Screen Sizing Rules and Running Guidelines to Maximise Horizontal Well Productivity

Christophe Malbrel, Pall Well Technology; Alex Procyk, Pall Corporation; and John Cameron, Oiltools International

ABSTRACT

Flow density across sand control screens in horizontal wells is very low. This is very favorable to the selection of screen-only completions as a cost effective sand control measure. However, phenomena specific to horizontal well completions have prevented them being as successful as they could be: 1) deployment contaminates the screen and reduces well productivity; 2) formation sands can mix in the annulus around the screen, modify the apparent sand sieve analyses, and affect the screen's ability to retain sand.

Therefore, screen sizing must not only include the selection of a screen medium capable to retain formation sands and tolerant to impairment caused by completion fluids, it also requires a careful review of other screen design features such as diameter, OD/ID ratio and the screen/blank ratio. To help select screens, sizing guidelines have been developed based on formation sand characteristics such as average size (D50) and uniformity (D40/D90).

A well productivity model has also been developed to assist in screen selection. Using reservoir characteristics such as permeability, heterogeneity, consolidation, design flowrate and fluid characteristics, it shows that incomplete screen clean-up can seriously affect well performance. While gravel packing reduces productivity losses associated with poor screen clean-up, minimizing screen impairment during deployment and/or cleaning it afterwards can prove to be a less costly alternative. A "Mud Plugging Index" is proposed to monitor screen plugging by a given drill-in fluid and help optimize fluid conditioning on the rig. Using centralizers on the screen during deployment and back-flowing fluid with a washcups assembly will also help enhancing well productivity.

INTRODUCTION

With their increased inflow area (sometimes by one or two orders of magnitude), horizontal wells help reduce flow density and the consequent drawdown across the reservoir and the near wellbore region. This offers several benefits: increased productivity, reduced formation fines migration, reduced coning. Despite these obvious advantages, horizontal completions may not deliver the expected productivity in reservoirs requiring sand control. Recent investigations have identified several sources of impairment that may explain reduced productivity:

- formation damage due to mud filtrate invasion in the near well bore area;[1]
- screen plugging by completion fluids or reservoir fines;[2,3,4]
- incomplete well bore clean-up leading to substantial impairment by mud cake residues and drill-in fluids.[5,6,7]

Other problems associated with horizontal well completions in sand prone reservoirs have recently surfaced:

- plugging-induced screen erosion;[8]
- screen failure caused by corrosion due to improper acidizing procedures.

It is tempting to increase slot or screen pore openings to reduce plugging risks, but this often leads to sand production. A recent study conducted in the Gulf of Mexico shows around a 20% failure rate in horizontal completions; "failure" being defined as sand production or well sanding up.[9]

Encouraging developments have been made in the past few years, including new screen designs to reduce screen impairment,[10,11] new drill-in fluid formulations that have led to a reduction in fluid leak-off (lower mud filtrate invasion) and mud filter cakes leading to higher return permeabilities.[5] Better well bore clean-up procedures have been proposed[12] and procedures and equipment to perform gravel pack placement in long horizontal wells are being developed.[13]

Sand control screen in horizontal wells must provide two conflicting functions: they must be fine enough to retain formation sands and yet coarse enough to minimize impairment, primarily during the completion and mud flowback operations. Often, the two issues have been treated separately. One notable exception is the study by Markestad *et al.* which comprehensively addressed screen selection issues for coarse and well sorted sands.[14]

The present paper provides a set of screen selection rules suitable for horizontal well screen completion and reviews screen design features and running guidelines recommended to increase well productivity.

SCREEN MEDIA SIZING GUIDELINES

Sizing rules used to select sand control screen in gravel pack and non gravel pack applications were developed for vertical wells producing oil or water. Developed by Coberly,[15] Schwartz,[16] and Saucier,[17] these rules are useful in that they provide easy-to-use rules of thumb. However, they may not be entirely applicable to horizontal well screen selection. Flow density through a long screen-only completion is one to two orders of magnitude lower than in a vertical well. Consequently, filter cake formation is much slower and results in a more permeable filter cake.

Additionally, gravity and particle settling does not impact filter cake build-up in the same manner and annular flow can easily modify the particle size distribution of the free flowing sand reaching the screen by mixing various sand and shale facies.

Limited Validity of Laboratory Experiments

Many laboratory experiments have been reported in the literature to demonstrate or compare screen plugging.[4,11,14] While these results may be well suited to comparing screen performance, they ought to be used with caution when analyzing the benefits of screen-only completion compared to other sand control alternatives (eg gravel packing). Field conditions, primarily fluid flowrates and solids concentration, are either unknown or extremely difficult if not impossible to duplicate in the laboratory for several reasons: testing duration becomes unacceptably long and experimentalists run into unsolvable practical problems such as solids settling in flowlines, particle size distribution measurements of low solids concentration, etc.

To illustrate the impact of flowrate on the performance of sand control screens, a series of tests were run in the laboratory. The screen selected was a fine screen (90% efficient at 60µm) as a way to circumvent some of the experimental problems described above. The selection of this screen allowed the use of a very fine, poorly sorted sand (d50 = 35 µm; d40/d90 = 50/5 = 10) that could be suspended in a 16 cp oil and circulated through a test stand described elsewhere.[10] To ensure proper solids suspension (20mg/L), the fluid was pumped at 10 l/min through a main flow loop and only a fraction of the suspension was flowed through the 90 mm test disk at a controlled flowrate using tubing with a diameter selected small enough to maintain turbulent flow conditions and sand suspension (3/8" tubing for tests at 3 l/min down to 3/16" tubing for tests at 0.1 l/min).

Figure 1 shows the effect of flowrate on screen plugging. Since various flowrates were investigated, the data was plotted as a function of amount of sand ingressed rather than as a function of time. At low flowrates (ie closer to real life conditions but nevertheless equivalent to a 50,000-150,000 bpd well), the amount of sand accumulated on the screen is markedly greater than at higher flowrates (3 l/min). At very low flowrates (0.2 to 0.1 l/min), an inflection on the plugging curves becomes noticeable and is classically attributed to the formation of a permeable filter cake responsible for the increased sand accumulation on the screen.

Open Annulus vs Collapsed Wellbore

Laboratory tests performed in the past primarily evaluated the ability of a gravel pack to retain a given sand (Coberly, Saucier, Schwartz). In these tests, a sand-pack was usually accumulated in contact with a pack of gravel to evaluate the ability of a gravel size to retain the sand. The "gravel sizing" rules developed from these tests were extrapolated to screen slot sizing and can still be applied to situations where formation sand is fully collapsed on the screen. In both cases, formation sands are retained by bridging over the pores, *i.e.* particles whose size is between 3 to 5 times the screen or gravel size will be blocked by bridges stabilized by the formation sands collapsed over the pores.

In the case of an open annulus, free flowing particles are impacting the screen. At low sand concentrations, the probability of two (or more) particles simultaneously reaching the gravel or screen pores is low. As a result, particle bridging is more difficult and the size of the sand particles that can be retained by the screen is close to the size of the screen openings. It is only once large particles are retained by the screen than finer ones start to be stopped. Thus, for a given formation sand, a given screen will control a broader particle size range when the formation is collapsed on it than in the presence of an open annulus.

The issue of screen sizing in an open annulus is further complicated by the fact that annular flow may affect filter cake formation and mix formation sands. Figure 2 shows eleven sieve analyses from cores taken from a vertical pilot hole drilled to evaluate the feasibility of a horizontal well. Although these samples do not necessarily represent the actual sand size distributions along the horizontal interval, they do illustrate the significant deviation typically found in multiple core samples.

Media Sizing Guidelines

The sand's D50 provides a general picture of the sand size. However, depending on how well sorted the sand is, it may not characterize it properly. The Uniformity Coefficient (Uc) is used to determine the relative spread of the sand size around the average particle size. It is defined as the D40/D90 ratio, or the particle size at the 40th percentile divided by the particle size at the 90th percentile.

In the case above where there is a range of sieve analyses available from a single well, usually the average sand size distribution will give the proper "character" of the sand. The fine size distributions can be used as a quality check to ensure that the chosen media will have some sand retention at these sizes.

Using a combination of standard gravel pack and screen selection rules (Saucier, Coberly, Schwartz), as well as laboratory experiments, a chart providing simple media selection guidelines is proposed for a series of screen manufactured using a sintered, non-woven metal fiber screen technology. Qualitatively, these guidelines are explained as follows:

For very well sorted with low uniformity coefficients ($2 < Uc < 3$), the recommendations follow the Coberly rule, where the screen is sized to the D10 of the sand (the D10 is extrapolated from the D50 and the Uniformity Coefficient, assuming a uni-modal sand following a standard log-normal distribution). Although 90% of the sand is smaller than the D10, the high amount of sand uniformity yields rapid filter cake formation and effective sand control.

At medium Uniformity Coefficients ($3 < Uc < 7$), the Coberly rule leads to too much sand production, especially in an open annulus configuration or in an injector well. The Saucier rule (screen pore size = $D50_{formation}$) is applied where the average sand size is at or greater than the average screen pore size.

For large Uniformity Coefficients ($Uc > 7$), sizing the screen according to the Saucier rule may not prevent long term sand production. The Schwartz rule (where screen pore size = $d70_{formation}$) - applicable for very poorly sorted sand - leads to the selection of a very fine screen that may be susceptible to fines plugging. To avoid premature plugging (*i.e.* build-up of a low permeability filter cake and/or partial penetration of fines in the screen pore structure), silt and clays (particles less than 44 µm) should be less than 20wt%. If formation fines are greater than 20wt%, a gravel pack is recommended to lock formation sand in place, and provide a barrier to sand migration as far away from the well as possible to reduce fluid velocity.

Field Validation

These screens have now been installed in over 500 wells during the past four years and were used in a wide range of configuration (from through-tubing insert screens[18] to horizontal wells completed with and without gravel pack in oil and gas fields). Sieve analyses, completion information and long term well performance data are not always available; nevertheless, the chart was validated using seven well documented field cases covering a fairly broad range of sands and screen media selections. These field cases are described in the Media Selection Chart in Figure 3 and screen/performance information is summarized in Table 1.

MAXIMIZING WELL PRODUCTIVITY

Drawdown, Friction Losses and Annular Flow

Well deliverability is conditioned primarily by three pressure drop contributions: drawdown, friction losses caused by fluid flowing inside the screen basepipe, and pressure drop induced by fluid convergence towards the screen.

Several screen features affect fluid hydrodynamics in and around the wellbore and thus can contribute to well productivity improvement: screen dimensions (diameter, screen area, OD/ID ratio), filter medium sand retention and plugging tendency. A sensitivity analysis using a method proposed in a recent paper by Burton and Hodge[19] helps understand the relative importance of several screen features. It is found that in order to maximize well productivity, screen design ought to be customized well beyond the simple "pore size" selection.

Drawdown

Reservoir drawdown caused by oil production can be expressed as the sum of pressure drop contributions caused by flow restrictions around and inside the wellbore (see Appendix for detailed description of equations used):

$$\Delta P = \Delta P_0 + \Delta P_1 + \Delta P_2 + \Delta P_3 + \Delta P_4 + \Delta P_5$$

Where:

ΔP_0: Reservoir drawdown (steady state flow)

ΔP_1: Pressure drop through the mud filtrate invaded zone

ΔP_2: Pressure drop through the annular fill

ΔP_3: Pressure drop through the screen

ΔP_4: Pressure drop due to convergence towards pinholes in the mud filter cake

ΔP_5: Pressure drop due to convergence towards openings in an incompletely cleaned screen ("hot spots")

Two cases are used to illustrate the sensitivity of drawdown values to screen design parameters. Base case parameters are given in Table 2 and represent data typical of Gulf of Mexico and North Sea reservoirs.

<u>Case # 1: "Gulf of Mexico"</u>

Typical Gulf of Mexico reservoirs tend to be thin, with low permeability, weakly consolidated sands that collapse on the screen. Table 2 shows that in this case, drawdown is relatively high and is primarily due to pressure drop associated with fluid flow in the low permeability and thin reservoir. Pressure drop contributions from near well bore phenomena are relatively small.

<u>Case #2: "North Sea"</u>

North Sea reservoirs are characterized by high permeability channels within relatively thick and consolidated sands, that often allow some annular flow around the screen. While flowrates are typically high, Table 2 shows drawdown values to be small. Substantial screen plugging or development of a very low permeability filter cake in the annulus can impact well productivity, considering the very low reservoir drawdown associated with this type of formation.

These results seem to indicate that screen selection and deployment considerations are particularly important in the case of high permeability/low drawdown reservoirs. Indeed, in this case, small damage/impairment to the screen or the wellbore easily change pressure drop contributions and affect well deliverability. However, this conclusion needs to be qualified further. In situations where some parts of the low permeability reservoir are more permeable (e.g. case of wells drilled to access a succession of laminated reservoirs), a simulation of the respective productions from the low and high permeability zones show that most of the production is coming from the high permeability zones. Figure 4 shows the contribution of two non-connecting reservoirs producing a total of 5000 bpd inside a 1000 ft horizontal well. The model suggests that even when the high permeability zone represent 5-10% of the total producing interval, most of the production is coming from it. As a result, screen selection in such reservoirs should follow high permeability guidelines with the additional challenge that flow density will be higher and thus pressure drop contributions due to annular fill or screen impairment will be amplified.

Formation sand mixing in an open annulus affect annular flow and drawdown, especially in highly heterogeneous reservoirs. Mixing of different sand size distribution results in a very poorly sorted sand whose permeability is substantially lower than each sand taken separately. A relationship developed by Krumbein and Monk for relatively coarse sands[20] (see appendix) may be extrapolated to finer sand fractions (note that the rule is not valid for shally formations where clay morphology affects filter cake permeability beyond the conditions tested by Krumbein and Monk). Figure 5 shows the effect of sand sorting on sand-pack permeability using an extension of Krumbein and Monk's equation expressed as a function of the Uniformity Coefficient:

$$k = 760\ D50^2 \exp(-2.8355\ \mathrm{Log}(Uc))$$

Clearly, sorting (as measured by the Uniformity Coefficient obtained from the sieve analysis) has a major impact on the value of the sand pack permeability.

In conclusion, the more heterogeneous the reservoir, the more effort should be made to reduce annular flow (by using a large screen OD, helping to collapse the wellbore onto the screen or setting zonal isolation measures) and increase screen area (to reduce fluid density so the skin through the low permeability filter cake is reduced to a minimum).

Friction Losses

In addition to drawdown, pressure losses caused by fluid flow inside the screen basepipe can affect fluid distribution around the well bore. To illustrate this, the wells described in Table 2 are used to model friction losses as a function of flowrates and screen size, assuming a uniform flow entry along the well (the equation used is defined in Appendix).[21] Figure 6 shows that pressure losses inside the "North Sea" screen completion are several orders of magnitude larger than the one achieved in the "Gulf of Mexico" reservoir for a given screen diameter. This is attributed to the length of the well as well as the flowrate typically experienced in high permeability reservoirs.

When the magnitude of these pressure losses is compared with estimated drawdowns (Figure 6 vs Table 2), it can be seen that flow distribution around the high permeability/high productivity "North Sea" well, and thus well deliverability, will be affected by pressure interactions between the near wellbore area and pressure drops inside the screen. Annular flow and restricted fluid entry are possible, if not likely. By contrast, friction losses experienced in the low permeability/low producing well are negligible compared to drawdown. As a result, screen diameter will be critical in a high permeability reservoir while it will not be so much of an issue in a low permeability reservoir. In the latter case, other considerations such as remediation options may be more influential in screen diameter selection.

Flow Convergence and Productivity Impairment

When fluid entry in the wellbore is restricted (incomplete mud cake removal or screen partially plugged during deployment), fluid converges towards the points of entry with increased velocity, thereby creating a pressure drop. This pressure drop is all the more important when entry points are few and distant from one another.

While poor mud cake removal from the wellbore wall is well known to cause flow restrictions and "hot spots" have been identified as a source of screen erosion,[8] the contribution of incomplete screen clean-up to drawdown has never been quantified. Table 3 illustrates the effect of flow convergence and the consequent productivity impairment, using the same two wells and assuming various degrees of screen impairment, different amounts of screen open, and looking also at the impact of a gravel pack. Two cases of improperly cleaned screen are illustrated; these represent the not-so-infrequent situation in which screens are coated with mud residues or clays during deployment and are only partially open to flow. The first case corresponds to a screen incompletely cleaned (only 10% of the screen is open to flow) with 10 cm diameter "patches" of bare screen available for flow; the second case is identical (still only 10% open to flow) but with smaller open "patches" (1 cm diameter). It can be seen that incomplete cleaning can lead to a loss in productivity in homogeneous reservoirs that is amplified in heterogeneous formations. Gravel packing is found to be beneficial in heterogeneous reservoirs. However, it is also in this type of reservoir that horizontal gravel packing is most difficult and often leads to voids and largely incomplete gravel placement.[9] Screen-only completion cleaning may be effective in maintaining well productivity. Figure 7 illustrates the impact of flow convergence, using 10cm "hot spots" and various degrees of screen clean-up.

Based on these results, only significant screen plugging lead to a measurable loss of productivity in a horizontal well. Poor completion conditions can and do impair screens to this extent. However, plugging can be avoided in most cases by optimizing the system's components: mud system, well bore cleanup procedures and the screen itself. Recommendations to prevent screen impairment are discussed in the next section.

MUD CONDITIONING GUIDELINES

Parameters affecting Screen Impairment

While a great deal of effort had focused on the formation damage potential of drill-in fluids, this effort is now slowly shifting towards a better understanding and controlling of screen impairment by these fluids.[5-7] In 1997, two comprehensive laboratory studies specifically investigated plugging of screens with drill-in fluids (DIF).[22,6] A number of parameters were investigated and showed varying impact on final screen productivity. According to these studies, several critical factors affecting screen impairment were identified:

- the relationship between the screen 'slot size' and the particle size distribution of the solids present in the DIF (weighting agent and drill solids);
- the amount of solids in the DIF (a high density and/or dirty mud plugs a screen faster than a light and/or clean one);
- the type of mud and LCM material used (the conditioning and particle-particle interactions affect mud dispersion and its plugging tendency).

Another parameter playing a role in enhancing (or reducing) screen impairment is the amount of open pores available to mud flow. For a given sand retention characteristics, a screen medium with a higher void volume resist impairment better than another one. Figure 8 compares the amount of mud required to plug two screens with the same sand retention characteristics (90% at 110-120 µm) but different void volume (as measured by helium pycnometry). This result is confirmed by sand retention tests where high void volume or high open area screen leads to a significant increase in plugging resistance compared to the woven mesh.[11]

Preventing Impairment with Effective Mud Conditioning

A light mud weight generally minimizes screen plugging. Even in this case, DIF conditioning is required to prevent screen impairment (*ie* use of fine shaker screens to remove drill solids and large mud aggregates[7]). The study of Marken *et. al.* suggests that a 200 mesh shaker provides adequate protection for a 100-150µm screen.[22] Actual field data reported by Browne *et. al.* demonstrated the use of 230 and 300 mesh screens to protect 20/40 prepack screens.[2]

The latter report provided some other useful recommendations. It indicated that significant mud crossflow through the screen may be taking place during the actual running of the screen caused by surge pressure. Deploying the screen slowly reduced but did not eliminate crossflow. Impairment could be minimized by displacing the top hole to a solids-free fluid before running the screen. The solids-free fluid filled up the void between the screen and the washpipe, thus reducing the impact of mud contamination during deployment.

Additional tests by Hodge *et. al.* compared the plugging performance of sized salt, calcium carbonate, and a clear mud systems without clean-up.[1] Although the different mud systems exhibited significantly different screen plugging tendencies, the introduction of drill solids into the mud systems resulted in virtually identical and unacceptably poor performance. In all tests, the return permeability of the 40/60 consolidated screen was less than 1% of the initial permeability, a permeability reduction of enough magnitude to affect well productivity. Acid cleanups did not necessarily guarantee a clean screen, and the breaker systems were very sensitive to corrosion inhibitors.

The study by Lau and Davies suggested a solution to this potential source of impairment:[6] acceptable screen permeability returns were achieved on screens impaired with DIF and drill solids once a 'backwash' step was implemented (this was effective only on surface filter media as depth filters such as prepacked screen could not be cleaned effectively in any case). By pulling a washpipe equipped with washcups (6 ft apart) at 6 ft/min while circulating at 3/4 bbl/min a solids-free fluid (through the screen, inside the annulus and back inside the tubing through a sliding sleeve), the filtercake deposited on the outer screen surface could be removed.

In a recent paper, Price-Smith *et. al.* provided a State-of-the-Art review of open hole horizontal well clean-up practices.[12] In the field cases described, completions designed to produce mud directly through the screen are limited to low density muds (< 1.3 s.g.) and a washpipe is always recommended to allow proper fluid circulation around the screen.

Oil based mud systems are often not displaced and are typically produced at the onset of oil production. The best method to ensure good return permeability in this case is to condition the mud through fine shaker screens so that most of the insoluble solids remaining in the mud will be able to pass through the sand control screen upon production. Recommended mud conditioning guidelines is to use shakers mesh sizes on the order of 1/5 to 1/4th of the screen openings.

Mud quality and the integrity of the solids control system on the rig must be carefully monitored as a small amount of contamination by a coarse mud fraction (5-10%) may be enough to induce significant screen impairment when producing the mud through the screen at the start of production.[23] In appendix, a mud test procedure is described that can be used both in the lab and on the rig to determine the quality of the mud for flowback and its screen damage potential. It is critical that such a technique be implemented operationally, especially when it is planned to produce the mud through the screen.

From the results shown in Figure 7 and Table 3, reducing contact between the screen surface and the wellbore walls considerably limit the onset of flow convergence associated with partial screen blockage. Using centralizers to maintain a standoff between the screen and the wellbore walls is strongly recommended for screen only completions.

Field Validation

An operator in West Africa successfully completed a horizontal well using a multilayer non woven metallic screen rated 120 µm. This well was completed directly in a synthetic ester based mud to save rig time. Prior to drilling the 6 inch horizontal section, the 9.0 ppg DIF was conditioned over a combination of 325 and 230 mesh shakers. MPI measurements (see Appendix A for details) during drilling operations varied between 1.0 and 1.15. After circulating the top of the hole with a solids-free mud so that screens could be deployed in a low impairment fluid, and thus reduce damage due to surge pressure, the screen was run in the hole and the hole circulated out with 3% KCl brine.

Deployment of the screen directly in the pre-conditioned ester based mud substantially reduced drilling costs and led to a well with improved PI: over 50 compared to the expected 15-20 achieved on offset wells.

CONCLUSIONS

1. Screen testing can be used to compare screen performance but caution is advised when concluding that a screen plugs, solely on the basis of laboratory testing. Indeed laboratory flowrates are so high that they artificially increase the screen plugging potential.

2. A new Screen Media Selection Chart is proposed to select a screen medium based on the average formation sand size and its uniformity coefficient. This chart was successfully validated using several field cases.

3. A simple well productivity model offers a useful means of identifying parameters controlling completion performance. It is found that reservoir characteristics such as permeability or reservoir heterogeneity impact screen selection well beyond screen media selection (diameter, OD/ID ratio, screen area, etc..).

4. Mud conditioning and effective screen clean-up is required to reduce flow convergence inducing damaging pressure drops in the annulus. Good screen cleaning is almost as effective in maximizing well productivity as gravel packing a horizontal well.

This work is still in progress. Emphasis is now being given to expanding it to gas wells where turbulence effects amplify flow restriction phenomena in the near well bore region. Another direction is to combine screen inflow performance and friction losses to get a better understanding of screen effects on reservoir productivity profiles.

ACKNOWLEDGEMENTS

The authors wish to acknowledge support for this work from Pall Corporation and Oiltools. Special thanks to Clive Bennett, Tracey Ballard and Dave Kennedy for numerous discussions providing a useful insight into well performance, screens and reservoir behavior.

REFERENCES

1. R.M. Hodge, B.G. Augustine, R.C. Burton, W.W. Sanders, and D.J. Atkinson, 'Evaluation and Selection of Drill-in Fluid Candidates to Minimize Formation Damage', SPE 31082, paper presented at the International Symposium on Formation Damage, Lafayette, LA, February 14-15 1996.
2. S.V. Browne, D.F. Ryan, B.D. Chambers, J.M. Gilchrist, and S.A. Bamforth, 'Simple Approach to the Clean-Up of Horizontal Wells with Pre-Packed Screen Completions', SPE30116, paper presented at the 1995 SPE European Formation Damage Conference, The Hague, May 1995.
3. J. Tronvoll, and E.F. Sønstebø, 'Productivity Effects of Drawdown and Depletion in Open Hole Completion : Do Screens Plug ?', SPE 38191, paper presented at the 1997 European Formation Damage Conference, The Hague, June 1997.
4. S.A. Ali and H.L. Dearing, 'Sand Control Screens Exhibit Different Degrees of Plugging', Hart's Petroleum Engineer International, Vol. 69, July 1996.
5. D.B. Burnett, 'Wellbore Cleanup in Horizontal Wells: An Industry Funded Study of Drill-in Fluids and Cleanup Methods', SPE39473, paper presented at the 1998 SPE Symposium on Formation Damage Control, Lafayette, February 1998.
6. H.C. Lau and C.L. Davies, 'Laboratory Studies of Plugging and Clean-Up of Production Screens in Horizontal Wellbores', SPE38638, paper presented at the 1997 SPE Annual Technical Conference, San Antonio, October 1997.
7. H.K.J. Ladva, M. Parlar, C. Price-Smith, L.J. Fraser, and S. Ali, 'Mechanisms of Sand Control Screen Plugging From Drill-In Fluids and its Cleanup Using Acid, Oxidizers and Enzyme Breakers', SPE39439, paper presented at the 1998 SPE Symposium on Formation Damage Control, Lafayette, February 1998.
8. A. Procyk, M. Whitlock, and S. Ali, 'Plugging-induced screen erosion difficult to prevent', Oil & Gas Journal, July 20, 1998.
9. J. McLarty, 'How To Complete A Horizontal Well In The Gulf Of Mexico: Operators Share Experiences', Hart's Petroleum Engineer International, Vol. 70, November 1997, pp 63-70.
10. G.S. Lester, C.A. Malbrel, and M. Whitlock, 'Field Application of a New Cleanable and Damage Tolerant

Downhole Screen', SPE 30132, paper presented at the 1997 European Formation Damage Conference, The Hague, June 1997.
11. T. Ballard, N. Kageson-Loe, and A. M. Mathisen, 'The Development and Application of a Method for the Evaluation of Sand Screens', SPE 54745, paper presented at the 1999 European Formation Damage Conference, The Hague, June 1999.
12. C. Price-Smith, C. Bennett, S.A. Ali, R.M. Hodge, R.C. Burton, and M. Parlar, 'Open Hole Horizontal Well Cleanup in Sand Control Completions : State of the Art in Field Practice and Laboratory Development', SPE 50673, paper presented at the 1998 European Petroleum Conference, The Hague, October 20-22 1998.
13. L.G. Jones, R.J. Tibbles, L. Myers, D. Bryant, J. Hardin, and G. Hurst, 'Gravel Packing Horizontal Wellbores with Leak-Off Shunt Tubes', SPE 38640, paper presented at the 1997 SPE Annual Technical Conference, San Antonio, October 1997.
14. P. Markestad, O. Christie, A. Aspedal, and O. Rørvik, 'Selection of Screen Slot Width to Prevent Plugging and Sand Production', SPE 31087, paper presented at the International Symposium on Formation Damage, Lafayette, LA, February 14-15 1996.
15. C.J. Coberly and E.M. Wagner, 'Some Considerations in the Selection and Installation of Gravel Pack for Oil Wells', in 'Well Completions', SPE Reprint Series No. 5, 1970, p. 156-175.
16. D.H. Schwartz, 'Successful Sand Control Design for High Rate Oil or Water Wells', in 'Well Completions', SPE Reprint Series No. 5, 1970, p. 182-195.
17. R.J. Saucier, 'Considerations in Gravel Pack Design', in 'Sand Control' SPE Reprint Series No. 43, 1996, p. 7-14.
18. L. Hebert and C.A. Malbrel, 'Thru-Tubing Sand Control Remediation Expands', Oil & Gas Journal, March 30, 1998.
19. R.C. Burton and R.M. Hodge, 'The Impact of Formation Damage and Completion Impairment on Horizontal Well Productivity', SPE 49097, paper presented at the 1998 SPE Annual Technical Conference, New Orleans, September 1998.
20. W.C. Krumbein and G.D. Monk, 'Permeability as a Function of the Size Parameters of Unconsolidated Sand', *Trans.*, AIME, Vol. 151, 1943, p. 153-160.
21. S.D. Joshi, 'Horizontal Well Technology', PennWell Publishing Company, Tulsa, OK, 1991, pp. 379.
22. C. Marken, P. Markestad, and O. Rørvik, 'Criteria for Back Production of Drilling Fluids Through Sand Control Screens', SPE 38187, paper presented at the 1997 European Formation Damage Conference, The Hague, June 1997.
23. T. Ballard, personal communication

APPENDIX A : MUD CONDITIONING TESTS

These tests are used to determine the shaker mesh size required to provide protection against screen impairment and quantify the mud plugging index (MPI) to be used on the rig to control mud quality prior to running the screen in the hole.

Equipment:
- HPHT cell with 2.5'' screen media disks
- Sieves of various size (200, 230, 270, 325 mesh)
- Constant air pressure source (100 psi)
- Graduated cylinder
- Stopwatch

Mud Conditioning Qualification Test

Scope: to select the shaker size to remove mud and drill solids damaging to the screen.

Objective: to remove mud solids coarse enough to damage the screen. In order to protect the screen, 3 'lab barrel', *ie* 1050 mL of mud must flow through a 2 ½" inch screen disk sample.

Procedure:
1. The mud should be a representative field sample, but if one is not available, a simulated field mud can be made from a fresh batch of mud with material added to simulate insoluble drill solids.
2. Install the screen samples at the bottom of the cell with the downstream valve closed;
3. Fill the container with unconditioned mud (approximately 500 mL) and pressurized the reservoir to 100 psi;
4. Flow 350 mL of fluid through the screen and relieve the pressure inside the cell;
5. Repeat step 2-3 a total of three times (to get a total mud throughput of 1050 mL) or record the total volume of mud throughput;
6. Change the screen sample;
7. Repeat step 1-5 with mud conditioned through 200 mesh sieve, mud conditioned through 230 mesh sieve, etc. down to 325 mesh sieve if necessary, until the required volume of mud (1050 mL) passes through the screen sample without plugging it.

MPI Index

Scope:
To qualify a field test procedure for the monitor of mud conditioning on the rig.

Objective:
When plugging occurs, the leak off rate through the screen medium decreases. By comparing the leak off time, T_1, of a first batch of mud (1 lab barrel), with that of a second, T_2, through the same screen sample, one can evaluate the plugging tendency of the screen and monitor mud quality. This test is designed to require very little equipment and expertise so that it can easily be run on the rig.

Procedure:

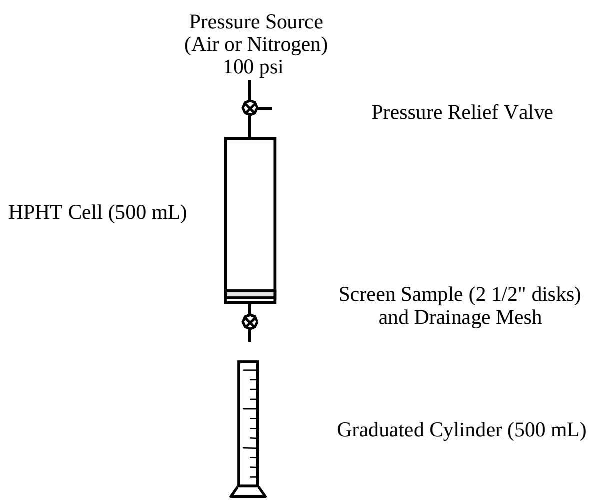
1. Close the valve underneath the screen sample and fill the mud cell with 350 mL of unconditioned mud;
2. Open the valve and measure the time taken by the mud volume to flow through the medium, T_1 (note: in this test, no pressure is applied. The mud flows by gravity only);
3. Close the valve again and fill the mud cell with another lab barrel;
4. Open the valve and measure the time taken by the second lab barrel to go through the same screen sample, T_2;
5. Calculate the MPI:

$$MPI = T_2/T_1$$

   Note: When there is no plugging, MPI = 1. As plugging increases, MPI increases.

6. Change the screen sample and repeat the test with mud conditioned through the sieve selected from the Mud Conditioning Qualification test.

These two MPI indices obtained with the unconditioned and conditioned mud provide a range that can be used as baseline for mud monitoring on the rig. Circulation through the shakers should be continued until the MPI is typically within 20% of the value obtained in the lab. Other tests with mud samples conditioned with coarser meshes are also recommended to get a feeling of the sensitivity of the test with respect to particle size cut-off.



APPENDIX B: EQUATIONS

Horizontal Well Inflow (steady state):[19]

Assumption: negligible turbulence effect (horizontal oil well)

$$Q = \frac{0.00708\ K_h\ H}{(\mu\ B)\ \{HGWF + [H/L\ \ (K_h/K_v)^{0.5}\ (\Sigma s_i + DQ)]\}}\ \Delta P$$

$$\Delta P = \frac{Q\ (\mu\ B)\ HGWF}{0.00708\ K_h\ H} + \frac{Q\ (\mu\ B)\ [H/L\ \ (K_h/K_v)^{0.5}]}{0.00708\ K_h\ H}\ \Sigma s_i$$

$$\Delta P = \Delta P0 + (\Delta P1 + \Delta P2 + \Delta P3 + \Delta P4 + \Delta P5)$$

$$\Delta P0 = \frac{Q\ (\mu\ B)\ HGWF}{0.00708\ K_h\ H}$$

with:

$$HGWF = HGWFxy + HGWFr$$

$$HGWFxy = \ln[(a + (a^2 - (L/2)^2)^{0.5}) / (L/2)]$$

$$HGWFr = (\beta\ H/L)\ \ln[(\beta\ H)/(2\ r_w)]$$

$$s_1 = [(K/K_d)-1]\ \ln[r_d/(r_w+r_{conv})]$$

$$s_2 = (K/K_a)\ \ln[r_w/r_{screen}]$$

$$s_3 = (K/K_s)\ \ln[r_{screen}/r_{pipe}]$$

$$s_4 = [(K/K_d)/n]\ (1/r_p - 1/r_{conv})$$

$$s_5 = [(K/K_a)/n']\ (1/r_o - 1/r_{conv'})$$

Nomenclature

a: Drainage Ellipse Major Semi-Axis (ft) $= (L/2)\ [0.5 + (0.25 + (2\ r_{eh}/L)^4)^{0.5}]^{0.5}$
A: Drainage Area (acre)
B: Formation Volume Factor (RB/STB)
D: Non-Darcy Flow Coefficient = 0 for non turbulent conditions
H: Reservoir Thickness (ft)
HGWFxy: Dimensionless Geometric factor for Flow Convergence in the xy Plane
HGWFr: Dimensionless Geometric Factor for Radial Flow Convergence
K: Effective Reservoir Permeability (mD) = $(K_h\ K_v)^{0.5}$
K_a: Annular Fill Permeability (mD)
K_d: Mud Invaded Zone Permeability (mD)
K_h: Horizontal permeability (mD)
K_v: Vertical Permeability (mD)
L: Well Length (ft)
MR: Mud Cake Removal Efficiency
MR’: Screen Impairment Removal Efficiency
n: Number of mud filter cake pinhole per foot $= (2\ r_w / r_p^2)\ MR$
n’: Number of Openings per Foot of Screen $= (2\ r_{screen} / r_o^2)\ MR'$
Q: Production Rate (bpd)
r_d: Mud Invaded Zone Radius (ft)
r_{conv}: Convergence radius/filter cake pinholes (ft) $= (2\ r_w / n)^{0.5}$
$r_{conv'}$: Convergence radius /screen opening (ft) $= (2\ r_{screen} / n)^{0.5}$
r_{eh}: Effective Drainage Radius (ft) = (43560 A / 3.14159)
r_o: Opening Diameter (ft)
r_p: Pinhole radius (ft)
r_{pipe}: Basepipe radius (ft)
r_{screen}: Screen radius (ft)
r_w: Well Radius (ft)
s: Skin Factors $= s_1 + s_2 + s_3 + s_4 + s_5 = \Sigma\ s_i$
β: Reservoir Anisotropy $= (K_h/K_v)^{0.5}$
ΔP: Total Drawdown (psi)
μ: Oil Viscosity (cp)

<u>Permeability as a Function of Particle Size:</u>[20]

Assumptions:

- 40% porosity (consistent with an unconfined sand-pack)

- Log-normal size distribution ("unskewed" sieve analyses)

$k = 760\ D50^2 \exp(-1.31\ \sigma_\Phi)$

Expressed as a function of the uniformity coefficient:

$k = 760\ D50^2 \exp(-2.8355\ \mathrm{Log}(D40/D90))$

Nomenclature

k: Sand Fill Permeability (D)

D50: Average Sand Size (mm)

Φ_{50}: Phi value of D50 = $-\mathrm{Log}_2\ D50 = -3.322\ \mathrm{Log}(D50)$

σ_Φ: Sand Size Distribution Standard Deviation = $\Phi_{84} - \Phi_{50}$

<u>Pressure Drop Inside the Basepipe:</u>[21]

Assumption: Uniform Fluid Entry along Wellbore

$\Delta P_f = \quad \Sigma\ \Delta P_i = \Sigma\ [1.14644 \times 10^{-5}\ f_{m,i}\ \rho\ q_i^2\ (l_i - l_{i-1})/d^5]$

Nomenclature

ΔP_f: Pressure Drop Inside the Basepipe (psi)

ΔP_i: Friction Pressure Drop due to Flow in the i^{th} Screen Joints from the Toe

d: Screen Internal Diameter (in)

$f_{m,i}$: Friction Factor

Laminar Flow ($Re_i < 2300$):

$f_{m,i} = 64/Re_i$

Turbulent Flow ($Re_i > 4000$)):

$f_{m,i} = \{1.14 - 2\ \ln[(\varepsilon/d) + 21.25 Re_i^{-0.9}]\}^{-2}$

$l_i - l_{i-1}$: Length Increment (screen joint length) (ft)

N: Total Number of Screen Joints

q_i: Cumulative Flowrate in the i^{th} Screen Joint (bpd) $= q_{i-1} + Q/N$

Q: Production Rate (bpd)

Re_i: Reynolds Number = $92.23\ \rho\ q_i / \mu\ d$

ε: Roughness (in)

μ: Oil Viscosity (cp)

ρ: Fluid Density (g/cc)

TABLE 1: Field cases used to validate the Screen Media Selection Chart shown in Figure 3.

	Medium	Completion	Performance	Comments
1	PMM	Horizontal Well (Gulf of Mexico) D50 = 40-60 µm	Sand Production Relatively High Drawdown (250 psi @ 1100 bpd)	Gravel pack should have been used with PMM as secondary barrier
2	PMM	Insert Screen (Gulf of Mexico) D50 = 70 µm <44µm = 20%	No Sand Production High Drawdown (200 psi @ 400 bpd)	Gravel pack should have been used in conjunction with PMM to improve drawdown
3	PMM	Horizontal Well (Gulf of Mexico) D50 = 100-160 µm	No Sand Production -3.5 skin	Good selection
4	PMF2040	Insert Screen (Gulf of Mexico) D50 = 60 µm	Sand Production	Media too coarse
5	PMF2040	Horizontal Well (Gulf of Mexico) D50 = 100-120 µm	No Sand Production Low Drawdown (80 psi @ 2500 bpd)	Good selection
6	PMF2040	Horizontal Well (Africa) D50 = 100-160 µm	No Sand Production PI = 50	Good selection
7	PMF1220	1220 Gravel Pack (Gulf of Mexico) D50 = 106 µm	Sand Production	Media/Gravel pack too coarse

TABLE 2: Effect of reservoir/well characteristics on pressure drop contributions to well drawdown.

	Gulf of Mexico	**North Sea**
Flowrate (bpd)	5,000	15,000
Fluid Viscosity (cp)	0.5	0.5
Form. Vol. Factor (RB/STB)	1.25	1.25
Drainage area (acre)	200	200
Well length (ft)	1000	3000
Reservoir Thickness (ft)	50	100
Reservoir Permeability (mD)	100	1000
Permeability Reduction in Mud Invaded Zone	50%	50%
Mud Invaded Zone Radius (ft)	1	2
Mud Cake Removal Efficiency	0.05	0.05
Annular Fill Permeability (mD)	100	1,000,000 (open)
Sand Consolidation	Very Weak	Partially Consolidated
Wellbore Diameter	8.5	8.5
Screen Nominal Size (in)	5.5	5.5
Screen Diameter (in)	6.1	6.1
Screen Permeability (mD)	100,000	100,000
ΔP_0 (psi) – undamaged reservoir	186.21	23.52
ΔP_1 (psi) – mud invaded zone	5.70	0.81
ΔP_2 (psi) – annular fill	1.45	0.00
ΔP_3 (psi) – screen (95% permeability reduction)	0.01	0.01
ΔP_4 (psi) – convergence towards pinholes	0.77	0.08
ΔP_5 (psi) – convergence towards screen openings	0.00	0.00
P.I. (bpd/psi)	25.75	614.28
$P.I./P.I._o$	0.959	0.963

Note: $P.I._o$ corresponds to the productivity of a well with no near wellbore damage, and no screen.

TABLE 3: Effect of screen clean-up and gravel packing on flow convergence and well productivity: Case of a 1000 ft well producing 5000 bpd).

	Reservoir	**PI/PI_o 100 % Clean-up**	**PI/PI_o 10% Clean-up 10 cm Openings**	**PI/PI_o 10% Clean-up 1 cm Openings**
No Gravel Pack	Homogeneous 100 mD	0.96	0.88	0.96
	Homogeneous 1000 mD	0.94	0.86	0.93
	Heterogeneous 90 % 100 mD 10% 1000 mD	0.86	0.70	0.83
Gravel Pack	Homogeneous 100 mD	0.97	0.97	0.97
	Homogeneous 1000 mD	0.95	0.95	0.95
	Heterogeneous 90 % 100 mD 10% 1000 mD	0.88	0.87	0.88

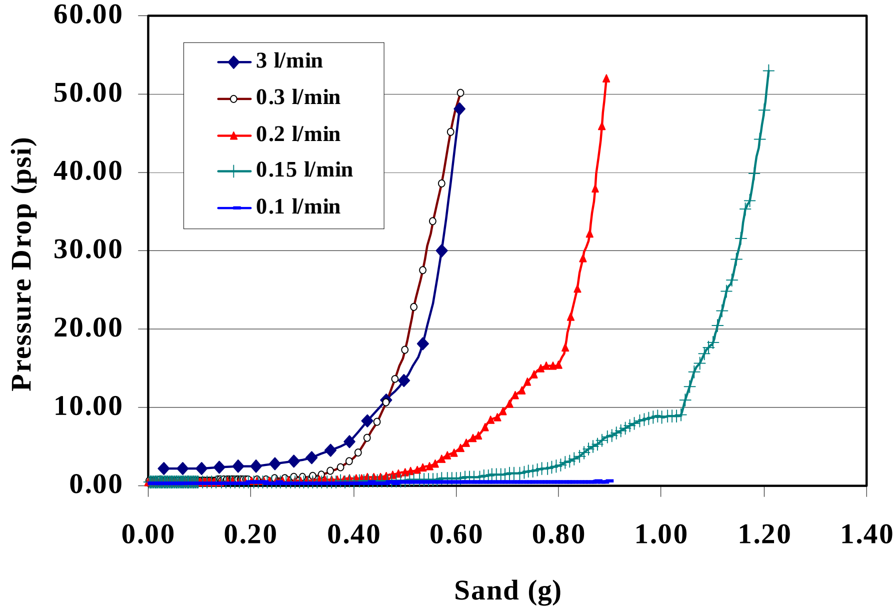


Figure 1: Effect of test flowrate on the plugging tendency of a fine screen.

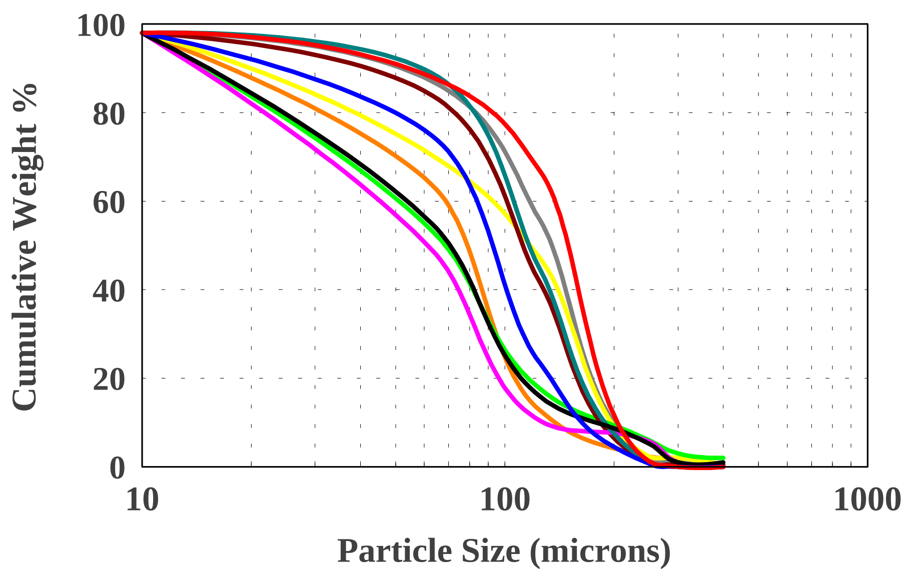


Figure 2: Variability of formation sand particle size distribution in a deepwater Gulf of Mexico reservoir.

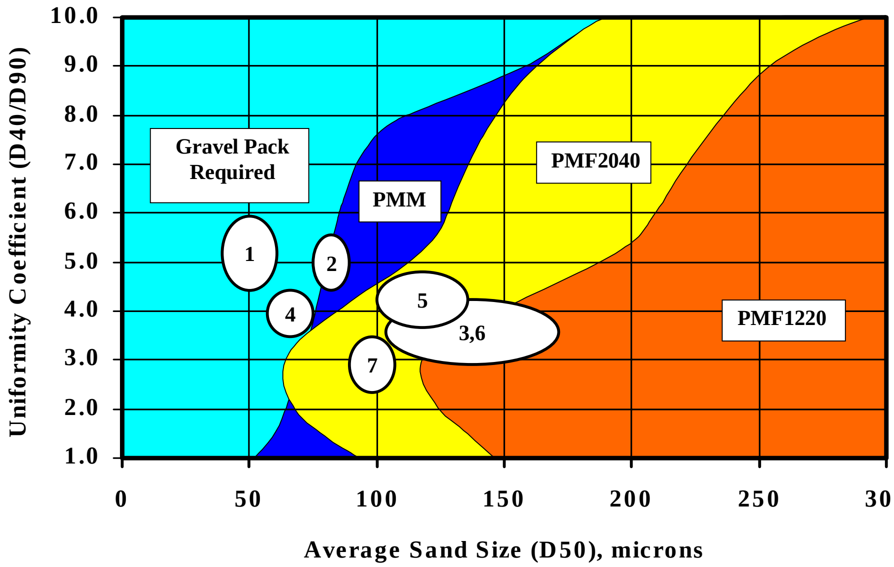


Figure 3: Screen Media Selection Chart for standard non woven screen media: PMM (60 µm); PMF2040 (120 µm); PMF1220 (200 µm). Application to field cases summarized in Table 1.

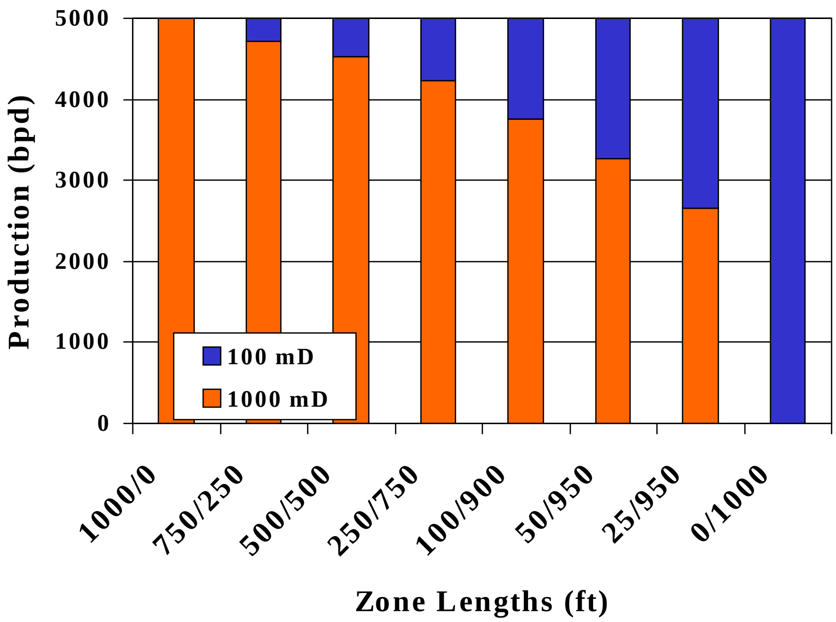


Figure 4: Production contribution of a high and a low permeability reservoir producing simultaneously out of one 1000 ft well. A "100/900" interval length corresponds to 100 ft of 1000 mD reservoir producing in conjunction with 900 ft of 100 mD formation (*Assumption: Friction losses effect are neglected).*

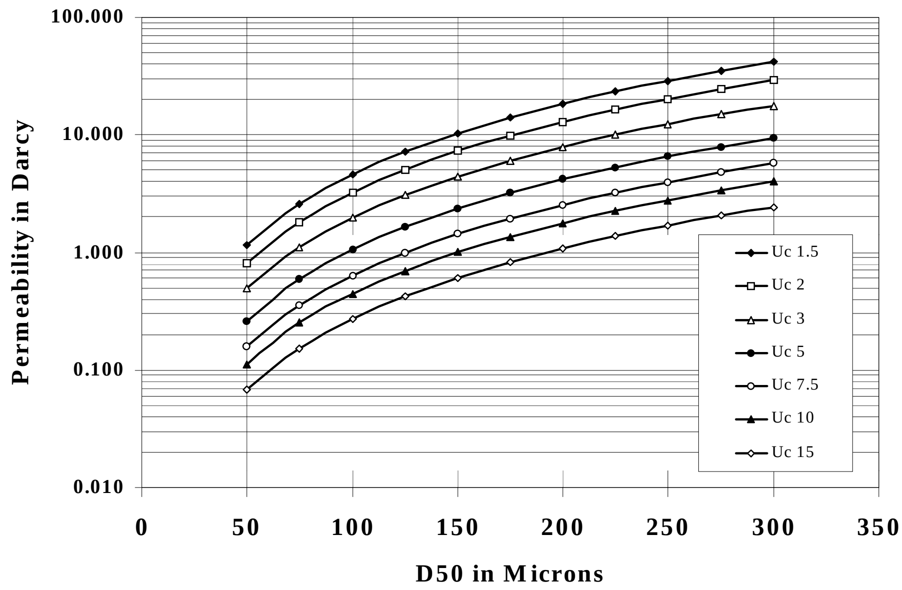


Figure 5: Permeability as a function of particle size distribution.

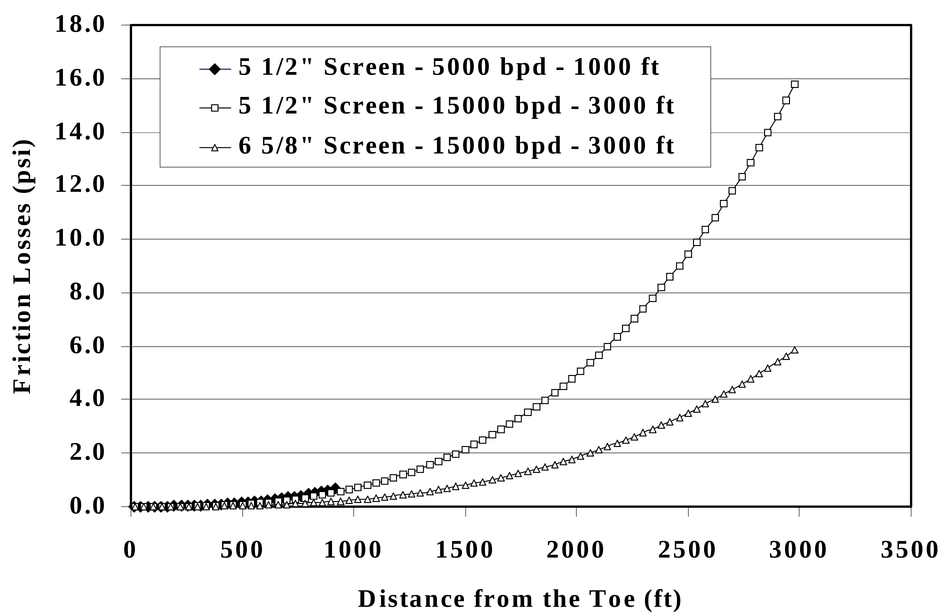


Figure 6: Friction losses inside the horizontal well assuming a uniform fluid entry along the wellbore – application to the wells described in Table 1 and effect of screen diameter.

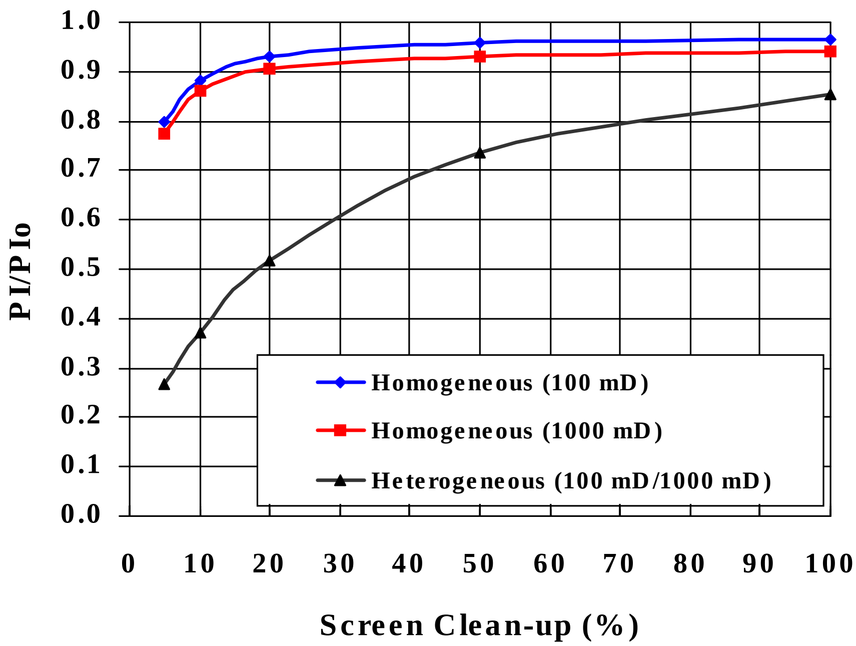


Figure 7: Productivity impairment associated with poor screen clean-up. Effect of flow convergence and reservoir heterogeneity. The heterogeneous reservoir corresponds to 100 ft of 1000 mD and 900 ft of 100 mD formation.

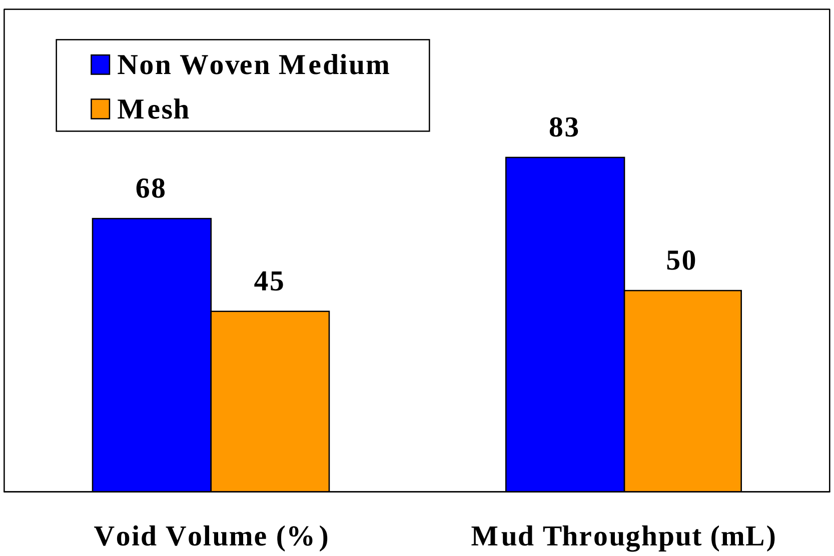


Figure 8: Correlation between mud plugging tendency and screen media void volume using a non woven screen and a mesh screen as examples.