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Optimum design and performance analysis of a gas lift system in the carbonate reservoir of Ahdab oil field

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Abstract

Gas lift is one of the most important artificial lift methods for increasing oil production, as wells often require this method after the reservoir's energy has decreased. In this research, an optimal gas lift system is designed for five horizontal wells in the Ahdab oil field, which suffers from low production. At the same time, water cut in some of these wells reaches 66%, while the productivity index is low in others, which makes the challenges clear, and a deep analysis is needed to find an optimal system. The Pipesim program is used to design the optimal gas lift system, which contains features that facilitate the implementation of the appropriate design and provide the ability to analyze and determine the optimal design values, as well as to detect future production problems. A single system is designed for wells located in the same formation, where an injection pressure of 1750 psi, an injection rate of 1 mmscf/d, and a wellhead pressure of 300 psi are chosen for wells in the Mishrif formation, noting that three valves will be installed in the system. For the wells in the Rumaila formation, an injection pressure of 1950 psi, an injection rate of 1.25 mmscf/d, a wellhead pressure of 475 psi, and four valves were selected for the unloading process. The results proved the design efficiency and that the selected values were optimal, as the increase in production for the five wells was 238%, 146%, 56.6%, 55.9%, and 37.4%.

Keywords: Ahdab oilfield; Artificial lift; Gas lift, Pipesim; Oil production.

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1- Introduction

Gas lift is the most efficient method of artificial lift in improving production, the oldest used and the most widespread in many oil fields around the world, as it is the longest age compared to other methods [1]. Wells naturally produce at the beginning of a field's life, depending on the reservoir energy, which exists in various forms, such as gas cap, water drive, etc. [2]. However, with production time, this energy weakens and becomes insufficient to lift fluids to the surface, necessitating the use of artificial lift methods to restore production rates [3]. In some oil fields, stimulation methods are used instead of artificial lift, such as hydraulic fracturing, which can improve well performance, but it comes at a very high cost [4].

The choice of the optimal artificial lift method is one of the requirements for increasing production and achieving the largest possible profitability, as the wrong choice does not lead to the highest productivity in exchange for increasing cost [5]. In general, the gas lift method is preferred and is used more compared to other artificial lift methods, because it contributes to greater productivity [6]. At the same time, the gas lift method is the lowest cost, which makes it suitable for field operators who suffer from production decline [7].

In the gas lift system, a compressed gas is injected at the surface to the bottom of the well through the annulus, then the production tube through the active valve of the gas lift system (usually the last valve) [8]. After entering the production tube, it raises fluids to the surface by aerating the mixture and thus reducing its density, in addition to the energy expansion capacity that pushes the fluids towards the surface [9]. The theoretical basis of this, after reducing the density of the mixture, the weight of the liquid column decreases, and the losses of friction decrease, and in both cases, the bottom hole flowing pressure decreases, which increases the difference with the reservoir pressure and thus the flow of fluids more towards the well and then to the surface [10].

Gas lift usually consists of two ways: continuous and intermittent. Continuous gas lift is the most used way, as the gas is injected into the well continuously, and gives better results in productivity [11]. It also offers ease of operation and relatively inexpensive equipment, but it requires system monitoring and a reliable gas source to ensure high efficiency [12].

Intermittent gas lift is the least used method, as the gas is injected into the well for a while, and when the fluids flow to the surface, the injection stops, then the process is repeated [13]. It should be noted that, sometimes, the change is made from continuous gas to intermittent, when the percentage of gas to the oil is very high [14]. Also, the method of lifting with intermittent gas can be used in the gas wells in which fluid accumulates, to raise it to the surface and improve gas production [15].

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The success of the gas lift system depends on the surface facilities that are used to treat gas before its injection and the compressors to provide the required pressure for the injection [16]. The success of the optimal design of the gas lift system mainly depends on the pressure of the injection, the injection rates, and the pressure of the wellhead, which in turn affects the rest of the design elements [17].

In general, the productivity of wells increases when the injection pressure or the injection rate increases, and it reaches the highest possible productivity. After this limit, any increase in the pressure or the injection rate leads to negative results and increased cost [18]. On this basis, it is important to analyze all design variables that directly affect the efficiency of the system so that optimal values are chosen for the design, which gives optimal production [19].

Improving the design of the gas lift system is to increase efficiency and reduce uncertainty between the calculated production when designing and the actual production after the implementation of the system [20]. In general, the improvements and developments on the gas lift system have continued from its use for the first time until this moment, as it introduced artificial digital intelligence to contribute to increasing efficiency and thus achieving the greatest possible profitability [21].

Ahdab oil field suffers from a significant decrease in production, as a result of a decrease in reservoir pressure and an increase in water cut in some wells, which makes the use of artificial lift methods necessary to restore production. On this basis, the study aims to design an optimal gas lift system in the Ahdab oil field, which maintains the feasibility of production from this field.

2- Field and reservoir characterization

2.1. Area of study

This study was conducted Ahdab oil field, which is located in Wasit Governorate (180 south of Baghdad) and is affiliated with Midland Oil Company. The field was discovered at the end of the 1970s and developed by Al-Waha Company in 2009. Production started in 2011. Ahdab Oil Field is subdivided into three well fields: Blocks AD1, AD2, and AD4. The Ahdab oil field is characterized by a carbonate-rimmed platform. The lithology is predominantly limestone with minor dolomite and shale. The stratigraphy includes Cretaceous formations such as Mishrif, Khasib, Rumaila, Tanuma, and Hartha. Clay minerals identified are smectite, illite, and glauconite [22, 23].

2.2. Well and fluid properties

Ahdab oil field consists of three major productive formations, and this study was conducted on five horizontal wells, three in Mishrif formation (ADM0-3H, ADM10-1H, and ADM4-8H), and two in Rumaila formation (ADRu1-3-2H and ADRu1-9-2H), where the measured depth of the five wells ranges between 4147 m and 4519 m. At the same time, the design of the wells is similar, as it consists of surface casing, intermediate casing, and liner. As for the point of deviation from the vertical axis, it is located approximately after 2100 m, and the backer above this point for all wells under study.

Reservoir pressure in Rumaila formation is higher than in Mishrif formation, where it is 3542 psi, and the other is 3182 psi. Additionally, the data from the well test conducted for one of the wells in Rumaila formation indicated a productivity index of 8.74, whereas the test for another well in the Mishrif formation yielded a low productivity index of approximately 1.66. At the same time, water cut in Mishrif formation is a very low range between 3%-16% for wells under study, while for both wells in Rumaila formation is 66%. As the density of oil, Ahdab oil field is characterized as heavy oil, with a density range of 26-27 API [22].

3- Methodology: Gas lift design and simulation workflow

3.1. Simulation model setup

This research will rely on the Pipesim program, which includes several stages: data collection and analysis, then building a physical model and a fluid model, and finally, designing an optimal gas lift system. Fig. 1 is a flowchart for the steps of the research methodology.

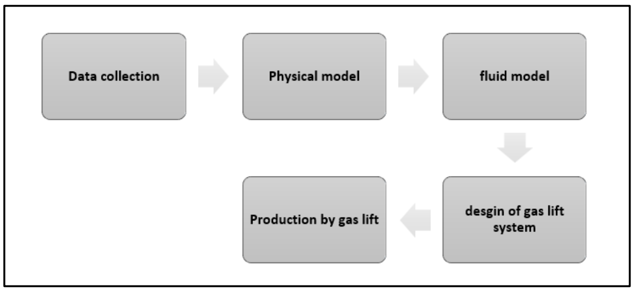

Fig. 1. Flowchart of methodology

3.2. Wellbore and completion model (physical model)

Physical modeling refers to the construction of the well structure after drilling is completed, including the lowering of the casing, production tubing, and other supporting equipment, as the well is prepared for production. This model needs much data that includes the casing (its types, depths, and diameter), production tube (its types, depths, and diameter), Kick Off Point, and packer. In addition to the degree of deviation for each depth, since all wells are horizontal, Table 1 summarizes all this data.

3.3. Fluid model (PVT model)

This model is built based on the available production data and reservoir data, where fluids are dealt with as multi-phase, and liquids and gases are referred to by a volumetric percentage (black oil model). The reservoir data is divided according to the productive formation; that is, the wells in the Mishrif formation have the same reservoir characteristics, and the same approach can be applied to the wells in the Rumaila formation. Regarding the production data, each well has a specific productivity that varies from one another in terms of production rate and water cut percentage. This information is summarized in Table 2.

In addition, many correlations that are used to calculate the various reservoir characteristics that contribute to building the model have been used, as Pipesim provides these correlations, which are clarified through Table 3.

The correlations used are among the most common and widely used in industrial and academic applications, and their effectiveness has been verified in numerous similar field studies, enhancing confidence in their results, especially in the absence of accurate laboratory data. Also, the study used the Black Oil model, which is based on simple properties that are empirically represented, and these correlations are common and proven to be effective within this model, as it provides good accuracy within the pressure and temperature range available in the Ahdab field, and is one of the recommended correlations in environments with low to medium GOR.

And to reduce the difference between the values calculated by the Pipesim and those measured by the laboratory, the Pipesim provides the feature of calibration, that is, the calculated values can be adjusted to increase the accuracy of the model. But this depends on the available laboratory data (Accurate calibration of the physical properties of fluids is not performed because laboratory data are not fully available). It should be noted that the productivity index was assumed to be a single value based on the productive formation due to the lack of available data (Detailed data on the productivity index for each well were not available). These assumptions will affect the accuracy of the model, but they are closest to the real result, and there is no other solution due to the lack of information.

Table 1. Depth of equipment for all the wells [22]

Equipment/well	ADM4-8H	ADM0-3H	ADM10-1H	ADRu1-3-2H	ADRu1-9-2H
Surface casing	310 m	309 m	310 m	309 m	312 m
Intermediate	2044 m	2075 m	2082 m	2066 m	2047 m
liner	1908 - 3048 m	1900 – 3166 m	1900 – 3019 m	1900 – 3228 m	1900 – 3000 m
Open hole	3048 – 4147 m	3166 – 4367 m	3019 – 4519 m	3228 – 4335 m	3000 – 4200 m
tubing	2000 m	2000 m	2150 m	2067 m	2100 m
packer	1970 m	1985 m	2100 m	2050 m	2085 m
KOP	2150 m	2100 m	2280 m	2110 m	2350 m

Table 2. Reservoir and production data [22]

Data/Well	ADM4-8H	ADM0-3H	ADM10-1H	ADRu1-3-2H	ADRu1-9-2H
Reservoir pressure (psi)	3183 psi	3183 psi	3183 psi	3542 psi	3542 psi
Reservoir temperature (T)	82 C	82 C	82 C	85 C	85 C
Productivity index (PI)	1.66	1.66	1.66	8.74	8.74
Well head pressure (Pwh)	363 psi	300 psi	319 psi	290 psi	305 psi
Bubble point pressure (Pb)	2851 psi	2851 psi	2851 psi	2799 psi	2799 psi
Gas oil ratio (GOR)	637 scf/stb	637 scf/stb	637 scf/stb	660 scf/stb	660 scf/stb
Water cut (Wc)	3%	8%	16%	66%	66%
API	26	26	26	27	27
Oil formation volume factor (Bo)	1.323	1.323	1.323	1.281	1.281

Table 3. Correlation used in Pipesim

Property	Correlation
Undersaturated oil viscosity	Vasquez & Beggs
Live oil viscosity	Beggs & Robinson
Dead oil viscosity	Beggs & Robinson
Bo above Pb	Vasquez & Beggs
Saturation gas at Pb	Lasater
Bo at Pb	standing
Gas viscosity	Lee et al.
Gas Z	standing

3.4. Optimization workflow

The gas lift system design was optimized using PIPESIM software through a structured simulation workflow consisting of four main steps to identify the most efficient operating parameters before finalizing the valve design. The workflow included the following stages:

Step 1: Base case simulation (natural flow performance)

Each well was initially modeled under natural flow conditions without artificial lift, using available production and reservoir data. This simulation established a reference case to evaluate the potential benefit of gas lift application and highlighted wells that required artificial lift due to low natural productivity or high flow resistance.

Step 2: Sensitivity analysis of injection parameters (pressure and rate)

A range of gas injection pressures and rates was tested to assess their impact on well performance. This analysis helped determine the effective operating window for each group of wells (Mishrif and Rumaila formations) by monitoring the production response under different injection conditions. The goal was to narrow down the pressure and rate ranges that would be evaluated later in more detail.

Step 3: Nodal analysis and constraint evaluation

A nodal analysis was performed for each case within the selected pressure and rate ranges. This step was used to determine the optimal operating point based on the intersection of the inflow and outflow curves. Additionally, operational constraints, such as flow velocity, were verified to ensure that the selected gas injection rates did not exceed erosion limits or cause production instability.

Step 4: Final valve design

Based on the results of the nodal analysis and operational considerations, the valve configuration was designed for each well. This included determining the number of valves, their spacing, port sizes, and the pressure differential required to ensure proper discharge behavior. The valve design aimed to match the injection strategy and reservoir characteristics while maintaining system reliability.

This workflow allowed for a systematic and iterative approach to gas lift design, ensuring that each well configuration was optimized for its specific operating and reservoir conditions.

4- Results

4.1. Natural flow performance

The results indicated production rates for the five wells under study, based on the Pipesim program. They highlight the importance of installing the gas lift system to boost production from these wells. The impact of water cut was evident in the wells located in the Rumaila formation, contributing to a significant decline in oil production, despite its high productivity index and suitable reservoir pressure. As water enters the well, the density of the mixture increases (since the density of water exceeds that of oil), leading to an increased weight of the hydrostatic column and greater frictional losses. This results in increased pressure at the bottom of the well, minimizing the difference compared to reservoir pressure, which subsequently reduces flow rates toward the well and increases the volume occupied by water within the total fluid volume. Regarding the wells in the Mishrif formation, the results reveal the necessity to enhance their productivity. Table 4 illustrates the productivity of wells under natural flow conditions.

Table 4. Production in natural flow

Property/well	ADM4-8H	ADM0-3H	ADM10-1H	ADRu1-3-2H	ADRu1-9-2H
Liquid rate (Ql)	962 stb/d	1074 stb/d	1078 stb/d	1100 stb/d	793 stb/d
Water cut (Wc)	3%	8%	16%	66%	66%
Oil rate (Qo)	933 stb/d	988 stb/d	905 stb/d	374 stb/d	269 stb/d

4.2. Parametric sensitivity

The need to install a gas lift system has become evident due to the productivity of wells during natural flow. However, this also requires selecting optimal parameters to ensure the system's success. As mentioned in the methodology paragraph, the Pipesim program offers the capability to conduct a sensitivity analysis to determine the optimal injection pressure and injection rate for wells within the same formation.

When performing the initial analysis of the wells in the Mishrif formation, it is clear that the deepest possible injection point can be reached at a pressure of 1500 psi. At the same time, productivity increases further with pressure rising to 2000 psi. The optimal pressure lies between these two values by relying on other design standards, but the injection pressure cannot be less than 1500 psi.

Regarding the injection rate, it is evident that productivity increases with injection rate, except when injection pressures are below 1500 psi. Conversely, injection rates higher than 1.25 mmscf/d yield only a slight increase in production rate. In other words, production increases are not proportional to injection rates exceeding this value, as this leads to excessive gas usage and, consequently, inefficient production as shown in Fig. 2. Based on this, the optimal injection rate should range between 0.75 and 1.25, as the final design will depend on the results of nodal analysis and the selection of optimal values that maximize productivity.

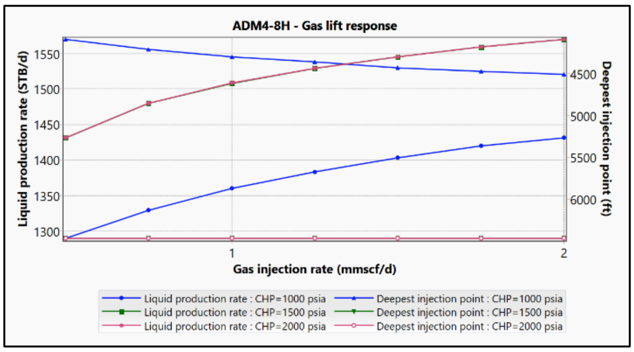

Fig. 2. Initial analysis for mishrif formation

As for the wells in the Rumaila formation, the initial analysis clearly shows that the pressure of the injection at 2000 psi can lead to the deepest possible point, and therefore, the final value will depend on a pressure close to this value, as the pressure of 1500 psi does not lead to the deepest point for injection in all cases.

As for the injection rate, it is also clear that production rates increase with an increase in the injection rate at a pressure of 2000 psi. It can be seen that the injection rate is higher than 2 mmscf/d does not lead to a significant increase in production, meaning that there is extravagance in the use of gas in return, a production that does not fit with the increase in the injection rate at that value, as shown in Fig. 3.

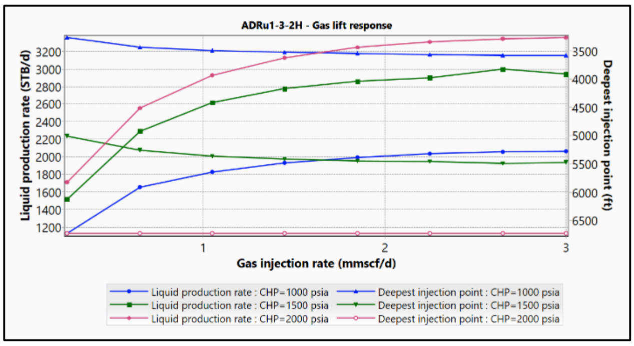

Fig. 3. Initial analysis for Rumaila formation

When conducting nodal analysis in these conditions, it turns out that the injection rate is higher than 1.25 mmscf/d causes production problems as shown in Fig. 4, as the injection rate is higher than this value leads to a significant increase in production, but at the same time causes internal erosion of the tube wall, as the flow velocity is very high is not commensurate with the size of the tube, which leads to future problems in production. Nodal analysis provided an accurate understanding of the relationship between injection rate and production problem. These results reinforce the importance of using nodal analysis as an accurate prediction tool for determining the optimal operating point, rather than relying solely on maximum production.

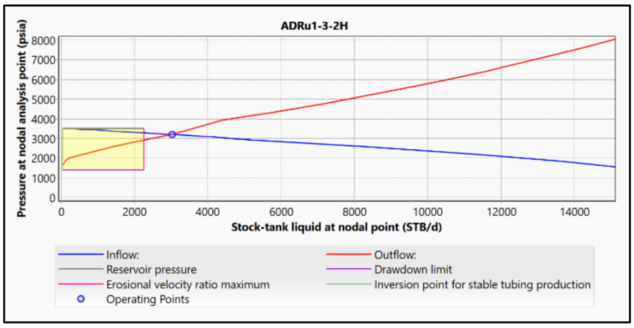

Fig. 4. Production problem due to high injection rate

4.3. Final gas lift design

For wells that are in the Mishrif formation, an injection rate and injection pressure have been chosen, as 1750 psi and 1 mmscf/d, and a well head pressure of 300 psi. Three valves will be used to complete the well unloading process.

As for the wells in Rumaila formation, the optimum injection rate has been chosen and the injection pressure that gives the highest possible productivity without future productive problems, which are 1950 psi and 1.25 mmscf/d, and the well head pressure was chosen to be 475 psi. The number of valves for the completion of the unloading process for the well is four. Table 5 shows the final design of all five wells under study and the rest of the design details, for example, the density of gas and less spacing between the valves, as these values are the optimal values for the success of the gas lift system.

Table 5. Final design of gas lift system

Property/well	ADM4-8H	ADM0-3H	ADM10-1H	ADRu1-3-2H	ADRu1-9-2H
Injection pressure (Pi)	1750 psia	1750 psi	1750 psi	1950 psi	1950 psi
Injection rate (Qi)	1 mmscf/d	1 mmscf/d	1 mmscf/d	1.25 mmscf/d	1.25 mmscf/d
Well head pressure (Pwh)	300 psi	300 psi	300 psi	475 psi	475 psi
Number of valves in the design	3	3	3	4	4
Type of valves	Injected operating pressure (IPO)	Injected operating pressure (IPO)	Injected operating pressure (IPO)	Injected operating pressure (IPO)	Injected operating pressure (IPO)
Depth of the last valve	1939 m	1954 m	2067 m	2019 m	2054 m
Port size of the last valves	0.25 in	0.25 in	0.25 in	0.5 in	0.375 in
Differential pressure to fully open the last valve	529 psi	529 psi	529 psi	302 psi	382.6 psi
Gas specific gravity	0.75	0.75	0.75	0.75	0.75
Minimum valve spacing	98.3 m	98.3 m	98.3 m	98.3 m	98.3 m

4.4. Predicted production performance with gas lift system

After designing and installing the gas lift system, the increase in production was clear, as the economic benefit of the wells was improved .As for the wells in Mishrif formation, the increase rate reached 56.6%, 55.9%, and 37.4%. Where the gas lift system contributed to improving production rates, even though the productivity index is low, with that system, production rates have improved from 1078 to 1688 stb/d for well ADM10-1H, from 962 to 1500 stb/d for well ADM4-8H, and from 1074 to 1476 stb/d for well ADM0-3H. Fig. 5, Fig. 6, and Fig. 7 show the nodal analysis of the three wells, as the production rates vary from one well to another, depending on the operating conditions of the well, especially the water cut ratio, which plays a significant role in determining the operating point when using a gas lift system. This is because the operating principle is to reduce the weight of the fluid column inside the production tube. This also depends on the depth of the last valve in each well, as the fluid weight reduction begins from the moment the gas enters the production pipeline. Therefore, there is a difference in the production rates of the three wells.

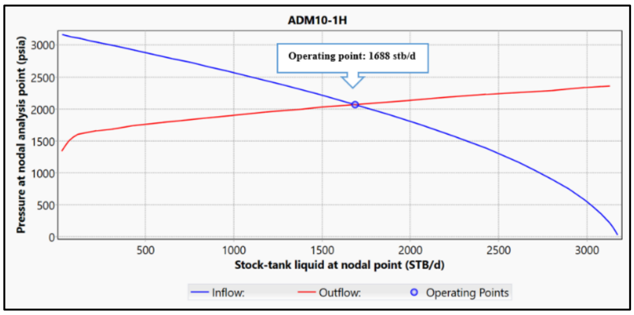

Fig. 5. Nodal analysis for well ADM10-1H

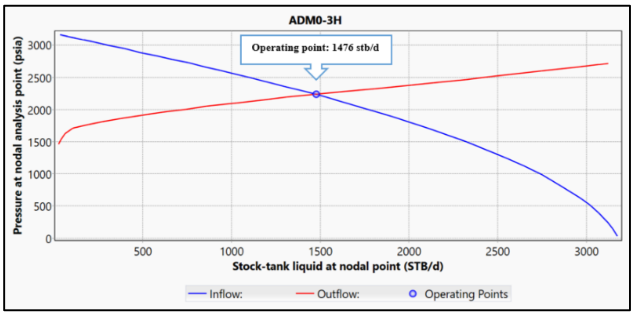

Fig. 6. Nodal analysis for well ADM0-3H

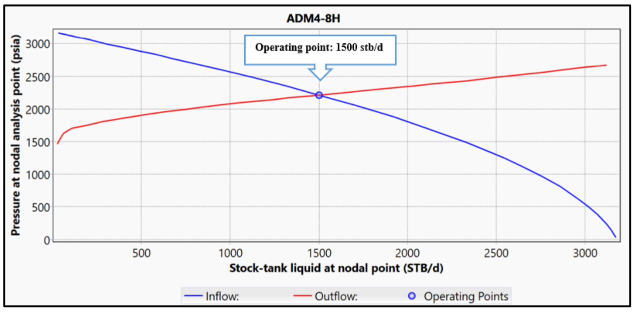

Fig. 7. Nodal analysis for well ADM4-8H

As for the wells in the Rumaila formation, the increase rate was 238% and 146%. The entry of water from the formation to the well contributed to increasing the density of the mixture and increasing the losses of friction, which led to an increase in bottom hole flowing pressure.

After installing the gas lift system, the wells regained their productivity at high rates of 2682 stb/d, after it was 793 stb/d for well ADRu1-9-2H and from 1100 to 2706 stb/d for well ADRu1-3-2H. The injected gas works to aerate the mixture after entering the production tube. The aeration of the mixture means reducing the mixture's density and friction losses. This leads to reducing the bottom hole flowing pressure of the well and thus increasing the difference with the pressure of the reservoir, which makes the fluids flow towards the well and then to the surface at higher rates. Fig. 8 and Fig. 9 show the nodal analysis of the wells in the Rumaila formation and the rate of production. The wells in the Rumaila Formation exhibit a slight difference in production rates due to the similar operating conditions in the two wells. This slight difference in production rates is attributed to the depth of the last valve of the gas lift system, where the weight reduction of the liquid column inside the production tube begins at the point of gas entry into the tube, as well as the structure and depth of the well itself.

Fig. 10 is a comparison between production before and after the installation of the gas lift system, as the design of an optimal system has led to a significant increase in production. The benefits of the gas lift system can be seen in the production rates after installing the gas lift system for all the wells under study. It contributed to a significant increase in some wells and improved productivity in others, confirming the importance and effectiveness of the system as a reliable method for increasing production rates.

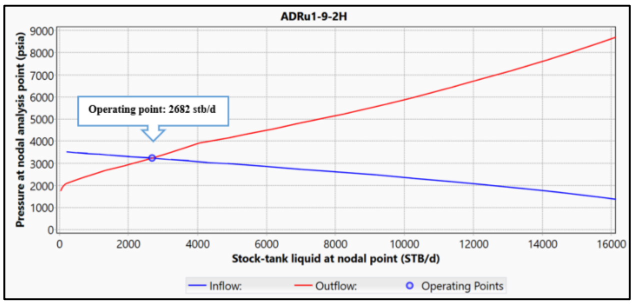

Fig. 8. Nodal analysis for well ADRu1-9-2H

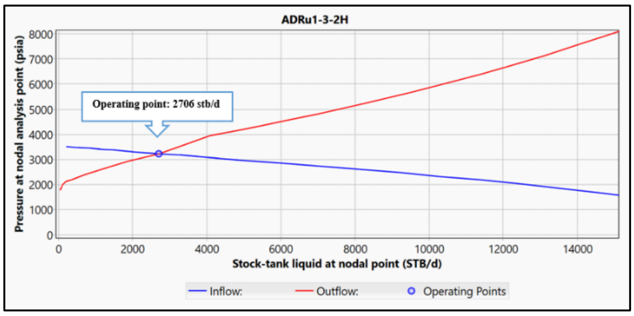

Fig. 9. Nodal analysis for well ADRu1-3-2H

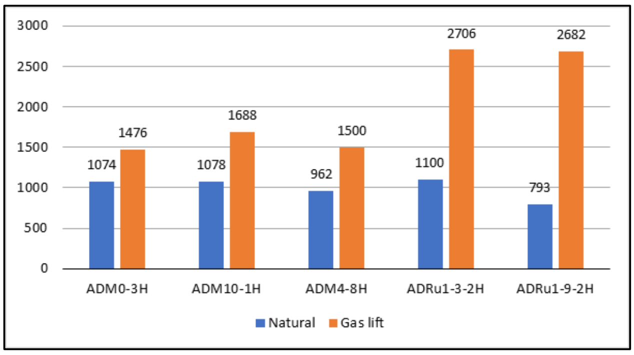

Fig. 10. Comparison between flow in natural flow and gas lift

Overall, the study demonstrated the important role that simulation tools such as Pipesim play in improving design accuracy and predicting future operational problems, which enhances decision-making based on accurate data and analysis, and increases production efficiency in fields with complex conditions.

5- Discussion

5.1. Analysis of production enhancement

The improved production rate after the system is installed is largely due to the system's ability to lower the flowing bottom hole pressure (BHP). The reduced density resulting from aeration of the fluid column reduces this pressure, thereby increasing the difference between the reservoir pressure and the flowing bottom hole pressure, which stimulates more flow from the formation into the well. This concept is also supported by the nodal analysis after aeration, which shows a clear difference in the intercept (operating) point compared to the original condition.

In the natural flow condition, the intersection between the inflow performance relationship (IPR) curve and the vertical lift performance (VLP) curve occurred at a lower flow rate and higher BHP. After gas injection, the VLP curve shifts downward, representing reduced lift pressure losses, and the new intersection point (operating point) occurs at a higher production rate and lower BHP. This shift confirms the success of the gas lift system in improving well performance by modifying the pressure pattern within the well.

Moreover, the degree of shift in operating point varied between wells, indicating that wells with higher water cut rates or greater flow resistance experienced greater benefits. This further supports the conclusion that gas lift is particularly effective in wells with high hydrostatic or frictional losses, even when the reservoir pressure or productivity index is relatively favorable.

5.2. Comparative performance: Mishrif vs. Rumaila formation

Analysis of the results of the Mishrif formation wells demonstrates that gas lift efficiency does not always require high initial productivity for its impact to be noticeable. Although these wells have a relatively low productivity index (1.66), production increases exceeded 55% in two wells, indicating that the primary challenge was overcoming flow resistance within the well, rather than within the reservoir itself. This is due to the decrease in bottom hole flowing pressure resulting from the reduced density of the fluid column after ventilation, which improved the difference between reservoir pressure and bottomhole flowing pressure, the most important factor in enhancing reservoir drawdown.

The significant production increases seen in the Rumaila wells, reaching 146% and 238%, reflect the ability of the gas lift system to restore production even in high-water cut environments. However, these results also highlight an important aspect: injected gas not only increases the production rate but also reshapes the flow profile within the well by reducing density and increasing fluid acceleration. However, high water content remains a future operational challenge and, if left without monitoring, could negatively impact gas lift stability.

Although positive results were achieved in all wells, improvement in some cases, such as ADM4-8H (37.4%), was lower than in the other wells. This is because this well was close to its optimal performance even in natural flow, due to low water cut and good reservoir pressure. This indicates that the improvement potential of gas lift is related to natural flow inefficiencies, not just to productivity index or reservoir pressure.

Fig. 10 and the data extracted from the previous figures show that the difference between natural flow and production after the implementation of the gas lift system was significant in most wells, reflecting the wells' reduced ability to maintain natural production due to decreased reservoir pressure or increased flow resistance. These differences highlight the importance of selecting the right timing for interventions using artificial lift techniques before performance deteriorates beyond repair.

5.3. Justification of optimal design parameter

The final design was depended directly on the initial analysis that was conducted. After conducting the nodal analysis, the optimal injection rate and the optimal injection pressure were chosen, which will give the highest possible productivity and do not cause future productive problems.

As for injection pressure, the optimal value was chosen based on the initial analysis that was conducted as shown in Fig. 2 and Fig. 3, which give deepest possible point for injection, but the final value for pressure relied on the effect on the productivity of the wells and the number of valves that can be used in the unloading process, as more injection pressure, the lower number of valves, with taking in consideration the success of the unloading process and the ability of compressor to provide the appropriate injection pressure. At the same time, the increase in pressure (more than the selected value) does not cause an increase in production.

As for choosing an optimal injection rate, it relied on the increase in production. It is important to know that the increase in production is commensurate with the injection rate and does not cause excessive use of gas in exchange for the limited production feasibility as shown in Fig. 2 and Fig. 3. At the same time, the injection rate should not cause any production problem such as erosion of tube wall duo to high velocity as shown in Fig. 4.

It is noteworthy that achieving the optimal pressure (1750–1950 psi) was key to reaching the deepest injection point, which improved pressure distribution throughout the wellbore and reduced losses from early bubbles or free gas in the upper sections. Also, choosing a moderate injection rate (1 to 1.25 mmscf/d) maintained a balance between production yield, operational cost, and corrosion risk. In general, adopting a unified design for wells within the same reservoir formation has proven to be technically and economically feasible, as the similarity in reservoir and structural conditions of the wells has helped implement a unified system without affecting efficiency, which facilitates operation and maintenance processes and reduces design complexity.

5.4. Study limitations and implications for field operation

A major limitation of this study was the lack of complete and accurate laboratory data for PVT measurements for all wells. Consequently, fluid modeling was performed using the black oil approach in PIPESIM, supported by widely accepted empirical correlations. While these correlations (such as those conducted by Vasquez, Biggs, and Standing) are considered reliable in low-to-medium gas environments, the lack of detailed PVT measurements limited the ability to accurately calibrate the model. This introduces a level of uncertainty into the prediction of fluid behavior and production performance, especially under variable pressure and temperature conditions.

Another limitation of this study is the assumption of a single value for the productivity index for the wells located in the same formation. This assumption affects the nodal analysis and thus the operating point. However, since all the wells are horizontal, this reduces the effect of this assumption because the horizontal wells share the same reservoir characteristics and almost the same well structure in terms of the length of the horizontal displacement within the producing zone, which makes the drainage area close together and thus the productivity index will be very close, which makes this assumption acceptable and the results obtained accurate.

Despite this limitation, the simulation results provided valuable insights into the expected performance of the gas lift system. However, the results also emphasized the importance of continuous field monitoring, particularly in Rumaila Formation wells, which exhibited high levels of water flow reduction (up to 66%). Reduced water flow significantly impacts gas lift performance by increasing fluid column density and friction losses, which raises downhole flow pressure and reduces gas injection efficiency. Therefore, for future field operations, it is essential to implement periodic water cut monitoring and management strategies to ensure the continued stability and efficiency of the gas lift system.

Furthermore, it is recommended that future development plans for the Ahdab oil field include more detailed fluid sampling and laboratory PVT analyses. This will improve model calibration and enhance the reliability of simulation results, especially if the gas lift system is to be expanded to include other wells or formations. Combining accurate reservoir data with continuous operational monitoring will be essential for improving artificial lift performance and maintaining long-term production gains in the field.

Although the wells in each formation were designed with the same pressure, injection rate, and number of valves, the production response was not completely uniform. This indicates subtle differences in reservoir properties or fluid compositions. Such behavior reflects the need to incorporate well-specific parameters into future designs, even within the same formation.

5.5. Economic analysis

The improved production of the five wells under study will have a clear impact on the expected profitability as a natural result of the increased production. For example, the financial return for well ADRu1-9-2H with a 238% increase in production will be the same percentage after deducting the water cut .

Assuming an oil price of 65 $ per barrel, the daily profitability of the well under natural flow (269 barrels of oil per day) will be approximately 17,000 $. After installing the gas lift system for this well, productivity increased by 238% (2682 stb/d with a water cut of 66%, oil production of 912 stb/d), meaning the profitability of this well will be approximately 59,000 .$

This analysis reflects the profitability resulting from the gas lift installation process and can be applied to the other wells under study. It is worth noting that the overall cost of the system was not calculated, as a comprehensive study of all wells that will be operated by gas lift is required. However, this economic analysis provides a general idea of the profitability resulting from the increased production of the wells.

6- Conclusion

The gas lift system has proven effective in improving the production of wells under study. However, to ensure the system's success, the optimal design must be chosen, as this leads to the highest economic productivity and profitability.

One design was chosen for the wells in the same formation, as wells in the same formation shared almost the same properties of the well and reservoir. 1750 psi injection pressure, 1 mmscf/d injection rate, and wellhead pressure of 300 psi were chosen for wells in the Mishrif formation, and the number of valves for the unloading process of this design is three. The injection pressure of 1950 psi, the injection rate of 1.25 mmscf/d, and the wellhead pressure of 475 psi were chosen for the wells in the Rumaila formation, and the number of valves in this design to complete the unloading process is four. The increase in the production rate for the five wells under study, as follows: 238%, 146%, 55.6%, 55.9%, 37.4%.

The main contribution of this work is to deliver a validated and practical framework for gas lift design in high-flow carbonate reservoirs, utilizing simulation tools such as PIPESIM. This method offers a clear process for choosing optimal injection parameters and valve configurations based on reservoir conditions and nodal analysis.

However, the study faced some limitations, especially the lack of complete PVT laboratory data, which restricted full model calibration. Future work should concentrate on post-installation performance matching and dynamic simulation to better validate the model under changing field conditions. Additionally, incorporating real-time production data and expanding the system to include more wells would improve the robustness and usefulness of the proposed design.

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التصميم الأمثل وتحليل الأداء لنظام الرفع بالغاز في المكمن الكاربونيتي في حقل الأحدب النفطي

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الخلاصة

يُعدّ رفع الغاز من أهمّ طرق الرفع الاصطناعي لزيادة إنتاج النفط، إذ غالبًا ما تحتاج الآبار إلى هذه الطريقة بعد انخفاض طاقة المكمن. في هذا البحث، صُمّم نظام رفع غازي أمثل لخمسة آبار أفقية في حقل الأحدب النفطي، الذي يُعاني من انخفاض الإنتاج. في الوقت نفسه، يصل قاطع الماء في بعض هذه الآبار إلى ٦٦%، بينما يكون مؤشر الإنتاجية منخفضًا في البعض الآخر، مما يُبرز التحديات، ويتطلب تحليلًا مُعمّقًا لإيجاد النظام الأمثل. يُستخدم برنامج Pipesim لتصميم نظام رفع الغاز الأمثل، الذي يحتوي على خصائص تُسهّل تنفيذ التصميم المُناسب، وتُتيح إمكانية تحليل وتحديد قيم التصميم الأمثل، بالإضافة إلى الكشف عن مشاكل الإنتاج المُستقبلية. صُمّم نظام واحد للآبار الواقعة في التكوين نفسه، حيث يُختار ضغط حقن يبلغ ١٧٥٠ رطل/بوصة مربعة، ومعدل حقن يبلغ ١ مليون قدم مكعب قياسي/يوم، وضغط رأس البئر ٣٠٠ رطل/بوصة مربعة للآبار في تكوين مشرف، مع العلم أنه سيتم تركيب ثلاثة صمامات في النظام. بالنسبة لآبار تكوين الرميلة، تم اختيار ضغط حقن قدره ١٩٥٠ رطل/بوصة مربعة، ومعدل حقن قدره ١,٢٥ مليون قدم مكعب قياسي/يوم، وضغط رأس البئر ٤٧٥ رطل/بوصة مربعة، وأربعة صمامات لعملية التفريغ. أثبتت النتائج كفاءة التصميم وأن القيم المختارة كانت مثالية، حيث بلغت الزيادة في إنتاج الآبار الخمسة ٢٣٨%، و١٤٦%، و٥٦,٦%، و٥٥,٩%، و٣٧,٤%.

الكلمات الدالة: حقل الأحدب النفطي، الرفع الاصطناعي، الرفع بالغاز، بايبسيم، إنتاج النفط.