the wellhead pressure eventually became constant or decreased. As observed, despite using a two-phase nozzle that allowed air to enter the pipeline evenly, air bubbles began to join together and, as they moved along the pipeline, formed air slugs inside the pipeline. In low injected gas flow rates, low-length slugs have been formed, and as a result, when the air slugs are passing through the barometer installed at the end of the pipeline, the pressure fluctuations are low; however, with the increase in the injected gas flow rate, the air slugs' length was also increased, and this increase led to the formation of sinusoidal pressure fluctuations that continuously increased the amplitude of these oscillations as the slug length increased. The data obtained from the mean values of these fluctuations are used for the final pressure at the wellhead in each injected gas flow rate. Thus, one of the results obtained from this experiment is that the production pressure increase would not be constant in the gas lift operation and acts as a sinusoidal wave. The amplitude of the oscillations is increased with the increase in the fluid's produced flow rate.

Therefore, it was concluded that when the injected gas flow rate becomes very high, the length of these air slugs is highly increased, and as a result, these slugs were connected, and only the gas fluid was continuously passing through the upper half of the pipeline, and the flow pattern in the pipeline was taken out of the slug mode and became stratified while the measured pressure became constant. However, this will be true for the horizontal mode and consequently the horizontal wells.

Since the main objective of this experiment was moving or, in other words, lifting the liquid fluid inside the pipeline by injecting air, if this injected air is taken out of the slug form, the gas would pass by the liquid fluid without pushing it, and reaches the end of the pipeline and the fluid washing operation for which the water was used in the current experiment, is not done well. It also happens in horizontal wells. Thus, the optimal flow rate of gas injection will be such that it can create the highest pressure, and it depends on the increase in the injected gas flow rate without getting out of the slug flow pattern.

It should be noted that one of the advantages of the use of this empirical method for investigation of the pressure at the end of the pipeline compared to the results of the PIPESIM is the observation of these sinusoidal oscillations of pressure at the end of the pipeline, which has not been investigated by this software since it has considered the final pressure to be constant. At the same time, it is not the case in reality.

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