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Appendix 2 SPE Paper 38593 – “Water-Fracturing vs. Frac-Packing: Well Performance Comparison and Completion Type Selection Criteria.

Appendix 3 SPE Paper 31147 – “Gravel Placement in Horizontal Wells”

Appendix 4 Petroleum Engineer Article – Applied Technology and Management
Introduction

The completion phase of well operations begins when drilling is completed, and ends when the well is brought on production. Typical completion operations include, but are not restricted to, perforating, placing gravel packs, acidizing, fracturing and setting production tubing and packers. The goal of these operations is to obtain a well which has a productivity that is not limited by the completion itself. While this sounds easy to accomplish, completion techniques are commonly used in many parts of the world that restrict the productivity of the well.

The issue of productivity is especially important in wells requiring sand control. Gravel packed wells are particularly sensitive to problems of extremely poor productivity if improper completion techniques are used. On the other hand, the implementation of recognized “best practices” can result in very acceptable productivity from gravel packed wells.

The purpose of this manual is to provide information on completion techniques for maximizing productivity and longevity of gravel packed wells. To achieve this purpose, the factors that can have a negative effect on the flow of fluids from a well should be understood. The nature of fluid flow towards a wellbore and a description of the potential restrictions to production are described in this chapter.

Radial Flow

The flow of fluids towards a well is governed by the principles of fluid flow through porous media. Darcy’s Law states that the flow of fluids through porous material is controlled by the pressure gradient from the virgin formation to the wellbore, the viscosity of the flowing fluid and the area available for flow in the formation. The constant of proportionality between pressure drop and flow rate is called permeability.
Chapter 1

RADIAL FLOW AND FORMATION DAMAGE

Figure 1.1
Radial Flow Geometry
The permeability of a formation is a measure of the available flow area within a given cross-sectional area of porous material. In a linear flow situation, the flow area is constant, and therefore the pressure drop required to induce a given flow rate is constant. However, fluids flowing toward a well do not represent a linear flow situation and are usually modeled more accurately as radial flow. Under radial flow conditions the area available for flow continuously decreases as the fluid gets nearer to the wellbore, as illustrated in Figure 1.1. As the flowing fluid approaches the wellbore, the decreasing area available for flow causes an increasing velocity of flow, with a corresponding increase in pressure drop. The equation below is Darcy’s Law for radial flow expressed in oilfield units. This equation can be used to examine the pressure changes surrounding a flowing well.

\[ p_i = p_e - \frac{141.2qB_o\mu}{kh} \ln\left(\frac{r_e}{r_i}\right) \]

where:
- \( p_i \) = pressure at point of interest (pounds per square inch)
- \( p_e \) = pressure at drainage radius of well (pounds per square inch)
- \( q \) = production rate (stock tank barrels of oil per day)
- \( B_o \) = formation volume factor of produced oil (reservoir barrels per stock tank barrel)
- \( \mu \) = viscosity of produced fluids (centipoise)
- \( k \) = formation permeability (millidarcies)
- \( h \) = thickness of the reservoir (feet)
- \( r_e \) = drainage radius of well (feet)
- \( r_i \) = radial distance from wellbore to the point of interest (feet)

The results of using this formula are illustrated in the graphs of Figure 1.2 for an oil well with a 200 millidarcy formation permeability that is flowing at 5000 stock tank barrels per day. The graph on the right is a detail plot of the left hand graph, and shows that the total pressure drop is equal to the reservoir pressure (approximately 2700 pounds per square inch), minus the pressure at the wellbore (approximately 2070 pounds per square inch), giving a total pressure loss across the area near the wellbore of 630 pounds per square inch. Notice that almost half of the 630 pounds per square inch of total pressure drop occurs within the 10 feet nearest the wellbore, and that more than 100 pounds per square inch of pressure drop occurs within a 1 foot radius of the wellbore.
Near Wellbore Flow Restrictions

Because most of the pressure drop takes place in the area very near the wellbore, this same area is where any additional restrictions to flow have the most detrimental effect. Two factors that affect the increase of this pressure drop are the amount of the permeability impairment, which is measured as a permeability reduction, and the radial thickness of the impaired or damaged area. Using the equation below to calculate the additional pressure drop associated with a near wellbore flow restriction, Figure 1.3 illustrates the additional pressure drop that is created by reducing the permeability surrounding a wellbore from 1000 millidarcies to 100 millidarcies. The different curves on this figure represent increasing radial distances of permeability damage ranging from 6 inches to 5 feet.

\[
\Delta p_{\text{skin}} = \frac{141.2 \, q B_o \mu}{k h} \left( \frac{k}{k_s} - 1 \right) \ln \left( \frac{r_s}{r_w} \right)
\]

where:
- \( \Delta p_{\text{skin}} \) = pressure drop through the damaged zone (pounds per square inch)
- \( q \) = production rate (stock tank barrels of oil per day)
- \( B_o \) = formation volume factor of produced oil (reservoir barrels per stock tank barrel)
- \( \mu \) = viscosity of produced fluids (centipoise)
- \( k \) = formation permeability (millidarcies)
- \( k_s \) = damaged zone permeability (millidarcies)
- \( h \) = thickness of the reservoir (feet)
- \( r_s \) = radius of damage (feet)
- \( r_w \) = radius of wellbore (feet)

This plot indicates that, as expected, the total system pressure drop increases with increasing depth of damage. However, the plot also illustrates that the majority of the increase in pressure drop is within a foot or so of the wellbore.
The other factor that determines the magnitude of damage is the permeability of the damaged zone. Figure 1.4 indicates the pressure drop increase associated with a damaged zone which has a radial depth of 2 feet. The damaged zone consists of material with a permeability of 100 millidarcies, 50 millidarcies and 25 millidarcies, which is equivalent to 10, 5 and 2.5 percent of the permeability of the virgin formation. Comparison of Figures 1.3 and 1.4 indicate that severe permeability impairment near the wellbore is much more detrimental than is moderate damage deep into the formation.
The importance of severe permeability impairment can be shown by a calculation of the damaged productivity of a well expressed as a ratio of the undamaged productivity. This ratio is calculated as a function of the radial thickness of the damaged zone and the degree of permeability reduction by the following equation:

\[
\frac{J_s}{J_o} = \frac{k_s}{k_o} \log \left( \frac{r_e}{r_w} \right) \log \left( \frac{r_s}{r_w} \right)
\]

where:
- \( J_s \) = productivity index of damaged well (produced stock tank barrels per day per pound per square inch of drawdown)
- \( J_o \) = productivity index of undamaged well (produced stock tank barrels per day per pound per square inch of drawdown)
- \( k_s \) = permeability of damaged zone (millidarcies)
- \( k_o \) = permeability of undamaged formation (millidarcies)
- \( r_e \) = drainage radius of well (feet)
- \( r_w \) = wellbore radius (feet)
- \( r_s \) = damaged zone radius (feet)

Figure 1.5 shows the results when this equation is plotted against the damaged zone radius for different degrees of damage. This figure further supports the critical influence of permeability reductions very close to the wellbore.
The permeability impairment surrounding a well is called “skin factor”, which is a dimensionless representation of the additional pressure drop across the near wellbore formation associated with the flowing of fluids through a near wellbore damaged zone. The following equation illustrates how the dimensionless skin factor relates to this increased pressure drop.

\[ s = \frac{0.00708kh \Delta p_{\text{skin}}}{q \mu B_o} \]

where:
- \( s \) = skin factor
- \( k \) = formation permeability (millidarcies)
- \( h \) = interval thickness (feet)
- \( \Delta p_{\text{skin}} \) = pressure drop through the damaged zone (pounds per square inch)
- \( q \) = flow rate (stock tank barrels per day)
- \( \mu \) = fluid viscosity (centipoise)
- \( B_o \) = formation volume factor of produced oil (reservoir barrels per stock tank barrel)

If the calculated skin number is positive, there is an increased pressure drop around the well and the well is considered to be damaged. On the other hand, if a negative skin is calculated, there is a zone of increased permeability present, typical of a stimulated well. Skin factors can range from about -6 to any positive number. Skin factors from +25 to +50 in high permeability formations are not uncommon.
The effect of formation damage can be approximated through the concept of flow efficiency. This is a measure of the relative percentage of the theoretical flow rate that can actually flow through a formation. The following equation presents an approximate method for calculating flow efficiency.

\[
FE = 100 \left(\frac{q_s}{q_o}\right) = 100 \left(\frac{\ln\left(\frac{r_e}{r_w}\right)}{s + \ln\left(\frac{r_e}{r_w}\right)}\right) = 100 \left(\frac{8}{s + 8}\right)
\]

where:
- \(FE\) = flow efficiency (percent)
- \(q_s\) = flow rate from damaged well (stock tank barrels per day)
- \(q_o\) = hypothetical flow rate possible from undamaged well (stock tank barrels per day)
- \(r_e\) = drainage radius of well (feet)
- \(r_w\) = wellbore radius (feet)
- \(s\) = skin factor
The approximation of 8 for the term \( \ln(r_e/r_w) \) results from the fact that the natural log of a large number divided by a small number is approximately 8. Based on this equation, a well with a skin of +20 will have a flow efficiency of only about 28 percent.

Skin factor is only a relative measure of an additional pressure drop in the flowing system. Skin factor does not distinguish between a near wellbore severely damaged zone and a deeper moderately damaged zone.

**Potential Formation Damage Mechanisms**

Skin is strictly a measure of an excess pressure drop in the producing formation as fluids flow into a well. This excess pressure drop can occur from any one or several of a wide variety of causes. Various damage mechanisms can be classified into the following general categories:

- drilling mud, cement and completion fluid filtrate invasion
- solids invasion
- perforating damage
- fines migration
- swelling clays
- asphaltene/paraffin deposition
- scale precipitation
- emulsions
- reservoir compaction
- relative permeability effects
- effects of stimulation treatments

The critical factor from a well completions standpoint is to limit, where possible, the creation of damage, especially severe plugging in the near wellbore area. This means avoiding plugging of the perforations in a cased-hole completion and avoiding plugging of the formation face in an open-hole completion. Methods to avoid plugging will be described later in this manual. Beyond taking steps to eliminate severe permeability reduction in the near wellbore area, the next step in a completion is to obtain the best possible communication of the wellbore with the virgin formation. Methods to bypass damage in the area near the wellbore will also be detailed in a later chapter.

**Summary**

Reducing or eliminating near wellbore reductions in permeability are critical to the success of any well completion. Wells requiring sand control are especially susceptible to near wellbore damage since the primary technique for controlling sand production, gravel packing, requires the introduction of additional fluids and gravel pack sand into the near wellbore area. Furthermore, once a gravel pack is in place, opportunities to clean-up the near wellbore area by flowing the well, acidizing or reperforating are somewhat limited. Therefore, the best approach to a
successful gravel pack completion is to ensure that minimal formation damage occurs from the moment the drill bit enters the pay zone until the well is brought on production.

References


CAUSES AND EFFECTS OF SAND PRODUCTION

Introduction

Chapter 1 addressed radial flow through porous media and showed the nature of the pressure distribution around a producing well. Negative effects on productivity caused by flow restrictions in the near wellbore area have been described. With the concepts of radial flow and formation damage understood, the problems unique to unconsolidated formations can be explored.

In highly unconsolidated formations, the production of formation fluids will probably be associated with the production of formation sand. In some situations, small quantities of formation sand can be produced with no significant adverse effects; however, in most cases, sand production leads to reduced productivity and/or excessive maintenance to both downhole and surface equipment. Sufficient sand production may also cause premature failure of the wellbore and well equipment.

Nature of Sand Production

The conditions which can cause sand production and the probable condition of the formation outside of the casing after sand is produced can be determined by the factors that affect the beginning of sand production. These factors must describe both the nature of the formation material and also the forces that cause the formation structure fail.

The strength of a sandstone is controlled by:

- The amount and type of cementing material holding the individual grains together
- The frictional forces between grains
- Fluid pressure within the pores of the rock
- Capillary pressure forces

The type of failure that is likely to occur in sandstone has been investigated by several researchers. Work at Exxon\(^1\) indicates that the nature of a failed perforation tunnel is indicative of a shear failure that will occur when the compressive strength of the rock is exceeded. In addition, the Exxon work indicates that in weakly consolidated sandstones, a void is created behind the casing. Exxon concluded that the rock’s compressive strength should be a good indicator of sand production potential, and that sand production will probably cause a void behind the casing that can be filled with gravel pack sand during a gravel packing operation. The details of the research work performed by Exxon may be found in Reference 1.
In general, the compressive strength of a rock is primarily controlled by the intergranular frictional forces, therefore, the strength of the rock will increase as the confining stress on the rock increases. In the situation of failure of the rock matrix surrounding a perforation tunnel, the rock will be in an unconfined state of stress, so sand production should be related to the unconfined compressive strength of the rock. The degree of consolidation (intergranular cementation) will be more important than intergranular frictional forces. The stresses that cause the rock to fail in this situation include the mechanical stress resulting from the overburden material, and the drag forces associated with the flow of viscous fluids through the rock matrix. The overburden stress is partially supported by the pore pressure within the rock; so the stress actually working to cause failure of the rock (i.e., the effective stress) is the difference between the overburden stress and the pore pressure.

The mechanical failure of unconsolidated rock surrounding a perforation is analogous to the failure of a loose material surrounding a tunnel in soft earth. The mechanism for load transfer surrounding a tunnel in such a situation was described by Terzaghi\(^2\) in 1943. As the earth material over the tunnel yields, the stress originally held in the yielded material is relieved and transferred to the more rigid material surrounding the tunnel. However, a portion of the original stresses is supported by intergranular friction above the tunnel. In tunneling operations, if there is no intent to provide internal support to the tunnel, then the common practice is to excavate a tunnel height approximately twice the tunnel width to create a stable arch so that the material above the tunnel will not collapse (see Figure 2.1). The arch is made more stable through the presence of cohesive forces as well as from surface tension stresses if the granular material is wet.

An altered state of stress exists in the material above a tunnel. This altered state of stress extends to a height above the tunnel approximately five times the width of the tunnel. The material in the area that is more than five times the width of the tunnel base above the tunnel does not feel any of the effects of the excavation, and remains in its original stress state.

![Figure 2.1](image.png)

**Figure 2.1**

*Loading of a Tunnel Support in Sand\(^6\)*
To a certain extent, the arching concepts used in tunneling apply to the unconsolidated rock surrounding a perforation. After some sand is produced from around a perforation tunnel, an arch is formed that has sufficient strength to support the weight of the surrounding material. Under certain conditions, the production of a limited amount of formation sand can be tolerated to allow an arch to develop, after which the production of formation sand ceases. Figure 2.2 illustrates the concept of a stable arch around a perforation; however, the stability of the arch is complicated by the fact that the state of stress surrounding the perforation is constantly changing due to changes in flow rate, reservoir pressure, producing water cut, etc.

**Figure 2.2**

Geometry of a Stable Arch Surrounding a Perforation

---

**Effects of Sand Production**

The effects of sand production are nearly always detrimental to the short and/or long term productivity of the well. Although some wells routinely experience “manageable” sand production, these wells are the exception, not the rule. In most cases, attempting to manage the effects of severe sand production over the life of the well is not an economically attractive or prudent operating alternative.

**Accumulation in Surface Equipment.** If the production velocity is great enough to carry sand up the tubing, the sand may become trapped in the separator, heater treater, or production pipeline. If a large enough volume of sand becomes trapped in one of these areas, cleaning will be required to allow for efficient production of the well. To restore production, the well must be shut-in, the
surface equipment opened, and the sand manually removed. In addition to the clean out cost, the cost of the deferred production must be considered.

If a separator is partially filled with sand, the capacity of the separator to handle oil, gas and water is reduced. For example, one cubic foot of sand in an oil/water separator with a 2 minute residence time will cause the separator to handle 128 fewer barrels of liquid per day. If the ratio of oil to water entering the separator is one to one (i.e., 50% water cut), the separator will deliver 64 fewer barrels of salable oil per day. At $18.00 per barrel, this adds up to $420,480.00 worth of oil per year that is not moving through the separator.

**Accumulation Downhole.** If the production velocity is not great enough to carry sand to the surface, the sand may bridge off in the tubing or fall and begin to fill the inside of the casing. Eventually, the producing interval may be completely covered with sand. In either case, the production rate will decline until the well becomes "sanded up" and production ceases. In situations like this, remedial operations are required to clean-out the well and restore production. One clean-out technique is to run a "bailer" on the end of slickline to remove the sand from the production tubing or casing. Since the bailer removes only a small volume of sand at a time, multiple slickline runs are necessary to clean out the well. Another clean-out operation involves running a smaller diameter tubing string or coiled tubing down into the production tubing to agitate the sand and lift it out of the well by circulating fluid. The inner string is lowered while circulating the sand out of the well. This operation must be performed cautiously to avoid the possibility of sticking the inner string inside the production tubing. If the production of sand is continuous, the clean-out operations may be required on a routine basis, as often as monthly or even weekly. This will result in lost production and increased well maintenance cost.

**Erosion of Downhole and Surface Equipment.** In highly productive wells, fluids flowing at high velocity and carrying sand can produce excessive erosion of both downhole and surface equipment leading to frequent maintenance to replace the damaged equipment. Figure 2.3 is a photograph of a section of screen exposed to a perforation that was producing sand. Figure 2.4 shows a choke that failed due to excessive erosion. If the erosion is severe or occurs over a sufficient length of time, complete failure of surface and/or downhole equipment may occur, resulting in critical safety and environmental problems as well as deferred production. For some equipment failures, a rig assisted workover may be required to repair the damage.
Collapse of the Formation. Large volumes of sand may be carried out of the formation with produced fluid. If the rate of sand production is great enough and continues for a sufficient period of time, an empty area or void will develop behind the casing that will continue to grow larger as more sand is produced. When the void becomes large enough, the overlying shale or formation sand above the void may collapse into the void due to a lack of material to provide support. When this collapse occurs, the sand grains rearrange themselves to create a lower permeability than originally existed. This will be especially true for a formation sand with a high clay content or wide range of grain sizes. For a formation sand with a narrow grain size distribution and/or very little clay, the rearrangement of formation sand will cause a change in permeability that may be
less obvious. In the case of an overlying shale collapsing, complete loss of productivity is probable. In most cases, continued long term production of formation sand will usually decrease the well’s productivity and ultimate recovery.

The collapse of the formation is particularly important if the formation material fills or partially fills the perforation tunnels. Even a small amount of formation material filling the perforation tunnels will lead to a significant increase in pressure drop across the formation near the well bore for a given flow rate.

 Causes of Sand Production

The solid material produced from a well can consist of both formation fines (usually not considered part of the formation’s mechanical framework) and load bearing solids. The production of fines cannot normally be prevented and is actually beneficial. Fines moving freely through the formation or an installed gravel pack are preferable to plugging of the formation or gravel pack. The critical factor to assessing the risk of sand production from a particular well is whether or not the production of load bearing particles can be maintained below an acceptable level at the anticipated flow rates and producing conditions which will make the well production acceptable.

The following list summarizes many of the factors that influence the tendency of a well to produce sand:

- Degree of consolidation
- Reduction in pore pressure throughout the life of a well
- Production rate
- Reservoir fluid viscosity
- Increasing water production throughout the life of a well

These factors can be categorized into rock strength effects and fluid flow effects. Each of these factors and their role in the prevention or initiation of sand production is discussed in the remainder of this chapter.

Degree of Consolidation. The ability to maintain open perforation tunnels is closely tied to how strongly the individual sand grains are bound together. The cementation of a sandstone is typically a secondary geological process and as a general rule, older sediments tend to be more consolidated than newer sediments. This indicates that sand production is normally a problem when producing from shallow, geologically younger Tertiary sedimentary formations. Such formations are located in the Gulf of Mexico, California, Nigeria, French West Africa, Venezuela, Trinidad, Egypt, Italy, China, Malaysia, Brunei, Indonesia and others. Young Tertiary formations often have little matrix material (cementation material) bonding the sand grains together and these formations are generally referred to as being “poorly consolidated” or “unconsolidated”. A mechanical characteristic of rock that is related to the degree of consolidation is called “compressive strength”. Poorly consolidated sandstone formations usually have a compressive strength that is less than 1,000 pounds per square inch. Additionally, even well consolidated sandstone formations may be changed by degrading the matrix material, which would allow sand
production. This can be the result of acid stimulation treatments or high temperature steam flood enhanced recovery techniques.

**Reduction of Pore Pressure.** As mentioned previously, the pressure in the reservoir supports some of the weight of the overlying rock. As the reservoir pressure is depleted throughout the producing life of a well, some of the support for the overlying rock is removed. Lowering the reservoir pressure creates an increasing amount of stress on the formation sand itself. At some point the formation sand grains may break loose from the matrix, or may be crushed, creating fines that are produced along with the well fluids. Compaction of the reservoir rock due to a reduction in pore pressure can result in surface subsidence. For example, the Ekofisk central platform in the North Sea is reported to have sunk 10 feet in its first 10 years of existence due to subsidence.
Production Rate. The production of reservoir fluids creates pressure differential and frictional drag forces that can combine to exceed the formation compressive strength. This indicates that there is a critical flow rate for most wells below which pressure differential and frictional drag forces are not great enough to exceed the formation compressive strength and cause sand production. The critical flow rate of a well may be determined by slowly increasing the production rate until sand production is detected. One technique used to minimize the production of sand is to choke the flow rate down to the critical flow rate where sand production does not occur or has an acceptable level. In many cases, this flow rate is significantly below the acceptable production rate for the well.

Reservoir Fluid Viscosity. The frictional drag force exerted on the formation sand grains is created by the flow of reservoir fluid. This frictional drag force is directly related to the velocity of fluid flow and the viscosity of the reservoir fluid being produced. High reservoir fluid viscosity will apply a greater frictional drag force to the formation sand grains than will a reservoir fluid with a low viscosity. The influence of viscous drag causes sand to be produced from heavy oil reservoirs which contain low gravity, high viscosity oils even at low flow velocities.

Increasing Water Production. Sand production may increase or begin as water begins to be produced or as water cut increases. Two possibilities may explain many of these occurrences. First, for a typical water-wet sandstone formation, some grain-to-grain cohesiveness is provided by the surface tension of the connate water surrounding each sand grain. At the onset of water production, the connate water tends to cohere to the produced water, resulting in a reduction of the surface tension forces and subsequent reduction in the grain-to-grain cohesiveness. Water production has been shown to severely limit the stability of the sand arch around a perforation resulting in the initiation of sand production. A second mechanism by which water production affects sand production is related to the effects of relative permeability. As the water cut increases, the relative permeability to oil decreases. This results in an increasing pressure differential being required to produce oil at the same rate. An increase in pressure differential near the wellbore creates a greater shear force across the formation sand grains. Once again, the higher stresses can lead to instability of the sand arch around each perforation and subsequent sand production.

Summary

The above discussion highlights the fact that the production of sand is a very complicated process that is controlled by the formation properties, the state of stress in the formation, and the fluid flow regime. Knowledge of these factors is often quite limited, hence the ability to predict sand production is a very imprecise process. However, there are methods available which attempt to predict the onset of sand production. These methods will be detailed in the next chapter.
References


PREDICTING SAND PRODUCTION

Introduction

Being able to predict whether a well will produce fluids without producing sand or predicting that some type of sand control will be required has been the goal of many completion engineers and research projects. In spite of the fact that there are a number of analytical techniques and guidelines developed to assist in determining if sand control is necessary, no technique has proven to be universally acceptable or completely accurate. In some geographic regions, guidelines and rules-of-thumb apply that have little validity in other areas of the world. At the current time, predicting whether a formation will or will not produce sand is not an exact science and more refinement is needed. Until better prediction techniques are available, the best way of determining the need for sand control in a particular well is to perform an extended production test with a conventional completion and observe if sand production occurs. Offset wells producing in the same formation, in the same field and under similar conditions are also a good indicator of the need for sand control.

Operational and Economic Influences

The difficulty of determining whether or not sand control is required in a given well is compounded when the well is drilled in an area where there is little or no producing experience and where the various reservoir factors are slightly different from previously exploited regions. Even if the reservoir and formation properties are almost identical to other developments, the operating conditions and risks may be such that different strategies apply. One example is a subsea project as opposed to a platform development. Here, the consequences and risks associated with sand production are significantly different due to differing cost and risk associated with remedial well operations. Hence, the decision to use a sand control technique is both an economic and operational decision that must be made with limited data. The decision is complicated by the fact that sand control techniques, such as gravel packing, are expensive and can restrict well productivity if not done properly. Therefore, gravel packing cannot be applied indiscriminately when the possibility for sand production from a well is unknown. Making the decision to gravel pack is not too difficult or risky if the formation material is either very hard or very weak. The difficulty arises when the strength of the formation material is neither strong nor weak, but is in the range between those two extremes. At that point the decision normally ceases to be primarily a technical issue but more of an economic and risk management exercise.
Formation Strength

The general procedure followed by most operators considering whether or not sand control is required, is to determine the hardness of the formation rock (i.e., the rock’s compressive strength). Since the rock’s compressive strength has the same units as the pressure drawdown in the reservoir, the two parameters can be compared on a one to one basis and drawdown limits for specific wells can be determined. Research performed at Exxon in the early 1970’s shows that there is a relationship between the compressive strength and the incidence of rock failure. These studies show that the rock failed and began to produce sand when the drawdown pressure is 1.7 times the compressive strength. As an example, a formation sand with a compressive strength of 1,000 pounds per square inch would not fail or begin to produce sand until the drawdown was about 1,700 pounds per square inch. The testing described was performed in the equipment illustrated in Figure 3.1 and an example of rock sample failure is shown in Figure 3.2. The correlation of the data from the research is shown in Figure 3.3. Other operators use Brinnell hardness of the rock as an indicator of whether to apply sand control. Actually, the Brinnell hardness of the rock is related to the compressive strength but is not as convenient to use since the units of hardness are dimensionless and cannot be related to drawdown as easily as compressive strength.

![Figure 3.1: Apparatus for Testing Failure of Rock with Pressure Drawdown](image-url)
Sonic Log

The sonic log can be used as a way of addressing the sand production potential of wells. The sonic log records the time required for sound waves to travel through the formation in microseconds. The porosity is related to the sonic travel time. Short travel times, (for example, 50 microseconds) are indicative of low porosity and hard, dense rock; while long travel times (for example, 95 microseconds or higher) are associated with softer, lower density, higher porosity rock. A common technique used for determining if sand control is required in a given geologic area is to correlate incidences of sand production with the sonic log readings. This establishes a quick and basic approach to the need for sand control, but the technique can be unreliable and is not strictly applicable in geologic areas other than the one in which it was developed.
Formation Properties Log

Certain well logs such as the sonic (as discussed above), density and neutron devices are indicators of porosity and formation hardness. For a particular formation, a low density reading is indicative of a high porosity. The neutron logs are primarily an indicator of porosity. A formation properties log is offered by several wireline logging companies that performs a calculation using the results of the sonic, density, and neutron logs to determine the likelihood of whether a formation will or will not produce formation material at certain levels of pressure drawdown. This calculation identifies which intervals are stronger and which are weaker and more prone to produce formation material. While the formation properties log has been used by some companies for over 15 years, the consensus is that this type of log is usually conservative in its predictions on the need for sand control.

Porosity

The porosity of a formation can be used as a guideline for the need for sand control. If the formation porosity is higher than 30 percent, the probability of a requirement for sand control is higher. Conversely, if the porosity is less than 20 percent, the need for sand control will probably be less. The porosity range between 20 to 30 percent is where uncertainty usually exists. Intuitively, porosity is related to the degree of cementation present in a formation; thus, the basis for this technique is understandable. Porosity information can be derived from well logs or laboratory core analysis.

Drawdown

The pressure drawdown associated with production may be an indicator of potential formation sand production. No sand production may occur with low pressure drawdown around the well whereas excessive drawdown can cause formation material to be produced at unacceptable levels. The amount of pressure drawdown is normally associated with the formation permeability and the viscosity of the produced fluids. Low viscosity fluids such as gas experience small drawdown pressures as opposed to the drawdown that would be associated with a 1,000 cp fluid produced from the same interval. Hence, higher sand production is usually associated with viscous fluids.

Finite Element Analysis

Probably the most sophisticated approach to predicting sand production is the use of geomechanical numerical models developed to analyze fluid flow through the reservoir in relation to the formation strength. The effects of formation stress associated with fluid flow in the immediate region around the wellbore are simultaneously computed with finite element analysis. While this approach is by far the most rigorous, it requires an accurate knowledge of the formation’s strength both in the elastic and plastic regions where the formation begins to fail. Both of these input data are difficult to determine with a high degree of accuracy under actual downhole conditions and that is the major difficulty with this approach. The finite element analysis
method is good from the viewpoint of comparing one interval with another; however, the absolute values calculated may not represent actual formation behavior.

### Time Dependence

Whether time has an effect on the production of formation sand is sometimes considered to be an issue; however, there is no data that suggests that time alone is a factor. There have been undocumented claims that produced fluids could possibly dissolve the formation’s natural cementing materials, but no data is available to substantiate these claims.

### Multiphase Flow

The initiation of multiphase fluid flow, primarily water and oil, can also cause sand production. Many cases can be cited where wells produced sand free until water production began but produced unacceptable amounts of formation material subsequent to the onset of produced water. The reasons for the increased sand production is caused by two primary phenomena: the movement of water-wet fines and relative permeability effects. Most formation fines are water wet and as a consequence are immobile when a hydrocarbon phase is the sole produced fluid because hydrocarbons occupy the majority of the pore space. However, when the water saturation is increased to the point that is also becomes mobile, the formation fines begin the move with the wetting phase (water) which creates localized plugging in the pore throats of the porous media. Additionally, when two-phase flow occurs, increased pressure drawdown is experienced as a consequence of relative permeability and increases the pressure drop around the well by as much as a factor of 4 to 5. The result of fines migration, plugging, and reduced relative permeability around the well increases the drawdown to the point that it may exceed the strength of the formation. The consequences may be excessive sand production.

### Summary

In some respects predicting the sanding potential of formations may be an academic exercise. Present technology can produce a calculation or other methodology to accurately determine whether sand control will be required in a particular well or reservoir. The irony of this situation is that at the point where the calculation or methodology has been developed and proven, the operator already knows whether sand control is necessary or not due to the producing experience gained while obtaining the necessary data for the calculations.

Experience has generally indicated that the best approach to completing wells, particularly in high productivity and high cost developments, is to avoid sand control in situations where the need for sand control is not clearly defined and where economics and risk analysis suggest that conventional (no sand control) alternatives are economically more attractive. Production experience from early wells should indicate whether this approach is correct. If sand control is in fact required, a few wells will have to be worked over; however, the sand control issue will be resolved once and for all and the remaining field development can proceed with a high degree of confidence in knowing the sand production tendencies of the formation. The exception to this argument is when water production is anticipated at some later date which may cause excessive sand production. If this event is anticipated, weighing whether to gravel pack the wells initially or
to wait until sand production occurs tends to be more of an economic exercise than a technical issue.
To summarize, the best technique for predicting sand control is the performance of the well in an extended production test. If such a test is not available, then existing technology, as discussed above, should be used to assess the sand producing tendencies of the formation. In the unfortunate event that applicable sand prediction techniques are inconclusive or borderline, the risk and economic analysis of not installing sand control can be evaluated to determine the type of well completion best suited for the formation and operating environment.

References


SAND CONTROL TECHNIQUES

Introduction
Numerous techniques are available for dealing with sand production from wells. These range from simple changes in operating practices to expensive completions such as sand consolidation and gravel packing. The sand control method selected depends on site specific conditions, operating practices and economic considerations. Some of the sand control techniques available are:

- Maintenance and workover
- Rate exclusion
- Selective completion practices
- Plastic consolidation
- High energy resin placement
- Resin coated gravel
- Slotted liner or screens without gravel packing
- Slotted liner or screens with gravel packing

Maintenance and Workover
Maintenance and workover is a passive approach to sand control. This method basically involves tolerating the sand production and dealing with its effects as and when necessary. Such an approach requires bailing, washing, and cleaning of surface facilities on a routine basis to maintain well productivity. This approach can be successful in specific formation and operating environments. The maintenance and workover method is primarily used where sand production is limited, production rates are low, risk of performing some service is low and economically feasible, or in marginal wells where the expense of other sand control techniques cannot be justified. Of importance are the formation characteristics which determine how much sand is produced and the effects on safety and productivity as discussed in Chapter 2.
Rate Exclusion

Restricting the well’s flow rate to a level which will reduce the sand production is a method used by some operators. The procedure is to sequentially reduce or increase the flow rate until an acceptable value of sand production is achieved. The object of this sand control technique is to attempt to establish a maximum flow rate possible in conjunction with a stable arch in the formation as discussed in Chapter 2. This is a trial and error approach that may have to be repeated from time to time as the reservoir pressure, flow rate and water cut change. The problem with rate exclusion as a sand control technique is that the flow rate required to establish and maintain a stable arch is generally less than the flow potential of the well and may represent a significant loss in productivity and revenue. For high rate production, this approach is impractical, not economical and unacceptable.

Selective Completion Practices.

As discussed in the section on formation strength in Chapter 3, the pressure drawdown required to produce a well can induce sand production if the magnitude of the drawdown is approximately 1.7 times the compressive strength of the formation. Application of this technique would be to produce only from the sections of the reservoir capable of withstanding the anticipated drawdowns. Perforating only the higher compressive strength sections of the formation allows higher drawdown. The high compressive strength sections will likely have the highest degree of cementation and, unfortunately, the lowest permeability. Therefore, the formation should have good vertical permeability to allow draining of the reservoir (see Figure 4.1).

![Figure 4.1](image-url)
Plastic Consolidation

Plastic consolidation involves the injection of plastic resins, which are attracted to the formation sand grains. The resin hardens and forms a consolidated mass, binding the sand grains together at their contact points. If successful, the increase in formation compressive strength will be sufficient to withstand the drag forces while producing at the desired rates.

Three types of resins are commercially available: epoxies, furans (including furan/phenolic blends), and pure phenolics. The resins are in a liquid form when they enter the formation and a catalyst or curing agent is required for hardening. Some systems use “internal” catalysts that are mixed into the resin solution at the surface and require time and/or temperature to harden the resin. Other systems use “external” catalysts that are injected after the resin is in place. The internal catalysts have the advantage of positive placement since all resin will be in contact with the catalyst required for efficient curing. A disadvantage associated with internal catalysts is the possibility of premature hardening in the workstring. The amounts of both resin and catalyst must be carefully chosen and controlled for the specific well conditions. Epoxy and phenolics can be placed with either internal or external catalysts; however, the rapid curing times of the furans (and furan/phenolic blends) require that external catalysts be used.

There are two types of plastic consolidation systems. These are called “phase separation” systems and “overflush” systems. Phase separation systems contain only 15 to 25 percent active resin in an otherwise inert solution. The resin is preferentially attracted to the sand grains leaving the inert portion that will not harden to fill the pore spaces. These systems utilize an internal catalyst which is mixed into the solution at the surface. Very accurate control of displacement is required to place the resin through the perforations. Overdisplacement will result in unconsolidated sand in the critical near wellbore area.

Phase separation systems may be ineffective in formations which contain more than 10 percent clays. Clays, which also attract the resin, have extremely high surface area in comparison to sands. The clays will attract more resin and because phase separation systems contain only a small percentage of resin, there may not be enough resin to consolidate the sand grains.

Overflush systems contain a high percentage of active resin. When first injected, the pore spaces are completely filled with resin, and an overflush is required to push the excess resin away from the wellbore area to reestablish permeability. Only a residual amount of resin saturation, which should be concentrated at the sand contact points, should remain following the overflush. Most overflush systems use an external catalyst, although some include an internal catalyst.

All plastic consolidation systems require a good primary cement job to prevent the resin from channeling behind the casing. Perforation density should be a minimum of 4 shots per foot to reduce drawdown and improve the distribution of plastic. Shaley zones should not be perforated. A clean system is essential for plastic consolidation treatments because all solids which are in the system at the time of treatment will be “glued” in place. The perforations should be washed or surged, workover rig tanks should be scrubbed and fluids should be filtered to 2 microns. Workstrings should be cleaned with a dilute HCl acid containing sequestering agents, and pipe dope should be used sparingly on the pin only. A matrix acid treatment, which includes HF and HCl is recommended for dirty sandstones.
Both phase separation and overflush systems require a multistage preflush to remove reservoir fluids and oil wet the sand grains. The first stage, generally diesel oil, serves to displace the reservoir oil. Epoxy resins are incompatible with water, and therefore, isopropyl alcohol follows the diesel to remove formation water. The final stage is a spacer which prevents the isopropyl alcohol from contacting the resin.

The main advantage of plastic consolidation is that it leaves the wellbore fully open. This becomes important where large OD downhole completion equipment is required. Also, plastic consolidation is suitable for through tubing applications, and may be applied in wells with small diameter casing. For many applications, the problems associated with plastic consolidation outweigh the possible advantages. The permeability of a formation is always decreased by plastic consolidation. Even in successful treatments, the permeability to oil is reduced because the resin occupies a portion of the original pore space, and because the resin is oil wet. The amount of resin used is based on uniform coverage of all perforations. However, perforation plugging or permeability variations will often cause some perforations to take more plastic than others. The perforations which received excess plastic may be plugged, and little, if any, strengthening will occur in the perforations not receiving resin. In systems which utilize an external catalyst, there will be no sand control in areas which are not contacted by both resin and catalyst.

The primary difficulty in using resin systems is complete and even placement of the chemicals in the formation. For this reason plastic consolidation is only suitable for interval lengths less than 10-15 feet. Longer intervals can be treated using packers to isolate and treat small sections of the zone at a time, but such operations are difficult and time consuming. Plastic consolidation treatments also do not perform well in formations with permeabilities less than about 50 millidarcies and/or bottom hole temperatures in excess of 225°F.

Plastic consolidation was used extensively in the late-1950’s through the mid-1970’s for completing wells in the Gulf of Mexico; however, this technique currently represents less than about 1% of all sand control completions worldwide. The reasons for decreased usage include the placement difficulties described above, as well as tight regulations on the handling of the chemicals, which are generally quite toxic (with the furans being the least toxic of the three). In addition, these treatments tend to have a high cost. Sand consolidation is used with good success in some fields in Africa where the formations meet the general screening criteria.

**High Energy Resin Placement**

As discussed above, one of the main reasons for the lack of acceptance of chemical consolidation techniques has been difficulties in placing the resin uniformly across the entire target interval, with problems being more severe in intervals greater than about 15 ft long. Causes for this are typically attributed to differences in injectivity caused by incomplete perforation clean-up during underbalanced perforating jobs or permeability variations in the formation interval length. By using a small amount of underbalance pressure, enough flow may be induced to bring formation sand into the perforation tunnel, but not enough to clean the tunnel.
A technique developed by Oryx,\(^1\) seeks to remedy this problem. In this new method the well is perforated, and resin is placed under highly *overbalanced* conditions. The resin is surged into the formation at rates that will place the resin before the formation has a chance to fail. Another benefit to the rapid resin placement is that this technique does not appear to be affected by permeability contrasts. This characteristic leads to more uniform placement over a long perforated interval.

Three methods are available for creating the high overbalance pressures that can assist resin placement. These are a propellant gas fracturing tool, overbalanced perforating, and overbalanced surging. Of these three techniques, the overbalanced perforating method is currently the method recommended by Oryx, when possible.

**Propellant Gas Fracturing.** The use of propellant gas fracturing tools involves the conversion of solid propellant by chemical reaction into a gas in the target zone of a wellbore.\(^1\) The chemical propellant is changed into combustion gases by one of two different mechanisms, detonation or flame propagation. Detonation involves a reaction characterized by a shock wave that moves rapidly through the interval to be treated. This shock wave, traveling as velocities between 15,000 and 25,000 feet per second, induces pressures ranging from 400 to 4,000,000 pounds per square inch, with pressurization rates up to 100,000 pounds per square inch per microsecond.

The flame propagation method is a much more controlled process. In this technique, the reaction proceeds without shock, at rates that can be as low as one foot per second, and pressures of only 100 pounds per square inch. Typical loadings for gas generators in this mode are approximately 1000 pounds per square inch per millisecond. This leads to a complete reaction event taking between 0.02 and 1.00 seconds.\(^1\)

The reaction products are contained in place by the liquid column in the wellbore above the tool (see Figure 4.2). The rapid generation of gas forces the resin placed in the annular space surrounding the tool out the perforations and into the formation. For this process to be successful, the casing must be in good condition and properly cemented; however, cementation is not as critical for this method as for the high-overbalanced perforating technique discussed later. Perforations must be clean and clear of debris, and all debris should be removed from the wellbore. Only clean sands should be perforated. Finally, if sand has been produced, the perforations should be prepacked with gravel prior to the treatment.

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\(^1\) Refer to the original source for detailed descriptions and technical specifications.
The process involved in completing a treatment of this type is to first pump a preflush to remove water from the target interval. Furan resin is then placed across the perforations, and the gas generating propellant tool is placed across the entire perforated interval. Nitrogen overbalance is applied to the workstring, and the propellant device is fired to inject resin above fracture pressure. The resin is then followed with an acid post flush to catalyze resin curing.

An advantage to this system is that resin will be placed in all perforations immediately across from the location of the gas generator tool. However, if multiple tool runs are required to treat an interval longer than about 36 feet, movement of the tool will make holding the resin in position difficult. The two methods of overbalanced perforating, and overbalanced surging are designed to alleviate the problem of maintaining the resin in position.

**Overbalanced Perforating or Surging.** High-overbalanced perforating resin placement (abbreviated as OB Perf Resin) may be used if the well has not been perforated. If a well has existing perforations, the interval can be prepacked and then the resin placed with a high pressure surge (OB Surge Resin). The description of these processes have been provided by Dees and Handren\(^2\) as follows:

The **OB Perf Resin** method is used when the casing has not been perforated in a wellbore suspected of being within an incompetent sand productive formation. Composition of the resin solution is furfuryl alcohol resin, solvent, coupling agent, and wetting agent. The resin catalyzes with an acid to form a furan plastic. The resin solution is positioned across an interval of planned perforations. A higher density fluid may precede below the resin to fill a portion of the wellbore below the zone of interest. A lower density fluid may follow above the resin in the wellbore to keep the resin from floating up above the zone of interest. This technique can ensure more accurate placement of resin across the interval soon to be perforated. Pressure in the wellbore fluid at the depth to be perforated is increased to a value higher than the pore pressure in the formation. This applied pressure before perforating may be higher than the formation fracturing pressure. Wireline through tubing or casing guns, or tubing conveyed perforating can all be used for perforating. Resin is forced into the new perforations upon perforating with the overbalanced pressure (see Figure 4.3). Acid is injected into the perforations to convert the liquid resin into a strong plastic that will consolidate the sand.
The **OB Surge Resin** method is used when the casing has existing perforations in a wellbore suspected of being within an incompetent sand productive formation. Tubing is used in the well with a means to hold high pressure differentials with a plug or frangible disk (see Figure 4.4). Additional resin placed in the tubing is pressured with gas such as nitrogen. Resin is forced into the perforations with the near instantaneous release of the overbalanced pressure surge. Acid injection into the perforations converts the liquid resin into a strong plastic consolidation of prepack gravel or formation sand.
An initial pressure pulse from the overbalanced fluid column drives a quantity of resin to fill adjacent perforations. The remainder of downhole resin is injected further into the formation by the overbalanced pressure condition. Additional resin from the surface is pushed into the formation by the pressure applied from a high pressure nitrogen or additional surface pumping with fluids. A subsequent acid overflush ensures setting, or cure, of the resin coating the formation sand near the wellbore.

Formation permeability is regained by displacement of resin with gas, brine spacer, and acid overflush. The displacement process leaves an oil-wet film of plastic to consolidate the friable formation sand grains. The thinness of the film leaves most of the original hydrocarbon permeability. Stimulation frequently occurs when the applied pressure fractures the formation sand. The sudden fluid surge of resin clears the perforations of formation sand and perforating debris. Formation sand near the well is left with an oil-wet coating of hard plastic resin acting as an external sand control screen.

**Resin Coated Gravel**

Resin coated gravel is high permeability gravel pack sand coated with a thin layer of resin. When exposed to heat, the resin is cured resulting in a consolidated sand mass. The use of resin coated gravel as a sand control technique involves pumping the gravel into the well to completely fill the perforations and casing. The bottomhole temperature of the well or injection of steam causes the resin to cure into a consolidated pack. After curing, the consolidated gravel pack sand can be drilled out of the casing leaving an unobstructed wellbore. The remaining consolidated gravel in the perforations acts as a permeable filter to prevent the production of formation sand.

Although simple in concept, using resin coated gravel can be a complex operation. First, and most important, a successful job requires that all perforations be completely filled with the resin coated gravel and the gravel must cure. Complete filling of the perforations becomes increasingly difficult as zone length and deviation increase. Secondly, the resin coated gravel must cure with sufficient compressive strength. The compressive strength of the resin coated gravel is dependent on temperature and time. Currently available systems will cure at temperatures exceeding 180°F after about 14 days; however, compressive strength is poor. To achieve high compressive strengths, temperatures in excess of 300°F are required for several hours. Such temperatures are difficult to achieve downhole unless the well is in a field utilizing thermal recovery techniques. Unfortunately, there is very little information on the use, success or failure of resin consolidated gravel as a sand control technique.
Slotted Liners or Screens without Gravel Packing

In some cases, slotted liners or screens are used without gravel packing to control the formation sand. Unless the formation is a well-sorted, clean sand with a large grain size, this type of completion may have an unacceptably short producing life before the slotted liner or screen plugs. When used alone as sand exclusion devices, the slotted liners or screens are placed across the productive interval and the formation sand mechanically bridges on the slots or openings in the wire wrap screen. Bridging theory shows that particles will bridge on a slot provided the width of the slot does not exceed two particle diameters. Likewise, particles will bridge against a hole if the hole diameter does not exceed about three particle diameters.

 Normally, the slot width or the screen gauge should be sized to equal the formation sand grain size at the largest 10 percent level. Chapter 5 contains details on determining formation grain size. Since the larger 10 percent of the sand grains will be stopped by the openings of screen, the remaining 90 percent of the formation sand will be stopped by the larger sand. The bridges formed will not be stable and may breakdown from time to time when producing rate is changed or the well is shut-in. Because the bridges can breakdown, resorting of the formation sand can occur which over time tends to result in plugging of the slotted liner or screen. When this technique is used to control formation sand, the slotted liner or screen diameter should be as large as possible to minimize the amount of resorting that can occur. Another potential disadvantage of both slotted liners and screens in high rate wells is the possibility of erosional failure of the slotted liner or screen before a bridge can form.

Using a slotted liner or screen without gravel packing is not recommended as a good sand control technique because some plugging will eventually occur and will almost always reduce the production capacity of the well. This reduction is caused by intermixing of formation sands, shales and clay as the formation sand is filling in around the screen. The mixture of sand, clay and shale may have much less permeability than the native formation sand. Note that this sand control technique is used extensively in horizontal wells and will be discussed in Chapter 15.

Slotted Liners and Screens with Gravel Packing

Gravel packing relies on the bridging of formation sand against larger sand with the larger sand positively retained by a slotted liner or screen. The larger sand (referred to as gravel pack sand or simply, gravel) is sized to be about 5 to 6 times larger than the formation sand. Gravel packing creates a permeable downhole filter that will allow the production of the formation fluids but restrict the entry and production of formation sand. Schematics of an open hole and cased hole gravel pack are shown in Figure 4.5. Because the gravel is tightly packed between the formation and the screen, the bridges formed are stable, which prevents shifting and resorting of the formation sand. If properly designed and executed, a gravel pack will maintain its permeability under a broad range of producing conditions.
Gravel packs are performed by running the slotted liner or screen in the hole and circulating the gravel into position using a carrier fluid. For optimum results, all the space between the screen and formation must be completely packed with high permeability gravel pack sand. Complete packing is relatively simple in open hole completions, but can be challenging in cased hole perforated completions. Although expensive, gravel packs have proven to be the most reliable sand control technique available and are, therefore, the most common approach used.

**Summary**

Many decisions involving sand control are made based on specific conditions and operating philosophy. Actually, the issue of sand production involves operations management. The best technical solution to sand control may not be the best economic solution. Whether a well produces formation sand may not be the issue. The real issue is which operating practice is the most economic for a particular field. If periodic sand clean-outs of the production equipment is the most economic approach for an operation, then clean-outs may be the method of choice. On the other hand, if high-rate wells are involved and there is risk of damaging equipment and creating a safety problem, sand production should be controlled in the well. Differences in operating strategy may also apply if the wells are onshore, in remote areas or located offshore. The sand control technique selected depends on the specific operating conditions. As a consequence, sand control management may involve dealing with a small amount of sand production if that approach is the most economically attractive and does not create unsafe operating conditions for personnel.
When sand control is required, gravel packing is the most common approach. Gravel packing can be applied in both open and cased hole completions, in well deviations from 0 to 110° and in zone lengths up to a few thousand feet. Systems are available for virtually any well temperature, pressure or environment. Gravel packed wells can be produced under high drawdown without concern of sand production. Although the gravel packing process can induce significant formation damage when not correctly performed, adherence to proper practices as well as advanced installation techniques can limit formation damage to acceptable levels.

References


GRAVEL PACK SAND DESIGN

Introduction

As discussed previously, a gravel pack is simply a downhole filter designed to prevent the production of unwanted formation sand. The formation sand is held in place by a properly sized gravel pack sand and the gravel pack sand is held in place with a properly sized screen. To determine what size gravel pack sand is required, samples of the formation sand must be evaluated to determine the median grain size diameter and grain size distribution. With this information a gravel pack sand can be selected using the technique outlined by Saucier.1 The quality of the sand used is as important as the proper sizing. The American Petroleum Institute (API) has set forth the minimum specifications desirable for a gravel pack sand in their Recommended Practices 58 (RP58).2

Formation Sand Sampling

Improper formation sand sampling techniques can lead to gravel packs which fail due to plugging of the gravel pack or the production of sand. Because the formation sand size is so important, the technique used to obtain a formation sample is also important. With knowledge of the different sampling techniques, compensations can be made in the gravel pack sand size selection if necessary.

Produced Samples. In a well producing sand, a sample of the formation sand is easily obtained at the surface. Although such a sample can be analyzed and used for gravel pack sand size determination, produced samples will probably indicate a smaller median grain size than the formation sand. The well’s flow rate, produced fluid characteristics and completion tubular design will influence whether a particular size of formation sand grain is produced to surface or settles to the bottom of the well. In many cases, the larger sand grains settle to the bottom, so that a sample that is produced to the surface has a higher proportion of the smaller size of sand grains. This means that the surface sample probably is not a good representation of the various sizes of formation sand which are present. Also, the transport of a sand grain through the production tubing and surface flow lines may result in small corners being broken from the sand grains, causing the presence of more fines and smaller grains. This is sometimes called grain shattering. Grain shattering also reduces the quantity of larger formation sand grains, giving the impression of a smaller median grain size than the formation sand actually has. The use of produced sand samples may result in the use of smaller gravel pack sand than required.
Bailed Samples. Samples collected from the bottom of a well using wireline bailers are also relatively easy to obtain, but these also are probably not representative of the actual formation sand. Bailed samples will generally consist of the larger size sand grains, assuming that more of the smaller grains are produced to surface. Bailed samples may also be misleading in terms of grain size distribution. When closing the well in to obtain a sample, the larger sand grains will settle to the bottom of the well first, and the smaller sand grains will fall on top of the larger ones. This results in a sorting of the formation sand grains into a sample which does not representative the formation sand. The use of bailed samples may result in the design of larger than required gravel pack sand which can result in sand production (small formation particles passing through the gravel pack) or plugging of the gravel pack (small formation particles filling the spaces between the gravel pack sand grains).

Sidewall Core Samples. Sidewall core samples are obtained by shooting hollow projectiles from a gun lowered into the well on an electric line to the desired depth. The projectiles remain attached to the gun via steel cables, so that when pulling the gun out of the well, the projectiles are retrieved with a small formation sample inside. Taking sidewall core samples is generally included in the evaluation stages of wells in unconsolidated formations and these are the most widely used sample type for gravel pack sand design. Although more representative than produced or bailed samples, sidewall core samples can also give misleading results. When the projectiles strike the face of the formation, localized crushing of the sand grains occurs, producing broken sand grains and generating more fine particles. The core sample may also contain drilling mud solids that can be mistaken for formation material. Experienced lab analysts can separate the effects of crushing and mud solids to some degree prior to evaluating the sample, thus improving the quality of the results.

Conventional Core Samples. The most representative formation sample is obtained from conventional cores. In the case of unconsolidated formations, rubber sleeve conventional cores may be required to assure sample recovery. Although conventional cores are the most desirable formation sample, they are not readily available in most cases due to the cost of coring operations. If available, small plugs can be taken under controlled circumstances at various sections of the core for a complete and accurate median formation grain size and grain size distribution determination.

Sieve Analysis

Sieve analysis is the typical laboratory routine performed on a formation sand sample for the selection of the proper size gravel pack sand. Sieve analysis consist of placing a formation sample at the top of a series of screens which have progressively smaller mesh sizes. The sand grains in the original well sample will fall through the screens until encountering a screen through which that grains size cannot pass because the openings in the screen are too small. By weighing the screens before and after sieving, the weight of formation sample retained by each size screen can be determined. The cumulative weight percent of each sample retained can be plotted as a comparison of screen mesh size on semi-log coordinates to obtain a sand size distribution plot as shown in Figure 5.1. Reading the graph at the 50 percent cumulative weight gives the median formation grain size diameter. This grain size, often referred to as $D_{50}$, is the basis of gravel pack...
sand size selection procedures. Table 1.1 provides a reference for mesh size versus sieve opening.

![Sand Size Distribution Plot from Sieve Analysis](image)

The samples used for sieve analysis must be representative of the formation if the analysis data is expected to provide accurate gravel packing information. If possible, a sample should be taken every 2 to 3 feet within the formation or at every lithology change. The minimum size of the formation sample required for sieve analysis is 15 cubic centimeters. Sieving can be performed either wet or dry. In dry sieving (the most common technique), the sample is prepared by removing the fines (i.e., clays) and drying the sample in an oven. If necessary, the sample is ground with a mortar and pestle to insure individual grains are sieved rather than conglomerate grains. The sample is then placed in the sieving apparatus, which uses mechanical vibration to assist the particles in moving through and on to the various mesh screens. Wet sieving is used when the formation sample has extremely small grain sizes. In wet sieving, water is poured over the sample while sieving to ensure the particles do not cling together.
Table 5.1
Standard Sieve Openings

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<tr>
<th>U.S. Series Mesh Size</th>
<th>Sieve Opening (in.)</th>
<th>Sieve Opening (mm)</th>
<th>U.S. Series Mesh Size</th>
<th>Sieve Opening (in.)</th>
<th>Sieve Opening (mm)</th>
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<td>10 0.0787 2.000</td>
<td>120 0.0049 0.124</td>
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<tr>
<td>12 0.0661 1.680</td>
<td>140 0.0041 0.104</td>
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<tr>
<td>14 0.0555 1.410</td>
<td>170 0.0035 0.088</td>
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<td></td>
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<tr>
<td>16 0.0469 1.190</td>
<td>200 0.0029 0.074</td>
<td></td>
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<td></td>
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<tr>
<td>18 0.0394 1.000</td>
<td>230 0.0024 0.062</td>
<td></td>
<td></td>
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<td></td>
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<tr>
<td>20 0.0331 0.840</td>
<td>270 0.0021 0.053</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>25 0.0280 0.710</td>
<td>325 0.0017 0.044</td>
<td></td>
<td></td>
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<td></td>
</tr>
<tr>
<td>30 0.0232 0.589</td>
<td>400 0.0015 0.037</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Gravel Pack Sand Sizing

There have been several published techniques for selecting a gravel pack sand size to control the production of formation sand. The technique most widely used today was developed by Saucier.¹ The basic premise of Saucier’s work is that optimum sand control is achieved when the median grain size of the gravel pack sand is no more than six times larger than the median grain size of the formation sand. Saucier determined this relationship in a series of core flow experiments where half the core consisted of gravel pack sand and the other half was formation sand as illustrated in Figure 5.2. The ratio of median grain size of the gravel pack sand and median grain size of the formation sand was changed over a range from two to ten to determine when optimum sand control was achieved.

Figure 5.2
Saucier’s Experimental Core
The experimental procedure consisted of establishing an initial stabilized flow rate and pressure drop through the core and calculating an effective initial permeability ($k_i$). The flow rate was increased and maintained until the pressure drop stabilized followed by a decrease in flow rate back to the initial value. Once again, pressure drop was allowed to stabilize and an effective final permeability ($k_f$) of the core was calculated. If the final permeability was the same as the initial permeability, a conclusion was made that effective sand control was achieved with no adverse productivity effects. If the final permeability was less than the initial permeability, the conclusion was made that the formation sand was invading and plugging the gravel pack sand. In this situation sand control may be achieved, but at the expense of well productivity. Figure 5.3 illustrates the results of the core flow experiments. As can be seen from the plot, the ratio of $k_f$ to $k_i$ decreases as the ratio of median gravel pack sand size to median formation sand size increases above six. Note that as the ratio of median gravel pack sand size to median formation sand size increases, the ratio of $k_f$ to $k_i$ begins to increase again. This indicates that the formation grain size is so small that formation grains begin to flow through the gravel pack sand without obstruction. This phenomena is known to occur, but was not verified as part of Saucier’s work.

In practice, the proper gravel pack sand size is selected by multiplying the median grain size of the formation sand by four and eight to achieve a gravel pack sand size range whose average is six times larger than the median grain size of the formation sand. This calculated gravel pack sand size range is compared to the available commercial grades of gravel pack sand. The available gravel pack sand that matches the calculated gravel pack size range is selected. In the event that the calculated gravel pack sand size range falls between the size ranges of commercially available gravel pack sand, the smaller gravel pack sand is normally selected. Table 5.2 contains information on commercially available gravel pack sand sizes.
### Table 5.2

<table>
<thead>
<tr>
<th>Gravel Size (U.S. Mesh)</th>
<th>Size Range (inches)</th>
</tr>
</thead>
<tbody>
<tr>
<td>8/12</td>
<td>.094 - .066</td>
</tr>
<tr>
<td>12/20</td>
<td>.066 - .033</td>
</tr>
<tr>
<td>20/40</td>
<td>.033 - .017</td>
</tr>
<tr>
<td>40/60</td>
<td>.017 - .0098</td>
</tr>
<tr>
<td>50/70</td>
<td>.012 - .0083</td>
</tr>
</tbody>
</table>

Note that Saucier’s technique is based solely on the median grain size of the formation sand with no consideration given to the range of sand grain diameters or degree of sorting, present in the formation. The sieve analysis plot discussed earlier can be used to get an indication of the degree of sorting in a particular formation sample. A near vertical sieve analysis plot represents a high degree of sorting (most of the formation sand is in a very narrow size range) versus a more nearly horizontal plot which indicates poorer sorting as illustrated by curves “A” and “D” respectively in Figure 5.1. A sorting factor, or uniformity coefficient, can be calculated as follows:

\[
C_\mu = \frac{D_{40}}{D_{90}}
\]

where:
- \(C_\mu\) = sorting factor or uniformity coefficient
- \(D_{40}\) = grain size at the 40% cumulative level from sieve analysis plot
- \(D_{90}\) = grain size at the 90% cumulative level from sieve analysis plot

If \(C_\mu\) is greater than five, the sand is considered to be poorly sorted and the next smaller size gravel pack sand than calculated using Saucier’s technique may be justified. Another method which can be applied when poorly sorted sand is encountered is to use the \(D_{75}\) grain size instead of \(D_{50}\) to calculate the appropriate gravel pack sand size.

### Gravel Pack Sand

Gravel pack well productivity is sensitive to the permeability of the gravel pack sand. To ensure maximum well productivity only high quality gravel pack sand should be used. The API RP58 establishes rigid specifications for acceptable properties of sands used for gravel packing. These specifications focus on ensuring the maximum permeability and longevity of the sand under typical well production and treatment conditions. The specifications define minimum acceptable standards for the size and shape of the grains, the amount of fines and impurities, acid solubility, and crush resistance. A summary of the API gravel test procedures and specifications are given in Table 5.3. Only a few naturally occurring sands are capable of meeting the API specifications without excessive processing. These sands are characterized by their high quartz content and consistency in grain size. A majority of the gravel pack sand used in the world is mined from the Ottawa formation in the Northern United States. Table 5.4 gives the permeability of common gravel pack sand sizes conforming to the API RP58 specifications.
### Table 5.3

**API Specifications for Gravel-Pack Sand**

<table>
<thead>
<tr>
<th>Specification</th>
<th>Details</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Sieve Analysis</strong></td>
<td>A minimum of 96% by weight of the tested sand sample should pass the designated course sieve and be retained on the designated fine sieve (with the designated course and fine sieves defined for specific size gravels in the RP58). Not over 0.1% of the total tested sample should be retained by the most coarse designated sieve and not over 2% of the total tested sample pass through the most fine designated sieve. No more than 1.9% of the total by weight should be retained by the second sieve screen (100% - 0.1% - 2% - 1.9% = 96%).</td>
</tr>
<tr>
<td><strong>Sphericity and Roundness</strong></td>
<td>Gravel pack sand should have an average sphericity of 0.6 or greater and an average roundness of 0.6 or greater as determined by visual analysis using the chart developed by Krumbein and Sloss (see Figure 5.4).</td>
</tr>
<tr>
<td><strong>Acid Solubility</strong></td>
<td>A 5 gram sand sample is added to 100 ml of 12%-3% HCl-HF acid and allowed to sit for one hour at 72°F to allow dissolution of contaminates (carbonates, feldspars, iron oxides, clays, silica fines etc.). The sand is then removed and dried. The before and after weights are compared to determine acid solubility. The acid soluble material in gravel pack sand should not exceed 1.0% by weight.</td>
</tr>
<tr>
<td><strong>Silt and Clay Content</strong></td>
<td>A 20 ml sample of dry sand is mixed with 100 ml of demineralized water and allowed to sit for 30 minutes. The sample is then shaken vigorously for 30 seconds and allowed to sit for 5 minutes. A 25 ml sample of the water-silt suspension is removed and the turbidity is measured. The resulting turbidity of tested gravel pack sand should be 250 NTU’s or less.</td>
</tr>
<tr>
<td><strong>Crush Resistance</strong></td>
<td>A sand sample is sieved to remove all fines and weighed. The sample is then exposed to 2,000 psi confining stress for two minutes. The sample is resieved to determine the weight of fines generated. Gravel pack sand subjected to this test should not produce more than 2% by weight fines. For large sand sizes, 12/20 U.S. Mesh and 8/12 U.S. Mesh, the amount of fines produced should not exceed 4% and 8% respectively.</td>
</tr>
<tr>
<td>U.S. Mesh Range</td>
<td>Permeability (Darcy’s)(^4)</td>
</tr>
<tr>
<td>----------------</td>
<td>-----------------------------</td>
</tr>
<tr>
<td>6/10</td>
<td>2703</td>
</tr>
<tr>
<td>8/12</td>
<td>1969</td>
</tr>
<tr>
<td>10/20</td>
<td>652</td>
</tr>
<tr>
<td>12/20</td>
<td>-</td>
</tr>
<tr>
<td>16/30</td>
<td>-</td>
</tr>
<tr>
<td>20/40</td>
<td>171</td>
</tr>
<tr>
<td>40/60</td>
<td>69</td>
</tr>
<tr>
<td>50/70</td>
<td>-</td>
</tr>
</tbody>
</table>
Gravel Pack Sand Substitutes

Although naturally occurring quartz sand is the most common gravel pack material used, a number of alternative materials for gravel pack applications exist. These alternative materials include resin coated sand, garnet, glass beads, and aluminum oxides. Each of these materials offer specific properties that are beneficial for given applications and well conditions. The cost of the materials will range from 2 to 3 times the price of common quartz sand. Table 5.5 summarizes the alternative gravel pack materials, their applications and limitations.

Resin coated gravel pack sand consist of standard gravel pack sand coated with a thin layer of resin. When exposed to high temperatures, the resin cures resulting in a consolidated sand pack. As discussed briefly in Chapter 4, resin coated gravel has been used on occasion as a sand control technique. The primary application of resin coated sand is in prepacked screens as discussed in Chapter 6.
Table 5.3
Gravel-Pack Sand Substitutes

<table>
<thead>
<tr>
<th>Material</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Resin Coated Gravel</td>
<td>Used primarily in prepacked screens. Also used in thermal wells where the resin is thought to protect the sand grains from dissolution by high pH steam. High temperature required to cure resin. Strength of consolidated pack is dependent on curing temperature and time. Consolidated pack will lose compressive strength when exposed to HCl-HF mud acid.</td>
</tr>
<tr>
<td>Garnet</td>
<td>Complex silicate. High specific gravity (3.4 to 4.3). Primary application is thermal wells due to resistance to dissolution by high pH steam. Resistant to HCl-HF mud acid. Grains are angular reducing permeability.</td>
</tr>
<tr>
<td>Glass Beads</td>
<td>Processed product. Grains are extremely round. Permeability is extremely high. Highly soluble in HCl-HF mud acid. Predecessor to Aluminum Oxides.</td>
</tr>
<tr>
<td>Aluminum Oxides</td>
<td>Processed product. Grains are extremely round. Permeability is extremely high. Permeability of 20/40 mesh sample is ±400 darcies. Primary application is intermediate to high strength proppants in hydraulic fracturing. Numerous proprietary formulations are available. Moderately to highly soluble in HCl-HF mud acid. Gravel packing applications include frac-packing and thermal wells.</td>
</tr>
</tbody>
</table>

References

Introduction

Wells conventionally completed in unconsolidated sandstone formations commonly produce a small fraction of the formation material caused by viscous drag forces when reservoir fluids flow towards the wellbore. The consequence of producing formation sand either fills surface facilities, erodes well and surface equipment, or plugs the casing if the flow rate is low. Having to deal with the formation material presents problems, particularly since it has no economic value but restricts a well’s ability to produce at the reservoir capacity. Ways of coping with formation sand production involve economic, operational, and technical issues. Sand production has to be dealt with either at the surface or downhole. For most oil and gas operations, the continuous inspection of surface facilities and the removal of formation material from production vessels is not acceptable, particularly in offshore installations. Hence, the solution of choice has been to control sand downhole as an integral part of the completion provided the productivity and longevity is acceptable.

Completion methods used to control the entry of formation sand into the wellbore have consisted of using either plastic consolidation, resin-coated gravel, gravel packing, or using slotted liners/wire-wrapped screens. Plastic consolidation has many economic, placement, and operational limitations and is an unacceptable solution except in short, high-permeability intervals. On the other hand, gravel packing can be used on almost any well. Both gravel packing and stand-alone screens or slotted liners have been used for sand exclusion in horizontal wells.

Gravel packing consists of placing gravel in the annulus between the slotted liner or screen and the formation to filter the solids from the reservoir fluids as illustrated in Figure 6.1. The gravel in this case is no more than unconsolidated sand that has a median diameter that is typically 5 to 6 times larger than the median size of the formation material. However, a retention device such as a slotted liner or a wire-wrapped screen is used to hold the gravel in place and prevent gravel migration into the wellbore. For most gravel packs, the slot width is typically about half the smallest gravel size.
Slotted Liners

Slotted liners are used in gravel packed completions to prevent the production of gravel pack sand or can be used in stand-alone service when the formation grain size is large. Slot widths are often referred to in terms of “gage” or “gauge”. Slot or screen gage is simply the width of the opening in inches multiplied by a 1,000. For instance, a 12 gage screen has openings of 0.012 inches.

Slotted liners are manufactured by machining slot openings through oil-field tubulars with small rotary saws. Slotted liners are fabricated in a variety of patterns as illustrated in Figure 6.2. The minimum slot widths that can be achieved is about 0.012 inches; however, slots widths cut below 0.030 inches in thickness involve higher costs because of excessive machine down time to replace broken saw blades that become overheated, warped and break. While the slotted liners are usually less costly than wire-wrapped screens, they have a smaller inflow area and experience higher pressure drops during production. Slotted liners also plug more readily than screens and are used where well productivity is low and economics cannot support the use of screens.

The single slot staggered pattern is generally preferred because a greater portion of the original strength of the pipe is preserved. The staggered pattern also gives a more uniform distribution of slots over the surface area of the pipe. The single slot staggered pattern is slotted with an even number of rows around the pipe with a typical 6 inch longitudinal spacing of slot rows.
The slots can be straight or keystone shaped as illustrated in Figure 6.3. The keystone slot is narrower on the outside surface of the pipe than on the inside. Slots formed in this way have an inverted “V” cross-sectional area and are less prone to plugging since any particle passing through the slot at the OD of the pipe will continue to flow through rather than lodging within the slot.

The length of the individual slots is gauged on the ID of the pipe. Usual practice dictates 1½ inch long slots for slot widths 0.030” and under, 2 inch long slots for slot widths between 0.030 to 0.060 inches and 2½ inch long slots for slot widths 0.060 inches and larger (see Figure 6.4). Slot width tolerance is generally ±0.003 inches for widths 0.040 inches and wider and ±0.002 inches for widths less than 0.040 inches.
Slotted liners are generally designed to have a 3 percent open area relative to the OD surface area of the pipe although open areas up to 6 percent are feasible in some cases. The number of slots per foot required to achieve a given open area is calculated with the equation below. Typical slot per foot values for standard pipe sizes are given in Table 6.1. The equation below can be used to determine the number of slots required to provide a desired inflow area.

\[
N = \frac{12\pi DC}{100WL}
\]

where:  
- \(N\) = required slots/foot (if \(N < 32\), round up to the nearest multiple of four, if \(N > 32\), round up to the nearest multiple of 8)  
- \(\pi\) = constant (3.1416)  
- \(D\) = outer diameter of pipe (inches)  
- \(C\) = required open area (percent)  
- \(W\) = slot width (inches)  
- \(L\) = length of slot measured on ID of pipe (inches)

<table>
<thead>
<tr>
<th>Slot Width (inches)</th>
<th>3% Liner (4.0 in(^2)/ft)</th>
<th>6% Liner (7.9 in(^2)/ft)</th>
<th>3% Liner (5.1 in(^2)/ft)</th>
<th>6% Liner (10.2 in(^2)/ft)</th>
<th>3% Liner (6.2 in(^2)/ft)</th>
<th>6% Liner (12.4 in(^2)/ft)</th>
<th>3% Liner (7.9 in(^2)/ft)</th>
<th>6% Liner (15.8 in(^2)/ft)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.012</td>
<td>224</td>
<td>352</td>
<td>288</td>
<td>568</td>
<td>352</td>
<td>696</td>
<td>352</td>
<td>704</td>
</tr>
<tr>
<td>0.015</td>
<td>176</td>
<td>296</td>
<td>232</td>
<td>456</td>
<td>280</td>
<td>560</td>
<td>352</td>
<td>704</td>
</tr>
<tr>
<td>0.018</td>
<td>152</td>
<td>256</td>
<td>192</td>
<td>384</td>
<td>232</td>
<td>464</td>
<td>296</td>
<td>592</td>
</tr>
<tr>
<td>0.020</td>
<td>136</td>
<td>216</td>
<td>176</td>
<td>344</td>
<td>208</td>
<td>416</td>
<td>264</td>
<td>528</td>
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<td>272</td>
<td>168</td>
<td>336</td>
<td>216</td>
<td>424</td>
</tr>
<tr>
<td>0.030</td>
<td>96</td>
<td>152</td>
<td>104</td>
<td>216</td>
<td>128</td>
<td>248</td>
<td>152</td>
<td>296</td>
</tr>
<tr>
<td>0.040</td>
<td>56</td>
<td>104</td>
<td>64</td>
<td>128</td>
<td>80</td>
<td>160</td>
<td>104</td>
<td>200</td>
</tr>
<tr>
<td>0.060</td>
<td>40</td>
<td>72</td>
<td>48</td>
<td>88</td>
<td>56</td>
<td>104</td>
<td>72</td>
<td>136</td>
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<tr>
<td>0.125</td>
<td>16</td>
<td>32</td>
<td>24</td>
<td>48</td>
<td>28</td>
<td>56</td>
<td>32</td>
<td>64</td>
</tr>
<tr>
<td>0.250</td>
<td>8</td>
<td>16</td>
<td>12</td>
<td>24</td>
<td>16</td>
<td>28</td>
<td>16</td>
<td>32</td>
</tr>
</tbody>
</table>
The slotting process reduces the tensile strength of the pipe. The tensile strength of a slotted liner manufactured with a single slot staggered pattern can be estimated using the following equation.

\[
T_m = \sigma \left[ \pi \left( \frac{D^2 - d^2}{4} \right) - \frac{NW(D - d)}{4} \right]
\]

where:
- \( T_m \) = maximum allowable tension (pounds)
- \( \sigma \) = tensile strength of pipe material (pounds per square inch)
- \( \pi \) = constant (3.1416)
- \( D \) = outer diameter of pipe (inches)
- \( d \) = inner diameter of pipe (inches)
- \( N \) = number of slots/foot
- \( W \) = slot width (inches)

The primary advantage of slotted liner over wire wrapped screens is usually cost; however, certain slotting geometry’s may cost almost as much as wire-wrapped screens. The disadvantages of slotted liner are limited flow area (creating a low tolerance to plugging) and minimum available slot size (approximately 0.012 inches). The practical minimum slot size is about 0.020 inch widths compared to 0.006 inches for wire wrapped screen. In slot sizes less than 0.020 inches, the saw blades are thin and blade breakage increases. Increased blade breakage adds time and cost to the manufacturing process. The broken blades often wedge in the slot interfering with the available flow area. Another potential problem with slot widths less than 0.020 inches cut in standard carbon steel pipe grades is corrosion closing the slots or, in some cases, opening the slot width so that the liner does not control sand.

Slotted liners should be deburred on the ID to remove burrs and other debris. Standard ID deburring consists of a reamer which moves along the full inside diameter length of the pipe. Simultaneously, a high volume, high velocity water spray directed at the outside of the pipe forces cuttings to the inside of the pipe for removal by the reamer. This procedure removes approximately 95 percent of all burrs and shavings. An additional procedure can be performed when installation of packers inside the slotted liner is planned. After the standard deburring operation, the ID is hydro-blasted with a combination of high pressure water and an abrasive. Hydro-blasting results in a smooth ID and the removal of all burrs.

**Wire-Wrapped Screens**

Wire-wrapped screens offer another alternative for retaining the gravel in an annular ring between the screen and the formation. The advantage of a wire-wrapped screen over a slotted liner is substantially more inflow area as Figure 6.5 illustrates. The screen consists of an outer jacket which is fabricated on special wrapping machines that resemble a lathe. The wire wrap is simultaneously wrapped and welded to longitudinal rods to form a single helical slot. The jacket is subsequently placed over and welded at each end to a supporting pipe base (containing drilled holes) to provide structural support. This standard design is generic and is manufactured by several companies. A schematic of the screen construction is shown in Figure 6.6.
A great deal is known about the performance properties of wire-wrapped screens since these designs have been used for the past 20 years in worldwide oil field operations. The typical pipe-base screen fabrication consists of a grade 316L stainless steel jacket placed over a N-80 pipe base; however, other metallurgy can be specified as required for the site specific application.
A version of the wire-wrapped screen is the rod-based screen which consists of the jacket only; however, rod-based screens may have additional, heavier rods and a heavier wire wrap than the jackets used on pipe base screens to provide additional strength. Rod-based screens are commonly used in shallow water-well completions which typically range from a few hundred to maybe a thousand feet in depth. Water wells are almost always drilled vertically. Hence, they do not require the strength that is gained by installing the screen jacket over a pipe base. Examples of pipe-base and rod-base screens are illustrated in Figures 6.7 and 6.8. Figure 6.9 illustrates details of the jacket and pipe-base construction.
Water wells that require sand control are not always gravel packed. While most high volume water source wells are either developed or gravel packed to enhance longevity, many private wells that supply water for single-family dwellings are equipped with a screen run across the uncased completion interval (open hole). Slot sizing for these applications is usually about twice the formation sand size at the ten (10) percentile point taken from a representative sieve analysis. Since single phase water is produced from these wells, this design is usually satisfactory. Using stand-alone slotted liners or wire-wrapped screens usually has not been acceptable in most oil or gas wells because of multiphase flow complications and other factors that cause them to plug. The stand-alone design has been more successful in horizontal wells, apparently because of low flow rates per foot of completion interval that reduces the tendency of the screen to plug.

**Prepacked Screens**

Prepacked screens are a modification of existing wire-wrapped screens and represent a modular gravel pack. They consist of a standard screen assembly with a layer of resin-coated gravel (consolidated) placed around it which is contained in an annular ring supported by a second screen (dual-screen prepack) or outer shroud (single-screen prepack). The thickness of the gravel layer can be varied to meet special needs. The screens with the lowest profiles are those which contain an annular pack between the jacket and the pipe base which has a thin lattice screen wrapped around it to prevent gravel from flowing through the drill holes in the pipe base prior to consolidation (SLIM-PAK™). Examples of prepacked screens are shown in Figure 6.10. They have been used in conjunction with gravel packs instead of a wire-wrapped screen in addition to being used as stand alone applications in horizontal wells.

![Dual-Screen Prepack](image1)
![Single-Screen Prepack](image2)
![SLIM-PAK™](image3)

**Figure 6.10**
**Types of Prepacked Screens**
Screens, prepacked screens or slotted liners were the initial horizontal completion method used to restrict the entry of formation sand into the well. Gravel packing horizontal wells has not been performed until recently, as this technology was not thought to be available but is gaining acceptance. However, within the past five (5) years several new screen designs have become available which are designed to be used as stand-alone applications. The new generation of screens were developed to address concerns that were perceived to be a problem with these completions; namely, plugging and erosion before the wells were depleted. The new generation screens that typically fall into this category include:

- SINTERPAK™ Screen (Halliburton)
- STRATAPAC® Screen (Pall Technology)
- CON-SLOT™ Screen (Filter and Sieve International)
- EXCLUDER™ Screen (Baker Hughes)

As mentioned earlier, a great deal is known about conventional screens and slotted liners since their designs are standard and are manufactured by several companies. However, the special screen designs listed above are fabricated by separate companies which in some cases have patented them. There are numerous claims made about the advantages of the special screens; however, many of these claims have not been documented, fully evaluated or verified with data or field experience.

**Flow Capacities of Screens and Slotted Liners**

Figures 6.11 through 6.15 show the pressure drop associated with standard slotted liners and commercial wire-wrapped screens manufactured by several manufacturers. These flow capacity tests were performed using water containing no plugging material. The data indicate that all screens have exceptionally high flow capacities. Flow testing with slotted liners revealed that their flow capacity was related to the slot density rather than the screen diameter (see Figure 6.11). Note that the flow rates were measured in increments of barrel/day/ft of screen or slotted liner. For flow rates that are typical of most wells, the pressure loss through the screen is negligible provided that they do not plug. Testing has demonstrated that slotted liners are more easily plugged than wire-wrapped screens since the slots are usually cut parallel. On the other hand wire-wrapped screens are fabricated with keystone-shaped wire that allows a particle to pass through the screen if it can traverse the minimum restriction at the OD of the screen. The keystone wire design can be observed in Figures 6.5 and 6.8.
**Figure 6.11**
Flow Capacity of Slotted Liners, 0.020 in. slots, with 20/40 U.S. Mesh Gravel

**Figure 6.12**
Flow Capacity of 12 Gauge Howard Smith Screens with 20/40 U.S. Mesh Gravel

**Figure 6.13**
Flow Capacity of 12 Gauge Johnson Screens with 20/40 U.S. Mesh Gravel
Tensile Strengths of Screens with 10 round API Connections

Table 1 lists tensile test results performed on screens and slotted liners in standard test equipment which reflects that standard pipe-base screens have higher tensile ratings than rod-base screens. Most of the recorded failures in these tests were actually at the coupling. While testing demonstrated that yielding occurred in the pipe body, the connection was also yielded. As a consequence, when yielding in the connection caused a thread to jump, the test was terminated. Figure 6.16 is an example of a typical failure where the pipe body was yielded but the failure was at the connection as described above. Figure 6.17 represents a tensile failure of a standard rod-base screen which was about half that of the pipe-base design for this particular product. These tests demonstrated that the tensile strength of standard pipe-base screens easily surpassed the rod-base screens which is probably the reason that the pipe-base screens are preferred. A comparison of the tensile strength test results is shown in Table 6.2. All wire-wrapped screens were fabricated with grade 304 stainless steel wrapped on grade J-55 pipe.


<table>
<thead>
<tr>
<th>Screen</th>
<th>OD (in.)</th>
<th>ID (in.)</th>
<th>Failure Load (lb.)</th>
<th>Stress (psi)</th>
<th>Type Failure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Howard Smith Wire-Wrapped</td>
<td>2-7/8</td>
<td>2.441</td>
<td>112,500</td>
<td>85,250</td>
<td>Coupling and screen</td>
</tr>
<tr>
<td>Howard Smith All-Welded</td>
<td>2-7/8</td>
<td>2.441</td>
<td>115,000</td>
<td>84,150</td>
<td>Coupling and screen</td>
</tr>
<tr>
<td>Howard Smith Wire-Wrapped</td>
<td>3½</td>
<td>2.992</td>
<td>149,000</td>
<td>74,930</td>
<td>Coupling and screen</td>
</tr>
<tr>
<td>Howard Smith All-Welded</td>
<td>3½</td>
<td>2.992</td>
<td>157,000</td>
<td>78,950</td>
<td>Coupling</td>
</tr>
<tr>
<td>Johnson Rod Base</td>
<td>2-7/8</td>
<td>2.441</td>
<td>48,250</td>
<td>--</td>
<td>Weld at coupling</td>
</tr>
<tr>
<td>Johnson Super-Weld</td>
<td>2-7/8</td>
<td>2.441</td>
<td>102,750</td>
<td>77,865</td>
<td>Coupling and screen</td>
</tr>
<tr>
<td>Johnson Rod Base</td>
<td>3½</td>
<td>2.992</td>
<td>70,000</td>
<td>--</td>
<td>Weld at coupling</td>
</tr>
<tr>
<td>Johnson Super-Weld</td>
<td>3½</td>
<td>2.992</td>
<td>149,500</td>
<td>75,180</td>
<td>Coupling and screen</td>
</tr>
<tr>
<td>Baker BAKERWELD®</td>
<td>2-7/8</td>
<td>2.441</td>
<td>102,500</td>
<td>77,675</td>
<td>Coupling and screen</td>
</tr>
<tr>
<td>Baker BAKERWELD®</td>
<td>3½</td>
<td>2.992</td>
<td>145,000</td>
<td>72,915</td>
<td>Coupling and screen</td>
</tr>
<tr>
<td>Houston Slip-On</td>
<td>2-7/8</td>
<td>2.441</td>
<td>102,500</td>
<td>77,675</td>
<td>Coupling and screen</td>
</tr>
<tr>
<td>Houston Slip-On</td>
<td>3½</td>
<td>2.992</td>
<td>150,000</td>
<td>75,430</td>
<td>Coupling and screen</td>
</tr>
<tr>
<td>Gang Slotted Liner</td>
<td>2-7/8</td>
<td>2.441</td>
<td>105,000</td>
<td>79,570</td>
<td>Coupling</td>
</tr>
<tr>
<td>Slotted Liner</td>
<td>2-7/8</td>
<td>2.441</td>
<td>100,500</td>
<td>76,160</td>
<td>Coupling</td>
</tr>
</tbody>
</table>
Collapse testing has shown that the collapse resistance of screens and slotted liners are related to the size and weight of the pipe base and the standoff between the jacket and the pipe base. This testing consisted of placing rubber sheathing around the screen and applying hydrostatic pressure until a collapse failure occurred (see Table 6.3). For standard weight tubulars with a screen jacket that fits snugly around the pipe base, the collapse failure pressure was about 50% higher than the collapse rating of the pipe base. For jackets that fit loosely, a standoff of 0.150 inches or more, the collapse failure pressure of the jacket was attained at 3,000 to 4,500 psi and was observed to deform against the pipe base; however, the pipe base was not deformed. Figure 6.18 is an example of a collapsed jacket with no pipe-base failure.
### TABLE 6.3
**Wire-Wrapped Screen/Slotted Liner Collapse Test Results**

<table>
<thead>
<tr>
<th>Manufacturer</th>
<th>Screen</th>
<th>Size (in.)</th>
<th>Failure Pressure (psi)</th>
<th>Type Failure</th>
</tr>
</thead>
<tbody>
<tr>
<td>Howard Smith</td>
<td>Wire-Wrapped (STANCLIFF™)</td>
<td>2-7/8</td>
<td>9,000</td>
<td>No failure</td>
</tr>
<tr>
<td></td>
<td>All-Welded</td>
<td>2-7/8</td>
<td>6,600</td>
<td>Screen</td>
</tr>
<tr>
<td></td>
<td>Wire-Wrapped (STANCLIFF™)</td>
<td>3½</td>
<td>8,800</td>
<td>No failure</td>
</tr>
<tr>
<td></td>
<td>All-Welded</td>
<td>3½</td>
<td>5,300</td>
<td>Screen</td>
</tr>
<tr>
<td>Johnson</td>
<td>Rod Base</td>
<td>2-7/8</td>
<td>5,200</td>
<td>Screen</td>
</tr>
<tr>
<td></td>
<td>All-Welded (SUPER-WELD™)</td>
<td>2-7/8</td>
<td>7,000</td>
<td>Screen and pipe</td>
</tr>
<tr>
<td></td>
<td>Rod Base</td>
<td>3½</td>
<td>4,500</td>
<td>Screen</td>
</tr>
<tr>
<td></td>
<td>All-Welded (SUPER-WELD™)</td>
<td>3½</td>
<td>5,000</td>
<td>Screen</td>
</tr>
<tr>
<td>Baker Hughes</td>
<td>All-Welded (BAKERWELD®)</td>
<td>2-7/8</td>
<td>5,200</td>
<td>Screen</td>
</tr>
<tr>
<td></td>
<td>All-Welded (BAKERWELD®)</td>
<td>3½</td>
<td>4,600</td>
<td>Screen</td>
</tr>
<tr>
<td>Houston</td>
<td>All-Welded (SLIP-ON™)</td>
<td>2-7/8</td>
<td>10,000</td>
<td>No failure</td>
</tr>
<tr>
<td></td>
<td>All-Welded (SLIP-ON™)</td>
<td>3½</td>
<td>4,200</td>
<td>Screen</td>
</tr>
<tr>
<td>Local</td>
<td>Slotted Liner</td>
<td>2-7/8</td>
<td>9,200</td>
<td>Pipe</td>
</tr>
<tr>
<td></td>
<td>Slotted Liner</td>
<td>3½</td>
<td>6,200</td>
<td>Pipe</td>
</tr>
</tbody>
</table>
Collapse testing of slotted liners showed that their collapse rating was equal to or greater than the API collapse rating of the tubing. However, further examination showed that the slot openings were forced to close prior to the collapse failure of the tubing. This phenomena does not occur for a drilled pipe base used on wire-wrapped screens because the round holes distribute the compressive force around the hole. The slot does not distribute the force and is compressed to the point that there is no slot opening when a critical force is exceeded.

**Strengths and Flow Capacities of Prepacked Screens**

The performance of prepacked screens has also been evaluated in terms of their tensile ratings and collapse resistance. The same recommendations are suggested for minimum tensile strengths and collapse resistance as those listed for pipe-base screens when designing completions with prepacked screens and with standard screen. For conservative designs, the tensile strengths should be either the lesser of 65% of the pipe body strength or the joint pullout published for the connections. The collapse ratings of 3,500 psi is suggested for conservative designs which represent a collapse of the jacket only in spite of the fact that significantly higher collapse pressures have been recorded where the jacket and the pipe base failed simultaneously. The flow capacities of prepacked screens are slightly less than those measured for standard wire-wrapped screens and are a consequence of lower
inflow areas which average about 3 to 4% of the total screen area compared with inflow areas for wire-wrapped screens that are typically over twice as high. However, the prepack material is significantly more prone to plug than is a wire-wrapped screen because of the variable pore openings that range from 40 to 200 microns depending on the grain size of the prepack material. Table 6.4 shows the pore size distribution of BAKERBOND® material for the various mesh sizes. BAKERBOND® is a phenolic resin-coated gravel where the resin coating represents about five (5) weight percent of the gravel.

<table>
<thead>
<tr>
<th>Proppant Type</th>
<th>Grain Size (U.S. Mesh)</th>
<th>Pore Throat Opening (microns)</th>
<th>Pore Size (microns)</th>
</tr>
</thead>
<tbody>
<tr>
<td>BAKERBOND</td>
<td>16/30</td>
<td>50-200</td>
<td>50-500</td>
</tr>
<tr>
<td>Resin Coated IP</td>
<td>20/40</td>
<td>40-120</td>
<td>50-400</td>
</tr>
<tr>
<td>BAKERBOND</td>
<td>12/20</td>
<td>40-200</td>
<td>50-700</td>
</tr>
<tr>
<td>BAKERBOND</td>
<td>20/40</td>
<td>40-90</td>
<td>50-400</td>
</tr>
<tr>
<td>BAKERBOND</td>
<td>40/60</td>
<td>30-60</td>
<td>20-200</td>
</tr>
</tbody>
</table>

Table 6.4
Pore Size Analysis of BAKERBOND™

Special Screen Designs

Recently developed, special designs are available. The discussion below is a brief assessment of the particular designs. The new designs include:
- SINTERPAK™ - Halliburton
- STRATAPAK® - Pall Technology
- CON-SLOT™ - Filter and Sieve International
- EXCLUDER™ - Baker Hughes

These designs were primarily developed for stand-alone screen installations in horizontal wells rather than in a gravel packed completion; however, gravel pack screen applications should not be ruled out. The implications with all of these designs are that they are premium equipment that surpass the performance of either a standard wire-wrapped screen or a prepacked screen in their ability to resist plugging and erosion. Since horizontal completions typically consist of a thousand to several thousand feet of completion interval, the main issue is the susceptibility of a particular design to plug with time rather than the initial flow capacity. Other issues involve the ability to run the screen without creating damage that would either prevent sand control or restrict productivity. Since these specialty screens are run in long horizontal sections, non API or proprietary connections are typically used because of their high strength and the ability to rotate if necessary.

The following discussion deals with the basic design and construction of the various special screens. Guidelines are reviewed for assessing their tensile strengths and collapse resistance. Since these screens are being used in many stand-alone applications, the results of in-house flow testing is reviewed, which was designed to assess the ability of particular designs to resist plugging.
**SINTERPAK™ Screens (Halliburton)**

The SINTERPAK™ screen design was the first of the special screen designs and was developed in about 1990. The design consists of placing a sintered metal sleeve which is 0.15 to 0.25 inches thick over a drilled pipe base. The sintered metal sleeve contains approximately 30% flow area. The sleeve acts as the filtration medium while the pipe base provides tensile strength and collapse resistance. Figure 6.19 is a schematic of the SINTERPAK™ screen design. The pore size distribution of the sintered metal is reported to be as follows:

<table>
<thead>
<tr>
<th>SINTERPAK™ Pore Throat Distribution</th>
</tr>
</thead>
<tbody>
<tr>
<td>Smallest pore diameter</td>
</tr>
<tr>
<td>Most frequent diameter</td>
</tr>
<tr>
<td>Effective pore diameter</td>
</tr>
<tr>
<td>Largest pore diameter</td>
</tr>
</tbody>
</table>

![Figure 6.19 SINTERPAK™ Schematic](image)

Tensile strength and collapse resistance of SINTERPAK™ screens should be consistent with the information provided in Tables 6.2 and 6.3. For conservative designs the tensile strength capabilities should be the about 65% of the lesser of either the published pipe strength or the joint pull out of the coupling. A conservative collapse rating should be similar to published values for wire-wrapped screens listed in Appendix “A”, about 3,500 psi.
STRATAPAC® Screens (Pall)

The STRATAPAC® screen represents Pall Corporation’s sole well-screen product which has been available since mid 1994. The screen design consists of multiple layers (3 or 4) of porous metal membrane (PMM), which contains about 30% open area through variable sized pore openings, between an underlying drainage and overlying protecting mesh screens which are placed concentrically between a drilled pipe base and a perforated outer shroud. A schematic of the screen’s construction is illustrated in Figure 6.20. Test data for STRATAPAC® screens shows tensile strength testing performed to 110k lbs and a collapse test to about 7,000 psi performed on 2-7/8 inch screens, both of which reflect the strength of the pipe base. These data are similar to that shown in Tables 6.2 and 6.3. For conservative designs, the tensile strength rating should be the lesser of 65% the pipe body or the connection since physical properties of the screen jacket and perforated shroud should not contribute to these properties significantly. At higher pressures there is a potential for the PMM to crack or fail near unsupported pipe-base holes.

The filter medium for the screen is sintered metal powder that is pressed against a stainless steel lattice screen which provides structural support for the filtration medium. The pore size distribution of the PMM is listed below:
### Pore Size Distribution of Porous Metal Membrane

<table>
<thead>
<tr>
<th>Size (μm)</th>
<th>Volumetric Distribution (cc/micron cc)</th>
</tr>
</thead>
<tbody>
<tr>
<td>16</td>
<td>5.86</td>
</tr>
<tr>
<td>25</td>
<td>7.90</td>
</tr>
<tr>
<td>30</td>
<td>9.33</td>
</tr>
<tr>
<td>40</td>
<td>12.92</td>
</tr>
<tr>
<td>50</td>
<td>15.67</td>
</tr>
<tr>
<td>60</td>
<td>15.19</td>
</tr>
<tr>
<td>70</td>
<td>14.60</td>
</tr>
<tr>
<td>80</td>
<td>12.92</td>
</tr>
<tr>
<td>90</td>
<td>12.50</td>
</tr>
<tr>
<td>100</td>
<td>11.96</td>
</tr>
<tr>
<td>110</td>
<td>10.53</td>
</tr>
<tr>
<td>120</td>
<td>8.73</td>
</tr>
<tr>
<td>150</td>
<td>4.97</td>
</tr>
<tr>
<td>170</td>
<td>3.23</td>
</tr>
</tbody>
</table>

**CON-SLOT™ (Filter and Sieve International)**

The CON-SLOT™ screens are available as rod-base or pipe-base designs; however, the promoted design is a heavy-duty, rod-base screen which allows it to be handled like ordinary pipe. These reports of high tensile strength and collapse ratings for these rod-based screens is accomplished by fabricating the screen from large-diameter longitudinal rods spaced closely together around the ID of the screen in addition to supplying wire wrap that is sometimes over twice the thickness of most standard wire-wrapped screens. The screen appears to be a quality, heavy duty wire-wrapped, rod-based screen. It is being promoted for use in open hole and horizontal completions as a stand-alone method of controlling formation sand which is believed to be risky. For these reasons it is addressed as a special screen design.

**THE EXCLUDER™**

This is the newest of the special screen designs and consists of three layers of media that form the jacket which are placed concentrically around a drilled pipe base. The base wrap for the jacket consists of a round stainless steel wire-wrapped support and drainage layer for the overlying Vector Weave filtration medium. The Vector Shroud is then placed concentrically over the Vector Weave. See Figure 6.21 for a schematic of the EXCLUDER design.

The purpose of the base wrap or inner jacket is for base support for the overlying Vector Weave against high differential pressure and also promotes using the Vector Weave’s entire surface area for...
filtration which optimizes plugging resistance. The openings in the base wrap are typically about 25 µm or larger than the Vector Weave to provide secondary sand control. The Vector Weave provides an inflow surface area that is comparable to that of the formation, about 30%. It contains uniform pore throat openings which assist in maximizing the inflow area which develops a more permeable filter cake. The design of the Vector Weave redirects the flow through it to minimize erosion and extend screen life. The EXCLUDER™ design being offered for Gulf of Mexico service is rated at a uniform pore-throat opening size of 110 µm; however, specific designs are available to other site-specific applications, such as the North Sea (230 µm). The Vector Shroud protects the inner Vector Weave during installation in the well and assists in redirecting the flow stream during production so that erosion of the Vector Weave is minimized. Schematics of the EXCLUDER™ components and their effects of the flow stream during production are illustrated in Figures 6.21-6.23.
The EXCLUDER™ has been performance tested to a collapse resistance of 6,000 psi, tensile tested to 2% elongation and torque tested to °/ft deformation. A crush test where the EXCLUDER™ was deformed up to 60% of the original diameter was conducted prior to flow testing which showed that after deforming the screen continued to provide sand control.

**Plugging Tests on Wire-Wrapped Screens**

Recently, in-house comparative testing has been performed on as many different screens that could be obtained from U.S. manufacturers. Two types of flow tests were performed: a laboratory and full-scale test.

The laboratory tests consisted of placing a 1.278 inch diameter test sample of a screen sample in a test fixture, Figure 6.24, and flowing water at a rate of 500 ml/min which contained 1,500 ppm, 50/50 blend of A.C. coarse test dust and 70/140 U.S. mesh gravel. The test was terminated when the injection pressure reached 100 psi. The flow time required to reach 100 psi was the time to plug for these test conditions. The implications were that screens that plugged quickly had low plugging resistance while those that plugged slowly had high resistance to plugging. Seven (7) screens were tested:
The results of the laboratory scale tests are shown in Figure 6.25 and 6.26. The EXCLUDER™ screen was clearly more resistant to plugging than the other screens tested.
Full-scale tests were also performed on 4 ft. long, 2-7/8 inch well screen samples placed in the test fixture illustrated in Figure 6.27. All testing was performed at a flow rate of 55 gpm using the same plugging materials and concentration listed for the laboratory-scale tests. Testing was suspended when the upstream pressure reached 1,500 psi.

The results of these tests are illustrated in Figure 6.28 and show similar relative plugging resistance as that recorded in the laboratory-scale tests. Figures 6.29 and 6.30 show the normalized plugging resistance to the above screens in addition to regular wire-wrapped and SLIM-PAK™ screens. Plotting the data in this manner may allow a more accurate, direct comparison of a screens performance due to slight differences in screen length and pump rate fluctuations during specific test runs. Regardless of which approach was taken, the EXCLUDER™ screen was observed to be the most resistant to plugging.
Figure 6.30 also shows that 4 and 8 gauge wire-wrapped screens were also tested. While plugging occurred rapidly on the 4 gauge screen, the 8 gauge screen required significantly more time to plug. The 8 gauge supported more plugging material per foot of screen but likely also passed more material through it. The implications here is that regular wire-wrapped screen should also be considered for stand-alone applications. We disagree with this strategy; however, upon observing the slot opening of these screens after the test, screen erosion was detected and is illustrated in Figure 6.31. Careful observations revealed that certain sections of the screen had been eroded, namely intervals where the screen is welded to the longitudinal rods. While the erosion observed here was enhanced by small irregularities in the slot width, oversizing a stand-alone, wire-wrapped screen would have the same effect since some material will pass through the screen and erode it. Hence, it would appear that relying solely on the wire wrap to provide long-term sand control primarily has application in uniform, large grained formations. Applied to other situations, a stand-alone wire-wrapped screen appears to be risky.
Erosion Tests

When water was the test fluid, screen erosion was noted with the wire-wrapped screens mentioned on the preceding page. Erosion tends to be much more serious when fluids are in a turbulent flow regime (Reynolds numbers > 2,100). To evaluate the erosion resistance of screens, testing was performed using compressed air as the flow medium which contained 30/100 mesh sand blast material about 10% of which were fines smaller than 60 mesh. The test consisted of placing a one-foot screen sample in the fixture schematic shown in Figure 32 and flowing air and blast sand through a port containing a 0.25-inch choke to simulate a perforation tunnel opposite the screen. The flow rate through the port was 49 cubic feet per minute at 60 psi containing the blast sand conveyed into the flow stream at a rate of 25 lb/min. Assuming that a well was perforated 12 shots/foot this equates to a flow rate of about 4.3 mmscf/day/ft. This rate was not meant to replicate any particular field condition. In fact it is considered to be on the high end of observed flow rates and sand production, but allowed comparisons in erosion resistance to be made quickly since the test duration was typically 2 minutes.

Screens subjected to testing were:

1. BAKERWELD® - 2 gauge (50 µm)
2. BAKERWELD® - 8 gauge (200 µm)
3. SLIM-PAK™ (40/60 mesh)
4. EXCLUDER™ (110 micron)
5. Multi-Layered Sintered Membrane
Observations from these tests showed that:

- **BAKERWELD® Screen** - Experienced severe erosion of the wire wrap in less than one minute (see Figure 6.33).
- **SLIM-PAK™ Screen** (40/60 mesh) - The wire wrap showed excessive erosion and most of the consolidated material was removed but the test fixture sanded up before complete failure (see Figure 6.34).
- **EXCLUDER™ 110 Screen** - Minor erosion of the Vector Shroud. Vector Weave and underlying support wire were unaffected (see Figure 6.35).
- **Multi-Layered Sintered Membrane** - Slight erosion of the perforated shroud. Four (4) holes eroded through the Multi-Layered Sintered Membrane opposite the drill holes in the perforated shroud (see Figure 6.36).

Testing showed that the EXCLUDER™ screen was the most erosion resistant of the screens tested. Implications of these results suggest that the Vector Shroud is a key element in screen design in that it resists erosion and thereby protects the inner filtration layer.
Conclusions

The flow capacities of wire-wrapped screens are substantially higher than those of slotted liners owing to the higher inflow areas of wire-wrapped screens.

The flow capacities, tensile strengths and collapse resistance of standard wire-wrapped screens of the same size and design are similar.

Prepacked screens with similar designs and dimensions also have approximately the same tensile strength, collapse resistance and flow capacity. However, the flow capacity of prepacked screens is lower than the wire-wrapped screens because of slightly less inflow area as a consequence of some resin-coated gravel in the slot openings.

The tensile strengths and collapse resistance of SINTERPAK™, STRATAPAC®, and EXCLUDER™ screens are similar for identical pipe-base dimensions.

Comparative flow tests designed to evaluate the plugging resistance of standard and specialty screens has clearly demonstrated that the EXCLUDER™ screen is significantly more resistant to plugging than the other screens tested.

Comparative erosion tests showed that the EXCLUDER™ screen was the most erosion resistant of the screens tested. Implications were that the Vector Shroud is a key element minimizing erosion.
GRAVEL PACK COMPLETION EQUIPMENT
AND SERVICE TOOLS

Introduction
There are numerous types, combinations and systems of gravel pack completion equipment available to handle virtually any conceivable well conditions. Illustrated in Figure 7.1 are typical offshore gravel pack completions in cased and open hole. The completions, as illustrated, make use of crossover type circulating gravel pack technology which is considered state-of-the-art in the industry today. This chapter outlines the functions of the individual system components and basic equipment design criteria.

Gravel Pack Completion Equipment
Gravel pack completion equipment is defined as the equipment that remains in the well as part of the completion after the gravel placement operations are complete. The equipment discussed below does not represent all the types of equipment that are available, but does represent a typical gravel pack completion. The equipment design recommendations discussed below are just that - recommendations. It is important to remember that certain well conditions may require compromises in the type and design of gravel pack equipment that can be run. The compromises must be made in light of the risks they create and certain compromises will be preferable to others. Another important concept to remember is that there may be several different, yet equally effective, ways to complete a well.

Sump Packer. The first step in installing a gravel pack completion is to establish a base. In cased hole completions, the most common type base is a sump packer. The sump packer is normally run into the well on electric wireline prior to perforating and is set a specified distance below the lowest planned perforation. The distance below the perforations must accommodate the length of the seal assembly and production screen overlap. The sump packer is normally set 5 to 10 feet below the lowest perforation.

In most cases, the sump packer is a permanent seal bore type packer like the Baker Model “D” or “F” Retainer Production Packer as illustrated in Figure 7.2. Retrievable seal bore packers like the Model “SC-1” Packer can also be used. In the case of multiple zone gravel packs, the gravel pack packer for the lower zone can be spaced out to serve as the sump packer for the upper zone. The advantage of using a sump packer compared to other techniques is that the packer provides access to the bottom of the well as a sump for debris left or dropped in the hole. The sump also facilitates the running of production logs below the producing interval to monitor oil, gas and water contacts.
Figure 7.1
Typical Gravel Pack Completion Equipment in Cased and Open Holes
Although sump packers are the preferred gravel pack base, other options such as a bridge plug or cement plug can be used. In open hole completions, provisions for a debris sump or logging access can be achieved, but are not routine; therefore, the gravel pack base is normally a bull plug on the bottom of the screen. The types of common gravel pack bases are illustrated in Figure 7.3.
Seal Assembly. The seal assembly is required to establish a seal in the bore of the sump packer to prevent gravel pack sand from filling the bottom of the well during gravel packing. In the case of multiple gravel packs, the seal is required for zonal isolation. The seal assembly used to engage the sump packer is normally a snap latch type or a multiple indicating type as illustrated in Figure 7.4.

The snap latch type seal assembly has threaded fingers that collapse inward as it contacts the top of the packer. When the assembly is fully lowered into the sump packer, the threaded fingers expand and engage the left-hand square threads in the top of the sump packer. Approximately 2000 pounds of set down weight is required to snap into the packer and 8,000 to 12,000 pounds are required to snap out. This tool can be snapped in and out of the sump packer as required, to verify that the gravel pack assembly is properly positioned. The snap out force will be reduced with repeated actuations.

The multiple acting indicator type seal assembly provides the most positive sump packer locating device. This tool incorporates a locating shoulder at the top with an indicating collet spaced out a known distance below. Approximately 2000 to 4000 pounds of set down weight is required to force the indicating collet through the packer bore. The tool is lowered until the locating shoulder contacts the top of the sump packer giving a positive set down weight indication. To verify that the seal assembly is in the sump packer, the tool is raised until the indicating collet contacts the bottom of the packer. Overpull of 6,000 to 15,000 pounds (depending on tool size) is possible to give a positive pick up weight indication. The tool may be raised and lowered between the upper and lower indicating positions with a known amount of stroke in between to provide an extremely positive indication that the seal assembly is engaged in the sump packer. The multiple acting
indicator type seal assembly is especially beneficial in highly deviated wells or wells completed with a floating vessel. The multiple acting indicator type seal assembly should only be used with permanent type packers since the indicating collet can actuate the release mechanisms on some retrievable type packers. Since the tool extends below the packer when engaged, it is not used in upper gravel pack completions in multiple zone wells.

**Gravel Pack Screen.** The purpose of the gravel pack screen is to create the annulus that is filled with gravel pack sand and act as a filter to ensure the gravel pack sand is not produced. As discussed in Chapter 6, there are several different types of screens and slotted liners available for gravel pack applications. The gage of the screen is determined by the size of the gravel pack sand as discussed in Chapters 5 and 6. This section discusses recommendations on centralization, length and maximum screen OD, and is applicable for all slotted liner and screen types.

*Screen Centralization.* Filling the annulus between the screen/casing (or open hole) with gravel pack sand is essential to the control of formation sand production. To ensure that the annulus is properly filled completely around the screen, centralization of the screen is required. In cased hole completions, weld-on blade type centralizers are normally used. The blades are cut from .25 to .50 inch thick plate steel and are approximately 6 inches long. The edges of the centralizers are beveled to ensure easy run-in. The centralizers consist of four blades welded to the screen base pipe 90° apart to result in an OD approximately 0.25 inches under the ID of the well’s casing. The centralizers are spaced 15 to 20 feet apart and can be positioned at the top, bottom and/or middle of a screen joint as required.

In open hole gravel packs, centralization is accomplished with bow spring type centralizers. These centralizers consist of a top and bottom collar connected with 4 to 6 steel spring bows. The bows can be compressed (i.e., centralizer is elongated) for running through restricted ID’s. When the centralizer enters a larger ID, the bows attempt to expand to their original position resulting in a centralization or restoring force. Sufficient centralizers are required such that the combined restoring force is capable of lifting the weight of the screen in the given hole conditions. Computer programs are available for determining optimum centralizer spacing for a specific bow spring centralizer, hole size and deviation.

The collars used on bow spring centralizers can be a slip-on or hinged type and are sized to fit around the base pipe of the screen. Depending on the centralizer spacing required, special screen lengths may be needed to accommodate the collars. When running in the hole, it is important that the centralizers are “pulled” in as opposed to being “pushed”. This is accomplished by fixing the position of the lower collar with set screws or by attaching it below a pipe coupling such that the centralizer elongates in the upward direction while going in the hole. Again, special screen design may be required to accommodate the elongation of the centralizers. Special combination type bow spring centralizers are available where the bottom collar fits on the base pipe and the top collar fits around the screen jacket to eliminate the amount of blank pipe required for centralizer elongation.
Screen Length. In cased hole completions, the length of the screen is generally selected to result in approximately 5 to 10 feet of overlap below and above the gross perforated interval. This overlap ensures that the entire perforated interval is covered by screen and will compensate for any minor space-out discrepancies. Additional overlap is often used above the gross perforated interval, but the benefits of the additional screen overlap is arguable. In open hole completions, the screen length is designed to cover from the bottom of the hole to approximately five feet below the casing shoe. There is a tendency for a void or a washout to occur directly beneath the shoe when drilling through it. This void can be difficult to gravel pack effectively. To prevent sand production from this void, blank pipe is run in this area.

Screen Diameter. For cased hole completions, the screen OD should be selected to provide an optimum annular gravel pack as well as provide for fishability in the event the gravel pack must be retrieved from the well. In most cases, maintaining a minimum annular clearance of 0.75 to 1.0 inches between the screen OD and casing ID is sufficient to accomplish both a good annular pack and fishability. In underreamed open hole completions, a minimum annular clearance of 0.75 to 1.0 inches between the screen OD and casing ID above the open hole is recommended. For open holes that are not underreamed, a minimum annular clearance of 0.75 to 1.0 inches between the screen OD and hole ID is recommended. Available washover pipe for fishing operations may influence the maximum screen OD selected.

Blank Pipe. The purpose of blank pipe is to provide a reservoir of gravel pack sand to ensure that the screen remains completely packed in the event of pack settling. During gravel pack operations it is possible for minor voids in the annulus pack to occur. In fact, gravel packing with viscous gel carrier fluids will always result in minor voids, particularly opposite the short lengths of blank pipe between screen joints. Depending on deviation angle, pack settling shortly after gravel placement will fill these voids, but it is important to have a sufficient reserve of gravel pack sand available for this process to occur without uncovering the top of the screen.

Blank Pipe Centralization. As with screen, the blank pipe needs to be centralized to ensure even gravel distribution in the blank and casing annulus. Weld-on centralizers are normally used in both cased hole and open hole completions since the blank pipe is almost always positioned inside the casing. Bow spring centralizers can be used if desired or required.

Blank Pipe Length. Several rules of thumb exist for determining the length of blank pipe required when using viscous gel carrier fluids. Perhaps the most scientific method would be to recognize that voids will occur within the length of screen wherever non-screen exists (i.e., screen joint connections, etc.). A long-standing guideline for gravel reserve has been to maintain a minimum of 30 feet of packed gravel in the blank pipe above the top of the screen. By adding this number to the total length of non-screen within the length of screen, a minimum value of packed blank pipe required can be determined. Recognizing that packing of the blank pipe when using viscous gel carrier fluids occurs by sand settling, the length of blank pipe must be increased based on the settling factor associated with the gravel concentration used as illustrated in Figure 7.5. This logic is shown in the following equation:
where: \( L_b \) = minimum length of blank required (feet)
\( L_{ns} \) = length of non-screen within the screen section (feet)
\( SF \) = settling factor for gravel pack sand in viscous gel carrier fluids (fraction)

From this equation it can be seen that as the length of non-screen within the screen section increases and/or the settling factor decreases, the minimum recommended length of blank pipe required will also increase. Notwithstanding the above calculation, a minimum of 90 feet of blank pipe should be run, if possible, when using viscous gel carrier fluids.

The length of blank pipe required when using non-viscosified brine carrier fluids is determined differently than when using viscous gel carrier fluids. With brine carrier fluids, filling of the blank pipe and casing annulus occurs by mechanical placement versus settling. Darcy’s Law for linear flow can be used to calculated the amount of blank filled since it is possible to pump through a packed gravel column with brine. The applicable equation is:
\[ h = \frac{0.00078kA(p_s - p_i)}{\mu q} \]

where:
- \( h \) = gravel height above top of screen (feet)
- \( k \) = permeability of gravel pack sand (darcies)
- \( A \) = flow area in casing/blank annulus (square feet)
- \( p_s \) = sand-out pressure (pounds per square inch)
- \( p_i \) = initial circulating pressure at sand-out rate (pounds per square inch)
- \( \mu \) = completion fluid viscosity (centipoise)
- \( q \) = sand-out pump rate (barrels per minute)

For given job parameters, a sand-out rate and pressure can be determined to result in the desired amount of packed gravel above the top of the screen. In most cases, a gravel height of 60 feet is easily achieved with reasonable sand out rates and pressures; therefore blank pipe lengths of 60 to 90 feet are common. It should be noted that the voids opposite screen connections that occur with viscous gel carrier fluids are not seen with brine carrier fluids.

**Blank Pipe Diameter.** For practical reasons, the blank pipe diameter is selected to be the same size as the base pipe of the screen. This prevents a drastic change in annular flow area at the blank pipe and screen interface. Alternately, larger blank pipe sizes can be used to more closely match the OD of the blank pipe with the OD of the screen. This should be considered when running Dual Screen Prepacks or Single Screen Prepacks whose OD is relatively large compared to the ID. The use of too small of blank pipe OD can result in the formation of a bridge at the top of the screen during the gravel pack due to the severe change in OD profile and corresponding change in flow area.

**Shear-Out Safety Joint.** A Shear-Out Safety Joint (SOSJ) consists of a top and bottom sub connected by a number of shear screws (see Figure 7.6). This device is incorporated in most gravel pack completion assemblies to allow retrieval of the gravel pack packer and extension independently of the blank pipe and screen. The SOSJ is parted with straight tension to shear the screws while pulling the packer with the packer retrieving tool. After removing the packer, the blank pipe and screen may then be washed over and retrieved using routine fishing techniques. If a SOSJ is not run, the blank pipe below the packer must be cut to allow retrieval of the packer. The shear pins used in the SOSJ must support the weight of the blank pipe and screen with a generous safety factor. The limitations of the workstring that will be used to retrieve the packer should also be considered when selecting a shear rating. Standard shear ratings are adjustable between 44,800 and 80,640 pounds depending on the size of the tool. The top and bottom subs are rotationally locked to allow torque transmission if required. SOSJ’s are not normally used when running permanent style gravel pack packers or when running extremely long and heavy gravel pack assemblies. Because these tools do shear with upward tension, gravel pack assemblies are normally set in compression to insure they do not shear when gravel packing pressures are applied.
Knock-Out Isolation Valve. The Knock-Out Isolation Valve (KOIV) is a mechanical fluid loss device that prevents completion fluid losses and subsequent damage to the formation after performing the gravel pack. The downward closing flapper in the KOIV is held open by the gravel pack service tools (normally the wash pipe) during the gravel pack. When the service tools are pulled out of the KOIV, the flapper closes preventing fluid loss to the formation (see Figure 7.7). The gravel pack service tools can be removed from the well and the completion tubing run. Under producing conditions the flapper will open. Alternatively, the flapper is made of a breakable material and can be broken hydraulically or mechanically prior to producing the well.
Gravel Pack Extension. Gravel pack extensions are used in conjunction with the gravel pack packer and service tools to provide a flow path from the tubing above the packer to the screen/casing annulus below the packer. The gravel pack extension consists of the upper extension (which contains flow ports for the gravel pack fluids), seal bore (sized to match the bore of the gravel pack packer) and lower extension (to house the gravel pack crossover tool throughout its range of motion). The length of the gravel pack extension is carefully designed to work with a particular gravel pack packer and crossover tool. Gravel pack extensions are available in two types, perforated and sliding sleeve (see Figure 7.8). In a perforated gravel pack extension, the upper extension simply has drilled holes for fluid exit. These holes should be isolated during the well production with a seal assembly as a precaution to prevent any gravel production. In a sliding sleeve gravel pack extension, the holes in the upper extension are open during the gravel pack but isolated with a sliding sleeve that is closed by a shifting tool when the gravel pack service tools are pulled out of the well.
**Gravel Pack Packer.** At the top of the gravel pack assembly is a gravel pack packer. This packer may be permanent or retrievable. However, retrievable type packers are recommended for gravel pack applications. Because gravel packing is a complex completion operation, failures during initial gravel placement or during the life of the reservoir can occur. A retrievable packer expedites workover activities without the potential cost and risk of milling a permanent packer. The retrievable packers used for gravel packing are seal bore type packers such as the Model “SC-1” Packer (see Figure 7.9). In addition to facilitating gravel pack operations the packer can be used for production; therefore, the packer must be designed for the temperature, pressure and environmental conditions present in the well.

The standard features of the Model “SC-1” are:

- Retrievable with straight pull releasing tool.
- Withstands differential pressures up to 6000 pounds per square inch from above or below and temperatures up to 250°F.
- Sets with a hydraulically actuated setting tool with no rotation required.
- Can be easily modified for use in hostile environments and thermal applications.
- Can be easily milled in emergency situations due to cast iron construction above the slips.
- Single, cup forming packing element facilitates milling by eliminating metal spacers as found in other retrievable packers.
- Available for most casing sizes.

The Model “SC-2” Packer and Model “HP-1” Packer are higher pressure versions of the Model “SC-1” Packer and are intended for gravel packing in more severe well environments. The Model “SC-2” Packer can withstand 7,000 to 9,000 pounds per square inch differential pressure and 350°F. The model “HP-1” packer can withstand 10,000 to 12,000 pounds per square inch differential pressure and 450°F. These packers function identically to the Model “SC-1” Packer, but have more sophisticated packing element systems and more rigorous material specifications to withstand higher temperatures and pressures.

Gravel Pack Service Tools

Gravel pack service tools are defined as the equipment necessary to perform the gravel pack, but which are removed from the well after gravel packing. In most cases, the service tools required for a gravel pack are dictated by the type of gravel pack equipment used. Further discussion of the service tools follows.
Hydraulic Setting Tool. The hydraulic setting tool is basically a hydraulic piston that generates the force required to set the gravel pack packer (see Figure 7.10). It is attached to the top of the crossover tool and has a sleeve shouldered against the setting sleeve of the packer. A setting ball is dropped to the ball seat in the crossover tool to plug off the ID of the workstring. Applied pressure to the workstring acts on a piston in the hydraulic setting tool to force the sleeve down to compress the slips and packing element of the packer. Special versions of the setting tool are available which allow for rotation and high circulating rates while running the gravel pack assembly.

Gravel Pack Crossover Tool. The gravel pack crossover tool creates the various circulating paths for fluid flow during the gravel packing operation. It consists of a series of molded seals surrounding a gravel pack port midway down the tool and a return port near the top of the tool (see Figure 7.11). A concentric tube design in the crossover tool along with the gravel pack packer and gravel pack extension allow fluid pumped down the workstring above the packer to “crossover” to the screen/casing annulus below the packer. Similarly, return fluids flowing up the washpipe below the packer can “crossover” to the workstring/casing annulus above the packer.
Mechanically, the crossover tool carries the weight of the gravel pack assembly into the well via a left hand square thread connection to the top of the gravel pack packer’s seal bore. The crossover tool also contains the ball seat to allow pressuring of the workstring to set the packer. After setting the packer, workstring pressure is increased to blow the ball into a sump area below the gravel pack ports of the crossover tool. At this time the crossover tool can be released from the left-hand square thread of the packer. Crossover tools are supplied with either a rotational release or a hydraulic release. The mechanical release requires 10 to 12 rotations to the right at the packer with slight upstrain. The hydraulic releasing mechanism is actuated by pressure in the workstring/casing annulus. The mechanical release may be used as a backup to the hydraulic release.
Gravel pack crossover tools have three positions - squeeze, circulating, and reverse circulating as illustrated Figure 7.12. The squeeze position is found by setting down weight on the packer to seal the return ports in the packer bore. The squeeze position allows all fluids pumped down the workstring to be forced into the formation and is used to perform squeeze gravel pack treatments and/or inject acid treatments into the formation. The circulating position is located by picking the crossover tool up approximately 18 inches above the squeeze position. The circulating position works in conjunction with properly sized washpipe to provide a flow path to circulate gravel pack sand to completely fill the screen/casing annulus. The flow path is down the workstring, into the crossover tool, out the gravel pack extension, down the screen/casing annulus, into the screen, up the washpipe, into the crossover tool again, and up the workstring/casing annulus.
The reverse circulating position is found by pressuring the workstring/casing annulus to approximately 500 pounds per square inch and slowly raising the gravel pack crossover tool until circulation up the workstring is seen. The reverse circulating position allows excess gravel pack sand to be reversed out the workstring at the conclusion of gravel pack operations. A rubber coated “low bottom hole pressure ball” or “reversing ball” placed in the bottom sub of the crossover tool acts as a check valve to prevent fluid losses to the formation while reverse circulating. In actual operations, the positions of the crossover tool are located and the workstring is marked at surface for easy reference prior to starting the gravel pack.

Variations of the gravel pack crossover tool exist for special applications. One variation incorporates a rotational lock feature to allow right-hand rotation to be applied through to the gravel pack assembly while running in the well. The rotational lock feature is used primarily in highly deviated wells where high frictional drag may be encountered. Other variations allow circulating straight through the crossover tool while running in the well. This feature is beneficial in removing fill without making a special clean-out trip. Still other variations are adapted to work in conjunction with floating rigs.

**Shifting Tool.** The shifting tool is run below the gravel pack crossover tool and is used to open and close the sliding sleeve in the gravel pack extension (see Figure 7.13). The tool is basically a collet designed to catch the fingers of the sliding sleeve and shift it closed with upward movement or open with downward movement. The shifting tool is only required if running the gravel pack extension with sliding sleeve.
Washpipe. Washpipe is run below the gravel pack crossover tool or shifting tool inside the blank pipe and screen to insure that the return circulation point for the gravel pack carrier fluid is at the bottom of the screen. This assists in getting gravel pack sand to the bottom of the screen and packing in a bottom up fashion. The end of the washpipe should be positioned as close to the bottom of the screen as possible.
Research\textsuperscript{1,2} indicates that maximizing the washpipe OD increases the resistance to flow in the washpipe/screen annulus. The greater resistance to flow forces the gravel pack carrier fluid to flow in the screen/casing annulus and carry the gravel pack sand to the bottom of the well. By accomplishing this, gravel packing of the screen/casing annulus is more complete. Based on the experiments, the optimum ratio of washpipe OD to screen base pipe ID should be approximately 0.8. Achieving this ratio in some screen sizes will require the use of special flush joint washpipe connections.
HIGH RATE, HIGH PRESSURE TOOLS

Introduction

The previous section described the tools and equipment used in standard water, or brine-based gravel pack operations. This section describes the design philosophy behind the new gravel pack tools designed to be used with all current gravel pack pumping and placement technologies in use today. This analysis was undertaken to insure Baker’s tools are able to provide the service required, no matter what pumping treatment is selected. Since current state-of-the-art pumping treatments are normally pumped at higher rates and pressures than considered the norm just a few years ago, it became imperative that the downhole life of all components was maximized, and that we understood the wear mechanisms involved. In other words, we wanted to determine the safe operating envelopes for the critical downhole tools -- the ones which are likely to experience the highest degree of erosion during a typical pumping treatment. We also wanted to know what the friction pressure drop across the downhole assembly would typically be so we could better evaluate treatment results. Finally, and perhaps, most importantly, we wanted to be able to positively ensure the position of the service tool string at all times, in order to make sure the pumped treatment goes where it is intended.

Operating Envelope -- Crossover Port

During the initial scoping of our tool enhancement re-design project, it was determined that the critical component, as far as erosion at high rates and pressures is concerned, is the crossover port in the crossover tool. This is the point from which the well treatment slurry exits the tubing string into the screen/casing annulus. Historically, the port has exhibited critical levels of erosion while the remainder of the tool string showed little, if any, erosion (see Figure 7.14). Consequently, we identified as critical the capability to know “how much is enough”. The purpose of determining an expected operating envelope, under a given set of input parameters such as rate, pressure, volume, proppant concentration, etc., is to be able to specify, with a high degree of accuracy, the life expectancy of the crossover port under the given conditions. During the investigation to determine these correlations, it was discovered that varying certain parameters caused others to move in a positive direction. For instance, if the sand concentration were lowered from a given value, then the pumping rate could be increased. Again, if the downhole viscosity of the slurry were increased, the sand loading could be increased, or the pumping rate increased, or both. The correlation is illustrated in Figure 7.15. It is based on full scale testing under the most conservative conditions (brine), and can be extrapolated to different carrying fluids of varying downhole viscosities. This correlation is available for all size crossover tools.

For ease of analysis during both pre-job planning and post-job analysis, a computer program has been developed which incorporates our correlative data thereby allowing a prediction of crossover port wear to be made based on the expected treatment design. Input parameters include the pumping schedule (rates, pounds of proppant added and time). Output is a calculation of crossover port erosion during the treatment. See Figure 7.16 for an example.
Figure 7.14
Typical Wear Final Port Design

Figure 7.15
Operating Envelope - Crossover Port
Pressure Drop Analysis

Another concern, and, therefore, another piece of information we wanted when studying the re-design of the crossover port, was the pressure drop the slurry experienced when being pumped through it. As it turns out, the pressure drop can be managed to be not substantial, and when this occurs, erosion through the port is also very manageable. See Figure 7.17 for a typical pressure drop summary.

Gravel Pack Completion Equipment

Other equipment has been modified to insure its compatibility with high rate/high pressure gravel pack treatments. Following is a discussion of the modifications made.

Gravel Pack Screen and Blank Pipe. When selecting screen for a high rate/high pressure application, consideration should be given to the applied pressures both the screen and blank pipe will be exposed to. Failure to do so could result is collapsed screen and/or blank pipe, possibly resulting in sand control failure caused by distorted screen gauge openings. Another possible result is a stuck crossover tool caused by proppant entering the ID of the screen/blank section, or by the screen/blank collapsing against the washpipe. Therefore, it may be appropriate to specify N-80 blank pipe and screen base pipe. It may also be appropriate to specify Bakerweld “140” Gravel Pack Screen. This is the heavier duty version of the standard Bakerweld Screen. It features thicker gauge wire wrap and increased collapse resistance.
Gravel Pack Extension. The Gravel Pack Extension run beneath the gravel pack packer in a high rate/high pressure sand control treatment has been modified in several ways. First, the upper section, or the joint of pipe directly below the packer features increased wall thickness and hardness in order to resist erosion. During normal gravel packing, the “B-250” Crossover Port will be positioned inside this heavy walled section of the extension in order to protect the casing from erosion. Second, the sliding sleeve (see Figure 7.18), is locked in place and will not accidently close during pumping operations. Finally, the sliding sleeve has also been modified so that it is permanently closed following pumping operations. This feature prevents the sliding sleeve from opening during production operations.

Figure 7.17
Pressure Drop Analysis
Size 80-40 Crossover Tool
Gravel Pack Packer. Generally, no modifications to Baker’s “SC” style packers are required to make them suitable for high rate/high pressure work. It is important, however, to again consider the maximum anticipated downhole pressures and temperatures. It may be necessary to upgrade to an “SC-2” gravel pack packer with its higher differential pressure rating. For most sizes, the “SC-2” has a pressure rating of 7,500 psi. An “SC-1”, for most sizes, has a pressure rating of 6,000 psi.

Model “A” Indicating Sub. In addition to the above, a Model “A” Indicating Sub was added to the gravel pack equipment (see Figure 7.19). The purpose of this sub is to provide the base on which Baker’s S.M.A.R.T. Collet operates. The operation of this tool is explained below.

Gravel Pack Service Tools

Some components of the gravel pack service tool string have been modified or added, for high rate/high pressure pumping operations. These changes are discussed, as follows.

Gravel Pack Crossover Tool. Already discussed was the fact that the crossover port in the crossover tool experienced critical erosion at times, and the various factors affecting it. This new port, called Baker’s “B-250” Crossover Port, has been optimized for extreme velocities (see Figure 7.20). It features an increased inner diameter for increased flow area through it. It also features increased flow through the port itself. In addition, the primary packer setting ball is now trapped after the packer is set, thereby eliminating the possibility of it returning to surface during reversing operations. The setting mechanism has been balanced so that it cannot shear early when setting the packer in low bottom hole conditions. The new port also allows for wash down and debris removal prior to gravel packing. This feature can be important, especially in open hole applications.
Figure 7.19
Hi-Rate Hook-Up
A new tool has been added to the bottom of the crossover tool, and takes the place of the traditional low bottom hole pressure ball. This new tool, the Flapper Anti-Swabbing Tool (see Figure 7.21), is a single acting device designed to keep the low bottom hole pressure flapper temporarily unseated, thus preventing the swabbing effects caused during positioning of the crossover tool during gravel packing operations. The flapper is released by picking up on the crossover tool past the reverse position. The F.A.S.T. features a positive, single acting, protected collet actuating system with a shear release of 18,000 lbs. It has an open ID prior to actuation which facilitates wash down/debris removal operations, and which also allows passage of the detonating bar when used in the One Trip Perforate and Gravel Pack System.
S.M.A.R.T. Collet. The S.M.A.R.T. Collet is a multi-acting locating device used to positively locate the gravel pack crossover tool down hole in different positions during gravel packing pumping operations (see Figure 7.22). This allows the crossover tool seals to remain in a static position when pumping. This is very important in high rate/high pressure pumping operations since crossover tool movement can occur otherwise, due to pressure and temperature induced pipe length change. If sufficient unaccounted for crossover tool movement were to occur while pumping, thereby moving the crossover tool out of its proper position, the pumped treatment could be diverted from its intended destination. This can cause several problems, including crossover tool sticking. In order to eliminate this possibility, the S.M.A.R.T. Collet, along with the previously mentioned Model “A” Indicating Sub, is run. This combination of tools positively locates the crossover tool during pumping operations, normally conducted in the circulating position. The S.M.A.R.T. Collet allows set down weight to be placed and maintained downhole thereby positively positioning the crossover tool in the desired pumping position, and providing a means of monitoring the crossover tool’s position on the surface by means of the rig’s weight indicator.

Used with the S.M.A.R.T. Collet is the Rotationally Locked Space-Out Sub (see Figure 7.23). The purpose of this sub is to accurately position the S.M.A.R.T. Collet in the service tool string, relative to the gravel pack assembly. This is done to insure the S.M.A.R.T. Collet accurately places the crossover tool in its various pumping positions. As indicated, it is rotationally locked, and has an adjusting stroke of two feet, which can be quickly and easily changed on location.
**Figure 7.22**
S.M.A.R.T. Collet

**Figure 7.23**
Rotational Locked Adjuster Sub
Open Hole Gravel Pack Completion Equipment

The previous discussion centered on performing gravel packs, either high rate/high pressure, or those which are less rigorous, inside a cased hole. All previously discussed equipment, with two exceptions, is suitable for use in an open hole gravel packed application. In order to optimize the gravel pack assembly for use in an open hole, the bottom of the assembly has been modified in order to allow circulation through it. Circulation through the bottom of the gravel pack assembly is considered important for two reasons. First, circulation, along with the ability to rotate the string, may assist in getting the assembly to bottom, in an open hole, especially if highly deviated or horizontal. Second, circulation may be necessary to displace drilling fluids and replace with a clear brine so that the risk of plugging the gravel pack with drilling solids is removed. To optimize the gravel pack assembly for use in an open hole, the following enhancements were added:

- The gravel pack packer, setting tool, and crossover tool have been rotationally locked to withstand up to 7,000 ft-lbs torque, for most sizes (see Figures 7.24 through 7.27).

- Shouldered connections are specified throughout the gravel pack assembly, again capable of up to 7,000 ft-lbs torque, for most sizes.

- As mentioned above, the bottom of the gravel pack assembly has been modified to allow circulation through it.
Figure 7.25
Rotationally Locked Setting System
With Hydraulic Releaser

Figure 7.26
Rotationally Locked Setting System
With Dual Hydraulic Release
Wash Down Shoe. The Wash Down Shoe has a built in bypass mandrel which can divert fluid flow from out the bottom of Shoe to the screen or slotted liner above (see Figure 7.28). It features single activation, and, once activated, is positively locked in the closed position. This feature will prevent any gravel pack or formation material from entering the gravel pack assembly through the Shoe. The Wash Down Shoe is used in conjunction with the Washpipe Extension (see Figure 7.29). It is installed in the warehouse into the Wash Down Shoe. It includes a soft release mechanism which closes the Wash Down Shoe with upward movement. It has 15 feet of stroke before it will close the Wash Down Shoe. The Washpipe Anchor Latch (see Figure 7.30) is run on the end of the washpipe when preparing the gravel pack assembly on the surface. It latches into the Washpipe Extension and retrieves it at the end of the job. It also features 15 feet of stroke.

These three tools together provide open hole washdown capability for gravel pack assemblies, while retaining the ability to gravel pack through the bottom of the screen.
Top Sub

Lock-Ring Housing

O-Ring Sleeve

Bottom Sub

Perforated Bull Nose Sub

Run-In Position

Closed Position

Lock Ring

By-Pass Mandrel

Figure 7.28
Wash Down Shoe

Anchor Sub

Extension Tube

Soft Release Collet

Figure 7.29
Washpipe Extension
References


WELL PREPARATION FOR GRAVEL PACKING

Introduction

Careful planning, well preparation, and completion execution are all required for completion success. The omission of any of these steps may account for a completion that falls short of its objectives since many of the completion operations are interdependent. To achieve the completion goals of sand control, productivity and longevity, attention must be given to drilling practices, cleanliness, completion fluids, perforating, perforation cleaning, acidizing, gravel specifications, tool specifications and rig and service company personnel. The proper preparation of a well for gravel packing can be the key to a successful completion.

Drilling Practices

Productivity of the open or cased hole gravel packed completion is determined in part by the condition of the reservoir behind the filter cake, quality of the filter cake and stability of the wellbore. Given this, it can be said that the completion begins when the bit enters the pay and therefore the goal of drilling is to maintain wellbore stability while minimizing formation damage.

Wellbore Stability. Wellbore stability in the form of washouts, hole collapse and fracturing is an effect of high fluid loss, high PV and YP, inadequate overbalance and or reaction between filtrate and formation. But for what ever reason, instability effects both open and cased-hole completions and can cause loss of the wellbore. Thick cement sheaths in washed-out sections result in poor to no perforation penetration and the lack of cement can make sand placement difficult. Hole collapse can prevent running either casing or screen to bottom and failure in the form of fracturing or collapse can stop an open-hole gravel pack, should failure occur while the pack is in process.

Since stability is an effect of the reaction between drill-in fluid and formation, filtrate, filter cake, weight and rheology become key parameters in building a drill-in fluid. These variables can be usually be addressed by using polymers and fluid-loss agents in a brine based fluid containing a properly sized bridging agent. PERFFLOW® is such a system.

Formation Damage. Formation damage is expressed in the form of skin and is an effect of filtrate and particle damage and filter cake quality in the case of open-hole gravel packs. Skin in turn is reflected in poor productivity and it is expensive to remove or bypass while rarely being completely removed or bypassed. Preservation of reservoir pore throats and rock requires keeping particles out of pores, minimizing filtrate loss and employing a filtrate that is compatible with rock and reservoir fluids. Quality of filter cake for open hole gravel packing is expressed in friability and low breakout pressure which is a function of the particles and polymers that make up the cake.
With open-hole completions filtrate requirements seem rather obvious, but they are generally over looked in cased-hole completions. Frequently it is assumed that any damage caused by filtrate will be bypassed with perforating. Looking at the times reservoirs are exposed and the moderate to high fluid losses, often expressed as a "thirsty mud", it is easy to have filtrate invade 1 to 3 ft. from the wellbore. If this filtrate is incompatible with reservoir rock and fluid, then there is a damaged ring past which it may not be possible to perforate. For open-hole completions, the quality of filter cake is also as important as the other requirements. Since the cake is to be gravel packed into place, it is necessary that the cake be thin, friable and have a low breakout pressure.

Again as with the wellbore stability issue, filtrate and filter cake become key parameters. Proper selection of a filtrate brine base along with polymers and fluid loss agents containing a properly sized bridging agent will usually meet these needs. PERFFLOW is such a system.

Cleaning the Casing, Open Hole, Work String, and Surface Facilities

Cleanliness may be one of the most important considerations when implementing a completion for gravel packing. Since a gravel pack represents the installation of a downhole filter, any action that promotes plugging the filter (i.e., the gravel pack sand) is detrimental to the success of the completion and well productivity. Many advances have been made in improving the cleanliness of gravel pack operations, particularly completion fluids. However, in spite of the fact that clean completion fluids are used, the lack of cleanliness in the casing, work string, lines, pits and other equipment is a source of potential formation damage and lost productivity. While cleaning the well and rig equipment can be expensive, it is not as expensive as lost productivity or having to rework the entire completion because proper cleaning was neglected in the beginning.
It requires only one cubic foot of solids to completely fill 495 average gravel pack perforations. At a typical shot density of 12 shots per foot, this amounts to 41 feet of perforated interval. In completing high permeability, unconsolidated formations, the formation should normally be experiencing fluid loss. If this is the case, all solids entering the well will most likely end up in the perforations. Hence, the risk of formation damage is real and the need for cleanliness is illustrated.

**Casing.** Reverse circulation is the preferred method of circulation for cleaning the casing and the recommended annular velocity is 130 ft/min for casing shoe deviations less than 60° and 300 ft/min for deviations greater than 60°. Reverse circulation is more effective than circulating the long way as material is moved down hole with gravity; unrecovered material is pushed to the bottom of the hole; work string scale and pipe dope, provided the connection is wiped off, does not enter the casing and, in the case of an open-hole completion, reverse circulation permits cleaning the casing to specification before addressing the open hole. Planning for a work string that will permit reverse circulation is required.

Both mechanical, hydraulic and chemical cleaning agents should be employed to clean the casing. Mechanical agents are usually in the form of casing scrapers and most hydraulic agents are push pills and filtered brine. Casing sweeps provide a chemical wash to address polymers, oil and/or solids adhering to the casing wall.

As a mechanical agent, scrapers will remove cement and scale that a bit will miss but unfortunately a packer may not. It is prudent to run casing scrapers to bottom or at least through the interval to be perforated. For open-hole completions, the scraper should be run to within 100 ft of the shoe or at least past the proposed packer seat. In displacing the drill-in fluid, a push pill is pumped first followed by a casing sweep which is followed by filtered brine (See Figure 8.1). Push pills serve as a hydraulic piston by creating a sharp interface between mud and casing sweep. The casing sweep removes polymers and solids adhering to the casing wall and the filtered brine provides turbulence to help remove and wash material out of the casing.

![Reverse Circulation Diagram](image-url)
Push pill volumes should at least be equal to the volume of 300 feet of work string, casing annulus, have the same density as the drill-in fluid and have a yield point that is 1.5 to 2.0 times that of the drill-in fluid. Thus they are easily made from a portion of the drill-in mud by the addition of a viscosifier to raise the yield point. Casing sweeps depend on the chemical employed to remove solids and polymer and to be effective will require some contact time at turbulent rates. For PERFFLOW, calcium hypochlorite (65% active) at 1.5 ppb and a 5 minute contact time will effectively remove PERFFLOW polymers and fluid loss agents.

**Open Hole.** As with the casing, reverse circulation is the preferred method of circulation. With the casing cleaned as previously discussed, now all attention can be focused on cleaning the open hole. Well bore losses and stability can be easily detected and repaired if necessary, and any unrecovered material will be pushed to bottom out of the way. Recommended annular velocity is 300 ft/min at any deviation to scour the filter cake in preparation for gravel packing and to clean the hole.

Push pills should be used to displace the drill-in fluid from the open hole. The pill should be spotted in the casing and work string annulus above the open hole using forward circulation, then the work string is run to bottom and the pill and drill-in fluid displaced from the open hole with filtered brine using reverse circulation (See Figure 8.2). Push pills are formulated and sized as previously discussed under casing clean up.

![Reverse Circulation Diagram](image)

**Work string.** The work string should be sized to permit reverse circulation and always be run in open ended to minimize back pressure on the formation. The work string will contain the same types of debris associated with the casing. However, unlike the casing, both the inner and outer surfaces must be clean because completion fluid will be circulated along both surfaces. Scraping the work string is usually not an option as with the casing, but visual inspections of the tubing before it is run into the well are encouraged to ensure that the tubing is in good mechanical condition and clean. As a minimum, a “rabbit” with a diameter equal to the drift diameter of the
work string will help to loosen scale and other debris, as well as providing assurance of the internal diameter of the work string. Once the work string is clean every effort must be made to keep it clean. A common source of contamination of the gravel pack is thread dope lubricant. Recommendations are to use thread dope lubricant sparingly only on the pin ends during the completion phase, and to eliminate the use of thread dope completely on the final run in the hole just prior to gravel packing the well. Pickling the work string with a pipe dope solvent and 10% HCl before starting a gravel pack is a must. As with any solvent, there is a required contact time and wash rate to dissolve lubricant and carry material out the work string. The use of a dedicated clean work string strictly for gravel packing should be considered if a number of wells are to be completed.

**Surface Facilities.** Tanks and lines are sometimes ignored but are a common cause of damaging materials, particularly when the rig that drilled the well is used for completing the well. Tanks must be thoroughly scraped and jetted to ensure any residual solids from the drilling fluids are removed. When possible, tanks should be dedicated to completion fluids when a drilling program involves drilling numerous wells requiring gravel packs. Casing sweep chemicals and sea water are recommended for removing debris from rig lines.

**Quality Assurance.** If properly filtered brine is used as per following discussion on filtration, the hole displaced as recommended and surface facilities cleaned, then it is easy to obtain brine returns less than 20 NTU’s on cleaning the cased and open hole and throughout the entire gravel pack operation. Again this is only possible if all of the steps are followed and there are no “short cuts”.

**Filtration**

As mentioned previously, gravel-pack completion fluids must be sufficiently clean in order that suspended particles do not plug or reduce the permeability of the formation, perforations or gravel-pack sand. To achieve a clean fluid requires filtration. Completion fluids are typically filtered to at least 2 microns, but in some cases they are filtered to 1 micron. The fluid can be filtered by either a diatomaceous earth (DE) filter upstream in combination with a cartridge filter unit downstream, or with a cartridge filter unit alone. A schematic of the diatomaceous earth unit is shown in Figure 8.3. A cartridge filter unit is shown in Figure 8.4. The diatomaceous earth filter unit does a majority of the filtration before the fluid arrives at the cartridge filter unit. Since diatomaceous earth is less expensive than cartridges, the use of a DE filter with a cartridge filter downstream will be more economical than a cartridge filter unit alone. This is especially true if the completion fluid is very dirty, which is usually true at some point during the completion, or if large volumes of fluid are required, as in the case of gravel packing.
DE filters are not absolute type filters, so a wide variety of particle sizes are capable of “bleeding through” the filter. The diatomaceous earth itself will also bleed through the filter. Diatomaceous earth is very capable of plugging the formation and is not acid soluble; therefore, a DE filter should always incorporate a downstream cartridge filter to stop the diatomaceous earth and provide additional finer fluid filtration.

Cartridge filter units can use either nominal or absolute type filter cartridges. The nominal filters are typically wound elements designed for bulk solids removal using depth type filtration. The absolute filters have pleated elements that rely on surface filtration to retain specific size particles. Absolute filters are rated based on their efficiencies indicated by their beta rating. Beta rating is defined as the ratio of the concentration of a given particle size entering the filter to the concentration of the same size particle exiting the filter. Commonly used filters have beta ratings from 100 to 5,000. **Note that the beta rating is very dependent on flow rate.** As an example, a filter that will stop a 2 micron particle at 1 gallon per minute (gpm) might not stop the same particle at 10 gpm. Also, beta ratio is dependent on the particle size considered. A cartridge will have a higher beta ratio (removal efficiency) when retaining large particles, but a lower beta ratio when retaining smaller particles. A typical cartridge performance curve is illustrated in Figure 8.5. The equation for calculating removal efficiency from the beta ratio is given below.

\[
RE_x = 100 \left( \frac{\beta_x - 1}{\beta_x} \right)
\]

where: \( RE_x \) = removal efficiency for particle size “x” (percent)
\( \beta_x \) = beta ratio for particle size “x”
Most completion fluids used for gravel packing are filtered to 2 microns with at a removal efficiency of 99 percent or better. Care should be taken while filtering to ensure the pressure differential while flowing through the cartridges does not exceed the cartridge manufacturer's recommendation (typically 30 to 50 pounds per square inch) or collapse of the cartridge may occur destroying its efficiency. Filtration of naturally viscous fluids may present a problem due to the increased pressure drop required to flow a viscous fluid through the cartridge. Occasionally, extremely dirty fluids may have to be dealt with. If time permits, it is advisable to allow the dirty fluid to stand undisturbed overnight to allow solids to settle to the bottom of the tank. The clean fluid can then be decanted from the top of the tank and filtered without having to deal with the large volume of settled particles. Oil entrained in the completion fluid can also present filtration problems.

![Cartridge Filter Unit for Completion or Workover](image_url)

If viscous polymer gels are used during the completion, the base fluid should be filtered before the polymers are added. After adding the polymers, the gel should be thoroughly sheared to remove unhydrated dry polymer clusters commonly referred to as “fish eyes”. After shearing, the polymers can be filtered through a cartridge filter unit. The cartridge filters used for gels are generally rated to 10 microns with a minimum 98 percent removal efficiency. Attempting to filter viscous polymer gels prior to shearing tends to plug the filter unit and remove the polymer from the base fluid.
To summarize, the technique used to filter the fluid is not the issue, it is the fluid cleanliness that is important. The filtration technique used is based strictly on achieving the desired results in the most economical fashion. All fluids entering the well after the initial casing clean-up should be filtered. Filtration should be performed throughout the entire completion operation, because small amounts of debris are continuously being removed from the well throughout the pumping operations.
Completion and Gravel Pack Fluids

In addition to being clean, the fluids used in the well completion must be compatible with the formation and formation fluids. Of particular concern is clay swelling and compatibility with formation water to avoid ion precipitation. The candidate completion fluids should be tested in the laboratory to ensure their compatibility with the formation and formation fluids. An incompatible completion fluid can cause permanent formation damage. The normal sources of completion fluids are produced brine, sea water or clear brines.

Of course, the overriding design criteria for a completion fluid is the hydrostatic requirements to maintain well control. Fluid density can be controlled by the addition of several soluble salts such as sodium chloride, sodium bromide, potassium chloride, ammonium chloride, calcium chloride, calcium bromide, zinc chloride, zinc bromide and lithium bromide. The densities of these fluids range from 8.33 to as high as about 20 pounds per gallon (ppg). All have their advantages and disadvantages and, depending on the density of the fluid required, their cost can exceed $500 per barrel.

The fluids used for gravel packing can be water or oil based. The water based fluids are usually the most desirable and are considered to be more flexible than the oil based systems. Because of this, the water based fluids are more commonly used. The simplest water based fluid used for gravel packing is the completion brine itself. Crude oil has been used in the past by some companies in preference to water because it was less expensive, however, with the increase in the cost of oil its use has been largely discontinued in preference to the water based systems. Crude oil is still a valid alternative in extremely water sensitive formations.

Fluid loss control is a common consideration when completing unconsolidated formations with a gravel pack. This is especially true in very high permeability formations. In addition to the potential formation damage caused by fluid loss, there is particular anxiety when high cost fluids are involved or when completion fluid reserves are low. The amount fluid loss that can be tolerated tends to be site specific, but when losses exceed about 30 barrels per hour (bph), concern is usually voiced. Chapter 10 deals specifically with fluid loss control techniques. At this point, it is important to emphasize that the fluid loss control technique selected should be compatible with the formation and any damage caused by the technique should be reversible.

Summary

The factors influencing the success of a completion begin when the drill bit enters the pay zone. From this point onward, all operations should be carried out with consideration given to their effects on the formation. In addition to proper drilling and cementing operations, successful completions are dependent on establishing and maintaining a clean wellbore environment. All fluids and equipment put in the well should be evaluated with this in mind. Simple quality control checks, such as NTU readings on completion fluid, can be implemented to monitor and ensure the wellbore is as clean as possible throughout the completion.
References


PERFORATING FOR GRAVEL PACKED COMPLETIONS

Introduction

This chapter reviews perforating technology applicable to gravel packs that focus on achieving high-productivity completions. Operations that aid in cleaning debris from the perforations prior to gravel placement will also be discussed.

Cased-hole completions must be perforated to establish communication between the formation and the wellbore. The perforating operation penetrates the casing, cement, damaged zone and, hopefully, into the undamaged formation to communicate it with the well. Perforating guns are configured to provide a variety of shot diameters, shot densities, and entrance-hole phasing. The perforating gun system consists of the charge (multiple charges are used in an actual gun), primacord, detonator, and the hollow carrier as shown in Figure 9.1 illustrates. The size, phasing, and shot density can be varied depending on the gun design. Figure 9.2 shows an example of the perforating pattern created by a 90° phased gun, but phasing of 0, 30, 45, 60, 120, and 135 degrees are also available. Shot densities as high as 21 shots/ft. are available depending on the guns size. Perforating is an effective way of communicating with the formation, but it is extremely violent, and may leave a considerable amount of debris within the perforation tunnel. In non-gravel packed wells, the debris usually can be flowed from the perforation during production. In gravel packed wells, there is a danger of trapping the debris in the perforation tunnel with the gravel pack sand, reducing its permeability which results in permanent damage to the well and reduced productivity.
Shaped Charge Technology

Shaped charge (jet perforators) are the primary method used to communicate the well with the formation for both gravel packed and non-gravel packed completions, but occasionally bullet guns are used when large gun sizes can be used and the formation temperature is less than 250°F. Shaped charges consist of a case to contain the charge, explosive charge and a liner made of some inert material such as powdered compressed copper. An example of a shaped charge is shown in Figure 9.3. Upon detonation, a high-pressure jet is formed that consists of the liner and explosive gases that is projected forward at a velocity of about 30,000 ft/sec. The jet produces an impingement pressure of about 15 million psi that impacts the casing, cement and formation to create (punch) the perforation since the impingement pressure exceeds the strengths of the surroundings.

The shaped charge detonation is initiated at the back of the charge and moves toward the front creating a pressure wave. The pressure wave causes the liner to collapse inward and forces it to move out along the center line of the charge. The pressure wave and collapsed liner material begin to form a jet and continue to travel along the center line of the shaped charge at a velocity of 30,000 feet per second (fps). The tail of the jet travels much slower (±15,000 fps) due to the lessening of explosive energy available as the charge spends. The extremely high pressure and velocity at the tip of the jet forces the casing, cement and formation to plastically yield and flow out the path of the jet to create the perforation. The shaped charge detonation sequence described above is illustrated in Figures 9.3 & 9.4, and a schematic of the pressures and velocities is portrayed in Figure 9.5.
Figure 9.3
Shaped Charge Detonation Sequence
Shaped charges used for perforating are available as deep penetrating (DP) charges and gravel pack (GP) charges. The interior shape of the housing and the shape of the liner determine the shape and size of the jet formed by the charge. A deep penetrating charge liner typically has a deep, sharp angle, usually in the range of 42° to 45°. The angle of the liner acts to focus the jet to achieve a greater depth of penetration (See Table 9.1). The DP charge creates a perforation that has a small diameter entry hole in the casing and deep penetration into the formation. A GP charge liner is designed with a wide angle to create a larger entrance hole. The GP charge creates a perforation that has a large diameter entry hole in the casing and a relatively shallow depth of penetration.

Figure 9.6 and Table 9.1 show the differences between the design & performance of deep penetrating and gravel pack charges. Other factors that affect the performance of the charge include the distance between the shaped charge and the ID of the gun carrier (i.e., stand-off) and the distance between the OD of the gun carrier and the ID of the casing (i.e., clearance). The engineering design of a gun seeks to optimize the various factors to create the desired type of perforation.

<table>
<thead>
<tr>
<th>Charge Characteristic</th>
<th>Deep Penetrating Charge</th>
<th>Gravel Pack Charge</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liner</td>
<td>Deep, sharp angle (42° to 45°)</td>
<td>Shallow, rounded liner</td>
</tr>
<tr>
<td>Entry Hole Penetration</td>
<td>≈ 3/8” to 1/2” diameter</td>
<td>≈ 1/2” to 1” diameter</td>
</tr>
<tr>
<td></td>
<td>≈ 13” to 30” deep</td>
<td>≈ 6” to 8” deep</td>
</tr>
</tbody>
</table>
Types of Explosives

The explosive materials normally used for shaped charges are RDX, HMX, HNS and PYX. The explosive selected is based on the time that the guns will be exposed to the maximum anticipated well temperature. The exposure limits for the various explosives are shown in Figure 9.7. (Exposure to high temperatures for extended lengths of time caused the explosives to either detonate low or high order or to outgas and melt.) Knowing which event occurs can not always be predicted. Hence, the temperature stability chart, Figure 9.7 is valuable in establishing safe time-temperature limits. Table 9.2 shows the maximum temperature that can be withstood by the various explosives for an exposure time of 100 hours. In term of cost, RDX is the lowest and PYX is the highest. The type of explosive will effect charge performance due to different detonation characteristics. RDX and HMX are essentially equal in energy output (i.e., performance) but are rated for lower temperatures, whereas HNS and PYX are rated for progressively higher temperatures. However, the performance of HNS is about 10 to 15% less than HMX while the PYX performance is about 10 to 15% less than HNS, i.e., while greater temperature stability is achieved with HNS and PYX, performance is decreased.
Figure 9.7
Temperature Ratings of TCP Explosive Systems

Table 9.2
Maximum Temperature Rating
of Explosives at 100 Hours Exposure

<table>
<thead>
<tr>
<th>EXPLOSIVE TYPE</th>
<th>TEMPERATURE LIMIT</th>
</tr>
</thead>
<tbody>
<tr>
<td>RDX</td>
<td>240°F</td>
</tr>
<tr>
<td>HMX</td>
<td>310°F</td>
</tr>
<tr>
<td>PYX</td>
<td>500°F</td>
</tr>
</tbody>
</table>
Perforating for Gravel Packing

In non-gravel packed wells, experience and theory\(^1\) indicate that a perforation density of four shots per foot is sufficient in most wells to equal the theoretical open-hole productivity of the formation (see Figure 9.8). The perforations in a gravel packed well will be gravel filled. In fact, filling the perforations with gravel pack sand is a critical phase of gravel packing. Since the gravel pack sand has a porosity of about 35 percent, a perforation filled with gravel will have about two-thirds of its cross-sectional flow area occupied by gravel with only a third of the perforation area capable of passing reservoir fluids. Viewed from another perspective, if two-thirds of the perforation cross-sectional area is occupied by gravel, a shot density of twelve shots per foot is required to achieve the effective cross-sectional flow area of four perforations not filled with gravel pack sand.

![Figure 9.8: Productivity Ratio Versus Perforation Penetration and Density\(^1\)](image)

The primary objective of perforating as applies to a gravel packed well, is to communicate with the reservoir, have adequate perforation area and to prepack each perforation with uncontaminated gravel. Said another way, not only is the perforation density a concern, but the perforations should be as large as possible and must be effective and contribute to flow. Even where the perforation density is 12 shots per foot, if the diameter of the perforations are small, there may be a substantial pressure drop through the perforations that limits the well’s flow capacity. Figure 9.9 illustrates a perforation filled with gravel pack sand. This geometry represents ideal conditions and is probably seldom achieved; however, every attempt must be made to place as much gravel as possible into each perforation to provide a defined interface and prevent mixing of formation sand and gravel pack sand. Referring to Figure 9.9, note the area of linear flow through the perforation tunnel. Neglecting compressibility effects and turbulent effects, Darcy’s equation is applicable to this area of liner flow is:
\[
\Delta p = \frac{1360322 \mu q L}{kd^2}
\]

where:
- \(\Delta p\) = flowing pressure drop (pounds per square inch)
- \(\mu\) = viscosity (centipoise)
- \(q\) = flow rate (barrels per day)
- \(L\) = distance from screen OD to cement sheath OD (inches)
- \(k\) = gravel pack sand permeability (darcys)
- \(d\) = diameter of perforation (inches)

For a given flowrate, the only non-reservoir factors that can be controlled to reduce the pressure drop is increasing the flow area by increasing the perforation diameter and increasing the permeability of the gravel pack sand. The permeability of the gravel pack sand is determined by the size of the gravel required for sand control as discussed in Chapter 5. Table 9.3 shows the results of the calculations using the above equation for different diameter perforations and gravel pack sand permeabilities. As can be seen from the table, increasing perforation size decreases the pressure drop required to maintain a given flowrate.
From the discussion thus far, it should be evident that perforating for gravel packed wells requires large hole diameters and high-shot densities. This point can be further emphasized by performing a systems analysis on the inflow of the reservoir and the outflow of the well’s tubing and completion. Such an analysis is frequently referred to as systems (inflow-outflow) or NODAL analysis and can be extremely valuable in optimizing a well’s productivity. The logic used with this method of analysis is that flow from the reservoir represents potential inflow into the system, while the tubing capacity represents outflow. Figure 9.10 shows the inflow-outflow results for a typical high permeability well requiring a gravel pack. The figure shows five reservoir inflow curves and one tubing outflow curve. The intersection of the inflow curves with the outflow curve indicates the theoretical flow rate possible from the well for that condition. The five reservoir inflow curves represent the case of ideal productivity (i.e., no damage and no gravel pack), high-shot density with large hole size, high-shot density with small hole size, low-shot density with large hole size and low-shot density with small hole size. As can be seen, the case of high-shot density with large perforation hole size comes closest to achieving the ideal well productivity. This situation is desired in wells requiring a gravel pack.
The large entry hole, high-shot density perforations required for gravel packed completions can be created with either wireline or tubing-conveyed guns, but tubing conveyed guns are usually preferred because they can perforate the entire production interval underbalanced in a single gun run. The capability to perforate long intervals in one operation becomes more significant because of the desirability of underbalancing the zone to be perforated. Wireline perforations can typically shoot only about 2 to 30 feet of perforations at a time because of lubricator length limitations. If the zone to be perforated is longer, multiple wireline runs are required, and the additional gun run will be shot at formation pressure (balanced) because the well pressure will equalize after the first perforating run. Hence, wireline perforating becomes more attractive for short intervals that can be perforated in a single gun run. When formation temperatures are high, the speed at which wireline guns can be run, positioned and detonated may allow the use of lower temperature rated, lower cost and more efficient RDX or HMX explosives as opposed to HNS or PYX which would have to be used in TCP perforating operations because of the longer temperature exposure time.

The system analysis approach can be used to design the optimum perforations required for a given formation, but may, in many cases, be an academic exercise because the exact number of perforations contributing to flow (due to misfires or tunnels not being in communication with permeable formation) is not always known. Also, it is difficult to determine how many perforations are plugged with debris. In most cases, the practical approach is to perform the systems analysis exercise to determine the ideal shot density and hole size requirements and then select the perforating gun that can generate the required perforation performance plus some additional performance in terms of hole size and shot density without causing significant cost or operational problems.
Another consideration is that unless the perforating guns are centralized, the perforations will not be the same depth or diameter in all directions. If the charges do not penetrate deeply (as is the case with gravel pack charges), the perforations made in one direction may never even penetrate the cement outside the casing. There is also the possibility that some charges in the gun may not perform as designed. Because of the potential of having perforations that do not meet the published perforation diameter and penetration, wells should always be perforated with as many perforations as is practical.

**Perforation Cleaning**

As stated previously, when a shaped charge explosive is detonated, a high-pressure jet is formed which can easily reach pressures in excess of 15,000,000 psi at the front of the pressure wave. At these pressures, virtually all materials are plastic and penetrable. The charge does not “burn” or “cut” a hole through the material in front of the pressure wave. Instead, the pressure jet literally pushes its way into the material, much the same way that a nail will push a path into a block of wood.

When the jet pushes through the casing and cement, and into the formation, it compacts the materials immediately surrounding the perforation. Since the cement and the formation are crystalline in structure, they are compacted to a greater extent that the steel. Because of this, a zone of reduced permeability is created at the boundary of the perforation in the formation as illustrated in Figure 9.11. This compacted zone can be up to 1/2 inch thick and can have a permeability that is substantially less than that of the bulk formation which can significantly restrict well productivity.

![Figure 9.11: Typical Results of Perforating Without Cleaning](image)

In addition, the shaped charge creates debris that is deposited in the perforation. The metal from the housing is typically steel and is not soluble in acid. The liner is usually made of compressed copper that forms a copper slug called a “carrot” after the perforation is created. The carrot may remain inside the hollow carrier and be retrieved or could remain in the perforation tunnel or become lodged in the perforation entrance hole in the casing.
The perforating debris and the compacted zone must be removed to maximize well productivity. Failure to remove the debris and compacted zone can reduce the potential production rate. The methods available for perforation cleaning include acidizing, washing, backsurging, and underbalanced perforating. Some recent developed techniques are also available to assist in the operation of cleaning the perforations.

Acidizing - Acidizing perforations involves injecting a predetermined type and volume of acid into the perforations after they have been created to dissolve any acid soluble material. In most cases, perforating debris is not highly soluble in acid, therefore, acidizing is more effective and better applied when used in conjunction with some of the other cleaning techniques discussed in this section. Some critical considerations when acidizing are the compatibility of the acid with the formation, the volume of acid to pump and uniform placement of the acid into the perforations.

Acid solubility tests should be performed on a formation sample to select the most effective acid. This is extremely important, because certain situations exist in which the acid will actually damage the formation instead of providing stimulation and higher productivity. The volume of acid to pump is typically determined by the number of perforations and the length of the perforated interval.

Poor placement of acid produces variable and inconsistent results possibly leading to a decrease in productivity. Ideally, each perforation would receive an equal volume of acid. In reality, the acid tends to go into the perforations that already open to flow and do not especially need cleaning. Meanwhile, other perforations that do need cleaning allow little or no acid to flow into them. To achieve uniform placement of acid into the perforations, an acid "diverter" can be used in an attempt to divert acid from the permeable perforations to the damaged perforations. The usual technique involves pumping several stages of acid separated by diverter slurries consisting of viscous gel and gravel pack sand. The diverter will flow into the most permeable perforations and fill them with gravel pack sand. The combination of gravel pack sand and the high viscosity of the gel reduces the ability of the perforation to accept fluid. The next acid stage should then flow into the other, more resistive perforations allowing for a more uniform treatment. This technique is referred to as a "staged acid treatment" or an "acid prepack" and can be performed immediately after underbalanced tubing conveyed perforating (for best results) or just prior to performing the gravel pack.

Washing - Washing perforations involves running an opposing cup type tool into the well after perforating the producing zone. The cup tool seals on the inside of the casing and allows a circulation path through the tool and out ports located between the opposing cups. The tool’s cups packing is usually about one foot to focus the washing operation over a short interval. The washing consists of pumping filtered completion fluid at as high rate as possible without breaking down the formation, as Figure 9.12 illustrates. The goal of washing is to establish communication between several sets of perforations to effectively remove the perforation debris and compacted zone from the well.
Perforating washing is an excellent way of cleaning perforations. Unfortunately, it is commonly performed incorrectly because the operation is time consuming. Prior to underbalanced tubing conveyed perforating, washing was a commonly applied perforation cleaning technique. Unfortunately, results of washing tended to be unpredictable because of the flawed procedures and as a consequence, its use is not widespread today. Although often discounted, washing has given favorable results in some fields and may be worthy of consideration, particularly in conjunction with other cleaning techniques such as backsurging and underbalanced perforating.

**Backsurging** - Backsurging involves running a calculated volume of atmospheric chamber into the well after perforating. The atmospheric chamber is trapped in the workstring between two valves. A packer is set and the lower valve is opened exposing the perforation to atmospheric pressure. The formation immediately surges in with significant force to hopefully remove the debris and compacted zone from the perforations. Backsurging can be a very effective perforation cleaning technique and is often used following overbalanced wireline conveyed perforating. The primary disadvantage of backsurging is that it requires a special trip in the hole with the backsurging tools. Also, results from backsurging have been documented to be somewhat inconsistent. More details on backsurging are available in SPE Paper 12106.²

**Underbalanced Tubing Conveyed Perforating** - Underbalanced tubing conveyed perforating has been shown to be an efficient means of cleaning perforations from a total operating standpoint because the underbalance can be preset prior to detonating the perforating guns. The goal of underbalanced perforating is to remove all debris and the compacted zone from the perforation tunnels as illustrated in Figure 9.13. Underbalanced perforating is similar to back surging in that the formation is exposed to a low pressure in the wellbore and is allowed to surge to clean the perforations. Unlike backsurging, which requires a special trip in the hole to execute, underbalanced perforating is done in conjunction with the perforating operation. Underbalanced refers to the condition where the hydrostatic pressure in the wellbore at the guns is lower than the pressure in the formation being perforated. Upon gun detonation, the formation is immediately
(within milliseconds) surged by backflow into the well. To effectively surge all the perforations, tubing conveyed perforating guns must be used. If wireline conveyed guns are used, only the first run in the well is surged as mentioned previously. Also, in some cases, the amount of underbalance must be limited to prevent blowing the guns up the hole after they are fired.

The amount of underbalanced pressure that the formation is exposed to can be adjusted to achieve optimum results. Typically, the underbalanced should surge the formation up to, but no exceeding, the point of massive formation failure. Excessive formation material surged into the well can stick the guns in the hole. Determining how much underbalance is required is a trial and error procedure within a specific formation. Normally, a starting underbalance of 500 psi is suggested for oil wells and 1,000 psi gas wells.

![Diagram of Effectively Cleaned Perforation After Underbalance Perforating](image)

**Figure 9.13** Effectively Cleaned Perforation After Underbalance Perforating

**Fracturing** - A relatively new technique is to bypass perforating damage instead of using a cleaning or removal technique. Extreme overbalance perforating is used to perforate and then fracture the formation. As of early 1995, the process has only been utilized on consolidated formations with relatively high compressive strengths.

Frac-pack and $\text{H}_2\text{O-FRAQ}^{\text{SM}}$ completions have been successfully used in unconsolidated formations to bypass perforating damage as well as drilling and cementing damage. Although these processes are still being evaluated, there is certainly evidence of increased productivity. Further discussion of fracturing to by-pass damage is contained in Chapter 12.

**Reduced Debris-Size Charges** - PERFFORM$^{\text{TM}}$ shaped charges have been developed to minimize the size distribution of perforating debris that is created and is left in the perforations. When a standard shaped charge is detonated, the solid copper liner creates a carrot that may remain the in perforation tunnel. However, when a PERFFORM$^{\text{TM}}$ shaped charge is detonated, no carrot is formed because the liner is fabricated with a patented alloy, which does not consolidate into a solid carrot. Instead, a high density jet is formed. In addition to eliminating the carrot, the PERFFORM$^{\text{TM}}$ shaped charge creates debris that is much smaller in size.
consequence is that the debris can more easily flow from the perforation tunnels as well as being more soluble in acid than the debris created by a standard shaped charge. Acid solubility tests reveal that the PERFFORM™ debris is 64% soluble, whereas the standard charge debris is only 3% soluble. Hence, by minimizing the particle size of the debris that is created and increasing the solubility of the debris that remains, reduced operational problems result, i.e., perforation tunnels will be much cleaner, acid treatments are more effective on perforation cleanup and ultimate productivity will be improved. Finally, the PERFFORM™ charge provides cleaner perforations without sacrificing entry hole diameter, shot density or penetration.

PERFFORM™ shaped charge advantages:
- Does not form a carrot
- Smaller debris size
- Increased debris solubility
- Cleaner wellbores and perforations
- Reduced completion problems related to perforating debris
- Enhanced formation treatments
- Improved productivity

Underbalanced Perforating with Auger Guns - Auger tubing conveyed perforating guns were developed in late 1990 and represent a unique and radically different approach to enhancing traditional underbalanced perforating. The basic concept of the system is to enclose standard tubing conveyed perforating guns and accessories in a perforated shroud. Attached to the outside of the shroud is a continuous spiral blade forming an auger which is capable of rotating out of packed sand as required. The ultimate goal and advantage of Auger tubing conveyed perforating guns is improved well productivity.

Auger tubing conveyed perforating guns are available for 7" and 9-5/8" casing and can be used with mechanically or hydraulically actuated firing heads. The auger shrouds with left hand helical augers are mounted on the perforating guns using special gun connectors. The gun connectors rotationally lock the shrouds to the guns and align the perforations in the shrouds with the gun's spiral shot pattern. The left hand auger allows the guns to be rotated out of packed sand with right hand rotation.

The auger shrouds must cover the entire length of the guns, firing head and tubing above the firing head to a flow port. Connections through the augered length of the hook-up are Stub Acme to allow high tensile and torque loads. Above the augered section of the hook-up, standard perforating accessories with API IF drill pipe connections are used. A special retrievable packer, to withstand high torque loads, completes the standard hook-up.
The features and benefits of the Auger Gun System include:

- Gun centralization due to the auger blades results in uniform and improved perforating charge performance.
- The helical pattern of the auger blades increases fluid velocity in the gun/casing annulus resulting in more efficient removal of formation fines and perforating debris. Fluid velocities around auger guns are 4 to 5 times greater than around standard perforating guns.
- Perforating can be done with significantly higher underbalance since the auger design overcomes gun sticking problems. Stuck guns can typically be retrieved with straight pull. If straight pull is unsuccessful, right hand rotation will unscrew the guns from the formation sand surged in from the perforations.
- In gravel packing applications, the well can be prepacked after flowing the well to remove perforating debris without unsetting the packer and moving the guns. This technique is especially applicable in high fluid loss wells since the prepack gravel becomes a clean non-damaging fluid loss control agent.
- Auger blades can reduce gun shock by as much as 40 percent.
- The auger blades and shroud do not interfere with the gun shot pattern resulting in standard API gun performance.
- Auger guns are compatible with PERFFORM™ reduced debris perforating charges.

Specifications and ratings of the Auger Gun System are as follows:

- The system for 7” casing uses a 4-1/2” 12 shots per foot, 45° phased perforating gun with a 4-3/4” OD shroud and 5-13/16” OD auger blades.
- The system for 9-5/8” casing uses a 6” 12 shots per foot 45° phased perforating gun with a 6-1/2” OD shroud and 8-1/8” OD auger blades.
- Torque rating is 6,000 ft/lbs.
- Tensile rating is 160,000 lbs. with no torque and 50,000 lbs. with 6,000 ft/lbs. of torque.
- Pressure rating is 17,000 lbs. per square inch.

Summary

The primary objective of perforating for a gravel packed well is to provide large inflow area (12 shots/ft. or higher and 3/4” or larger perforations) through the casing because the subsequent gravel pack will fill about two thirds (2/3) of the perforations with gravel. The secondary objective is to clean the perforations to remove all debris and formation material prior to packing the perforation tunnels with gravel prior to performing the annular gravel pack. Ways of achieving these objectives is to perforate the well underbalanced in a single operation using large diameter, high-shot density perforating guns. Washing or surging are also alternatives to providing additional perforation cleaning over and above that achieved with underbalanced perforating.

References

Chapter 10

FLUID LOSS CONTROL

Introduction

Fluid loss should be controlled or managed but not necessarily stopped. As mentioned in Chapter 8, the amount of fluid loss that can be tolerated during the completion is site specific. Ideally, nothing would be done to stop fluid loss, but when expensive high density brine is being lost, completion fluid reserves are low or the loss rate makes operations unsafe, some type of loss control system must be employed. Also, the formation damage potential of continued fluid loss (even though the fluid is filtered) should be considered in light of the potential damage from employing a fluid loss control system.

The normal methods for controlling fluid loss are:

- Reduced hydrostatic pressure
- Viscous polymer gels
- Graded solid particles
- Mechanical means

The type of fluid loss control that is recommended depends upon where in the well completion process you are. Since the completion process should be considered as beginning as soon as the bit enters the pay and continues through the running of production tubing, fluid loss may become an issue at the following times:

- While drilling the reservoir
- During an open hole gravel pack (especially for a highly deviated hole)
- Immediately after perforating
- After prepacking
- After gravel packing

When selecting a fluid loss control technique, the condition of the well at the current time, operations that still must be completed, and available remedial techniques for elimination of the ill effects of fluid loss control must all be considered. These considerations will lead to different fluid loss control techniques being utilized throughout the completion process.

Hydrostatic Pressure

Fluid loss is a direct result of differential pressure into the formation due to the overbalanced condition created by the hydrostatic pressure of the completion fluid. A reduction in the rate of fluid loss can be accomplished by simply lowering the density of the completion fluid. Some operators have even allowed the hydrostatic pressure exerted by the completion fluid to equalize with the formation pressure by letting the completion fluid seek its own level in the wellbore. Working with a low fluid level in the well would only be acceptable in wells that are not capable of flowing to surface. Regulatory authorities and/or operator imposed safety regulations may
dictate the minimum hydrostatic overbalance allowed which could limit the effectiveness of this technique.

The rate of fluid loss associated with a given overbalance pressure is controlled by several factors. To estimate the fluid loss rate for a given differential pressure, Darcy’s Law for radial flow can be examined.

\[ Q = \frac{kh\Delta P}{24 \times 1412 \times B_o \times \mu \times \left( \ln \left( \frac{r_e}{r_w} \right) - 0.75 + S \right)} \]

Where:
- \( Q \) = Loss rate (bph)
- \( k \) = Permeability (md)
- \( h \) = Net sand thickness (ft)
- \( \Delta P \) = Pressure differential (psi)
- \( B_o \) = Formation vol. factor of comp. fluid
- \( \mu \) = Visc. of comp. fluid (cp)
- \( \ln(r_e/r_w) = \) Assume = 8
- \( S \) = Skin

This equation indicates that the flow of fluids from the wellbore for a given differential pressure is controlled by the formation’s permeability, the interval thickness, the viscosity of the flowing fluid, the compressibility of the reservoir fluids, as well as the degree of formation damage surrounding the wellbore. Figure 10.1 illustrates the level of fluid loss rates associated with a 1 cp fluid leaking off to formations of different permeabilities with overbalance pressures ranging from 0 to 500 psi. This plot makes it clear that while a reduction of overbalance pressure may successfully control fluid loss for moderate to low permeability formations, for high permeability formations excessive loss rates may still occur even for overbalance pressures down to 100 to 200 psi. Overbalance pressures much below this level will impose additional well control concerns on the operation.
There are two factors, increased brine viscosity and formation damage, that can improve the ability of hydrostatic head reductions to control fluid loss. Figure 10.2 is a plot of fluid loss rate for a 3 cp brine, with all other well conditions being the same as those modeled in Figure 10.1. Comparison of Figure 10.2 to Figure 10.1 illustrates that a 3:1 increase in viscosity leads to a 3:1 reduction in fluid loss rates. However, for high permeability formations, the losses can still be excessive.

The effect of a damaged zone surrounding a well is also to reduce the fluid loss rate, but not as significantly as does an increase in fluid viscosity. Figure 10.3 indicates that a doubling of skin from 5 to 10 results in a 30 percent reduction in fluid loss rate.
Viscous Polymer Gels

Examination of Figures 10.1 and 10.2 shows that fluid loss rate is directly affected by the viscosity of the fluid that is lost to the formation. This relationship between loss rate and viscosity has led to the common use of viscous polymer gels to control fluid loss. Viscous gels are very effective at controlling losses provided the permeability of the formation and the overbalance are not too great. In general, it becomes impractical to control fluid loss if the wellbore pressure exceeds the reservoir pressure by more than about 500 psi. In addition, elevated temperatures are detrimental to the ability of gels to control fluid loss. The gels will degrade at high temperatures and often additional gel pills will be required throughout the course of the completion or workover to keep the loss rate at an acceptable level. The total volume of pills likely to be needed can be calculated based upon Darcy’s Law calculations combined calculations of viscosity increase as the velocity decreases with radial distance into the formation. Figure 10.4 illustrates the results of such a calculation.
If the temperature is such that the gel degrades too slowly or incompletely, chemical breakers may be required. Breakers are chemicals which act to degrade the polymer and restore the viscosity to the original value of the base brine in which the polymer was mixed. The biggest disadvantage to the use of viscous polymer gels as a fluid loss control technique is a tendency of residual polymer or viscous gel to remain in the near wellbore area where it inhibits flow.

Hydroxy-ethyl-cellulose (HEC) is one of the most commonly used polymers for viscosifying oilfield brines. It is supplied as a dry powder and is easy to transport, safe to handle and environmentally acceptable. It is also compatible with a wide range of completion fluids and may be broken with a wide range of breakers. If required to be stored for more than a few days after hydrating, biocide must be added because bacteria present in the brine, tanks or lines will cause the polymer to break prematurely. Biopolymers like XC and Shellflo-S have also been used for fluid loss control, but like HEC, are not effective in extremely high permeability formations.

HEC is commonly mixed in ratios of 65 to 75 pounds per 1,000 gallons of brine when used as a gravel pack carrier fluid. For fluid loss applications, HEC can be mixed in ratios of 90 to 150 pounds per 1,000 gallons. At 194°F, an HEC gel pill without a breaker will probably completely break in a few days. At 185°F, approximately 14 days will be required for an HEC gel pill to totally break. Below that 185°F, the gel is unlikely to completely break without the use of a chemical breaker. HEC gel can be broken at low temperatures with a weak solution of any
of the commonly available enzymes. At medium to high temperatures oxidizers and weak acids, such as sulfamic, formic, citric, hydrochloric, etc. are used as breakers.

Before oxidizers are used as breakers, consideration should be given to the possibility of the damage to the formation caused by the oxidizer. The freshness of oxidizers is also important, since the quality of oxidizers deteriorates fairly quickly once a container has been opened. If the oxidizing agent is not fresh, then the gel will not break completely, and in some circumstances may not break at all for a significant length of time causing plugging in the near wellbore area and inhibition of production.

At normal well temperatures, a maximum of 0.15 percent by volume of HEC remains behind as residual solids after complete viscosity reduction with chemical breakers. If large quantities of gel are pumped into a well which has been cased and perforated, consideration should be given to the resultant volume of residual solids produced by the broken gel. The solids volume may prove to be a significant portion of the volume of the perforation tunnels. As discussed in Chapter 8, the HEC gel should always be pumped through a shear device to ensure that all the dry HEC material has completely hydrated. The hydrolyzed gel should then be filtered before being pumped into the well.

Crosslinked HEC systems have been investigated for use as a fluid loss control technique in high permeability formations; however, they should be used with caution. The high viscosities and sophisticated breaker systems of crosslinked HEC may give promising sealing and dissolving results under laboratory conditions, but their use is questionable for field applications. A crosslinked HEC system is not filterable to 2 micron specification, is very sensitive to hydraulic shearing and involves the use of exotic breaker systems that have not been totally reliable in field operations. Crosslinked HEC systems designed to control fluid losses over time normally involves the use of encapsulated, delayed chemical breakers designed for formation fracturing operations that can cause dramatic permeability impairment in wells that will be gravel packed.

**Graded Solid Particles**

The third class of fluid loss control materials is the use of graded solid particles. These materials consist of solid particles of different types that have been carefully sized to form a filtercake either on the formation face or on gravel pack sand. These solids should be designed to provide fluid loss control by creating a thin filter cake to reduce adhesion and operational problems and to provide better opportunity for complete removal. Particle sizing must be designed so that little invasion of solid particulate occurs. The general assumption is that particles with sizes as small as 1/3 of the pore throat openings of the formation will aid in plugging or bridging of the pore throats to form a thin impermeable filter cake. The square root of the formation permeability in millidarcies can be used as a rough estimate of the size of the pore throat opening.

The base fluid used to carry the solids into the well must be compatible with the formation fluids and matrix mineralogy of the formation. The solids and viscous carrier fluids must be stable under downhole conditions without phase separation and migration of particles. The final density of the material must be heavier than the completion brine to prevent density underbalance effects in deviated wellbores.
The three most common fluid loss systems using graded solids mixed in viscous carrier fluids are:

- Resin particles (soluble in solvents like xylene or diesel)
- Salt particles (soluble in undersaturated brine)
- Calcium Carbonate particles (soluble in acid)

**Oil Soluble Resins**

Establishing a mechanical bridge at the formation face requires carefully sized solids mixed in a viscous carrier fluid and pumped in the well. One such solid material is oil soluble hydrocarbon resins. Oil soluble resin systems were developed for use as fluid loss control and acid diverting agents, and have been utilized successfully in gravel pack applications in some fields. Oil soluble resin fluid loss control systems were improved considerably at the end of the 1980’s and have been used extensively in the North Sea.

A typical oil soluble resin systems consist of:

- Brine as a base fluid
- HEC as a viscosifying agent
- Graded oil soluble hydrocarbon resins for loss control in larger pore throats
- Starch and/or crosslinked starch for fluid loss control in the smaller pore throats
- Magnesium oxide as a pH buffer at higher temperatures

Oil soluble resins normally have an upper temperature limit of 212°F. The most common type of oil soluble resin is made of polymerized hydrocarbons. A new type oil soluble resin made by processing natural pine resin has recently been developed. This resin is stable in temperatures up to 300°F and easier to dissolve.

Laboratory testing of oil soluble resins at actual well conditions and formation parameters is recommended to determine the suitability of the resin system. In addition to bridging particles at the face of the formation, some of the resin can liquefy. The amount of liquefied resin depends on the amount and type of hydrocarbons the resin contacts in the well and on the downhole temperature. In some cases, this liquefying effect has been known to produce a gummy mass which effectively invades the formation and is difficult to remove. Resins have also been seen to coagulate into a hard mass causing operational problems. These examples serve to emphasize the need for laboratory testing prior to using oil soluble resins in a particular field for the first time. Oil soluble resins have a specific gravity of approximately 1.10 and may tend to float when the density of the brine in the well exceeds the resin density. This has also caused some operational problems.

The size of the oil soluble resin pill needed to control fluid loss is normally equal to twice the hole volume of the perforated or open hole interval. The pill should be displaced downhole and squeezed into the formation at the maximum practical rate. The seal effectiveness of the pill should be tested by applying 200 to 300 pounds per square inch of pressure against the filter cake.
The oil soluble resin is removed using a hydrocarbon based resin solvent that is pumped into the well. In the past, xylene (mutual solvent) at a 25 percent concentration was used because it was very effective in cleaning the resin from the formation. However, the use of xylene has been discontinued in many parts of the world because of environmental and safety concerns. The most successful and practical resin removal method employed today is a mixture of approximately 75 percent diesel with approximately 25 percent oil-wetting surfactant or mutual solvent.

The proper sizing of the oil soluble resin beads with respect to the formation is important and becomes obvious at the two extremes. If the particles are too large, they will not form an effective filter cake at the formation face and fluid loss will continue. If the beads are too small, they will completely or partially invade the formation and are less likely to be removed during clean-up operations. This can result in formation damage and reduced well productivity.

Oil soluble resin systems designed to work in highly permeable formations are much more expensive than graded salt or graded calcium carbonate. In addition the fluids required for clean-up are more expensive. This makes oil soluble resins unsuitable as a drill-in or underreaming fluid for open-hole gravel packing. Also resins in large quantities will cause disposal problems since they cannot be disposed of in the sea due to environmental restrictions.

Oil soluble resins have very good fluid loss control characteristics and can, if properly designed, completely stop losses to the formation. The limited use of oil soluble resins as a fluid loss control technique is due to uneasiness regarding adequate clean-up, since a poor clean-up job can severely reduce well productivity. Failure to achieve a satisfactory clean-up is the greatest single problem with using oil soluble resins, and may be affected by several factors, including, but not limited to:

- Improper diesel/surfactant diversion technique
- Temperature of the formation
- Improper sizing of the resin beads in relation to the formation pore size
- Ineffective final clean-up due to low production flow rate and/or gravity of the formation oil.

**Graded Salt Systems**

Another widely available system using solid material for fluid loss control is graded salt pills. Graded salt pills contain various sized solid salt particles and starches which act as bridging agents on the face of the formation. The combination of solid salt particles of different sizes and the starch act as a membrane with a lower permeability than the formation. The overbalance created by the completion fluid hydrostatic pressure holds the particles in place.

The graded salt systems are designed for application in completion and workover operations to provide fluid loss control in a wide range of fluid densities and downhole temperatures of up to 300°F. The system consists of:

- Brine as a base fluid
- Xanvis as a viscosifying agent and suspending agent
- Graded salt particles for loss control in larger pore throats
- Crosslinked starch for fluid loss control in the smaller pore throats
• Magnesium oxide as a pH buffer at higher temperatures

The graded salt particles are added to the system to achieve a seal on the formation face in the wellbore. A proper concentration and distribution of the correct size salt particles is essential to form a thin, ultra low-permeability filter cake on the formation face. Controlling fluid loss in micro-fractures, extremely high permeability sands or on the inside of a slotted liner or wire wrapped screen is possible, but requires coarser salt particles. The optimum blend of salt particle sizes that provide fluid loss control and good clean-up characteristics may have to be determined from field experience.

The salt particles are not subject to deformation like the oil soluble resins and will not liquefy and be squeezed into the formation pore throats. The filter cake created by a graded salt pill is capable of withstanding extremely high pressure differentials. In some workover applications, up to 1,000 pounds per square inch of pressure has been applied to the filter cake with no detrimental effects. Normally an overbalance pressure differential of 200 to 300 pounds per square inch is sufficient to hold the filter cake in place.

The volume of graded salt pill required to control fluid losses is normally very small since it is only necessary to establish the filter cake on the face of the formation. In a gravel pack application it is advantageous to place small volumes of graded salt pill at the formation face and allow the particles to bridge. It is important to limit the amount of total treatment placed in the wellbore to the minimum which will accomplish the desired effect of controlling fluid loss. The salt particles have a specific gravity of 2.165 and the coarser particles may settle out of the pill after placement; however, this has not caused major operational problems as compared to the upwards migration of light oil soluble resins in heavy brines.

From laboratory tests and field operations, temperature is seen to have an effect on the dissolving efficiency of the salt particles in the filter cake. At temperatures above 176°F the speed at which the filter cake dissolves in undersaturated fluid with a breaker is significantly increased compared to lower temperatures. For cased hole applications at 185°F, weak organic acids like citric and formic, are recommended. The acids attack the polymers in the filter cake prior to using undersaturated brine for dissolving the remaining salt. Proper diversion techniques are vital in achieving a uniform dissolution of the filter cake with minimal productivity impairment.

Clean-up is accomplished by circulating undersaturated brine, produced brine or acid which dissolve the salt particles. However, prior to dissolving the salt, an oxidizer is required to break the polymer and allow the salt to be contacted. Another difficulty in obtaining complete cleanup is that the cubic structure of NaCl (Figure 10.5) leads to a tightly packed tough filtercake. This strong cake can cause clean up fluids to “worm-hole” through the cake, and not provide total removal.
Another method of fluid loss control which is functionally similar to the graded salt system is the sized calcium carbonate system. As with graded salt systems, calcium carbonate is pumped into the well to the perforated interval and forms an extremely low permeability cake on the face of the formation or on the gravel pack sand.

As with the oil soluble resin and graded salt system, a proper concentration and distribution of the correct size particles is essential to forming a thin, ultra low-permeability filter cake on the formation face. If the calcium carbonate particles are too large, they will not form an effective filter cake at the formation face and fluid loss will continue. If the calcium carbonate are too small, they will be completely or partially invade the formation and are less likely to be removed during clean-up operations. This can result in formation damage and reduced well productivity.

One definite advantage of calcium carbonate pills is the primary removal technique is acid which also has a stimulation effect on many formations. If the formation will not be damaged by exposure to acid or if an acid treatment is already planned as part of the gravel packing program, the calcium carbonate can be applied and fluid loss control established after the perforations have been prepacked. With this done, the gravel pack can be installed and the screen and casing annulus packed. With the gravel pack in place, the acid job is pumped to dissolve the calcium carbonate filter cake.
PERFFLOW\textsuperscript{\textregistered}

Baker Hughes has developed a new fluid loss control system which solves many of the problems and difficulties inherent in existing fluid loss control methods. Designated as PERFFLOW, the fluid contains suspended sized calcium carbonate in a brine base and is applied directly to the formation face in an open hole or prepacked perforations having unacceptably high fluid losses. The solids are placed at the formation face or the prepacked sand face in the same way that graded salts are applied and the overbalance of the well holds the solids in place. When fluid loss control is no longer required, the well is allowed to flow, carrying the solids out of the formation or prepacked sand face with the produced fluid. The PERFFLOW system is compatible with light completion fluids. PERFFLOW has also been tested to seal against highly permeable formations.

PERFFLOW is a blend of bridging, viscosifying and filtration control agents. It is formulated in a single packaged product to simplify the mixing and to ensure uniform composition of the fluid. The bridging material utilized in PERFFLOW is a specially selected hard, graded, angular to sub-angular calcium carbonate blend with a particle size distributions ranging primarily from 1 to 192 microns (Figure 10.6). The filtration and viscosifying agents are a combination of modified starch and biopolymers which actively coat (Figures 10.7 and 10.8) the calcium carbonate particles. This coating prevents the particles from adhering to each other and therefore allows for ease in particle removal upon production of the well.
The net effect of the above features of the PERFFLOW system is that the filtercake formed is a very thin, yet friable cake (Figure 10.9). Because of the wide particle size distribution, the calcium carbonate bridges very quickly, preventing the filtercake from penetrating the formation.
(Figure 10.10). The result of producing a friable, non-penetrating filtercake is that it can be removed from the formation face with very little back pressure (Figure 10.11). Likewise, because of the wide particle size distribution, the smaller end of the carbonate particles can be produced back through the gravel pack sand providing in excess of 80% return permeability (Figure 10.12). Both the elevated breakout pressure, and the somewhat reduced return permeability for the test performed at 265º F, result from polymer breakdown at the elevated temperature. Finally, the friable nature of the filtercake becomes important when the filtercake must be flowed back through a screen in a non-gravel packed completion. The PERF FLOW filtercake breaks up easily to allow flow through the screen without plugging.
Figure 10.10
Pore Throat Bridging with PERFFLOW®

Figure 10.11
Low Filtercake Breakout Pressure with PERFFLOW®
One concern when using PERFLOW, or any other solids-based fluid loss control material, is attempting to bridge against gravel that is 20/40 Mesh or larger. To prevent excessive penetration of the calcium carbonate into the gravel pack sand, additional carbonate at the larger end of the particle size distribution can be added. Figure 10.13 indicates that this approach allows successful fluid loss control being obtained on gravel sizes of at least 12/20 Mesh.
Gravel Pack Sand

In gravel packed wells, a critical factor to obtaining a successful completion, is to fill perforation tunnels with high-permeability gravel-pack sand. As will be detailed in Chapter 12, fluid leakoff during the perforation packing process is required to accomplish this. Therefore, if a fluid loss control pill is pumped prior to perforation packing, very poor perforation filling may result. For this reason, the use of gravel pack sand as a fluid loss control material can prove to be very beneficial. Gravel pack sand does not require removal, has no temperature limitations and when placed in the perforations to limit fluid loss has the added effect of greater perforation filling efficiencies. If sand is utilized in conjunction with the perforating hardware, potentially damaging fluid loss control agents can be eliminated. This eliminates the need to remove fluid loss control agents prior to gravel packing and provides two opportunities to place the gravel in the perforations. The results include higher productivity and higher production longevity. This issue will be further expanded in the Chapter 12 on prepacking.

Mechanical Fluid Loss Control

Since any type of fluid loss control pill has the potential of damaging the formation, it is advantageous for fluid loss to be controlled through mechanical means whenever possible. Two of the most commonly applied devices for this purpose are the Knock-Out Isolation Valve (KOIV) and the Iso-Sleeve assembly.

Knock-Out Isolation Valve. The Knock-Out Isolation Valve (KOIV) is a mechanical fluid loss device that prevents completion fluid losses and subsequent damage to the formation after performing the gravel pack. The downward closing flapper in the KOIV is held open by the gravel pack service tools during the gravel pack. When the service tools are pulled out of the KOIV, the flapper closes preventing fluid loss to the formation (see Figure 10.14). The gravel pack service tools can be removed from the well and the completion tubing run. Under producing conditions the flapper will open. Alternatively, the flapper is made of a friable material and can be broken hydraulically or mechanically prior to producing the well.

Iso-Sleeve. The Iso-Sleeve assembly (Figure 10.15) straddles the entire gravel pack screen assembly, totally isolating the zone. The washpipe seals in seal bores located above and below the screen. The washpipe is also mechanically locked to prevent premature actuation during gravel packing. The washpipe can be perforated with a tubing punch to open the zone for production. Alternatively, sliding sleeves can be included in the assembly.
Figure 10.14
Model “C” Knock-Out Isolation Valve
Recommended Applications

Given the wide range of available fluid-loss control techniques, it is important to review when, or if, each of these are recommended. If we examine the list of possible times during the completion operation when fluid-loss control may be required, it is recognized that not only is the wellbore condition different during each of these operations, but the subsequent operations yet to be performed are also different. Table 12.1 is provides an explanation of the most important aspect of the completion operations that dictate the fluid-loss control technique recommendation. This table also lists the primary, and where applicable, a secondary recommendation.

<table>
<thead>
<tr>
<th>Stage of Completion</th>
<th>Critical Issue</th>
<th>Primary Recommendation</th>
<th>Secondary Recommendation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Drilling of Reservoir</td>
<td>High Quality Filtercake</td>
<td>PERFFLOW DIF</td>
<td>Graded Salt DIF</td>
</tr>
<tr>
<td>Prior to</td>
<td>High Quality Filtercake Filtercake Cleans Up w/</td>
<td>PERFFLOW</td>
<td>“Virgin” PERFFLOW (no Calcium Carbonate)</td>
</tr>
</tbody>
</table>
Open Hole GP | Production | (if losses occur after running screen)
--- | --- | ---
Following Perforating | Don’t Totally Shut Off Leakoff | Gravel Pack Sand | Xanvis w/ Breaker PERFFLOW if loss rate high
Following Prepacking | Bridges on Gravel Pack Sand | PERFFLOW Pills | Graded Salt Pills
Following Gravel Packing | Non-Damaging to Gravel Pack | Mechanical Devices | PERFFLOW (with large particle size distribution)

During the drilling of the pay section, the choice of drill-in fluid should be strongly influenced by the type of completion planned. If a stand-alone screen completion is planned, the filtercake must be able to be produced back through the screen. The friable PERFFLOW filtercake greatly assists this process. Graded salt systems have also been used with some success. If the well is to be gravel packed, the filter cake also must withstand the pumping of brine during the gravel packing operation. This requirement eliminates the applicability of graded salt systems.

There are two points during a gravel packing operation that the improper use of fluid-loss control materials can be very detrimental. First, as will be discussed in Chapter 12, for cased-hole gravel pack completion, it is critical that all of the perforations be completely filled with gravel pack sand. Since leakoff is required to pack perforations, it is recommended that the well be prepacked just as soon as possible, ideally immediately after perforating. In this situation, the gravel pack sand itself can be thought of as a fluid-loss control material.

If it is not possible to prepack the perforations, the next choice would be to use just enough HEC to reduce losses to a manageable level. If losses are excessive, PERFFLOW can be used in empty perforations; however, an acid soak will be required to remove the filtercake prior to gravel packing. A caution that must be addressed is that PERFFLOW is not compatible with HEC. Therefore, if it is recommended that another gel such as Xanvis be used if there is a possibility that PERFFLOW may also be required.

Another critical point for the use of fluid-loss control materials, is at the conclusion of gravel pack. When losses occur at point, the typical practice is to spot the fluid loss pill out of the end of the workstring, and allow it to be pulled into the screen. Once losses have been controlled, the workstring is pulled from the hole. The difficulty with this approach is that if this pill does not clean-up with production, a coiled-tubing workover is required. An alternative approach is to use some sort of mechanical fluid-loss control technique, so that pills do not have to be spotted inside the screen. If mechanical options are not acceptable, then a PERFFLOW pill with the coarse calcium carbonate particle size distribution is recommended to prevent the pill from penetrating the gravel pack.

The special situation of an open-hole gravel pack requires that the filtercake be able to flow back through the gravel pack, as well as provide good leakoff control during the complete gravel packing operation (including pumping). Because of the unique formulation of the PERFFLOW
system, this is the only material that we have found that meets this requirement. However, even though the PERFFLOW is extremely durable, and experience indicates that screen can easily be run across it without damaging it fluid-loss control capabilities, there are situations when additional fluid loss control is required after the screen has been run. To help limit the probability of screen plugging, it is recommended that fluid loss control at this time be accomplished by the base PERFFLOW polymer system (without the calcium carbonate).

**Summary**

Fluid loss is a common occurrence in gravel packed well completions due to the relatively high to extremely high permeabilities of unconsolidated formations. Fluid loss is further aggravated by the fact that the formation may be exposed to losses for several days after perforating while the gravel pack is installed and completion tubing run. The absolute best alternative to dealing with fluid loss is to accept it. Although perceived as a problem in the completion process, fluid loss after perforating indicates the perforations are open and clean, the completion fluid is compatible with the formation and the reservoir is permeable. The real problem occurs when fluid loss is stopped, indicating that something either intentionally or unintentionally has plugged the formation.
Introduction

Gravel packing consists of installing a down-hole filter in the well to control the entry of formation material but allow the production of reservoir fluids. The gravel packed completion is perhaps the most difficult and complex completion operation performed on a routine basis. As discussed in previous chapters, the success of a gravel pack is influenced by many factors beginning when the drill bit enters the productive pay and ending when the completion tubing is run in the well. Since the gravel pack is a filter, any operation or procedure that leads to plugging will impair well productivity. Hence, the importance of minimizing near wellbore damage, using compatible completion and stimulation fluids and establishing a clean wellbore environment is imperative. Also, perforation requirements and cleaning techniques are critical to gravel placement in them by ensuring that they are effective and that there is finite fluid loss for the transport of gravel.

Gravel Placement Objectives

There are two primary objectives in gravel packing a well. First the annulus between the screen and casing must be packed with gravel. Filling the annulus with the properly sized gravel will ensure that the formation sand is retained downhole and not produced to surface. The second objective is to pack each perforation with gravel. Filling the perforations with gravel is the key to obtaining high productivity from the well. In an unconsolidated formation, any perforation that is unfilled with gravel will fill with formation sand and restrict well productivity. As discussed in Chapter 9, the flow through a gravel packed perforation tunnel is represented by linear darcy flow. The Pressure drop through the perforation tunnel is minimized if the tunnel is filled with high-permeability gravel as opposed to formation sand. Tables 11.1 and 11.2 compare the calculated pressure drops in different perforation diameters for formation sand and gravel-filled perforation tunnels and emphasize the importance of perforation filling during the gravel placement process.

| TABLE 11.1 |
| Pressure Losses in a Packed Perforation (Formation Sand - 1,000 md) |
| Flow Rate (BPD/Perforation) | Pressure Drop (psi) |
|  | 3/8-in Dia Perforation | 1/2-in Dia Perforation | 3/4-in Dia Perforation |
| 1 | 450 | 190 | 64 |
| 10 | 27,760 | 9,280 | 2,091 |
Gravel Placement Techniques

The crossover circulating technique is the most common method used to place the gravel in the perforations and around the screen. The gravel pack equipment and service tools allow circulating the gravel down the workstring above the packer and into the screen/casing annulus below the packer with returns coming back up the washpipe and up the workstring/casing annulus as discussed in Chapter 7. The fluid used to carry the gravel can either leak-off to the formation or be circulated out of the hole through the wash pipe (as illustrated in Figure 11.1) depending on the position of the service tools and the condition of the perforation in terms of excepting fluid leak-off.

A variety of fluids have been used as gravel carrier fluids for gravel packing operations such as include brine, oil, diesel, crosslinked gels, clarified xanthum gum (XC) gel and hydroxy-ethyl-cellulose (HEC) gel, and foam. The most commonly used fluids have been brine and HEC gel. Gravel packs performed with brine carrier fluids are referred to as water packs or conventional packs. Gravel packs performed with HEC gel carrier fluids are referred to as slurry packs, gel or viscous packs.

Table 11.3 is a comparison of HEC gel and brine characteristics in regards to their use as gravel transport fluids. When using HEC, the gravel pack sand is influenced primarily by viscous forces (i.e., the gravel is suspended by the gel). When using brine as a transport fluid, the gravel is influenced primarily by gravity forces (i.e., the gravel settles quickly). Hence, higher pump rates may be required to cope with settling in some situations as Table 11.3 suggests.

<table>
<thead>
<tr>
<th>Table 11.2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Pressure Losses in a Packed Perforation (20/40 gravel - 119,000 md)</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>Flow Rate (BPD/Perforation)</th>
<th>3/8-in Dia Perforation</th>
<th>1/2-in Dia Perforation</th>
<th>3/4-in Dia Perforation</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
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<td>0.4</td>
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<td>21</td>
<td>6</td>
</tr>
<tr>
<td>25</td>
<td>272</td>
<td>99</td>
<td>25</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Table 11.3</th>
</tr>
</thead>
<tbody>
<tr>
<td>Comparison of HEC and Brine Gravel Pack Carrier Fluids</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Fluid Viscosity</th>
<th>HEC Gel</th>
<th>Brine</th>
</tr>
</thead>
<tbody>
<tr>
<td>300 - 750 cp</td>
<td>1 - 2 cp</td>
<td></td>
</tr>
<tr>
<td>Typical Gravel Concentration</td>
<td>10 - 15 ppg</td>
<td>1 - 3 ppg</td>
</tr>
<tr>
<td>Typical Pump Rate</td>
<td>1 - 4 bpm</td>
<td>4 - 5 bpm</td>
</tr>
<tr>
<td>Tell-Tale Screen Used</td>
<td>Yes</td>
<td>No</td>
</tr>
</tbody>
</table>
Figure 11.1

Flow Paths During Gravel Packing
Historical Background

The earliest gravel packs were performed in shallow, vertical wells by simply pouring gravel into the tubing/casing annulus and allowing the gravel to settle around a screen. This technique is still employed in the water well industry, but is seldom used in oil or gas wells. As equipment and technology improved, gravel packing of oil and gas wells was accomplished by mixing sand in brine and pumping the mixture into the hole. Brine represents the simplest of the transport fluids. Prior to the early 1960’s, brine continued to be the preferred (in terms of use) gravel pack fluid because many other fluid systems had not been developed at that time.

The early equipment used to mix brine and gravel was inefficient and resulted in the “slugging” of gravel into the hole as opposed to a consistent brine and gravel mix ratio. The brine was seldom filtered and no specifications were in place to ensure gravel pack sand quality was acceptable. Overall rig housekeeping was poor and the perforating techniques available were limited to small-diameter charges that produced entrance-hole diameters that were less than 0.5 inches. The combination of all these factors resulted in inefficient gravel packs completions which were commonly damaged.

In the late 1960’s, research efforts\textsuperscript{1,2,3} by several companies focused on improving the gravel packing process. The culmination of the research efforts was the introduction of viscosified gravel carrier fluids. The viscosified carrier fluid of choice was HEC. HEC gel provided a reasonably clean medium for isolating and transporting the gravel pack sand to the bottom of the well. The gel allowed consistent batch mixing and protected the gravel from crushing and contamination during pumping operations. Due to its apparent advantages, HEC gel carrier fluids rapidly replaced brine as the gravel packing fluid of choice. Viscous HEC gel carrier fluids remained the “state-of-the-art” gravel transport fluid for many companies until the early 1990’s.

Despite the technology advances in gravel quality, wellbore cleanliness, fluid filtration and perforation quality, gravel packed wells were not, in general, producing as efficiently as theoretically possible. Also, it became common knowledge that gravel packs performed with gelled fluids commonly contained voids in the gravel packs. Attention was focused on HEC gel as a potential cause of the poor productivity. It was discovered that HEC was not as non-damaging as originally assumed and as a consequence, improved shear mixing procedures were developed.\textsuperscript{6} Despite better mixing, damage due to residual gel remained likely. Research also indicated that HEC did not pack perforations efficiently as well deviation and zone length increased.\textsuperscript{7} Alternatives to HEC, such as X\textsuperscript{C} and Shellflo-S were proposed but were never completely accepted as were a myriad of other fluid systems which were being developed for use as the ideal gravel-pack fluid.

Significant research and operating data were presented by Exxon in the early 1990s which showed that water was a general purpose gravel transport fluid that produced low porosity packs that did not contain voids and was capable of prepacking perforations provided that there was acceptable fluid loss. Baker Hughes developed the Gravel Infuser as the first efficient brine and sand mixing equipment for water-pack systems. The equipment allowed consistent mixing of gravel in brine and redirected attention to brine as the gravel transport fluid of choice. Coupled with research data and positive field results, the Gravel Infuser initiated the trend for the rest of
the industry accept brine as a gravel pack carrier fluid.\textsuperscript{8,9} Although gel represented an improvement in technology at the time and is still applicable for certain well situations, brine is the most widely used gravel pack carrier fluid in the industry today.

Continued evolution of procedures saw the introduction of diatomaceous earth filtration systems (circa 1980) which were able to filter large quantities of brine quickly at reasonable costs. Coupled with the increasing use of clear brine (as opposed to mud), diatomaceous earth filtration systems resulted in a substantially cleaner wellbore environment than had been previously possible.

In 1986, the API introduced specifications for gravel pack sand (API RP 58).\textsuperscript{4} These specifications established rigorous requirements for gravel pack sand. The API specifications called for gravel sieved to strict tolerances with low crush resistance and acid solubility which was capable of passing through pumping equipment with little or no degradation.\textsuperscript{5} Finally, in the early 1980’s, underbalanced tubing conveyed perforating became a common and well established technique for achieving the high shot density, large hole diameter, clean perforations required for maximum gravel packed well productivity.

All of the above improvements, developments and changes significantly improved the gravel packing systems that are offered today as a routine service.

**Physical Model Observations of Brine and Gel Packing**

Exxon studied the gravel packing characteristics of brine and gel carrier fluids in a 22 foot long clear plastic gravel pack model. The model simulated 7 inch casing conditions with perforation shot density variable from 0 to 12 shots per foot. The model could be rotated to simulate well deviations from 0 to 110° from vertical. The results of the study were reported in 1993 in SPE Paper 22793,\textsuperscript{7} and are summarized below.

**Brine Transport Fluids** - Simulations with brine carrier fluids were performed at 0 to 45°, 45 to 60° and 60 to 110°. The gravel-packing sequence at well deviations from 0 to 45° were highly controlled by gravity and packed from the bottom of the well upwards as Fig. 11.2 portrays. As long as finite leak-off occurred through a given perforation it was packed with gravel. The gravel did not begin filling the perforation tunnels until the level of the gravel in the annulus reached the perforation entrance. At this point, the gravel would divert into the perforations (if the perforation was experiencing leak-off) and completely pack the perforation as the annular pack level rose. The end result was a tight annular pack and completely prepacking the perforations experiencing leak-off. In the 45 to 60° range, the well was also completely packed, but the packing began on the lowside of the hole and filled the annulus with a series of dunes propagated up and down the length of the model. At about 60° well deviation, the gravel is in transition between falling to the bottom of the interval or remaining at the top of the interval on the lowside of the hole. As a consequence, the packing is random as shown in Figure 11.3. The reason for this behavior is that at about 60° represents the complement of the angle of repose for gravel which is about 28° as illustrated in Figure 11.4.
Figure 11.2
Packing Sequence With Brine Carrier Fluids In Wells Less Than 45°

Figure 11.3
Packing Sequence With Brine Carrier Fluids In Wells At 60° Deviation
As the well deviation exceeds 60°, a gravel dune forms initially at the top of the completion interval and is propagated sequentially from the top to the bottom of the completion interval. This occurs because the angle of repose has been exceeded and gravity becomes a more dominant force that causes the gravel to settle high in the completion interval. To ensure propagation of the dune, the ratio of the wash-pipe OD to the screen ID must be about 0.70 or larger. The purpose of the large-diameter wash pipe is to divert flow from the annulus between the wash pipe and the screen to the annulus outside the screen. Testing and field experience has shown that the ideal ratio is probably in the range of 0.70 to 0.80. Additionally, the return flow rate to cross sectional area ratio between the screen and the casing should be at least 1 ft/sec to supply sufficient transport velocity. If the ratio of washpipe OD to screen ID is too small, excess fluid will flow in the small annulus and the gravel dune will prematurely stall high in the completion interval, resulting in a “premature sandout” (see Figures 11.5). Figure 11.6 shows the effect of wash pipe to screen diameter ratios on gravel placement efficiency. If the ratio of washpipe OD to screen ID is too large, sticking the wash pipe is a concern as well as potentially high pump pressures during the final stages of gravel placement. A schematic of the gravel packing process in wells greater than 60° when large diameter wash pipe is used is illustrated in Figure 11.7. This figure shows the dune deposited and propagated along the lowside of the hole until it reaches the end of the completion interval (alpha wave). At this point a secondary deposition (beta wave) backfills and packs the volume over the top of the alpha wave to complete the gravel pack.
Figure 11.5
Failed Packing Sequence With Brine Carrier Fluid In High-Angle Well Resulting From Low Rate and Small Diameter Washpipe

Figure 11.6
Effect of Washpipe OD to Screen ID Ratios on Gravel Placement Efficiency
Gel Transport Fluids - Simulations with gel carrier fluids were also performed at 0 to 45°, 45 to 60° and 60 to 80°. The packing mechanisms with gel were more complex than with brine. At 0 to 45°, the high viscosity of the gel allows radial packing around the gravel pack screen and node build-up at the perforations. At screen connections, voids were commonly observed immediately after pumping ceased. But the voids where typically filled by gravel settling after a few hours provided that the well deviation was less than about 60°. As with brine, perforation packing was complete but occurred only if the perforation experienced fluid leak-off. At deviations greater than 60°, voids persisted in areas where incomplete slurry dehydration occurred (opposite screen joint connections or unperforated sections of the interval). Unlike the lower deviation simulations, gravel pack settling at deviations greater than 60° resulted in voids along the top of the gravel pack. When the voids occurred opposite perforations, gravel pack sand placed in the perforations would be unloaded into the voids when production occurred. Under actual conditions, this phenomena would result in either sand production or localized plugging of the gravel pack as the perforation tunnels filled with formation sand.

Transport Fluid Summary. Based on the results of laboratory testing and field experience, brine exhibits more complete packing of the perforations and annulus under a wide variety of well conditions and is considered to be a general purpose gravel pack fluid. Gel transport fluids should be limited to use in wells with deviations less than 45° and gross zone lengths less than 70 feet in length.

Field Results

The main objective of annular gravel placement is to effectively pack the annulus between the screen and the casing or the open hole. For cased-hole completions an added objective is to pack the perforations with gravel since the latter significantly improves well productivity and longevity.
See Chapter 12 for additional details. In addition to perforation packing, the quality of the pack in the screen/casing annulus is important regardless of whether the well is completed open or cased hole. Figures 11.8, 11.9, 11.10 and 11.11 show gravel pack log examples from actual wells where both water and gels were used as the transport fluid. These logs indicate complete annular packing when using brine carrier fluids. The gravel packs performed with viscous gel carrier fluids show the presence of large voids in the annular pack which, if not repaired, will result in formation sand production. Figures 11.12 and 11.13 are examples of wells gravel packed with viscous gel and then re-packed with brine due to voids in the initial viscous gel pack. The subsequent brine pack filled the voids.
Figure 11.10
Brine Pack in Oil Well
(12,800 ft Depth, 68°, 50 ft Net Perfs)

Figure 11.11
Viscous Gel Pack in Oil Well
(13,600 ft Depth)

Viscous Gel Pack
Brine Pack

Figure 11.12
Comparison of Viscous Gel Pack and Brine Pack in Gas Well
(3,500 ft Depth, 54°, 110 ft Net Perfs)
Viscous Gel Pack

Brine Pack

Figure 11.13
Comparison of Viscous Gel Pack and Brine Pack in Gas Well
(4,200 ft Depth, 63°, 20 ft Net Perfs)

References


CASED-HOLE GRAVEL PACKING PRACTICES

Introduction

Cased hole gravel packs are one of the most common methods for controlling the production of formation sand in oil and gas wells. Cased hole completions are more commonly applied than open-hole gravel packs for several reasons. First, if the operator is not aware of a need for sand control when the well is drilled, a perforated casing completion can be installed, with the gravel pack being installed later if the need arises. Also, cased-hole completions are often required for the upper zones of multi-zone completions. In addition, water or gas exclusion is easier in a cased hole completion, and wellbore stability is more easily maintained. One negative aspect of the cased hole completion is low productivity unless gravel is placed through and outside the perforations properly.

Perforation Prepacking

Several completion techniques have been developed to help alleviate the problems associated with cased hole gravel packs. One commonly applied technique, which Penberthy has demonstrated to be quite effective is perforation prepacking. This process involves placing gravel through the perforation tunnels, into the cavity created at each perforation behind the casing (see Figure 12.1).

Prepacking controls fluid loss, increases perforation filling efficiencies and decreases drawdown pressure drop through the perforations tunnels by preventing formation sand filling the tunnels. Filling the perforations with gravel is the key to obtaining high productivity from the well. In an
unconsolidated formation, any perforation not filled with gravel will fill with formation sand. As discussed in Chapter 9, the flow through a gravel packed perforation tunnel is represented by linear darcy flow. Pressure drop through the perforation tunnel is minimized if the tunnel is filled with high permeability gravel as opposed to formation sand. Tables 12.1 and 12.2 compare the calculated pressure drops in different perforation diameters for formation sand filled and gravel filled perforation tunnels. These tables dramatically emphasizes the critical importance of complete perforation filling during the gravel placement process.

### Table 12.1
Pressure Losses in a Packed Perforation (Formation Sand - 1,000 md)

<table>
<thead>
<tr>
<th>Flow Rate (BPD/Perforation)</th>
<th>Pressure Drop (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>3/8” Diameter Perforation</td>
</tr>
<tr>
<td>1</td>
<td>450</td>
</tr>
<tr>
<td>10</td>
<td>27,760</td>
</tr>
</tbody>
</table>

### Table 12.2
Pressure Losses in a Packed Perforation (20/40 gravel - 119,000 md)

<table>
<thead>
<tr>
<th>Flow Rate (BPD/Perforation)</th>
<th>Pressure Drop (psi)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>3/8” Diameter Perforation</td>
</tr>
<tr>
<td>1</td>
<td>2</td>
</tr>
<tr>
<td>10</td>
<td>55</td>
</tr>
<tr>
<td>25</td>
<td>272</td>
</tr>
</tbody>
</table>

The practical effect of the productivity lost from the increased pressure drop caused by partial filling of perforation tunnels with formation material has been described in a recent publication and is illustrated in Figure 12.2.
When it is considered that prepacking can be defined as: *any method that intentionally places gravel into the perforation tunnels and out into the formation*, it becomes obvious that several techniques should be available to accomplish this. Filling of perforation tunnels can be accomplished either with a dedicated operation prior to running the gravel pack assembly, or it can be accomplished by forcing injection into the perforations during gravel packing. So in evaluating a cased-hole gravel pack completion techniques the distinction becomes: was a dedicated prepack performed, was the prepack performed with the gravel pack assembly in the hole, or was a circulating gravel pack performed with limited leakoff to the formation. The technique utilized is normally dictated by well parameters such as excessive fluid loss, extended rat hole area, reservoir acid sensitivity, zone length, etc. An additional concern that must be addressed is which carrier fluid was used for the prepacking operation.

**Carrier Fluid Selection**

As with the annular packing process described in Chapter 11, there are two basic classes of carrier fluids available for prepacking perforation tunnels, non-viscous (brine) carrier fluids, and viscous (gelled) carrier fluids. Many of the same transport mechanisms present during annular packing with these two classes of fluids are also operative when they are used to transport gravel into a perforation tunnel.

To assess the effectiveness of each of these fluids for perforation filling, three factors become important:
1. the fluid-loss characteristics of the carrier fluid
2. the packing sequence within the perforation tunnel
3. the injection rate.

Leakoff to the formation is required to allow gravel pack sand to enter the perforation tunnel. If no leakoff exists, thus not providing a flow path for completion fluid to leave the perforation to allow a volume of gravel to enter, the only mechanism available for perforation filling is gravity settling (Figure 12.3). If only a small portion of the perforation tunnel is filled with formation sand, severe reductions in effective permeability will result (Figure 12.4). To remedy this situation, every effort must be made to maintain leakoff during the perforation filling process. If a gelled carrier fluid is used, the carrier fluid itself can act a fluid-loss control material. The lack of leakoff control with brine carrier fluids, is a major reason why field data demonstrate that more gravel can be placed outside casing while using non-viscous carrier fluids.

![Figure 12.3](image_url)  
**Figure 12.3**  
Leakoff is Required for Perforation Filling
Another important issue concerning the ability to fill perforation tunnels is the gravel transport mechanism of the selected carrier fluid. As is the case for annular packing, as described in Chapter 11, when a viscous carrier fluid is used, the viscous forces of the fluid are greater than the gravitational forces acting on the gravel. Under these conditions, the perforation filling progresses from the tip of the perforation tunnel, then back towards the wellbore (Figure 12.5). The problem with this packing sequence is that as the perforation packs, a viscous fluid is leaking off to the formation immediately outside the casing. The leakoff of the viscous fluid will tend to restrict further leakoff, thus restricting the ability to pack the tunnel in the critical area immediately adjacent and through the cement and casing.

\[
k = \frac{L}{\sum_{j=1}^{n} \frac{L_j}{k_j}}
\]

\[L = 1\]

\[k_{\text{formation}} = 150 \text{ md}\]

\[k_{\text{gravel}} = 120,000 \text{ md}\]
When a non-viscous carrier is used, the gravitational forces now dominate, and the gravel transport is through an equilibrium bed mechanism, similar to the annular packing of a highly-deviated wellbore. With this mechanism acting, gravel is first placed in the tunnel through the casing and cement, and then out into the formation (Figure 12.6). In addition to losing only non-damaging fluid that does not restrict further leakoff, this packing sequence leads to more efficient packing.
A final aspect that affects the ability to pack perforation tunnels, especially when using brines as carriers, is the injection rate. While it is a misconception that elevated viscosity is required to cause the gravel to “turn the corner” into the perforations, a minimum injection rate is required to maximize the perforation filling efficiency. Several industry studies\(^2\,^3\) suggest that an injection rate of 0.2 gpm/perforation optimizes perforation filling efficiency. This value should be considered a general guideline, and may vary for some applications, especially for intervals consisting of multiple sand layers. For these wells, only a portion of the overall zone may be taking fluid at any one time; therefore, injection requirements as based on the overall zone length are reduced.

**Field Evaluation**

A common approach to qualitatively assess the results of a gravel pack is to determine the “pack factor”. The pack factor is simply a measure of the quantity of gravel placed behind casing during the gravel packing operations. The pack factor is calculated using a material balance as follows:

\[
PF = \frac{V_t - V_{cp} - V_s - V_b - V_r}{H_n}
\]

where: 
- \(PF\) = perforation pack factor (pounds of gravel per foot of perforations)
- \(V_t\) = total amount of gravel pumped during prepacking and gravel packing (lbs)
- \(V_s\) = total amount of gravel filling the screen and casing annulus (lbs)
- \(V_b\) = total amount of gravel filling the blank and casing annulus (lbs)
- \(V_{cp}\) = total amount of gravel filling casing after prepacking (lbs)
- \(V_r\) = total amount of gravel reversed out of the well after prepacking & gravel packing (lbs)
- \(H_n\) = net perforated interval (feet)

While the pack factor does not provide strong correlation to well performance, it does provide information upon which comparisons of perforation filling efficiencies of different carrier fluids can be made. Figures 12.7 - 12.9 demonstrate the effectiveness of brine carrier fluids as compared to gels. Figure 12.7 is a presentation of pack factor for four general classes of wells, old and new oil wells and old and new gas wells. This plot indicates that regardless of the well type, brine carrier fluids are capable of placing more gravel behind casing than are the viscous carriers. Similar results can also be recognized as a function of interval length and well deviation (Figures 12.8 & 12.9). These results combine to offer strong support that non-viscous carrier fluids are actually more efficient in filling perforation tunnels than are the gelled fluids.
Figure 12.7
Perforation Pack Factor as a Function of Well Type

Figure 12.8
Perforation Pack Factor as a Function of Interval Length
Figure 12.9 illustrates that, although some scatter is present, there is a benefit of increased injection rates when using brine to carry gravel into perforation tunnels. These data suggest that the best practice for prepacking perforation tunnels, especially when packing below fracture pressure, is to inject the brine/gravel slurry at the maximum rate practical.
Because perforation filling is so important, it is recommended that the prepacking operation be carried out at the earliest possible opportunity (i.e., immediately after perforating). In addition to helping control fluid loss, prepacking immediately after perforating affords two opportunities to place gravel in the perforations (i.e., during the prepack and during the gravel pack). Although this method may require an additional trip to clean out the well prior to gravel packing, the improved gravel placement typically outweighs the additional cost associated with the additional wash trip.

Where high fluid-loss situations exist and there is a need for fluid-loss control agents, the recommendation is to prepack the perforation tunnels prior to using fluid-loss control agents. Prepacking with gravel-pack sand offers a number of significant advantages in the well killing operation of gravel-pack completions:

- The largest pressure drop in gravel packs occurs in the perforation tunnels. Therefore filling these tunnels with high permeability gravel will help maximize well productivity (see Figure 12.2).
- When the perforation tunnels are filled with proppant of a known particle size, the optimum fluid loss control treatment that will successfully bridge out on this gravel is easier to design.
- A properly designed prepack should reduce the surface area that fluid loss control is required to cover. This lowers the volume of loss control material required and simultaneously reduces removal problems, fluid loss control material cost, and time and effort required to remove smaller amounts of material.
- By placing the fluid loss control material as near to the wellbore as possible, the subsequent operations to remove the material are made easier. Maximizing the removal of fluid loss material increases well productivity.
- Placing the fluid loss control material inside the perforations can lead to voids in the gravel inside those perforations over the life of the well as formation fluid may dissolve residual loss control material. These voids can be filled with formation sand, which will result in reduced productivity or failure to control sand production, or both.

The success, or lack of success, associated with gravel-pack completions is dependent on filling all perforations and any cavities outside the perforations created by perforating, washing, or backsurging. Table 12.3 illustrates the relative productivity of open-hole gravel pack completions, non-gravel pack perforated completions, and cased hole gravel packs with and without a prepack. Note that the cased hole completions in this example were perforated with 4 to 6 shots per foot. Therefore, these productivities do not represent productivities that are possible with current gravel packing techniques. However, the benefit of prepacking is illustrated.
Brunei Shell Petroleum (BSP) published the results of a series of field trials with the purpose of improving productivity of gravel pack completions. The results of this study were similar to those summarized in Table 12.3. That is, while prepacking did provide an incremental improvement, cased hole gravel packs with a prepack still produced at significantly lower rates than open-hole gravel packs in similar intervals. The BSP paper suggested that the reason for this is that the process of perforating and washing did not completely remove the damage surrounding the wellbore. Figure 12.11 illustrates how this may occur. When prepacking is carried out below fracture propagation pressure, gravel can only fill the empty volumes behind casing created during the underbalanced perforating and flow back period. If the perforation tunnel and/or any cavities created do not extend beyond the near wellbore damaged zone, a positive skin can be expected.

However, another very real possibility for the reduced productivity of the previously cited cased-hole gravel pack work has much to do with how the gravel packs were placed. Many of those treatments utilized gravel packing techniques since identified as leading to low efficiency completions. Gravel packing techniques have improved, and use of proper procedures can lead to cased-hole gravel pack completions with efficiencies at least as high as open-hole gravel packs.

<table>
<thead>
<tr>
<th>Productivity Index (bopd/psi)</th>
<th>Interval 1</th>
<th>Interval 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>Open-Hole Gravel Pack</td>
<td>48.4 (14)</td>
<td>6.4 (13)</td>
</tr>
<tr>
<td>Gun Perforated Casing</td>
<td>36.6 (20)</td>
<td>5.2 (14)</td>
</tr>
<tr>
<td>Cased hole Gravel Pack (with prepack)</td>
<td>12.9 (19)</td>
<td>3.2 (12)</td>
</tr>
<tr>
<td>Cased hole Gravel Pack (without prepack)</td>
<td>4.0 (14)</td>
<td>1.7 (3)</td>
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( ) - Number of wells

Figure 12.11
Conventional Perforation Prepacking May not fully Penetrate Damaged Zone
To allow for a valid comparison to be made concerning the various prepacking techniques that are available, common definitions are required to classify these techniques. The classification offered here will divide prepacking into two major subsets: techniques carried out below the formations fracture pressure, and those performed above fracturing conditions. This distinction is important because the ability to produce a high-efficiency completion will be based upon the ability to effectively remove formation damage when treating below fracture pressure treatments, and to bypass the damage for the treatments carried out above fracture pressure.

**Prepacking Below Fracture Pressure**

*Circulating Water Pack:* Brine used as a carrier fluid. No effort to intentionally force leakoff (in excess of natural losses) to the formation. While a high-quality annular pack may be obtained, perforation filling will not be optimal.

*Brine Prepack:* This can be a dedicated prepack (prior to running the gravel pack assembly), or leakoff can be forced to the perforations either by restricting returns at the surface or by pumping the treatment with the crossover in the squeeze position. Injection rates will be less than 0.2 gpm/perf.

*Gel Prepack:* The same as a Brine Prepack with the exception that the prepack is pumped with a gelled carrier fluid. Gel loading is typically low, commonly using 20 lb/1000 gal HEC; however, higher gel loadings may also be used. It is important to specify the prepack carrier fluid, especially when a brine annular pack is performed.

*Acid Prepack:* Pumping a multi-stage acid treatment with diverters prior to gravel packing. When gravel is used as a diverter material, an acid prepack becomes a gravel prepacking technique. Because it is the goal of these treatments to remove near-wellbore formation damage (rather than to bypass it) these treatments are typically pumped at low rates. If the injection rate is increased up to the maximum possible and still remains below the formation’s fracture pressure, these treatments may be classified as *High-Rate Acid Prepacks.*

*H₂O-PAQ*: Prepacking technique that is carried out below the formation’s fracture pressure, incorporates a brine as a carrier fluid, and injects the brine/gravel slurry into the formations at rates that exceed 0.2 gpm/perf. The value of 0.2 gpm/perf arises from the results of several industry studies⁴,⁵ that suggest that this value is a minimum to optimize perforation filling efficiency (see Figure 12.10). This value should be considered a general guideline, and may vary for some applications, especially for intervals consisting of multiple sand layers. For these wells, only a portion of the overall zone is taking fluid at any one time; therefore, injection requirements as based on the overall zone length are reduced. For an H₂O-PAQ, gravel concentrations are held below 2 ppa to allow the treatment to be self-diverting; therefore, providing the opportunity to prepack several sand intervals with a single pumping operation.

*High-Rate Gel Prepack:* As with the Gel Prepack, this process is similar to an H₂O-PAQ treatment in all aspects other than carrier fluid. Rather than a brine carrier fluid, a lightly-gelled fluid is used. The injection rates still exceed 0.2 gpm/perf, and the formation fracture pressure is again NOT exceeded.
Performance Comparison for Prepacking Below Fracture Pressure

To determine which of the above listed procedures leads to the best quality completion, well test data can be examined for several of these techniques. First, to provide a baseline upon which recent advances in cased-hole gravel packing processes can be compared, well performance information from completions typically termed “conventional gravel packs” can be provided. Figure 12.12 is a plot of skins reported in the Shell Brunei paper\(^3\) for cased-hole gravel packs performed with gelled carrier fluids. Examination of these data supports the conclusion that the use of gel while gravel packing by its very nature severely reduce the productivity of a well. In fact for the data set presented in Figure 12.12 the average flow efficiency is about 25 percent.

![Figure 12.12](image_url)

It has already been shown that one of the potential causes for low productivity for cased-hole gravel packs performed below a formation’s fracture pressure is that it is difficult to effectively place gravel completely though the near-wellbore damaged zone. One method to solve this problem is to attempt to remove the damage by injecting acid into the formation. Acid prepacking techniques have been the major technique for attempting to accomplish this goal.

A critical aspect of a successful damage removal procedure is that the acid must come into contact with the entire interval. In addition, it has been commonly thought that contact time must be sufficient to allow all of the damage to be dissolved. Therefore, with these assumptions, acid prepacking quickly evolved into a process where a diverted acid treatment is pumped at a low...
rate. Several studies indicate that one of the most effective diverters for acid prepacking is to carry relatively small quantities of sand in an HEC gel. While this combination did provide good diversion, well test results (Figure 12.13) tend to be very inconsistent, especially in high kh applications. Poor perforation filling resulting from injecting a sand/gel slurry into the perforations at a low rate coupled with formation damage resulting from the use of HEC are the most likely causes for these elevated skins. The detrimental effects of this poor perforation filling can easily overpower any benefit obtained from the acid.

![Figure 12.13](image.jpg)

**Figure 12.13**
Acid PrePack Performance vs. Formation kh

High injection rates, and the use of non-viscous carrier fluids are two techniques that have been demonstrated to provide improved perforation filling. The traditional acid prepacking techniques violate both of these conditions. If the perforation filling is indeed the critical factor of a cased-hole gravel pack, completions methods that focus on filling perforations should prove superior to those that sacrifice perforation filling for damage removal.

Figure 12.14 illustrates this point. A major operator has presented skin values for 56 Gulf of Mexico wells, 42 of which were prepacked at a high-rate with a 20 lb/1000 gal HEC (slickwater) carrier fluid, and 14 that were completed with an H₂O-PAQ (high-rate brine prepack followed by an annular brine pack). The wells completed with a high-rate gel prepack required a post-gravel pack acid job to achieve the performance reported in Figure 12.14. However, in both sets of data, the carrier fluid was able to easily leakoff to the formation, and high injection rates were used to enhance placement of gravel in the perforation tunnels. The data presented indicate that not only
are the average skins reduced over acid prepacking and slurry packing results, but that the overall consistancy is also improved (especially for high kh formations).

![Figure 12.14](image_url)

Figure 12.14
H₂O-PAQ and High-Rate Gel Prepack Performance vs. Formation kh

It has therefore been demonstrated that when prepacking below fracture pressure it is more important to ensure that as many perforations as possible are completely filled with gravel pack sand than for the damage to be removed. However, this does not negate the fact that improved well performance will result if damage can be effectively removed without jeopardizing the ability to fill perforations. It is this goal that is sought in a recent advance in acid prepacking. High-rate acid prepacking injects acid at the maximum rate possible while remaining below the formation’s fracture pressure. If the injection rate is gradually increased to maintain constant bottomhole pressure as the formation damage is removed, the treatment can be made to be self-diverting. In addition, if diverters are required, gravel pack sand (carried in brine) can be very effective at the elevated injection rates. The one aspect of acid prepacking that is eliminated with this technique is long contact times. However, the Shell Auger development used high-rate acid injections to obtain some very efficient completions, suggesting that the long contact times may not be as important as once believed.
Prepacking Above Fracture Pressure

One of the main detriments to prepacking below fracture pressure is that gravel can only be placed into spaces created during the perforating and perforation cleanup operations. If this amount of penetration into the formation does not extend completely through the near-wellbore damaged zone, restricted well productivity will result. To overcome this difficulty it becomes necessary to remove the damage with acid. As has just been shown, while this is possible, it is not always trivial to accomplish. Another technique to eliminate the effects of the damaged zone is to bypass it rather than to attempt to remove it. This is accomplished by hydraulically inducing a fracture.

Techniques available to create these fractures include brine fracturing (the Baker Oil Tools $H_2O$-FRAQ$^{SM}$ process), or a full-scale frac-pack. A type of treatment, which is used on occasion, can be considered a compromise between these two processes. This third technique, which we will term a gel prepack above frac, consists of creating a short fracture with a moderate to low viscosity gel carrier fluid. As will be demonstrated, this process does not create a large enough fracture to overcome the damage associated with the gelled carrier fluid; therefore, the final result is typically higher skin completions than are obtained with either frac-pack or $H_2O$-FRAQ completions. To allow frac-packing and $H_2O$-FRAQ to be distinguished, a description of these techniques follows:

**Frac-Pack:** A fracture with a length of at least 25 ft is created with a highly viscous carrier fluid. High pump rates are typically employed (15 to 20 bpm) and proppant loading is ramped from low concentrations up to 12 to 15 ppa. The total amount of gravel pumped is typically in excess of 900 lbs/ft.

**$H_2O$-FRAQ$^{SM}$:** A fracture with a length between 5 and 15 ft (Figure 12.15) is created with a low-viscosity (brine) carrier fluid. Pump rates are higher than conventional gravel packing operations, but usually lower than for a frac-pack. Typical pump rates are in the range of 8 to 12 bpm. Proppant loading is held constant between 1 and 2 ppa, and total job size is typically from 100 to 150 lbs/ft. These treatments can be multi-staged to further enhance the ability to effectively treat several sand subintervals with a single treatment.

![Figure 12.15](image-url)
Near-Wellbore Focus

A critical aspect of an H₂O-FRAQ completion is that it is considered part of the gravel pack; therefore, it is important that the focus remains in the near-wellbore area. Included in this focus are concerns that the fracture not be excessively long, that nothing is done during the creation of the fracture that may jeopardize the quality of the annular gravel pack, and that the gravel (proppant) is placed close to the wellbore. Treatment objective is to prepack the perfs and to extend the fracture past any formation damage, with long fractures not being required for high permeability formations. A fracture of this type is best created by the use of low-viscosity carrier fluids (water) to ensure that the proppant is not carried too deeply into the fracture, and to provide a high quality annular pack. In addition, since long fractures are not required, small treatments can be pumped, leading to the ability to pump the jobs using rig-based pumping equipment typical of gravel pack operations.

Fracture Length. Since H₂O-FRAQ completions are typically performed in highly permeable, unconsolidated formations, most of the improvement in well performance will result from placing a highly conductive, propped fracture through the near-wellbore damaged zone, rather than from formation stimulation. Figure 12.16 illustrates the results of a well inflow simulation, which demonstrates that, for a 200 millidarcy oil well, the majority of the productivity improvement comes from bypassing a near-wellbore damaged zone. Also, while additional fracture length may have some benefit, a fracture length beyond 10 to 20 feet leads to significantly decreasing benefits.

![Figure 12.16](image)
Similar conclusions can be drawn from examination of two recent publications covering the optimum fracture length for “frac-pack” completions. In the first paper, by Hunt et. al. of Halliburton Energy Services\textsuperscript{8}, a single-well reservoir model was used to determine the effect of fracture length on the productivity of a damaged wellbore. In this study, a damaged zone of 10 ft was assumed, and the conclusion results indicate that a 12 ft fracture is all that is required to maximize the well’s productivity. If these same results are used to estimate the necessary fracture length to maximize productivity for a well with a damage zone extending only 2 to 3 ft into the formation (as is more typically assumed) a length of closer to 5 ft is suggested.

In a second, more recent study, R.H Morales of Dowell Schlumberger et. al.\textsuperscript{9}, calculate the optimum fracture length based on a NPV analysis. Figure 12.17, taken from this paper, is a plot of the optimum fracture length as a function of reservoir size. While this plot suggests continually increasing benefit with fracture length, if drainage radii for typical reservoir sizes of 40 or 160 acres, an optimum fracture length of 2 to 15 ft is again indicated. A caution is provided in this paper concerning fracture length. That caution being that the fracture length must be sufficient to exceed beyond the zone of mechanical damage surrounding the wellbore. However, plots in this paper (Figure 12.18 and 12.19) indicate that this mechanically damaged zone should extend about 3 wellbore radii into the formation. For an 8.5 inch borehole, this would equate to about 1 ft into the formation.

\begin{figure}[h]
\centering
\includegraphics[width=0.8\textwidth]{fracture_length.png}
\caption{Optimum Fracture Length as a Function of Reservoir Size (From Ref. 9)}
\end{figure}
Figure 12.18
Extent of Mechanical Damage (From Ref. 9)
(Number of Wellbore Radii into Formation)

Figure 12.19
Radial Extension of Tangential Stresses (From Ref. 9)
(Number of Wellbore Radii into Formation)
**Water as a Carrier Fluid.** In conjunction with creating a short fracture, it is also necessary to place the proppant close to the wellbore, and not carry it deeply into the fracture. A good method to accomplish this is to use a low-viscosity fluid, such as water, to carry the proppant. The lack of viscosity causes the proppant to be deposited by the formation of an equilibrium bank\(^{10}\) (see Figure 12.20), thus resulting in most of the proppant being concentrated very close to the wellbore.

![Equilibrium Bank Formation Within a Fracture](image.png)

Another benefit associated with the use of water as a carrier fluid arises when the prepacking and annular packing are performed as a single step. In this situation, it is vital that the fluid selected provides the highest quality annular pack possible. Since research in the Baker Oil Tools gravel pack simulator indicates that the likelihood of creating a void (see Figure 12.21) is much greater when using a viscous fluid to carry gravel, the usefulness of water is again highlighted.
The third important benefit of the use of brine as a carrier fluid is related to the elimination of several of the major damage mechanisms that can plague frac-pack completions. Wong et. al.\textsuperscript{11} have identified four factors that may lead to a damaged frac-pack completion. These four factors are: the fracture skin (related to fracture conductivity), perforation skin (related to the proppant permeability as well as the total area available for flow), the choked fracture skin (related to a reduction of fracture width in the immediate near-wellbore area), and the fluid leakoff skin (related to the formation damage imposed due to the leakoff of the high-viscosity fracturing fluids). Of these four damage mechanisms, use of brine as a carrier fluid can eliminate (or significantly reduce) the fracture skin, the choked fracture skin, and fluid leakoff damage.

Fracture skin is eliminated by avoiding proppant permeability reductions caused by gel residue. The lack of gels also greatly reduces the formation damage along the fracture face. Finally, the elimination of the choked fracture effect relates to how frac-pack treatments are often pumped. Since frac-packs are usually pumped with the gravel pack assembly in place, it is critical that no voids remain in the screen/casing annulus at the end of pumping. However, as already mentioned, the use of gelled fluids results in a high probability that voids will be created. To remedy these voids, the pressure is rapidly bled off of the annulus at the conclusion of pumping, in hopes of bringing proppant into the wellbore from the fracture to fill voids. For this to occur, the fracture width in the near-wellbore vacinity must be reduced, thus leading to a choked fracture.

When brine is used as a carrier fluid, the risk of creating voids in the screen/casing annulus is virtually eliminated. Therefore, there is no need to surge proppant into the wellbore from the fracture. In addition, the equilibrium bank transport mechanism present with a low-viscosity carrier fluids concentrates the proppant close to the wellbore, further reducing the choking effect.

The total results of these damage mechanisms on the performance of frac-pack completions as compared to H\textsubscript{2}O-FRAQ completions is illustrated in Figure 12.22. This plot shows well
performance vs. fracture length for undamaged fractures. In addition, curves are also plotted for a frac-pack that has experienced the damage mechanisms described above. These results point out that any benefit of fracture length can easily be negated through these damage mechanisms.

![Figure 12.22 Effect of Fracture Damage on Productivity]

The final factor that must be addressed when brine is considered as a fracturing is whether the formation can be fractured. To create a hydraulic fracture in a formation, one must be able to pump into the formation faster than fluid can leakoff. The rate that a formation can accept leakoff is controlled by the permeability of the formation, the interval length, the difference between the formation pore pressure and the fracture pressure, and the viscosity of the injected fluid. The actual rate required to fracture a formation can be predicted through theoretical calculations or measured in the field.

The theoretical calculations are based upon Darcy's Law for flow through porous media. The equation below is Darcy's Law written in "oil field units" and rearranged to consider radial flow. The equation also takes into consideration the effect of a near-wellbore damaged zone by incorporating a skin factor. It must also be recognized that the form of Darcy's Law presented in below is for pseudo-steady-state flow. During an H₂O-FRAQ treatment this condition will not be met, but that does not negate the usefulness of this equation for rough approximations.
q = \frac{kh\Delta p}{203328.0\mu \left( \ln \frac{r_e}{r_w} + \frac{3}{4} s \right)}

where:
- \( q \) = injection rate (barrels per minute)
- \( k \) = reservoir permeability (millidarcies)
- \( h \) = formation thickness (feet)
- \( \Delta p \) = pressure differential between wellbore and reservoir pore pressure (pounds per square inch)
- \( \mu \) = fluid viscosity (centipoise)
- \( r_e \) = drainage radius of well (feet)
- \( r_w \) = wellbore radius (feet)
- \( s \) = skin factor

If \( \Delta p \) is set at the difference between the pore pressure and the fracture initiation pressure, then the maximum injection rate for radial flow through the rock's matrix may be calculated for various values of permeability and net permeable thickness, fluid viscosity and skin. Figure 12.23 illustrates these calculations for an example well.

This calculation technique can be used to investigate the expected fracturing rate for different formation permeabilities, interval lengths and fluid viscosities. It must be realized when making these calculations, that none of these factors are well understood. First, prior to treating a well the formation permeability can only be estimated, and the value of the damaged zone permeability is even less clear. Likewise, for long intervals, it is not necessarily true that the entire interval will fracture at one time. Especially in situations where the interval consists of several subintervals, a small portion of the total zone may fracture first. Finally, it must also be realized that not all brines have a viscosity of 1 cp. Rather, depending on brine weight and reservoir temperature, viscosities of brines can range from about 0.5 cp up to 5 cp (see Figure 12.24). Since the fracturing rate is inversely proportional to fluid viscosity, this range of viscosity can lead to a ten-fold reduction in injection rate required for fracture initiation.
Darcy's Radial Flow Equation

\[ Q = \frac{k \times h \times \Delta P}{24 \times 60 \times 141.2 \times B \times u \times (\ln(re/rw)-0.75+S)} \]

- \( \Delta P \) = Frac. pressure - reservoir pressure
- \( k \) = permeability
- \( h \) = formation thickness
- \( B \) = formation volume factor of injected fluid (1 for water)
- \( u \) = viscosity of injected fluid (1 cp for water)
- \( re/rw \) = ratio of drainage radius radius to well radius, assume \( \ln(re/rw)=8 \)

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**Test Well No. 1**

Injection Rates Required to Induce Fracturing While Injecting Water Into Formations of Various Thicknesses and Permeabilities
Because of the uncertainty of the input information, theoretical determination of fracturing rate is somewhat questionable. Therefore, it is highly recommended to perform a step-rate test prior to every H₂O-FRAQ to determine if the planned treatment will exceed fracturing pressure. The recommended procedure for performing a step-rate test is as follows:

1. Begin injecting water at lowest practical rate (approximately 0.25 barrels per minute) and inject at stabilized injection rate for at least 2 minutes.
2. Record last injection pressure and increase injection rate by 0.25 barrels per minute increments until above fracture propagation pressure or approximately 1.25 barrels per minute. Record last injection for each increment.
3. Increase injection rates to 2, 3, 4, 5, 7, 9 and maximum barrels per minute for 2 minutes at each rate.
4. Record last injection pressure for each rate.
5. Plot injection rate versus pressure (with pressures corrected for frictional effects).
6. A reduction in slope indicates the initiation of fracture propagation pressure.

Figure 12.25 illustrates results from a step-rate test for the same well who’s fracturing rate was predicted in Figure 12.23. In this figure, a minimum injection rate of 2.7 barrels per minute is indicated to cause fracturing at a fracturing pressure of approximately 4950 psi. This is very good agreement between the theoretical estimate and measured values for fracturing rates and pressures.
CLOSURE Pressure (from Step Rate plot) 4608 psi.
FRACTURE EXTENSION Pressure (from Step Rate plot) 4935 psi.
FRACTURE EXTENSION Rate (from Step Rate plot) 2.7 bpm.

Examination of Figure 12.25 indicates that successful analysis of step-rate test results requires that data be obtained both above and below fracturing rates. Therefore, the data recorded at the low pump rates is extremely important. The Darcy’s Law equation presented earlier can be used to determine what pump rates are required to allow a high-quality step-rate test to be obtained.

**Multi-Stage Treatments**

Once the required injection rate is determined, it is important to determine how the H₂O-FRAQ treatment will be pumped. The goal of a H₂O-FRAQ treatment design is to provide good coverage of the entire perforated interval, by pumping a self-diverting treatment.

H₂O-FRAQ treatments usually are designed to inject a pad of brine followed by a slurry at a constant concentration, ranging between 1 and 2 pounds per gallon. Proppant volumes are sized to provide about 100 pounds per foot outside the casing. For long intervals, the entire interval should not fracture at the same time. Rather, one zone should breakdown first, followed in succession by a breakdown of other portions of the perforated interval (see Figure 12.19).
To assist the process outlined in Figure 12.26 to proceed to completion, a multi-stage H₂O-FRAQ may be pumped. Under these conditions several pad/slurry stages are pumped in succession. When the pad is first injected, some portion of the perforated interval will breakdown (it may or may not be the bottom of the interval as shown in the figure). The created fracture will preferentially take the slurry until it becomes filled with proppant. Once the fracture is filled, a screenout occurs, and the injection pressure begins to rise. When the pressure reaches the fracture initiation pressure for some other portion of the perforated interval and the next pad stage is at the perforations, the new subzone will fracture, and slurry will begin to fill this fracture. Prior to the second pad stage reaching the perforation, any slurry from the preceding stage that cannot enter the first fracture will seek the easiest path, most likely filling perforations not in communication with the fracture. The process of creating successive fractures should continue until the entire perforated interval is treated. A simple 2-stage H₂O-FRAQ pumping schedule is listed in Table 12.4. This treatment was designed for a well with two perforated intervals of approximately 50 ft., which are separated by a 15 ft. shale section.
Multi-stage H₂O-FRAQ treatments are generally used for intervals that are made up of more than one sand unit (Figure 12.27). Under this scenario, a treatment would be designed for an average sand thickness in the sequence. Each stage would be separated by a brine pad. This low-viscosity pad should enhance the ability to fracture a new interval rather than continue to inject into the interval that is filled with proppant. With one stage for each sand subinterval, excellent proppant coverage over the entire perforated interval should be obtained.

There are several methods currently available for determining the best pumping schedule for a given well. The technique that provides the greatest opportunity to optimize treatments is to use a 3-D hydraulic fracture numerical simulator to predict the fracture geometry resulting from various pumping schedules. From this information, the treatment that provides the combination of the best perforation coverage and fracture conductivity can be selected. The difficulty with applying this technique on a routine basis is that much of the input data necessary for these programs are usually not known, and estimates must be made. This problem may be overcome to some extent if several treatments are performed in the same field. Under this situation, “history matching” of previously completed jobs may be performed to obtain a better estimation of effective formation properties.
Another, more simplified approach, is to size these treatments using a "Interval Unit" approach. An example of this design method considers the formation in 20 foot units. Each unit is treated with 800 to 1,000 gallons of pad, followed by 1,000 gallons of 1.5 pound per gallon slurry. A sufficient number of these stages are pumped to cover the entire perforated interval. The ability to multi-stage H₂O-FRAQ treatments allows long intervals to be effectively treated.
Performance Comparison: H$_2$O-FRAQ vs. Frac-Packs

To assess the relative advantages of the three methods for prepacking above fracture pressure: Baker Oil Tools H$_2$O-FRAQ process, gel prepack above frac, and a full scale frac-pack, the comparative performance of each technique must be examined. Figure 12.28 indicates the relative performance for these three types of treatments. The H$_2$O-FRAQ completions, as well as the five gel prepack above frac treatments, represent Baker Oil Tool jobs (some additional details of these treatments have been appended). The frac-pack treatments are those reported in three different SPE papers\textsuperscript{15-17} (as indicated on the plot). Two of the SPE papers\textsuperscript{15&16} highlight GOM completions of major operators, while the third paper\textsuperscript{17} describes the experiences of another major operator in West Africa.

Several conclusions can be reached from the examination of Figure 12.28. First, the gel prepacks above frac do not perform as well as either the H$_2$O-FRAQ or the frac-pack treatments. The cause for these higher skins is likely that the treatment is an attempted compromise between an H$_2$O-FRAQ and a frac-pack. By making this compromise, the job is sized similar to a H$_2$O-FRAQ treatment, which is not large enough to overcome the effects of gel damage within the fracture as well as in the formation. For this reason, treatments of this type are not recommended.
Since the gel prepacks above frac are not recommended, we will focus now on a comparison of H₂O-FRAQ’s and frac-packs. Examination of Figure 12.28 shows that although both the H₂O-FRAQ process and frac-packs experience the occasional high-skin well, these instances are usually fairly easily explained. Excluding the few high skin cases, both of these completion options provide skin distributions that are nearly identical (Figure 12.29).

<table>
<thead>
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<th>57 Frac-Pack Wells</th>
<th>23 H₂O-FRAQ Wells</th>
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</thead>
<tbody>
<tr>
<td>0 to 3</td>
<td>0 to 3</td>
</tr>
<tr>
<td>&lt;0</td>
<td>&lt;0</td>
</tr>
<tr>
<td>3 to 5</td>
<td>3 to 5</td>
</tr>
<tr>
<td>5 to 10</td>
<td>5 to 10</td>
</tr>
<tr>
<td>&gt;10</td>
<td>&gt;10</td>
</tr>
</tbody>
</table>

Table 12.5
Reported Causes for High Skins in Figure 12.28

To help understand the reasons for elevated skins in Figure 12.28, Table 12.5 is offered. This table lists the most likely cause of the high skins as determined by in-house analysis for the H₂O-FRAQ treatments, and as described in the associated SPE papers for the frac-pack completions. Once these outliers are eliminated, it can be observed that for the majority of applications an H₂O-FRAQ completion is equally effective as a frac-pack. In addition, this plot indicates that treatments above fracture pressure produce more consistent results than those pumped below fracture pressure.
Figure 12.30 provides some additional information to help further understand the effects of various operational practices on the H₂O-FRAQ process. In particular, the effect of gels either as a carrier fluid (as in the gel prepack above frac treatments), or as a fluid loss control pill is highlighted. This plot indicates that the most detrimental factor to H₂O-FRAQ treatments is to carry the gravel in a gelled fluid. In addition, the use of fluid loss control pills is also shown as detrimental, yet not nearly as bad as when they are used as a carrier fluid. This is particularly true if these pills are pumped immediately after gravel packing, with no acid cleanup. As indicated by Well A in Table 12.5, an unbroken gel pill (whether or not it contains a solid-based leakoff control material) has the potential of creating a very high skin. As mentioned previously, mechanical (not FLCM’s) fluid loss control devices should be used after gravel packing. If no pills have been pumped, our experience to date is that completion skins in the 0 to +3 range are commonly obtained.
A final issue that often arises concerning prepacking above fracture pressure is whether it is beneficial to pump acid prior to prepacking the formation. The data in Figure 12.31, a plot of skin for wells that had acid pumped prior to a water-frac treatment, suggest that little additional improvement can be seen when varying amounts of acid are pumped prior to a fracture treatment. In fact, the one well in the data set that had a multi-stage acid prepack pumped with gel and sand diverter, experienced the highest skin. While this evidence may not be conclusive, it does suggest that acid can be both non-beneficial and potentially detrimental when pumped prior to a fracture treatment. One exception is acid pumped at the beginning of a frac-pack treatment to assist in gel cleanup. The acid’s detrimental effects can arise from a variety of sources including: the diverters pumped, incorrect acid volumes, and acid/formation incompatibilities. Therefore, if the appropriate formation mineralogy information is not available, the risks associated with incompatible acids are best avoided by eliminating the acid altogether and simply bypassing the damage.
Figure 12.31
Effect of Acid Prior to Water-Frac Damage Bypass Treatment
Pumping Equipment Requirements

An important aspect of H₂O-PAQ and H₂O-FRAQ operations is that they are performed with gravel packing equipment (Figure 12.32), not hydraulic fracturing equipment. The significantly reduced surface equipment requirements are a direct result of the small scale treatments. Typical pump rates are on the order of 5 - 10 barrels per minute, and require several hundred, rather than several thousand, hydraulic horsepower. This horsepower reduction leads to significantly reduced pump requirements.

In addition to smaller (and fewer) pumps, the near-wellbore focus of H₂O-FRAQ operations lead to reduced fluid and proppant volumes. This not only leads to less storage space being required on the platform, but it also leads to significant cost benefits. Figure 12.33 illustrates a typical equipment layout for a H₂O-PAQ or an H₂O-FRAQ treatment. This compact design allows all equipment to be placed on the platform, eliminating the need for a stimulation vessel.
Since the use of brine carrier fluids is instrumental to the success of H₂O-PAQ and H₂O-FRAQ treatments, the ability to accurate control sand loading while pumping a sand/brine slurry is critical. This is particularly when pumping multi-stage H₂O-FRAQ treatments, which will be described in the following section. The Baker Oil Tools Gravel Infuser¹⁸ (Figure 12.34) is designed to allow accurate control of the mix ratio between sand and brine. This device also allows rapid response as sand is started and stopped during a multi-stage pumping program (Figure 12.35).
Figure 12.34  
High-Rate Gravel Infuser

Figure 12.35  
Gravel Infuser Allows Close Control of Gravel Mix Ratio in Brine Carrier Fluids
Completion Type Selection Criteria

With the performance of H$_2$O-PAQ, H$_2$O-FRAQ, and frac-pack completions having been reviewed, we can now establish a criteria for selecting between these completion options. As these criteria are presented, it should be remembered that all three of these techniques are capable of providing a low-skin completion. Therefore, while the criteria that is about to be presented is designed to help establish the optimum completion for various situations, these rules are not meant to describe the only possible method. In addition, it should be realized that these selection criteria represent the best of our understanding at this time. As more experience is gained, these criteria may be slightly modified.

Influence of Formation Properties on Completion Selection

The first factor that must be considered when it comes to selecting between a prepacking method is to determine the relative effect of increased fracture length. If the effect of fracture length is insignificant, formation stimulation cannot be expected, and improvement in well productivity will only result from the bypassing of near-wellbore formation damage. Figures 12.36 and 12.37 indicate the relative benefit of fracture length for formations of various permeabilities.

![Figure 12.36](image)

**Figure 12.36**

Effect of Fracture Half-Length on 35º API Oil Well Productivity from Formations of Various Permeabilities

Depth = 5,000 ft  Reservoir Pressure = 2,500 psi  Separator Pressure = 500 psi  2-7/8 inch Tubing
The information presented in these two figures illustrate that the benefit for increased fracture length becomes significantly less important as formation permeability increases. In addition, the maximum permeability where formation stimulation can be expected is lower for a gas well than for an oil well. These two plots represent only two specific well conditions; therefore, some leeway is allowed for the cutoff permeability. Based upon these data, a general guideline has been established that for oil wells with formation permeability less than about 50 md, and for gas wells with permeabilities less than about 10 md, a frac-pack would be the recommended completion option. An exception to this rule would be if the interval consists of more than one sand layer. The reason for this exception is that a multi-stage H₂O-FRAQ treatment can be pumped that will greatly increase the likelihood for placing gravel into all of the subzones. The increased probability for providing an undamaged completion across the entire interval will outweigh the benefit obtained from a longer fracture, which may not cover the entire interval.

Another issue that must be addressed when determining where an H₂O-FRAQ treatment is applicable is the ability to fracture the formation with brine at an injection rate available with rig-based pumping equipment. Factors controlling our ability to fracture the formation with brine...
include: formation permeability, interval length, degree of formation damage, reservoir pore pressure, and reservoir fluid viscosity and compressibility. To help make this assessment, Figure 12.38 is offered. This chart represents the results of Darcy Law calculations for the maximum formation permeability height product (kh) that can be fractured when injecting brine at 10 bpm given an estimate of initial skin and reservoir pressure. Findings based on the results presented in Figure 12.38 are:

1. If the kh of the formation (or the kh of any single sand layer in an interval consisting of multiple sands) is less than 15,000 md-ft, a fracture can easily be created with brine. Therefore, any near-wellbore formation damage can be bypassed equally well with either a \( \text{H}_2\text{O-FRAQ} \) or a frac-pack. This range of formation permeabilities covers a large proportion of the gravel packing applications worldwide, and therefore, supports the results of the performance comparison presented in Figure 12.29.

2. If the formation kh increases to a value between 15,000 md-ft and 40,000 md-ft, it begins to become more difficult to fracture the formation with brine. For formations of this conductivity the \( \text{H}_2\text{O-FRAQ} \) will still be applicable as long as a skin of at least 5 to 25 is present. This moderate level of formation damage might be expected if the well is a new completion drilled with a conventional drilling fluid. If reservoir kh exceeds 15,000 md-ft, and the formation is relatively undamaged (skin less than 5, as would be typical for a well drilled with a specially selected drill-in fluid), this formation would not be able to be fractured with brine. However, because of the low amount of formation damage, the need for any type of fracture to bypass this damage is questionable. Therefore, it is recommended that an \( \text{H}_2\text{O-PAQ} \), possibly preceded by an acid prepack (either non-diverted, or using foam or sand as the diversion material) should be successful at removing the small amount of damage that may be present, thus resulting in a highly-efficient completion.

3. If formation kh exceeds 40,000 md-ft, the well will need to be highly damaged to allow fracturing with brine. Therefore, for the situation where an old well with severe near-wellbore formation damage is to be worked over, either an \( \text{H}_2\text{O-FRAQ} \) or a frac-pack should successfully bypass this damage. For the \( \text{H}_2\text{O-FRAQ} \), the reduced permeability will provide the leakoff control while the fracture is propagating through the damaged zone. Once the fracture extends beyond the damage, the leakoff rate will increase, and fracture propagation will cease. Therefore, an \( \text{H}_2\text{O-FRAQ} \) should be successful at placing gravel pack sand through the damage zone, but not too far beyond. However, for a highly permeable formation, this would be sufficient.

If a high kh formation is to be completed, which is expected to have only a moderate amount of damage, it may prove difficult to create a fracture with a brine. However, there would still be a need to bypass this damage, therefore, a frac-pack would be the recommended treatment.

Formation kh and skin are not the only factors that control the ability to fracture a formation with brine. Another factor that affects the leakoff rate of a brine is the viscosity and compressibility of the reservoir fluids. For high-viscosity crudes, natural leakoff control is provided by the reservoir fluids themselves. Therefore, even for very high kh wells, \( \text{H}_2\text{O-FRAQ} \) completions can be very successful in situations where the reservoir fluids have an API gravity of approximately 20º or
less. Again, benefits of H\textsubscript{2}O-FRAQ will be strengthened if multiple sand subzones are present in the overall interval.

![Figure 12.38](image)

**Fracture Growth and Operational Constraints**

Besides factors directly related to formation permeability, other concerns affect the decision to select either a frac-pack or an H\textsubscript{2}O-FRAQ. In general it can be assumed that because of the reduced leakoff associated with a gelled fracturing fluid, as well as the increased pump rate, vertical fracture growth is expected to be greater for a frac-pack. This can be either good or bad depending upon the reservoir condition.

For example, a frac-pack would be recommended over an H\textsubscript{2}O-FRAQ completion for intervals greater than about 50 ft that consist of thinly laminated sand/shale sequences (6-inch to 1 ft thick sand lenses). In formations of this type it is beneficial to create a single fracture to place all of the sand layers into communication with the wellbore. For a short interval, this can likely be accomplished with either an H\textsubscript{2}O-FRAQ or a frac-pack. However, as the interval length exceeds about 50 ft, it may be difficult to achieve sufficient vertical frac growth with an H\textsubscript{2}O-FRAQ treatment. Therefore, a frac-pack may prove to be beneficial. One method for extending the application of H\textsubscript{2}O-FRAQ in this application is to multi-stage the treatment to increase the...
probability for creating more than one fracture, thus allowing the entire zone to be treated. However, without distinct sand intervals, the self-diverting nature of multi-stage H$_2$O-FRAQ treatments is less clearly defined.

When several distinct sands are to be treated, a multi-stage H$_2$O-FRAQ is the recommended treatment. By alternating brine pads and brine/gravel slurry stages, the bottomhole treating pressure increase that is associated with fracture filling can be used to assist in diverting the treatment and creating fractures in several sands during a single pumping operation. The high sand concentration as well as the gelled fluids used during frac-pack operations tend to prohibit this self-diversion from taking place. This, coupled with the fact that soft shales can be very effective barriers to vertical fracture growth, indicates that there is a strong possibility for a frac-pack to treat only a portion of the entire interval. Therefore, an H$_2$O-FRAQ should be used whenever multiple sands are to be treated and one time.

A situation where extended vertical fracture growth would be detrimental is when the perforated interval is located close to a gas/oil or an oil/water contact. Because of the combined effects of a high leakoff rate and a small job size, our experience has indicated that fractures created by an H$_2$O-FRAQ treatment stay quite close to the perforated interval. Treatments have been successfully pumped without breaking into water when the perforations were as close as 10 feet from the water contact. This ability to contain fracture growth increases if a shale is present between the perforations and the contact. While a shale is also capable of containing a fracture from a frac-pack, a shale thickness of at least 20 ft is typically desired for these applications. It must be cautioned, however, that treatment modeling would be necessary to assess the risk of unacceptable fracture height growth for any type of fracture treatment carrier out near a gas/oil or oil/water contact.

Other factors that often control the applicability of H$_2$O-FRAQ are operational constraints. Since H$_2$O-FRAQ utilize smaller scale treatments, they are pumped with rig-based pumping equipment. However, severely overpressured reservoirs may dictate elevated hydraulic horsepower requirements, thus leading to the selection of a frac-pack. Similarly, if a severely underpressured reservoir is to be treated, the fluid-loss rate may be too high to overcome while pumping a brine at reasonable rates. Therefore, a frac-pack may again prove beneficial.

The brine carrier fluids used in the H$_2$O-FRAQ completions are beneficial in two situations: treating high-angle, long intervals, and treating high temperature wells. Because of improved gravel transport mechanics of low-viscosity fluids in a high-angle well, there is a greatly improved chance to obtain a void-free annular pack using an H$_2$O-FRAQ. Likewise, since no gels are used in this process, the degradation of fracturing fluids at high temperatures is not an issue for H$_2$O-FRAQ.

**Summary of Selection Criteria**

To help summarize the reservoir conditions affecting the decision between H$_2$O-PAQ, H$_2$O-FRAQ, and frac-pack applications Figure 12.38 is offered. This chart provides a systematic method for narrowing down the choice between H$_2$O-FRAQ and frac-pack; however, it does not
cover all of the important issues. Some of the other issues that influence this decision process are outlined in Figure 12.40. The remaining criteria primarily relate to the fracture growth mechanics of these two processes, as well as some of the operational constraints.

Examination of Figures 12.39 and 12.40 indicate that the only call-out for an acid prepack completion is for high kh wells with a limited amount of damage. Our experience has been that in general acid prepacks are less effective in removing damage than H₂O-FRAQ’s are in bypassing it. In addition, attempting to combine the benefits of acid prepacking with an H₂O-FRAQ can produce problems that lead to an elevated skin. This difficulty arises by trying to achieve adequate diversion during the acid treatment. To accomplish this, it is often necessary to use gel or gel & sand diverters. Apart from the damaging effects of the gel, the use of gel & sand causes perforation tunnels to be poorly packed, thus resulting in a increased pressure drop along the tunnels, and therefore a reduced completion efficiency.

Since, it is not generally recommended to use acid prepacking in conjunction with an H₂O-FRAQ completion, the question becomes: are there any application for this technology? The best application for this type of treatment is for jobs that either need to be pumped below fracture pressure (i.e., those with a very close (less than 10 ft away) GOC or OWC) or those where only a small amount of damage needs to be removed. To eliminate the detrimental effects of gels, other options should be considered for use as diverters. Some additional options include the use of either foam, gravel pack sand carried in NH₄Cl, or no diverter at all for short zones. The use of sand diverters will require that higher pump rates be used than are typical for acid prepack treatments. This will reduce the contact time, and may reduce the damage removal capability of the acid. However, these methods should provide adequate diversion without imposing the damaging effects of gels into a portion of the formation that has just been acidized.
Figure 12.39
Completion Type Selection Flow Chart
<table>
<thead>
<tr>
<th>Well Condition</th>
<th>H:O-FRAQ Application</th>
<th>Frac-Pack Application</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir Conductivity:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>average reservoir permeability &lt; 10 md for gas well or &lt; 50 md for oil well</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Fracturing Constraints:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>individual sand interval, $k_h &gt; 40,000$ md-ft w/ initial skin &gt; 25</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>individual sand interval, $k_h &gt; 40,000$ md-ft w/ initial skin from 10 to 25</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>individual sand interval, $k_h &gt; 15,000$ md-ft w/ initial skin &lt; 5</td>
<td>No need to fracture</td>
<td>No need to fracture</td>
</tr>
<tr>
<td>$k_h &gt; 40,000$ md-ft and high-viscosity crude ($\approx 20^\circ$ API or less)</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>multiple sand intervals, $k_h$ for each subinterval &lt; 15,000 md-ft w/ any initial skin</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>$k_h$ for any sand interval from 15,000 md-ft to 40,000 md-ft w/ skin &gt; 5</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Fracture Growth</td>
<td></td>
<td></td>
</tr>
<tr>
<td>thinly bedded sand/shale w/ interval length &lt; 50 ft</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>thinly bedded sand/shale w/ interval length &gt; 50 ft</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>interval of any length consisting of several sand lobes</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>GOC or OWC within 10 ft in same sand</td>
<td></td>
<td></td>
</tr>
<tr>
<td>GOC or OWC &gt; 10 ft away in same sand</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>shale barrier between pay and water sand &lt; 20 ft thick</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>shale barrier between pay and water sand &gt; 20 ft thick</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>Operational Constraints</td>
<td></td>
<td></td>
</tr>
<tr>
<td>severely overpressured (pore pressure &gt; 15 ppg)</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>severely underpressured (pore pressure &lt; 6 ppg) &amp; damaged</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>severely underpressured &amp; low initial skin</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>bottomhole temperature &gt; 250$^\circ$ F</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>hole deviation &gt; 60$^\circ$ &amp; interval length &gt; 50 ft</td>
<td></td>
<td>X</td>
</tr>
<tr>
<td>poor quality cement job</td>
<td></td>
<td>Do Not Fracture</td>
</tr>
</tbody>
</table>

Figure 12.40
Completion Type Selection Chart
Summary

It has been demonstrated that the process of perforation prepacking can lead to highly effective gravel-pack completions. If this prepacking process succeeds at placing a highly conductive flow path completely through the near-wellbore damaged zone, completion efficiency will be further increased. Methods to enhance the ability to provide this flow path are the Baker Oil Tools H₂O-PAQ and H₂O-FRAQ process as well as frac-pack completions.

Performance data from H₂O-PAQ, H₂O-FRAQ, and frac-pack completions have been compared to build a set of criteria for selecting between these completion options. This evaluation indicates that the performance of H₂O-FRAQ completions is virtually the same as that of frac-pack completions. Both completion options experience the occasional high skin well, but these are usually easily explained. The main causes of elevated skin on H₂O-FRAQ completions are the use of gelled carrier fluids, and the use of fluid-loss control pills inside the gravel pack screen. To eliminate these potential damage mechanisms, only non-gelled carrier fluids should be used, as should mechanical fluid-loss control rather than pills.

Because of this very similar performance, either H₂O-FRAQ’s or frac-packs can be used in the vast majority of sand-control applications. However, there are applications where one technique is superior to the other. Frac-packs will tend to be recommended for low-permeability formations (<10 md for a gas well, < 50 md for an oil well), for moderately damaged wells in formations with kh > 40,000 md-ft, and for sections of thinly laminated sand/shale sequences that are greater than 50 ft in extent. Conversely, H₂O-FRAQ completions are better suited for situations with a nearby gas/oil or oil/water contact; long, highly-deviated intervals; high temperature reservoirs; as well as for intervals that consist of more than one sand layer. In this last situation, a multi-stage H₂O-FRAQ treatment greatly increases the probability for treating the entire interval.

For situations where fracturing would not be required, such as an undamaged, high-permeability formation, an H₂O-PAQ is recommended. In this situation completely filling all perforations with gravel pack sand and obtaining a high-quality annular pack will lead to a highly efficient completion. Since this type of treatment will not bypass near-wellbore formation damage, it is recommended that the H₂O-PAQ be combined with an acid prepack to assist in removing any damage that may be present. This is also the case for wells where it is recommended to not fracture the formation, with the exception of wells with a poor quality cement job (i.e., for wells with a very close gas/oil or oil/water contact). To help the acid prepack be as effective as possible, it is recommended to use foam, or sand diverters, rather than gel or gel & sand. The hope here is to remove as much damage as possible, while not imposing another damage mechanism onto the system.

Since it is the purpose of an H₂O-FRAQ treatment to bypass damage, and the purpose of an acid prepack to remove the damage, these two treatment types are not always mutually beneficial. It is often the case that procedures necessary to optimize the acid treatment may hinder the effectiveness of the fracture treatment. The net result being that a completion efficiency less than or no more than equal to that obtainable by the H₂O-FRAQ treatment alone would be obtained. Therefore, the added cost of the acid treatment would not be justified. For this reason, it is recommended that an acid prepack not be combined with an H₂O-FRAQ treatment.
References


OPEN HOLE GRAVEL PACKING

Introduction

As discussed in the previous two chapters, much of the focus of cased hole gravel packing is aimed at completely packing the perforations with high permeability gravel pack sand. Failure to completely pack the perforations jeopardizes well productivity and completion longevity. Open hole gravel packs completely avoid the difficulties and concerns of perforation packing, and reduce the gravel placement operations to the relatively simple task of packing the screen/open hole annulus. Because open hole gravel packs have no perforation tunnels, formation fluids can converge toward and through the gravel pack radically from 360° eliminating the high pressure drop associated with linear flow through perforation tunnels. The reduced pressure drop through an open hole gravel pack virtually guarantees that it will be more productive than a cased hole gravel pack in the same formation. Figure 13.1 illustrates the theoretical pressure drops experienced in an open hole and cased hole gravel pack assuming completely packed (prepacked), partially packed (no prepack) and formation sand filled perforations. As can be seen from the figure, open hole gravel packs result in virtually no additional pressure drop as the formation fluids converge on the wellbore.

![Figure 13.1](https://via.placeholder.com/150)

Comparison of Pressure Drawdowns for Cased and Open Hole Gravel Packs

**Flow Rate (B/D/ft)**

**Pressure Drop (psi)**

- **Formation Sand in Perf**
- **20/40 Gravel No Prepack**
- **20/40 Gravel Prepacked**
- **Open Hole**
Guidelines for Selecting Open Hole Gravel Pack Candidates

Despite their potential for creating high productivity wells, open hole gravel packs are not suitable for all reservoirs and formations. One disadvantage of the open hole completion (including open hole gravel packs), is the inability to always isolate unwanted water and/or gas production. Unlike cased hole completions that can be precisely and selectively perforated only in the zones of interest, open hole completions sometimes offer less control over which fluids (water, oil and gas), are exposed to the wellbore. Furthermore, remedial operations (such as squeeze cementing, plug-backs or straddle pack-offs) to isolate unwanted fluid production can be carried out with a reasonably good chance of success with little to no forward planning in a cased hole well. Such remedial operations in an open hole (with the exception of a plug-back), require more forward planning to isolate undesirable fluids. Also zonal isolation considerations for the open hole will be different for a deviated and horizontal completion. With this in mind, open hole completions are best suited for a single reservoir completion rather than multiple completions with water or gas between the completions. Open hole completions are also suitable for formations that will produce with a high water-oil or gas-oil ratio despite the type completion (cased or open hole) employed. In this case, the higher productivity afforded by an open hole completion takes precedence.

Maintaining borehole stability during the drilling and completion phase is an essential requirement for open hole gravel packs. Concern over the lack of borehole stability is a primary reason why open hole gravel packs are not used more often in unconsolidated, dilatant formations. Unstable boreholes will make running of the gravel pack assembly difficult and may prevent proper gravel placement if the formation flows in around the screen. Fortunately, state-of-the-art drill-in fluids, such as PERFLOW, are effective in maintaining borehole stability while making a horizontal completion in dilatant type formations known to present problems in the past.

Open hole gravel packs should be avoided in formations with several sand and shale laminations, if the shales are prone to eroding and/or sloughing. During gravel placement, the shale can intermix with the gravel pack sand resulting in reduced gravel permeability and impaired well performance. Again, proper drill-in fluid selection can alleviate some of the problems associated with laminated sand and shale formations.

A summary of the advantages and disadvantages of open hole gravel packs as well as the guidelines for selecting open hole gravel pack candidates is listed below.

Advantages of open hole gravel packs:

- Low drawdown and high productivity
- Excellent longevity
- No casing or perforating expense

Disadvantages of open hole gravel packs:

- Sometimes difficult to exclude undesirable fluids such as water and/or gas
- Not easily performed in shales the erode or slough when brine is pumped past them.
- Requires special fluids for drilling the open hole section
Guidelines for selecting open hole gravel pack candidates:

- Formations where cased hole gravel packing has unacceptable productivity
- Situations where increased productivity is required
- Reservoirs where long, sustained single phase hydrocarbon flow is anticipated
- Situations where workovers for isolating gas or water cannot be accomplished.
- Wells where high water-oil or gas-oil ratios can be tolerated
- Reservoirs with single uniform sands (avoid multiple sands interspersed with troublesome shale layers or water sands)
- Formations that can be drilled and completed maintaining borehole stability in the completion interval
- Situations where cased hole completions are significantly more expensive (i.e., long horizontal wells)

Top Set Open Hole Gravel Pack

The most common type of open hole completion is referred to as “top set” as illustrated in Figure 13.2. While this figure show a vertical completion this discussion is pertinent to horizontal completions. In this completion, the production casing is set at the top of the completion interval to isolate overlying strata. Once the casing is cemented, the productive formation is drilled to total depth, hole cleaned and the gravel pack is installed. Critical issues in top set open hole gravel packs include selecting the casing seat, drilling the open hole, underreaming if necessary, cleaning the hole and gravel packing.

Selecting the Casing Seat. Selecting the casing seat at the proper depth can have a significant impact on the success and cost of an open hole completion. Normally, the casing should be set at the top of the reservoir and just barely into the productive interval. Should the overlying formation
be an unstable or sloughing (heaving) shale, failure to isolate the shale behind casing may cause problems and delays throughout the remainder of the completion and even through the entire life of the well. Well logs should be run to ensure all offending strata have been penetrated and will be cased prior to running the casing. In some instances, several logging runs may be required as the well is deepened to determine exactly when the casing should be run. In the case of logging while drilling, the casing point can be easily picked without multiple logging runs. Alternatively, the well can be drilled to total depth and logged to determine the appropriate casing depth. A sand plug can then be placed across the productive interval prior to cementing the casing or a cementing stage packer can be used to avoid contaminating the formation sand face with cement solids and/or filtrate.

Drilling the Open Hole. Several options are available for drilling the open hole completion interval. How this is performed and the type of fluids used depends on the mineral and fluid content of the formation (i.e., whether it is sensitive to the drilling and/or completion fluid). Another factor is whether the open hole will be enlarged by underreaming as discussed later. The fluid used for drilling the open hole is critical to the success of the completion. The general requirements of an ideal drill-in (or underreaming) fluid are as follows:

- Compatible with the reservoir rock and fluids (non-damaging)
- Good suspension properties
- Low friction loss
- Low fluid loss
- Density easily controlled
- Readily available
- Inexpensive
- Easily mixed and handled
- Non toxic
- Thin friable filter cake with low break-out pressure

While most fluids do not have all of these properties, some, such as calcium carbonate brine based systems have performed well as drill-in and underreaming fluids. PERFLOW is an example of a calcium carbonate brine based fluid that has been used as a drill-in fluid. The critical issue is that the drill-in fluid should do minimal irreversible damage to the face of the formation. The solids laden fluids should quickly form a filter cake to minimize filtrate losses. The filter cake should be easily removable prior to or after gravel packing and the ease to which it is removed is reflected in a low break-out pressure. Break-out pressure is that drawdown pressure required to initiate production after the formation has been mudded off with the drill-in fluid. In some cases, clear brines have been acceptable as a non-damaging drill-in fluid. If the open hole will be underreamed, standard drilling mud may be used as a drill-in fluid, provided the underreaming operation removes the mud invaded, damaged portion of the formation.

Underreaming. Underreaming is the operation of enlarging the hole size below the casing shoe. One reason for underreaming an open hole is to remove damage present in the pilot hole which is unnecessary if the pilot hole is drilled with a non-damaging fluid. The larger diameter hole will also enhance the well productivity slightly, but in most cases this is not significant. Underreaming may be performed simply to provide greater clearance between the screen and the open hole. In
any event, underreaming should be performed with a non-damaging fluid. Traditional drilling muds should only be used as a last alternative and damage removal treatments should be planned prior to placing the well on production.

Underreaming is usually more of an annoyance than an incremental time, cost or productivity issue, since a cased hole completion also requires changing over to a clean fluid prior to perforating. Perforating, of course, is unnecessary for an open hole completion. On an incremental cost basis, the position normally taken is that underreaming and perforating cost usually offset each other.

In the event that running a liner across the completion interval at a later date is an option to isolate unwanted fluids, underreaming should probably be avoided. The cement sheath in an underreamed hole will be much thicker than normal and will interfere with effective perforating or make perforating operations more difficult. The difficulties, perforating, or ineffective perforations, will adversely effect gravel packing operations and subsequently, will restrict well productivity.

**Hole Cleaning.** Solids in the form of drill-in fluids, drill solids and thick filter cakes plug screens, tools and gravel pack sand. The importance of cleaning the hole and scouring the filter cake is shown in Figure 13.3. This bar graph based on field data collected from 10 wells, shows the relationship between completion skin and hole cleaning. This relationship is not too surprising but what is often overlooked is the fact that once a well is damaged, subsequent acid work not yield an undamaged well. Before running screen in the hole and gravel packing, it is necessary to remove the drill-in fluid, drill solids from the hole, clean the hole and scour the filter cake down to its dynamic thinness. Details for cleaning the hole are given in Chapter 8.
Gravel Pack Equipment. Running and installing the gravel pack equipment in an open hole is basically the same as in a cased hole gravel pack. As discussed in Chapter 7, bow spring centralizers are required, particularly if the completion interval is underreamed. While there is considerable debate as to the degree that bow-spring centralizers interfere with gravel placement, model work does not show any interference. However, other options for centralization are not available except in very short intervals. In some underreamed open hole gravel packs completed in short intervals, no bow-spring centralizers may be required. Centralization can be achieved by underreaming to about 10 to 15 feet short of total depth. The non-underreamed interval at total depth provides centralization for the bottom of the screen. The packer at the top of the screen provides centralization at the top.

Running the screen in an open hole differs from a cased hole in that there is no sump packer. The screen is normally landed a foot or two from the bottom of the well. Setting the screen in compression should be avoided to prevent buckling which will be detrimental to centralization. Shear-Out Safety Joints are not typically used in open hole gravel packs. If the screen is not set on bottom or in the event the bottom of the well is “soft”, the hydraulic pressures created during gravel placement can generate sufficient forces to cause downward movement of the screen and shearing of the Shear-Out Safety Joint.

One other item to note when doing a open hole gravel pack is the type cross-over tool to be employed. High rate frac cross-over tools are typically designed to maximize flow area into the wellbore, consequently the return ports are usually small. These smaller return ports can create sufficient back pressure that the open hole cannot be circulated at the required pack rates below frac pressure. A rate verses pressure drop curve for the high rate frac tool is a must when making an open hole gravel pack evaluation.

Gravel Placement. Gravel placement operations in open holes are again almost identical to those performed in cased holes, except that no special operations to fill the perforations are required. Typically the gravel volume required for gravel packing will be 25 to 50 percent greater than theoretical. This is true at all wellbore deviations. If available the open hole volume should be obtained from a caliper log. Again, based on experience in a certain field or formation, a generous amount of excess gravel may be required since calipered volumes often underestimate the actual hole volume due to hole irregularities and washouts.

As to the physical placement of sand around the screen, returns are not an issue at wellbore deviations less than 55°. Sand will fall to bottom and pack the screen with no returns as long as the injection loading does not exceed the fall rate of the sand in brine. At Deviations greater then 55° sand no longer “falls” down the hole. This is understandable considering the angle of repose for dry sand is around 28°, making the complementary wellbore deviation 62° (See Figure 13.4). As sand is pumped out the cross-over tool it falls to the bottom of the casing and builds a dune. For sake of definition this dune is called the alpha wave. Now returns are necessary and a minimal annular velocity of 1.0 ft/sec in the screen open hole annulus is required to move the alpha wave to bottom. The alpha wave is shown as areas 1 through 6 in Figure 13.5. With the alpha wave at bottom sand is then deposited on top of the alpha wave, and the well gravel packed.
back to the top screen. The wave coming back is called the beta wave and is shown as areas 7 thru 12 in Figure 13.5.

To meet the annular velocity of 1.0 ft/sec, losses to the formation must be controlled and bypass between the wash pipe - screen base pipe annulus minimized. Controlling losses to the formation is accomplished by selecting of a proper drill-in fluid as discussed in Chapter 8. Keeping the wash
pipe OD - screen ID ratio around 0.8 will minimizing bypassing between wash pipe and screen (See Figure 13.6).

**Treating the Formation.** Treating the formation to remove formation damage may be required in some situations. If the drill-in fluid filter cake or fluid loss material used is acid soluble, an HCl acid treatment (7.5 to 15 percent) is usually sufficient to dissolve the plugging material and restore production. Typical acid volumes are 10 to 15 gallons per foot. Acid may dissolve formation cementation causing formation sloughing prior to gravel placement; therefore, formation acid treatments should be delayed until after the gravel pack if possible.

![Figure 13.6](image)

**Horizontal Gravel Pack**

*Figure 13.6*

Set-Thru Open Hole Gravel Pack

In situations where accurately setting the casing depth is difficult or when secondary pay zones exist above the primary target, set-thru open hole completions can be applied. In this type completion the casing is run through all formation pay zones and cemented in place. Open and cased hole well logs are used to determine the exact location of the pay zones behind the casing, and windows are milled opposite the completion interval to create an “open hole” environment. The well can then be gravel packed. Schematics of example set-thru type completions are shown in Figure 13.7. Due to the amount of debris created by milling casing windows, it is recommended that all set-thru type open hole completions be underreamed to expose a clean, non-damaged formation face. The criteria for underreaming fluids is the same as discussed in the previous section. A requirement in applying set-thru type completions is a good cement job. The casing must be securely cemented to facilitate milling operations and maintain alignment between the upper casing and the lower casing sections. Because a sump packer can be used, a set-thru
gravel pack assembly is basically the same as a cased hole type assembly. The only exception would be the use of bow spring type centralizers in long open hole sections. Set-thru type completions are especially well suited for up hole recompletions in existing wells.

Summary

As a result of their potential for high productivity, open hole completions are receiving new, widespread attention for wells that require gravel packing. As will be discussed in the next chapter, open hole gravel pack completions can be among the highest productivity type completion. In addition, open hole gravel packs demonstrate good longevity.

References

Introduction

The success or failure of a completion technique is best determined by its performance in the field. Field performance may be affected and influenced by many factors not necessarily related to the quality of the completion technique applied. Examples of these factors include human influences, operational restraints, reservoir misunderstandings, regulatory requirements or combinations of these. Despite these outside influences, after a sufficient number of completions have been conducted, trends in performance can be established. Performance trends, if properly documented, are extremely valuable in planning future well completions or project developments.

Although not as plentiful as desired, data is available on the performance of gravel pack wells that shows the effects of different completion types and techniques on well productivity and longevity. This chapter presents some of the available gravel pack performance data. These data reflect general trends resulting from many gravel pack completions; however, as stated above, some of the results may be influenced by site specific conditions. When evaluating trends, it is important to remember that future results (especially in different operating environments and formations) may deviate somewhat from past results.

Productivity and Longevity

Gravel pack field results are most often presented in terms of productivity or longevity. Productivity can be defined in terms of skin factor, productivity index or flow efficiency (as discussed in Chapter 1) or variations of these factors for a specific study. Longevity is generally defined in terms of cumulative sand free production for a particular sand control technique. The equation\(^1\) to calculate the longevity, or success, of a particular completion technique is given below. Success can be plotted against cumulative production to estimate the longevity of a particular type of gravel pack completion technique.

\[
S_B = \frac{n_B}{T - \sum_{i-1}^{n_{i-1}} S_{i-1}}
\]

where:  

- \(S_B\) = success at “B” barrels of production (fraction) 
- \(n_B\) = number of zones that have produced at least “B” barrels 
- \(T\) = total zones 
- \(i\) = production increments 
- \(n_{i-1}\) = number of jobs that have produced at least “i-1” but have not yet had the opportunity to produce “i” increments of production 
- \(S_{i-1}\) = success at “i-1” increments of production (fraction)
**Perforating Techniques**

Chapter 9 discussed the importance of achieving the proper size and number of perforations to minimize pressure drop in cased hole gravel pack completions. The importance of clean perforation tunnels was also stressed and perforation cleaning techniques were discussed. Figure 14.1 presents field results of gravel pack success versus perforated flow area. This data is obtained from wells producing from short intervals (i.e., average is less than 10 feet of net perforated pay), so the perforation flow areas indicated are for the entire zone. The implication of this plot is that higher flow areas reduce fluid velocity making the gravel pack less likely to fail due to formation sand plugging of the perforation tunnels or annular gravel pack. Figure 14.2 shows the effects of perforation cleaning technique on gravel packed well productivity. The field study from which this data is derived compared washing (perf-wash), backsurring (perf-surge) and underbalanced perforating (surge-perf). The gravel pack productivity is represented by the “completion index”. The completion index, in this case, is a skin factor that takes into account the effects of formation damage as well as perforation efficiency. Like skin factor, the lower the completion index the less damaged the well. From this study, underbalanced perforating resulted in the lowest average completion indices by a factor of two-to-one over perforation washing and three-to-one over backsurring. The paper documenting this study (SPE Paper 12106) is given in Appendix 1.
Perforation Packing

As discussed in Chapter 11, completely filling the perforation tunnels with gravel pack sand is a critical requirement for a successful cased hole gravel pack completion. Packing the perforations ensures completion longevity by preventing the formation sand from moving in and plugging the tunnels and/or annular gravel pack. Furthermore, packing the perforations places the highest possible permeability material in the critical linear flow area through the perforation tunnel resulting in minimal pressure drop. Prepacking techniques (as discussed in Chapter 12) provide the greatest opportunity for complete perforation packing; thus, the importance of perforation packing can be assessed by comparing prepacked and non-prepacked gravel packed wells. Figure 14.3 indicates the effects of perforation prepacking on completion longevity. Figure 14.4 indicates the effects of prepacking on well productivity. In terms of longevity and productivity, prepacking has a positive influence on cased hole gravel packing. Figure 14.5 shows the positive effects of the H2O-FRAQ technique discussed in Chapter 12. These data indicate that very low skin completions are possible when prepacking is performed with brine carrier fluids above the formation fracture pressure.
Figure 14.3
Longevity of Cased-Hole Gravel Packs as a Function of Prepacking

Figure 14.4
Productivity of Cased-Hole Gravel Packs as a Function of Prepacking
Remedial Gravel Packs

The question is raised from time to time regarding the success of gravel packs performed in formations that have already produced some formation sand versus gravel packs installed in the initial completion. Such remedial gravel packs are typically performed in wells that were not originally gravel packed, but have started to produce sand in an unmanageable fashion. Figure 14.6 shows that the completion success of gravel packs in “old” intervals is lower than the success of gravel packs performed when the well is “new”. Whether this can be explained as a consequence of inadequate procedures or is the result of other causes is not clear. Intuitively, one would expect more problems attempting to gravel pack a well that produced sand due to the possibility of large cavities behind pipe or as a result of resorting and permeability reductions of the formation material in the near wellbore area as sand was produced. In the field study results illustrated in Figure 14.6, a tubingless completion is a well that is completed inside of 2-7/8 or 3½ inch “casing” and produced without an inner tubing string.
Open Hole Versus Cased Hole Gravel Packs

As discussed in Chapter 13, open hole gravel packing should provide higher productivity wells since the additional pressure drop associated with incompletely packed perforation tunnels is avoided. Field results support the productivity enhancements achievable with open hole gravel packs. Table 14.1 shows productivity indices of open hole gravel packs compared with non-gravel packed cased hole completions, cased hole gravel packs with prepacking and cased hole gravel packs without prepacking. This study is unique in that four different completion techniques were applied in the same fields under similar conditions. Note that the data confirms that open hole gravel packs are capable of achieving high productivity. The data in the table is from two different reservoirs in Venezuela. In spite of the fact the absolute values of the productivity indices are different, the trend is the same. Another case history showing that open hole gravel pack completions have better productivity than cased hole gravel packs is shown in Figure 14.7.

<table>
<thead>
<tr>
<th>Productivity Index</th>
<th>LL-5 Reservoir</th>
<th>LL-3 Reservoir</th>
</tr>
</thead>
<tbody>
<tr>
<td>Open-Hole Gravel Pack</td>
<td>48.4 (14)</td>
<td>6.4 (13)</td>
</tr>
<tr>
<td>Gun Perforated Casing</td>
<td>36.6 (20)</td>
<td>5.2 (14)</td>
</tr>
<tr>
<td>Cased- Hole Gravel Pack (with prepack)</td>
<td>12.9 (19)</td>
<td>3.2 (12)</td>
</tr>
<tr>
<td>Cased-Hole Gravel Pack (without prepack)</td>
<td>4.0 (14)</td>
<td>1.7 (3)</td>
</tr>
</tbody>
</table>

( ) - Number of wells
In addition to better productivity, case histories also support that open hole gravel packs have greater completion longevity than cased hole gravel packs. This is illustrated in Figures 14.8 and 14.9. In addition to oil and gas wells, several water source wells completed with open hole gravel packs have produced in excess of 25 million barrels each.¹
Summary

Field experience with gravel pack completions has yielded the following results that can be used for planning purposes:

- Higher perforation quantity and quality enhances completion longevity and productivity in cased hole gravel packs.
- Perforation prepacking enhances the productivity and completion longevity of cased hole gravel packs.
- Cased hole gravel packs performed on the initial completion are more successful than gravel packs performed in a remedial workover.
- Open hole gravel packs have higher productivity and completion longevity than cased hole gravel packs.

Site specific well conditions, formation properties, field procedures and applications will influence actual results in future fields.

References


**HORIZONTAL WELL COMPLETIONS**

**Introduction**

Horizontal wells have received considerable attention as a way of improving well productivity and project economics. Although horizontal wells have enjoyed their greatest popularity over the past ten years, they were used as early as the late-1930’s in the mid-continent region of the United States and in West Texas to enhance production rates. The original horizontal wells, referred to as drainholes, were beginning to be accepted as a viable technique to increase productivity when Amoco developed the hydraulic fracturing stimulation process in 1953. At the time, hydraulically fractured wells were capable of matching or exceeding the productivity of a horizontal drainhole with considerably less expense. As a consequence, the drainhole technology remained dormant for about the next 25 years until the oil producing companies realized that horizontal wells had advantages over fracturing in certain reservoir conditions. In the past 10 years, horizontal well technology (particularly drilling) has improved substantially to the point that some new reservoirs are being developed solely with horizontal wells. Horizontal sidetracks from existing mature wells have also enabled some operators to extend the production life of fields that would have been abandoned if conventional well technology was the only means of exploiting the remaining reserves.

A rigorous definition of a horizontal well is a drilled hole achieving a deviation angle of 90° from vertical. In application, the technology is much broader than this, and well profiles with deviation angles exceeding ±70° are often referred to as “horizontal” if the length of the wellbore within the producing formation is many times greater than the thickness of the producing formation. As a very general statement, horizontal wells cost about 50% more than a conventional well, but their productivity may be many times that of a conventional well in the same field. Therefore, a horizontal well may represent less capital expense per unit of production. Because of this, horizontal wells have been drilled worldwide and the number of wells has increased significantly since 1985 as shown in Figure 15.1.

![Figure 15.1](image-url)
Chapter 15

HORIZONTAL WELL COMPLETIONS

Industry Horizontal Well Experience Since 1985
Why Horizontal Wells are Drilled

There has been a great deal of discussion as to why horizontal wells have become so popular. Their potential for increasing productivity is an obvious incentive, but another possible reason for the popularity of horizontal wells is the volatility of oil prices. Since 1985, operators have placed increasing emphasis on the use of cost effective programs to increase productivity in order to survive in the era of low oil prices. Other factors contributing to the popularity of horizontal wells include improvements in and increased use of 3-D seismic to provide greater in-depth understanding of the areal extent of reservoirs. Finally, drilling technology has improved to include measurement-while-drilling (MWD) capabilities coupled with steerable drilling systems to permit the accurate placement of horizontal sections in specific locations within the reservoir with confidence. Despite the technological improvements, without question, the economic impact of horizontal wells is the primary reason for their increased popularity. The factors that contribute to the improved economics are:

- Increased productivity
- Improved reservoir management
- Increased recoverable reserves

While horizontal wells have received considerable attention, their use does not imply that conventional well technology is a thing of the past. Both technologies are here to stay and the use of horizontal wells is merely another alternative which is available to improve project economics.

Types of Completions for Horizontal Wells

Considerable publicity has been given to drilling horizontal wells, but the completion technology has largely been downplayed. However, how horizontal wells are completed is as important as how they are drilled. As with conventional wells, there are two generic ways of completing a horizontal well, either cased hole or open hole. Both completion techniques have their advantages and disadvantages and site specific applications.

Cased Hole Completions. Cased hole completions offer distinct advantages in terms of zonal isolation and successful future remedial work; therefore, cased hole horizontal wells have been applied primarily in reservoir situations where the ability to achieve zonal isolation (either initially or in the future) is paramount to the success of the well. This situation is similar to the application of cased hole completions in conventional wells. The disadvantages of a cased hole completion in a long horizontal well include the cost of the casing and cementing operations, as well as the cost of the tubing conveyed perforating operations. If in addition, the well requires sand control, the completion cost can easily exceed the drilling cost of the well. For this reason, cased hole horizontal completions are not as common as open hole completions, and, in general, cased hole completions are applied in formations that do not require sand control.
Open Hole Completions. Open hole completions are by far the most common approach taken to complete horizontal wells. The types of open hole completions include barefoot, pre-drilled pipe, slotted liner or screen, prepacked screen and gravel packs (see Figure 15.2). The barefoot and pre-drilled pipe options are generally applied in competent formations where sand production is not an issue. Barefoot completions offer no control of the production profile of the well and zonal isolation is not possible. Pre-drilled pipe completions can be used in conjunction with external casing packers to provide some degree of zonal isolation as illustrated in Figure 15.3. Completing horizontal wells in unconsolidated formations requires difficult decisions regarding the type of sand control to use. Slotted liners or screens, prepacked screens and gravel packs have all been used in unconsolidated formations. Each of these techniques will be discussed in more detail in later sections. The advantages and disadvantages of horizontal open hole completions are basically the same as in conventional open hole completions as discussed in Chapter 13.

![Figure 15.2 Types of Horizontal Well Completions](image-url)
Drilling Influence. The techniques used to drill the well can have a profound influence on the type of completions that can be applied. Horizontal wells are loosely referred to as long, medium and short radius depending on how quickly the well deviates from 0 to 90°. Table 15.1 shows the differences in long, medium and short radius wells in terms of build angle and radius. Long radius wells are extensions of standard directional processes and allow the greatest flexibility in terms of the types of completions that can be installed. The abrupt change from 0 to 90° in a short radius well makes it difficult to get certain completion components like screens, casing and external casing packers “around the bend”; therefore, completion options may be restricted. Medium radius wells may or may not present completion problems depending on the exact build rate and specifications of the desired completion equipment. In any event, special attention is required in the selection of completion equipment to ensure it is suitable for the given well conditions. The ability to rotate and circulate while running the completion equipment can assist in overcoming the torque and drag required to push the equipment around the bend and into the open hole. Completion equipment incorporating rotational and washdown features is available for use in horizontal wells.

<table>
<thead>
<tr>
<th>Type Well</th>
<th>Build Angle</th>
<th>Radius</th>
</tr>
</thead>
<tbody>
<tr>
<td>Short</td>
<td>1 to 3.5°/ft</td>
<td>19 to 42 ft</td>
</tr>
<tr>
<td>Medium</td>
<td>8 to 20°/100 ft</td>
<td>286 to 716 ft</td>
</tr>
<tr>
<td>Long</td>
<td>3 to 6°/100 ft</td>
<td>1,900 to 1,000 ft</td>
</tr>
</tbody>
</table>
Special Considerations for Unconsolidated Formations

Horizontal wells are characterized by long productive pay intervals. Because so much of the pay zone is exposed, horizontal wells are capable of producing at much higher rates than conventional wells. Despite the higher total rate, the flow rate per foot of formation in horizontal wells is usually substantially less than the flow rate per foot of formation in a conventional well. In addition, the flowing pressure drop required to produce a given rate from a horizontal well is significantly less than that of a conventional well. The combination of lower flowing pressure drop and lower flow rate per foot reduces the viscous drag forces on the formation material making horizontal wells less likely to produce formation sand than their conventional counterparts. A conventional well in a particular formation may require sand control; whereas, a horizontal well in the same formation may produce sand free. Unfortunately, the problem is complicated by the unavailability of techniques to accurately predict sand production potential, so most operators take some precautions against sand production in horizontal wells in unconsolidated formations. These options range from simple slotted liners to gravel packs.

As with conventional wells, the best technique to determine the optimum completion method is based on experience in the field with other wells. Due to changing reservoir conditions over the life of the well, it is not always immediately apparent if the completion method chosen is optimum; thus, an extremely difficult situation arises. As more and more fields are developed solely with horizontal wells and because fields developed with horizontal technology require less wells to adequately drain the reserves, the importance of each well to the project is magnified. The consequences of an improper sand control completion can be severe if wells are unable to produce due to sand problems. There now exists a number of horizontal wells in unconsolidated formations that have been producing for several years. As these formations are depleted and water production begins, the industry will be better able to access the applicability of different sand control completion techniques.

Slotted Liner or Screen Completions

Slotted liners or screens represent the simplest approach to sand control in a horizontal well. The openings in the slotted liner or screen are typically sized to be twice the diameter of the formation sand grain at the largest ten percentile ($D_{10}$). This sizing criteria stems from the work of Coberly\textsuperscript{1} who determined that a sand grain will bridge on a slot opening twice its diameter provided two particles attempt to enter the slot at the same time. Of course, establishing the bridges requires that a sufficient concentration of formation sand attempting to enter the slotted liner or screen at the same time. If the produced fluids liberate only a small concentration of formation sand, there is a possibility of sand production rather than sand control. For a slotted liner or screen to be effective, it can only be used in well sorted, large grained, relative high permeability formations with little or no clay. If sufficient clay is present in the formation, the sand bridges formed on the slotted liner or screen are subject to plugging. If a wide sand particle size range exists, plugging of the slotted liner or screen with sand grains is possible.
The choice between slotted liner or screen is largely based on economics. Slotted liner is less expensive, but has limitations on minimum practical slot width (as discussed in Chapter 6) and generally has less available flow area. Screens are capable of much smaller openings and have greater flow area, but are more expensive.

Advantages of slotted liners or screens:
- Reasonably inexpensive
- Easy to run
- Can provide reasonable sand control under proper conditions

Disadvantages of slotted liners or screens:
- Susceptible to plugging under certain conditions
- Suitable only for well sorted, large grained, high permeability formations with little or no clay materials or other fines

**Prepacked Screen Completions**

As discussed in Chapter 6, prepacked screens contain a thin layer of consolidated resin coated gravel within the screen assembly to act as a positive guard against formation sand production. Prepacked screens were designed and intended for use with a gravel pack to prevent sand production in the event voids occurred during gravel placement. The nature of the consolidated resin coated gravel makes it a very efficient filter for stopping formation sand production, but unfortunately, like all filters, prepacked screens are prone to plugging. In a gravel packed well, this tendency to plug is desirable and in fact is what prepacked screens are designed to do. In a non-gravel packed well, the tendency to plug can be disastrous to the longevity of the completion.

The use of prepacked screens without gravel packing was never intended as a viable completion technique but arose out of necessity in horizontal wells where the ability to effectively gravel pack was suspect. Given the situation of a horizontal well in an unconsolidated formation that is likely to produce sand and the situation where gravel packing is not possible with any degree of confidence, the only real sand control option is to complete the well with prepacked screens. This was the situation of the industry in the late-1980’s when horizontal drilling technology begin to be used in unconsolidated formations. Thus, the industry precedence was set, and prepacked screens are now widely used without gravel packing as a completion technique for horizontal wells drilled into unconsolidated formations. To date, many of these completions have been successful. The apparent success of prepacked screens without a gravel pack in horizontal well completions may be due, in part, to the formation not producing sand. It is hoped that wells completed with prepacked screens continue to be successful as the older horizontal wells began depleting and producing water. There have been documented cases of prepacked screens plugging due to formation sand production in horizontal wells. Stand-alone screen failure rates due to plugging, erosion, and otherwise have been as high as 50% in some operations. The average failure rate in the Gulf of Mexico is over 25%.
Despite their tendency to plug, there are applications where prepacked screens can be used successfully in a horizontal well environment without a gravel pack. Guidelines for using prepacked screens are much the same as with slotted liners and screens (i.e., well sorted, large grained, high permeability formations with little or no clay materials or other fines), but emphasis must be placed on using them in clean formations where the flow rate through the screen is less than about 5 barrels per day per foot of screen. The consequence of subjecting them to high throughput rates is a higher probability that plugging will occur.

Another consideration with prepacked screens is their applicability to short-radius type wells. In these wells, the consolidated resin coated gravel may experience cracking while being pushed through the high build angles. This cracking may affect the sand filtering properties of the screen. This is particularly true in Single Screen Prepack type screens where cracking of the consolidated resin coated gravel can cause the gravel to fall out of the perforated outer shroud directly exposing the wire wrapped screen jacket to formation sand production. New screen products using multiple layers of wire mesh have been developed that resist damage due to bending. Because the pore openings in the wire mesh are more consistent, the screens made with the mesh do not seem to plug as fast as a prepacked screen. However, screens made with wire mesh will still have a tendency to plug over time and their use should be restricted to well sorted, large grained, high permeability formations with little or no clay materials. The time required to plug a prepacked screen or wire mesh screen is dependent on the particle size distribution, concentration and rate of the formation material being produced. This data is extremely difficult to obtain, and, for the most part, defies prediction; therefore, the longevity of prepacked screens used without a gravel pack is a concern.

Advantages of prepacked screens:
- Relatively easy to run, but care must be taken to displace solids laden mud from the hole prior to running screens to prevent plugging
- Excellent sand control

Disadvantages of prepacked screens:
- Highly susceptible to plugging over time
- Expensive relative to slotted liners or non-prepacked screens
- Suitable only for well sorted, large grained, high permeability formations with little or no clay materials or other fines

Gravel Packed Completions

Gravel packing is another option for completing horizontal wells in unconsolidated formations. While this technology is more complicated and sophisticated than slotted liners, screens or prepacked screens, it is a more general purpose completion for horizontal wells where sand control presents a problem. Gravel packing can be used in either cased or open hole completions. While using slotted liners, screens or prepacked screens may be applicable only for certain wells, a gravel pack can be used on almost any horizontal completion provided that the gravel placement guidelines outlined in this section are followed.
Gravel packing has not been widely used in horizontal wells until recently. The reason for the lack of use appears to be a reluctance on the part of operating companies to try a long, horizontal gravel pack because of the perception that the technology is not available to place gravel over an interval of several thousand feet with success. The industry has long recognized the difficulties of successfully gravel packing long, highly deviated conventional wells using viscous gravel carrier fluids. Since horizontal wells represent the ultimate long, highly deviated well, a reluctance to gravel pack is well founded. At the time horizontal wells were beginning to be drilled in unconsolidated formations, viscous gel carrier fluids represented the state-of-the-art in gravel packing technology. Research and studies in physical models confirm that performing a successful gravel pack in a horizontal well using viscous gravel carrier fluids is extremely difficult. Today, brine is the state-of-the-art gravel carrier fluid. Research and studies in physical models confirm that performing a successful gravel pack in a horizontal well using brine is possible.

**Field-Scale Testing**

The feasibility of gravel packing a long, horizontal well which includes the completion equipment design, pumping schedules and other related procedures have been determined using scaled physical models. Up to well deviations of about 60°, gravity tends to initially assist in transporting the gravel to the bottom of the completion interval as Figure 15.4 indicates. However, at well deviations exceeding 60°, the angle of repose of the gravel is exceeded (see Figure 15.5). As a result, dimensional changes must be made to the gravel-pack equipment and higher pump rates are required to completely gravel pack the entire interval. The main requirement is that the ratio of the OD of the wash pipe to the ID of the screen must be at least 0.75 and returns through the wash pipe must be sufficient to transport the gravel to the toe of the well.
The gravel placement at deviations exceeding 60° is initiated at the top of the completion interval rather than at the bottom of the well, which is what happens when well deviations are lower. The subsequent gravel placement extends downwards until the gravel dune, commonly referred to as the alpha wave, reaches the bottom of the well. At that point, secondary placement, or beta wave deposition, packs the volume above the alpha wave as Figure 15.6 reflects. However, if the gravel concentration is too high, the flow rate is too low, or the wash pipe permits excessive flow in the annulus between it and the screen, the alpha wave will prematurely stall. Increasing the diameter ratio to 0.75 and maintaining a return flow superficial velocity of 1 ft/sec (the ratio of the flow rate to the cross-sectional area of the annulus) promotes the stable alpha-beta wave packing sequence illustrated in Figure 15.6.

Studies in a 7-inch OD by 25-ft long scaled gravel-pack simulator have confirmed the findings portrayed in Figures 15.4 and 15.6. However, because the model was short, there was concern that horizontal gravel-pack tests would not be representative for actual conditions since tests could be dominated by end effects. Consequently, a longer field-scale model was designed and constructed at the Baker Hughes test site in Willis, Texas. The model consisted of 1500 feet of 4½-inch casing equipped with a 2-1/16 inch screen and is illustrated in Figure 15.7. Fluid loss was simulated by using foot-long pipe filled with resin-coated gravel. The difference in the flow into the model and the returns through the wash pipe was the fluid loss to the formation. The model was equipped with high-strength plastic windows that allowed the visualization of the gravel
packing process as it progressed down the model. Figure 15.8 shows the alpha wave traversing a window.

Figure 15.6
Packing Sequence With Brine Carrier Fluid In High Angle Well Using High Rate and Large Diameter Washpipe

Figure 15.7
1500 Foot Horizontal Gravel Pack Model
A typical plot of the location of the alpha and beta waves as a function of time for a horizontal gravel pack is illustrated in Figure 15.9 and demonstrates that the entire 1500-ft model was packed with gravel. Testing clearly revealed that the height of the alpha wave was not constant with pack length as had been implied from studies conducted in 25-ft models. Instead the height of the alpha wave is inclined upwards from the heel to the toe of the model as Figure 15.10 illustrates. The reason for the inclination is a result of fluid loss which reduces the annular flow velocity with length. The consequence is an increase in the alpha-wave dune height with length. Should the top of the borehole interfere with deposition over the top of the alpha wave, deposition stalls and beta wave deposition begins at the stall location. To avoid a premature stall, the annular velocity must be maintained above a minimum value which has been determined to be a superficial velocity of 1 ft/sec based on return flow through the wash pipe. Provided that the design of the gravel pack is dimensionally correct and a superficial velocity of 1 ft/sec is maintained, gravel packing a long horizontal gravel pack can be performed with routine procedures. However, for open-hole completions, a clean, stable wellbore is an additional requirement for a quality gravel pack to avoid contamination with formation material. Displacing the hole to brine prior to running the screen and gravel packing the well is preferred.
The recorded pressure, rates, and gravel concentration as a function of time for a field-scale test in the 1500-ft model and are illustrated in Figure 15.11. For this test, the pump rate was 1.5
bbl/min with 0.75 bbl/min return flow through the wash pipe. The entire model was gravel packed. After about 2 hours of pumping, there was a distinct increase in the slope of the pressure vs. time. The change in slope reflects the end of alpha-wave and the initiation of beta-wave deposition. Data acquisition from an actual completion, a 2500-ft horizontal gravel pack, is illustrated in Figure 15.12 and shows similar data. For this well, the pump rate was about 5 bbl/min and the return rate was 4 bbl/min. This is typical for most horizontal gravel packs performed to date in 8-1/2 inch holes where the open-hole completion was displaced to brine prior to running the screen. Also, note the change in slope of the pump pressure-time relationship at about 6 1/2 hours into the gravel pack which also signaled the initiation of beta wave deposition. The similarity in these data is not unique to these two examples and is routinely observed in horizontal gravel packs.

![Figure 15.11](image_url)

**Figure 15.11**
Results From 1,500 Foot Horizontal Gravel-Pack Model - Pressure, Rate, and Gravel Mix Ratio vs. Time
Field Results

As of March 1997, approximately 75 wells have been horizontally gravel packed by Baker Oil Tools. Tables 15.2 and 15.3 tabulate the completion and job execution results of selected horizontal gravel packs performed to date. All horizontal gravel packed wells were completed open hole and most used 40-60 U.S. mesh gravel and prepacked screens. Note that the deepest well was 10,000 ft, the longest pack was 3300 ft, and that most wells had horizontal lengths between 1500-2000 ft. Wellbore diameters have ranged from 4.75 to 8.5 inches. Typical gravel mix ratios pumped have been about 1 ppa (pound per gallon added); however, pack times have been reasonably short except for large diameter holes. Typical gravel pack times are in the 4-6 hour range. Wells that have been gravel packed do not experience the productivity declines observed with stand-alone screens provided that the completion process described above is followed. For example, Well 1 in Tables 15.2 and 15.3 has a significantly better PI than wells in the same project that were completed with stand-alone prepacked screens. Well 7 represents the average of 11 wells in a particular project that were gravel packed. About half way through the project, it was decided to run a stand-alone 40-60 U.S. mesh prepacked screen to determine if gravel packing was actually needed. The stand-alone prepacked screen completion experienced a significant productivity decline from the onset. After several months the screen was removed and the well was gravel packed. The ensuing productivity was superior to the prepacked screen completion, consistent with the other gravel packed wells and did not experience the decline in productivity that was noted with the stand-alone prepacked screen. This particular property was subsequently acquired by another operator who drilled and completed three additional wells with stand-alone, proprietary multi-layer sintered metal screens on the resumption that they would not plug like the prepacked screens. The initial productivity from these completions could not be sustained and the well performance has been disappointing and has declined with time. As a consequence, the operator has elected to remove the screens and gravel pack the wells.
Wells 2-6 are all from the same project which has completed about 50 horizontal gravel packs. An additional 12 wells will be gravel packed before the project is completed. Ironically, the initial completions were stand-alone slotted liners. Their initial flow rates were 3000-5000 bbls/day, but sand production was excessive and the wells plugged upon the onset of water production. By gravel packing the wells, productivity has been maintained even after water breakthrough.

Table 15.2
Horizontal Gravel Pack Information
Completion Geometry

<table>
<thead>
<tr>
<th>Well</th>
<th>Depth (ft.)</th>
<th>Horizontal Length (ft.)</th>
<th>Hole Diameter (in.)</th>
<th>Screen Type</th>
<th>Screen Diameter (in.)</th>
<th>Washpipe Diameter (in.)</th>
<th>Wash/Screen OD/ID (in.)</th>
<th>Workstring</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>7,385</td>
<td>2,500</td>
<td>8.500</td>
<td>SSPP</td>
<td>5.000</td>
<td>3.500</td>
<td>0.790</td>
<td>3.5/50</td>
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<tr>
<td>2</td>
<td>4,276</td>
<td>1,980</td>
<td>6.125</td>
<td>Bakerweld</td>
<td>3.500</td>
<td>2.750</td>
<td>0.793</td>
<td>3.5</td>
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<tr>
<td>3</td>
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<td>1,739</td>
<td>6.125</td>
<td>Slim-Pak</td>
<td>3.500</td>
<td>2.750</td>
<td>0.793</td>
<td>3.5</td>
</tr>
<tr>
<td>4</td>
<td>4,285</td>
<td>1,743</td>
<td>6.125</td>
<td>Slim-Pak</td>
<td>3.500</td>
<td>2.750</td>
<td>0.793</td>
<td>3.5</td>
</tr>
<tr>
<td>5</td>
<td>4,261</td>
<td>1,667</td>
<td>6.125</td>
<td>Slim-Pak</td>
<td>3.500</td>
<td>2.750</td>
<td>0.793</td>
<td>3.5</td>
</tr>
<tr>
<td>6</td>
<td>4,274</td>
<td>1,642</td>
<td>6.125</td>
<td>Slim-Pak</td>
<td>3.500</td>
<td>2.750</td>
<td>0.793</td>
<td>3.5</td>
</tr>
<tr>
<td>7</td>
<td>3,600</td>
<td>1,800</td>
<td>8.500</td>
<td>Slim-Pak</td>
<td>3.500</td>
<td>2.750</td>
<td>0.790</td>
<td>4.5</td>
</tr>
<tr>
<td>8</td>
<td>5,400</td>
<td>600</td>
<td>6.875</td>
<td>SSPP</td>
<td>2.875</td>
<td>1.900</td>
<td>0.790</td>
<td>3.5</td>
</tr>
<tr>
<td>9</td>
<td>6,900</td>
<td>1,128</td>
<td>6.125</td>
<td>Slim-Pak</td>
<td>3.500</td>
<td>2.750</td>
<td>0.790</td>
<td>3.5</td>
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</tbody>
</table>
Table 15.3

Horizontal Gravel Pack Information
Job Execution/Results

<table>
<thead>
<tr>
<th>Well</th>
<th>Pump Rate (bpm)</th>
<th>Return Rate (bpm)</th>
<th>Pump Pressure (psi)</th>
<th>Gravel Conc. (ppg)</th>
<th>ACT/CAL Placed (%)</th>
<th>Time (hrs.)</th>
<th>Prod Comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>5.00</td>
<td>4.20</td>
<td>1,000</td>
<td>1.00</td>
<td>129</td>
<td>7.50</td>
<td>1,200 BOPD / 1,950 psi / 1/8”</td>
</tr>
<tr>
<td>2</td>
<td>3.20</td>
<td>2.80</td>
<td>1,400</td>
<td>1.00</td>
<td>89**</td>
<td>4.00</td>
<td>710 BOPD/Pump</td>
</tr>
<tr>
<td>3</td>
<td>4.40</td>
<td>4.38</td>
<td>1,500</td>
<td>1.00</td>
<td>154</td>
<td>5.75</td>
<td>1,694 BOPD / 2561 choke</td>
</tr>
<tr>
<td>4</td>
<td>3.00</td>
<td>3.00</td>
<td>600</td>
<td>1.00</td>
<td>151</td>
<td>6.00</td>
<td>2,259 BOPD / 3664 choke</td>
</tr>
<tr>
<td>5</td>
<td>3.03</td>
<td>2.12</td>
<td>460</td>
<td>1.00</td>
<td>102</td>
<td>3.00</td>
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<tr>
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<td>3.07</td>
<td>1.02</td>
<td>600</td>
<td>1.00</td>
<td>92****</td>
<td>3.50</td>
<td>1,800 BOPD / 2064 choke</td>
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<tr>
<td>7</td>
<td>5.00</td>
<td>4.00</td>
<td>1,000</td>
<td>1.00</td>
<td>130</td>
<td>7.00</td>
<td>6,000 BOPD / Pumped</td>
</tr>
<tr>
<td>8</td>
<td>5.00</td>
<td>4.00</td>
<td>1,500</td>
<td>0.60</td>
<td>100*</td>
<td>2.00</td>
<td>1,100 BOPD / WHP – 150 psi</td>
</tr>
<tr>
<td>9</td>
<td>4.00</td>
<td>3.50</td>
<td>1,200</td>
<td>1.25</td>
<td>75****</td>
<td>2.50</td>
<td>1,100 BOPD / WHP – 210 psi</td>
</tr>
</tbody>
</table>

* Pumped only theoretical volume
** PERFFLOW not displaced from the wellbore prior to gravel packing.
*** Bottomhole “knocked out” when shearing out setting ball
**** Plugging due to exposed to shale

Based on the preceding discussion, gravel pack technology is available for completing long, horizontal wells. Regardless of whether the horizontal well is completed cased or open hole, the same gravel packing procedures and guidelines apply. As pointed out in the previous discussion, maintaining sufficient returns is critical to the success of a horizontal gravel pack. The amount of fluid returns is directly related to the amount of fluid loss to the formation during gravel packing. If high losses are experienced, the pump rate must be increased to maintain the minimum required fluid returns. If fluid losses are extreme or pump rate capacity is limited, the length of horizontal interval that can be packed will be reduced. As discussed in Chapter 11, fluid loss is essential for properly packing the perforation tunnels. In a cased hole horizontal well this creates a paradox. Fluid loss is required for perforation packing and high well productivity, but fluid loss will limit or jeopardize the length of horizontal interval that can be packed. Although technically possible, gravel packing cased hole horizontal wells is considerably more difficult than packing an open hole horizontal well.

The recommended procedure to gravel pack an open hole horizontal well is to eliminate fluid losses to the formation by using a filter cake building drill-in fluid. After drilling the well, the drill-in fluid is displaced from the hole with a clear brine leaving only the filter cake at the face of the formation. The gravel pack assembly is run and the well is gravel packed. Because there are no perforations to pack and fluid loss to the formation is controlled by the filter cake, gravel packing is a relatively easy process. After gravel packing, the filter cake must be removed. If the PERFFLOW® system is used as a drill-in fluid, the filter cake can be removed simply by flowing the well. If other types of drill-in fluids are used, special chemical soaks and treatments may be
required to adequately remove the filter cake. The PERFFLOW® system has been used on several successful open hole horizontal gravel packs with encouraging productivity results.

**Guidelines for gravel packing a horizontal wells**

Based on field scale testing and actual field results and procedures, the following guidelines for gravel packing horizontal wells are suggested:

- Use a drill-in fluid such as PERFFLOW® to control fluid loss and obtain an initial fluid return ratio greater than 70%.
- Maintain a minimum superficial velocity of 1 foot per second in the flow area outside the screen based on fluid return rate.
- Use brine as a carrier fluid.
- Keep the gravel concentration below 2 pounds of gravel per gallon of carrier fluid.
- Ensure that the ratio of wash pipe OD to screen ID is 0.75 to 0.80.

Gravel packing offers distinct advantages over a simple prepacked screen in horizontal completions in unconsolidated formations. Gravel packing places a finite stress against the formation at the gravel/formation interface that reduces the movement of fines into the gravel pack. Prepacked screens are a suspended filter that do not place a finite stress against the formation. A consequence of the lack of stress against the formation is that formation particles are free to move with the produced fluids. Since the formation fines are more mobile than the load bearing particles in the formation, the accumulation of fines at the outside surface of the prepacked screen and/or just below the outside surface can cause plugging and a loss in productivity. This problem becomes more significant when fine grained, or high clay content formations are involved and when there is production of viscous fluids. In this case, plugging of a prepacked screen alone is inevitable and gravel packing would seem to be the only long term sand control technique available.

Another potential advantage of gravel packing over prepacked screens alone is zonal isolation possibilities. A horizontal well completed with prepacked screens can incorporate external casing packers to achieve zonal isolation. The success of the zonal isolation is dependent on setting the external casing packers in the right location and the sealing characteristics of the packer. Accurately predicting the setting location required for future zonal isolation can be difficult. Gravel packing can incorporate external casing packers, but this requires more complex service tools and operations to accomplish setting of the external casing packers and gravel packing. Another evolving zonal isolation technique takes advantage of the gravel filling the annulus outside the screen. By pumping the proper chemicals, the permeability of the gravel pack sand can be artificially destroyed creating some degree of zonal isolation. As stated, this technology is evolving and field results are limited.

**Advantages of gravel packing horizontal wells:**

- Excellent sand control.
• Enhanced completion longevity.
• Potential for zonal isolation.

Disadvantages of gravel packing horizontal wells:
• Slightly higher cost than stand-alone screens.

Summary
The same completion options available for conventional wells are available for horizontal wells; however, there is a trend toward performing a higher percentage of open hole completions in horizontal wells than in conventional wells. If the horizontal section is cased the well can be produced sand free, provided that the reservoir is competent. However, if sand production presents a problem, running screens or slotted liners will significantly reduce productivity as a consequence of the perforations becoming plugged with formation sand. For a cased hole completion, gravel packing appears to be the primary alternative for maintaining sand control and completion productivity. Successfully gravel packing a cased hole horizontal well requires significant job planning and complex field execution.

Open hole horizontal completions offer additional flexibility over cased hole horizontal completions. Sand control options include slotted liners, screens and prepacked screens in formations with well sorted, large grained, high permeability formations containing little or no clay materials or other fines. External casing packers can be used to achieve some degree of zonal isolation. In poorly sorted formations or formations containing significant quantities of clay, gravel packing should be considered to ensure completion longevity. If suitable drill-in fluids are used, gravel packing an open hole horizontal well is a relatively simple operation.

References