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Improving Gas Reservoirs Productivity Using Methanol-Treated Fracturing Fluids

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Abstract

Many gas reservoirs are subject to problems and formation damage during hydraulic fracturing operations caused by low permeability and incompatible fracturing fluids. In order to achieve optimum productivity enhancement and gas flow rates, they need advanced fracturing fluids. During stimulation, formations are susceptible to water blockage which is one of the main mechanisms of reduced productivity after fracturing operations even in successful ones. Detrimental gas relative permeability effects are often induced by the injected conventional water-based fracturing fluids that will increase the initial water saturation and reduce the available area for flowing gas, that makes stimulating gas wells a big challenge and requires more evaluation for the reservoir characteristics in order to select the optimum fracturing fluid. The aim of this study is to present and evaluate a novel fracturing fluid for stimulating low permeability gas reservoirs. Methanol has been widely used to improve gas production rates during stimulating water-sensitive formations. Several experimental studies proved that the addition of Methanol to fracturing fluids improve gas flow rate and permeability recovery by two means, improving the mobility of fracturing fluids during liquid displacement phase by gas and boosting the evaporation rate of the trapped fluids after displacement phase. Over twenty-five gas wells were stimulated using 10% methanol fracturing fluid system, analysis of post-Frac production data proved the effectiveness of adding Methanol to fracturing fluids in order to minimize water blockage and increase gas production by more than three folds comparing to conventionally stimulated gas wells.

Keywords: *Stimulation; Hydraulic fracturing; Water block; Gas reservoirs; Productivity recovery; Fracturing fluids; Formation damage.*

1. Introduction

During fracturing stimulation treatments for gas reservoirs, large amounts of fluid volumes are injected into the formation, most of these fluids get blocked into the formation which leads to deleterious relative permeability effects and reduction in gas reservoirs productivity instead of improvement. Water block is popular when capillary forces exceed the gas driving force, although water block may occur in some high-permeability formations it is most severe in lower permeability formations (less than 10 mD) in which capillary pressure tends to be high because of small pore sizes.

Many gas reservoirs are in the sub-irreducible water saturation state, in which initial water saturation is less than the capillary irreducible water saturation, which provides a higher gas relative permeability and therefore a higher well productivity [1]. Invasion of water-based fracturing fluids increases water saturation above Swi even after well clean-up [2]. This increase in water saturation, due to water block, results in gas permeability reduction from Kr @ Swi to Kr @ Swc [2].

This formation damage, referred to as phase trap, causes great potential damage to gas permeability and gas production and increases with increasing the difference between initial water saturation and the critical water saturation.

The aim of this work is to present and evaluate a novel fracturing technique to address the possible water blockage during gas-wells fracturing treatments, field applications using 10% methanol fracturing fluid system proved the effectiveness of methanol to minimize water block and achieve higher gas rates comparing to conventional water-based fracturing fluids.

All previous studies concerned with water block and its effect on productivity reduction plus some studies interested in methanol role to minimize water block, in addition to experimental studies conducted to evaluate 10% methanol effect to minimize water block and enhance gas productivity. But this is the first time to evaluate 10% methanol fracturing fluid system through field application cases and provide an excellent solution for water blockage during stimulating low-permeability gas wells to get the maximum of its productivity.

Authors developed several correlations to predict the severity of water block, two of these correlations, see Appendix A, will be used in this paper to evaluate the severity of water block for stimulated formations in order to facilitate recognizing permeability reduction causes after fracturing stimulations in certain cases.

Bahrami *et al.* [3], Friedel *et al.* [4], and Bennion *et al.* [5] compared to the productivity increase by the fracturing job, the impact of water blocking is more significant as water imbibition is known to be one of the key mechanisms for formation damage. Liu, Wang, Xu and Xiang [6] showed that increasing liquid saturation across fracture/formation interface in low permeability gas reservoirs extremely hinders gas flow. Motealleh and Bryant [7] proved that water invasion causes mechanical formation damage and reduces effective permeability in the water invaded zone. Mahadevan *et al.* [8] showed that invaded liquids during fracturing cause phase trapping and reduce the well productivity. Bennion and Brent [1] leak-off of liquids into the formation may be serious in the case of hydraulic fracturing, and water damage can affect the efficiency of the well more noticeably. Low-permeability reservoirs with sub-normal initial water saturation are significantly susceptible to water phase trapping effect, so water blocking will affect the gain of hydraulic fracturing in gas reservoirs with low permeability. Parekh and Sharma [9] studied parameters affecting well deliverability after fracturing treatment using numerical simulation, they found that effective water block clean-up occurs only when well's drawdown is three times greater than the capillary pressure. Parekh and Sharma [9], Kamath and Laroche [10], and Mahadevan and Sharma [11], studied the factors affecting clean-up of water blocks and identified that clean-up occurs in two stages- fluids displacement followed by vaporization by the flowing gas. Settari *et al.* [12] addressed the issue of reduction in permeability during the drawdown and how it impacts the rate of cleanup. Many laboratory studies [13-14] cite water block as one of the fluid retention mechanisms when a water-based fluid imbibes into a water-wet formation with sub-irreducible water saturation.

Abrams and Vinegar [15] capillary pressure is high in the case of low-permeability formations due to very tight pores, so the ratio of drawdown to capillary pressure has a major impact on return permeability. Holditch [16] developed a numerical model to identify the controlling factors for cleanup process as near-wellbore damage and capillary pressure. Studies of Shanley *et al.* [17] suggest that when water saturation exceeds 40 to 50 percent, gas production suffers significantly.

Using methanol in fracturing fluids enhancing cleanup for formation damage [18-20] Coulter and McLeod [21] studied the influence of volatile fluids on water block clean-up. They suggest that alcohol can boost water block clean-up in formations of more than 5% clay material, and recommend optimum alcohol concentrations depending on fluid type.

2. Mechanism of water block during fracturing stimulation

Water block mechanism can be summarized in three stages [5]:

Stage-1 Is before introduction of water-based fracturing fluids where the initial water saturation is at the minimum and flow area is at maximum that means maximum gas effective permeability.

Stage-2 After invasion of fracturing fluids, voids are filled with water.

Stage-3 After flow back process, water saturation did not back to the low water saturation and hence flow area available for gas flow is reduced which causes a reduction in effective permeability; this reduction in permeability is referred to as mechanical formation damage.

3. Factors impacting the severity of water block

1. Capillary pressure and relative permeability which are direct functions of wettability
   a. Water saturation
   b. Pore geometry
   c. Interfacial tension between the injected fluid and the produced fluid
2. Reservoir pressure and temperature
3. Depth of invading fluid penetration

4. Review of conventionally-treated gas wells

Prior to the application of 10% methanol fracturing fluid system many gas wells were treated using conventional water-based fracturing fluids. We noticed that a lot of these wells produced a lower rate than the expected one, in certain cases some wells showed no improvement at all and even reduction in the rate after treatment. Accordingly there must be some type of formation damage that induced by fracturing fluids.

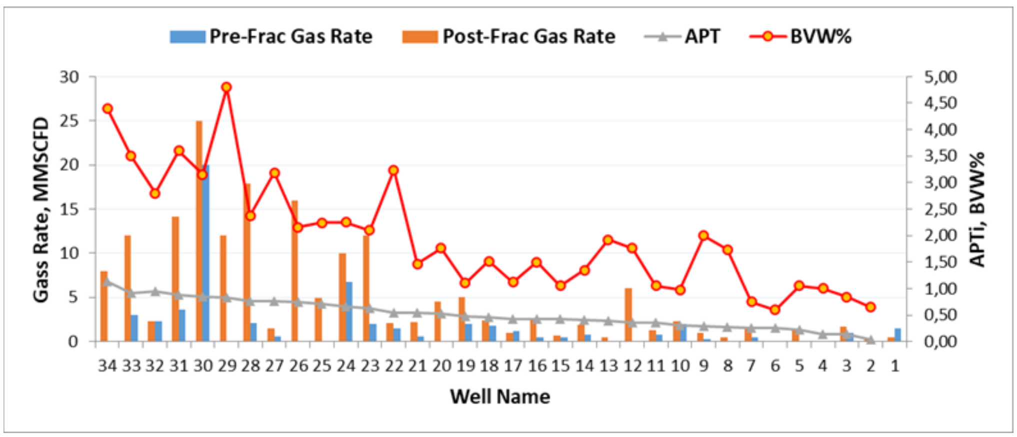

Figure 1. Flow rates comparison and APTi & BVW% trends

Thirty four gas wells were selected arbitrary to review and evaluate their performance after fracturing stimulation. Table 1 shows reservoir properties of these wells in addition to gas rates before and after the stimulation treatment. APTi and BVW% were calculated for each well to be an indication for formation water sensitivity. Figure 3 shows flow rates of each well, wells were ordered in a descending way according to APTi values.

It is so clear from Figure 1 that there is a relation between APTi and BVW% values and the gas rate improvement for stimulated wells, as APTi and BVW% decrease which in turn will increase the formation sensitivity to water block, wells show less improvement which emphasizes that these wells were affected by water block during stimulation operations.

On the other hand wells with high values of APTi and BVW% showed good improvement after fracturing stimulation as these wells have fewer tendencies to block fracturing fluids and hence less affected. As a result of this reduction in permeability due to water block, we changed the strategy of stimulating gas wells and shifted to using 10% methanol fracturing fluids in subsequent treatments.

Table 1.Reservoir data for conventionally treated wells

Well	K md	Porosity %	Water Saturation %	Res. Pressure Psi	Res. Temp. F	Pre-Frac Rate MMSCFD	Post-Frac Rate MMSCFD	APTi	BVW%
C-34	0.1	5	13	6500	290	1.5	0.5	0.04	0.65
C-33	0.3	7	12	6005	290	0.01	0.3	0.13	0.84
C-7	0.5	10	10	5534	280	1	1.7	0.14	1.00
C-26	0.4	7	15	5700	295	0.01	0	0.23	1.05
C-27	3	10	6	1500	288	0.01	1.5	0.25	0.60
C-29	0.5	5	15	5950	290	0.01	0	0.25	0.75
C-20	0.03	5.8	30	5700	287	0.5	1.5	0.28	1.74
C-23	0.26	10	20	Tight	290	0.01	0.5	0.29	2.00
C-28	1	7	14	5730	280	0.3	1	0.31	0.98
C-30	1.2	7	15	6500	290	2	2.3	0.35	1.05
C-8	0.3	8	22	5952	285	0.8	1.3	0.35	1.76
C-19	0.3	8	24	5646	287	0	6	0.40	1.92
C-12	2	9	15	3051	280	0	0.5	0.41	1.35
C-14	2.3	7	15	5839	290	0.8	1.89	0.42	1.05
C-31	2.3	10	15	2600	290	0.5	0.7	0.42	1.50
C-4	2	7	16	5135	288	0.44	2.4	0.43	1.12
C-32	1.4	8	19	4065	285	1.2	1	0.45	1.52
C-16	1.3	5.5	20	5634	290	1.84	2.38	0.47	1.10
C-22	1.4	8	22	4460	288	2	5	0.52	1.76
C-25	2	7	21	4993	290	0	4.5	0.54	1.47
C-13	0.1	9	36	5922	290	0.6	2.16	0.54	3.24
C-10	0.7	7	30	5763	280	1.5	2.05	0.62	2.10
C-6	3	9	25	5465	294	1.98	12	0.67	2.25
C-3	2.6	8	28	5900	300	6.8	10	0.72	2.24
C-17	0.7	6	36	5460	290	0.01	4.9	0.75	2.16
C-9	3	11	29	4500	280	0.01	16	0.76	3.19
C-15	1.1	7	34	4086	283	0.6	1.5	0.76	2.38
C-11	0.6	12	40	5763	280	2.05	17.9	0.82	4.80
C-21	2	9	35	3670	289	0.01	12	0.85	3.15
C-2	1	9	40	2623	300	20	25	0.88	3.60
C-5	5	8	35	3630	278	3.6	14.12	0.94	2.80
C-18	3.5	10	35	5900	293	2.25	2.3	0.91	3.50
C-1	10	11	40	2678	302	3	12	1.13	4.40
C-24	2	7	50	4440	290	0.01	8	1.18	3.50

5. 10%methanol system overview

Methanol has many properties that make it the best choice for water-sensitive formations stimulation treatments such as:

- The ability to decrease the surface tension.
- Maximizing the fracturing fluids recovery by increasing its mobility.
- Accelerating the clean-up period "Better flowback" due to its volatility.
- Improving the gel stability even at higher temperature "Less gel loading/Less damaging".

5.1. Effect of methanol on fracturing fluids stability

A lab test was conducted to evaluate the impact of methanol on gel stability, results, as shown in Figure 2, show that addition of methanol improves gel stability and delays the gel breaking time which enables using less gel loading to minimize formation damage.

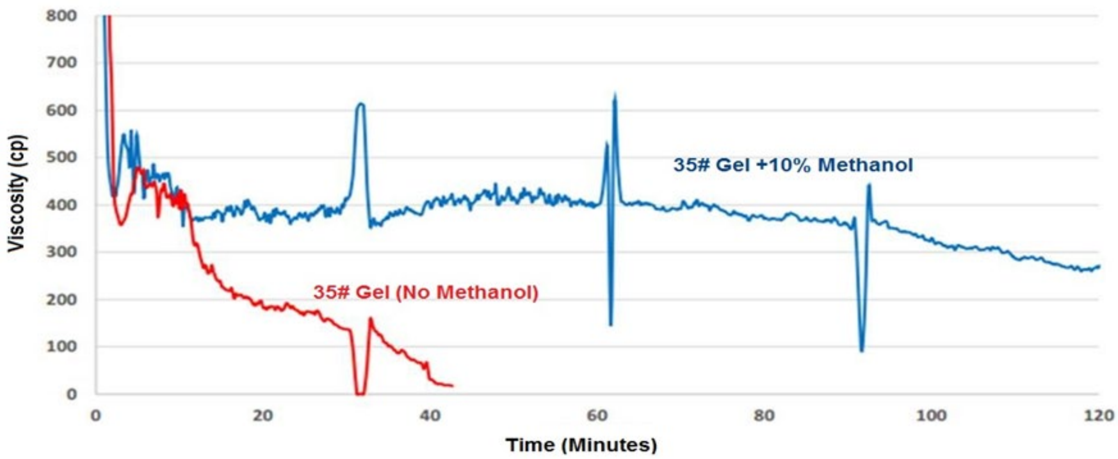

Figure 2. Effect of methanol on fracturing fluids rheology

Above 10% methanol concentration, the gel will show excessive stability and long time for breaking which is inappropriate with our hydraulic fracturing volumes so we limited the application of methanol to only 10% concentration as it is the optimal for our fracturing volumes.

10% methanol system is prepared by mixing 10% methanol with fresh water or brine then chemicals such as cross-linker, breakers, bactericide, etc., are added and well mixed, the resulting cross-linked system has the same properties of conventional fracturing fluids regarding to proppant transport, rheology, fluid loss, etc.

5.2. 10% methanol system application

Best candidate formations for the 10% methanol system are those of low permeability, low bottom hole pressure, and low initial water saturation " Sub-irreducible Saturation'', all these characteristics increase the ability of formation to retain injected Frac fluids "Water Block". These trapped fluids will lead to deleterious gas relative permeability effects and a noncommercial gas flow rates.

Using 10% methanol has the ability to reduce water saturation near wellbore below the irreducible saturation which increases gas permeability, this is observed in wells stimulated with 10% methanol and produced large amounts of water although these wells produced no water prior to stimulation operations.

6. Field case histories

Over twenty-five gas wells were stimulated using 10% methanol and proved the effectiveness of this system to minimize water blockage and maximize gas production rate. Some of these wells will be reviewed to evaluate the system.

Case#1

Four different wells were completed by hydraulic fracturing. Conventional water-based fracturing fluid was pumped for two wells while the other two offset wells were treated with the 10% methanol system. This new technique was chosen to address the possible suspected water block effect on production. By application of this new technique, the production increased three folds comparing to the offset wells treated conventionally as being shown in Figure 3. Post hydraulic fracturing treatment data are summarized in Table-2.

Table 2. Frac data summary

Well/Parameter	M-16	M-17	C-7	C-8
Closure Pressure, Psi	11140	10563	10656	10713
F.E, %	26.0	41.0	28.6	63.8
Net Pressure, Psi	2915	1612	3048	3585
Fluid Type	10% methanol Sys.	10% methanol Sys.	Conventional cross–linked gel	Conventional cross–linked gel
Fluid Vol., BBLs	2700	2596	2640	2820
Proppant Vol., Ib	175000	220900	215000	195000
PAD %	40	30	35	35
Average Rate, BPM	18	45.4	39.4	40.2
Average Treating Pressure, Psi	10116	7914	10425	9733
Max Prop Concentration, PPA	6.5	8.2	8.5	6.14

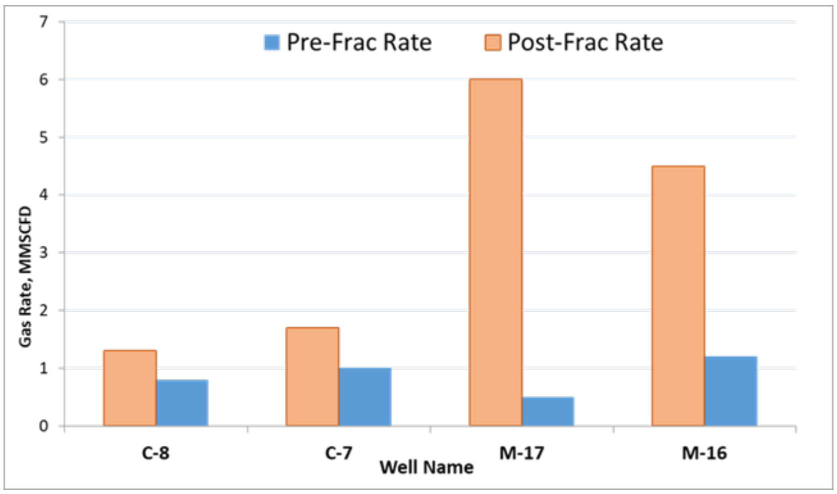

Figure 3. Flow rates comparison for wells treated conventionally (C-8 & C-7) against those treated using 10% methanol (M-17 & M-16)

Two predictive formulas were applied to check formation sensitivity to water block. Results were as shown in Table 3.

Table 3. Reservoir data and APT severity for the treated wells

Well	K, md	Porosity, %	Sw, %	APT	BVW%
M-16	0.2	4.5	13	0.11	0.59
M-17	0.4	4	33	0.63	1.32
C-7	0.5	10	10	0.14	1.00
C-8	0.3	8	22	0.44	1.76

Depending on the criteria for interpreting values of APT and BVW%, all wells will likely exhibit significant sensitivity to water block, this may explain the unexpected low post-Frac gas rates for conventionally treated wells, most properly affected by water block after stimulation.

Another notice is the water production increase for methanol-treated wells after stimulation comparing to pre-stimulation one as a result of enhancing mobility of water. This will definitely result in water saturation reduction and subsequent increase in gas flow rate.

Case#2

M-23 and M-24 are two wells targeted same reservoir at 4400 m deep with reservoir pressures and temperatures in excess of 9500 Psi and 310 degrees Fahrenheit respectively. After workover operations, which included conventional hydraulic fracturing, wells showed very low production rates of 1.5 MMSCFD that were very disappointing and low compared to expectations from log data. The suspected cause of this drop in productivity is water blockage caused by fracturing fluids used. Acid stimulation was carried out to restore wells productivity but in vain.

Accordingly 10% methanol fracturing fluid system was used to overcome the above mentioned damage. Wells were tested after Methanol fracturing with a stabilized rate of 35 MMSCFD and 3000 BPD condensate. 10% Methanol system proved its effectiveness when formation is susceptible to water block. Figure 4 shows sand quality for both M-23 and M-24 wells.

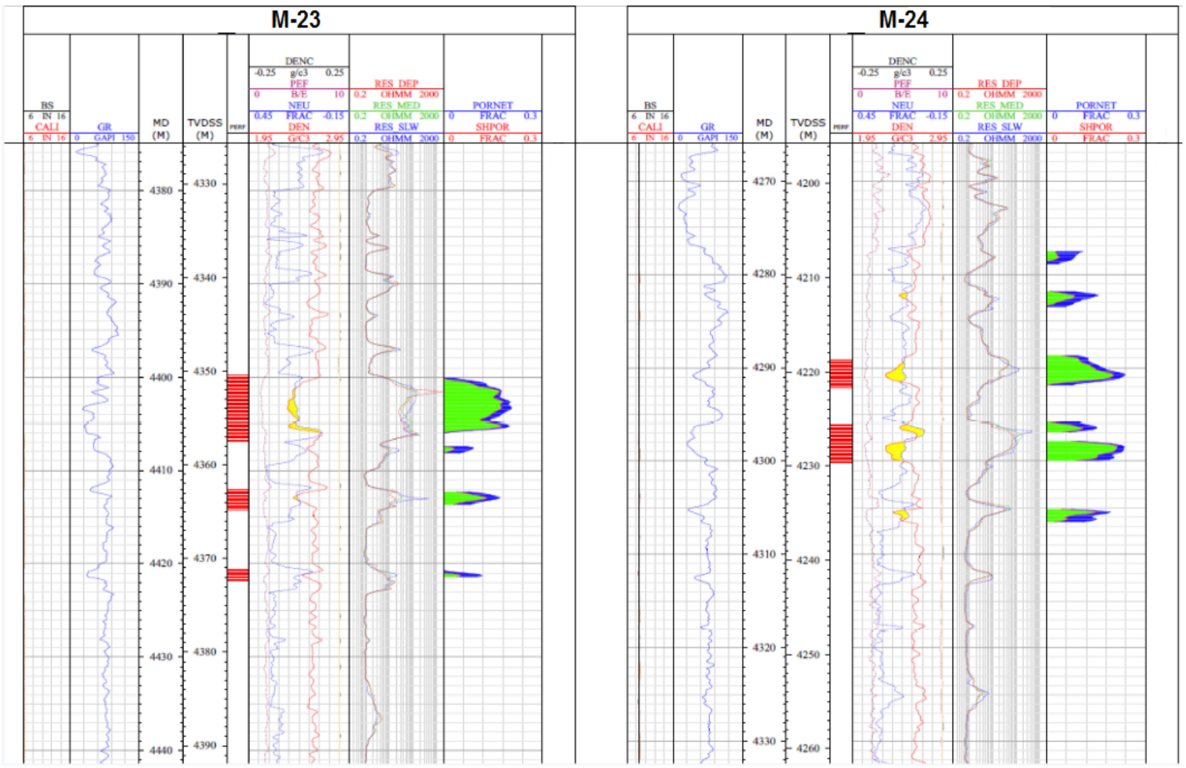

Figure 4. Sand quality for both M-23 and M-24 wells

Case#3

Conventional Frac stimulation was performed in well M-19 with post-Frac production rate of 2 MMSCF gas and 107 BPD condensate. These rates are below away from our expectations depending on formation quality and thickness, Table 4 shows reservoir characteristics for M-19. We believe that some type of formation damage may be the cause of that low production rate.

Hence decision was taken to re-Frac the same well using 10% Methanol system to address the suspected water blockage and optimize well productivity in order to get the maximum possible gas rate. Table 5 shows a summary of Frac job data. Well was tested after fracturing with stabilized rates of 11 MMSCFD gas and 673 BPD condensate.

Table 4. Reservoir data for M-19

Parameter	Value	Parameter	Value
Reservoir pressure	5900 Psi	Water saturation	22%
Reservoir temperature	280 F	Mobility	9 md/cP
Permeability	1 md	APT	0.48
Porosity	9%	BVW%	1.98

From Table 4 the reservoir parameters indicate that this formation is susceptible for water block which explains the low rate after conventional water-based stimulation treatment

Table 5. Frac stimulation data summary for well M-19.

Parameter	Value
Closure Pressure	8045 Psi
F.E	32%
Net Pressure	1596 Psi
Fluid Type	10% Methanol Sys.
Fluid Volume	1895 BBLs
Proppant Volume	204800 lb
PAD Volume	50%
Average Rate	35 BPM
Average Treating Pressure	7678 Psi
Max Prop Concentration	7.2 PPA

7. Results and discussion

The present study verified the impact of water block during hydraulic fracturing on gas relative permeability and showed how using water-based fracturing fluids in low-permeability gas reservoirs will adversely affect the productivity and resulting in low or no gain at all, also showed how the addition of Methanol to fracturing fluids is effective in mitigating water blockage and optimizing gas flow rates by reducing interfacial tension and increasing volatility of the fracturing fluids. The results demonstrate that water blockage is tied to reservoir permeability, drawdown, and water saturation, with lower values promoting water blockage.

Using APT and BVW% will help predicting the sensitivity of the formation for phase trapping hence assisting choosing the appropriate fracturing fluid, as some gas wells showed good performance after fracturing without using Methanol we may save cost by good evaluation for reservoir sensitivity for water block.

8. Conclusions

Addition of methanol to fracturing fluids enhances gas flow rates by minimizing water blockage and improving fluids flow back. Field applications show that 10% methanol system allows quick and more effective cleanup comparing to water-based fracturing fluids.

The best candidates for Methanol-treated fracturing fluids are formations of low permeability, low water saturation, and low bottom hole pressure. When treating formations susceptible to water blockage, 10% methanol system is preferred as it reduces the aqueous fluid saturation and minimizes fluid imbibition near wellbore. 10% methanol system is a cost effective comparing to other fracturing fluids. With adequate facilities, proper preparation and treatment implementation, and rigorous staff training, safety concerns can be satisfactorily handled.

Appendix A

Predictive formulas

Index of APT

Bennion *et al.* [??] proposed a simple equation to evaluate APT, he defined the index of APT, APTi, using only two parameters (see Eq. 1)

$$APTi = 0.25\log10\,(K) + 2.2Swi \qquad (1)$$

where: K is the air permeability in mD, and Swi is initial water saturation in fraction. The value of APTi for a given reservoir evaluates APT in that reservoir as shown in Table A1.

Table A1. Criteria for interpreting values of APTi

APTi Value	Prediction
APTi ≥ 1.0	Reservoir unlikely to exhibit significant permanent sensitivity to APT
0.8≤ APTi ≤1.0	Reservoir may exhibit sensitivity to APT
APTi < 0.8	Reservoir will likely exhibit significant sensitivity to APT

Percent of bulk volume water

Another formula was proposed by Davis and Wood [??]. In this approach only two parameters are used to determine the percent of bulk volume water (see Eq. 2)

%BVW=S_"wi" .φ ×100 (2)

In which φ is the porosity in fraction. Interpretation of %BVW is presented in Table A2.

Table A2. Criteria for interpreting values of %BVW

%BVW Value	Prediction
%BVW ≥ 3.5	Reservoir unlikely to exhibit significant permanent sensitivity to APT
2.0 ≤ %BVW ≤3.5	Reservoir may exhibit sensitivity to APT
%BVW < 2.0	Reservoir will likely exhibit significant sensitivity to APT

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