Production Impairment and Purpose-Built Design of Hydraulic Fractures in Gas-Condensate Reservoirs

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Abstract

Hydraulic fracturing has been the stimulation/completion method of choice for the vast majority of gas reservoirs throughout the world. There is no fundamental difference in the design of hydraulic fractures in reservoirs of any permeability. However, for low-permeability reservoirs, obtaining the indicated length of the hydraulic fracture has been the key element in the execution of the stimulation treatments; for high-permeability reservoirs increasing the fracture conductivity (width multiplied by fracture permeability) is important. For the latter, “tip screen-out” treatments have been developed.

Damage to the fracture, which causes a reduction in the well performance, has manifested itself in two ways, 1) reduction of the proppant-pack permeability because of polymer residue, choking of the near-well region and over-displacement and 2) damage to the fracture face, i.e., reduction to the reservoir permeability normal to the fracture, because of polymer leakoff during the fracture execution. Both types of damage affect primarily higher-permeability formations, the first reducing the much-desired large fracture conductivity and, the second, providing an impediment to flow, which becomes important because of short fracture lengths. For long fractures and short penetrations of fracture-face damage the reduction to the well performance is insignificant.

In gas-condensate reservoirs a situation emerges very frequently that is tantamount to fracture-face damage. Because of the pressure gradient that is created normal to the fracture, liquid condensate is formed which has a major impact on the reduction of the relative permeability-to-gas. Such a reduction depends on the phase behavior of the fluid and the penetration of liquid condensate which, in turn, depends on the pressure drawdown imposed on the well. These phenomena cause an apparent damage, which affects the performance of all fractured wells irrespective of the reservoir permeability (including very low-permeability values). Well testing of such wells would invariably calculate much shorter apparent lengths than actually placed.

We are presenting here a model that predicts the fractured well performance in gas-condensate reservoirs, quantifying the effects of gas permeability reduction. Furthermore we present fracture treatment design for condensate reservoirs. The distinguishing feature primarily affects the required fracture length to offset the problems associated with the emergence of liquid condensate. Also, guidelines for the calculation of the appropriate pressure drawdown during production to optimize well performance are provided.

Introduction

In a two-phase depiction of petroleum oil and gas, the phase envelop describes a dew point pressure curve that starts at the pseudo-critical point (pseudo-critical pressure and pseudo-critical temperature) and curves to the right until it reaches a maximum temperature value, the cricondenharm. Between these two temperature values, liquid emerges as the pressure declines below the dew point value (at a constant temperature). As pressure continues to decrease the amount of liquid in the reservoir increases. However, after a certain limiting value, further pressure reduction causes liquid to re-vaporize. This is the region of retrograde condensation. Many natural gas reservoirs behave in this manner. During production from such reservoirs, the pressure gradient formed between the reservoir pressure and the flowing bottomhole pressure is likely to result in liquid condensate near the wellbore.

The producing rate of gas condensate reservoirs is affected greatly by the flowing bottomhole pressure and not only because of the pressure gradient in the reservoir. The value of the bottomhole pressure controls the amount and distribution of liquid condensate accumulation near the well with an unavoidable relative permeability reduction.
One way to prevent the formation of condensate is to maintain the flowing well bottomhole pressure to be above the dew point pressure. This is often not satisfactory because the reservoir pressure drop may not be sufficient enough for economic production rate. In any case, a survey of several gas condensate reservoirs has revealed that, invariably, the initial reservoir pressure is, at, or very near, the dew point pressure. As a consequence, to have any appreciable driving force in the reservoir, production from gas condensate reservoirs should be the result of an optimization of

\[ q_g \propto k \frac{p - p_{wf}}{p_{wf}} \int_{r_w} \frac{r}{r_{wg}} \, dr \]

The relative permeability to gas, \( k_{rg} \), is a function of the flowing bottomhole pressure, \( p_{wf} \) and therefore there exists an optimum \( p_{wf} \) value for a given reservoir pressure which would maximize the product of relative permeability and the drawdown. Cvetkovic et al. (1990) have described the mechanism of production from gas condensate reservoirs and addressed the issue of optimization in detail.

However, the bottomhole pressure “path”, i.e., its evolution with time is important. Once condensate is formed near the well in radial flow, very little can re-vaporize into the gas phase even if the pressure is built up to the original reservoir value (Fussell, 1973, Economides et al., 1987.) Thus, if a condensate well is shut in and then re-opened, the production rate of the new flow period will continue largely unaffected by the buildup. The well experiences hysteresis and the only way to recover the original permeability-to-gas is through the injection of lean gas. An appropriate stimulation treatment is to inject gas in a “huff and puff”, cyclic sequence. The frequency and volume of injected gas can be simulated and it is a function of the PVT properties of the in-place fluid (Cvetkovic et al., 1990).

This approach to gas condensate production is relatively common and is repeated several times in the life of the well. For economic reasons, however, this process often cannot be implemented (Sanger and Hagoort, 1998).

An attractive alternative is to inject nitrogen into injector wells in a gas-condensate reservoir. Nitrogen is cheap, safe, non-corrosive, non-polluting and available everywhere. It maintains the reservoir pressure and thus prevents condensate dropout as a result of pressure depletion. However, nitrogen causes stronger liquid dropout in the mixing zone between the gas-condensate and the injected gas, which could reduce recovery (Sanger et al., 1994). A compromise is to inject both nitrogen and methane (Sanger and Hagoort, 1998) which develops a miscible displacement process and results in high condensate recoveries.

How to remove the bank of condensate from the near-wellbore region, is still a challenge for the oil industry and, thus, very important to optimal production of gas-condensate reservoirs.

It is this difficulty, coupled with the frequent need to hydraulically fracture gas condensate wells that has led to the subject of this paper.

Distribution of the liquid condensate around the fracture, whose length can be several hundred feet for low-permeability reservoirs and tens of feet for high-permeability reservoirs, can alleviate or greatly soften the impact on gas production. Optimization is necessary because of the need to adjust the fracture geometry, invariably to increase the fracture length at the expense of fracture width.

**Hydraulic Fracture Optimization**

Valkó and Economides (1998) and Fan et al. (2000) have presented a physical optimization approach to hydraulic fracture performance where the fracture length and the fracture conductivity are combined in a coherent manner. Because the fracture length and the fracture width are intimately connected with the injected fracture volume, there exists a compromise between the created fracture dimensions. Too large length but inadequate width means that the fracture is a bottleneck to production. Conversely, too wide a fracture may be handicapped by a short fracture length. The latter then becomes the bottleneck. In this approach, there is no real distinguishing difference between the hydraulic fracture designs for low- and high-permeability reservoirs and the method constitutes a *unifying* theory in fracture optimization.

The first step is the pseudo-steady state productivity index relating production rate to pressure drawdown:

\[ J = \frac{q}{p - p_{wf}} = \frac{2\pi k \mu}{\alpha B} \frac{J_D}{J_B} \]

where \( J_D \) is the dimensionless productivity index, \( k \) is the formation permeability, \( h \) is the pay thickness, \( B \) is the formation volume factor, \( \mu \) is the fluid viscosity and \( \alpha \) is a conversion constant (one for a consistent system). A similar expression applies for gas wells. For a fully penetrating vertical well located in a bounded region the dimensionless productivity index can be given in terms of the shape factor and skin as:

\[ J_D = \frac{1}{\frac{1}{2} \ln \left( \frac{4A}{\alpha} C_A r_w^2 \right) + s} \]

For a well located in the center of a circular drainage area this reduces to
\[ J_D = \frac{1}{\ln \frac{r_e}{r_w} - \frac{3}{4} + s} \]  \hspace{1cm} (4)

In the case of a propped fracture there are several ways to incorporate the stimulation effect into the productivity index. These are merely algebraic manipulations tantamount to an accounting procedure. A common approach is to use the pseudo-skin concept:

\[ J_D = \frac{1}{\ln \frac{r_e}{r_w} - \frac{3}{4} + s_f} \]  \hspace{1cm} (5a)

Another approach is to use the dimensionless productivity index as a function of the fracture parameters.

\[ J_D = \text{function (drainage-volume geometry, frac parameter)} \]  \hspace{1cm} (5b)

This second option is the most general and convenient.  

Many authors have provided charts and correlations in one or another form for special geometries, reservoir types, etc. Unfortunately, most of the results are less obvious to apply in high permeability environment. Valkó and Economides (1998) provided a fresh look. This is summarized below.

For a vertical well intersecting a rectangular vertical fracture which penetrates fully from the bottom to the top of the square drainage area the performance is known to depend on the x-directional penetration ratio:

\[ I_x = \frac{2x_L}{x_e} \]  \hspace{1cm} (6)

and on the dimensionless fracture conductivity:

\[ C_{fp} = \frac{k_f w}{k x_e} \]  \hspace{1cm} (7)

where \( x_L \) is the fracture half length, \( x_e \) is the side length of the square drainage area, \( k \) is the formation permeability, \( k_f \) is the proppant pack permeability, and \( w \) is the average fracture width.

The key to formulating a meaningful technical optimization problem is to realize that penetration and dimensionless fracture conductivity (through width) are competing for the same resource: the propped volume. Once the reservoir and proppant properties and the amount of proppant are fixed, one has to make the optimal compromise between width and length.

The known propped volume puts a constraint on the two dimensionless numbers in the form:

\[ I_x^2 C_{fp} = \frac{4k_f x_L w}{k x_e^2} = \text{const} \]  \hspace{1cm} (8)

In fact, one way to interpret the quantity, \( I_x^2 C_{fp} \) is to consider it as the ratio of propped to reservoir –horizontal cross-sectional area multiplied by the permeability ratio and by two. It is, however, more intuitive to think in volumes.

Multiplying both the numerator and denominator by the net pay thickness, \( h_p \), we obtain

\[ N_{prop} = I_x^2 C_{fp} = \frac{4k_f x_L w h_p}{k x_e^2 h_p} = \frac{2k_f V}{k V_r} \]  \hspace{1cm} (9)

"Productivity increase" graphs are numerous in the published literature (McGuire and Sikora, 1960, Soliman, 1983.) The curves flatten out at large \( C_{fp} \), and the limiting values plotted as a function of penetration ratio delineate the “infinite conductivity” fracture performance.

These past approaches are not very helpful to solve the optimization problem involving any fixed amount of proppant. For this purpose a convenient algorithm to calculate \( J_D \) is available (Valkó and Economides, 1998.). Figure 1 presents these results, and the individual curves represent \( J_D \) at a fixed value of the proppant number, \( N_{prop} \).

As seen from Fig. 1 for a given value of \( N_{prop} \) there is an optimal dimensionless fracture conductivity, representing the optimal compromise between the ability of the formation to provide flow into the fracture and the ability of the fracture to conduct the flow into the wellbore.

At "low" proppant numbers (low proppant volume), the optimal compromise occurs at \( C_{fp} = 1.6 \). This is not surprising; Prats (1961) pointed out that the optimum \( C_{fp} \) is 1.6, for any proppant volume in an infinite-acting reservoir.

The behavior at large \( N_{prop} \) is not surprising either. We know that the absolute maximum for \( J_D \) is \( 6/\pi \approx 1.909 \) (this value is the productivity index for a perfect linear flow in a square reservoir, Miller, 1962). When the propped volume increases, the optimal compromise happens at larger dimensionless fracture conductivities because the penetration cannot exceed unity.

In Fig. 1, we connected the optimum productivity indices with a curved arrow. This arrow starts at \( C_{fp} = \infty \) and ends at \( C_{fp} = 1.6 \). Fig. 1 also shows that with \( N_{prop} = 1 \) we are already “half-way” to the theoretical maximum performance and increasing the propped volume further brings diminishing returns of performance increase.

The proppant number clarifies the basic difference in
fracture design between high and low permeability reservoirs. For high permeability fracturing in most cases the available propped volume allows only small proppant numbers, less than 0.1.

![Graph](image)

**Fig. 1. Calculated dimensionless productivity index as a function of dimensionless fracture conductivity and proppant number**

For treatments with $N_{\text{prop}}$ less than 0.1 the optimal value of the dimensionless fracture conductivity is 1.6. For larger $N_{\text{prop}}$ numbers, we provide a new correlation based on the results shown in Fig. 1.

Fan et al. (2000) have presented correlations for the maximum $J_D$ for fractures with $N_{\text{prop}} < 0.1$ which would be the case for high-permeability fracturing and for $N_{\text{prop}} > 0.1$ which would be the case for low-permeability fracturing.

For $N_{\text{prop}} < 0.1$ where the optimum $C_{fd} = 1.6$ the maximum productivity index is simply (Fan et al., 2000)

$$J_{D, \text{max}} = \frac{1}{0.990 - 0.5\ln N_{\text{prop}}}$$  \hspace{1cm} (10)

**Relative Permeability Impairment Because of Liquid Condensate Drop Out.**

We have already mentioned above that in producing gas-condensate reservoir, once the pressure falls below the dew point, retrograde condensation occurs and the condensate liquid partially blocks the gas flow channels which significantly decrease the relative permeability and productivity of gas.

There have been few laboratory studies in the past investigating the gas-condensate relative permeabilities (Henderson et al., 1996, 1997, Boom et al., 1996, Blom et al., 1997, Morel et al., 1997). Experiments such as theses are difficult to perform and their interpretation can be questionable because flow and phase behaviors are intimately coupled. Henderson et al. (1996, 1997) have conducted steady-state relative permeability experiments on model gas-condensate fluids to show that relative permeabilities depend on both the saturation and the capillary number. Hysteresis is unimportant in high capillary number flows. These experiments were conducted at low Reynolds number ($<0.01$) and thus did not have any non-Darcy effect. The saturation range at which relative permeability was obtained is rather limited. To overcome the difficulty of working with pressure-sensitive condensate fluids, other researchers (Boom, 1996, Blom, 1997) have used model fluids and have shown that the condensate permeability can be approximated by the permeability of a wetting fluid by matching the capillary or the bond number. Non-Darcy flow experimental data are available for gas and gas-brine systems (Liu et al., 1995), but few are available for gas-condensate systems (Lombard et al., 1998). Coles and Hartman (1998) used core samples containing various liquid saturations of solidified paraffin wax to mimic an immobile condensate phase, and estimate the effective non-Darcy coefficient at the different liquid saturation. The experiments were performed under ambient conditions and the paraffin was immobile even at high liquid saturation (above critical condensate saturation), which led to a large inaccuracy in the prediction of the gas-condensate reservoir behaviors.

Correlations are available in the literature to model the capillary number dependence of two-phase flow (Blom and Hagoort, 1998, Pope et al., 1998). Many of them were developed for surfactant flooding or miscible flooding. It is widely recognized that relative permeability improves when the interfacial tension is very low (Bardon and Longeron, 1980, Asar and Handy, 1988, Hanif and Ali, 1990, Fulcher et al., 1985, Schechter and Haynes, 1992, Munkerud, 1995, Wang et al., 1996). Several laboratory studies (Hartman and Cullick, 1994, Boom et al., 1995, Chen et al., 1995, Henderson et al., 1996, Hanif and Ali, 1990, Boom et al., 1996, Kalaydjian et al., 1996, Ali et al., 1997, Blom et al., 1997) supplied the evidence that relative permeabilities of the gas and condensate depend on the ratio of viscous to capillary forces on a pore scale.

In this study, gas relative permeability curves, derived by using a pore-scale network model (Wang and Mohanty, 1999a and 1999b) are represented by a weighted linear function (Blom and Hagoort, 1998) of immiscible and miscible relative permeability curves:

$$k_{rg} = f k_{rgl} + (1-f)k_{rgM}$$  \hspace{1cm} (11)

where $k_{rg}$ is the gas relative permeability, and $f$ is the weighing factor (Whitson and Fevang, 1997) which is a function of the capillary number.
where \(a\) and \(b\) are parameters which are 1.6E-3 and 0.324, respectively, and \(N_c\), is the capillary number which is defined as

\[
N_c = \frac{k\nabla p}{\sigma} \quad \text{...................................................(13)}
\]

In Eq. 13 \(k\) is the permeability, \(\nabla p\) is the pressure gradient, \(\sigma\) is the interfacial tension; \(k_{rg}\) is the conventional relative permeability for capillary dominated (immiscible) flow, which is defined as

\[
k_{rg} = \left( \frac{S_g}{1 - S_{wi}} \right)^{n_g} \quad \text{...................................................(14)}
\]

where \(S_g\) is the gas saturation, \(S_{wi}\) is the connate water saturation, \(n_g\) is a constant equal to 5.5; \(k_{rgM}\) is the relative permeability function in the limit of viscous dominated (miscible) flow, which is defined as

\[
k_{rgM} = \frac{S_g}{1 - S_{wi}} \quad \text{...................................................(15)}
\]

### A Fracture Face “Damage” Model for Production in Hydraulically Fractured Gas Condensate Reservoirs

Cinco-Ley and co-workers (1978, 1981) in a series of important publications have described the production and pressure transient performance of wells intersected by finite-conductivity fractures. These publications gave a “modern” look on the concept of fracture conductivity. Its performance can be impaired readily by the reduction of the fracture permeability which is greatly affected by the condition of the proppant and the residual damage to the proppant pack by unbroken polymer which is used in the transport of the proppant slurry during execution.

This type of damage, if unavoidable, can be readily accounted for in the fracture design by virtue of the scheme described earlier on in this paper. It will certainly affect the optimum fracture length to provide the maximum productivity index for a given proppant mass injected.

The second type of damage identified by Cinco and Samaniego (1981) is fracture face damage where the permeability, normal to the fracture face and extending into the reservoir is impaired. The conventional perception of this damage is that damage is caused by fracturing fluid leakoff into the reservoir. Holditch (1979) has shown that for long fractures (e.g. 500 ft and longer) such damage is inconsequential even if the penetration of damage is significant (1 ft).

For much shorter fractures (e.g. <100 ft), which are indicated for high-permeability reservoirs, Mathur et al. (1995) have shown that fracture face damage is not only significant but it could be the deciding factor in post-treatment positive skin factors for hydraulically fractured wells.

Cinco and Samaniego (1981) provided an expression of the fracture face skin effect that becomes additive to the dimensionless pressure for the finite conductivity fracture performance. The skin is

\[
s_{fs} = \frac{\pi b_s}{2\chi_f} \left( \frac{1}{k_{rg}} - 1 \right) \quad \text{...................................................(16)}
\]

where \(b_s\) is the penetration of damage and \(k_s\) is the damaged permeability.

An analogy can be made readily for a hydraulically fractured gas condensate reservoir. Liquid condensate dropout, normal to the fracture face, can also result in a skin effect reflecting the reduction of the relative permeability to gas. The penetration of damage would be the zone inside which liquid condensate exists, i.e., at the boundary the pressure is the dew point pressure. The permeability ratio reduces to the ratio of the relative permeabilities and because at the boundary \(k_{rg}\) is equal to 1, then Eq. 16 becomes simply

\[
s_{fs} = \frac{\pi b_s}{2\chi_f} \left( \frac{1}{k_{rg}} - 1 \right) \quad \text{...................................................(16)}
\]

### Optimization of Fracture Morphology With Fracture Face Skin.

Assume we are to create a fracture with Proppant Number, \(N_p\) = 0.01, i.e., the amount of proppant is fixed.

With no fracture face skin the optimum dimensionless fracture conductivity is \(C_{df} = 1.6\) and the corresponding optimum penetration ratio is \(I = 0.07906\). If, e.g., the drainage area is a 2,000 ft by 2,000 ft square, then the optimum fracture half-length is 79 ft. The optimum fracture placement would realize a dimensionless productivity index, \(J = 0.3049\).

Now let us assume that the fracture-face damage will cause an equivalent skin, \(s = 1\), when we create a 79-ft fracture. Such a fracture face skin could be caused by (Eq. 16)

\[
s_{fs} = 1 = \frac{\pi}{2} \left( \frac{505 - 1}{79} \right) \quad \text{...................................................(17)}
\]
where 0.1 ft is the depth of polymer invasion and 504 is the permeability damage ratio \(k/k_s\).

For such a fracture-face damage, the impaired productivity index would be

\[
J_D = \frac{1}{\frac{1}{0.3049} + s} = \frac{1}{\frac{1}{0.3049} + 1} = 0.2301 \quad \text{(18)}
\]

Obviously, if we decide to create a longer, but narrower fracture, the productivity index will vary for two reasons: the fracture pseudo-skin will increase while the fracture face-skin will decrease. If everything else remains the same and the Cinco-Ley and Samaniego formula is valid, then only the fracture length increases in Eq. 17 above and hence the fracture-face skin will vary according to:

\[
s_{fs} = 1 \times \frac{0.079}{I_x} = \frac{79}{x_f} \quad \text{(19)}
\]

Figure 2 shows the results of calculations for the above problem. As the dimensionless fracture conductivity decreases and the penetration ratio (length) increases, the productivity index goes through a maximum. For the given example, the optimum placement requires \(C_fD = 0.9\) and correspondingly \(I_x = 0.105\) that is \(x_f = 105\) ft.

**Figure 2. Optimum Fracture Geometry with \(s_{fs} = 1\)**

If the we assume, that the fracture-face skin is 10 at the nominal fracture length 79 ft, (e.g., because

\[
s_{fs} = 10 = \frac{\pi}{2} \left(504 - 1\right) \frac{1.0}{79} \quad \text{(20)}
\]

then Eq. 19 takes the form

\[
s_{fs} = 10 \times \frac{0.079}{I_x} = \frac{790}{x_f} \quad \text{(21)}
\]

and the effect will be more dramatic, as seen from Fig. 3. For this fracture-face damage one has to create a \(C_fD = 0.3\) and \(I_x = 0.183\) fracture, that is the optimum length should be \(x_f = 183\) ft (instead of 79 ft). The productivity index realized will be \(J_D = 0.1076\), while the 79-ft fracture (with fracture-face skin equal to 10) would have only \(J_D = 0.0748\).

**Figure 3. Optimum Fracture Geometry with \(s_{fs} = 10\)**

These calculations demonstrate how important it is to consider the fracture-face damage when optimizing fracture dimensions.

**Hydraulic Fracture Geometry Optimization in Gas Condensate Reservoirs**

In gas condensate reservoirs the fracture performance is likely to be affected greatly by the presence of liquid condensate, tantamount to fracture face damage. An assumption for the evaluation is that at the boundary of this “damaged” zone the reservoir pressure must be exactly equal to the dew point pressure. For any fracture length and a given flowing bottomhole pressure that is known to be inside the retrograde condensation zone of a two-phase envelop the pressure profile normal to the fracture phase and into the reservoir will delineate the points where the pressure is equal to the dew point pressure. From this pressure profile the fracture face skin distribution along the fracture face is determined. Using Eq. 16 (the modified Cinco-Ley and Samaniego expression) the depth of the affected zone is determined. An additional necessary element is the relative permeability impairment given by the correlation we have presented earlier (Eqs. 11-15.)

Two case studies are presented below. The first represents a reservoir of 5 md permeability and a gas condensate with a dew point pressure equal to 2545 psi. The flowing bottomhole...
pressure is 1800 psi. First, hydraulic fracture optimization without the effects of the fracture face skin and for a proppant number, \( N_p \), equal to 0.02 results in an expected dimensionless fracture conductivity equal to 1.6 and a fracture half-length equal to 220 ft for a 4,000 ft square reservoir. (The value of the proppant number, assuming \( k_f = 50,000 \text{ md} \), \( h = 50 \text{ ft} \), \( \rho_p = 165 \text{ lb/ft}^3 \) and \( \phi_p = 0.4 \), implies a proppant mass approximately equal to 80,000 lb.) The dimensionless productivity index would be 0.35.

Then a series of simulations is done with the fracture length increasing, keeping the proppant number constant, i.e., the mass of proppant that is injected. This, of course results in an unavoidable reduction in the fracture conductivity while the purpose is to maximize the productivity index.

Figure 4 is a graph of this calculation, showing an optimum fracture half-length equal 255 ft (16% increase from the zero-skin optimum) and an optimum dimensionless conductivity equal to 1.2 rather than 1.6. Much more important is the drop in the optimum productivity index to 0.294.

Far more important is that to accomplish the same productivity index as the expectation from the zero-skin assumption there would be a need for a proppant number approximately equal to 0.045, which would mean more than doubling the required mass of proppant.

For a much higher permeability reservoir (200 md) when ingoring the fracture face skin the same calculation resulted in an optimum fracture face length equal to 35 ft (\( C_{ID} = 1.6 \)). The proppant number for this case is equal to 0.0005 (for the same mass of proppant as in the previous case.) The corresponding dimensionless productivity index is 0.171.

Here the impact of gas condensate damage on the productivity index expectations and what it would be needed to counteract this effect is far more serious. The required proppant number would be about 0.003 or, putting it differently, this would mean a required mass of proppant about 6 times the originally contemplated one. Obviously such fracture execution would be virtually impossible and the expectations from well performance would need to be pared down considerably.

Figure 5 is the optimization for the fracture dimensions with gas condensate damage, showing an optimum half-length equal to 45 ft (a 30% increase over the zero-skin optimum.) The new optimum \( C_{ID} = 1 \) and the corresponding productivity index is 0.171.

Gas condensate wells, when fractured hydraulically, experience a considerable reduction in their expected ideal productivity index because of liquid condensate that forms normal to the fracture face. This is the result of the pressure gradient into the reservoir, which invariably describes a region with pressures below the dew point. The effect is tantamount to a fracture face damage skin because of the reduction in the relative permeability to gas.

While fracture face damage, caused by polymer invasion is generally not a problem in low-permeability reservoirs but it is a problem in high-permeability cases, the gas-condensate induced damage affects all reservoirs. The reason is that in low permeability reservoirs, in contrast to the penetration of polymer damage, which is of the order of a few inches at maximum, liquid condensate may be present for tens of feet. Naturally, the impact on the productivity index is far more severe in high-permeability reservoirs.

Gas condensate effects manifest themselves in two ways. First, for a given mass of proppant to be injected, not only the productivity index will be impaired but the optimum fracture conductivity would no longer equal 1.6 but it would be lower. The fracture length would need to be larger than the zero-fracture-face-skin optimum, in some cases considerably larger. This would require adjustments to the fracture execution design to affect the new geometry.
Second, and more crucial, is the required mass of proppant to obtain the expected productivity index if the effects of condensate were ignored. Significantly to extraordinarily larger fracture treatments would be required which, in high-permeability reservoirs, would be prohibitive. In such cases this work would help not only in the appropriate sizing of the fractures but also to pare down unrealistic expectations.

Nomenclature

\[ A = \text{drainage area, ft}^2 \]
\[ b_t = \text{depth of polymer invasion, ft} \]
\[ B_o = \text{oil formation volume factor, RB/STB} \]
\[ C_A = \text{well-reservoir shape factor (single well)} \]
\[ C_{DP} = \text{dimensionless fracture conductivity} \]
\[ h_f = \text{formation thickness, ft} \]
\[ I_p = \text{penetration ratio: } 2x/x_c \]
\[ J = \text{productivity index, BOPD/psi} \]
\[ I_D = \text{dimensionless Productivity Index} \]
\[ k = \text{formation permeability, md} \]
\[ k_f = \text{fracture permeability, md} \]
\[ k_{fi} = \text{relative permeability of gas} \]
\[ k_s = \text{damaged permeability, md} \]
\[ N_p = \text{proppant number} \]
\[ r_w = \text{wellbore radius, ft} \]
\[ q_g = \text{gas flow rate, STB/D} \]
\[ \bar{p} = \text{average reservoir pressure, psi} \]
\[ p_{of} = \text{flowing bottomhole pressure, psi} \]
\[ s_f = \text{fracture face skin} \]
\[ s = \text{total (pseudo) skin of well} \]
\[ S_g = \text{gas saturation} \]
\[ S_w = \text{water saturation} \]
\[ x_f = \text{fracture half length, ft} \]
\[ x_c = \text{size of study area in x-direction} \]
\[ y_e = \text{size of study area in y-direction} \]
\[ V_p = \text{volume of proppant in pay, ft}^3 \]
\[ V_t = \text{volume of pay, ft}^3 \]
\[ w = \text{propped fracture width, ft} \]
\[ \Gamma = \text{Euler's Constant } = 0.57721566 \ldots \]
\[ \mu = \text{fluid viscosity, cp} \]
\[ \phi = \text{porosity, fraction} \]
\[ \sigma = \text{interfacial tension (pressure units)} \]
\[ \alpha_l = \text{conversion factor (for field units 887.22)} \]

References


