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Improving Productivity of Low-Pressure Reservoirs Using Cost Effective N_2-Energized Fracturing Fluids

Ahmed A. Elgibaly[1], *Adel M. Salem*[1], *Tarek A. Ali*[2]

[1] *Faculty of Petroleum and Mining Engineering, Suez University, Egypt*
[2] *Qarun Petroleum Company, Egypt*

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Abstract

Hydraulic fracturing of low-pressure reservoirs is a necessary treatment since reservoir pressure is not high enough to give the required productivity to produce oil and gas in economic rate. When water based fracturing fluid are used, clean-up of fracturing fluid after treatment is challenging. The water held in pore space and will cause a considerable decrease in the conductivity of the fracture. Energized gases are added to the fracturing fluid to facilitate the clean-up of the fracture after the treatment. One the energized gases used is nitrogen gas added with foaming agent to provide the required energy to clean up the fracture and improve its conductivity.

In this paper, we highlighted the benefits, constraints, and limitations of using N_2 energized fracturing fluids. In addition, we presented the optimum procedures to maximize the flow back of N_2 energized fracturing fluids and achieve higher productivity enhancement and evaluate it economically. The methodology is based on the analysis of fluid performance compared to a conventional fracturing fluids with decline curve analysis and type curve matching of the production data collected from different fields in the Egyptian Western Desert. N_2-energized fracturing fluids outperformed conventional fracturing fluid in low pressure reservoirs with foam quality from 20 -30% as less fluid pumped and better clean up occurred. This low foam quality will not cost more and will increase surface treating pressure with small percent.

Keywords: *Fracturing fluids; N_2-energized; Foam fluid; Foam quality; Low-pressure reservoirs.*

1. Introduction

Hydraulic fracturing is one of the main important techniques for improving well productivity. During hydraulic fracturing, a conductive channel through near wellbore damage is created to bypass this crucial zone. The fracture is usually, extended to a significant depth into the reservoir to further increase productivity and change the fluid flow through the reservoir from radial to Near linear flow [1]. Radial flow is not the optimum flow pattern due "jamming" of the fluid and reduction in flow. A properly designed and executed hydraulic fracture can change flow from radial to nearly linear [2]. The fracturing fluid is a critical component of the hydraulic fracturing treatment. An ideal fracturing fluid would be one that; have an easily measured controllable viscosity and fluid loss characteristics; would not damage the fracture or interact with the formation fluid; and would be harmless, inert, and cost effective [3].

The key to successfully fracture a low pressure formations is minimizing fracture damage produced by fluid leak off. Throughout the fracturing treatment, fracturing fluid has direct contact with formation rock. Under the high-pressure difference between the fracturing fluid and fluid in formation rock pores, the fracturing fluid tends to leak from fracture into formation, which is usually referred to as leak-off. The dynamic fluid leak off during fracturing has significant impact on the fracture propagation [4]. Once filter cake formed fluid leak will decrease. After treatment, a chemical called breaker is injected to degrade the filter cake and brake the fluid viscosity to allow flow back of the fracturing fluid. The real zero-damaging fracturing fluid is still nonexistent [5].

In perfect circumstances, only about 40% of the water that is pumped during any hydraulic fracturing job is recovered during following the well back after hydraulic fracture treatment. A single hydraulic fracture treatment consumes thousands of gallons of the fracturing fluid, thousands of pounds of proppant which all costs hundreds of thousands of dollars. Every engineering decision is valuable because of significant increases in production or decreases in cost [4]. Reservoir pressure in oil wells must overcome capillary pressure to achieve better cleaning efficiency after fracture treatment. But in gas or condensate wells capillary pressure has the smallest impact on the well productivity [6].

For low-pressure reservoirs, the reservoir energy is not enough to sweep the fracturing fluid from the formation back to the wellbore. Based on that, adding more energy is necessary to decrease formation damage produced by the fracturing fluids.

1.1. N_2 and CO_2 as energizing gases

The energized fluids are generated by mixing the gaseous phase with the liquid phase, in the presence of a proper surface-active agent. The common energized gases are N_2, CO_2 or mixed of them. Energized fluids have many challenged such as high surface pressure due to high friction pressure, corrosion in case of CO_2, stability at high temperature, availability of gas and the need for specialized equipment [7].

The main difference between N_2 and CO_2 when used as energized gases is the solubility in water. The solubility of N_2 in water is much less than CO_2 in water [8]. The solubility of N_2 is less than 0.5 mol % whilevCO_2 solubility can reach up to 3.5 mol %. Also the solubility of N_2 in water is less sensitive to temperature compared to the solubility of CO_2 [9].

The relative inertness, low solubility, easy handling and availability of N_2 make it a suitable gas to be used in hydraulic fracturing operations. CO_2 was reported to outperform N_2 in most cases because of its higher solubility in water at fracturing temperatures and pressures [10]. But the availability of N_2 gas makes it the proper choice as energized gas.

1.2. Foam quality

Energized fluids will substitute conventional stimulation fluids in low reservoir pressure, water-sensitive formations, or the necessity for reducing flow back time [7]. Foam is described by its quality, texture, and rheology [11]. The foam quality (FQ), depends on the percentage of gas in the fracturing fluid. The quality of fluid is determined by the following formula Eq.1:

$$FQ = \frac{V_g}{V_g + V_l} * 100 \quad (1)$$

where V_g is the volume of gas and V_l volume of liquid.

The term “foam fluid” refers to fluids having at least one gas component with foam quality at least 52%. Energized fluids have a gas component with quality that does not exceed 52% [12]. Gas/liquid mixture are classified according to their quality: Dispersion if FQ< 52%, wet foam (52 %< FQ > 74%), dry or polyhedral foam (74 %< FQ <≈ 96%), and mist (FG>≈ 96%) [11].

Desired foam rheology for fracturing is gained by using surfactants and an appropriate viscous external phase, both of which assist maintenance of the foam structure (quality and texture) [12]. For high foam quality (>52%), collisions between bubbles cause energy dissipation resulting in a high effective viscosity. The internal phase is stable till qualities are touched (~95%) and the gas becomes the external phase, referred to as a mist. At low qualities (less than 52%), the interactions between bubbles are minimal so the fluid viscosity be similar to that of the base fluids [13].

The rheological properties of 25% to 75% foam quality N_2 containing borate cross-linked guar was studied at a temperature from 75 to 300°F for cross-linked gel borate-cross-linked 40 lbm/Mgal guar. They found that for linear gel the viscosity increase with foam quality but for cross-linked gel, the order reversed due to a high percent of crosslink additives due to a high percentage of water, so viscosity is higher than 50% and 75%. Conventional fluid gives higher viscosity than foamed fluids due to large percent of crosslink, but at higher temperatures, the foamed fluid is more stable [14]. So, adding N_2 with 30% FQ will not affect fracture geometry but decrease damage produced by conventional fracturing fluids by increasing the efficiency of cleanup.

Low foam quality range (30 to 50%) is good enough as they allow enough gas to saturate the liquid to maximize gas flow back and they yield long fractures. The higher the solubility of the gas, the higher the foam quality needed to make sure the liquid is fully saturated [8].

Under the high-pressure difference between fracture pressure and reservoir pressure, fluid tends to flow from the fracture into formation, which is usually referred to as leak-off. The dynamic fluid leak off during fracturing has a significant impact on the fracture propagation [15].

So, using 20 to 30% quality will not affect the viscosity of fluid, however it will be stable at higher temperature and better flow back compared with conventional one.

1.3. Residue of fracturing fluid

Conventional fracturing fluid contains polymer. This polymer after breaking by the effect of temperature and chemical breaker will leave some residue inside pores that greatly affect fracture conductivity [16].

1.4. Fluid selections

Fluid selection for any fracture treatment is the key to success. Several publications are available to guide in the selection of the proper fracturing fluid. All these publications focused on CO_2 gas as energized fluids, only low permeability formation, and high foam quality [8, 17–20].

For high pressure reservoirs, recovery of fracturing fluids are not a major concern but using energized fluid may eliminate the need for lifting the well. In low-pressure reservoirs, recovery of fracturing fluid can be challenging so it is recommended to use Energized Fluid that can facilitate the back flow. Energized fracturing fluids are necessary for low-pressure reservoirs, low permeability, or in water sensitive formations [20].

1.5. Conventional and channeling fracturing techniques

N_2-energized fluid can be used with different fracturing technique. The differences between Conventional and channeling fracturing techniques are the way of pumping and chemical used**.** In conventional fracturing, all of the proppant particles are in mutual contact. Fluid flow is confined to the interstices between the proppant grains. In a channeling type discontinuous proppant pack used. It is consist of proppant agglomerations or columns, creating open channels through which fluid may flow [21]. Study the efficiency of N_2-Energized fluid with these two techniques will be done.

This study will shed light on N_2-Energized Fracturing Fluid in low-pressure reservoirs. The optimum procedure required to get the maximum benefits from these fluids will be discussed. In addition, studying the limitation of using N_2 energized fluids. Finally, study theses fluids economically with respect to the obtained results. The foam quality used is less than or equal to 30%, permeability of oil reservoirs range from low to moderate permeability reservoirs.

2. Methodology

Stimulation data and production data for wells fractured with N_2-energized fracturing fluid will be compared with wells fractured with conventional fluids. Our work will be done using decline curve analysis (Arps & Fetkovich type curve analysis). All what one needs are production history, reservoir data and bottom hole pressure.

With oil production rates after the Frac job, using Arps decline curve analysis initial decline rater (Di), decline exponent (b) and initial flow rate (q_i) will be obtained. These data will be used to match the curve in Fetkovich type curve. Arps decline analysis will be used to analyze the data in the period of boundary-dominated flow. Fetkovich introduced the idea of log-log type curve analysis to production analysis for both transient flow period and boundary-dominated flow period [22].

Using the production history and pressure data of wells for the first year of production. Based on the curve matching analysis between field data and Fetkovich–Arps type curves. The q~t curve will be drawn on the log–log plot. Similar to the well test analysis, matching the q~t plot with the theoretical type curves [23].

One matching points will be chosen and the actual matching point (t, q) $_M$ and the corresponding theoretical matching point (t_{Dd},q_{Dd}) $_M$ will be recorded. On the basis of the time matching point, the initial decline rate Di will be determined using Eq.2. Based on the matching results, record the value of dimensionless reservoir drainage radius r_{eD} and decline exponent b. On the basis of the value of r_{eD} and initial flow rate q_i, the value of permeability k will be determined according to Eq.3. The apparent wellbore radius will be determined according to Eq. 4 based on the time matching point. And then determine the skin factor S according Eq.5. Finally Fold of increase FOI will be obtained according to Eq.6 [24].

$$D_i = \left(\frac{t_{Dd}}{t}\right)m \tag{2}$$

$$K = \frac{\mu B(\ln r_{eD} - \frac{1}{2})}{2\pi h(p_i - p_{wf})}\left(\frac{q}{q_{Dd}}\right)_m \tag{3}$$

$$r_{wa} = \sqrt{\frac{2\frac{k}{\emptyset\mu C_t}}{\left(\left(\frac{r_e}{r_w}\right)_m - 1\right)(\ln r^2{}_D - 0.5)}\left(\frac{t}{t_{Dd}}\right)_m} \tag{4}$$

$$S = \ln\frac{r_w}{r_{wa}} \tag{5}$$

$$FOI = \frac{\ln\frac{0.472r_e}{r_w}}{\ln\frac{0.472r_e}{r_w} + S} \tag{6}$$

where q_{Dd} & t_{Dd} are the dimensionless rate and time respectively.

Also this FOI will be compared with the value expected from the fracture design to the percent obtained from this design. This will be done by obtaining the Dimensionless Fracture Conductivity using Eq.7

$$C_{fD} = \frac{k_f w_f}{k x_f} \tag{7}$$

where C_{fD} is the dimensionless fracture conductivity; $k_f w_f$ is the fracture conductivity (md.ft); **k** is the formation permeability (md); and x_f is the fracture half length (ft).

Then from C_{fD} skin factor S_f after frac job be obtained [25], then expected FOI will be determined using Eq.6. This value will be compared with the value obtained from analysis to evaluate the percent achieved from any Frac job.

3. Date used and software's employed

Data used from wells in the Egyptian Western Desert. Analysis has been done using (KAPPA-Topaze)™ (Rate Transient Analysis) software. Data range of wells as in Table 1.

Table 1. Data range of Wells

Parameter	From	To
Permeability range, md	1	16
Reservoir Pressure ,psi	600	2100
Porosity range ,fraction	0.172	0.251
Proppant volume , lb.	80 000	260 000
Gel load , lb/Mgal	35	40
Temperature , F	145	200
Depth , ft	4 000	7 500
Foam quality	20	30

4. Results and discussion

According to Arps Decline Curve analysis the value of Initial decline rate Di, decline exponent b and initial flow rate q_i will be obtained. These data will used to match the curve in Fetkovich type curve.

4.1. Fetkovich-Arps type curve

Using Fetkovich-Arps type curve analysis, results of each well compared with each offset, effective wellbore radius will be obtained then skin factor and fold of increase are calculated. Results obtained are represented in Table 2 for conventional frac technique and Table 3 for channeling frac technique.

Table 2. Skin factor and fold of increase of conventional frac technique job

Conventional frac technique					
N_2 Energized fracturing fluid			Conventional fracturing fluid		
Well	Skin factor	Fold of increase (FOI)	Well	Skin factor	Fold of increase (FOI)
Y-1	-4.03	2.14	Y-2	-3.61	2.02
W-5	-2.68	1.45	W-14	-2.4	1.4
A-5	-3.24	1.72	A-10	-2.03	1.34

Table 3. Skin factor and fold of increase of channeling frac technique job

Channeling frac technique					
N_2 Energized fracturing fluid			Conventional fracturing fluid		
Well	Skin factor	Fold of increase (FOI)	Well	Skin factor	Fold of increase (FOI)
Y-3	-1.94	1.33	Y-4	-2.29	1.38
W-6	-4.22	2.2	W-7	-1.97	1.33
A-6	-4	2.13	A-8	-2.13	1.36

From results found that N_2 energized fracturing fluid outperforms conventional fracturing fluid type in most cases. For conventional Frac technique Figure 1, 100% of N_2 energized fluid wells get higher values for Skin factor and FOI than their offset wells which used conventional fluids.

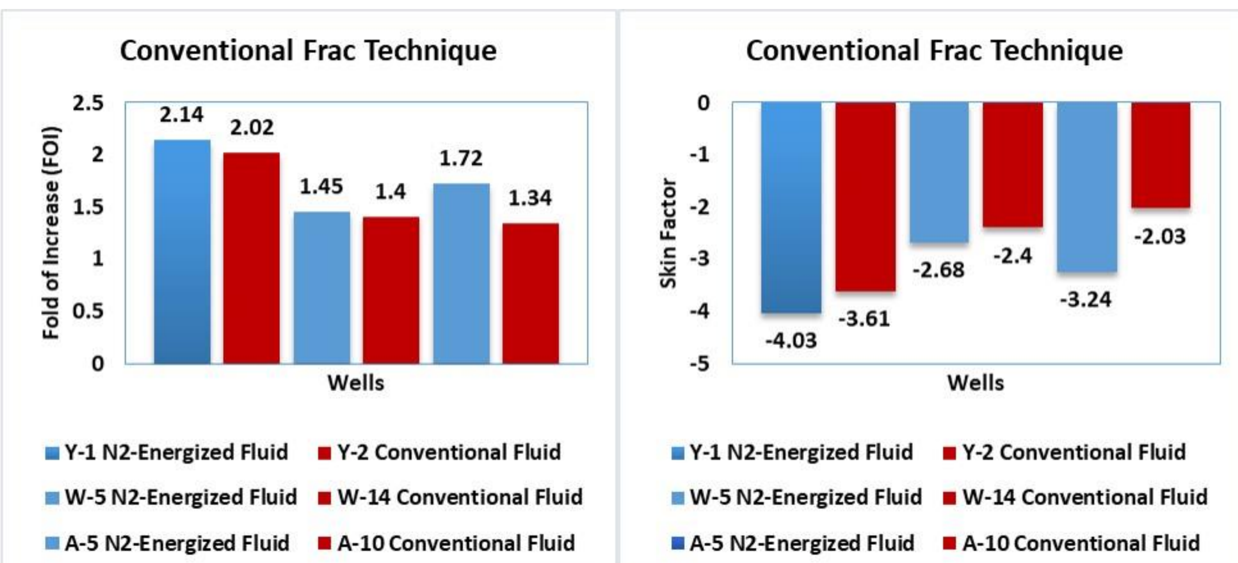

Figure 1. Skin factor and FOI for conventional frac technique

For channeling frac technique Figure 2 about 66% N_2 energized fluid wells get higher values for skin factor and FOI than their offset wells which used conventional fluids.

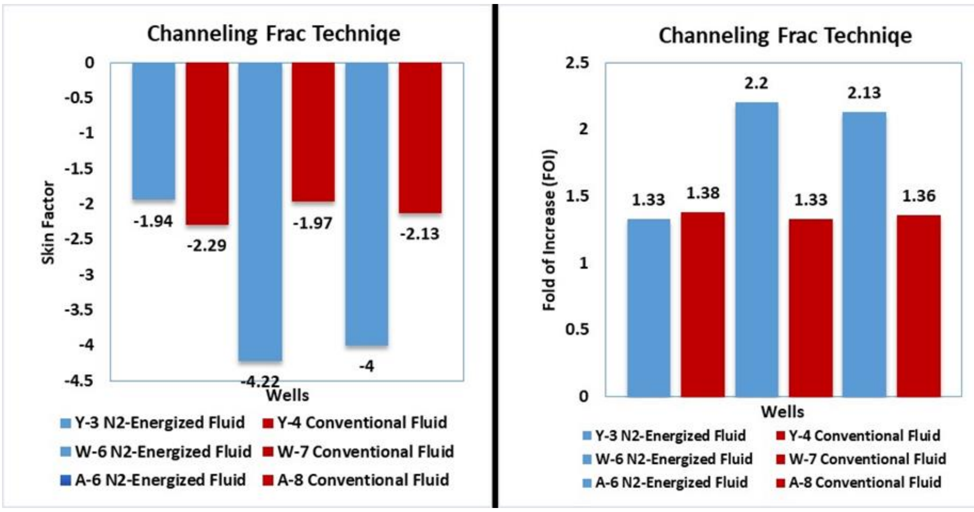

Figure 2. Skin factor and FOI for channeling frac technique

4.2. Cumulative production

The cumulative production values after one year for wells fractured with N_2 energized fluid and conventional fluid for both Frac techniques are obtained in Table 4.

Table 4. Cumulative production after one year for conventional and channeling frac techniques

Conventional frac technique			Channeling frac technique		
Well name	Fracturing fluid type	Cumulative production one year (MMSTB)	Well name	Fracturing fluid type	Cumulative production one year (MMSTB)
Y-1	N_2-energized fluid	0.029	Y-3	N_2-energized fluid	0.020289
Y-2	Conventional fluid	0.021	Y-4	Conventional fluid	0.04825
W-5	N_2-energized fluid	0.130767	W-6	N_2-energized fluid	0.018933
W-14	Conventional fluid	0.042315	W-7	Conventional fluid	0.048084
A-5	N_2-energized fluid	0.026	A-6	N_2-energized fluid	0.034
A-10	N_2-energized fluid	0.023	A-8	N_2-energized fluid	0.029

From the results found that for conventional frac technique Figure 3 all wells fractured with N_2 energized fracturing fluid achieve higher cumulative production compared with offset well fractured using conventional fluids. For channeling frac technique Figure 4 about 30% of wells fractured with n_2 energized fracturing fluid achieve higher cumulative production compared with offset wells fractured using conventional fluids. This means that conventional frac technique outperform the channeling type with n_2 energized fracturing fluid.

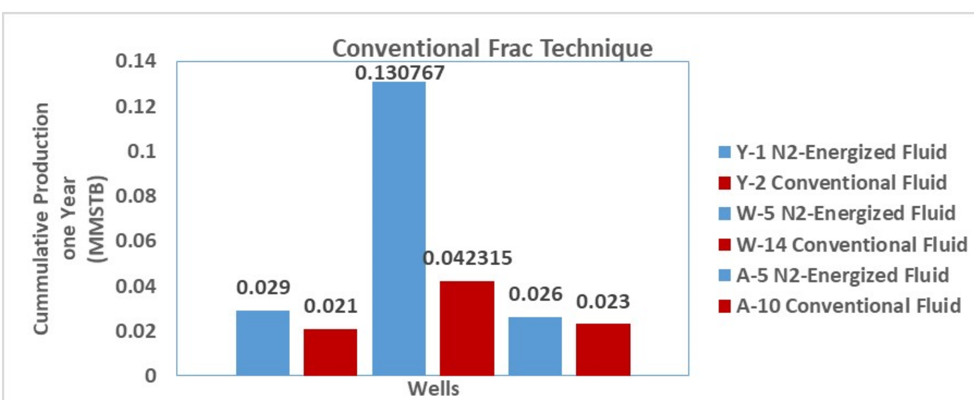

Figure 3. Cumulative production data after one year for conventional frac technique

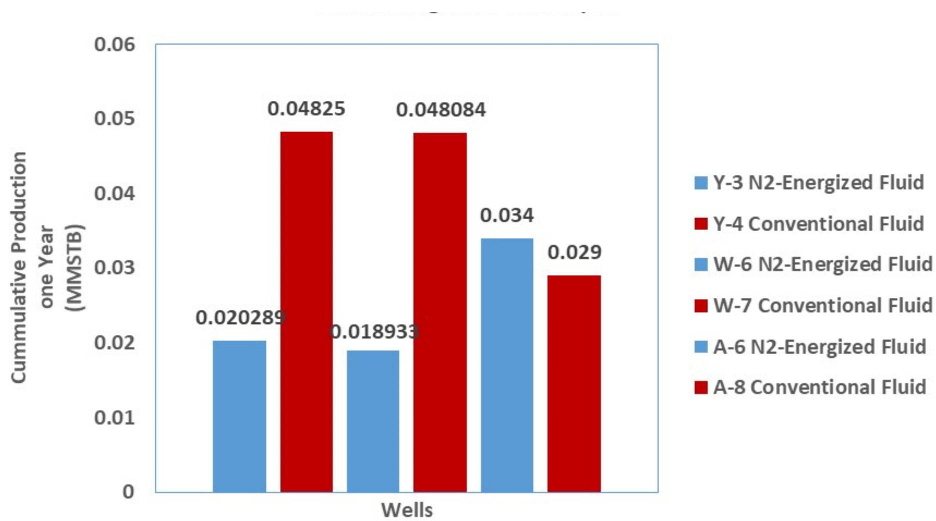

Figure 4. Cumulative production data after one year for channeling frac technique

4.3. Percent of success of frac job

Any hydraulic fracture design will assume fold of increase value, when comparing the designed value with the calculated one percent of success will be obtained. N2 Energized fluid obtained higher percent of success than conventional fluids as shown in Table 7.

Table 5. Percent of success data for conventional and channeling frac techniques

Conventional Frac			Channeling Frac		
Well name	Fracturing fluid type	Percent of success %	Well name	Fracturing fluid type	Percent of success %
Y-1	N_2-energized fluid	55%	Y-3	N_2-energized fluid	31%
Y-2	Conventional fluid	48%	Y-4	Conventional fluid	41%
W-5	N_2-energized fluid	51%	W-6	N_2-energized fluid	53%
W-14	Conventional fluid	45%	W-7	Conventional fluid	36%
A-5	N_2-energized fluid	45%	A-6	N_2-energized fluid	51%
A-10	N_2-energized fluid	40%	A-8	N_2-energized fluid	39%

From the results found that for conventional frac technique Figure 5 all well fractured with N_2 energized fracturing fluid achieve higher percent of success compared with offset well fractured using conventional fluids.

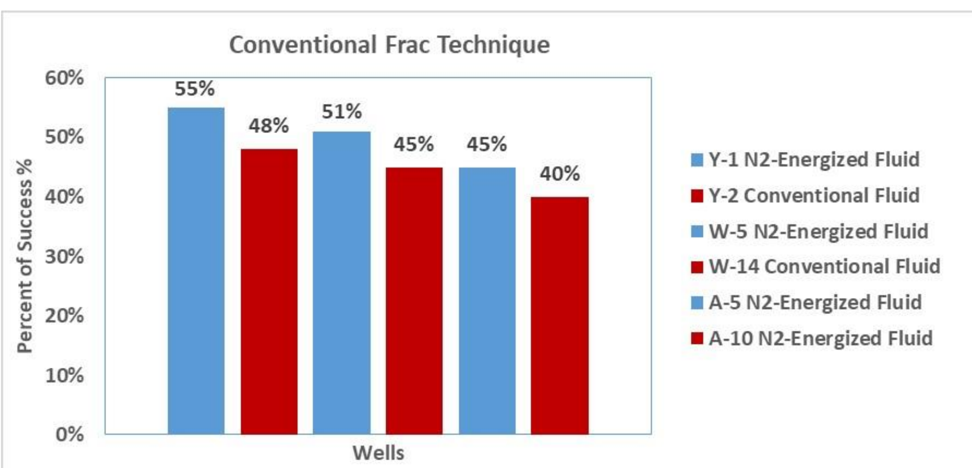

Figure 5. Percent of success for conventional frac technique

For channeling frac technique Figure 6 about 66 % of well fractured with N_2 energized fracturing fluid achieve higher percent of success compared with offset well fractured using conventional fluids. This means that conventional frac technique outperform the channeling type with N_2 energized fracturing fluid. In general N_2 energized fracturing fluid outperform conventional type with average percent of success 50% for conventional frac technique and 40% for channeling frac technique.

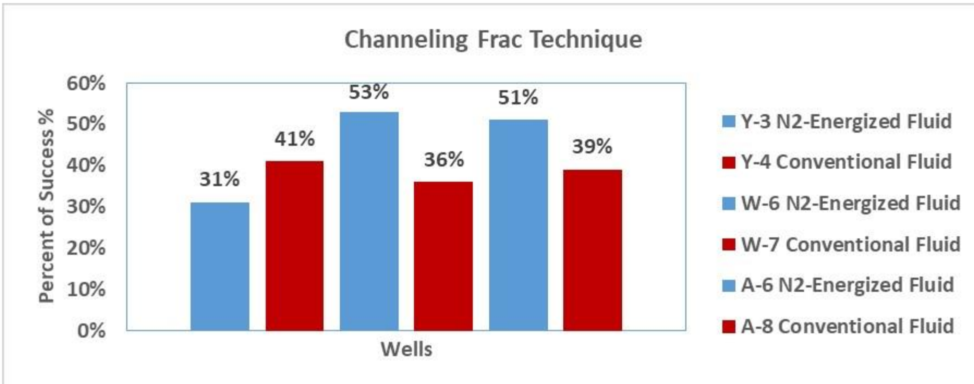

Figure 6. Percent of success for channeling frac technique

4.4. Fall out factor

Fall out factor is the percent of proppant fall in the well during pumping. By analysis of all cases found that N_2 energized fluid outperforms conventional fluid type in this issue. This means better carrying capacity of these fluid. This was done using coiled tubing tagging after frac job. These data are represented in Table 6.

Table 6. Fall out factor (percent of proppant pumped)

Conventional Frac			Channeling Frac		
Well name	Fracturing fluid type	Fall out factor of proppant (% of proppant pumped)	Well name	Fracturing fluid type	Fall out factor of proppant (% of proppant pumped)
Y-1	N_2-energized fluid	1.2	Y-3	N_2-energized fluid	0.85
Y-2	Conventional fluid	3.25	Y-4	Conventional fluid	1.68
W-5	N_2-energized fluid	2.67	W-6	N_2-energized fluid	1.51
W-14	Conventional fluid	2.96	W-7	Conventional fluid	3.56
A-5	N_2-energized fluid	1.84	A-6	N_2-energized fluid	2.39
A-10	N_2-energized fluid	3.4	A-8	N_2-energized fluid	3.24

All cases show better carrying capacity Figure 7 as less percent of proppant fall off in the rat hole of the well during pumping the Frac job. This means that N_2 energized fluid has better carrying capacity compared with conventional fluid which will be reflected on Frac dimension.

4.5. Treating pressure limitations

The concern of using N_2 energized fracturing fluid is the possibility of screen out because of lower hydrostatic pressure and as result higher surface treating pressure. But using N_2 energized fluid with such low foam quality (20-30%) will reduce hydrostatic pressure with little percent. By analysis of data found that this increase may range from 10% to 20% and in some cases may the same. This means that pressure limitations with this foam quality will not affect the selection criteria of fracturing fluid especially when dealing with low pressure reservoirs.

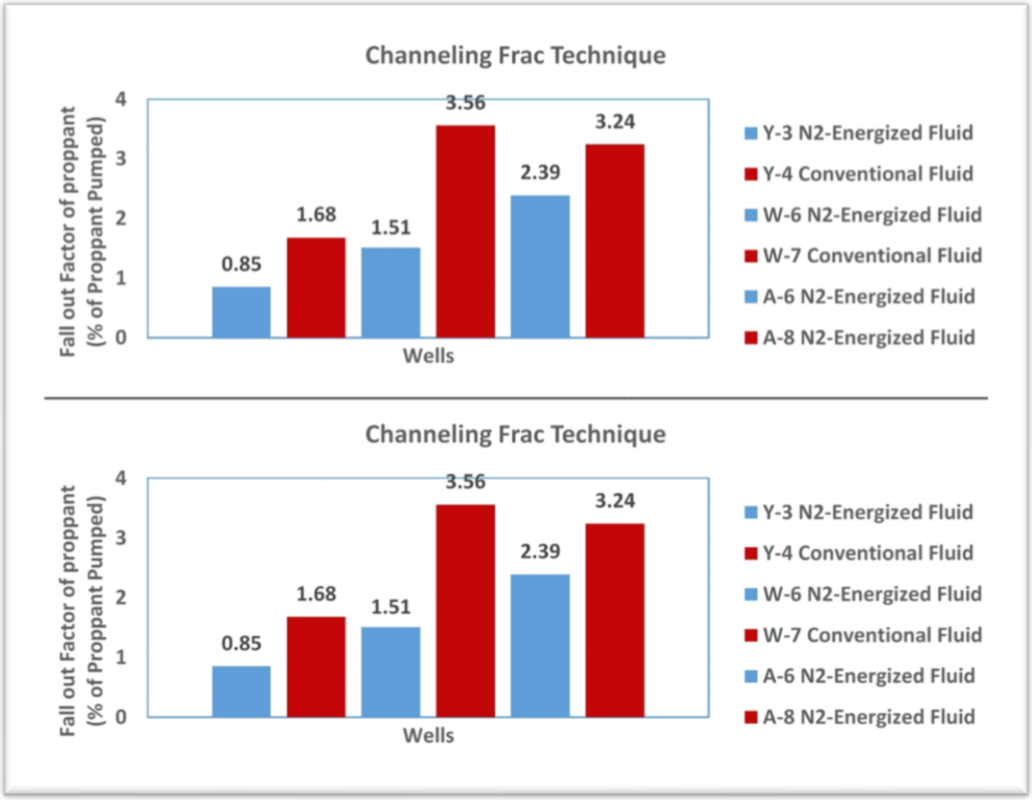

Figure 7. Fall out Factor of proppant in rate hole

4.6. Economic study

Studying both fluids economically one found that cost of N_2-energized fluid was slightly higher than conventional one. But this depend on availability and cost of water and N_2. In some areas handling the available quantity of water is difficult and expensive. If there is increase in cost when compared with results obtained it is marginal.

Assume that the same volume of proppant pumped, CAPEX and OPEX was the same except the frac job cost. For conventional frac job the cost consist of service charge, fluid and proppant cost. For N_2 energized fluid additional cost due to N_2 volume and foaming agent charge but less fluid used. This will be based on foam quality used.

For example well can be fractured with conventional fracturing fluid by pumping 120,000 lb proppant, rate 35 bpm and pumping time is 40 min, gel will be 58,800 gals. The same well can be fractured by N_2-Energized fracturing fluid with foam quality 20% foam quality gel will be 47040 gal, N_2 will be 3000 gals and foaming agent 185 gals (5 gal/1000 gal).

Assume cost of gel will 0.69$/gal, N_2 is 2.2$/gal and foaming agent is 35$/gal. So the different in price will as in Table 7.

Table 7. Cost comparison of N_2 energized and conventional fluids

Items		N_2-energized	Conventional
Gel	Volume	47 040	58 800
	Cost	32 457.6	40 572
N_2	Volume	3 000	0
	Cost	6 600	0
Foaming agent	Volume	326	0
	Cost	11 410	0
Other items		200 000	200 000
Total		250 468	240 572

So, adding N_2 to the fracturing fluid may be sometimes costly but this cost is marginal when compared with results obtained. Less fluid pumped means less damage, and less cost. The cumulative production after one year show that N_2 energized fluid will give higher production which will offset any increase in frac job cost.

5. Conclusions

After the calculations that were performed to evaluate the N_2-energized fracturing fluid in low-pressure reservoirs and compare between it and the conventional fracturing fluid in different aspects, one finally manages to reach the conclusion that show the main positive points for the type of fluid and the negative aspects.

The N_2-energized fracturing fluid has proven itself as a fracturing fluid, especially in low-pressure reservoirs. Better clean up, less fluid pumped, higher fluid efficiency and better carrying capacity. The N_2-energized fracturing gives better carrying capacity indicated from percent of proppant fall out in the well during pumping. This can be obtained by measuring proppant fall in the rate hole after frac job using coiled tubing tagging. Foam quality of 20 to 30% will give better results with the least cost.

In some cases of higher permeability wells it has been found that no change in cumulative production compared with the conventional type. However, one take the benefits that you pump the same amount of proppant with less volume of water. Less water means less damage to the formation, as well as less damage to the environment. The operator must open the well directly after frac job (forced closure) to get the maximum benefits from this fluid.

Surface treating pressure will be higher than before due to lower hydrostatic pressure of the mixture. With 20-30% foam quality pressure increase range will be (10-20) % or less.

The conventional fracturing technique appeared more successful with n_2 energized fluid compared with channeling fracturing technique. However that channeling technique is theoretically give a higher conductivity. As compared to conventional fracturing fluid economically N_2-energized fluid will not be expensive as less fluid used will offset the cost of N_2 volume.

Recommendation

According to filed practice and obtained results, N_2 energized fluid frac wells must be open directly after the job (forced closure), so frac companies must prepare the required connection for this purpose.

Also some companies use in N_2 –energized job use conventional fluid without N_2 in the flush stage and this will affect the energy added because of higher hydrostatic pressure. So it is recommended to continue with N_2 till the end to get the maximum benefits of gas energy for improving flow back.

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Nomenclature

DCA	*Decline Curve Analysis*	q_{Dd}	*Dimensionless rate*
Di	*Initial Decline Rate, Day-1*	r_{ed}	*Effective drainage radius*
EUR	*Estimated Ultimate Recovery, MMSTB*	r_e	*Drainage Radius, ft.*
FOF	*Fall out factor of proppant in the well*	r_w	*Wellbore Radius, ft.*
FOI	*Fold of Increase*	r_{wa}	*Apparent wellbore radius, ft*
FQ	*Foam Quality, %*	*S*	*Average Skin Factor*
PI	*Productivity Index, STB/day/psi*	S_f	*Skin factor after Frac*
P_r	*Reservoir pressure, psi*	*SPI*	*Specific Productivity Index, STB/day/psi/ft.*
P_{wf}	*Bottom hole following pressure, psi*	t_{Dd}	*Dimensionless time*
q_i	*Initial flow rate, STB/day*		

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To whom correspondence should be addressed: Tarek A. Ali, Qarun Petroleum Company, Egypt,
E-mail: tarek.fattah.ali@gmail.com