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## Optimizing gas lift for enhanced recovery in the Asmari formation: a case study of Abu Ghirab field in Southeastern Iraq

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The gas lift technique applies gas bubble injection into the vertical wells to raise production. Gas and liquid rates, shifts in flow regimes, and system equilibrium influence this process. This study explores the efficient implementation of gas lift techniques to maximize production from the Asmari Formation in the Abu Ghirab Field, southeastern Iraq, using a continuous gas lift for maximum production rate by PIPESIM™ software. The results of the gas lift design for the four wells (AGCS-33, 26, 28, and 36) show that the Vogel method provided the best results for the gas lift design, and faults and facies distribution impact the gas lift injection and oil production rates. These will become evident with wells AGCS-33 and 36 as their proximity to faults will increase oil production rates with a gas injection rate limit of 7 MMSCF/d. Conversely, for wells 26 and 28, the limit will marginally rise, starting at 5 MMSCF/d. In addition, the effect of gas lift is clearly in the middle western of the crest, which shows an increasing percentage of oil production of 136.6% at minimum rate and 198.5% at maximum for the well AGCS-26, 89.7% and 105.7% for the well AGCS-36. Wellhead pressure has a significant impact on gas-lift performance, and improving gas-lift efficiency can be accomplished using an electric control valve. The feasibility of implementing gas lift in the Asmari Formation depends on the water cut, well location, and water saturation distribution within the Formation.

**Keywords** Gas lift, Recovery, Asmari formation, Abu Ghirab field, Nodal analysis

### Abbreviations

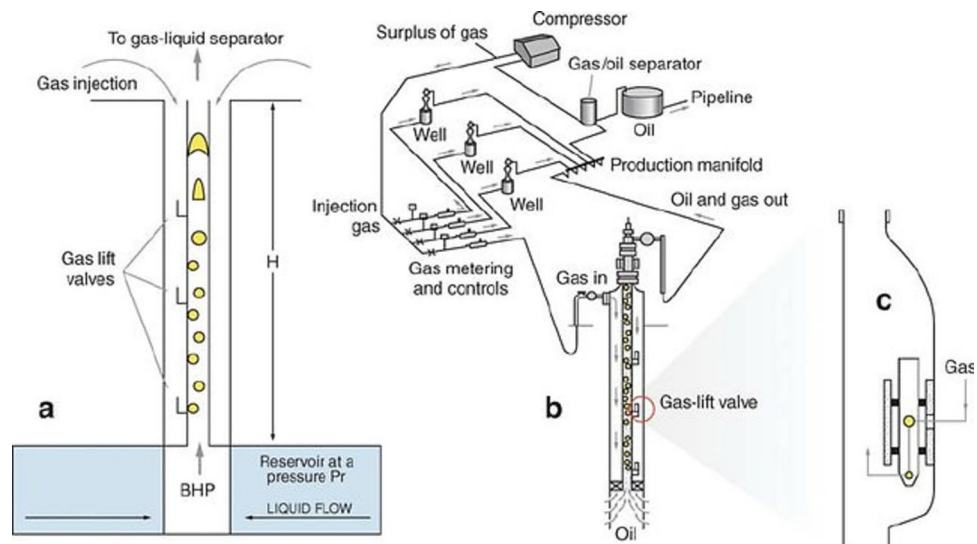
$\rho$	Density (lb/ft <sup>3</sup> )
$\mu$	Viscosity (cp)
AOF	Absolute open flow
bbl	Barrel
BHP	Bottom hole pressure (psi)
Bo	Oil formation volume factor (bbl/STB)
Cp	Centipoise
Cpl	Completion
Csg	Casing
D	Day
ESP	Electrical submersible pump
F°	Fahrenheit
ft <sup>3</sup>	Cubic feet
GL	Gas-lift
GLINC	Method by Wang and Litvak
GLIR	Gas-lift injection rate (Scf)
GLPC	Gas-lift performance curve
GLR	Gas liquid ratio (Scf/STB)
GOR	Gas oil ratio (Scf/STB)
IPO	Injection-pressure-operated gas lift valve

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IPR	Inflow performance relationship
J	Productivity index
m	Slope value on a gas-lift performance curve.
MID	Maximum injection depth (ft)
MWt	Molecular weight
NIF	Non-instantaneous flow
Pb	Bubble point pressure (psi)
Ph	Wellhead pressure (psi)
Pk	Packer
Pr	Reservoir pressure (psi)
Psi	Pound per square inch
Pv	Valve pressure (psi)
Q	Flow rate (bbl/d)
$Q_{gi}$	Gas injected flow rate (MMscf/d)
$Q_{pl}$	Produced liquid flow rate (STB/d)
SCF	Standard cubic feet
SG	Specific gravity
SLP	Sequential linear programming
STB	Stock Tank Barrel
SW	Water saturation (V/V)
TGP	Threshold pressure gradient (psi/ft)
TR	Temperature of reservoir (F°)
$\Delta p$	Drawdown pressure (psi)

Natural gases are normally associated with crude oil during early stages of production. The formation gas and reservoir pressure provide sufficient energy to lift fluid from the reservoir to the surface<sup>1</sup>. However, over time, this energy will be depleted, leading to a rise in the water cuts if the reservoir is not associated with an aquifer. Eventually, the pressure will become inadequate for lifting the fluid from the bottom to the top, leading to the discontinuation of flow<sup>2</sup>. It is essential to augment the fluid's power through some form of artificial lift to resume production in a well or boost from a poorly flowing well<sup>3</sup>. Gas lift and gas injection augment flow and production from a reservoir<sup>4</sup>. Gas lift is considered a primary artificial lift technique used throughout the well's lifespan, while miscible gas injection is a secondary or tertiary enhanced recovery method<sup>5</sup>. Gas injection can be implemented in older or tight wells where additional assistance is required<sup>6</sup>. One key distinction between the two methods lies in the gas flow direction: gas injection is directed into the reservoir, while gas lift is directed into the wellbore and towards the surface<sup>7</sup>. A significant difference is that gas injection often necessitates a high-pressure compressor or pump because the injected gas competes with the existing reservoir pressure to access the formation<sup>8</sup>, on the other hand, gas lift pressures depend primarily on the well's depth and tend to decrease at equivalent depths<sup>9</sup>. The gas lift technique involves gas bubble injection into the vertical wells to enhance production by reducing the tubing pressure gradient<sup>10</sup>. This process is influenced by various fluid-flow phenomena, including gas and liquid rates, shifts in flow regimes, and system equilibrium issues<sup>11</sup>.

The gas lift system is straightforward regarding equipment and operational principles, as depicted in Fig. 1. Choosing the most suitable artificial lift technique is critical for long-term Well production. An inappropriate choice could lead to poor outcomes and increased operating costs<sup>12</sup>. Various approaches are utilized in gas lift



**Fig. 1.** Gas lift system (Guet and Oom 2006).

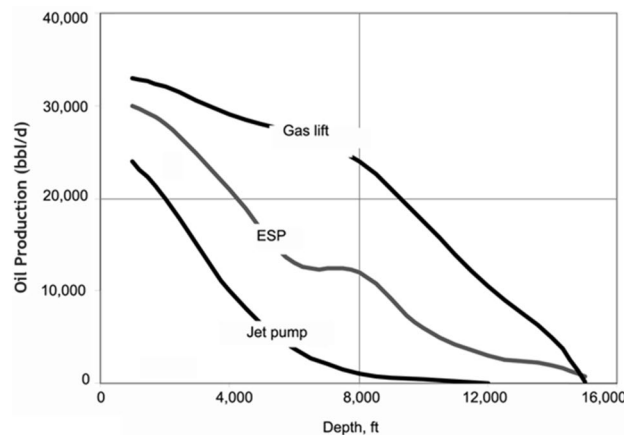
operations. In the continuous method, gas is injected into the well at an appropriate depth and rate to mix with oil in high-flow-rate wells (exceeding 0.5 STB/D/psi). The intermittent technique will be appropriate for low-pressure reservoirs with lower flow rates (less than 0.5 STB/D/psi)<sup>13</sup> and oil accumulates in the wellbore, and gas surge is injected into the oil column to achieve the desired production<sup>14</sup>. The gas lift performance curve (GLPC) illustrates the production rate concerning the gas injection rate<sup>15</sup>. A modified threshold pressure gradient (TGP) method considering pressure sensitivity and realistic reservoir fluid Seepage capacity considering various miscible degree and pore scale was evaluated<sup>16</sup>. A quantitative approach was developed to address excessive gas production in field depletion development, even if the formation pressure is below the dew point<sup>17</sup>.

### Advantages and limitations of gas lift

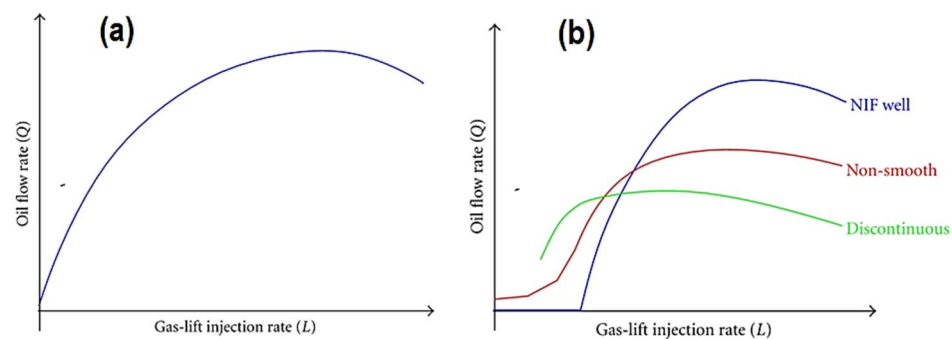
The gas lift system is versatile, adapting to different production rate ranges and depths of lift. It can be compared to other artificial lift methods if injection gas pressure and volume are available<sup>4</sup> (Fig. 2). Gas lift is one of the most adaptable artificial lift techniques. An inadequately designed system will manage to lift some fluid<sup>16</sup>. Highly deviated wells with highly formed Liquid Ratio (GLR) prone to sand production are ideal candidates for gas lift implementation when artificial lift is necessary<sup>17</sup>. The main limitations for gas lift operations include the absence of formation gas or an external gas source, well spacing, and the availability of space for compressors on offshore platforms<sup>18</sup>. Generally, gas lifts are unsuitable for single-well installations, and widely spaced wells are not conducive to a centrally located power system<sup>19</sup>. Implementing gas lift can exacerbate issues related to dense crude production, super-saturated brine, or emulsions<sup>20</sup>. Gas lift operations may be impractical with old casing, sour gas, and long, small-ID flow lines<sup>21</sup>. Additionally, the reliability of gas lift operations can be compromised by wet gas without adequate dehydration<sup>22</sup>.

### Nodal analysis

Nodal analysis generates the gas lift performance curve according to actual pressure and temperature with an appropriate multiphase flow correlation<sup>24</sup>. The optimum gas-lift injection rate (GLIR) is often only set to deliver the most increased production rate on the (GLPC) (Fig. 3a). The maximum GLIR and oil rate can be useable to establish the optimal valve depth setting and the wellhead pressure ( $P_{wh}$ )<sup>25</sup>. Computer models can be utilized to analyze Well behavior, conduct diagnostics, redesign, and others to generate Well relationships (GLPC), and



**Fig. 2.** Gas lift, ESP and jet pump performance curve<sup>23</sup>.



**Fig. 3.** Gas lift performance curve at a given wellhead pressure ( $P_{wh}$ ), (a) by nodal analysis, (b) by sequential linear programming<sup>25,28</sup>.

complete optimization<sup>26</sup>. The lift gas can be examined for a single well by nodal analysis<sup>27</sup>. The back pressure consequences can be assessed by gas injection on two wells earlier to analyze the wells network. Sequential Linear Programming (SLP) techniques were suggested for gas lift, and the resulting lift performance curves were considered to be linear through a first-order Taylor series expansion. The linear model may be an inadequate expression of the highly nonlinear system, and non-instantaneously flowing (NIF) wells can be problematic (Fig. 3b)<sup>28</sup>. Recent researches utilize separable programming, the adjacency condition, and particular order sets to qualify each well's lift performance curve and optimize the linear solver's performance<sup>29</sup>, whereas a better precise well model was presented depending on mass, energy, and momentum equilibrium<sup>30</sup>. A better-suited model for field-wide simulation was presented, with no field applications to test this model. The compositional models over simple black oil are also recommended practice for better accuracy<sup>31,32</sup>.

This study is considered the first for the Asmari Formation in the Abu Ghirab Field, characterized by excessive fault distributions that make any developing plan very difficult. Therefore, this study tried to evaluate the increase in the oil production rate according to the location of the wells and the best gas injection rate and pressure by selecting four wells in different pads for the field. For future work, the authors will modify this work by the whole oilfield simulation using Pipesim™ and CMG™.

## Geological setting

The Abu Ghirab oil field was discovered in 1971 and entered the production line in 1976. It is located in the southeastern part of Iraq with an area of 106.8 km within a mountainous area ranging from 70 to 160 m of height formed of two domes with a saddle area between these domes<sup>33</sup> (Fig. 4). It is part of the Kirkuk embayment zone in the unstable stand of the Arabian plate<sup>34</sup>. This region is active due to the crash of the Arabian and Iranian plates, so the Abu Ghirab field has a complicated structure. Figure 5 shows the stratigraphic column of the area<sup>35</sup>.

The Asmari Formation is part of Tertiary deposits (Oligocene-Lower Miocene) in southeast Iraq<sup>36–40</sup>. Kirkuk Group includes three sub-zones: A- Upper Kirkuk consists of limestone, dolomite, and some sandstone<sup>41</sup>. B- Buzurgan Member of dolomite, sandstone, limestone, and upper shale in the upper part<sup>42</sup>. In the Abu Ghirab structure, the pre-geological studies indicate the presence of two distinct types of forces caused by folding movement<sup>44</sup>. These forces led to tension forces in the upper portion of the structure and compression forces in

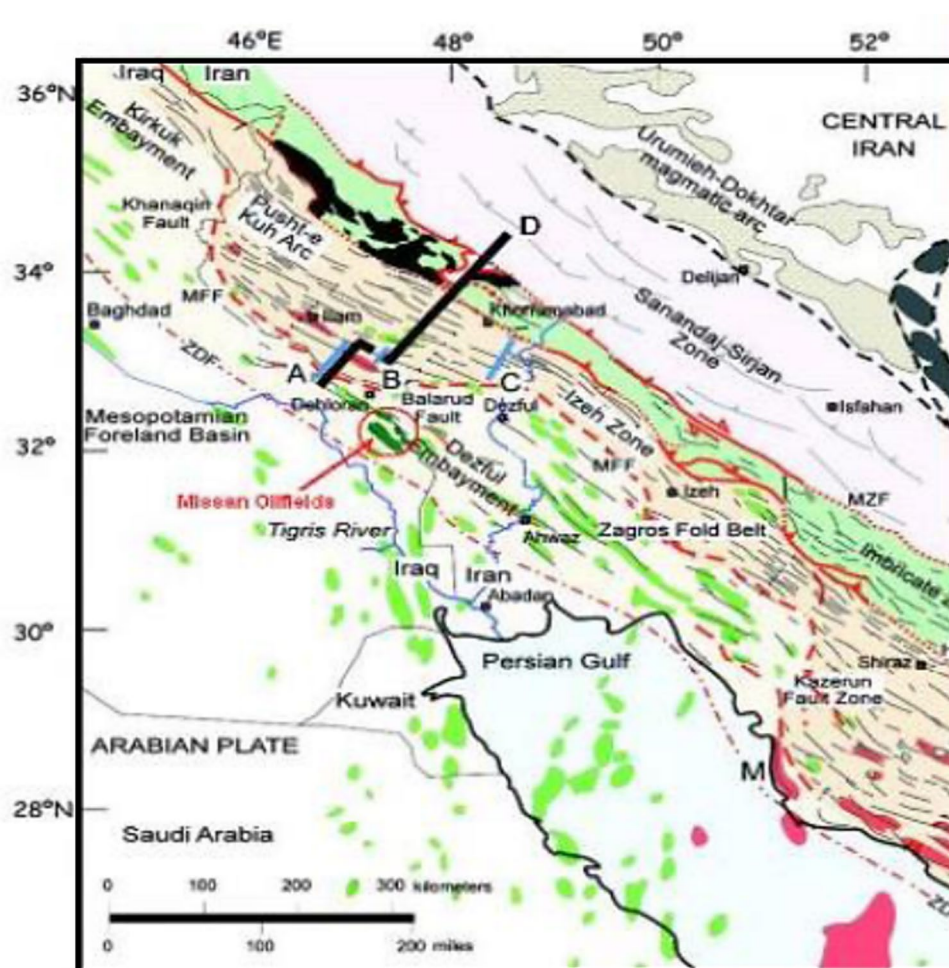


Fig. 4. Abu Ghirab oil field, Southeastern Iraq<sup>35</sup>.

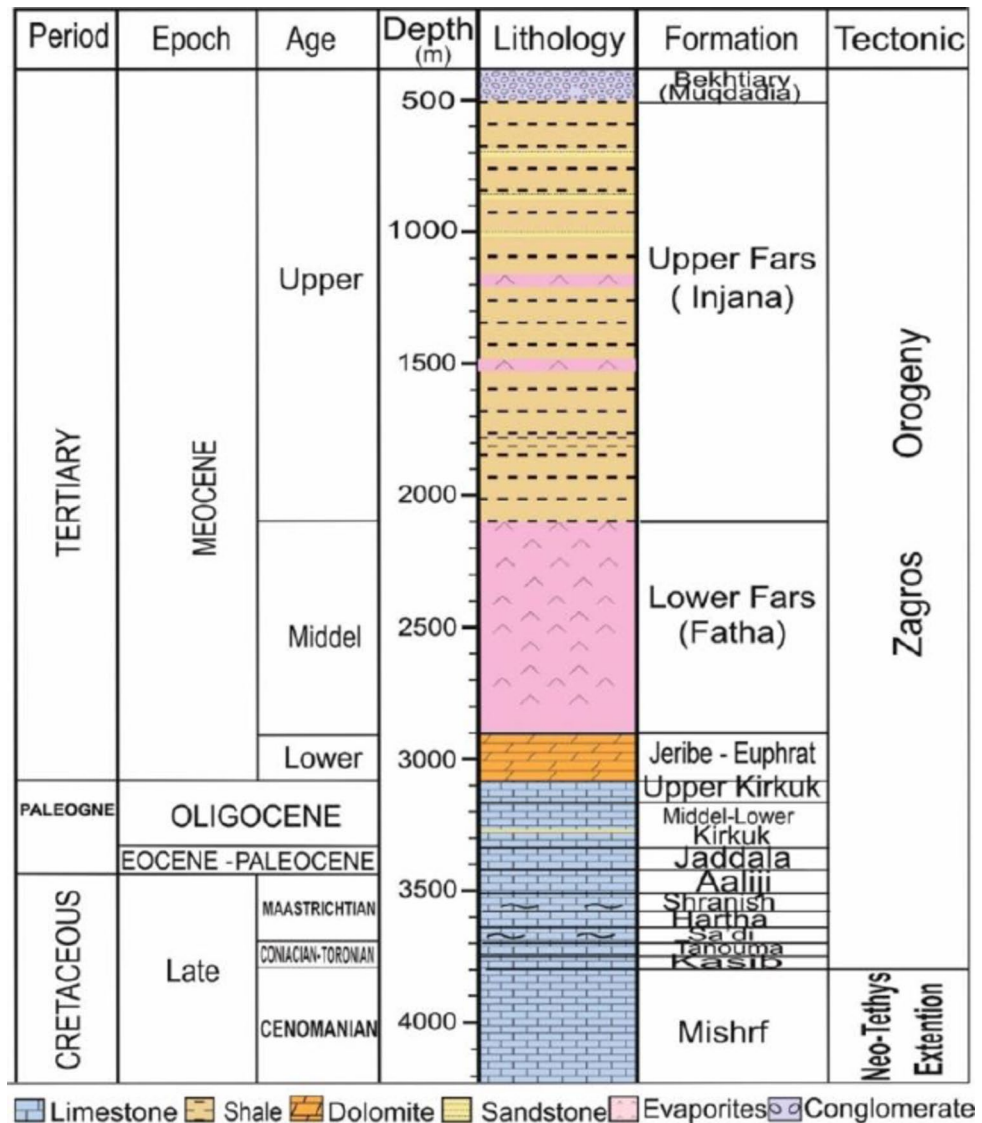


Fig. 5. Stratigraphic column of Abu Ghirab<sup>43</sup>.

the lower parts. As a result, the structure exhibited tangential deformation, taking on a longitudinal shape. The intensity of deformation was high in the limbs, while the anticline axis displayed low intensity<sup>38</sup>.

### Data and methods

This study delivers an all-around outline of artificial lift for the Asmari Formation in the Abu Ghirab Field. Commercial software PIPESIM™ is used in this study to determine the Well performance. The PIPESIM™ includes option for determining artificial lift performance to estimate the optimum quantity of gas injected, and injection pressure, as well as optimum injection depth and understanding the impact of these factors on production, the estimation of the optimal injection conditions when water cut shifts<sup>45,46</sup>. Figure 6 shows the locations of wells under study (AGCS 26, 28, 33, and 36). The facies logs were obtained from wireline logs and facies model constructed by Petrel™<sup>47,48</sup> (Fig. 7). AGCS-33 well is located in the north part of the south dome in the Abu Ghirab field and completed to develop the Asmari reservoir with a total depth of 3214.0 m, then perforated and acidized at flow back unit (A) with three different choke sizes. The well AGCS-26 is located in the north part of the south dome of the Abu Ghirab field with the producing Unit (A and B) of the Asmari reservoir (Fig. 6), a total perforated thickness of 75m. AGCS-26 well was put into production on Dec. 21, 2014. Other wells (AGCS-28 and 36) in the south part of the south dome, but with different characteristics (Fig. 8 and Table 1).

A natural gas was utilized in the continuous gas lift system after the necessary treatments. Table 2 shows properties and composition of the natural gas. A design for the gas lift system includes the depth of the injection valves, size of the valve port, number of valves, and amount of spacing between. PIPESIM™ was used to simulate the gas lift process for wells (AGCS-33, 26, 28, and 36) based on the field data of the Abu Ghirab field.

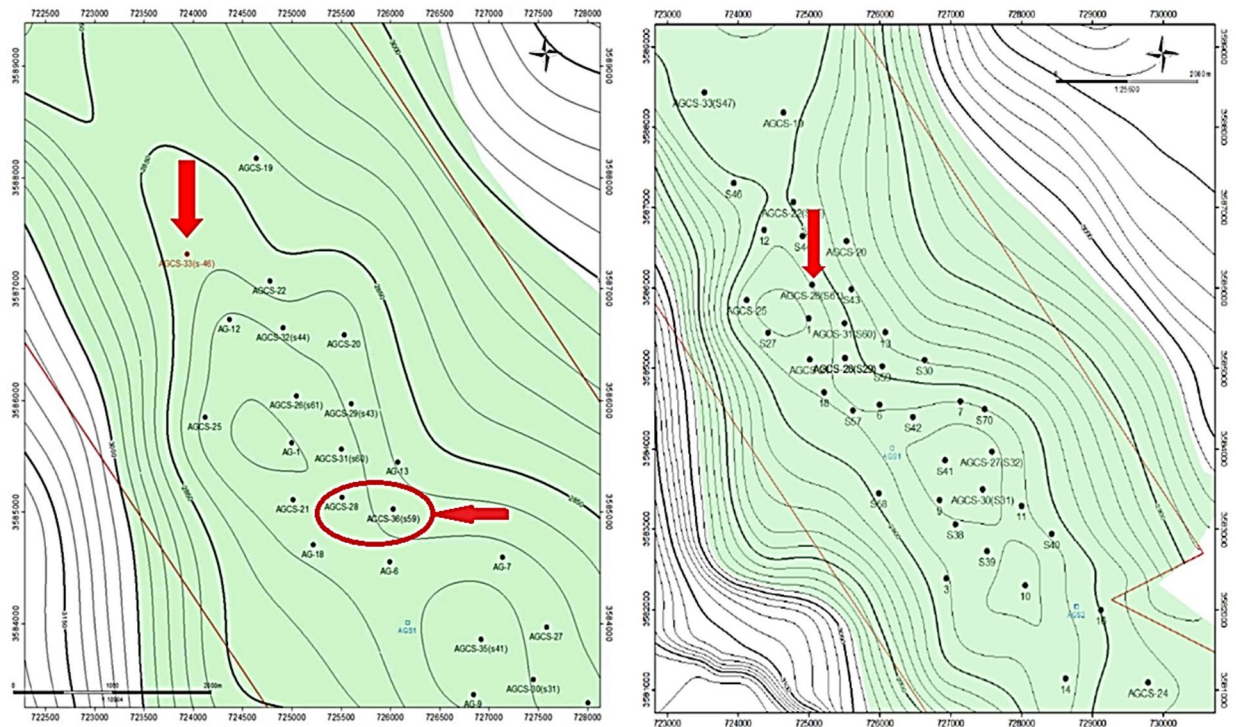


Fig. 6. Wells locations in Abo Ghirab field.

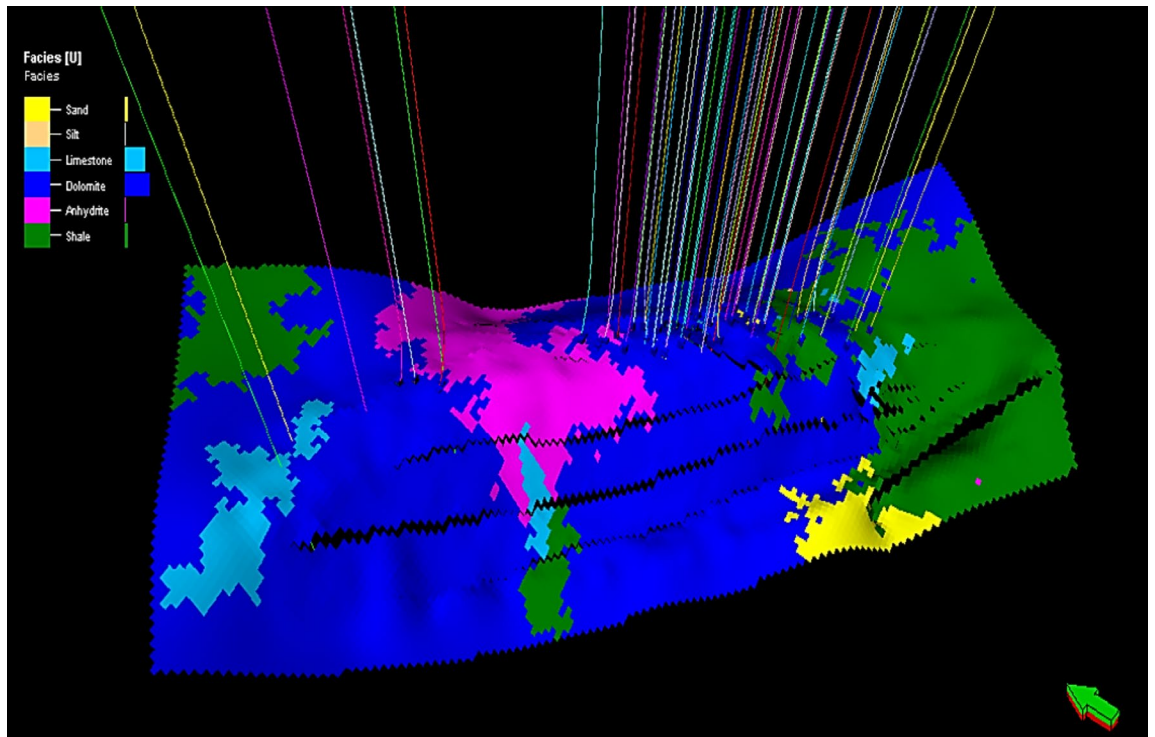


Fig. 7. Facies model for Asmari formation in Abo Ghirab field<sup>35</sup>.

## Results and discussion

### Productivity index (PI)

The productivity index (PI) is an important variable used to evaluate production well performances in the oil and gas industry. It's a measure of the amount of oil produced concerning the decrease in pressure. Equation 1 shows the correlation for estimating PI as  $q/\Delta p$ , where  $q$  is the production flow rate, and  $\Delta p$  is the drawdown pressure. PI is typically measured in bbl/day/psi units<sup>49</sup>. The results of the well performances are shown in Table 3.

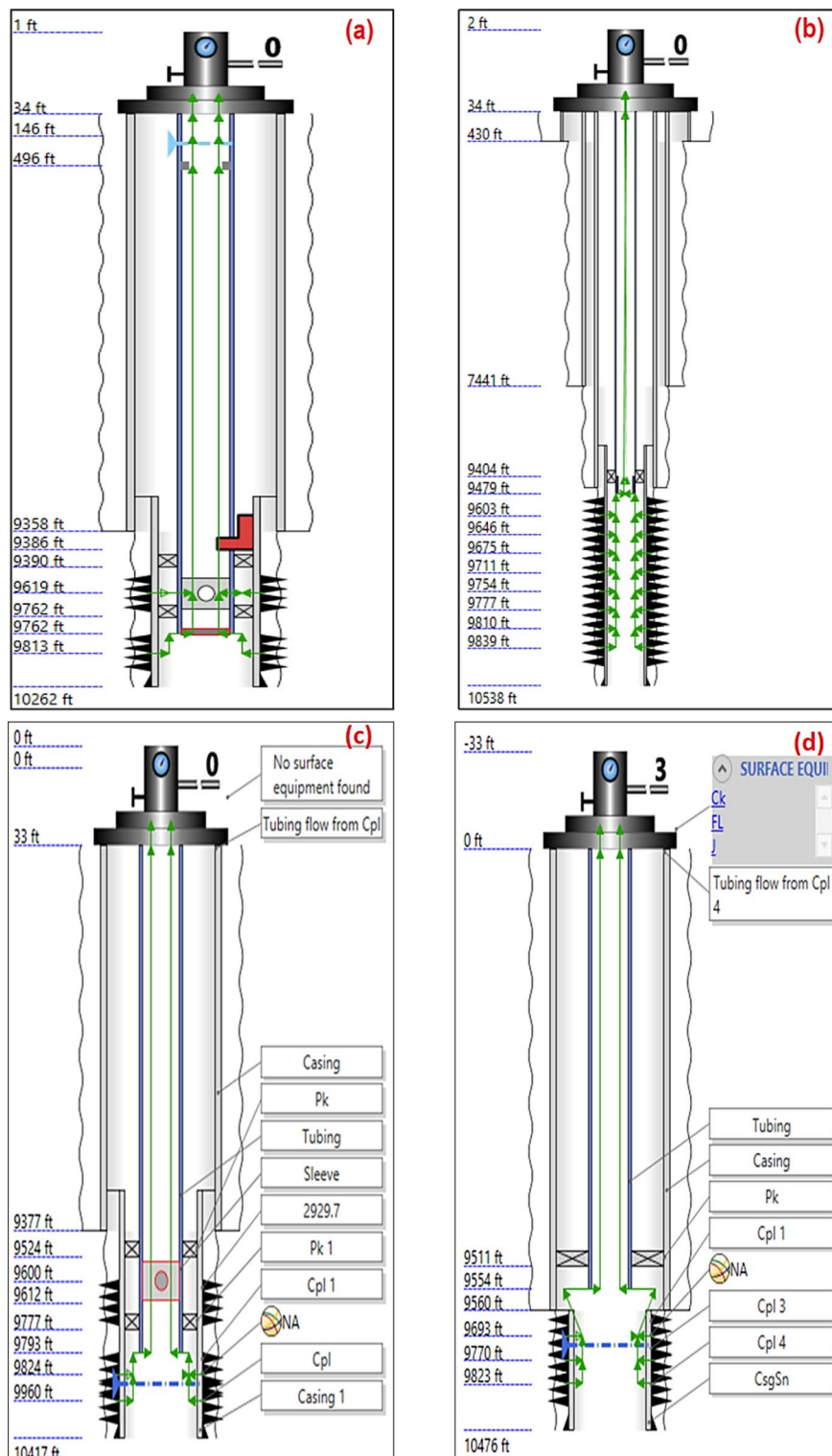


Fig. 8. Completion of the wells (a) AGCS-33, (b) 26, (c) 28, (d) 36.

$$J = \frac{Q_o}{P_R - P_{wf}}$$

**Inflow performance (IPR)**

Inflow performance (IPR) is an empirical two-phase (oil + gas) inflow performance relationship correlation<sup>50</sup>.

Property	Unit	AGCS-33	AGCS-26	AGCS-28	AGCS-36
GOR	Scf/STB	577	612	577	577
P <sub>b</sub>	psi	2450	2944	2450	2450
API		21.9	21.6	21.9	21.9
μ	cp	1.59	1.24	1.59	1.59
B <sub>o</sub>	bbl/STB	1.36	1.35	1.36	1.36
ρ	lb/ft <sup>3</sup>	60.86	57.68	60	60.2
Q	bbl/d	2860	940	1310	2100
P <sub>H</sub>	psi	1300	720	14.7	800
Choke size	inch	36/64	36/64	64/64	52/64
TR	F°	196.25	196.25	197	196

**Table 1.** Wells characteristics.

Composition %	Pressure (Kg/cm <sup>2</sup> )								
	150	130	110	96	70	50	30	10	ATM
Nitrogen	5	4.09	1.56	0.91	0.85	0.76	0.64	0.60	0.50
Methane	74.97	75.98	77.68	77.49	75.13	71.68	66.41	43.01	10.49
Carbon dioxide	0.36	0.41	0.43	0.39	0.42	0.47	0.59	0.66	0.34
Hydrogen sulphide	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil
Propane	4.36	4.49	4.74	5.02	5.64	6.68	7.82	15.88	29.06
i-Butane	0.47	0.47	0.49	0.50	0.55	0.63	0.90	1.85	4.72
n-Butane	1.44	1.43	1.47	1.48	1.62	1.88	2.29	4.96	15.32
i-Pentane	0.40	0.39	0.39	0.38	0.40	0.46	0.65	1.44	4.65
n-Pentane	0.60	0.56	0.56	0.53	0.57	0.64	0.85	1.87	5.94
Hexane	0.98	0.78	0.73	0.62	0.65	0.70	0.67	1.46	3.98
Heptanes	1.27	0.84	0.63	0.41	0.35	0.34	0.20	0.46	0.94
Octanes	0.21	0.12	0.09	0.05	Trace	Trace	Trace	Trace	0.03
Total	100	100	100	100	100	100	100	100	100
Gas SG	0.7833	0.7622	0.7508	0.7443	0.7584	9.7872	0.8274	1.0631	1.5778
Gas MWt	22.68	22.07	21.74	21.55	21.96	22.80	23.96	30.79	45.69

**Table 2.** Properties and composition of the natural gas.

Well No		P <sub>R</sub> (psi)	P <sub>wf</sub> (psi)	Q (STB/d)	J (STB/d *psi)	Q <sub>max</sub>
AGCS-33		4730.8	4172.9	3157.6	5.66	26,759
AGCS-26	Zone A	4700	4126	408.8	0.713	3350.82
	Zone B	4700	4215	565.8	1.166	5480
AGCS-28		4763	4250	300	0.585	2790.7
AGCS-36		4710	4150	1250	2.231	10,522

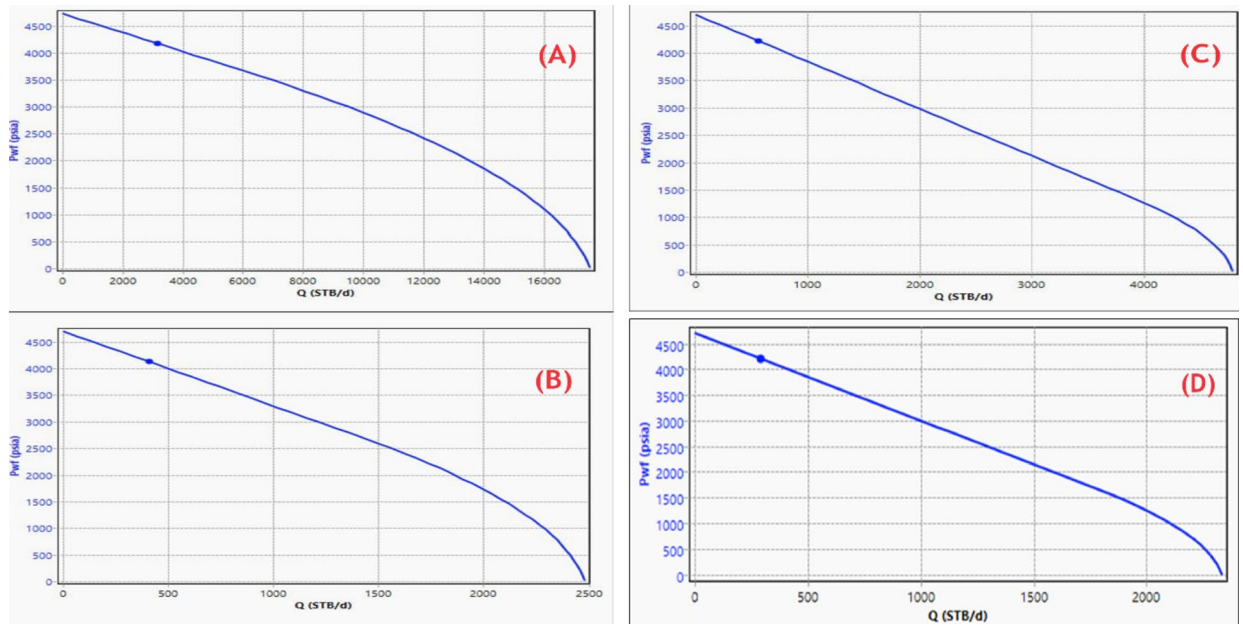
**Table 3.** Well performance data.

The productivity of an oil well producing a solution-gas drive reservoir was investigated by Vogel using numerical simulation. Simulations covering a wide range of oil, PVT properties, and relative permeabilities were made. By dimensionless pressures and rates, Vogel found that well's productivity could be described by Eq. 2 (Vogel's Equation) as shown in Fig. 9 and Table 3.

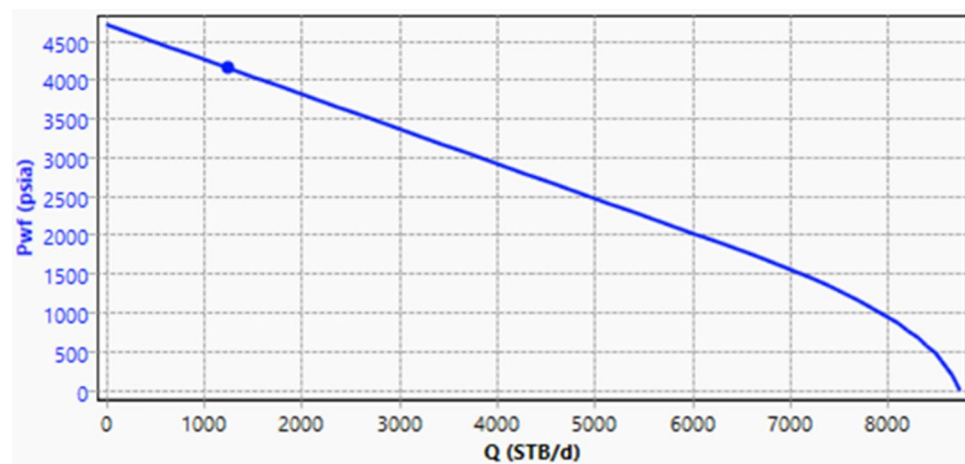
$$\frac{Q_o}{Q_{max}} = 1 - 0.2 \left( \frac{P_{wf}}{P_R} \right) - 0.8 \left( \frac{P_{wf}}{P_R} \right)^2 \quad (2)$$

Figures 9 and 10 represent the inflow performance IPR of the four wells in the Asmari reservoir under different flow rates due to the decrease in the reservoir pressure during the production process. The productivity index PI was about 5.66 STB/d\*psi for AGCS-33. As for AGCS-26, because it contains two zones, the productivity index (PI) for zone A is approximately 0.713 STB/d\*psi, and for zone B is 1.166 STB/d\*psi and the Absolute





**Fig. 9.** Inflow performance for wells (a) AGCS-33, (b) 28, (c) AGCS-26/zone A, and AGCS-26/ zone B.



**Fig. 10.** Inflow performance for well AGCS-36.

Open Flow (AOF) for AGCS-33 of 16,900 STB/d. Likewise, for AGCS-26, AOF is 2500 STB/d (zone A) and 3900 STB/d for zone B, about 2750 STB/d and 8500 STB/d for wells 28 and 36 respectively. An increase in PI leads to an increase in the AOF of the well, considered positive from a Production perspective, as increasing the AOF leads to increasing production, which is the main objective of this study. The PI in AGCS-33 is much greater than the PI in AGCS-26, and this is due to the PI perpendicular to the saturation of the layer, as the oil saturation in So AGCS-33 is much greater than AGCS-26, which contains water cuts of up to 55%.

### Nodal analysis

The nodal analysis was performed by the PIPSIM simulator for the four wells (based on the oil production data) to determine the operating point that represents the field production simulation and the best, as well as the point that gives the best production rate with the best pressure (Fig. 11).

Figure 10 shows that a change in the reservoir pressure leads to a change in the production rate. A nodal analysis was conducted to determine the optimal production of the four wells before the gas lift and the production state. The operating point must be within certain limits that represent the relationship of the operating point to the production conditions. If the operating point is within these limits, the production is stable with no problems (Fig. 10 AGCS-33). For the wells AGCS-26, 28, and 36, the operating point is not within these limits, and there are problems in the production, such as the Inversion point problem for stable tubing production. This problem can be overcome by increasing the wellhead pressure from 720 to 800 psi during the gas injection.

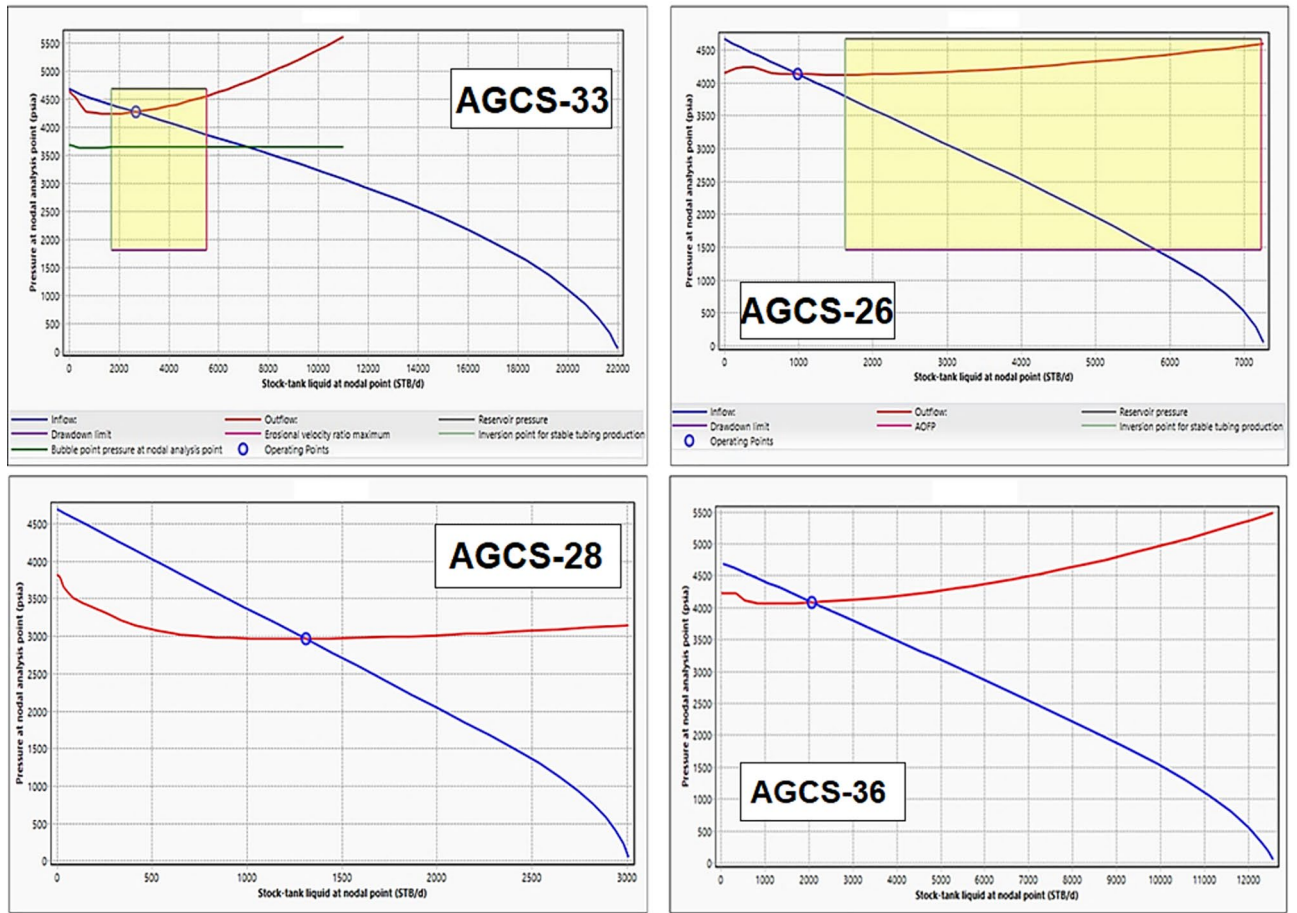


Fig. 11. Nodal analysis for wells AGCS-33, 26, 28, and 36.

### Gas lift design

The simulator was designed as an integrated gas lift system for the two wells based on the fluid properties and Well information. The injection-pressure-operated gas lift valve (IPO) system was obtained from SLB (Camco) for Schlumberger with a valve size of 1.5 in (Tables 4, 5, 6, 7 and Fig. 11).

Valve No	Valve depth (ft)	Series	Type	Pv open (psi)	Pv close (psi)
1	2888	R20-20	IPO	2676	2630
2	4502	R20-20	IPO	2740	2715
3	5286	R20-20	IPO	2763	2749
4	5682	R20-20	IPO	2759	2759

Table 4. Valve design information of AGCS-33.

Valve No	Valve depth (ft)	Series	Type	Pv open (psi)	Pv close (psi)
1	1979	R20-20	IPO	1675	1632
2	3360	R20-20	IPO	1698	1670
3	4218	R20-20	IPO	1707	1988
4	4768	R20-20	IPO	1706	1694
5	5428	R20-20	IPO	1700	1692
6	5700	R20-20	IPO	1709	1689

Table 5. Valve design information of AGCS-26.

Valve No	Valve depth (ft)	Series	Type	Pv open (psi)	Pv close (psi)
1	2146.9	R20-20	IPO	1047.8	998.5
2	3718.7	R20-20	IPO	1055.6	1019.4
3	4796.3	R20-20	IPO	1055.4	1029.1
4	5557.4	R20-20	IPO	1050.3	1031.6
5	6074.8	R20-20	IPO	1041.7	1028.6
6	6413.1	R20-20	IPO	1030.4	1021.5
7	6735.6	R20-20	IPO	1038.2	1014.0

**Table 6.** Valve design information of AGCS-28.

Valve No	Valve depth (ft)	Series	Type	Pv open (psi)	Pv close (psi)
1	2753.3	R20-20	IPO	2130.2	2079.4
2	4469.5	R20-20	IPO	2176	2146.8
3	5371.3	R20-20	IPO	2192.4	2175.5
4	5859.6	R20-20	IPO	2193.9	2184.2
5	6182.1	R20-20	IPO	2201.5	2184.9

**Table 7.** Valve design information of AGCS-36.

The simulator will be spacing and choose which type of series, orifice, and port size is preferred for the Well design, the final distribution, and valve details in Tables 3, 4, 5, 6. Figure 12 shows the process of distributing injection valves. The depth of point for placing the valve is 6000 ft, 5600 ft, 7200 ft, and 6200 ft for the wells AGCS-33, 26, 28, and 36, respectively. The valve state is in continuous closure below these depths because the pressure inside the tube is greater than the annular. According to valve technology, it opens automatically when the annular pressure is higher than the pressure inside the tube. If the injection pressure inside the ring has reduced, the valve will be closed.

### Gas lifting process

The amount of gas available for the injection process is essential for the production performance of the field. If limited gas is available for injection, the gas must be allocated to each well in the field to maximize the total field oil rate and enhance the gas-lift well's performance. Different gas rates (Table 8) were injected in the wells AGCS-33, 26, 28, and 36) (Table 9), which were produced by natural flow to investigate the effect of gas injection rate on production flow rate and how the gas-lift technique can be improved production rate.

Table 8 shows gas injection and liquid production rates with a maximum injection depth of MID for the well (AGCS-33) after gas lifting. The lift performance curves are plotted as the liquid rate of the well versus the gas injection rate for a gas injection pressure (2500 psi) and show the production system response to continuous gas lifting as shown in Fig. 12a. The gas injection pressure at 1600 psi, and the production system responded to continuous gas lifting for the well (AGCS-26) after gas lifting (Fig. 12b). The gas injection pressure at 100 psi and 2000 psi for the wells AGCS-28 and 36 (Fig. 12c and d).

The results of gas lift design for the four wells (AGCS-33, 26, 28, and 36) show that the maximum oil production rate for the wells are 4678, 2806, 2050, and 4332 STB/d (Figs. 13 and 14). The gas injection rates are (6 to 7), 7, 4, and 6 MMSCF/d (Tables 8 and 9) at an operating pressure of 1300, 800, 30, 850 psi (Fig. 12). The available at casing head and the bottom hole following pressure is 4268, 4118, 3000, and 4100 psi (Fig. 11) with five, six, seven, and five injection point pressure (IPO) valve type (Fig. 11) respectively. According to Tables 8 and 9 and Figs. 13 and 14, the maximum oil production rate that can be obtained from gas lift design for the Asmari Formation in the Abu Ghirab Field, Southeastern Iraq is (4678) STB/d for the well (AGCS-33) and 2806 STB/d for (AGCS-26). Production is affected by the gas lift system by several factors, the most essential of which are the gas injection rate and the gas injection pressure. Figures 13 and 14 show that increasing the gas injection rate can increase production to a certain extent due to the sliding phenomenon of the gaseous phase over the liquid phase. The injection pressure has a high effect on the production rate. When injection pressure is increased, the production rate increases until the limit that any increase in injection pressure leads to a slight increase in the production rate. When the production rate was plotted against injection pressure and gas injection rate, it was clear the production rate increased with increasing injection pressure to a limit that no economic benefit for further injection rates (Fig. 15).

According to Tables 1 (current production bbl/d), 7, and 8 (production by gas lift), there is a significant increase in oil production in all wells (Fig. 16). The effect of gas lift Has increased oil production as seen at the middle of the crest in Fig. 16, which shows an increasing percentage of oil production of 136.6% at minimum rate and 198.5% at maximum for the well AGCS-26, 89.7% and 105.7% for the well AGCS-36.

Figure 17 shows that gas lift injection and oil production rates are affected by the faults near the well and the facies distribution. The validation of this are for wells 33 and 36 whose oil production rates increased till gas lift

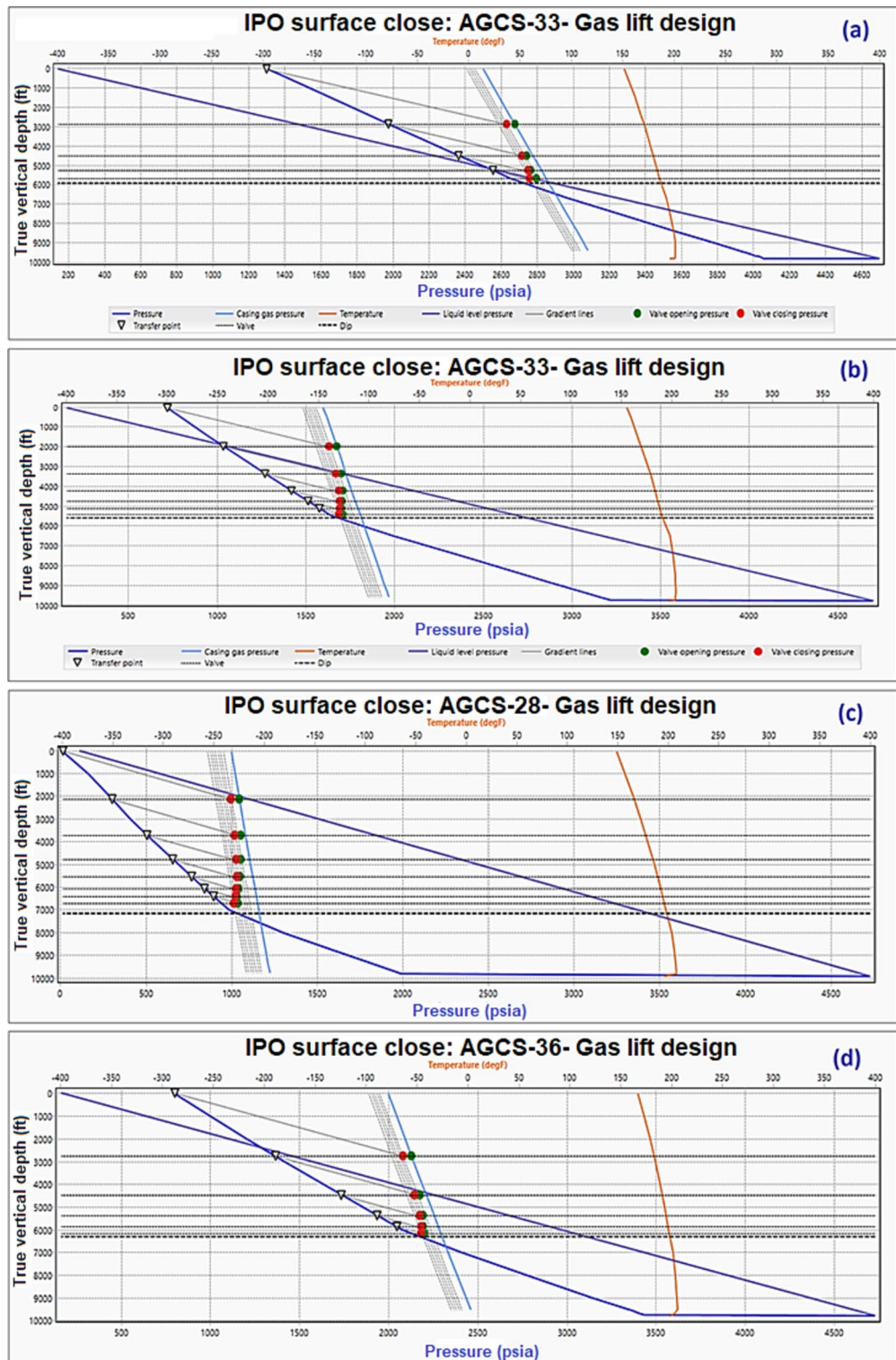


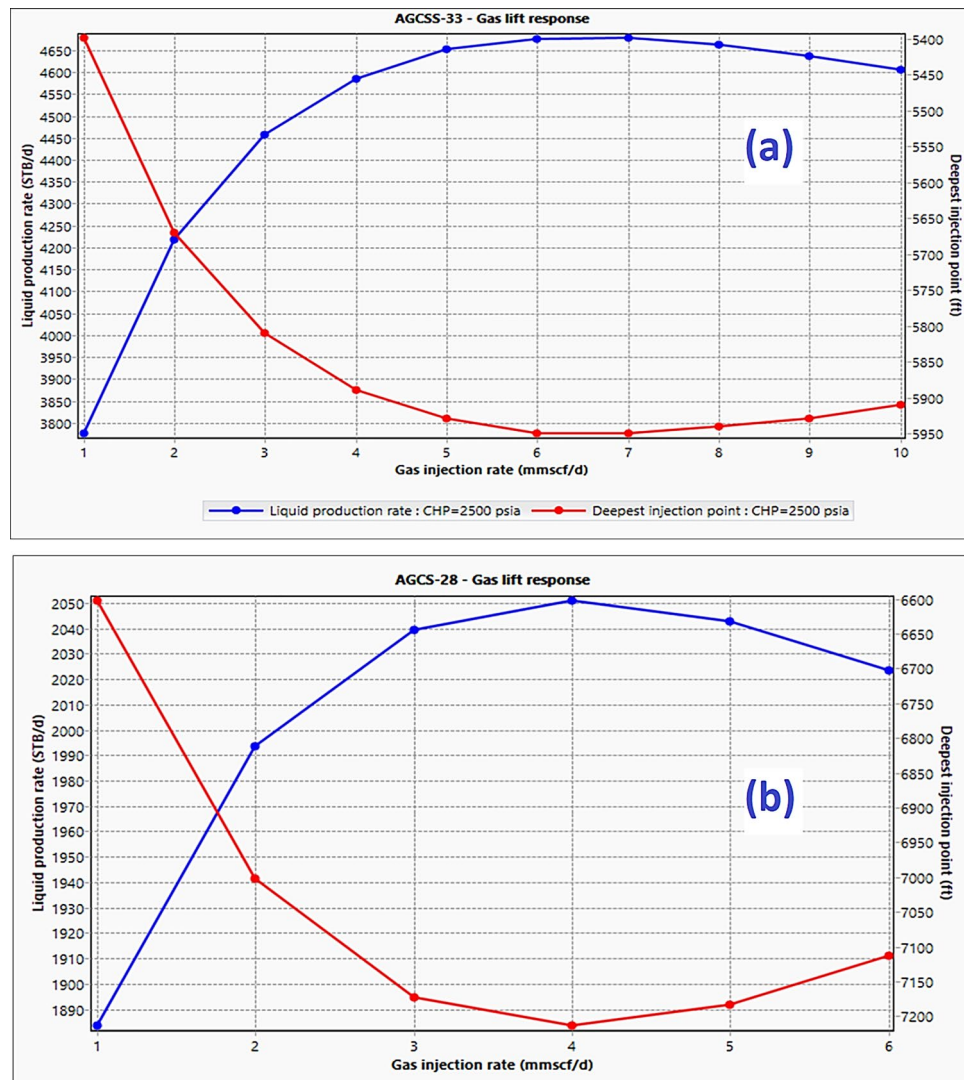
Fig. 12. Valve design of the wells (a) AGCS-33, (b) 26, (c) 28, and (d) 36.

$Q_{gi}$ (MMscf/d)	1	2	3	4	5	6	7	8	9	10
$Q_{pi}$ (STB/D)	3776	4219	4456	4585	4651	4675	4678	4662.3	4637	4604
MID (ft)	5398	5670	5810	5889	5929	5949	5950	5939	5929	5910

Table 8. Gas lifting data of the well AGC33.

Well No	Q <sub>gi</sub> (MMscf/d)	1	3	5	7	9	10
AGCS-26	Q <sub>pl</sub> (STB/D)	2224	2648	2766	2806	2803	2787
	MID (ft)	4652	5346	5536	5606	5596	5576
	Q <sub>gi</sub> (MMscf/d)	1	2	3	4	5	6
AGCS-28	Q <sub>pl</sub> (STB/D)	1882	1994	2040	2050	2042	2022
	MID (ft)	6615	6999	7175	7230	7195	7100
	Q <sub>gi</sub> (MMscf/d)	2	4	6	8	10	
AGCS-36	Q <sub>pl</sub> (STB/D)	3984	4274	4332	4319	4267	
	MID (ft)	6011	6310	6370	6360	6300	

**Table 9.** Gas lifting data of the wells AGCS-26, 28, and 36.



**Fig. 13.** Gas lifting for the well (a) AGCS-33, (b) 26.

rates of 7 mmscf/day due to closeness to faults, while for wells 26 and 28, the limit will slightly increase starting with 5 MMSCF/d. There is no economic benefit to increasing the gas injection rate. Increasing the shale volume above and below the production zone will play a crucial role in the efficiency of the process.

According to the Water cut, wells (AGCS-26, 28, and 33) show high rates while well AGCS-36 at a low rate during different periods due to the life of the well (Fig. 18). The results of Fig. 18 reflect the effect of water saturation levels on the well's production due to the location of the well and water saturation distribution in the

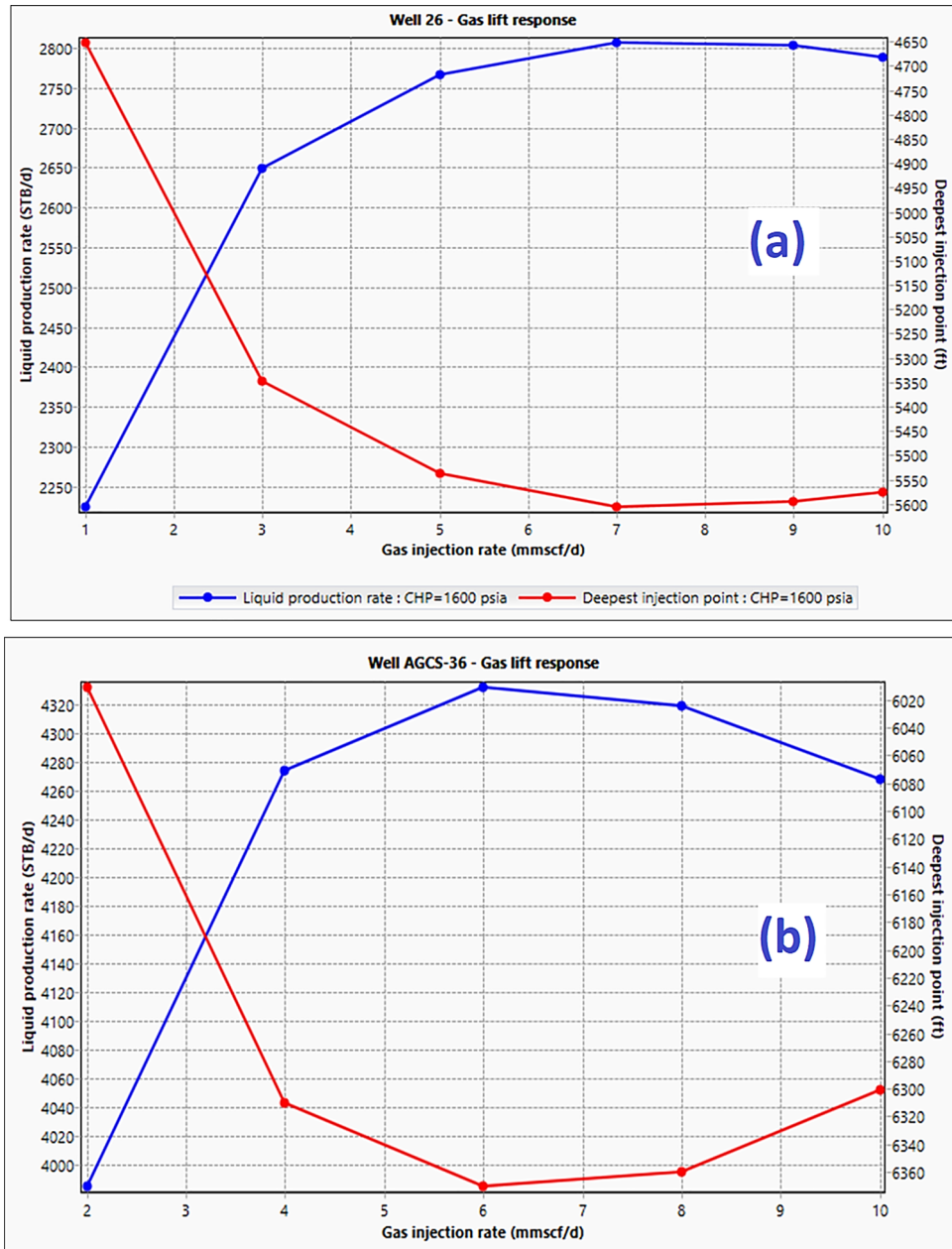


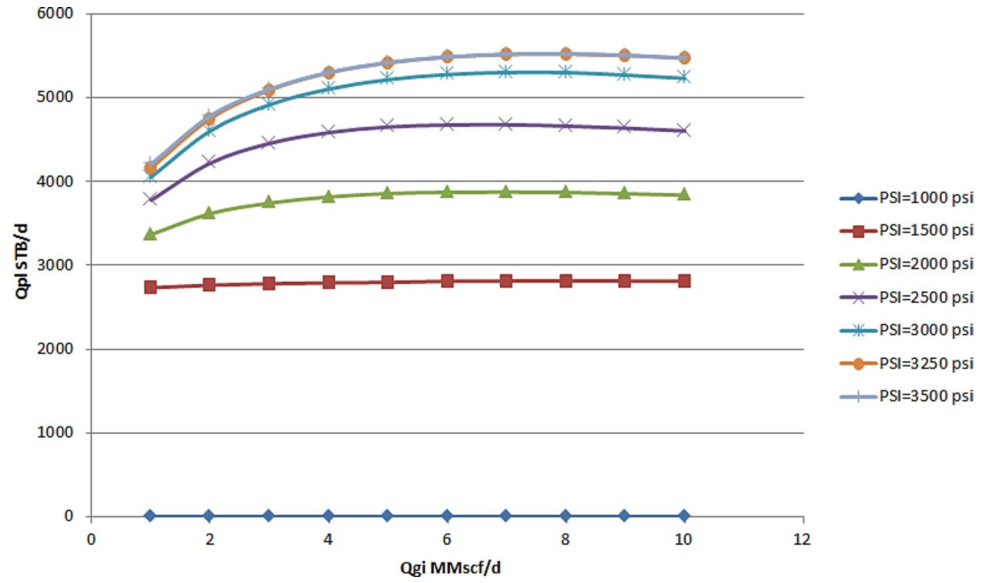
Fig. 14. Gas lifting for the well (a) AGCS-28, (b) 36.

Formation (Fig. 19). All these results will lead to the belief that the water cut must be considered if the gas lift process is applicable in the Asmari Formation.

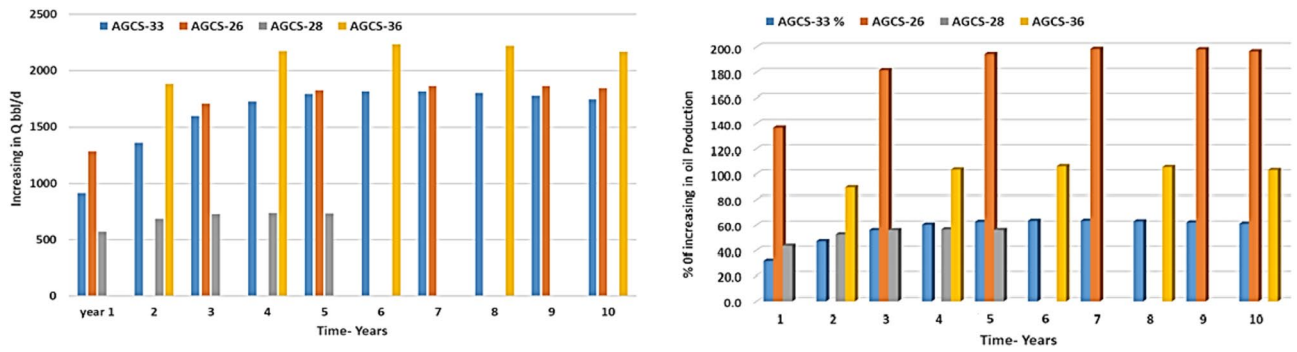
### Conclusions

In conclusion, the case study of optimizing gas lift for the Asmari Formation in the Abu Ghirab Field, Southeastern Iraq, has provided valuable insights into the complexities and potential of maximizing reservoir production through efficient gas lift techniques. The findings emphasize the significance of considering various factors such as injection pressure and injection rate, valve design, and water cut-off. In this study, a gas lift valve was utilizable to control the gas injection rate by opening the valve with different percentages using PIPESIM™.

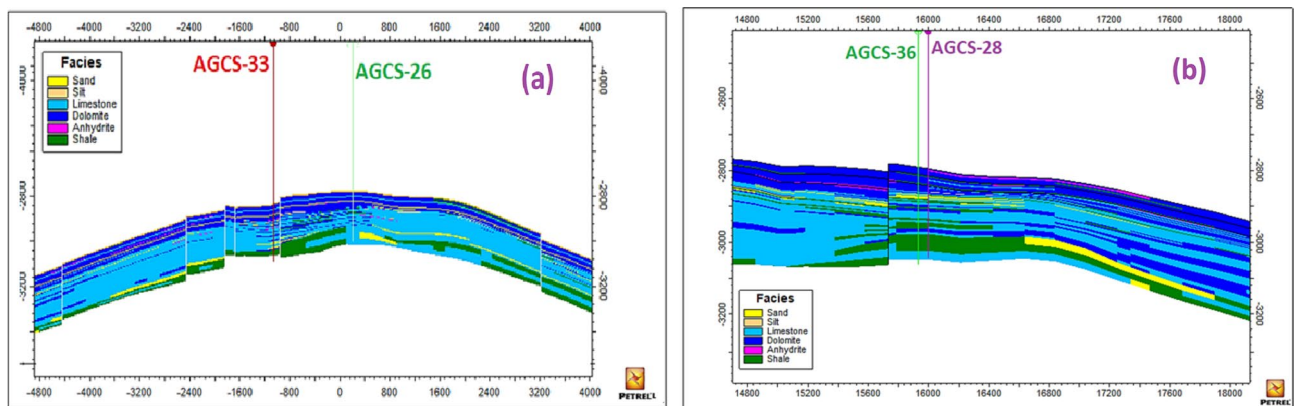
1. The results of the gas lift design for the four wells (AGCS-33, 26, 28, and 36) show that the maximum oil production rate will increase according to the existence of faults and the facies distribution.
2. This method has proven successful in increasing the oil production rate with high efficiency and effectiveness. The maximum oil production rate that can be obtained from gas lift design for the Asmari Formation in the Abu Ghirab Field, Southeastern Iraq is (4678) STB/d for the well (AGCS-33) and 2806 STB/d for (AGCS-26).



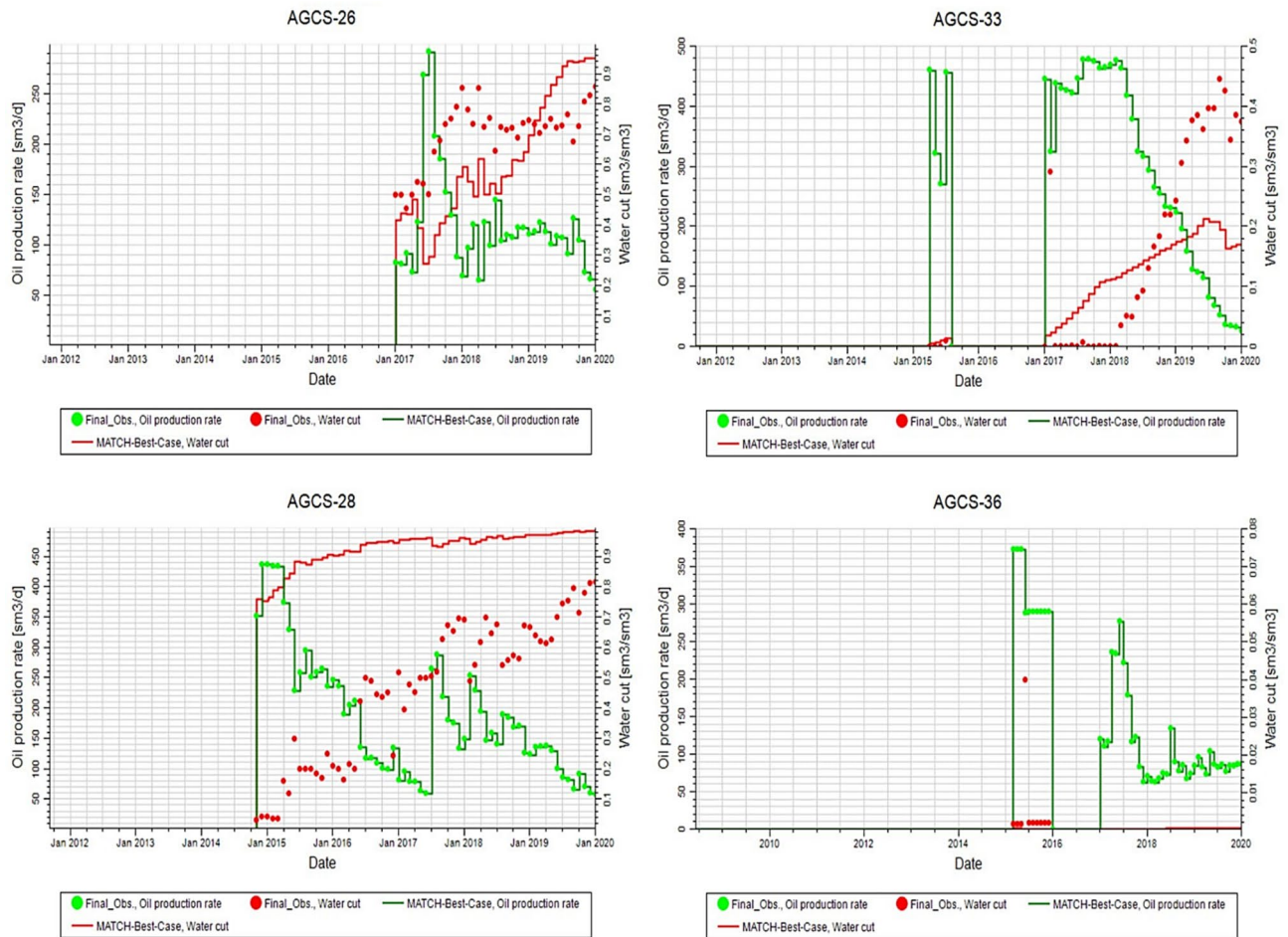
**Fig. 15.** The relationship of production rate to injection pressure and gas injection rate by lift gas injection for the well AGCS-33.



**Fig. 16.** Top-increasing in oil production (bbl/day), bottom- increasing percentage by gas lift for the four wells.



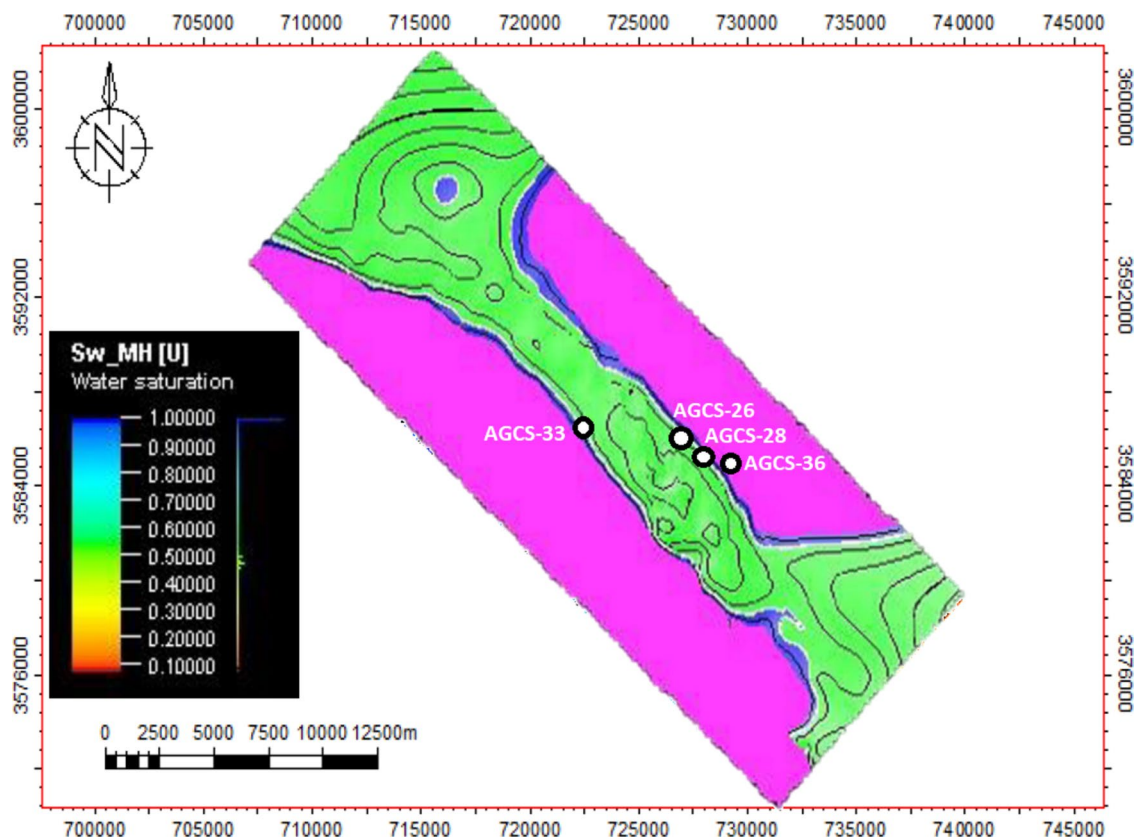
**Fig. 17.** A cross section of Facies model for (a) wells AGCS 33 and 26; (b) AGCS-36 and 28.



**Fig. 18.** Water cut values according to the oil production rate till the year of 2020.

3. The increase in the oil production by gas lift technique is obvious in the middle western of the crest, which shows an increasing percentage of oil production of 136.6% at minimum rate and 198.5% at maximum for the well AGCS-26, 89.7% and 105.7% for the well AGCS-36.
4. There is no economic benefit to increasing the gas injection rate for the wells far from the fault area.
5. Increasing the gas injection rate can increase production to a certain extent due to the sliding phenomenon of the klinkenberg effect. The production rate increases until the limit that any increase in injection pressure leads to a slight increase in the production rate.
6. The wellhead pressure significantly influences gas-lift performance, and enhancing gas-lift performance can be achieved by employing an electric control valve.
7. Production through gas-lifting would not only depend on injection rate but also can be optimized through the completion design and monitoring of the gas-lift supply pressure, total gas available, and other variables. Accordingly, the gas injection rate can be adjusted to yield maximum production rates.
8. Reservoir pressure, productivity index, and water cut-off are vital factors in the oil production rate.
9. The water cut must be considered if the gas lift process is applicable in the Asmari Formation according to the location of the well and water saturation distribution in the Formation.
10. Pre-development assessments to determine the feasibility of gas lift adoption are recommended. This technique will be suitable for severely heterogeneous Formations and prone to undesirable fluids breaking through early. Investigation of the impact of gas lifting on other types of wells, such as (multilateral wells and horizontal wells).





**Fig. 19.** Water saturation percentages in facies of the Asmari Formation before gas lift.

### Data availability

The datasets used and/or analyzed during the current study are available from the corresponding author and Maaly S. Asad upon reasonable request.

Received: 8 March 2024; Accepted: 26 August 2024

Published online: 31 August 2024

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### Author contributions

The authors confirm their contribution to the paper as follows: Study conception and design: M.S.A. and A.A.K. Data collection: Author M.S.A. Analysis and interpretation of results: M.S.A. and A.N.A. Draft manuscript preparation: A.N.A. checking and validation A.A.K. All authors reviewed the results and approved the final version of the manuscript. I would like to submit the manuscript entitled: Optimizing Gas Lift for Enhanced Recovery in the Asmari Formation: A Case Study of Abu Ghirab Field in Southeastern Iraq by Maaly S. Asad; Ahmed N. Al-Dujaili; Abdulkareem A. Khalil to be considered for publication as an original paper in the Scientific Reports Journal.

### Competing interests

The authors declare no competing interests.

### Consent to participate

We know of no conflict of interest associated with this publication and I as corresponding author confirm that the manuscript has been read and approved for submission by all the named authors.

### Additional information

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