FOOLPROOF COMPLETIONS FOR HIGH RATE PRODUCTION WELLS

A Thesis

by

SLAVKO TOSIC

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

December 2007

Major Subject: Petroleum Engineering

FOOLPROOF COMPLETIONS FOR HIGH RATE PRODUCTION WELLS

A Thesis

by

SLAVKO TOSIC

Submitted to the Office of Graduate Studies of
Texas A&M University
in partial fulfillment of the requirements for the degree of

MASTER OF SCIENCE

Approved by:

Chair of Committee,   Christine A. Ehlig-Economides
Committee Member,   Maria Barrufet
     Peter P. Valko
Head of Department,   Stephen A. Holditch

December 2007

Major Subject: Petroleum Engineering

ABSTRACT

Foolproof Completions for High Rate Production Wells. (December 2007)

Slavko Tosic, B.S., University of Belgrade

Chair of Advisory Committee: Dr. Christine A. Ehlig-Economides

Operators, especially those managing production from deepwater reservoirs, are striving to produce hydrocarbons at higher and higher rates without exposing the wells to completion failure risk. To avoid screen failures, recent studies have favored gravel pack (GP) and high rate water pack (HRWP) completions over high-permeability fracturing (HPF), known in the vernacular as a frac&pack (FP) for very high rate wells. While a properly designed GP completion may prevent sand production, it does not stop formation fines migration, and, over time, fines accumulation in the GP will lead to increasing completion skin. Although, and not always, the skin can be removed by acidizing, it is not practical to perform repeated acid treatments on deepwater wells, particularly those with subsea wellheads, and the alternative has been to subject the completion to increasingly high drawdown, accepting a high skin effect. A far better solution is to use a HPF completion. Of course the execution of a successful HPF is not a trivial exercise, and frequently, there is a steep learning curve for such a practice.

This work explains the importance to HPF completions of the well trajectory through the interval to be hydraulically fractured, for production, not execution, reasons. A new model quantifies the effect of the well inclination on the connectivity between the fracture and the well via perforations. Guidelines based on the maximum target production rate, including forecasts of multiphase flow, are provided to size the HPF completion to avoid common completion failures that may result from high fluid rate and/or fines movement. Skin model will be developed for both vertical and deviated wells. Once the HPF is properly designed and executed, the operators should end up with a long term low skin good completion quality well. The well will be safely produced at the maximum flow rates, with no need for well surveillance and monitoring.

ACKNOWLEDGMENTS

I would like to express deep gratitude to Dr. Christine Economides for always challenging me and encouraging me throughout my academic studies at Texas A&M. Dr. Economides' continuous support and patient guidance during the thesis writing process have significantly helped me to complete this work. Dr. Economides always made sure I stayed on track during the research and writing stages and her continuous support and involvement are greatly admired and appreciated.

She also introduced me to the fascinating world of Pressure Transient Analysis that I continuingly apply in both academic and professional settings. This is an area that I will further explore throughout my career.

Many thanks to Dr. Michael Economides for great discussions and our collaboration on this work. His fascinating engineering knowledge has been a great resource to me during this project.

I would like to thank Randy Harbaugh for introducing me to this topic while working together on the deep water well projects in the Gulf of Mexico. Randy encouraged me to explore this topic.

TABLE OF CONTENTS

LIST OF FIGURES

CHAPTER I

INTRODUCTION

1.1 Research Problem

In the last decade the need for downhole completion stability has became paramount. It is not uncommon for a new deepwater completion to produce over 30,000 STBOPD or more than 100 MMSCFD from reservoirs less than 100 ft thick. Typically high rate wells have high permeability and the formations usually require sand control to avoid production of formation fines. Sand control is achieved either by GP or FP, and today HRWP is a frequently used GP technology that ensures successful placement of the gravel in perforation tunnels and the entire annulus between the GP screen and the well casing. Many GP and FP wells have been lost, reportedly due to destabilization of the annular pack,[1] erosion or collapse of the gravel pack screen[2], and/or formation compaction.[3]

The current emphasis in the literature is on controlling the well flow rate to avoid exceeding estimated velocity or drawdown limits. This is a form of sand management when what is really needed is reliable sand exclusion at target production rates. In general, deepwater reservoirs are capable of delivering high rates with very little drawdown when the completion skin is less than or equal to zero, and the estimated velocity or drawdown limits are highly dependent on the completion design and execution. The problem is how to design a fool proof completion that can sustain target rates without failing.

_____

This thesis follows the style and format of the *SPE Journal*.

1.2 Research Objectives

Instead of focusing on determining the maximum rate at which a well can flow based on the velocity limit calculation and well monitoring, a reactive approach that yields undesirable choices, the objective of this work is to show how to design a high permeability fracture well completion that will ensure safe well operation for the target design flow rate, and will not require considerable reservoir surveillance, if any. Based on the reservoir, fluid, rock properties, and the reservoir geology, the indicated completion design will ensure that the well is safely produced at the target flow rates. In this work special attention will be paid to the angle between the well trajectory and the far field HPF plane orientation dictated by regional stresses, and hence the connectivity of the fracture to the wellbore.

1.3 Previous Work

The industry has been focused more on clarification and solution of existing problems and their possible causes, than on the root of the problem and its avoidance. Nearly all work related to this topic in the literature was about the drawdown and downhole velocity guidelines for high rate well producers.

The fracture will initiate in the plane of the wellbore in response to drilling induced near wellbore stresses. Then the fracture will turn in the span of a few wellbore radii to align normally to the minimum stress direction.[3] In this work the term fracture plane refers to the main fracture plane that is aligned with far field or regional stresses.

Veeken *et al.*[5] emphasized the importance of close alignment between the wellbore axis and the far field fracture plane. Unless the well is deliberately drilled to align with the fracture plane, their experiments showed that the well would have limited entry effects and reduced productivity due to poor communication between the wellbore and the hydraulic fracture. They stated that communication between the fracture and wellbore is determined by the orientation of wellbore and perforations with respect to the in-situ stresses. There is also a possibility of forming of multiple fractures. Furthermore, they did a combined theoretical and experimental study to investigate key parameters for well-to-fracture connectivity. Their findings were compelling and highly relevant to this work even though their study emphasized aspects of the hydraulic fracturing execution, while this study is focused on production implications.

A key conclusion in the work by Veeken *et al.*[5] was a recommendation that the wellbore trajectory be drilled to align normal to minimum horizontal stress, either by drilling vertically through the productive

interval or by turning the inclined well to this alignment. Since then many operators and service providers have rejected this advice for various reasons. Cleary, *et al.*[6] have recommended pumping strategies that tend to avoid multiple fractures. Also, many of the operators simply overlooked well trajectory importance altogether.

Furgier *et al.*[7] boast that they were able to place the fracture planes in highly deviated wells, as though that were the sole objective, but they also report skins that are consistently well above zero. Furthermore, Furgier *et al.*[7] concluded that FP completions are common practice in 65° deviated wells and good completion efficiency is achieved (mechanical skin less than 5). This paper is focused only on hydraulic fracture execution and does not indicate the production rates at which the wells have been flowed, or whether the wells must be monitored to avoid completion failures.

Behrmann *et al.*[8] concluded that fractures initially unaligned with the far field stress become aligned within one wellbore diameter. They also stated that in order for fractures to initiate at a perforation and then to extend, the perforation must be oriented at a small angle to the plane normal to the minimum far field stress. Based on the testing that they performed this angle should be less than 10°.

Abass *et al.*[9] listed possible causes of formation sand failure. They categorized sand formations that potentially exhibit sand failure and sand production. They concluded that a short conductive fracture alleviates formation sand failure and sand production. In most cases the formation sand failure is caused by poor completion (e.g. excessive drawdown, high flow velocity). Although formation sand failure is not by itself a completion failure, it greatly impacts the completion stability. Destabilization of the near wellbore region results in fines movement leading to gravel pack plugging, skin increase, and well productivity loss.

By estimating an average skin for various completion strategies, Welling[10] recommended the best completion practices based on the reservoir permeability. Claiming that only a few perforations per foot may have to carry all of the flow from the fracture in the FP case, or from the reservoir in the GP case, Welling[10] concluded that the HRWP and open hole gravel pack (OHGP) completions are preferred if the reservoir permeability is above 900 md for oil or 600 md for natural gas. This decision was based on calculation of an average normalized pressure drop of 257 psi for HRWP wells compared to 322 psi for the FP oil wells. **Fig. 1.1** (from Welling[10]) shows the typical fracture-to-well connection. Welling[10] stated that the field matches showed that in general 0.7 to 2.3 shot per foot (SPF) are in connection with the fracture. **Fig. 1.2** (from Welling[10]) shows the HRWP with radial flow to all perforations providing on average 5 SPF.
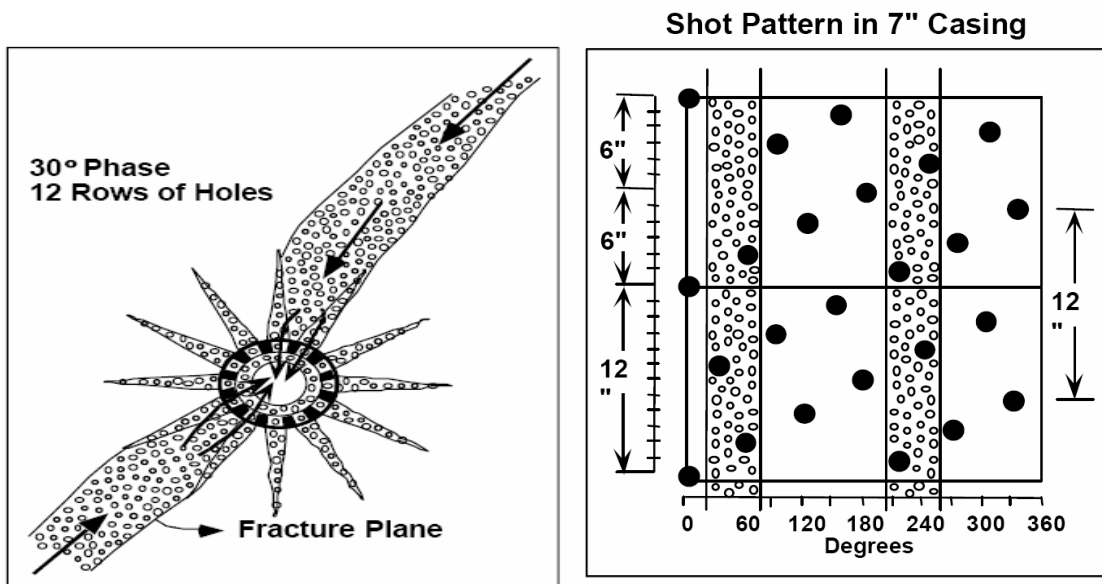
Figure 1.1 Schematic of typical fracture-to-well connection, 30 degree perforation phasing, 12 rows of holes, fracture half length=40ft, fracture width=0.2 ft, and shot patter for 7" casing, 12 SPF, 30 ° phasing (from Welling[10])
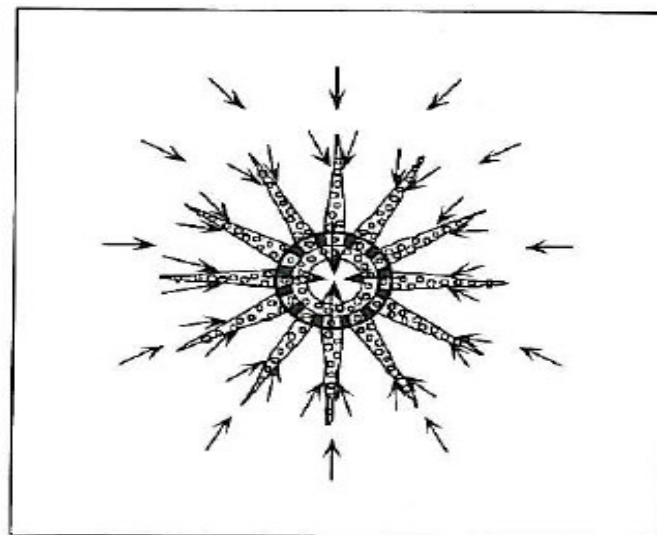
Figure 1.2 HRWP model, radial flow to all perforations (from Welling[10])

The following table summaries Welling[10] completion selection for oil and gas wells, based on the reservoir permeability, k, and the gas rate, Q, for gas wells.

Table 1.1 Optimum completion ranges for varying reservoir permeabilities and flow rates

	FP	OHGP	HRWP
Oil Wells	k<900 md	k>900 md	
Gas Wells (Q <200 MSCFD)	k<300 md		k>300 md
Gas Wells (Q >200 MSCFD)	k<200 md		k>200 md
Gas Wells (Q >500 MSCFD)	k<150 md	k>600 md	k>150 md

Tiffin et al.[3] moved from the "old school" drawdown guidelines to downhole velocity limits across the annulus packed area, and the screen. The Tiffin et al.[3] work focused on case studies of failed completions and what remedial or surveillance action should have been taken. This paper detailed a method for determining maximum safe production rates for sand control wells. The method was developed from a thorough compilation of data from over 200 sand control wells. The authors offered a simple method to optimize and safely operate sand control wells (cased-hole FP and cased-hole GP completions) based on a function of flux through the screen. The flux definition in this case, and in this work, is defined as a volumetric rate per unit area of screen. Furthermore, the authors[3] stated that too high a rate results in an unacceptable well failure rate and too low a rate results in lost production.

Fig. 1.3 (from Tiffin et al.[3]) is a valuable input for this work. It shows a database of 160 wells. The selected wells were pre screened and only the wells with good completion quality were selected. From this figure it can be seen that drawdown does not correlate with the well failure. Some wells had a drawdown of 2,500 psi and did not fail, while the other failed with a drawdown of only 250 psi.
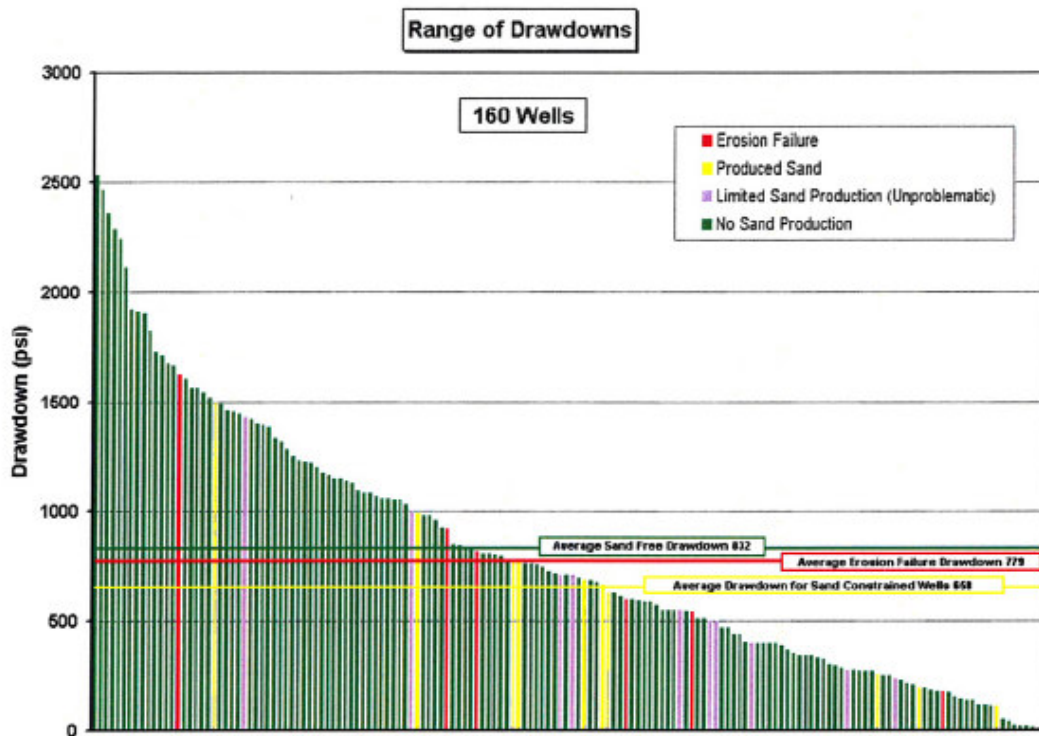
Figure 1.3 Drawdown data and well failure from 200 wells database (from Tiffin et al.[3])

Tiffin et al.[3] concluded that drawdown applied in this way does not help predict safe operating conditions; nor can it be used to optimize production rates. Their analysis of screen failures indicated that screen erosion was by far the most common completion failure mechanism even with a good completion quality. Screen erosion is caused by fluid flow through the screen and is aggravated by even a small amount of fine sand particles.

Drawdown limits were changed from 750 psi to the maximum calculated flux at the screen base-pipe and then corrected using skin calculations to estimate partial penetration and percent wellbore area flowing. By applying these new flux-based limits they were able to successfully increase production without completion failures in a number of wells.

The following equation (from Tiffin et al.[3]) shows a C factor (erosion factor) where mixture density, ρ_m, is in pounds/cubic foot and perforation velocity, $V_{p\text{max}}$, is in ft/sec;

$$C = \sqrt{\rho_m} V_{p\max} \tag{1.1}$$

Mixture density is obtained by weighting each phase density by its volume percent of flow. The resulting C factor is basically the square root of the kinetic energy of the fluids that carry sand into the screen.

Tiffin et al.[3] indicated that downhole fluid flow rates are relatively easy to determine from the surface rates, but that many assumptions are required to calculate the actual area of the screen taking most of the fluid flow. They therefore concluded that it is not realistically possible to analytically calculate flux through a downhole screen, and advocated instead use of a sand detector to warn of any sand production and a downhole pressure gauge and well test analysis to monitor the flux directly.

Wong et al.[1] presented their work at the same time as Tiffin et al.[3]. Their work is based on the same approach as Tiffin et al.[3], but they provided more elaboration on the flux calculation method. The proposed well surveillance method was fully developed for cased-hole GP and FP completions assuming the gravel-filled perforations dominate flow within the completion. Their well surveillance method monitors downhole flowing velocity and completion pressure drop to operate the well without introducing unnecessary completion impairment and sand control risks. **Fig. 1.4** (from Wong et al.[1]) shows the completion components of cased-hole-gravel packs and depicts the production flow path through the system.
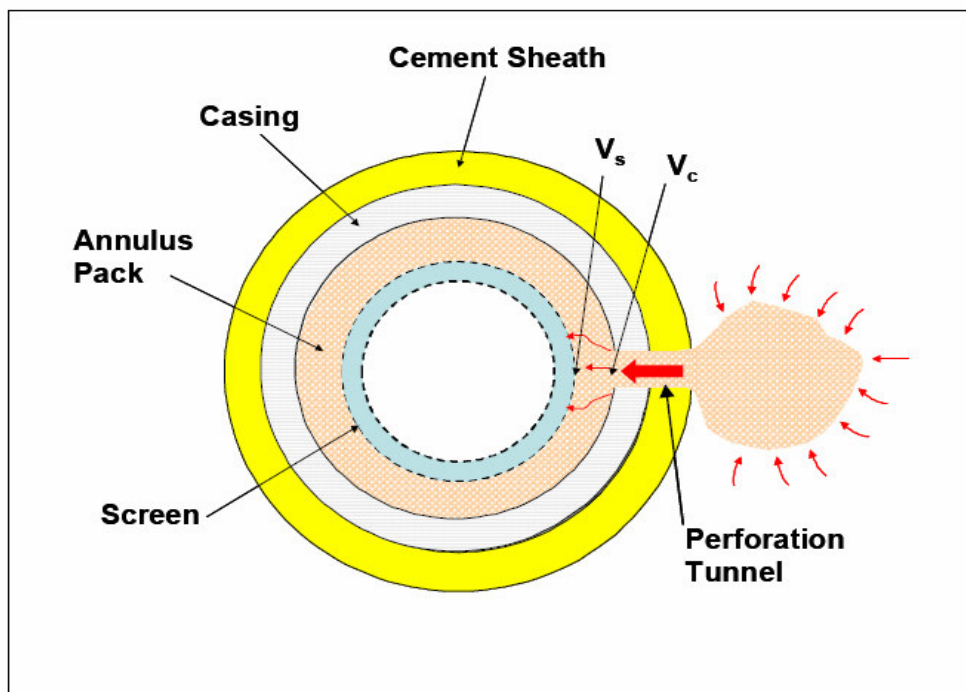

Figure 1.4 Completion components and flow schematics for cased-hole gravel packs (from Wong et al.[1])

Fig. 1.4 illustrates the highest flowing velocity is through the perforations where the flow converges. The average flowing velocity exiting the perforation at the casing inside diameter (ID) is labeled as V_c, and the flowing velocity on the screen surface directly across the perforation is labeled as V_s. Wong *et al.*[1] stated that the destabilization of the annular pack is an instability failure that occurs when the perforation velocity at the casing ID (V_c) is high enough to "fluidize" the granular pack in the annular region around the perforations. They recommended a conservative maximum velocity limit of 10 ft/sec to avoid destabilization of the annular pack, and 1 ft/sec for a maximum velocity to avoid screen erosion. Although the Wong *et al.*[1] study was about GP and FP completions only, in this work the approach for computing V_c can be considered for HPF as well. Wong *et al.*[1] then calculated downhole flowing velocity with a realistic completion model that describes the flow in the dominant failure mode. However, these computations are not straightforward tasks, numerous assumptions are needed, the result and outcome are almost always subjective, and they depend on the empirical data. It is though true that the industry does not have many choices. For the existing wells they can either use a flux surveillance method based on the velocities over different areas, or they can apply "old school" drawdown practices. The flux surveillance method is useful to predict whether and where fines will be moving. It is useful also for estimating the theoretical skin.

Keck *et al.*[11] mentioned that they measured mechanical skin from build-ups in Na Kika wells in deepwater Gulf of Mexico (GOM), but here the meaning of mechanical skin is the total skin determined from pressure transient analysis (PTA), not a component of the total skin. While well "productivity quality" could be measured by skin, the well completion quality requires more (especially completion hardware). For these wells, a low skin factor did not always guarantee a good completion, and vice versa. Keck *et al.*[11] mentioned that the well deviation for Na Kika wells had no correlation with skin. Moreover, they mentioned that the well failure generally could not be correlated with the skin.

1.4 Summary

The eight studies mentioned in this introduction all focus on modern sand exclusion completion practices, but each ends with suboptimal recommendations. Welling[10] looked only at inclined wells and concluded that because OHGP completions will have the most perforations taking the flow from the reservoir to the wellbore this should be the completion choice for highest rate wells. Tiffin *et al.*[3] developed a flux criteria for determining the safe well production rate based on the flow velocity through perforation tunnels. Wong *et al.*[1] spelled out the way to compute the flow velocity needed for the flux criteria. None of these studies addresses a way to design a completion that avoids the need to monitor flux. This work will show that a properly designed HPF is the best choice for high rate wells, and that it will maintain target rates through the life of the well.

CHAPTER II

COMPARISON BETWEEN IDEAL GRAVEL PACK AND HIGH PERMEABILITY FRACTURE COMPLETIONS

2.1 Preliminary Discussion

As the deepwater operations evolve, operators are trying to produce wells at maximum rates and achieve payback in a minimum time. Many wells are still GP completed, and this is concerning as several authors already demonstrated that GP is not an optimum choice by far. Dusterhoff *et al.*[12] mentioned that the GP wells inherently create the damage situation and thus lower the potential production in most instances. Tiner *et al.*[13] noted that one of the major production companies has estimated that over 50 % of their production capability is lost through GP completions.

The flow geometries for GP and HPF wells are different and will cause different drawdown and different flow velocity for the same flow rate. Also, the resulting skin in HPF wells should be negative while a GP completion will always have positive skin. All of the above mentioned points will greatly impact the well productivity index and overall well performance and completion stability. Clearly the lower skin will give better well performance. Lower velocity at the annulus pack and the screen will have lower risks for well failure. This chapter explains the fundamentals of different completion types and shows the skin and velocity calculation for an ideal GP and HPF wells. The possible completion failure mechanisms will also be addressed.

2.2 Gravel Pack and High Rate Water Pack Completions

The execution of a GP should be a straightforward process. In cased-hole well completions, gravel is placed in the perforations and in the annular area between the screen and the casing. In OHGP completions the gravel is placed between the screen and the open borehole. From the production point of view there may be significant differences in the well performance for cased-hole and OHGP wells because flow into the cased-hole gravel pack must pass through the perforations. To avoid creating a fracture during the GP execution, the formation fracture gradient must not be exceeded.

The rationale for GP completions is to prevent production of fines into the well. Operators dealing with subsea flowlines cannot tolerate even minimal fines production. Reasons include possibilities of fines build up, erosion of subsea chokes and hardware, and in severe instances even flowline plugging. Complex flow assurance will worsen these problems. Remediation of any of these problems would require an expensive workover.

If there was a need for sand control in the first place, over time formation fines will gradually collect in the GP and will cause an increasing pressure drop (skin) across the GP. The tendency for fines to accumulate in perforation tunnels is dependent on drawdown and flux in the formation around the perforations. Generally, a flow rate low enough to avoid fines movement into the perforations will be too low to be economic. Therefore, gradual increase in skin over time is to be expected and is a sign of a successful and necessary GP completion. Acid stimulation can dissolve accumulated fines in the GP and restore the well productivity. However, acid treatments can be detrimental in reservoirs with zeolite content, and for this reason they are not usually recommended for deepwater GOM reservoirs. Also, most of the wells in deepwater GOM have wet trees where complex completion hardware making acid stimulation very challenging and not always feasible.

It should be relevant to note that a successful GP filtering function begins at the perforation cavities. As fines collect in the perforation cavities it is easy to see that this is the likely source of increasing GP skin. However, perforation cavities do not plug uniformly, and over time fewer and fewer perforations may be open to flow. Continued production at the same high flow rate will cause increasing flux across fewer perforations as the completion skin increases. Excessive drawdown and/or flux can cause destabilization of the annular pack or screen collapse.[1] This happens when the pack is damaged over time causing the expected increase in skin, but the operator continues to produce at high rate, causing failure due to excessive drawdown. A critical element in a GP performance is a proper sizing of the gravel and a screen. Even a perfect GP will accumulate fines over time, and remedial work is considered necessary.

Many problems in GP wells with excessive sand production, high skin, gravel plugging, and completion failure motivated introduction of the high rate water pack (HRWP) completion method. HRWP completions are GP completions packed at a high rate to ensure that gravel is placed in all of the perforation tunnels, and all "debris" is pushed away in the reservoir. This is no small matter because without high rate gravel placement, it is difficult to pack all the perforation tunnels, particularly in over pressured formations, and those left unpacked will soon be plugged with fines once the well is put on production. For this reason historically gravel packs had very high skins, and modern HRWP's have much lower skins. However, it has been commonly reported that over time well productivity declines in HRWP

completions.[13] Therefore, remedial work is required for all GP completions, including HRWP's. In the case of subsea wells with wet trees the workover would cost in the range of 20 million USD, and as already said, the procedure would not always be successful.

Based on the author's information from different service companies, the number of acid jobs has fallen drastically since the FP became a trend in GOM. This fact supports a conclusion that the even perfect GP will plug over time and that FP's do not accumulate fines.

2.3 High Permeability Fracture Completions

Originally FP's were GP's with fracture geometry. In a FP, a fracture plane is formed by injecting gravel at pressures above the formation fracture gradient. Aggour[14] stated that FP completions allow for more complete zonal coverage which can be beneficial in laminated reservoirs and non-perforated zones.

High permeability fracturing (HPF) are generally FP completions employing a tip screenout (TSO) design to control the fracture length and width, and using high conductivity proppant instead of gravel. Today, it is understood that the fracture can be designed with a flow area large enough to keep the flow velocity at the fracture face below the critical sand flow velocity. Therefore, instead of gravel pack material designed to stop formation fines from flowing into the wellbore, high permeability proppant can be used to maximize the fracture conductivity. As such, the term high permeability fracture is more descriptive of modern hydraulic fractures in high permeability formations. The main distinction between the HPF and FP wells is that FP in early times used gravel with grain sizes like what would be used in a gravel pack, and HPF now uses high permeability proppant without concern for stopping formation fines. In effect, the HPF is desirable as a means to eliminate sand production at high production rates.

The HPF is intended both to provide sand control and to extend past drilling and completion damage. If this is not achieved then damage will not be bypassed and the well will have a higher skin. It has been shown[15] that when the fracture half length extends beyond the radial damage skin due to drilling mud filtrate invasion or a certain type of completion fluids invasion, there will be no contribution from this component to the overall HPF skin.

The flow geometry is different in GP and HPF wells. With a HPF well, reservoir fluids flow linearly to the fracture plane, and from there to the wellbore in a slab of high permeability. **Fig. 2.1** shows the inflow

geometry for the HPF completions. In contrast, flow to a GP or HRWP well is radial, as was shown in Fig. 1.2.
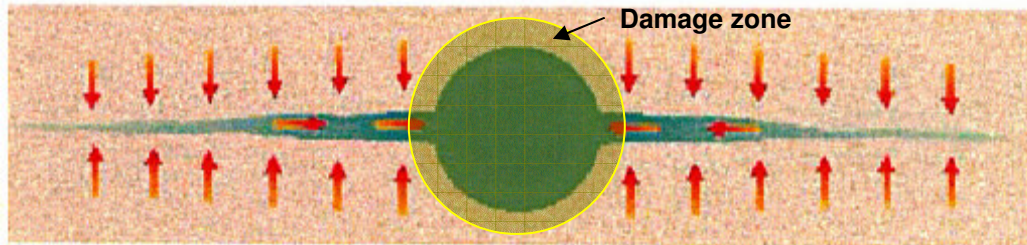
Figure 2.1 HPF completion flow geometry

Furthermore, there is very likely a radial zone of reduced permeability in high permeability reservoirs (gray radial zone in Fig. 2.1). Radial flow to a GP must pass through this lower permeability zone, thereby causing additional pressure drop or skin near the wellbore. In contrast, with sufficient half-length, flow through the fracture bypasses the near wellbore radial skin.

Modern HPF should be based on unified fracture design (UFD).[16] HPF execution in high permeability reservoirs should employ the TSO procedure. TSO enables propagating the fracture to the design fracture half length, and then inflating it to the designed conductivity. Field experience indicates that the TSO can be difficult to model and detect.[15] The problem is that an apparent TSO may be only a halo effect. The so-called halo effect occurs when some of the proppant forms an annulus between the cement and the formation, as diagrammed in **Fig. 2.2** (red dots are perforations). What may happen instead is that most of the injected proppant ends up in the halo, with little in the fracture, and unfortunately, this can appear to show an injection history characteristic of TSO.[17] The halo effect may be limited mainly to unconsolidated formations, such as are common in the GOM.

2.4 Formation Face Flow Velocity Comparison for Ideal GP and HPF Completions

Fig. 1.2 shows the radial flow from the reservoir to the wellbore in GP and HRWP wells. The flow area at the formation face is less than the area of a cylinder with radius equal to the wellbore radius and height equal to the drilled length of the productive interval because in reality flow to the well is only through the perforations. As it can be seen from Fig. 2.1 in HPF completions flow from the formation to the fracture

is linear. In this case the flow area is the product of four times the fracture half length times the fracture height. Since the flow velocity is simply the flow rate over the flow area, it is obvious that the formation flow velocity in HPF wells is much smaller than in GP wells.
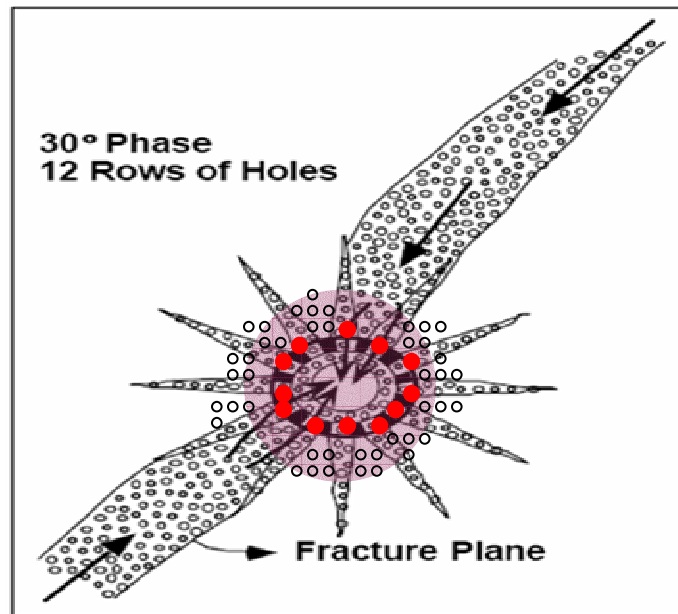
Figure 2.2 Halo effect interpretation (Modified Welling[10] Figure)

The following example will clarify the benefits of HPF completions. If we use a field example with a perforated interval 100 ft thick, having 16 SPF, wellbore radius of 0.3 ft, with an average perforation diameter of 1 in, and the perforation length of 1 ft, the total cylindrical perforation area would be 418.9 ft^2 (Eq. 2.2). This example was extremely conservative assuming that all perforations were initiated and were open for flow. In reality this will not be the case. Some of the shots will be misfired; some will not be created, and some will get plugged. For the HPF completions the fracture face area will be completely open for flow. If the fracture height is 90 ft and the fracture half length of 30 ft (typical for soft reservoirs), the surface of the fracture flow would be 10,800 ft^2 (Eq. 2.4). The outcome is compelling. The flow area for HPF completion in this example is 25 times more than the flow area for GP or HRWP completions. The velocity for GP or HRWP completions in this example will be higher for 25 times than for HPF completions. Since this was an oil well making 10,000 STBOPD, the flow velocity for the HPF case would be 0.00006 ft/sec, while for the GP or HRWP case the flow velocity would be 0.00155 ft/sec. For

this particular formation the core test reveled that the critical velocity to initiate fines movement is 0.00095 ft/sec. The flow velocity for HPF completions calculated above will not likely move any fines. However, if this well was HRWP completion, with the same rate fines would have been moved. This would mean that the well could not have been making 10,000 STBOPD without formation fines movement.

The linear flow will cause much smaller pressure drop in the formation than the radial flow due to the higher flow area for the linear flow. Also, by comparing Fig. 1.1 and Fig. 2.1 (radial vs. linear flow to the wellbore) it is apparent that much less turbulence occurs in HPF wells than in GP wells because the HPF avoids convergent radial flow. This is especially important for gas wells.

One of the most important objectives in HPF design is to determine what fracture half length will ensure that the formation flow velocity opposite the fracture face will not exceed the velocity at which formation fines would flow. The importance of the flux at the formation face is to determine whether formation fines will move. Depending on the formation sand type (particularly sand mineralogy and sand consolidation) different flow velocities are needed to initiate fines movement. Each reservoir has a unique flow rate at which it starts migrating fines. The minimum required flow velocity for the fines movement can be determined from a lab test. However, if fines move, they will be stopped by a properly designed GP, probably in the perforations and thereby plugging them. The HPF can be designed to supply sufficient flow area to ensure that the formation flux is never great enough to flow formation fines. In that case, the HPF well will never be plugged over time. In fact, while the GP grain size distribution must ensure that formation fines will not flow through the GP to the screen, the HPF proppant grain size distribution need not stop the fines because they will never flow in the first place. Hence, modern HPF designs are using very large proppant diameters without concern.

Flow velocity at the formation sand face for GP or HRWP wells will be;

$$v_{SF} = \frac{6.5 \cdot 10^{-5} qB}{A_{GP}} \qquad (2.1)$$

where qB is the downhole flow rate in BOPD, and A_{GP} is the flow area at the sand face in ft^2. While in the GP or HRWP completion the flow area is a cylindrical perforation area, in reality perforation tunnel is a cone like area but for simplicity cylindrical area will be used in this work.

For GP and HRWP wells the flow area, A_{GP}, will be;

$$A_{GP} = 2r_p \pi L_p SPF \qquad (2.2)$$

where r_p is perforation radius, and L_p is the perforation length.

The function of the GP is to prevent the formation fines from flowing into the wellbore. However, this velocity is expected to be large enough to flow formation fines into the GP, especially after water breakthrough since the relative permabillites will be changed. This will mean that GP will be doing its job and the formation fines are being moved and produced. Consequently, the completion skin will increase.

For HPF wells the flow velocity at the fracture face should always be lower than a critical flow velocity for fines movement. To avoid formation fines movement and bypass near wellbore damage, the following criteria should be applied for HPF wells:

1. The critical flux velocity for single phase liquid, $v_{c,SF}$, must be determined for the formation in question. This velocity can be determined from the core lab test or based on the analog reservoirs. The sand face velocity, v_{SF}, must be less than the critical flux velocity;

$$v_{SF} = \frac{6.5 \cdot 10^{-5} qB}{A_{HPF}} < v_{c,SF} \qquad (2.3)$$

where qB is the downhole flow rate in BOPD, and A_{HPF} is the flow area of the fracture faces, which for HPF wells is given by;

$$A_{HPF} = 4x_f h_f \qquad (2.4)$$

where x_f is fracture half length, and h_f is fracture height.

2. The velocity at the fracture face is given by;

$$v_{SF} = \frac{6.5 \cdot 10^{-5} qB}{4x_f h_f} < v_{c,SF} \qquad (2.5)$$

3. The fracture half length must be longer that the radius of drilling and completion induced damage, r_d;

$$x_f > r_d \qquad (2.6)$$

4. The fracture flow area, x_{fA}, must be sufficient that the formation flux is less than what would induce fines movement at the fracture face;

$$x_{fA} > \frac{6.5 \cdot 10^{-5} qB}{4h v_{c,SF}} \qquad (2.7)$$

5. Given the target flow rate, q, the critical flux velocity inducing fines movement, and a margin of error in the velocity of 2, and the minimum fracture half length should be the larger of the criteria in Eq. 2.3and Eq. 2.4;

$$x_f \geq \max(r_d, 2x_{fA}) \qquad (2.8)$$

According to the UFD, optimal productivity for a fracture length that is small compared to the radius of the drainage area occurs for dimensionless conductivity, C_{fD}, of;

$$C_{fD} = \frac{k_f w}{k x_f} = 1.6 \tag{2.9}$$

where w is average fracture width, k_f is average fracture permeability, and k is average reservoir permeability.

Therefore, the fracture width should be;

$$w = \frac{1.6 k x_f}{k_f} \tag{2.10}$$

In an ideal HPF the halo effect will enable all perforations to contribute equally to flow to the wellbore whenever the well trajectory has been drilled in the plane normal to the minimum stress direction. Fracture execution is judged by whether the fracture reaches its design length before TSO, after which injection continues in order to reach the design fracture width and, therefore, conductivity, given by the product of the fracture width with the fracture conductivity estimated from the proppant selection. However, if only an expanded GP (EGP) has been created, it could easily fail to extend past the drilling and completion damage radius. For the case that most or all of the proppant ends up distributed radially around the wellbore, the radius of the EGP, r_{egp}, can be estimated by the following equation by solving for r_{egp};

$$V_i = \pi(r_{egp}^2 - r_w^2)h_p \tag{2.11}$$

Where V_i is injected proppant volume, r_w is wellbore radius, and h_p is perforated interval.
Using this radius, the formation flow velocity into the EGP, V_{EGP}, is computed as;

$$V_{EGP} = \frac{q}{2\pi r_{egp} h_p} \tag{2.12}$$

Solving a previous field example with a fracture height of 90 ft and fracture half length 30 ft, and with fracture width of 1 in, the injected volume would be 450 ft^3. If, the same injected volume winds up as entirely a halo effect EGP, the EGP radius will be 1.31 ft. The flow area will be 740 ft^2, and for a target flow rate of 15,000 STBOPD the formation flux will be 0.0013 ft/sec. If, instead the same injected volume created the fracture with half-length of 30 ft, and the height of 90 ft, the flow area would be 10,800 ft^2, and for the same target flow rate the formation flux into the fracture is 0.00009 ft/sec, more than 10 times less. Certainly, the higher flow rate in GP case would easily exceed the critical velocity for fines movement.

A major additional factor to consider is that the sand in a GP will have a particle size distribution designed to stop fines migration, but an EGP will probably be filled with proppant that would not stop formation fines. Hence, if an intended HPF ends up as essentially an EGP, and if this is not evident from the injection pressure record during fracture pumping, the operator would not know to limit the well flow rate, and there would be a strong likelihood that fines would be produced. The last section of this chapter addresses mechanisms for completion failure, including screen erosion. Normally fines would not be produced through an HPF, but if the HPF is essentially an EGP, formation fines could go right through it.

The above flux calculations assume that all of the GP perforations are flowing. Only in ideal GP completions will all perforations contribute to flow. Welling[10] (Fig. 1.2) concluded that the flow is radial to all perforations. However, not all perforations will be created and also not equally packed and opened for flow, and even HRWP completions are likely to have a number of non-flowing perforations. HRWP completions may have all perforations opened for flow in early well life, but for conventional GP's often this is not the case. If most of the perforations are poorly packed and become plugged with formation fines, the flow will be concentrated over a smaller area, and the flux at the sand face can be much greater.

2.5 Skin Comparison for Ideal GP and HPF Completions

Wellbore damage can be caused by many mechanisms such as mud filtrate invasion during drilling, completion fluids contamination, asphaltene flocculation, perforation damage, wax precipitation, etc. Unlike the GP, the HPF is designed to bypass near wellbore damage and the total skin factor will be notably less than in GP or HRWP wells. Some of the damage mechanisms mentioned above are unavoidable and do not depend on the completion type. It has been already said that the skin in GP and HRWP wells will gradually increase with time while this is not the case for properly designed HPF wells. Not only the fracture should bypass any near-wellbore created damage but also should insure good reservoir-to-wellbore connectivity.

Welling[10] provided theoretical quantification for various components of the total skin for GP and HPF in gas and oil wells. Starting with the OHGP, Welling[10] computed the total skin, S_t, as;

$$s_t = s_{fl} + s_{cake} + s_{pl} + s_{gr} \qquad (2.13)$$

He computed the fluid loss skin, S_{fl}, as;

$$S_{fl} = (\frac{k}{k_{fl}} - 1)\ln\frac{r_{fl}}{r_{cake}}$$ (2.14)

where k_{fl} is fluid loss zone permeability, r_{fl} is fluid loss radius, and r_{cake} is filter cake radius.

He computed the filter cake skin, S_{cake}, as;

$$S_{cake} = (\frac{k}{k_{cake}} - 1)\ln\frac{r_{cake}}{r_w}$$ (2.15)

where k_{cake} is filter cake permeability, and r_w is wellbore radius. He computed the partial completion skin, S_{pl}, as;

$$S_{pl} = (\frac{H_{tot}}{H_{of}} - 1)(\ln(\frac{H_{tot}}{r_w}) - 2)$$ (2.16)

where H_{tot} is total thickness, and H_{of} is open flow length. Finally, he computed the gravel skin, S_{gr}, as;

$$S_{gr} = (\frac{k}{k_{gr}} - 1)\ln\frac{r_g}{r_{oc}}$$ (2.17)

where k_{gr} is gravel permeability, r_g is under reamed radius, and r_{oc} is outside screen radius.

For the HRWP oil wells, Welling[10] computed the total skin as the sum of the perforation tunnel pressure drop given by;

$$S_{HRWP} = \frac{DPkh}{141.2qB\mu}$$ (2.18)

Where DP is delta pressure drop through the perforation tunnel and it has two components, the linear pressure drop, DP_{lin}, and the turbulent pressure drop, DP_{tur}.

The total pressure drop and its components are given by;

$$DP = DP_{lin} + DP_{tur}$$ (2.19)

$$DP_{lin} = aq$$ (2.20)

$$DP_{tur} = bq^2$$ (2.21)

Laminar pressure drop factor, a, in reservoirs without skins is;

$$a = \frac{888L_g\mu B}{k_p A_p N}$$ (2.22)

where L_g is the connection flow length (difference between drilled radius and screen radius), k_p is the perforation permeability, A_p is the perforation cross sectional area, and N is the number of perforations connecting the fracture and the wellbore.

Turbulent pressure drop factor, b, is;

$$b = \frac{9.08x10^8 \beta_g L_g \rho_m B^2}{A_p^2 N^2} \tag{2.23}$$

where β_{goil} is turbulence factor for gravel given by;

$$\beta_{goil} = \frac{6.5x10^4}{k^{0.996}} \tag{2.24}$$

Welling[10] stated that the turbulence factor for gravel was determined by in-house lab measurement.

Welling[10] computed the total skin for the HPF as the sum of the fracture skin and the perforation skin, where the fracture skin, S_f, was computed as;

$$s_f = \ln\left(\frac{r_w(1/C_{FD} + 2)}{x_f}\right) \tag{2.25}$$

The perforation skin, S_p, was computed as the sum of a laminar flow term and a turbulent flow term. With negligible turbulent flow for single phase oil flow, the perforation skin is;

$$s_p = \frac{2\pi k h L_g}{k_p A_p N} \tag{2.26}$$

The perforation skin for HPF well can be also computed using the same equations for HRWP wells.

Welling[10] also provided skin equations for gas wells for all three completion geometries. For OHGP gas wells the total skin is computed by using Eq. 2.13 and its components by using Eq.2.14 to Eq. 2.17.

For HRWP and HPF gas wells Welling[10] used the same equations as for oil wells but for the linear and turbulent pressure drop calculations he used different constants.

In the case of the GP, there is a good chance the radius of damage is greater than the radius of GP, r_{gp}, or even greater than the radius of EGP, r_{egp}, increasing further the overall GP skin. Welling[10] did not account for this skin component.

Neumann $et\ al.$[17] in their study mentioned that the GP completions had disappointingly high skins even using the best completion practices. Then they started using FP completions and the resulting skin was much lower. They observed that a bad FP job was always better or, at least, as good as a good GP in Campos Basin soft formations.

The current industry trends show an average skin of +3 for HPF wells and more than +20 for GP wells. It is not uncommon for GP wells to have a positive skin of 40.[13]

The following two equations from Wong *et al.*[1] are being used for the flux calculation. The main parameter for quantifying the completion is the skin (S);

$$S = \frac{kh}{141.2qB\mu} \Delta p_{skin} \tag{2.27}$$

where B is formation volume factor, and μ is fluid viscosity.

The pressure drop due to skin (Δp_{skin}) is determined from the PTA.

Generally, Δp_{skin} could be separated into different components;

$$\Delta p_{skin} = \Delta p_{skin-mechanical} + \Delta p_{skin-geometrical} + \Delta p_{skin-other} \tag{2.28}$$

The $\Delta p_{skin-geometrical}$ is attributed to the geometry of the wellbore such as partial penetration, hole deviation angle etc. Wong *et al.*[1] stated that this skin component does not impact the completion failure mechanism even though it affects the total completion performance. However, in deviated FP wells with misaligned fracture and wellbore this skin component may play major role in completion failure. If there is a misalignment the fluid will be forced to flow through only a few perforations causing a high flow velocity and the screen erosion may occur.

The $\Delta p_{skin-other}$ is the part of the pressure drop that is not directly attributed to the completion failure mechanism. It includes all phase and rate dependant effects such as reduction of the relative permeability if the bubble point is crossed, or a condensate banking where liquid is formed around the well in retrograde condensate reservoirs.

According to Wong *et al.*[1] $\Delta p_{skin-mechanical}$ is the main part of the completion pressure drop that directly impacts the completion failure mechanism in question. This skin component is the damage skin. Since the damage occurs near the wellbore region the greatest pressure drop will be around the wellbore for GP wells. The pressure drop due to friction between the pressure gauge and the perforations should be deducted from this skin component.

If we use the previous example from this chapter assuming that the well was drilled properly (along the maximum horizontal stress direction) where most of the perforations are connected to the fracture the total skin for HPF completion should be negative 3.3 (Eq. 2.25). Perforation tunnel pressure drop will be

negligible if the perforation gravel permeability is not significantly reduced by some damage. The GP or HRWP completion will have a skin as low as 3 (assuming all perforations are open for flow and well packed) and as high as 30 if 10 percent of perforations are open for flow.

Clearly, the higher the formation flow velocity the faster and more fines movement. Consequently, GP and HRWP wells will result in the skin increase over time, while HPF wells skin will remain the same over a well life. As already mentioned the screen failure is caused by high fluid velocity and fines movement. Yet again, HPF completions should not have any fines and hence the screen erosion should not occur.

One more advantage of FP completions is the occurrence of high turbulence for high rate gas wells. It is not uncommon to have reservoirs with more than 200 STBOPD/ft or 1 MMSCFD/ft. With these high rates the turbulence is dominant in the gas wells, and also in high rate oil wells. Wang *et al.*[19] concluded that to combat the strong turbulence that plagues high rate gas wells, extensive hydraulic fracturing is a must. If the reservoir permeability is more than 5 md, turbulence overwhelms practically all other factors, including damage. The turbulence effect is more pronounced in GP and HRWP wells than in HPF wells.

Fig. 2.3 is from Wang *et al.*[19] work showing the fractured well (linear flow geometry to the wellbore) vs. a radial flow (e.g. GP or HRWP). It is apparent that the radial flow GP geometry cannot compete with the hydraulically fractured wells. Due to the difference in the reservoir vs. fracture conductivity, and the flow geometry, the pressure drop is greater for the radial flow than for the linear flow. In the previous section we already explained the downhole velocity difference for GP and FP completions.

2.6 Completion Failure Mechanisms

Completion failures can have detrimental consequences especially for subsea wells with expensive hardware and workover. Small sand production can cause choke erosion and cutting, flowline plugging, and in some instances environmental disaster can take place caused by fluid leak.

Completion failure mechanisms can be classified in two categories. The first and most frequently occurring category is screen erosion caused by high flux. If the GP is properly designed and executed, the screen should not erode, provided the well production rate does not exceed rate or drawdown limits that can cause destabilization of the annular pack.

If we take a look at Eq. 1.1 it is clear that the erosion is dependant on the flow velocity and the flow mixture density. This would mean that formation fines will aggravate the screen erosion process. For cased hole GP's the purpose of the screen is to hold the gravel pack, and the purpose of the GP is act as a filter that stops fines migration. However, the GP must have as high permeability as possible to avoid imposing excessive pressure drop through the completion. Therefore, the GP grain size distribution must be carefully designed to provide as high permeability as possible while stopping fines from flowing into the wellbore. If the GP is working properly, no fines should reach the screen. Yet several papers[1,2,3,11] are reporting that a common reason for failure in GP completions is erosion of the screen. It is not always obvious whether the screen eroded due to formation fines produced with reservoir fluids, or whether erosion was due only to high velocity fluid flow. Once the screen fails, the pack itself can flow to the surface with sufficient fluid flow rate.
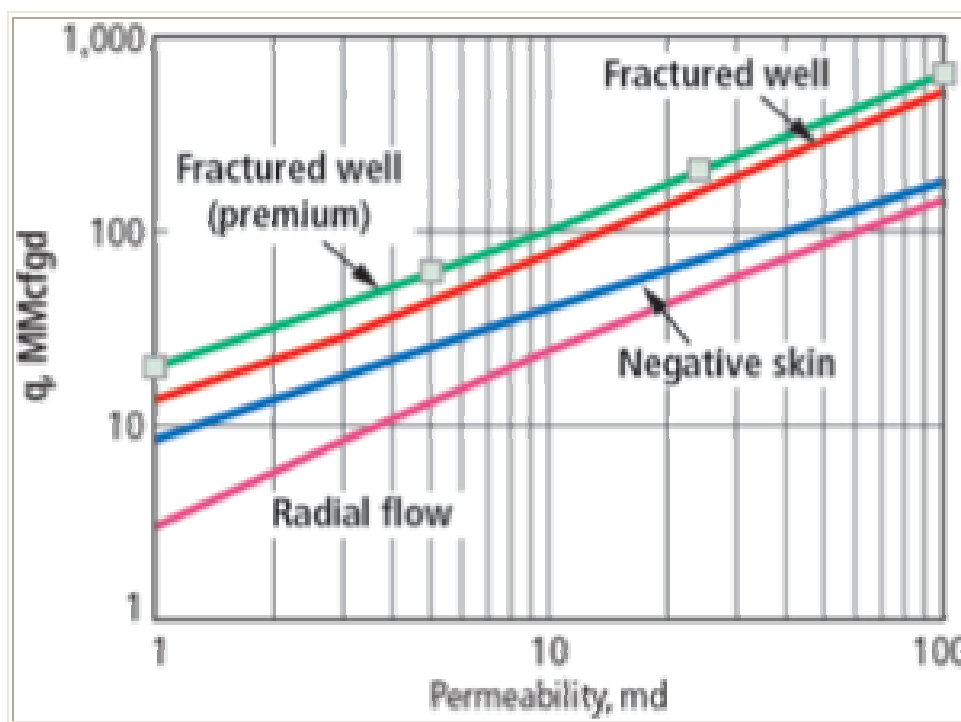

Figure 2.3 Comparison of gas production rates from non-fractured wells, wells with negative skin and fractured wells (from Wang *et al.*[19])

The second category would include mechanical failures such as completion collapse caused by excessive differential pressure over the completion hardware or caused by formation compaction. An abrupt high pressure gradient can cause formation sand unconsolidation and the sand failure. Once failed, formation sand can plug the GP. Then if the well continues to flow at high rate, high pressure gradient in the GP can cause it to destabilize and result in sufficient stress to collapse the completion. Another reason that formation sand may plug the GP is after water breakthrough. Other reasons for completion failures may be due to completion execution problems such as poor well cementing or poor GP placement.

Completion failures in the second category can also result from screen plugging. Organic deposits (asphaltenes or paraffins) may precipitate as the pressure or temperature is reduced.[20] This form of damage is typically located in the tubing, perforations, or formation. Perforation or screen plugging can occur which may cause completion failure.

Tiffin et al.[3] noted that a series of wells failed in a GOM field because of massive reservoir depletion and compaction forces. Well failure was due to casing collapse, screen collapse, and other problems. This is typically the case with high permeability reservoirs as they usually have high compressibility. For completion failures caused by formation compaction there are no major differences between GP and HPF wells. Deviated wells are more sensitive to casing damage due to overburden stress and compaction forces induced to the casing. The vertical wells will have much less chances for the casing failure. Since the reservoir depletion and compaction are unavoidable, the risk to lose the well due to the casing/tubing failure is high. This is a good reason for wells to be drilled vertically in high compressibility reservoirs.

Apart from completion failures related to compaction, it is evident that GP wells should be more vulnerable than HPF wells to completion failure.

2.7 Chapter Summary

A comparison between ideal GP and FP completions was made. The HPF was distinguished from FP. HPF is using a proppant while FP is using gravel as the injected material. While HRWP completion performance is initially better than GP completion, the overall mid and late well performance is often similar. This is due to the fact that both completion types will result in fines movement and plugging of the perforations and annular pack. A remedial work (an acid treatment or well recompletion) will be needed to restore the well productivity.

HPF completions are superior to any other completions. The flow area of the HPF completion is much higher than the flow area of GP or HRWP completion. This will result in the lower formation flow velocity at the fracture face for the HPF completions. Since the flow velocity is low enough, it will ensure that fines do not move, and, hence, the skin should remain unchanged over the well life.

The resulting completion skin for ideal HPF wells is significantly smaller than for GP or HRWP wells, hence the well productivity for HPF wells will be considerably higher than for GP or HRWP wells. The well productivity for HPF wells should remain the same throughout the well life.

Equations were given to calculate HPF design parameters that should ensure low skin, no fines movement, and bypass of near wellbore region damage. Because the resulting formation flow velocity will be below the critical velocity, the well can be operated at the maximum achievable flow rates without being put at the risk for fines movement, screen erosion, or screen collapse.

Different completion failures will impact the well performance. Depending on the completion failure seriousness, the well may be jeopardized. However, properly designed and executed HPF completion should not be prone to the listed failure mechanisms and should not have any of the completion failures mentioned above.

CHAPTER III

WELL TRAJECTORY AND GEOLOGY IMPORTANCE (IMPACT) TO HPF COMPLETIONS

3.1 Preliminary Discussion

The previous chapter explained why ideal HPF completions should out perform any GP or HRWP completions. Unfortunately, operators do not necessarily strive for ideal HPF completions. The HPF choice is not justified merely to avoid remedial work. As we saw in the example from the previous chapter, the post treatment skin for HPF completions should always be considerably smaller than GP or HRWP completions. Some would ask why we need an ideal HPF when the well performance has significantly improved over the last decade or so. A positive skin factor for oil wells of +10 used to be an excellent post treatment stimulation result, and now we are targeting up to +2 or less. Yet the following example shows that production could double or even triple with a negative skin factor.

Assuming a typical GOM well reservoir permeability of 300 md and a thickness of 100 ft, the nodal analysis in **Fig. 3.1** shows that a nearly ideal GP skin of +10 would result in a production rate of around 2,700 STBOPD and a drawdown of 1,000 psi. An average GP well with a skin of +40 would produce less than 1,000 STBOPD for the same drawdown. A commonly occurring HPF skin equal to +2 would lead to a production rate of over 5,000 STBOPD, certainly a considerable improvement over GP wells. However an ideal HPF with a negative skin of -3 would result in a production rate of nearly 10,000 STBOPD. It is apparent that HPF could more than triple the rate of a modern GP completion.

This example answers the question why operators should select the HPF completion, properly design it and execute it. The production increase would be enormous compared to the current HPF completion trends. Prominently getting an ideal HPF well should not be a big challenge if the well trajectory is considered during the well planning phase. The next section explains the reason why many HPF completions have a positive skin and why more than a reduced flow rate may be at stake.
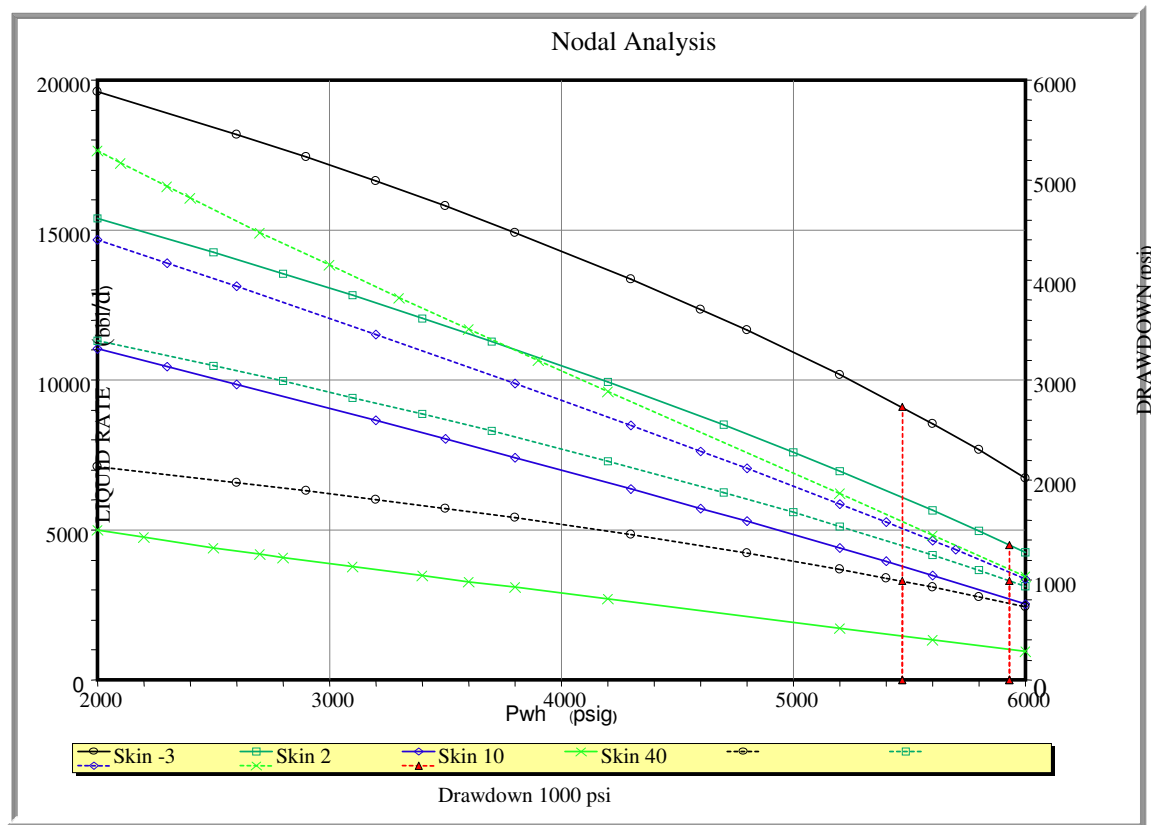
Figure 3.1 Nodal analysis result for Example in section 3.1

3.2 Production from a Fractured Deviated Well

A reservoir at depth is under a state of stress that can be characterized by three principal stresses. In reservoirs at depths greater than 1,500 ft the vertical, or overburden, stress is the largest of the three, and the other two are horizontal.[15] The hydraulic fracture plane will be normal to the minimum stress direction, leading to vertical hydraulic fracture planes in almost all petroleum production applications.

There exist reservoirs in which the minimum stress direction is horizontal, leading to a horizontal fracture plane.[21] Two main situations where fracture planes may be horizontal are in very shallow reservoirs or in highly overpressured reservoirs. Also, the fracture plane may be neither vertical nor horizontal for highly dipping beds. Section 3.4 will address the problem how to design the well trajectory in dipping reservoirs depending on whether the well will be completed with GP or HPF.

The original hydraulic fractures were in hard rock and typically in wells drilled on land with a strictly vertical trajectory. In contrast, many HPF completions are in offshore wells drilled from a platform at high deviation to achieve the extended reach required to reach the target reservoir location. While many operators request S-shaped[22] wells in order to penetrate the reservoir with a vertical trajectory, some operators insist that this is not necessary.

From the production point of view a critical HPF characteristic is fracture to-well connectivity. Since this study assumes the maximum stress is vertical, the trajectory of a vertical well will always align with the final and main plane of the hydraulic fracture. However, the well azimuth of an inclined well usually does not coincide with the final fracture plane, and the fracture plane will initiate in the plane of the well and twist, causing "tortuosity" in its path to the final azimuth normal to the minimum stress direction. This is the major problem with current trends in HPF, and Section 3.3 explains why HPF wells do not have negative skin as they should. **Fig. 3.2** depicts an unaligned fracture with a deviated wellbore.
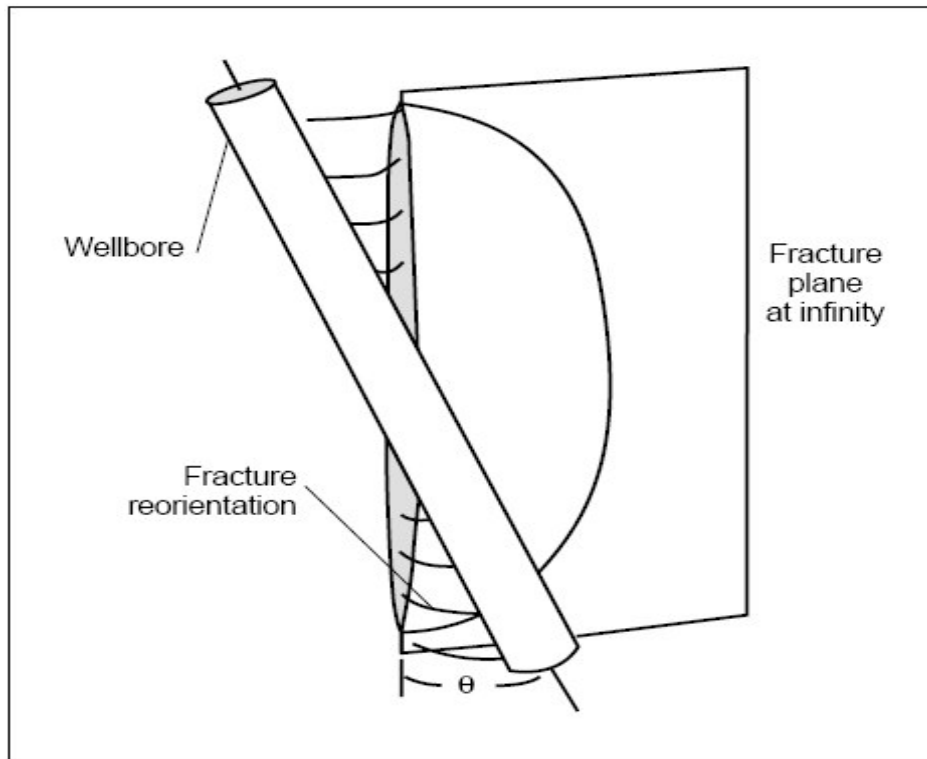

Figure 3.2 Twisted fracture aligned with the preferred direction (From Economides *et al.*[20])

Welling[10] states that the wells are all inclined for their study, but he never explains why. Except in the very unlikely event that the well path is in the plane of the fracture, hydraulic fracturing in a deviated well is sure to severely limit the number of perforations connecting with the fracture. Therefore, Fig.1.1 (from Welling10) is misleading for deviated wells unless the fracture plane coincides with the well trajectory. The number of perforations connecting the fracture to the wellbore may be a lot fewer than indicated by Welling.[10] Since typically inclined wells are perforated along the entire productive length before fracturing usually without any knowledge of the far field stresses, during the initial HPF injection some or all of the perforations may take injected proppant. While some of the proppant may fill an annulus between the cement and the formation as a so-called halo effect, the plan is that most of the proppant manages to form a single plane that starts in the plane of the well and ends up in the plane normal to the minimum stress direction. If the final fracture plane is at an angle with the well trajectory, it is not unreasonable to expect that flow to the well will be established in the easiest paths from the fracture to the well, which would very likely be through a few perforations.

Fig. 3.3 shows fracture-perforation intersection for different fracture plane orientations. Fig. 3.3 A shows the case where the fracture plane is normal to the plane of the wellbore axis, giving an angle of 90° between the wellbore and the far field fracture plane. Obviously, this is one of the worst possibilities. In this case the connection will be poor with connection to only a few perforations (total of four). Fig. 3.3 B shows a fracture plane at an angle of about 10° intersecting the opened wellbore as a sine wave. The fracture plane will probably intersect the maximum possible perforations, in this case, perhaps as many as 10 (red perforations), but via the halo effect, there may be connection to all perforations from the maximum to the minimum of the sine wave, giving a total of 31, as shown in yellow. Fig. 3.3 C shows the full fracture-to-well connectivity where less than seven shots per foot times the thickness in feet is connected. If the perforation phase were 180° with perforations oriented to be in the plane of the fracture, then the connectivity would be even better, or with halo effect, perhaps all perforations are connected even without oriented perforating.

A general equation for the number of perforations connected to fracture is;

$$N = \min(h_{inc}, \frac{r_h}{\sin(\min(\alpha, \beta))}) \cdot SPF \tag{3.1}$$

where h_{inc} is the total measured thickness, r_h is the halo radius, α is the wellbore deviation from vertical, and β is the angle between the fracture plane and the plane of the wellbore axis.
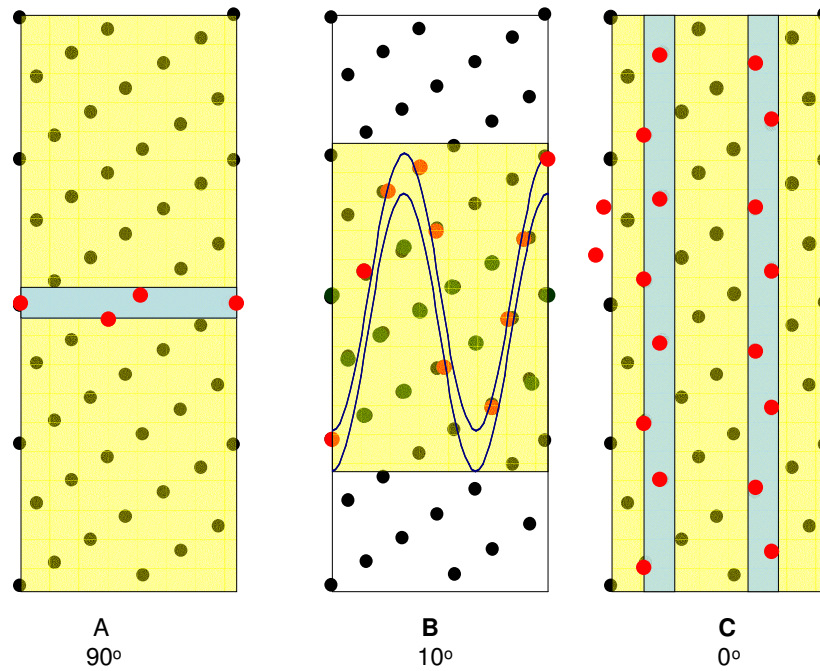
Figure 3.3 Fracture-perforation intersection for different fracture plane orientations

As an example, consider a well drilled 15° from vertical with a 6 in wellbore halo and with the wellbore axis 90° from the axis of the hydraulic fracture. The fracture plane will pass through 3.73 ft of the wellbore length. At 12 SPF, whatever spacing is, this will amount to about 23 perforations. Using Welling's equations the resulting perforation skin is 1.5. The perforation velocity will be 12 ft/sec, and C factor will be 88 if we are flowing oil with density 55 lb/ft^3 (Eq. 1.1).

When the angle between the wellbore and the far field fracture plane is large, another possibility is that a number of small *en echelon* fractures may form instead of one common fracture plane. These may or may not extend past near wellbore damage, and they may not contain sufficient proppant to provide any real stimulation. The net result in this case may be that the working proppant that takes flow to the wellbore is effectively only that in the perforation tunnels and the annular GP. In other words, what is left may be little more than a conventional GP. If, instead, the proppant forms a halo, at least the radius of the halo may provide somewhat more flow area than a conventional GP, but nowhere near the flow area that would have been provided by a properly executed HPF. Eq. 2.11 provided an estimate for the halo radius in the worst case scenario that all of the proppant intended for a HPF ended up instead as a halo, and the resulting sand face flow velocity was provided in Eq. 2.12.

Yew *et al.*[23] have indicated that as the initial fracture grows, it deviates from the initial plane formed along the wellbore because of the influence of off-shear stresses. Then, the twisting of the fracture occurs in a short distance, estimated at only a few well diameters.

A rule of thumb for successful fracture execution is to avoid letting the angle between the well axis and the final fracture plane exceed 15°.[24] However, this pertains to fracture execution, not flow to the fracture during production. In reality, if the well is deviated and the wellbore axis is not aligned with the final fracture plane, the fracture-to-well connectivity will be poor, and logically the fracture will be connected effectively with only those perforations near the intersection between the wellbore axis and the final fracture plane. Perforations more distant from the final fracture plane will have been abandoned during execution as proppant flow followed the preferential shorter flow paths to the final fracture plane. Likewise, during production, flow to the well will be preferentially through the fracture, thereby bypassing perforations no longer connected to the final fracture plane.

3.3 Estimating the Skin for a High Permeability Fracture in a Deviated Wellbore

Chen *et al.*[25] considered the effect of fracture tortuosity as narrowed fracture width at the connection between the final fracture plane and the wellbore produced a choked fracture. Alternatively, using the approach of Welling [10] the number of perforations connecting the final fracture plane to the wellbore can be estimated as the product of the well length intersected by the fracture plane multiplied by the perforation HPF. Because of the halo effect, all of the perforations in that interval may be counted. The total skin for a deviated well will be computed from combined Eq.2.25, Eq.2.26, and Eq. 3.1. The resulting skin in oilfield units is;

$$S_{dw} = \frac{DPkh}{141.2qB\mu} + \ln\left(\frac{r_w(1/C_{FD}+2)}{x_f}\right)$$

(3.2)

The total pressure drop through peroration tunnels, DP, will be computed by using Eq. 2.19 where number of flowing perforations, N, will be computed by using Eq. 3.1.

If we consider field example from Chapter II, knowing that the well deviation angle from vertical was 20°, the fracture plane azimuth was 40°, the well azimuth 340°, and no halo, then the total number of flowing perforations would be 18 (Eq.3.1). The resulting skin would be 1.6 (Eq.3.2). The resulting skin is positive even though the well was HPF. The initial pressure build-up done on this well gave a skin of 1.3. There is no significant difference between the calculated skin and the measured skin by PTA. This example seems to confirm that HPF wells end up with positive skin due to poor fracture to well connectivity. With current technology, proppant damage should be small and should not account for additional positive skin.

3.4 Potential for Screen Erosion for a HPF Well in a Deviated Wellbore

As was shown in Eq. 1.1 the C factor is basically the square root of the kinetic energy of the fluids flowing into the screen. As was mentioned in Chapter I Tiffin *et al.*[3] emphasized the importance of this parameter for high rate production wells and related it to screen erosion. The current recommendation to avoid screen erosion is to ensure that the screen velocity is less than 1 ft/sec. The research to establish screen erosion velocity is ongoing and currently it is proprietary information. Clearly, the denser fluid the faster erosion will occur. Also, a greater amount of fines in the fluid mixture will erode the screen faster.

In a HPF well it is unlikely that fines will be flowing to the screen. If the screen erodes in a HPF well very likely this occurred because of high fluid flow velocity without fines. Section 3.2 explains that very few perforations may be connecting the fracture to the wellbore and section 3.3 shows that observed skins in HPF wells are consistent with a skin calculation using a small number of perforations. Furthermore, the interval through which this flow is occurring is computed as the length of the fracture-perforation-intersection, h_{int}. Therefore, the screen velocity, V_s, is computed as;

$$V_s = \frac{q}{2\pi r_s h_{int}}$$
(3.3)

where r_s is the screen radius.

This shows that even with a negative skin there may still be high velocity flow through few perforations (hot spots) which could lead to screen erosion, or annular pack destabilization. Once the annular pack is "destabilized" the flow velocity at the screen face will be higher and the screen will be exposed to high failure risk.

Fig. 3.4 shows a sensitivity study for a 20,000 STBOPD oil well. The perforation permeability is assumed to be 200,000 md, and the halo radius is assumed to be 0.5 ft. Even at a 45° deviation, the total skin may

be less than zero. However, the flow velocity through the screen for this case is about 0.82 ft/sec, what is considered a safe flow velocity.

From the Fig. 3.4 it can be seen that the velocity behavior is the same regardless of the perforation density. This is because the screen area used in Eq. 3.3 is dependent on the length of the fracture-perforation-intersection, h_{int}, which is not dependant on the perforation density. If the halo radius was greater then we could get a few more perforations and the velocity would be slightly reduced.
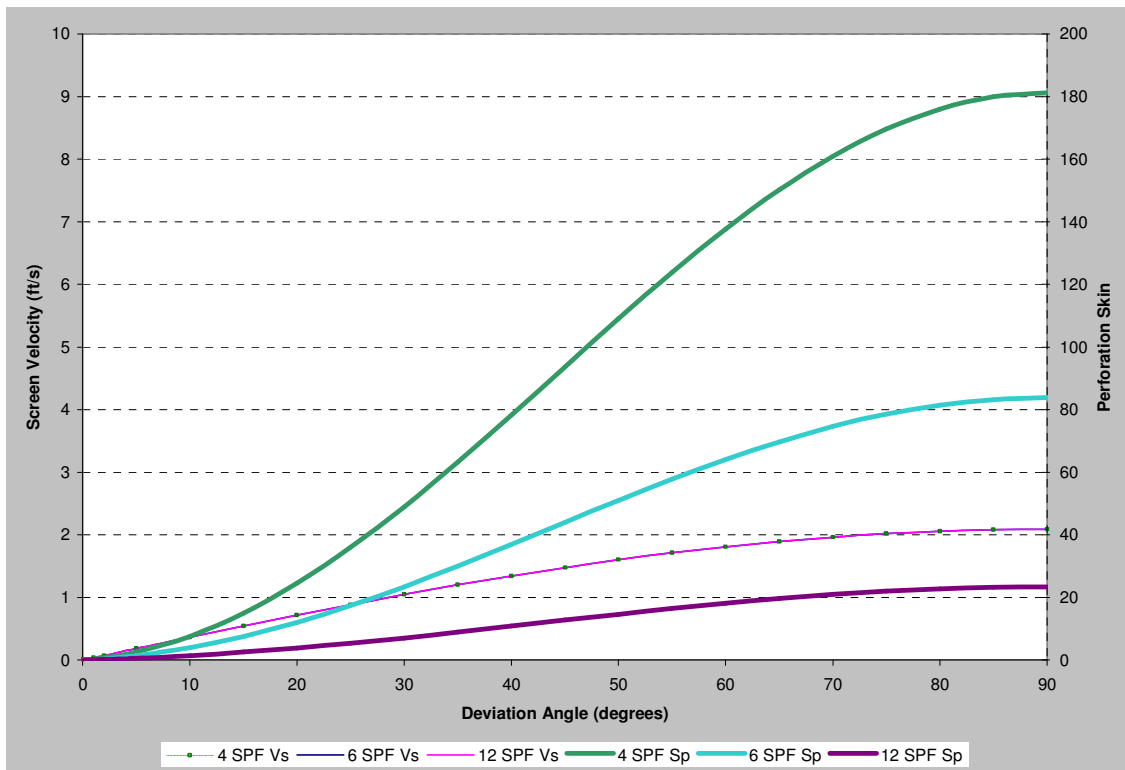

Figure 3.4 FP perforation skin and screen velocity for larger perforation densities, assuming 90° angle between wellbore and main fracture planes

It can be seen from Fig. 3.4 that the perforation skin is never less than zero. However, the total skin can be less than zero as it is composed of different skin components.

For the field example from Chapter II the screen velocity is 0.7 ft/sec. Therefore, this well is not at risk. However, the literature indicates that a number of HPF wells have failed due to screen erosion. A close look revels that in most or all of the reported cases the wells were inclined.

3.5 HPF in Dipping Reservoirs

Welling[10] indicates that field matches for FP completions suggest that 0.7 to 2.3 SPF are flowing in deviated wells and concludes that flow in high rate oil and gas wells in high permeability reservoirs is perforation limited. Therefore, he prefers HRWP completions because field matches show on average 5 SPF are flowing except for highest permeability reservoirs, in which he recommends OHGP. Fig. 1.1 assumes that the fracture plane is completely aligned with the wellbore with both fracture wings. This will only be true when the wellbore and the fracture plane coincide. For deviated wells, in order to have wellbore totally connected with the fracture; the well azimuth must normal to the minimum horizontal stress. Because of this we find very compelling the logic of drilling wellbores strategically to be in the fracture plane, so that it does not need to turn from the local wellbore stress to the far field stress. In most cases this would normally mean drilling the well vertically through the productive formation.

For dipping reservoirs, the generalization that maximum stress is likely to be vertical may not always hold. If the maximum stress direction is not vertical in a dipping reservoir, then geomechanical analysis must be done to determine the well trajectory that will ensure that the wellbore is aligned with the created fracture. The geomechanical analysis for dipping beds is considered beyond the scope of this study. However, what this work implies is that once a geomechanical study has determined the stress magnitudes and directions, then the well trajectory can be designed such that the wellbore will align with the hydraulic fracture plane.

3.6 Should OHGP Be Recommended in High Rate Gas Wells?

Welling[10] recommended using OHGP completion for oil wells if the reservoir permeability is above 900 md, and if it is above 600 md for high rate gas wells. This work shows that the Welling[10] equations are correct but he makes two errors in applying them. The first error is that his perforation count is not correct. For HPF in inclined wells the perforation count can be much less than he assumes. The second error was when matching field behavior Welling[10] reduced the gravel permeability to compensate for the excessive number of perforations. The model in this work agrees with the field case shown.

If the number of perforations connected to fracture are properly counted (by using Eq. 3.1) then HPF would result in lower skin than OHGP completion skin. This confirms that the HPF completion is a better

choice than OHGP completion. Also, OHGP completions are not practicable in high permeability unconsolidated formations due to the wellbore instability.

3.7 Chapter Summary

If the wellbore trajectory is vertical through the pay zone almost always the wellbore will be aligned with the hydraulic fracture plane. For deviated wells, in order to have wellbore entirely connected with the fracture; the well azimuth must be normal to the minimum horizontal stress. Therefore the horizontal stress measurement must be determined before drilling the wellbore section through the productive interval.

If the well is deviated and not drilled perpendicularly to the minimum horizontal stress direction then potential for screen erosion and annular pack destabilization is high because of limited fracture to well connectivity. All flow will be forced to pass through a few perforations. Equations were developed showing the number of perforations connecting the fracture and the wellbore, and the total skin for HPF deviated well.

In inclined wells it is important to properly count number of perforations connected to fracture. HPF completion will result in lower skin than a OHGP completion.

For dipping beds, the maximum stress may not be strictly vertical. However, advanced geomechanical study can reveal the minimum stress direction so that the well can be drilled normal to this direction. With this strategy the wellbore will be aligned with the hydraulic fracture.

CHAPTER IV

SUMMARY, CONCLUSIONS, AND
RECOMMENDATIONS FOR FUTURE WORK

4.1 Summary and Conclusions

Often existing completion practices do not lead to optimal well performance, and well production is constrained to avoid high velocity and drawdown which could cause premature completion failure. The resulting skin in HPF wells was almost always positive which is contradictory to the theoretical skin definition for hydraulically fractured wells. The main reason for poor completion and high mechanical skin in HPF wells was the fracture-to-well connectivity. Most of the wells in deepwater GOM are deviated and are not drilled perpendicularly to the minimum horizontal stress.

In this work we recommended high permeability fracture (HPF) completions. HPF completions are superior to any other, provided the far-field fracture is in the plane of the wellbore. By selecting, properly designing and executing the HPF the resulting mechanical skin should be negative. The well productivity is increased; the well is safely produced at its maximum achievable flow rate, the risk of sand production is minimal, or even impossible. Also, high rate gas wells will benefit from HPF by minimizing the turbulence effects. The full set of equations was given for proper HPF well design. The deviation between the proposed model and the real well performance should be negligible, unless some obvious details were overlooked or the HPF execution phase did not go as planned. A new and more accurate calculation of the theoretical skin and flow velocity for HPF completion for deviated wells was given.

The vertical well through the net pay is the best option. In most cases, this will ensure that the fracture plane and the wellbore are aligned, and that, therefore, fracture-to-well connectivity is good. Since the high permeability reservoirs are usually prone to compaction, the vertical well will be a better choice than a deviated well. If the vertical well trajectory can not be selected, then the stress measurement should be done and the well should be drilled along the maximum horizontal stress. If the well is inclined it is important to properly count number of perforations connected to fracture. If the stress measurement was not interpreted and applied it must not be assumed that the fracture is connected entirely to the wellbore.

4.2 Recommendations, Comments, and Future Work

The future work on this topic should consider mechanisms for further improvements in selected completion design. In order to ensure that the HPF is properly designed, this method should be checked against the empirical data from the wells. A halo effect possibility is still in research. Even though the halo effect existence is confirmed in soft reservoirs, drilling the vertical wells would be preferred over inclined in this case.

As an alternative the new well surveillance method can be developed which would ensure that the well is operated safely in the case that the completion method is not selected properly, or the completion execution was not successful. The current surveillance method has many assumptions, it is not applicable to various applications, and is not reliable in most cases. With the industry evolution there might be new screen which could withstand higher erosion velocity. If so, the well flow rate could be increased.

Since a significant number of wells are inclined without a stress measurement, the fracture choking is likely. There is no satisfactory PTA model for choked fracture flow. Development of this model would help operators to properly examine existing wells performance.

Correlations for critical fines movement for different formations should be developed. Correlation would help to determine critical fines movement velocity. Since many wells are not cored having the critical velocity result prior to well completion would aid for further well completion decisions.

NOMENCLATURE

a	=	Laminar pressure drop factor in reservoirs without skins, dimensionless
b	=	Turbulent pressure drop factor, dimensionless
A_{GP}	=	Flow area at the sand face for gravel pack completion, ft^2
A_{HPF}	=	Flow area of the fracture face, ft^2
A_p	=	Perforation cross sectional area, ft^2
B	=	Oil formation volume factor, RB/STB
C	=	Erosion factor, dimensionless
C_{fD}	=	Dimensionless fracture conductivity, dimensionless
h_f	=	Fracture height, ft
h_{inc}	=	Total measured thickness, ft
h_{int}	=	Length of the fracture-perforation-intersection, ft
H_{of}	=	Open flow length, ft
h_p	=	Perforated interval ft
H_{tot}	=	Total thickness, ft
K	=	Reservoir permeability, md
k_{cake}	=	Filter cake permeability, md.
k_f	=	Average fracture permeability, md
k_{fl}	=	Fluid loss zone permeability, md
k_{gr}	=	Gravel permeability, md
k_p	=	Perforation permeability, md
L_g	=	Connection flow length (difference between drilled radius and screen radius), ft
L_p	=	Perforation length, ft
Q	=	Volumetric gas production rate, MSCFD
Q	=	Volumetric oil production rate, BOPD
r_{cake}	=	Filter cake radius, ft
r_d	=	Radius of drilling and completion induced damage, ft
r_{egp}	=	Radius of extended gravel pack, ft
r_{fl}	=	Fluid loss radius, ft
r_g	=	Under reamed radius, ft
r_h	=	Halo radius, ft
r_{oc}	=	Outside screen radius, ft
r_p	=	Perforation radius, ft
r_s	=	Screen radius, ft

r_w	=	Wellbore radius, ft
S_{cake}	=	Filter cake skin, dimensionless
S_{fl}	=	Fluid loss skin, dimensionless
S_{gr}	=	Gravel skin, dimensionless
S_{pl}	=	Partial completion skin, dimensionless
V_c	=	Flow velocity existing casing, ft/sec
$v_{c,SF}$	=	Critical flow velocity for single phase fluid, ft/sec
V_{EGP}	=	Formation flow velocity into the extended gravel pack completion, ft/sec
V_i	=	Injected proppant volume, ft^3
V_{pmax}	=	Maximum perforation velocity, ft/sec
V_s	=	Flow velocity at the screen surface, ft/sec
V_{SF}	=	Velocity at the fracture face, ft/sec
W	=	Average fracture width, ft
x_f	=	Fracture half length, ft
x_{fA}	=	Fracture flow area, ft^2

Greek Letters

β	=	Angle between the fracture plane and the plane of the wellbore axes, degree
β_{goil}	=	Turbulence factor for gravel when oil is flowing, 1/ft
μ	=	Fluid viscosity, cp
α	=	Wellbore deviation from vertical, degree
ρ_m	=	Fluid mixture density, lbs/ft^3

REFERENCES

1. Wong, G.K., Fair, P.S., Bland, K.F., and Sherwood, R.S.: "Balancing Act: Gulf of Mexico Sand Control Completions, Peak Rate Versus Risk of Sand Control Failure," Paper SPE 84497 presented at the 2003 SPE Annual Technical Conference and Exhibition, Denver, CO, 5-8 October.

2. Colwart, G., Burton, R.C., Eaton, L.F., Hodge, R.M., and Blake, K.: "Lessons learned on Sand-Control Failure, and subsequent Workover at Magnolia Deepwater Development," Paper SPE 105542 presented at the 2007 SPE/IADC Drilling Conference, Amsterdam, Netherlands, 20-22 February.

3. Tiffin, D.L, Stein, M.H., and Wang, X.: "Drawdown Guidelines for Sand Control Completions," Paper SPE 84495 presented at the 2003 SPE Annual Technical Conference and Exhibition, Denver, CO, 5-8 October.

4. Yew, C.H. and Li, Y.: "Fracturing of a Deviated Well," Paper SPE 16930 presented at the 1987 SPE Annual Technical Conference and Exhibition, Dallas, TX, 27-30 September.

5. Veeken, C.A.M., Davies, D.R., and Walters, J.V.: "Limited Communication Between Hydraulic Fracture and (Deviated) wellbore," Paper SPE 18982 presented at the 1989 SPE Joint Rocky Mountain Regional/Low Permeability Reservoirs Symposium and Exhibition, Denver, CO, 6-8 March.

6. Cleary, M.P., Johnson, E.D., Kogsboll, H.H., *et al*.: "Field Implementation of Proppant Slugs To Avoid Premature Screen-Out of Hydraulic Fractures With Adequate Proppant Concentration," Paper SPE 25892 presented at the 1993 SPE Joint Rocky Mountain Regional/Low Permeability Reservoirs Symposium and Exhibition, Denver, CO, 12-14 April.

7. Furgier, J.N., Lavoix, F., and Lemesnager, F.: "Pushing the Limits of Frac-Pack Operating Envelope," Paper SPE 107699 presented at the 2007 SPE European Formation Damage Conference, Scheveningen, The Netherlands, 30 May-1 June.

8. Behrmann, L.A. and Elbel, J.L.: "Effect on Perforations on Fracture Initiation," Paper SPE 20661 presented at the 1990 SPE Annual Technical Conference and Exhibition, New Orleans, LA, 23-26 September.

9. Abass, H.H., Nasr-El-Din, H.R., and Ba Taweel, M.H.: "Sand Control: Sand Characterization, Failure Mechanisms, and Completion Methods," Paper SPE 77686 presented at the 2002 Annual Technical Conference and Exhibition, San Antonio, TX, 29 September-2 October.

10. Welling, R.W.F.: "Conventional High Rate Well Completions: Limitations of Frac&Pack, High Rate Water Pack and Open Hole Gravel Pack Completions," Paper SPE 39475 presented at the 1998 SPE International Symposium on Formation Damage Control, Lafayette, LA, 18-19 February.

11. Keck, R.G., Colbert, J.R., and Hardham, W.D.: "The Application of Flux-Bases Sand-Control Guidelines to the Na Kika Deepwater Fields," Paper SPE 95294 presented at the 2005 SPE Annual Technical Conference and Exhibition, Dallas, TX, 9-12 October.

12. Dusterhoff, R.G. and Chapman, B.J.: "Fracturing High Permeability Reservoirs Increases Productivity," *Oil and Gas Journal* (1994) **92**, 25.

13. Tiner, R.L., Elly, J.W., and Schraufnagel, R.: "Frac Packs-State of the Art," Paper SPE 36456 presented at the 1996 SPE Annual Technical Conference and Exhibition, Denver, CO, 6-10 October.

14. Aggour, T.: "Optimization Strategies for Hydraulic Fracturing in High Permeability Reservoirs," Paper SPE 68131 presented at the 2001 SPE Middle East Oil Show, Bahrain, 17-20 March.

15. Mathur, A.K., Ning, X., Marcineau, R.B., Ehlig-Economides, C.A., and Economides, M.J.: "Hydraulic Fracture Stimulation of Highly Permeable Formations: The Effect of Critical Fracture Parameters on Oilwell Production," Paper SPE 30652 presented at the 1995 SPE Annual Technical Conference and Exhibition, Dallas, TX, 22-25 October.

16. Economides, M. J., Oligney, R.E., and Valkó, P.P.: *Unified Fracture Design* (hardbound) Orsa Press, Houston (2002).

17. Upchurch, E.R.: "Near-Wellbore Halo Effect Resulting From Tip-Screenout Fracturing: Direct Measurement and Implication for Sand Contol," *Oil and Gas Journal* (2001) **16**, 1.

18. Neumann, L.F., Pedroso, C.A., Moreira, L., and Bezerra de Melo, R.C.: "Lessons Learned from a Hundred Frac Packs in the Campos Basin," Paper SPE 73722 presented at the 2002 SPE International Symposium and Exhibition on Formation Damage Control, Lafayette, LA, 20-21 February.

19. Wang, X. and Economides, M.J.: "Aggressive Fracturing Slashes Turbulence in High-permeability Gas Wells," *World Oil* (2004) **225**, 7.

20. Economides, M.J. and Nolte, K.G.: *Reservoir Stimulation*, Third Edition, 750 p. (hardbound) John Wiley, New York (2000).

21. Gidley, J.L., Holditch, S.A., Nierode, D.A., and Veatch, R.W.: *Recent Advances in Hydraulic Fracturing*, Monograph Series, SPE, Richardson, TX (2001).

22. Martins, J.P., Abel, J.C., Dyke, C.G., Michel, C.M., and Stewart G.: "Deviated Well Fracturing and Proppant Production Control in the Prudhoe Bay Field," Paper SPE 24858 presented at the 1992 Annual Technical Conference and Exhibition, Washington, DC, 4-7 October.

23. Yew, C.H. and Schmidt, J.H.: "On Fracture Design of Deviated Wells," Paper SPE 19722 presented at the 1989 SPE Annual Technical Conference and Exhibition, San Antonio, TX, 8-11 October.

24. Economides, M. J., and Nolte, K.G.: *Reservoir Stimulation,* Second Edition*,* Prentice Hall, New Jersey (1989).

25. Chen, Z. and Economides, M.J.: "Effect of Near-Wellbore Fracture Geometry on Fracture Execution and Post-Treatment Well Production of Deviated and Horizontal Wells, " Paper SPE 39425 presented at the 1998 SPE Formation Damage Control Conference, Lafayette, LA, 18-19 February.

VITA

Name: Slavko Tosic

Permanent Address: Dr. Christine A. Ehlig-Economides

                                  3116 TAMU-710BA Richardson Building

                                  College Station, TX 77843-3116

                                  USA

E-mail Address: slavkony@hotmail.com

Education: Texas A&M University, College Station, Texas, USA

                                  Master of Science Degree in Petroleum Engineering

                                  October 2007

                                  University of Mining and Geology, Belgrade, Serbia and Montenegro

                                  B.S. in Petroleum Engineering

                                  April 2001

Affiliations: Society of Petroleum Engineers