



Improving hydraulic fracturing effectiveness in depleted and low-pressure reservoirs using N₂-energized fluids

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Abstract

Foamed and energized fluids fracturing has been used in both conventional and unconventional reservoirs, as they reduce the amount of water used and hence minimize deleterious impact on water-sensitive formations. They also aid in the flow back after treatment in reservoirs where drawdown is limited. In this paper, the most important foam properties are presented, in addition, when to use energized fluids fracturing and how to choose the best energizing component with the best quality. The impact of N₂-energized fluids fracturing (NEF) on wells that were previously fractured using conventional fracturing fluids is also presented. In addition, a comparison between the results of N₂-energized fluids fractured and conventional fluid fractured wells is presented. The effect of using 20 to 50% (NEF) on production through surface well testing and live production data showed excellent and sustainable production rates. An economical study is presented through comparing the total capital cost of both NEF and conventional fluids fracturing, in addition to the hydrocarbon recovery of wells after both types. Data considered in this work represent about 40 wells fractured using NEF in the Egyptian Western Desert.

Keywords Foam quality · Energizing component · Nitrogen-energized fluids · Conventional fracturing fluids · Low-pressure reservoirs

Abbreviations

NEF	Nitrogen-energized fluids
BHP	Bottom-hole pressure, psi.
BHT	Bottom-hole temperature, f.
K	Reservoir permeability, md.
E	Young's modulus, psi.
ν	Poisson's ratio
X_f	Fracture half-length, m
H_f	Fracture height, m
W_f	Fracture width, in
FC	Fracture conductivity, md.ft
W.C. _o	Pre-fracturing water cut, %
Q _o	Pre-fracturing gross rate, bpd
W.C. _f	Post-fracturing water cut, %
FOI	Fold of increase, unitless and given by Q_f / Q_o
Q _f	Post-fracturing gross rate, bpd

ARG	Abu Roash G Formation
ARE	Abu Roash E Formation
BAH	Bahariya Formation
U.BAH/ M.BAH	Upper and middle Bahariya Formation
N	Original oil in place
A5	Appolonia 5 Formation
A.BUEIB	Allam Al-BUEIB Formation
L.SAFA	Lower SAFA formation
EUR	Estimated ultimate recovery

Introduction

Foam stimulation became one of the major techniques used for fracturing oil and gas wells. Foam is a dispersion of gas phase inside liquid phase, where CO₂ or N₂ gas is the internal phase, and liquid such as water, oil or even alcohol is the external phase (Gandossi. 2013). During foam production, a compatible surfactant must be used to combine both phases to maintain foam stability during the treatment as illustrated in (Montgomery. (2013)). Generally, most of the foam properties including its rheology and viscosity are controlled by the foam quality, which is the percent of gas phase volume

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to the total volume of fluid used (gas + liquid). The foam quality is given by:

$$\text{Foam quality} = \frac{V_{\text{gas}}}{V_{\text{gas}} + V_{\text{liquid}}} \% \quad (1)$$

As illustrated in (Mitchell, (1969)) & (David and Marsden 1969), N_2 is the oldest foaming gas, and its use dates to 1960 as indicated in (Petty et al. 1964). The other gas commonly used is CO_2 and its use started in the early 1980s as represented in (Bullen and Lillies 1983). Due to flow-back challenges in low-pressure formations, foam-based fluids become very common for use in low-pressure reservoirs. Recently, the US Department of Energy (DOE) is focusing to identify a thermodynamic pathway to utilize natural gas (NG) obtained from producing wells in foam fracturing (Beck and Verma 2016) & (Verma 2016). Later, the study was extended into laboratory-scale experiments to measure NG-foam fluid rheology, and it was found to be similar to foams based on N_2 and CO_2 (Beck, et al. 2017). The use of NG as an energizer has not been practiced widely yet, but applications of NG foamed field test and reaping the economic benefit from simplified logistics and improved production would enable operators to invest in improving the use of NG foams for wellsite treatments.

Typical foams exist when the foam quality ranges between 52 and 95%, and at foam qualities greater than 95%, the gas becomes the external phase and referred to as mist flow as illustrated in (Economides and Nolte 2000). Stable dispersions of gas in liquids can also be prepared with qualities less than 52% which can be called foams or energized fluid as in (Watkins et al. 1983).

A hydraulic fracturing treatment can be energized by introducing a compressible gaseous component into the treating fluid. The gaseous component inside the energized fluid treatment expands when the treatment is completed and pressure is released. This facilitates the flow back of treatment fluids post-treatment. Energizing the fracturing fluid can be used for many reasons, but mainly its applications are in reservoirs that have a low pore pressure, low permeability or water-sensitive formations.

Stimulation of depleted and low-pressure reservoirs became one of the most important challenges in the past decade. When using conventional fluids in fracturing these reservoirs, the results were very disappointing, due to the formation damage caused by these fluids and the disability of reservoir pressure to overcome the fluid column in the well, as well as flow-back fracturing fluids after treatment.

Recently, energized fluid fracturing showed very good and satisfactory results in depleted and low-pressure reservoirs. In addition, it showed excellent production results when used in high-pressure reservoirs. The use of CO_2 or N_2 in energizing fluids in foam fracturing can reduce the

amount of water up to 90% (depending on the foam quality). This consequently reduces the damage caused by water in low-pressure reservoirs. They are becoming very popular for use in stimulation treatments of depleted and low-pressure reservoirs. This is due to their excellent properties such as low leak-off rates, excellent proppant transfer capacity, longer fractures with less fluids, minimum formation damage and superior energetic post-treatment cleanout.

Energized fluids properties

Composition and rheology

The most popular foams are made from nitrogen, water and a foaming surfactant. At first, the surfactant is mixed with the liquid phase, and then, the injection of both gas and surfactant solution into the well (Haugen 2014) explains this operation in detail. Simple water foams have low viscosity relative to gelled water foams and a shorter half-life. They are used in shallow wells with low bottom-hole temperatures, and where only low proppant concentrations are required. They are also used in wells where damage due to gelling agent is critical. Adding a gelling agent extends the half-life of the foam for treatments of linear gel (non-cross-linked) which gives increased viscosity to foams over that of water-only foams. The additional viscosity produces greater fracture width to allow higher proppant concentrations to be placed. The use of delayed cross-linking agents in foam fluids greatly multiplies the viscosity obtained by foam fluids. The higher viscosity fluid creates greater fracture width for easier proppant placement and lower fluid leak-off. Sand concentrations as high as 12 lb/gal have been successfully placed. The cross-linked gel liquid phase imparts much longer half-life to the foam and leaves a cross-linked gel filter cake. So, it is important to break the gel prior to flow back. Failure to break the gel will limit the fluid recovery.

Figure 1 illustrates viscosity generated in water foamed with N_2 . Little viscosity increase is noted until the gas quality gets above 52%. Above 52% quality, the viscosity increase is exponential. Viscosity also decreases with shear rate, showing that foam is a shear-thinning-type fluid, i.e., foam viscosity is low in high-shear conditions such as pumping down tubing and higher in low-flow, laminar condition such as flowing down a fracture system carrying proppant. Cross-linking the liquid phase will compensate for the decrease in viscosity caused by using low foam qualities that are less than 52%. This makes it possible to use foam qualities less than 52% with higher viscosity and good proppant carrying capacity.

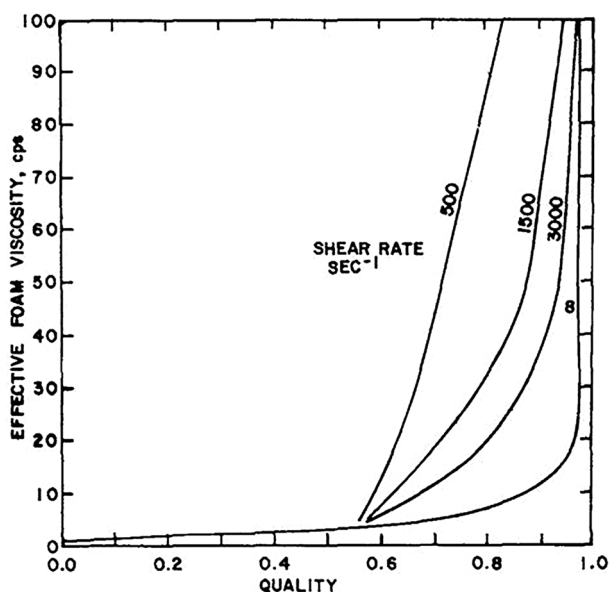


Fig. 1 Effect of foam quality on foam viscosity (Steven et al. 1983)

Proppant carrying capacity

In foam fracturing, the viscosity of the created foam is much more than each of the single phases comprising the foam. This gives foam a higher viscosity than other conventional fracturing fluids such as water. This assists in even mixing of the fracturing fluid during the treatment and reducing proppant sedimentation. Slick-water fracturing creates longer fractures compared to N_2 -energized treatments, but leaves much of the fracture length created un-propped compared to the N_2 -energized treatments; therefore, foams and energized fluids are more suitable than slick-water in carrying proppant throughout the fractures. According to (McAndrew 2014), the proppant distribution inside the created fracture is of great importance as it affects the reservoir performance. Foam and energized fluids create the optimum desired proppant distribution inside the fracture with high proppant concentration, compared to other conventional fracturing fluids as illustrated in (Yu 2015).

Energized fluids selection and quality control

Applications of energized fluids over conventional fluids

The use of energized fracturing fluids is determined based on the drawdown level in the formation, which is classified high or low based on the capillary pressure, which in turn is a function of formation permeability. For drawdown pressure

lower than the capillary pressure limit, energized fracturing is highly recommended. In the case that the drawdown pressure is high (more than the capillary pressure limit), it makes no difference to use energized fracturing over conventional fracturing, where the conventional fracturing fluids would give the same results. As the drawdown is sufficient to recover the fracturing fluids after treatment, the use of energized fracturing can be justified to tight and low-pressure formations.

Choosing the best energizing component

After determining that energizing the fluid is the way to go, it is necessary to evaluate which energizing component works best. In this section, we evaluate the most popular energizing components: N_2 , CO_2 and binary systems of both N_2 and CO_2 as illustrated in Table 1. It is obvious that N_2 is more familiar, available and easier to handle than CO_2 . However, CO_2 is preferred to use over N_2 if the adequate environment and equipment are available due to:

- Higher solubility in water.
- Compatibility with formation fluids.
- Lower surface treating pressures.
- Accessibility to deeper reservoirs.
- In addition, it is considered an EOR method as it dissolves in oil and decreases its viscosity.

Choosing the optimum foam quality

After deciding that energized fluid fracturing is the way to go and determining which energizing component works best, now it is time to determine the optimum foam quality to be used. Studies showed that longer but thinner fractures result from lower quality (20–30%) and shorter but more conductive fractures result from high quality (60–70%). For most tight reservoirs, it is required to have a longer and thinner fracture to increase the contact area with the reservoir; this is why the lower quality fluids are preferred.

To conclude, 30 to 50% quality energized fluids are recommended because they allow enough gas to saturate the liquid while giving the best fracture dimensions for tight reservoirs. Higher quality (up to 70%) may be necessary if shorter and wider fractures are required.

Objectives of this study

The objectives of this study are to demonstrate that:

1. 20 to 50% quality energized fluids are optimum for use in the Egyptian Western Desert.

Table 1 Advantages and limitations of the most popular energizers

Energizer	N ₂	CO ₂	Binary N ₂ + CO ₂
Parameter			
Advantages	<p>Inert gas, which does not react with formation fluids</p> <p>Low density, which aids in fluid recovery by reducing the hydrostatic column in the wellbore</p> <p>Very high expansion factor at low pressure, which allows fluid recovery with less bottom-hole pressures</p>	<p>High density close to that of water, hence requiring less pumping pressure than N₂ foams</p> <p>Foams generated with CO₂ exhibit longer half-life than similar quality foams made with N₂</p> <p>This greater density also gives greater proppant transport ability to CO₂ foams</p> <p>Higher solubility than N₂.</p> <p>Higher solubility than N₂, which is considered an EOR method</p>	<p>Laboratory and field studies by service companies were done and have not shown any technical advantage or greater oil production using binary foams over N₂ and CO₂ foams</p>
Disadvantages	<p>The low density yields high surface treating pressures</p> <p>Limited experience</p> <p>High capital cost compared to conventional fluid fracturing</p> <p>Environmental issues regarding flow back</p>	<p>Environmental issues regarding flowing back of CO₂ to the environment after treatment</p> <p>Higher solubility in both water and hydrocarbons, so it takes more CO₂ to saturate the liquid and create the foam</p> <p>CO₂ produces a low-PH (acidic effect) when dissolved in water, so special cross-linked fluids must be used which are PH-compatible with CO₂</p> <p>CO₂ has corrosive effect on steel, so it requires special types of surface and downhole equipment</p> <p>High cost and limited availability</p>	<p>Require two separate pumping systems for the gases</p> <p>More difficult to control the ratios of the two separate gases</p>
Capital cost	<p>Lower cost compared to other energizing components, but higher cost if compared to conventional fluid fracturing</p>	<p>High cost and limited availability</p>	<p>Binary foams are expensive and require extra labor and equipment</p>
References	<p>N₂ was first introduced for use in energizing liquid phase in the early 1960s as in (Petty et al. 1964)</p>	<p>The use of CO₂ was introduced in the early 1980s by (Bullen and Lillies 1983). A comparison between common energizing components in detail is presented in (Kyle et al. 2009)</p>	<p>The Western Company in the USA was the first company to pump binary foams</p>

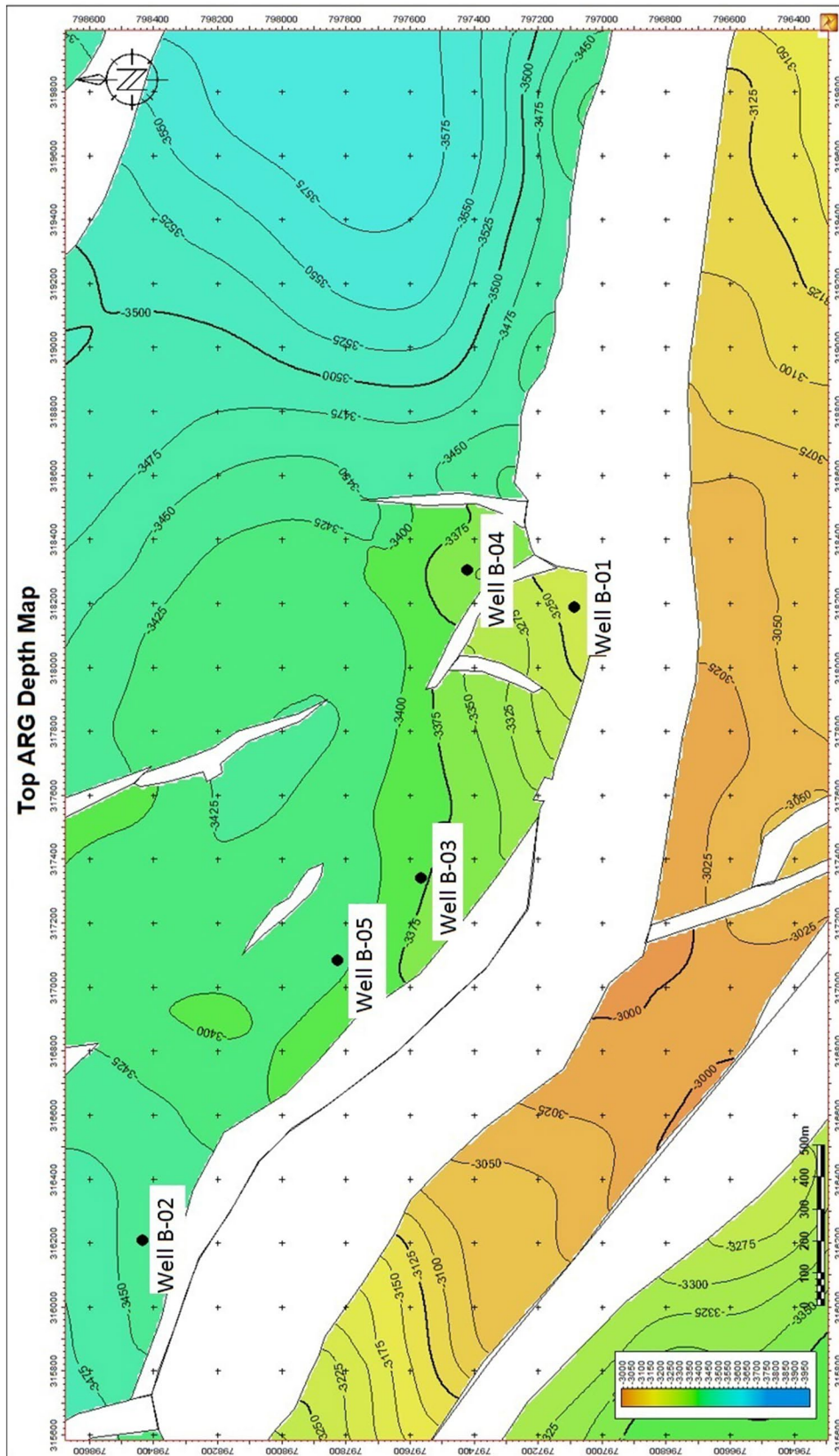


Fig. 2 The topographic map for block (B)

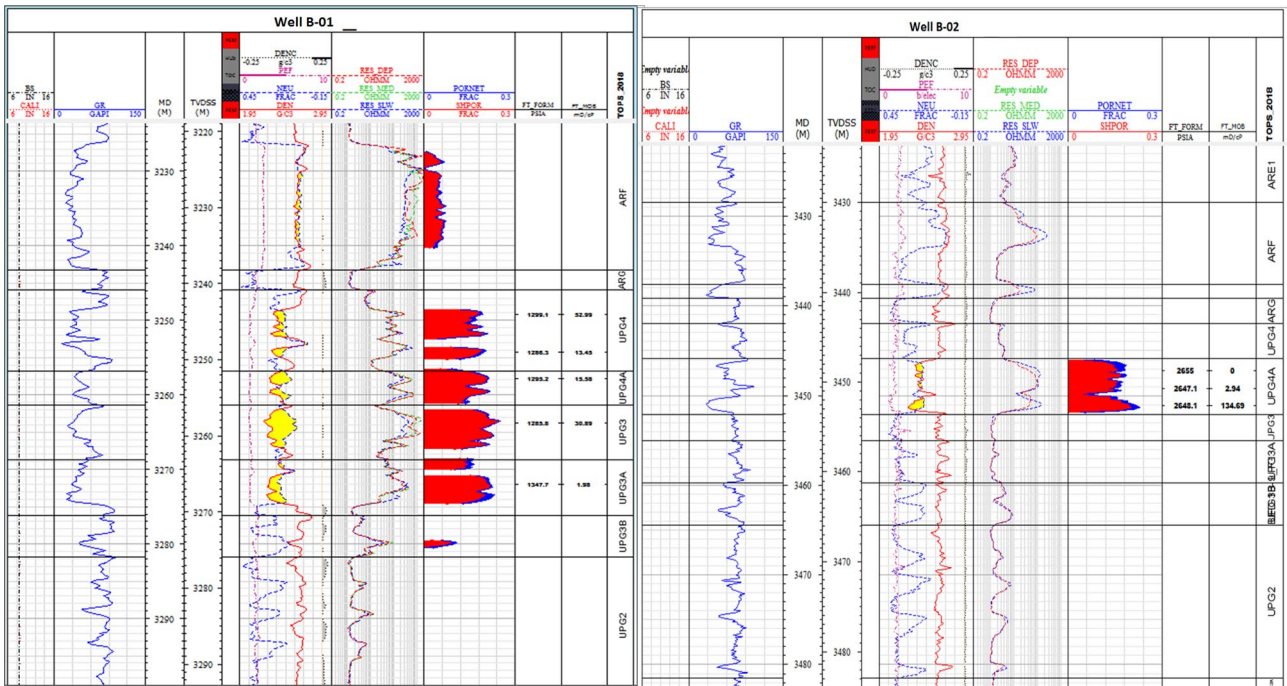


Fig. 3 The well logs for Well B-01 and Well B-02

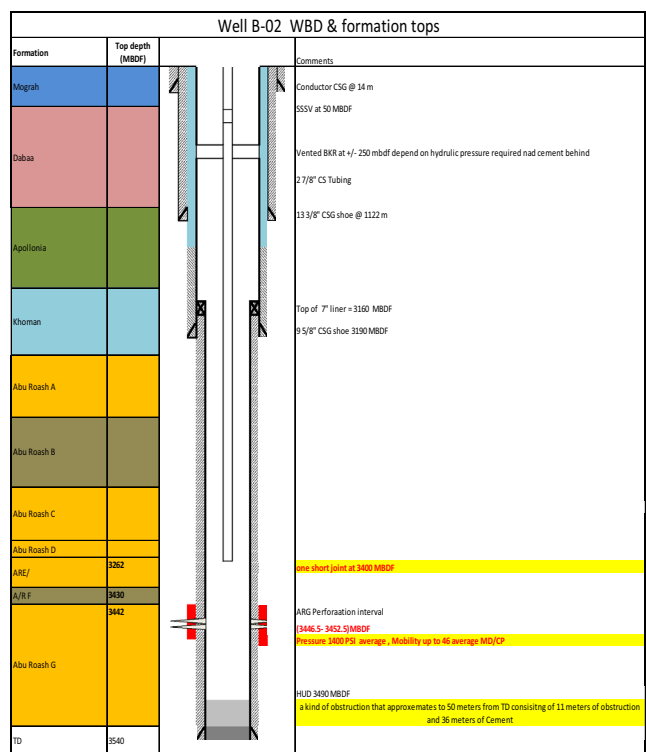
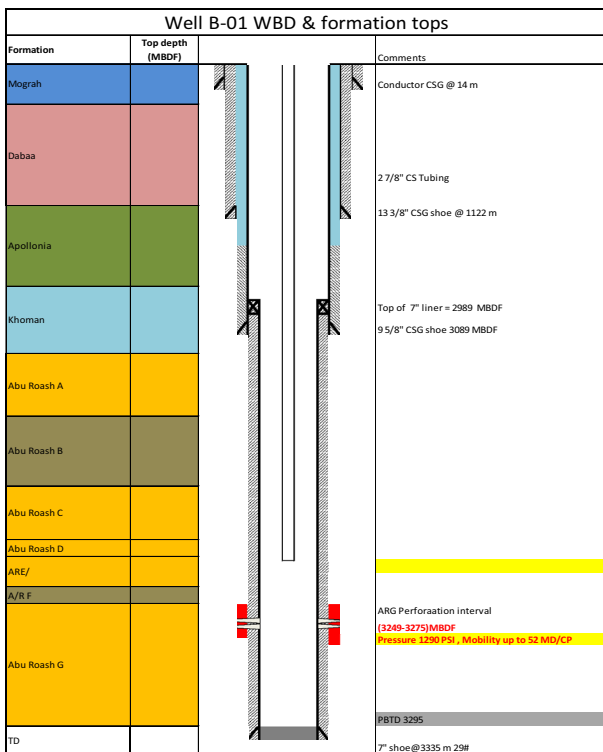


Fig. 4 Well bore diagram with formation tops for Wells B-01 and B-02

Table 2 The fracturing data of the first conventional fluid fracture for **Well B-01** and **Well B-02**

Well	Well B-01	Well B-02
Parameter		
Formation/lithology	ARG/sandstone	ARG/sandstone
Pumping rate, BPM	20	18
Gel loading, ppg	40	35&30
Fluid type	Conventional cross-linked gel	Conventional cross-linked gel
Job liquid volume, bbl	760	1450
Proppant mass, lbs	49,584	82,871
Max. proppant concentration, ppg	7	7
X_f , m	48	110.2
W_f , in	0.32	0.35
H_f , m	30	33.5
FC, md.ft	52,410	22,681
Average gel fluid retained factor	0.6	0.3

- NEF fracturing succeeds to recover oil from previously fractured wells using conventional fracturing fluids. In addition, a comparison between the results of NEF fractured and conventional fluid fractured wells is presented, through testing and live production.
- Adding a component such as methanol to an energized system would help in fracturing tight gas reservoirs where aqueous phase trapping is a potential problem.
- NEF treatments are more economically preferable than conventional treatments in terms of overall cost.

Field applications

In Egypt, where CO₂ is not used due to the mentioned reasons in the previous section, only N₂ is used in energizing the liquid phase to fracture depleted and low-pressure reservoirs with foam qualities ranging from 20 to 50%. Foam quality is limited to this range because the follows:

Table 4 Comparison between conventional fluid and NEF fracturing for **Well B-01** and **Well B-02**

Parameter	WELL B-01		WELL B-02	
	After conventional fluid fracturing	After NEF fracturing	After conventional fluid fracturing	After NEF fracturing
Gross rate, BPD	125	720	220	520
FOI,	5.76		2.36	
Job liquid volume, bbl	760	881	1450	1518
Fracture dimensions	X_f 48 m	X_f 87 m	X_f 110 m	X_f 190 m
	H_f 30 m	H_f 30 m	H_f 33 m	H_f 15 m
	W_f 0.32in	W_f 0.28in	W_f 0.35in	W_f 0.3in
FC, md.ft	32,410	53,720	22,681	59,817
Average gel fluid retained factor	0.6	0.8	0.3	0.6

Table 3 The re-fracturing data for **Well B-01** and **Well B-02**

Well	Well B-01	Well B-02
Parameter		
Fracturing type	Channel fracturing	Channel fracturing
Pumping rate	20	18
Gel loading, ppg	35&30	35&30
Fluid type	NE cross-linked gel	NE cross-linked gel
N2 Foam quality %	35%	30%
Proppant mass, lbs	76,040	89,290
Max. pressure, psi	5505	8890
X_f , m	87.5	190
W_f , in	0.28	0.39
H_f , m	29.8	15
FC, md.ft	53,720	59,817
Average gel fluid retained factor	0.8	0.6

- Previous studies showed that under a wide range of reservoir conditions, foam qualities of 20 to 50% are optimum because they allow enough gas to saturate the liquid, to maximize gas flow back, and they yield long fractures. Higher quality (up to 70%) may be necessary if shorter and wider fractures are required (Kyle et al. 2009).
- Increasing foam quality will require larger supply of gas, special surface and subsurface equipment.

Effect of using NEF fracturing in Egyptian Western Desert

This section reflects successful applications of using 20–50% quality NEF in the Egyptian Western Desert. NEF showed very good and satisfactory results when used in stimulating low-pressure reservoirs as well as high-pressure ones. The following section shows the rise of using NEF in fracturing low-pressure reservoirs in the Egyptian Western Desert. It was started by 2 wells that were fractured using conventional

Table 5 Pre- and post-NEF fracturing results for successful applications in the Egyptian Western Desert

Parameter	Well type	Formation	BHP, psi	BHT, F	K, md	Q_o , BPD	W. C. _o , %	N2 quality used, %	Q_p BPD	W. C. _p , %	FOI
Well											
Well A-01	Oil	ARG	4500	250	13	870	5%	35%	1800	2%	2.07
Well S-01	Oil	ARG	2500	230	38	230	55%	40%	400	3%	1.74
Well S-02	Oil	ARE	3400	246	27	210	38%	35%	450	24%	1.36
Well S-03	Oil	ARG	3600	240	29	265	47%	40%	525	34%	1.98
Well SC-01	Oil	ARG	4235	240	28	543	0%	30%	2670	9%	4.9
Well SC-02	Oil	U.BAH	4200	230	9	180	61%	25%	680	67%	3.78
Well SC-03	Oil	ARG	4300	240	37	370	10%	35%	1016	0%	2.75
Well YC-01	Oil	ARG	3800	236	48	220	45%	40%	770	2%	3.5
Well YC-09	Oil	ARG	2300	238	22	450	60%	35%	1650	75%	3.67
Well Y-10	Oil	ARG	5000	240	19	90	35%	30%	480	20%	5.33
Well BS-01	Oil	BAH	3308	244	5.8	130	0%	40%	850	20%	6.53
Well BC-01	Oil	ARG	4400	235	31	110	12%	25%	370	2%	3.36
Well YC-4	Oil	ARG	3000	240	18	150	15%	35%	290	20%	1.93
Well YC-6	Oil	ARG	1780	240	32	310	33%	30%	550	10%	1.77
Well YC-7	Oil	ARG	1700	240	27	170	15%	30%	330	5%	1.94
Well S-04	Oil	U.BAH	3500	253	33	335	24%	35%	735	35%	2.19
Well S-05	Oil	ARG	3400	230	38	160	25%	40%	400	35%	2.5
Well S-06	Oil	ARG	5500	220	32	220	17%	40%	490	5%	2.23
Well N-05	Oil	BAH	2800	235	28	310	16%	40%	480	15%	1.54
Well Q-01	Oil	BAH	1700	180	24	470	32%	30%	840	35%	1.78
Well Q-03	Oil	BAH	1650	175	26	356	37%	30%	790	49%	2.2
Well Q-08	Oil	BAH	1850	182	23	490	29%	32%	900	41%	1.83
Well F-04	Oil	M.BAH	1700	177	28	230	50%	25%	550	55%	2.39
Well F-05	Oil	M.BAH	1680	181	32	287	53%	27%	600	65%	2.1
Well F-08	Oil	M.BAH	1750	190	25	265	64%	26%	490	60%	1.85
Well B-09	Oil	A5	1800	147	19	280	14%	45%	535	16%	1.9
Well NP-01	Oil	U.BAH	1890	190	39	147	35%	30%	390	55%	2.65
Well NP-03	Oil	U.BAH	2156	185	34	220	45%	37%	410	61%	1.83
Well NP-09	Oil	U.BAH	2046	194	28	195	51%	32%	350	45%	1.79
Well K-01	Oil	A.BUEIB	4500	220	34	250	10%	40%	480	12%	1.92
Well K-03	Oil	A.BUEIB	3900	230	28	240	15%	35%	410	16%	1.7
Well K-04	Oil	A.BUEIB	4200	235	41	290	3%	30%	500	14%	1.72
Well K-07	Oil	A.BUEIB	4300	240	38	310	5%	33%	490	19%	1.58
Well K-09	Oil	A.BUEIB	4000	240	18	320	18%	39%	570	10%	1.78
Well K-11	Oil	A.BUEIB	4600	230	24	380	22%	29%	595	8%	1.56
Well M-11	Oil	ARG	4000	230	4	115	11%	20%	360	4%	3.13
Well M-13	Oil	ARG	2900	237	11	250	25%	40%	350	25%	1.4
Well BQ-03	Oil	ARE	2140	239	12	70	0%	35%	160	12%	2.28
Well B-16	Oil	L-ARG	4100	260	16	135	0%	30%	410	5%	3

fluid fracturing, but showed very disappointing results in both production and sustainability. They were then stimulated using NEF fracturing. Their impressive results made NEF fracturing the ideal choice to stimulate depleted and low-pressure reservoirs.

Wells (B-01 and B-02) were drilled in the same block (B) targeting the same reservoir ARG. Figure 2 illustrates the topographic map for the well in block (B).

Well B-01 successfully encountered the primary targeted sand on upper-ARG level of about 22.6 m net sand with good quality (average porosity = 0.19%) and reservoir

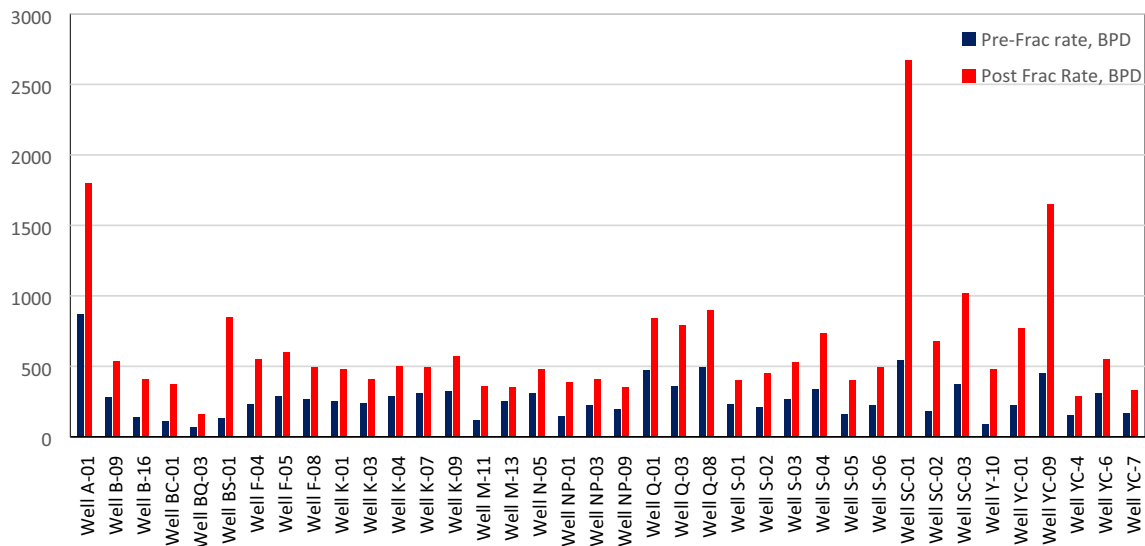


Fig. 5 Summary of pre- and post-fracturing gross rates for a sample of successful applications in the Egyptian Western Desert

pressure found around 1400 psi. **Well B-02** successfully encountered the primary targeted sand on upper-ARG level of about 6 m net sand, with good quality (average porosity = 0.16%) and reservoir pressure found around 1400 psi. At first, the two wells were stimulated using conventional fracturing fluid, and Figs. 3 and 4 show the well logs and the completion summary for the two wells, respectively. Table 2 illustrates the data for the first conventional fluid fracturing for both wells. It indicates very low average gel fluid retained factor, which indeed affects the fracture conductivity, as it will appear in the production data of the two wells.

Results and discussion

Both **Well B-01** and **Well B-02** were tested after their first conventional fluid channel fracturing. Their production data showed very low and declining rate with time, and the production data for **Well B-01** after the first conventional fluid fracturing while lifting with N_2 showed oil rate of **7–70 BOPD**. While the production data for **Well B-02** showed oil rate of **50–600 BOPD**. The production rates of both wells were very low and declined rapidly. After these disappointing results of the conventional fluid fracturing, both wells were re-fractured using NEF and showed exceptional results. The challenge was to bypass the damage caused by the first conventional fracturing fluids and achieve good and sustainable production rates despite their low reservoir pressures. Table 3 demonstrates the re-fracturing data for both wells.

The production figure of **Well B-01** after NEF re-fracturing showed a gross rate of **720 BPD**, which sustained for nearly one year, while the production figure of **Well B-02**

after NEF re-fracturing showed a gross rate of **520 BPD**, which sustained for 9 months.

As demonstrated in Table 4, NEF fracturing showed very good and sustainable production results compared to those of conventional fluid fracturing as follows:

1. Both wells showed very good and sustainable rates after NEF fracturing compared to their results after conventional fluid fracturing.
2. The fracture half-lengths X_f for **Well B-01** and **Well B-02** obtained from NEF fracturing are 87 m and 190 m, respectively, which are nearly double the half-lengths obtained from conventional fluid fracturing using the same liquid volumes.
3. The fracture conductivities for **Well B-01** and **Well B-02** obtained from NEF fracturing are 53,720 md.ft and 59,817 md.ft, which are nearly double that obtained from the conventional fluid fracturing.
4. The average gel retained factor is higher in case of NEF fracturing for both wells (0.8 and 0.6), respectively, than in case of conventional fluid fracturing (0.6 and 0.3), which is the percent of gel fluid extracted after treatment. The higher this percent, the lower the residual gel material left in the formation, which affects the fracture conductivity.

Successful applications of NEF fracturing in the Egyptian Western Desert

After the impressive results of NEF fracturing in Wells B-01 and B-02, it is now a role of thumb to use NEF in fracturing

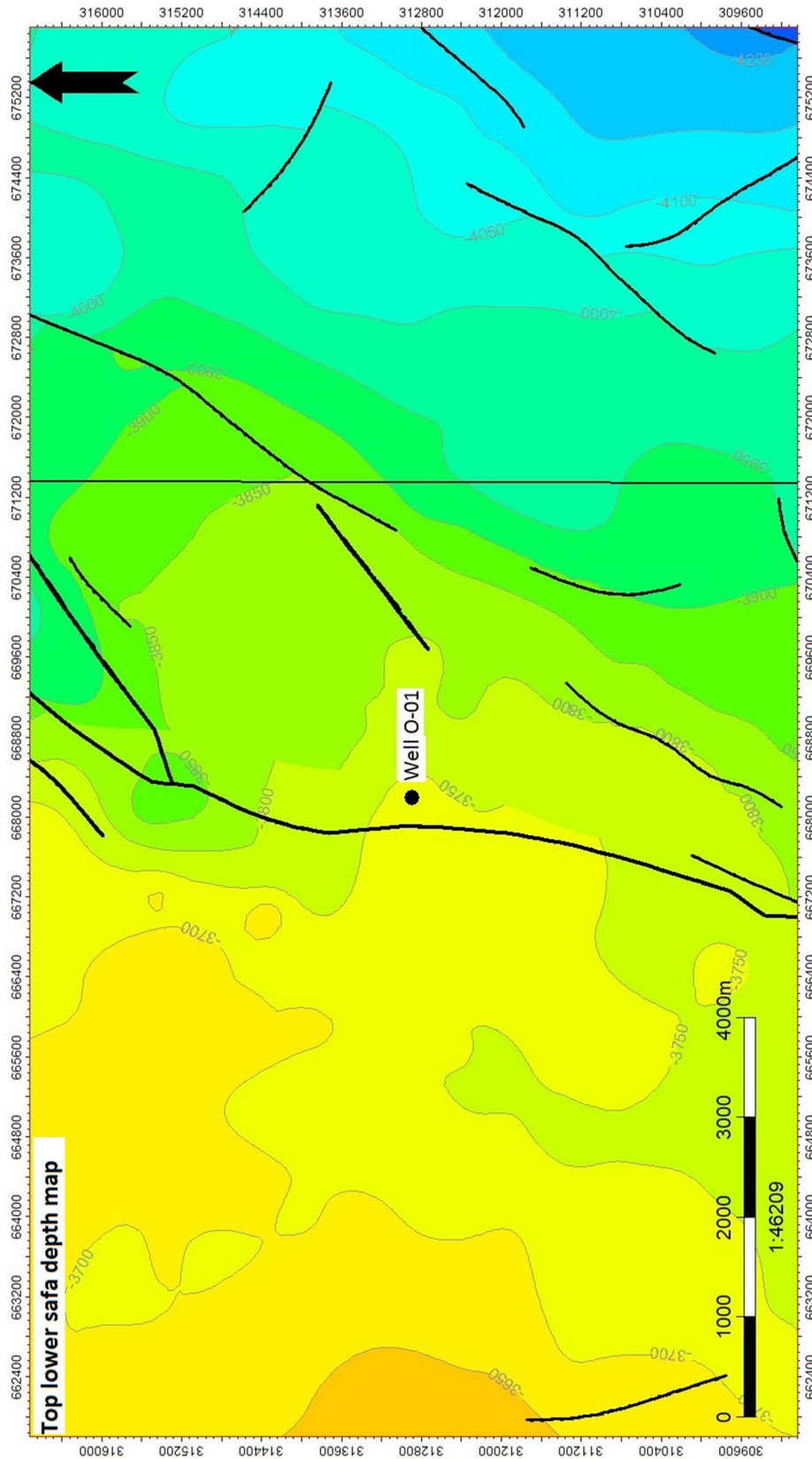


Fig. 6 The topographic map for lower SAFA formation top

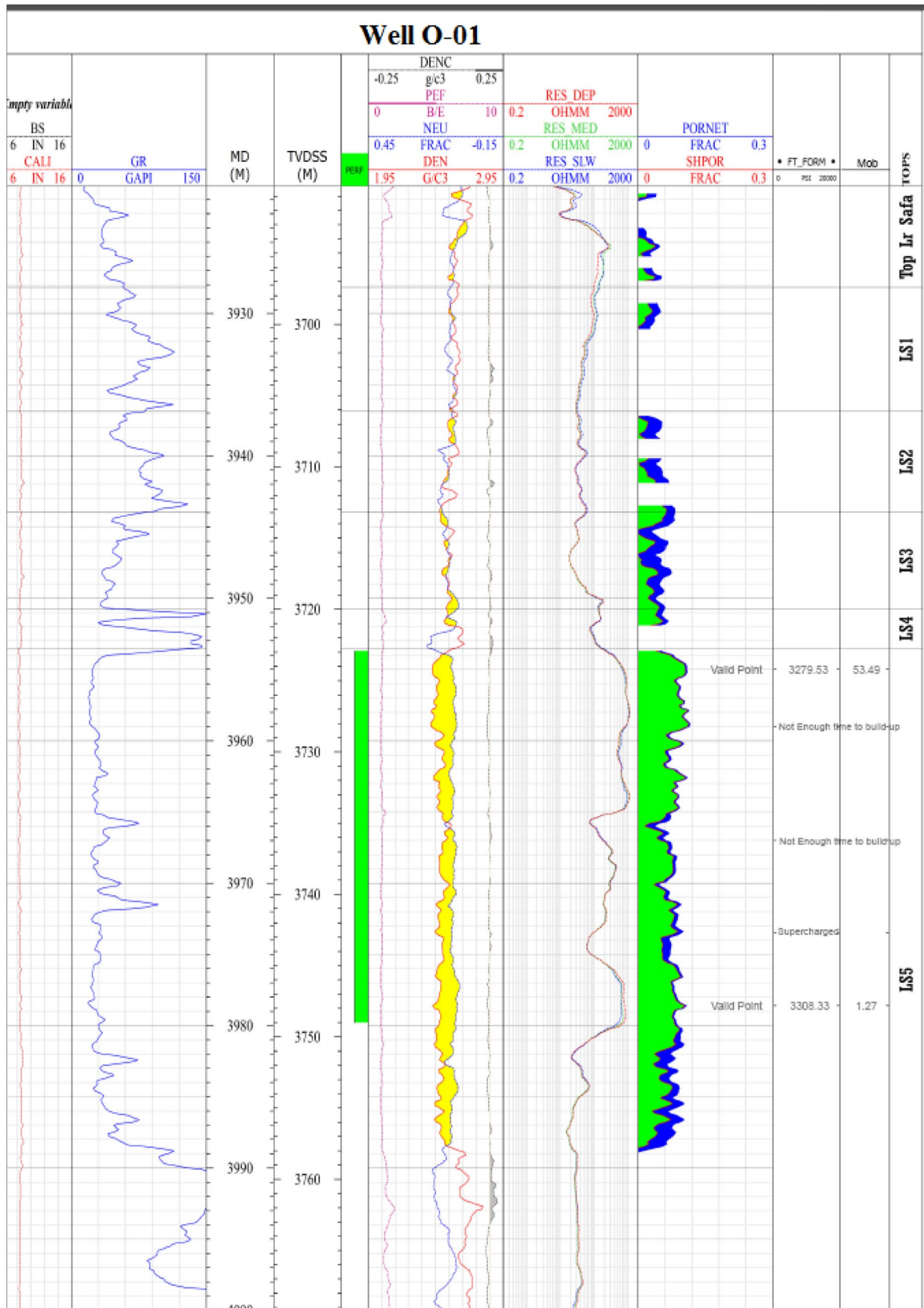


Fig. 7 Well O-01 open hole log

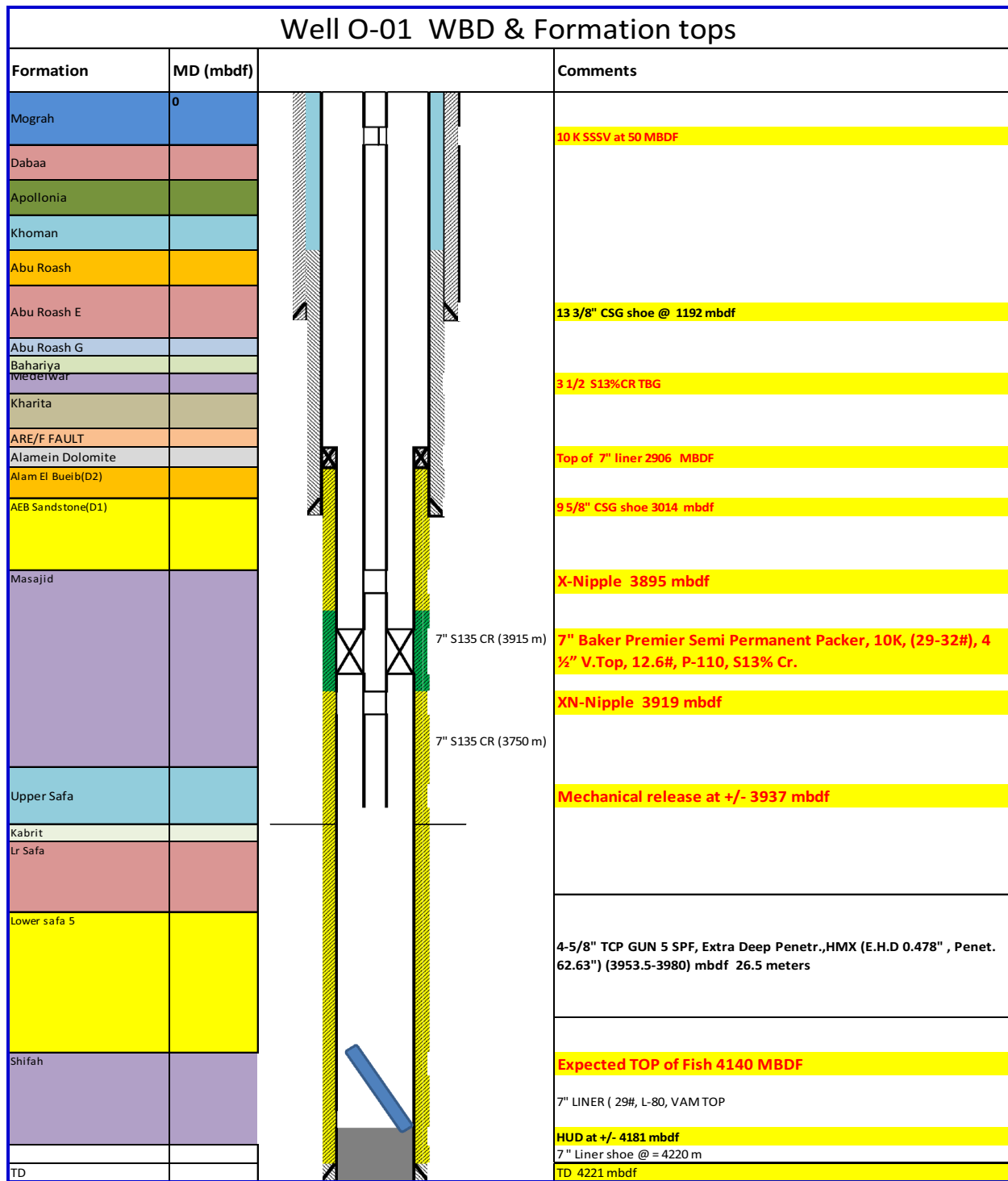


Fig. 8 Well bore diagram and formation tops for Well O-01

low-pressure reservoirs to minimize the formation damage and aid in the flow-back operations after treatment. Table 5 shows a summary of successful applications of NEF in fracturing low-pressure reservoirs in the Egyptian Western Desert. Figure 5 summarizes pre- and post-energized fluid

fracturing gross rates for a sample of wells in the Egyptian Western Desert.

Well O-01 gas producer was a special challenge. Well O-01 successfully encountered the primary targeted sand on lower SAFA level of about 26.5 m net sand with moderate

Table 6 Reservoir and fracturing data for **Well O-01**

Parameter	Well O-01
Type	Gas producer
Formation/lithology	L-SAFA/sandstone
BHP, psi	3300
BHT, <i>f</i>	270
<i>K</i> , md	0.2
<i>E</i> *10 ⁶	6.2
ν	0.16
Perforation interval, mbd	3953–3980
N ₂ quality used, %	25%
<i>Q</i> _o , MMSCFD	0.5
<i>Q</i> _f , MMSCFD	2.8
FOI	5.6

quality (average porosity = 0.08%), reservoir pressure found depleted around (3300 psi) and very tight (0.2 md). Figure 6 illustrates the topographic map for L-SAFA formation, and Figs. 7 and 8 show the well log and completion summary for **Well O-01**, while Table 6 illustrates its reservoir and petro-physical data, which indeed requires a special type of stimulation.

The limited drawdown led to deciding that energizing fluid fracturing is the way to go, but another issue was encountered which is the APT (aqueous phase trapping) due to the very low reservoir permeability. Adding a component such as methanol to the energized fluid system could help. The final decision was made to stimulate that well using foam-methanol fracturing, where 10% methanol was added to the fracturing fluid before energizing with 25% quality N₂. **Well O-01** showed good enhancement in gas production rate, as shown in Fig. 9 a, quick comparison between pre- and post-fracturing gas rates, where pre-fracturing gas rate was **0.5 MMSCFD**, while post-fracturing gas rate was **2.8 MMSCFD** with a FOI equal to **5.6**.

Economic benefits of using NEF fracturing

Granting the very impressive results of NEF in fracturing depleted and low-pressure reservoirs on production rates and sustainability. NEF fracturing treatments appear to be more economically preferable to conventional fluid fracturing ones.

In this section, we will take a sample of wells to discuss the economic benefits of using NEF fracturing over conventional fluid fracturing in depleted and low-pressure reservoirs.

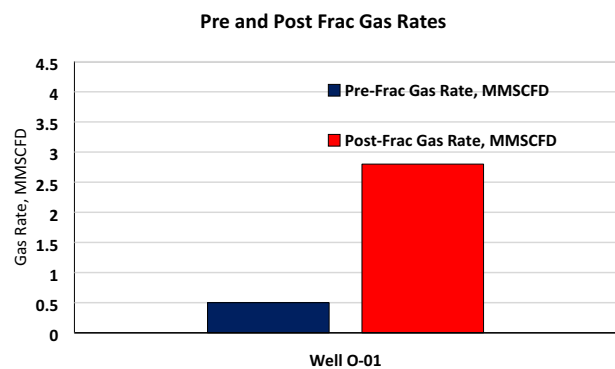
Wells A-01, A-02 and A-03 were drilled in the same reservoir block, targeting ARG formation. Figures 10 and 11 show the topographic map and the well logs for the three wells, respectively, while Fig. 12 shows the well completion summary for the three wells. **Wells A-02 and Well A-03** were stimulated using conventional fluid fracturing, while **Well A-01** was stimulated using 35% NEF fracturing. As shown in Table 7, it is obvious that treatments of the three wells used nearly the same liquid volumes and proppant mass. The treatment cost of NEF fracturing is about 15–20% much more than that of conventional fluid treatments. However, this additional cost is offset by the cost of unloading and flowing back the well in case of conventional treatments. Also NEF treatments showed very impressive estimated ultimate recovery (EUR), these reasons make NEF treatments more economically preferable than conventional ones.

Figure 13 shows the cumulative production from the three wells during a three-month period, represented as a fraction of original oil in place (N). Well A-01 produced about 0.016 N gross production, while Wells A-02 and A-03 produced about 0.009 N and 0.0092 N.

Conclusions and recommendations

Based on the field data conducted and presented in this paper, the following conclusions can be drawn:

1. 20 to 50% quality NEF fracturing showed exceptional results mainly in low-pressure reservoirs in the Egyptian Western Desert, in addition to their good results in high-pressure reservoirs.
2. Adding a component such as methanol to an energized system helps in fracturing tight gas reservoirs where

**Fig. 9** Pre- and post-NEF fracturing rates for Well O-01

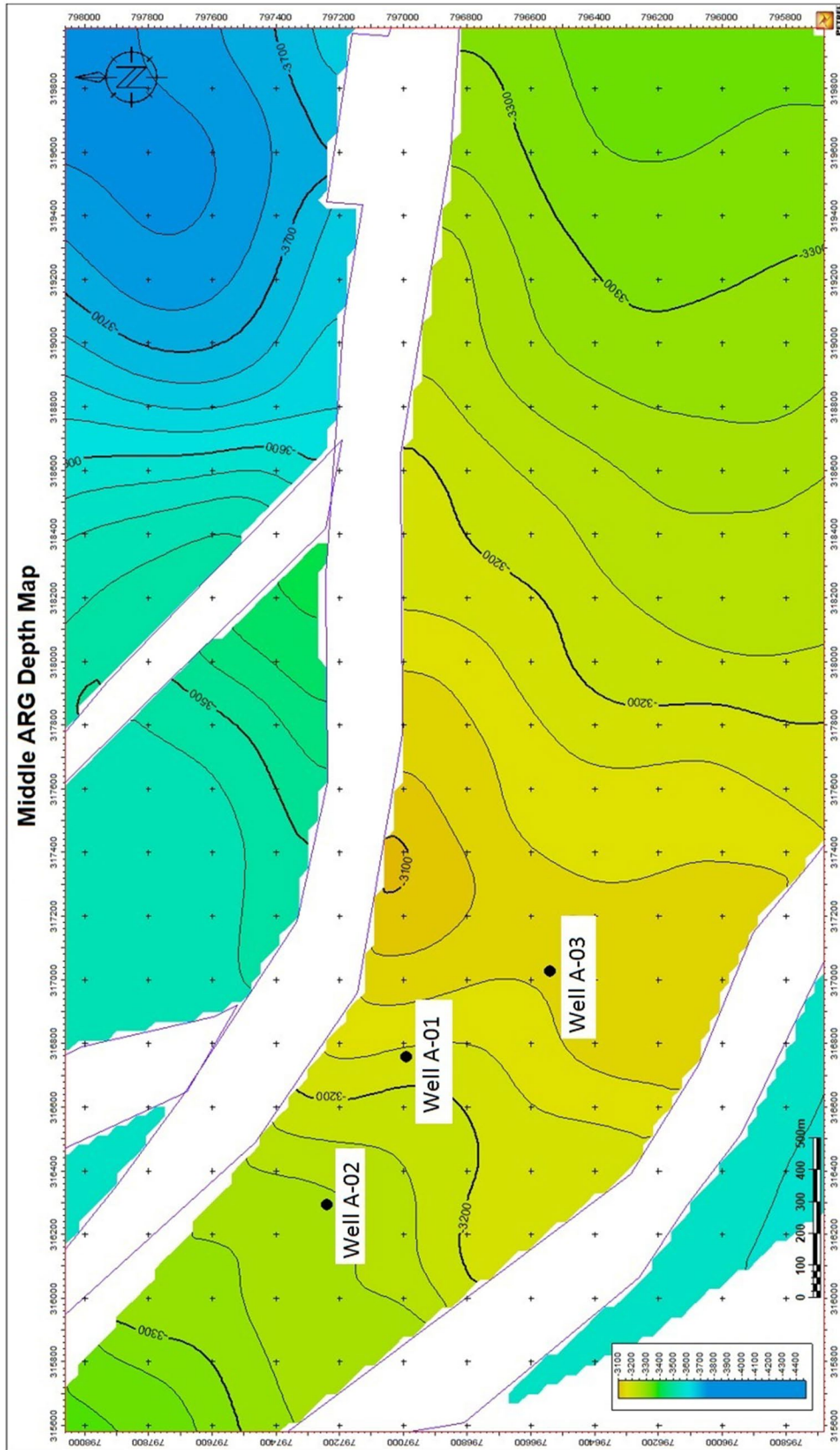


Fig. 10 Topographic map for Wells A-01, A-02 and A-03

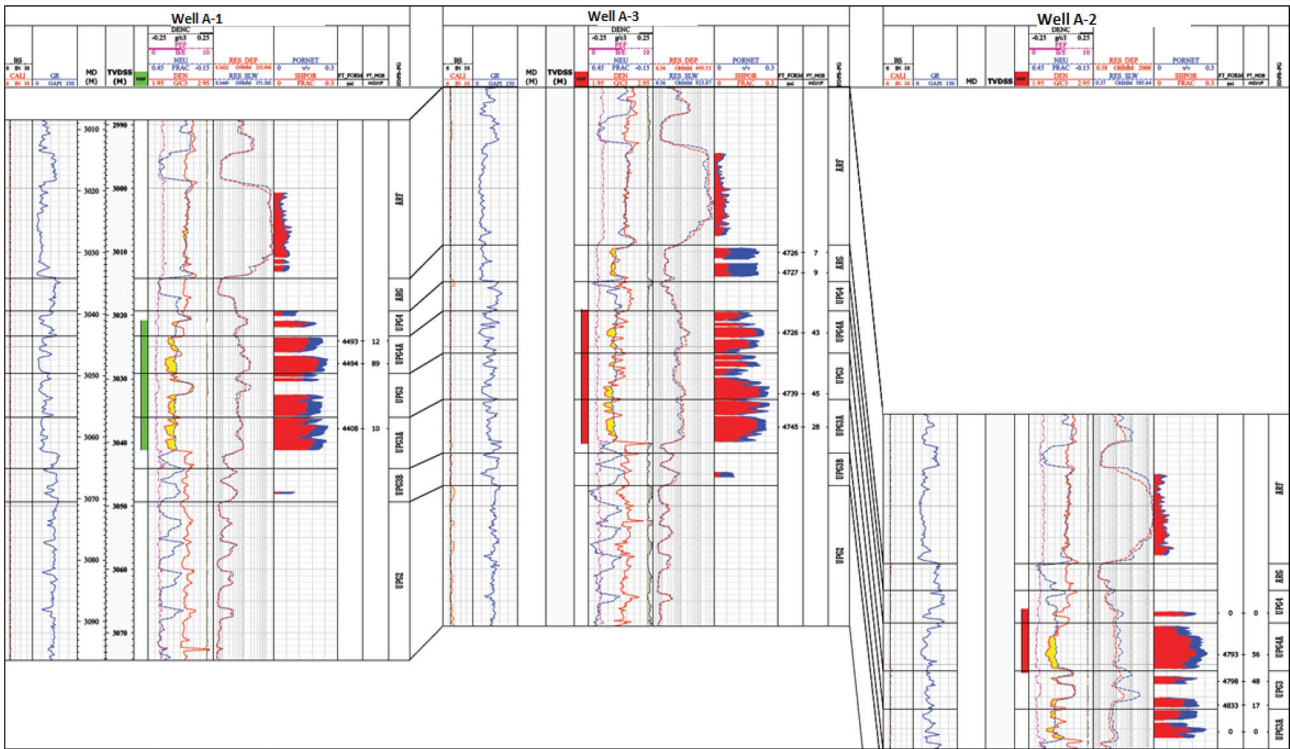


Fig. 11 Well logs for the 3 offset wells: Well A-1, Well A-2 and Well A-3

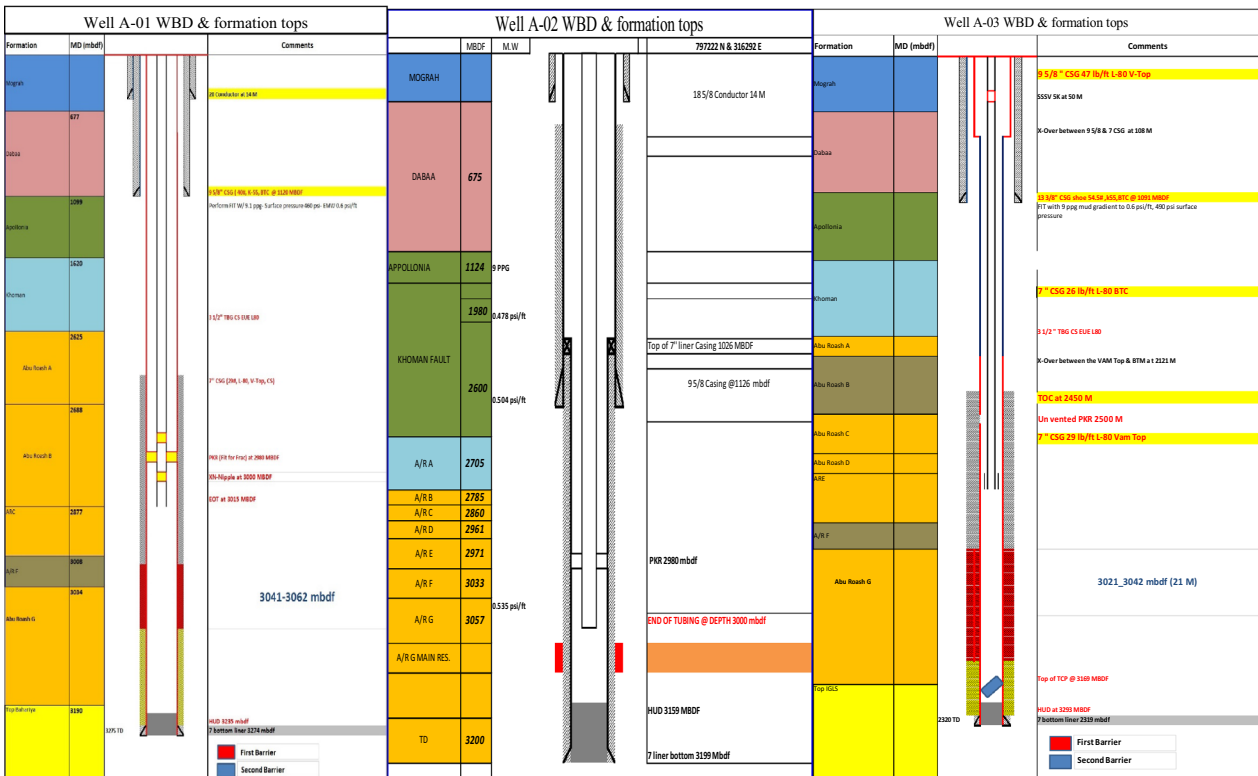
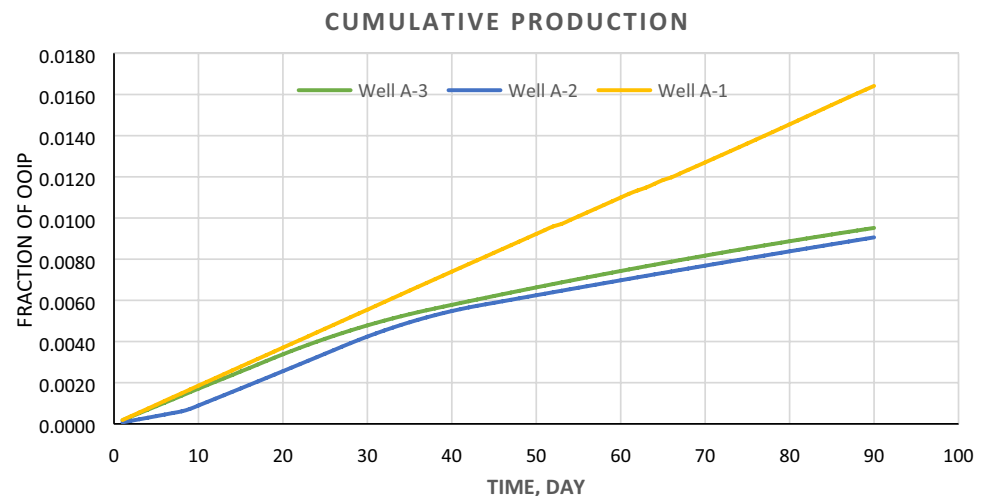


Fig. 12 Well bore diagram for the three Wells A-01, A-02 and A-03

Table 7 Fracturing and economic data for Wells A-01, A-02 and A-03

Parameter	Well A-01	Well A-02	Well A-03
Type	Oil producer	Oil producer	Oil producer
Formation/lithology	ARG/sandstone	ARG/sandstone	ARG/sandstone
BHP, psi	4500	4700	4700
BHT, <i>f</i>	250	250	250
<i>K</i> , md	27	30	39
<i>E</i> *10 ⁶	3	2.7	3
ν	0.218	0.26	0.213
Perforation interval, mbd	3041–3062	3070–3085	3031–3042
Fracturing fluid type	35% NEF fracturing	Conventional fluid fracturing	Conventional fluid fracturing
Liquid volume, bbl	1355	1480	1292
Proppant mass, lbs	85,800	94,400	83,900
Treatment cost, 1000\$	260	215	225
Unloading cost, 1000\$	Nil	35	20
Total cost, 1000\$	260	250	245
Total recovery in 3 months, %	0.016 N	0.009 N	0.0092 N

Fig. 13 Cumulative production of the three Wells A-01, A-02 and A-03 for a period of 3 months

aqueous phase trapping is a potential problem as the case in **Well O-01**.

- NEF treatments are economically preferable than conventional fluid treatments.

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Compliance with ethical standards

Conflict of interest Each author has substantially contributed to conducting the underlying research and drafting this manuscript. Additionally, the named authors have no conflict of interest.

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