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The Effect of Micro-Emulsion on High and Low GOR Gas Wells

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Abstract

An extensive, on-going investigation into the effectiveness of a micro-emulsion (ME) as a stimulation fluid additive is being conducted. Results from a population of 114 wells and 498 stimulation stages of hydraulic fracture stimulation provide the basis for this report. As part of the basis for the performance analysis, twenty four of the wells are producing from the Lance interval in the northeastern Pinedale Anticline area of the Green River Basin, Wyoming. The remaining 90 wells produce from the northern Denver-Julesburg Basin Codell and Niobrara formations. In both data sets about half of the wells had 1.5 gallons of ME per thousand used throughout the fracture stimulations, but at no other time during in-well operations. The stimulation fluid systems in the remaining wells contained no similar interfacial tension / surfactant system. Based on the performance matched reservoir properties and degree of effective stimulation, these comparisons and other performance metrics were used to assess the potential benefit arising from using ME. The determination of potential benefit was assessed using classical statistical methods to ensure that the interpretation was as unbiased as possible. From that analysis, there is distinct and clear benefit to be gained from using the micro-emulsion to facilitate placing the fracture stimulations, to increase effective fracture length and especially to increase hydrocarbon recovery from the wells in which the micro-emulsion system is used.

Review of Prior Work

The Codell-Niobrara reservoirs in the DJ Basin have been studied extensively (Refs. 1 – 4). Characterization of the reservoir system is well documented. Almost 80 percent of the wells in this study are in the “oily” portion of the Codell-Niobrara reservoir system. Likewise, the Lance formation in the Green River Basin has received considerable attention (5 – 8, 10). In particular, an analysis of the impact of micro-emulsions on well performance has previously been reported for the Green River Basin, Lance Formation (Ref. 5), in which ME is shown to facilitate placing the fracture stimulations, to increase effective fracture length, to minimize damage arising from operational shut-ins and to increase gas recovery of wells in which ME is used. The results of that investigation are relied upon in this study, as well.

Similar studies have been conducted in the Canyon Sands of West Texas by Pursley, Benton, Nordlander, *etal.* (6). They concluded that the wells in which a micro-emulsion (ME) was used a) had better reservoir conductivity, b) longer effective fracture lengths, c) better resistance to damage resulting from shut-in events and d) better long-term performance than those without it. Reports have been made regarding the impact of ME on formation damage mitigation (7). Other studies have particularly investigated the impact of zone isolation (8, 9) and proppant type effectiveness (10). Neither of these employed rigorous normalization procedures to ensure proper assessment of the impact of reservoir quality, etc. The latter authors did note that the use of semi-log “decline curve analysis” was ineffective.

Assessment Method and Data

Of the 114 wells investigated in this study, 90 are producing from the Codell-Niobrara reservoir system in the northeastern Colorado DJ Basin (1). The wells are stimulated in a single or dual completion strategy depending on the perceived potential for either or both zones to be productive. After stimulation, there are two modes of operating practice. Some wells are placed on production within two to five days. Others may not go on production for over a month. Once on production the usual operating practice is to record daily condensate, gas and water rates and tubing or casing pressures for about thirty days, after which the well is placed on production through a multi-well battery. Of this well population, 51 wells had micro-emulsion (ME) used throughout the stimulation at a 0.15% concentration. Seventeen wells employing ME had tubing landed immediately at the top of the perforations. Fourteen of the non-ME wells also had tubing installed. Values for thickness, porosity, water saturation and depth were taken from published literature (1 - 4). As a consequence of the short histories for the Codell-Niobrara wells, it was not deemed feasible or particularly meaningful to attempt to perform long-tem forecasting to estimate ultimate recovery. However, even though their histories are short, reasonable reservoir and completion quality assessments were possible (17, 20). For both sets of wells, the specific micro-emulsion system examined was Halliburton's exclusive GasPerm 1000™ micro-emulsion (ME), a CESI Chemicals' patented fracturing surfactant.

By contrast, the 24 Green River Basin wells had relatively long-term daily rate and pressure histories. Ten of these wells had a 0.15% ME concentration used during the stimulation operations. All of the ME wells also had tubing landed at or below mid-perforations. Six of the fourteen non-ME wells were producing through tubing. Detailed descriptive data for the wells was provided by the operator (5).

The performance analysis of all 114 wells was performed using the Reciprocal Productivity Index Method® (Refs. 16 - 19). Statistical analysis of the data sets employed stratification of the data sets (13) to account for known differences in well management strategies, such as early installation of tubing and particularly the use of micro-emulsion. In order to test the significance of the impact of and differences between the various strata, the classic null hypothesis test (13, 14) was employed.

The use of the null hypothesis test is normally conducted by specifying the "alpha" or significance level, which is really the probability that a "Type I" error can be tolerated. A "Type I" error is the event that the test is actually valid, but has been rejected as being invalid. The "test statistic" is calculated from the observed data and compared to the "critical point" for the specified significance. If the test statistic exceeds the critical point, then the hypothesis being tested is accepted. Typically, the "hypothesis" being tested is a statement such as "the means of two populations are the same".

The application of the null hypothesis test has been slightly modified in this study. The statement being tested is a question: "at what significance level (probability) are the means of the two populations different". The process is very simple. The significance level is back-calculated from the assertion that the test statistic is equal to the critical point. That computation is generally reported as the "P-Statistic", but in this case the value needed is one minus "P", since the difference, not the similarity, is being tested.

The Normalization Process

The usual process of estimating how well performance is influenced by changes in operating practices, stimulation methods, etc is a relatively simplistic approach. Among the traditional metrics are:

- Peak day rate of gas or oil
- Load water recovery to a point in time
- Six month cumulative gas production
- Time to first gas

Except for the last one, these are actually integrals over time of usually only one of the fluid phases consuming pressure energy during flow in the system. Use of these metrics often leads to misleading or at least inconclusive results.

However, rearrangement of the usual equations for modeling the behavior of transient systems (15, 17) yields the basis for better understanding of both the need for and the process of normalization of well performance metrics. The traditional equation form has been somewhat rearranged and shown as an integral over time. It is also portrayed as a multiphase relationship to account for how energy (pressure) is consumed over time by the production of each of the phases. So the integral over a six month period of the gas rate (the first term in the equation) would yield the traditional six month cumulative gas production metric. Integration of the third term, the water rate, should yield an estimate of load water recovery (were it not for mobilized formation water being produced, as well).

$$\int q_{gs}\rho_{gs}dt+\int q_{os}\rho_{os}dt+\int q_{ws}\rho_{ws}dt=\int \frac{\zeta Kh\bar{\rho}\left(P_i-P_w(t)\right)}{\bar{\mu}\ln\left(\dfrac{\xi Kht}{\phi h\mu c x_f^2}\right)}dt \quad (1$$

Clearly, considering only one of the rate integral terms on the left-hand side of Equation 1 does not give a good depiction of the well system's performance, because the other phases may be the more significant consumer of energy from the system. Inspection of the right hand side of Eqn. 1 gives some insight into the relationships necessary to normalize the traditional performance metrics. For example, two different wells almost never follow the same pressure drawdown "path". So the integral over time of the pressure drawdown could strongly influence the cumulative production, not just of the individual phases but how they interact (17, 21, 22). Therefore, just comparing cumulative gas production would be misleading. Obviously, reservoir quality (permeability * thickness, KH, conductivity) have a strong influence and would affect all four of the traditional metrics. One effect, which is virtually always disregarded, is the passage of time or time of observation. So, it should be expected that observing peak day rates at different times since the start of production would not be a fair, reliable metric.

The equation also provides the basis for understanding that a well with tubing should not be expected to behave the same as one without, if for no other reason than the potentially increased friction loss. The effective fracture length and its potential change over time during clean-up is obviously part of the relationship, so very likely amount of proppant, proppant ramping schedule, etc might play roles in the traditional metrics, as well.

Results of the Analysis

The objective of this study is to assess the effect of employing a micro-emulsion system during the stimulation of wells which exhibit a wide range of gas-oil ratios (GOR), or liquid condensate yield. This well population has a GOR range from 855 scf/bbl to infinite, or yields from zero to 1.17 bbl/MCF. The stimulation programs for the wells range from 250,000 pounds of proppant to over 2.5 million pounds. Net interval thicknesses range from about 18 feet to over 4000 feet of open interval. Further, about half of the wells had tubing installed. Also, the range of conductivity is from 0.21 mDs*ft to 6.43 mDs*ft. Clearly, to have meaningful performance metrics, normalization becomes a crucial part of this process. For this analysis, the data will be stratified into two sets:

* Wells with and without Micro-Emulsion (ME)
* Wells with and without tubing

All other parameters will be treated as independent process variables for the statistical analysis. Table 1 shows the various metrics or process variables employed for the data, when only the presence or absence of ME is considered. Table 2 presents similar results, but only for those wells in which tubing had been installed.

As previously discussed, the normalization process is a critical part of this investigation. Examination of Table 1 provides a framework for that. The conductivity (permeability * thickness) on the third line is an independent measurement, determined directly from the slope of the RPI® MDH plot, thus requires no normalization. However, because of the wide range of proppant weights and amount of proppant per foot of zone open, it is appropriate to normalize the effective fracture lengths for both variables, as shown on line 4 of the table and referred to as "Norm'd Effective Fracture Length".

On the fifth line, the cumulative equivalent production is considered. First, the cumulative equivalent production is converted from the individual phase rates on a weight or density basis to an equivalent gas volume or rate at standard conditions. For the entry on the fifth line, only the effect of the amount or weight of proppant was considered, so the cumulative equivalent volume divided by the weight of proppant is presented. Notice that one could not conclude that the use of ME is necessarily beneficial. There is only a 22% likelihood that the ME wells performed better than those without, on this basis. However, when the time on production, the different reservoir conductivity, the different pressure drawdown paths and the amount of proppant are taken into consideration, line six makes the compelling argument that ME wells out-perform the non-ME wells 99.9 percent of the time. Said differently, when properly compared, only one in one thousand ME wells should be expected to under-perform a non-ME well.

Table 2 presents the results in a similar manner, but only for those wells in which tubing was installed. Comparison of the two tables gives a qualitative sense of the value of installing tubing. Particularly, the proppant weight normalized effective fracture lengths for both ME and non-ME wells with tubing is better than the total population. However, the fully normalized cumulative equivalent production is indicated to be poorer for wells with tubing than the total population. The cause of that response for the ME wells is due to three outliers with very high liquid yields and low cumulative equivalent production. This can be seen easily on Fig. 5.

The right-most column on both tables is the result of the analysis of variance procedure (14) which provides the information necessary to perform the modified null hypothesis test previously described. The column shows the probability that the ME wells are different from the non-ME wells with respect to the particular metric or process variable.

Examination of Fig. 1 shows a compelling reason for normalization of the traditional well performance metrics. For this population of wells, micro-emulsion (ME) was consistently used only in the poorer reservoir conductivity wells, so much so that there is no statistical probability that the two conductivity populations of ME versus non-ME are the same. The non-ME wells produce from reservoirs almost twice as good as the ME wells. Therefore, it should be no surprise that traditional metrics would not indicate the benefit of using an ME.

Figure 2 shows that the stimulation fluid systems that include ME result in performance-based effective fracture lengths which are about 60% longer, when normalized for weight of proppant per foot of stimulated interval. This phenomenon is not necessarily attributable only to a longer fracture, but may be due to less damage on the formation face, easier flow of hydrocarbons to and in the wellbore, etc.

Figures 3 and 4 present the cumulative frequency histograms for the cumulative equivalent gas production normalized by two different methods. In the first case, the density equivalent liquid and gas cumulative production converted to a gas equivalent volume were only normalized for the weight of the total placed proppant for each well. So no adjustment is made for reservoir conductivity, the amount and timing of changes in flowing backpressure or drawdown, or actual time on production, other than the assumed 30 days (some of the wells had as little as 20 and as much as 37 days). This simplistic approach, although more rigorous than the usual methods of only looking at only the first month cumulative gas, for example, suggests that there is little, if any benefit to be gained from using ME. However, Fig. 4 makes the case for using ME, because it asserts that on the fully normalized basis, a well with 0.15% ME in the stimulation fluid system will recover almost twice as much hydrocarbon as a non-ME well could 999 times out of 1000.

Effect of Liquid Hydrocarbon Yield (GOR) on Performance

The central thesis of this analysis was to attempt to assess the effect of using ME in the stimulation fluid systems on well performance, when the well population includes a wide range of liquid yields or GORs. As previously indicated, this well population includes several wells with GORs below 1000 and several which have not produced any hydrocarbon liquids to date. It became apparent that there are significant liquids management issues in this data set. A preliminary analysis of the bottom hole flowing conditions was conducted using Beggs and Brill (11) and Coleman's (23) correlations to assess the quality of the data. The performance indicated by those wells which had no tubing was at best random, but in particular suggested that high GORs resulted in low recoveries, unless no liquids at all were produced. In those cases, the multi-phase flow correlations showed that the sandfaces were far into the bubble flow regime and flooded for the entire lift of the well. So the decision was made to only assess the performance of those wells in which tubing had been installed, presuming that the tubing represents a sufficient liquids management strategy.

From the signature shown in Fig. 5, it appears that the use of ME allows the well to be significantly less sensitive to high yield fluid systems. Based on the slopes of the two trendlines, the wells in which ME has been used were only one-third as sensitive to liquid yield (GOR) as the non-ME wells were. Clearly, ME allows better recovery on average than for non-ME wells, as indicated in both Table 2 and this figure. The cumulative equivalent gas volume shown has been normalized for reservoir quality, total proppant weight per foot of open interval, pressure drawdown and time on production.

Figure 6 shows that for the same group of wells, the effective fracture length normalized for total proppant placed per foot of open interval is significantly better for the ME wells regardless of the amount of liquid hydrocarbon yield. On average, when corrected for the liquid yield, the ME well will have a normalized effective fracture length over twice that of the non-ME wells, based on the zero yield intercept points for the two trendlines. This response is likely due to relative permeability effects, reduced energy consumption due to interfacial tension, the ability to create a mobile gas saturation further out in the created fracture, and contribution across a larger extent of the reservoir / fracture face (12, 22). Certainly, there are other factors, such as natural fractures, that also affect this response.

Upside Opportunity

Especially from examination of Fig. 5 and comparison of the results shown in Tables 1 and 2, it is clear that aggressive liquids management is beneficial regardless of whether a micro-emulsion is used or not. Nevertheless, this evidence suggests that using an ME has such low risk of failure, that it should always be done, regardless of well quality, stimulation strategy or GOR.

Conclusions

Use of traditional metrics such as cumulative production of a phase do not provide reliable bases upon which to make well management decisions. The use of normalization for such factors as reservoir quality (conductivity), amount and timing of pressure drawdown, open zone thickness, among others is a critical part of the process. Further, the data sets should be “stratified” to allow investigation of known process differences, for example, the installation of tubing.

This investigation has shown that the use of a micro-emulsion in wells with a wide range of condensate yields or GORs is very beneficial, both to the effective fracture length and the cumulative hydrocarbon recoveries, when examined with proper normalization. Specifically, the effective fracture length normalized for the amount of proppant placed per open foot is 60% greater for wells in which ME was used than those non-ME wells. The fully normalized cumulative gas equivalent recovery is nearly 75% greater for the ME wells. The ME wells with tubing are a third less sensitive to high liquid yields (low GORs) than the non-ME wells are. Also, the ME wells with tubing have normalized effective fracture lengths over twice as long as the non-ME wells for the same level of liquid yield (GOR).

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SI Metric Conversion Factors

cp x 1.0 E-03*	= Pa · s
ft x 3.048 E-01*	= m
ft^2 x 9.290 304 E-02*	= m^2
ft^3 x 2.832 685 E-02	= m^3
in x 2.54 E+00*	= cm
lbf x 4.448 222 E+00	= N
md x 9.869 233 E-04	= μm^2
psi x 6.894 757 E+00	= kPa

*Conversion factor is exact

Nomenclature

c – compressibility (consistent units)
h – thickness (consistent units)
K – permeability (consistent units)
P – pressure (consistent units)
q – flow rate (consistent units)
t – time (consistent units)

ρ - composite fluid density (consistent units)
μ – composite fluid viscosity (consistent units)
Φ – porosity (fraction)
ζ – units conversion factor
ξ – units conversion factor

subscripts

f – fracture
s – standard conditions
o,g,w – fluid phase
i – initial conditions at same datum as P_w

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Table 1. Comparison of Metrics for wells with and without Micro-Emulsion.

Metric	Units	Micro-Emulsion Wells	non-Micro-Emulsion Wells	Likelihood of Difference
Well Count		61	53	
Perm*Thickness	mDs*ft	0.93	1.83	100.0
Norm'd Eff Frac Length	Feet/ K# Prop	1.05	0.66	99.1
Prop Norm'd Eqv Cum Production*	CuFt Eqv/ # Prop	44.8	43.9	22.3
Fully Norm'd Eqv Cum Production**	CuFt Eqv/ # Prop	132.9	76.2	99.9
Condensate Yield	Bbl/MCF	0.220	0.229	41.2

* - Gas Equivalent Cumulative Production only normalized for weight of proppant pumped.
** - Gas Equivalent Cumulative Production normalized for pressure drawdown over the period, permeability*thickness of the well, duration on production, and weight of proppant pumped.

Table 2. Comparison of Metrics for wells with and without Micro-Emulsion and with tubing in place.

Metric	Units	Micro-Emulsion Wells	non-Micro-Emulsion Wells	Likelihood of Difference
Well Count		27	20	
Perm*Thickness	mDs*ft	1.14	1.25	38.2
Norm'd Eff Frac Length	Feet/ K# Prop	1.59	0.85	98.3
Fully Norm'd Eqv Cum Production**	CuFt Eqv/ # Prop	104.6	72.0	94.8
Condensate Yield	Bbl/MCF	0.204	0.120	77.5

** - Gas Equivalent Cumulative Production normalized for pressure drawdown over the period, permeability*thickness of the well, duration on production, and weight of proppant pumped.

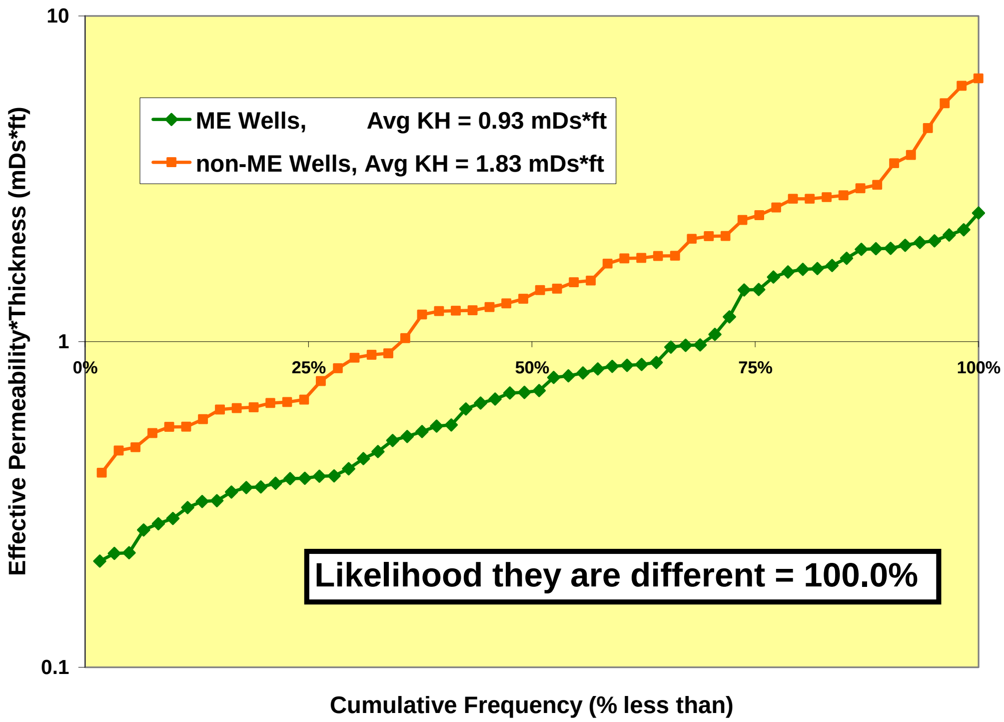

Fig. 1. Cumulative Frequency Histogram comparing reservoir quality (permeability * thickness) of the 61 wells with ME versus the 53 non-ME wells.

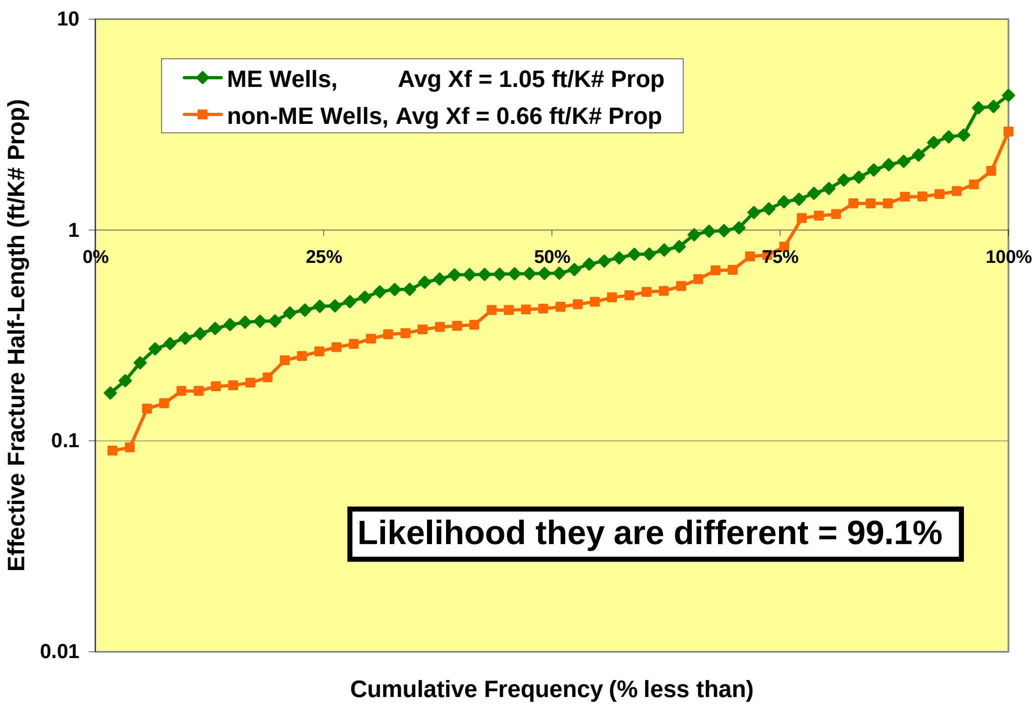

Fig. 2. Cumulative Frequency Histogram of Proppant Weight normalized effective fracture half-length for the 61 ME wells compared to the 53 non-ME wells.

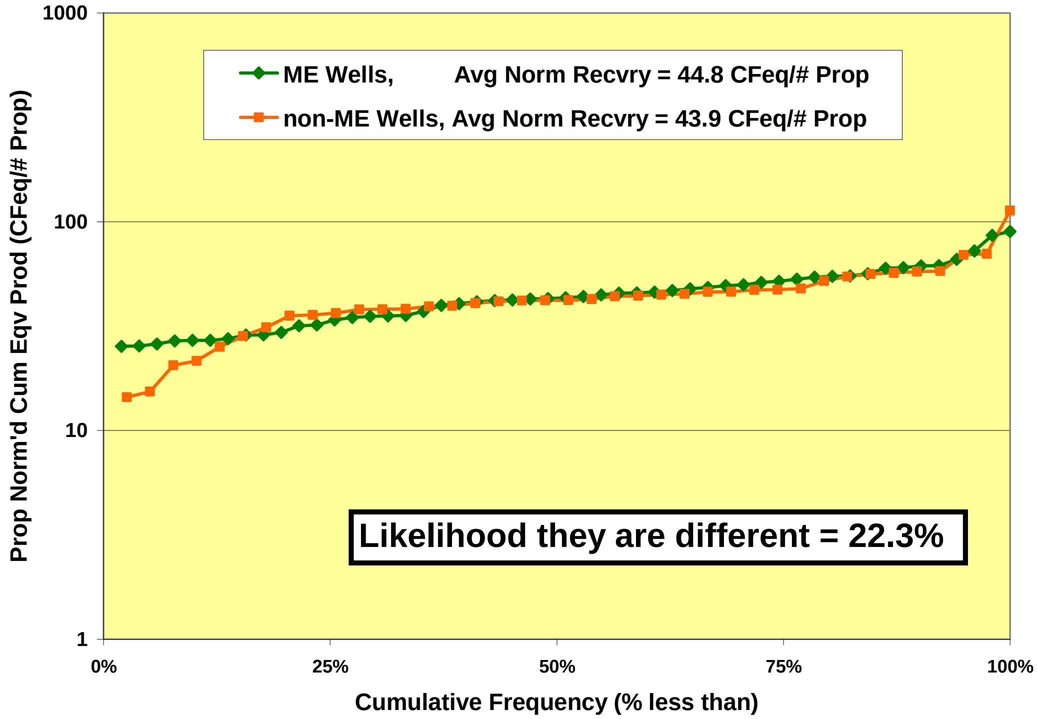

Fig. 3. Cumulative Frequency Histogram of cumulative equivalent gas production normalized for weight of proppant placed in the 61 ME wells and 53 non-ME wells.

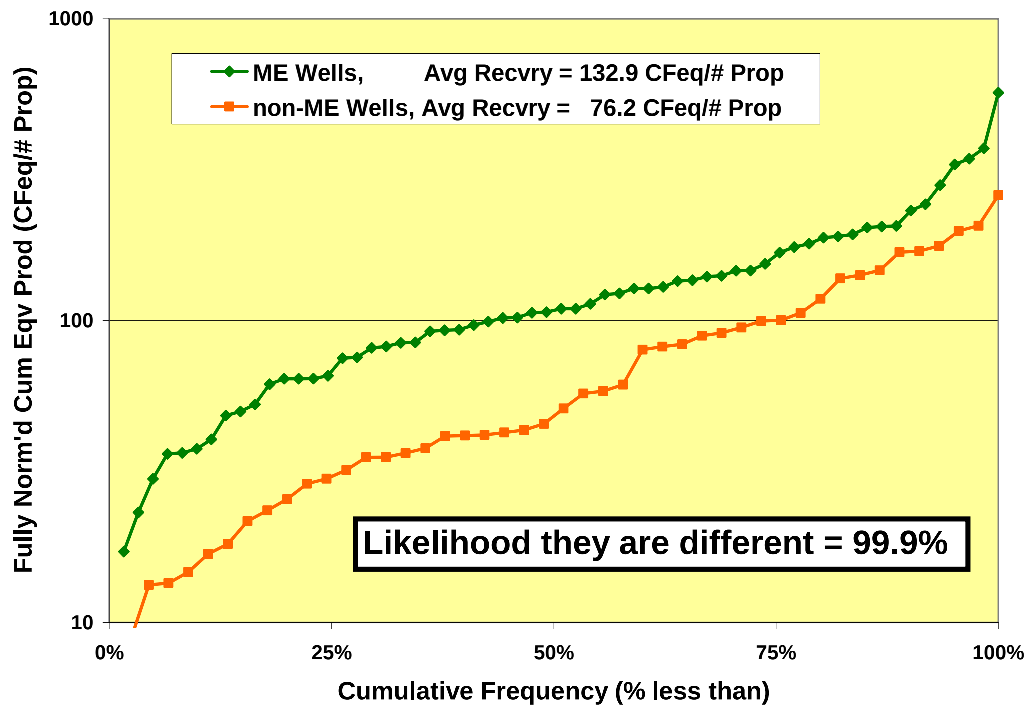

Fig. 4. Cumulative Frequency Histogram of 30 day cumulative equivalent gas production normalized for time on production, reservoir quality, amount of pressure drawdown and weight of placed proppant for 61 ME wells and 53 non-ME wells.

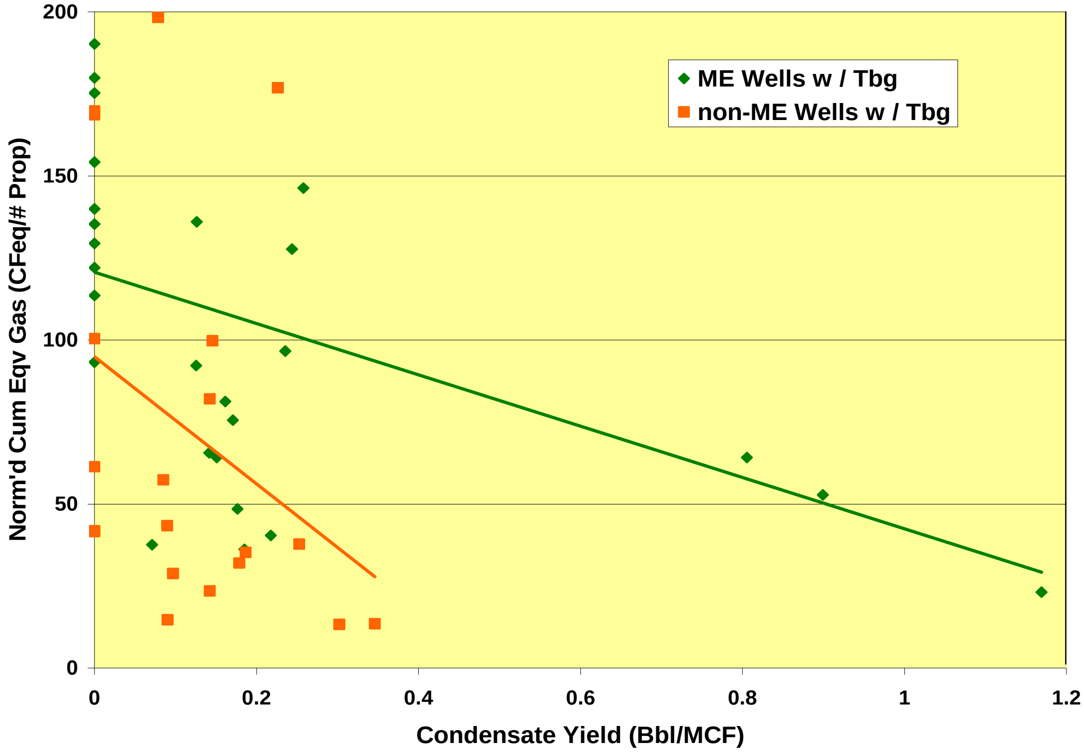

Fig. 5. 30 Day Cumulative Equivalent Gas Production normalized for time on production, reservoir quality, pressure drawdown and placed proppant as a function of condensate yield for the 27 ME wells and 20 non-ME wells with tubing.

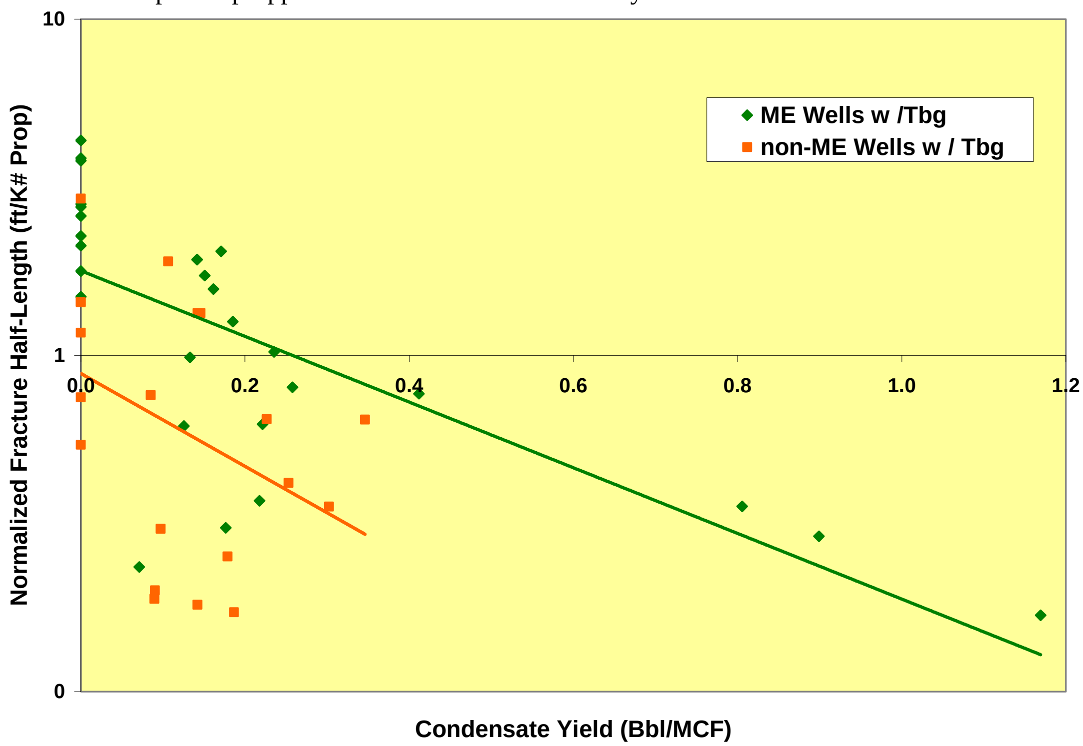

Fig. 6. Proppant weight normalized effective fracture half-length for the 27 ME and 20 non-ME wells with tubing installed as a function of condensate yield.