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Alternate Paths: Do We Need Them for FracPacking in Long Deviated Intervals?

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Abstract
A great deal of interest regarding the use of alternate path technology for gravel-packing long deviated intervals has recently been noted in the oil field. These alternate-path systems are designed to provide insurance against incomplete packs or voids that could lead to a sand control failure of the completion. While the alternate-path completions have been very successful in ensuring complete packs, there are other considerations that can affect the completion results; i.e., alternate path systems can result in higher costs or the smaller screen sizes needed can restrict production.

This paper will present case histories of fracpacks that were performed over long, deviated intervals without the use of alternate paths. The wells discussed have been chosen because they are typical of scenarios where alternate paths could have been considered. The results from the wells will also be discussed, and tracer logs will be shown to illustrate the success in obtaining a complete gravel pack. The paper will also provide suggestions on where alternate paths should be used.

Introduction
As fracpacking has developed into the preferred completion option for the Gulf of Mexico and other areas, the type of reservoir sands that must be completed using a fracpack have grown in size and complexity (60 m). Currently, it is not uncommon to fracpack interval lengths of 200 feet and more with deviations greater than 60-degrees, or two intervals that are separated by a shale or silty sand barrier. There are several reasons for this. One of them may be the industry's growing comfort level with fracpacks. As the industry's collective experience and success with fracpacking procedures has increased, the accepted range of application for fracpacks has grown. Before this experience was gained, intervals greater than 100 feet, deviations greater than 40-degrees, or permeabilities greater than 500 md were cause for concern. Today, intervals of up to 500 feet, deviations to near horizontal, and permeabilities greater than 3 Darcy's have been successfully fracpacked.[1,2]

New challenges have continued to surface from the move to completions in deepwater reservoirs as well as the need to improve economics by completing several layers simultaneously. Drilling paths for subsea wells in deepwater can result in high deviations through the producing interval. In some cases, there may be two or more highly permeable zones that are separated by a shale or silt zone of poorer quality. Economic factors also become more critical in deep-water scenarios. If it is possible to complete two (2) intervals that are close together with a single completion rather than a stacked completion, the cost, time, and the risk associated with the completion can be minimized. Another challenge has addressed the need for new, higher-rate fracpack tools.[3]

The presence of voids when completing long deviated intervals with a gravel pack is believed to be one of the leading causes of completion failure. Thus, the need for treating these long, deviated intervals and maintaining high completion reliability has resulted in increased interest in the use of alternate path techniques, since these techniques have shown that in certain completion scenarios, they can increase the likelihood of obtaining a void-free gravel pack.[4,5]

The concern with fracpacks is that a high leakoff zone could lead to dehydration across the pack and create a bridge in the casing-screen annulus. This bridge could prevent the packing of the rest of the casing-screen annulus below that point. Such a bridge could occur as a result of:

1. *High leakoff caused by multiple fractures created in long deviated intervals* is due to the stress field orientation not being aligned with the well path. **Fig. 1** illustrates this scenario.
2. *Multiple fractures caused by clean sand zones separated by shales/silty sands*. Since the shales may have higher stresses, a fracture may only propagate across a limited section of the interval. When the fracture screens out, this may lead to the creation of a

bridge that could prevent a complete annular pack. **Fig. 2** illustrates this scenario.

3. *Presence of a high permeability zone*. Since the fracture is most likely to propagate initially in the high permeability/high leakoff zone, a premature screenout in this section could lead to an incomplete annular pack. **Fig. 3** illustrates this scenario.

DeBonis and Park[6,7] showed that long perforated intervals could be completed reliably in high-angle wells in their documentation of the sand-control completions of a Gulf-of-Mexico development. Their presentation covered a number of fracpack completions with deviation at the perforations from 60 to 80 degrees and perforation intervals from 250 to 520 ft. The early fracpack treatments in this development, which included intervals from 250 to 270 feet, were performed with an HEC gel system and showed a high incidence of what was defined as wellbore screenouts with 33 to 92 percent of the proppant placed versus the design. A switch to a borate cross-linked gel system resulted in 90 to 100 percent of proppant being placed in intervals of 300 to 520 feet. There were with no wellbore screenouts observed with the cross-linked fluids. Reportedly, none of the completions experienced a sand-control failure. It might be inferred from these results that the controlling leakoff with the higher viscosity cross-linked gel system aided in controlling leakoff, and quite possibly, prevented the wellbore screenouts observed with the HEC fluid systems. The ability to cover the entire interval with the fracpack may have improved as well. Further information is given in Park.[7]

While alternate path techniques do help to deliver a void-free gravel pack, there are some restrictions to its use. One of the main drawbacks is the reduction in screen size that occurs in order to accommodate the size of the alternate path channels inside the casing. This can lead to restricted production from the zone. In addition, some of these systems would be difficult to retrieve if required. In such a case, it may be necessary to sidetrack the well, which would lead to significantly higher costs.

It is possible to reduce the risk of bridging by proper selection of the injection rates, fluid properties, screen design, and fracpack design. The use of sophisticated simulators that allow for the modeling of multiple fractures can also be used to minimize the risk of bridging. Finally, some of the steps inherent in the fracpacking process may also help minimize the presence of voids. It has been speculated that bleeding pressure from the casing annulus at the end of the fracpacks prior to reversing out may help with packing of the casing-screen annulus. During this bleed-off, the bottomhole pressure drops from above fracture extension pressure to below fracturing pressure in a very short time period. This sudden pressure drop could induce a short period where fluid flows from the tubing through the crossover ports, and circulates through the screen. This would cause the proppant to be packed into the casing-screen annulus.

In discussing candidate selection for alternate-path completions, there has been some debate as to which completion types are appropriate. This paper will provide examples that illustrate that the range of reservoir zones that can be fracpacked without the use of an alternate path design may be broader than originally thought. In addition, some recommendations are presented concerning the type of conditions appropriate for the use of alternate path systems.

Discussion of Factors Causing Premature Screenout

As mentioned earlier, there can be several reasons for the occurrence of a premature screenout. These are discussed below:

1) ***Multiple fractures created by stress anisotropy***. As illustrated in **Fig. 1**, the effect of multiple fractures caused by the orientation of the stress field is one of the reasons that premature screenouts occur. This effect has been observed in more consolidated formations.

Field experience, however, suggests that this phenomenon may not be as significant in soft-rock formations due to the lack of any significant contrast between the maximum and minimum horizontal stresses. If the horizontal stresses are almost equal, which is likely in unconsolidated formations, then, the fracture is likely to propagate along the perforations. Tracer logs from fracpacks in oriented wells tend to support that there is uniform coverage along the wellbore. This will be illustrated in Case History 1. This fact has also been reported in the results obtained from fracpacks from the Pompano and Amberjack in the Gulf of Mexico.[6] These zones consisted of high-angle wells drilled at angles in excess of 70 degrees and had interval lengths ranging up to 500 ft (152.4 m). Both tracer and production logs from these wells indicated production from the entire interval. This has also been observed in other wells in the Gulf of Mexico. Since most wells in the Gulf of Mexico are not drilled to orient the well path along the preferred fracture direction, the uniform coverage and production may be indicative of the lack of any significant stress contrast in soft rocks.

2) ***Multiple fractures caused by clean sand zones separated by shales/silty sands***. **Fig. 2** illustrates another possible scenario where a premature screenout might occur, and alternate paths have been suggested as a method for bypassing any bridges. Under this scenario, multiple fractures are generated because of the presence of a high-permeability zone that may prevent a fracture from propagating across the entire interval. Alternatively, a single fracture may grow just in the top zone. When the top zone screens out, there is the potential for the creation of a bridge and an incomplete pack.

The extent to which this phenomenon occurs is dependent on the existence of a high-stress contrast between the layers and also having leakoff through the upper fracture that is sufficiently high to create a screenout and a bridge.

Although stress contrasts do exist in soft rock formations, the magnitude of the contrast may not be sufficient to contain a fracture unless a competent shale barrier exists. Field experience indicates that fine, silty sands, which may look like shales on logs, do not have stresses that are significantly different from those in the clean formations themselves. This is also illustrated in Case History 1.

Also, even if a screenout were to occur, a bridge is most likely to form if the leakoff rate through the top fracture equals or exceeds the injection rate. **Fig. 4** illustrates the scenario where a fracture has screened out at the top of the formation. For the illustration, the fracture zone is assumed to be 50-ft high. At the point of screenout, the fracture will have packed all the way to the perforations, and therefore, leakoff into the fracture will be controlled by leakoff through the perforations that are packed with sand. This is shown in **Fig 5**. It is possible to estimate the leakoff through the perforations using Darcy's Law for different viscosity fluids. **Table 1** shows the parameters for these simulations. Note these simulations make the worst-case assumption that the permeability of the reservoir is so high that it offers no significant barrier to fracturing fluid flow. All leakoff is controlled only by the packed perforations. **Fig. 6** shows the expected leakoff through the perforations for different viscosity fluids. The model indicates that for a gravel pack fluid such as completion brine; i.e., 1 cP viscosity, leakoff through the perforations will be in excess of 1500 bbl/min. This clearly will lead to dehydration across the pack. Similarly, the use of a linear gel such as 40-lbm HEC, which has a viscosity around 50 cP, would result in leakoff rates of the order of 30 bbl/min, which again, should lead to a screenout. However, if a fracturing fluid such as a 40-lbm cross-linked borate is used, then the viscosity of such a gel is on the order of 400 cP. The leakoff of this fluid would be on the order of 3 to 4 bbl/min. Considering that most fracpack injection rates in long deviated intervals are on the order of 20- to 50 bbl/min, the likelihood of creating a full annular bridge around the screen is reduced. Case History 2 seems to support this hypothesis.

3) ***Presence of a high permeability zone at the top***. This is perhaps regarded as the classic case where an alternate path technique should be applied. In this scenario (Fig. 3), the facture grows preferentially in the top layer because of the cleaner sand. When the fracture screens out, it could lead to the creation of a bridge that might prevent packing of the entire annulus. One major operator has reported evidence of this occurring. However, as shown in Figs. 4 to 6, just the presence of a high permeability zone by itself may not be enough to require the use of alternate path systems. The zone must be sufficiently large to create a major leakoff zone under the specific reservoir conditions. However, it may be possible to minimize the risk of a void by proper design of injection rates, fluid properties, and fracpack design.

Case History 1:
The first case history shows the results of a completion in a deepwater project. The completion interval that was to be completed consisted of a 274-ft interval at a deviation of 44-degrees. The permeability in this zone ranged from 50-md to 1 Darcy based on sidewall core analysis. As can be seen by the gamma-ray log on the left, the interval had varying permeability across the entire zone with a high permeability streak at the top and a silty, low-permeability barrier separating the upper sand from the lower high-permeability sand.

Fig. 7 shows the results of the minifrac and the fracpack over the interval. Due to the concern about height growth and potential for voids, it was decided to tag the minifrac by using a radioactive tracer in the fluid. The tracer was placed in the entire fracpack treatment. Due to the limitation on the number of tracers available, only a single tracer could be used for the entire fracpack treatment. Therefore, it is difficult to ascertain how the fracture growth occurred. However, the tracer in the minifrac conclusively proves that the entire zone was broken down during the minifrac. The tracer is found uniformly across the zone and indicates that the low-permeability silty layer in between the high-permeability sand, and the low-permeability sand was not sufficient to prevent fracture height growth. Despite the long, deviated interval, the fracture grew along the entire interval, and there is indication of some fracture-height growth past the perforated interval. This suggests that this soft formation may not have a preferential fracture direction due to lack of any meaningful stress contrasts.

Case History 2:
This well resulted in a world record being set for the fracpack injection rate! The successful completion of this zone was aided by the development of new high-rate fracpack tools. The testing and qualification of the fracpack tools for this completion are described in a separate paper.[8] The zone to be fracpacked consisted of a laminated zone with multiple sand/shale sequences.

Fig. 8 shows a log of the zone. The zone consists of a 370-ft measured depth interval. The true vertical depth (TVD) height of the interval was 222-ft, and the wellbore deviation was approximately 53-degrees. In addition, the zone had several high-permeability sands that were separated by 20 to 50-ft thick shale/silty sand layers. In fact, as can be seen from the log, there was a distinct shale/silty barrier from 20,080 to 21,110 ft. The permeability for the zone ranged from 3- to 500 md.

In order to address the question of leakoff and to design the fracpack to cover the entire interval, it was decided to pump the treatment at 60 bbl/min with a 30-lbm borate cross-linked fluid system. The minifrac was performed at 50 bbl/min. **Fig. 9** shows the minifrac for the treatment. The chart shows the results from the three temperature gauges that were run inside the washpipe as well as the bottomhole pressure. The trend of the three bottomhole gauges is of particular interest. The lowermost temperature gauge shows a very different trend as compared to the upper and middle gauges. The lowermost gauge essentially stays flat for approximately 5 to 7 minutes before showing a decline, whereas the other gauges show an immediate cool down. This could indicate that an effective fracture across the upper and middle gauges had taken place but that the fracture had not grown to the position of the lowermost gauge. Finally, at approximately 18:06, the lowermost gauge started to cool down, which also coincided with a decline in the bottomhole pressure. This would indicate that the fracture had broken across a barrier and was now starting to grow downwards. This trend was further confirmed by the accelerated temperature decline seen in the upper and middle gauges and the early data from the main fracpack treatment. Based on the analysis of the treatment, it was decided to pump the fracpack at 60 bbl/min. **Fig. 10** shows the early time data for the fracpack. As in the minifrac, the lowermost temperature gauge initially shows a flat profile while the other gauges show a cool down from the fracture. However, after approximately 7 minutes of pumping 60 bbl/min, the bottomhole temperature gauge showed a sharp decline indicating that the fracpack had now grown to the bottommost gauge position. The data indicated that the high injection rates were instrumental in ensuring that the fracpack was capable of covering the entire interval and that rates as high as 60 bbl/min may be necessary in the future for some of these deepwater zones. This treatment resulted in a total of 287,000 lbm of proppant being pumped of which 268,787 lbm were placed into the formation. The peak horsepower used was 16,292 hydraulic horse power (HHP) and achieved a rate of 60.1 bbl/min. The maximum treatment pressure was in excess of 12,300 psi, and the average treating pressure was 11,060 psi. **Fig. 11** is a chart showing the entire treatment. **Fig. 12** shows the results for the calculated fracture-height growth and geometry as calculated by the fracture design model. **Fig. 13** shows the results of the tracer log for the fracpack. Only two tracers are shown, the Scandium (yellow) shows the 0.5 to 7 ppg stage and the Iridium (red) shows the placement of the 7 to 10 ppg stage. The Iridium tracer again shows entire coverage of the zone.

Case History 3

The deviation of this zone is 58 degrees, and the total interval height is 62 ft. Although the interval is relatively moderate in length, this reservoir shows a high-permeability zone on top of a lower-permeability zone. **Fig. 14** shows the log for the zone. There is an approximately 40-ft high-permeability zone on top of a silty low-permeability interval. The average permeability of the two intervals are 50 to100 md and 5 to 10 md respectively. Therefore, there is an order of magnitude difference in between the permeabilities of the two zones with the higher permeability on top. Again, this is potentially a situation where voids can occur because of a premature screenout on the high-permeability zone on top. **Fig. 15** shows the results from the main treatment. It should be noted that the fracpack screened out early, which would again be consistent with having high risk of voids in the gravel pack if only the high-permeability zone was covered by the fracpack.

The temperatures logs from the two gauges show identical behavior indicating that the zone fractured uniformly. The same behavior was seen during the minifrac, which again supports this conclusion. **Table 3** shows a summary of the treatment, and **Fig. 16** shows the calculated geometry for the zone. The fracture model indicated coverage of the entire zone. This conclusion is supported by the tracer log of the zone that is shown in **Fig. 17**. The tracer data shows that the proppant was distributed uniformly. The gravel-pack shows a tight pack all the way along the interval and into the lower permeability zone.

Table 4 presents a list of other wells that were successfully fracpacked without the use of alternate paths.

Application of an Alternate Path System

While the paper illustrates several case histories which were successfully completed without the use of alternate path technology, this does not imply that the alternate path has no application for fracpacking. However, in many cases where it has been used, the justification often seems to be the need for assurance rather than any well-defined technical parameters.

Some cases where alternate paths may have application is the case where one has an ultra-high permeability (> 1 D) zone of significant length on top that is separated from another zone by a large shale (i.e. high stress zone) that could act as a fracture growth barrier. In addition, the upper zone would have to fracture first, and it is not possible to adjust fluids and rates sufficiently to reduce the risk of preventing bridging. Cases where the concern is of multiple fractures, or where there is a silty-sand barrier do not seem to present a significant concern that voids will occur.

Conclusions

1. The case histories presented have shown that long deviated intervals can be successfully fracpacked without the use of alternate path technologies.
2. The risk of bridging caused by high leakoff rates can be significantly reduced by using properly designed cross-linked fluid systems.
3. Some of the lessons learned from traditional gravel packing may need to be modified to account for the different physics inherent in the fracpack process and fluids.
4. Although the risk of voids in long deviated intervals exists, the risk can be minimized through careful injection rates and fracpack design.
5. Better understanding and data are needed to define the candidate selection criteria for alternate paths.

Acknowledgements

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SI Metric Conversion Factors

in	x 2.54*	E + 01 = mm
ft	x 3.048*	E - 01 = m
psi	x 6.894 757	E + 00 = kPa
bbl	x 1.589 873	E - 01 = m^3
gal	x 3.785 412	E - 03 = m^3
bbl/min	x 2.649 788	E - 02 = m^3/h
ppg	x 1.198 264	E - 02 = kg/m^3
ft	x 2.831 685	E - 02 = m^3
in	x 2.54*	E + 01 = mm
psi	x 6.894 757	E + 00 = kPa
°F	(°F –32)/1.8 =	°C

*Conversion factor is exact

Table 1 — Parameters for Simulation

Height of FracPack Zone	50	ft
Permeability of Proppant	300	D
Perforation Density	12	spf
Perforation Diameter	1	in
Length of Perforation	12	in
DP = Fracture. Pressure - Reservoir Pressure.	2000	psi
Viscosity of Leakoff Fluid	400	cP

Table 2 — Summary of Results of FracPack

FracPack pump rate	60.1 bbl/min
Initial FracPack Tubing Pressure	12,000 psi
Tubing popoff setting	12,500 psi
FracPack fluid	30# DeltaFrac
Fracture gradient	0.84 psi/ft
Fracture height (TVD)	257 ft
Fracture half length	117 ft
Max fracture width	1 in.
Net pressure	150 psi
Proppant type	20/40 Interprop
Proppant around screen/blank	10,714 lbm
Proppant in formation	268,787 lbm
Proppant lbm/ft(MD of perfs)	726 lbm/ft

Table 3 — Summary of FracPack for Case History 3

FracPack pump rate	18 bbl/min
Initial FracPack Tubing Pressure	7,200 psi
Tubing popoff setting	12,000 psi
FracPack fluid	30# DeltaFrac
Fracture gradient	0.87 psi/ft
Fracture height (TVD)	88 ft
Fracture half length	77 ft
Max fracture width	0.75 in.
Net pressure	705 psi
Proppant type	20/40 Carbolite
Proppant around screen/blank	3,085 lbm
Proppant in formation	14,107 lbm
Proppant lbm/ft(MD of perfs)	228 lbm/ft

Table 4 — Table of Recent High Angle or High Deviation FracPacks Completed Without Alternate Path

Perforated interval(MD)	Deviation thru' Pay (deg)	Fluid	Permeability
ft	deg		
270	79	HEC	50-200
270	79	HEC	50-200
270	77	HEC	50-200
250	76	HEC	50-200
330	79	Borate Crosslink	50-200
345	49	Borate Crosslink	50-200
300	60	Borate Crosslink	50-200
520	80	Borate Crosslink	50-200
300	75	Borate Crosslink	50-200
200	54	Borate Crosslink	50-200
150	70	Borate Crosslink	500
272	54	Borate Crosslink	> 1000
64	65	Borate Crosslink	
64	65	Borate Crosslink	
224	64.8	Borate Crosslink	>1000
122	63	Borate Crosslink	
95	63	Borate Crosslink	
16	63	Borate Crosslink	
69	62.7	Borate Crosslink	>1000
79	62.6	Borate Crosslink	>1000
80	62	HEC	
73	62	HEC	
130	60	Borate Crosslink	500
85	60	Borate Crosslink	500
82	60	Borate Crosslink	
104	57	Borate Crosslink	
113	56	Borate Crosslink	500
100	54	Borate Crosslink	
184	50	Borate Crosslink	
350	30	Borate Crosslink	
190	34	Borate Crosslink	
185	49	Borate Crosslink	
181	22	Borate Crosslink	
166	49.3	Borate Crosslink	>1000
164	38	Borate Crosslink	
164	26	Borate Crosslink	
158	1	Borate Crosslink	
148	24	Borate Crosslink	

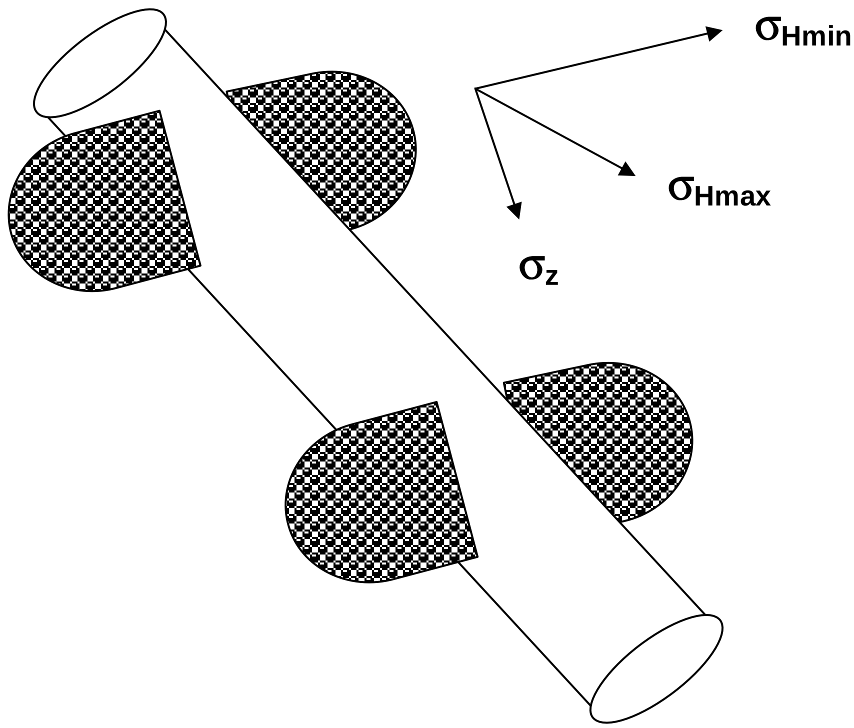

Fig. 1 – Creation of Multiple Fractures by Stress Orientation

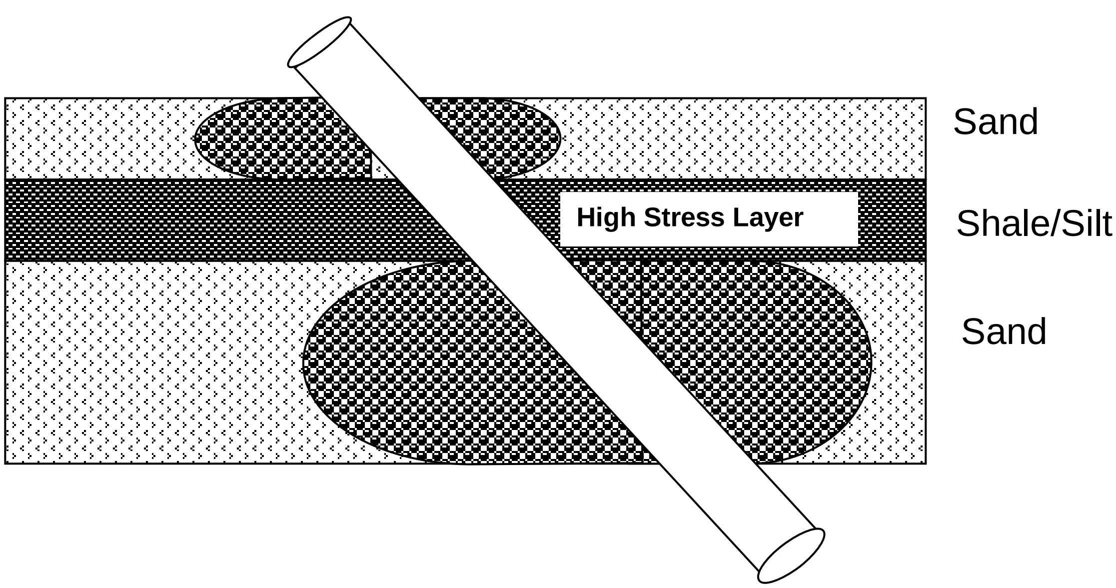

Fig. 2 – Creation of Multiple Fractures by Shale/Stress Barriers

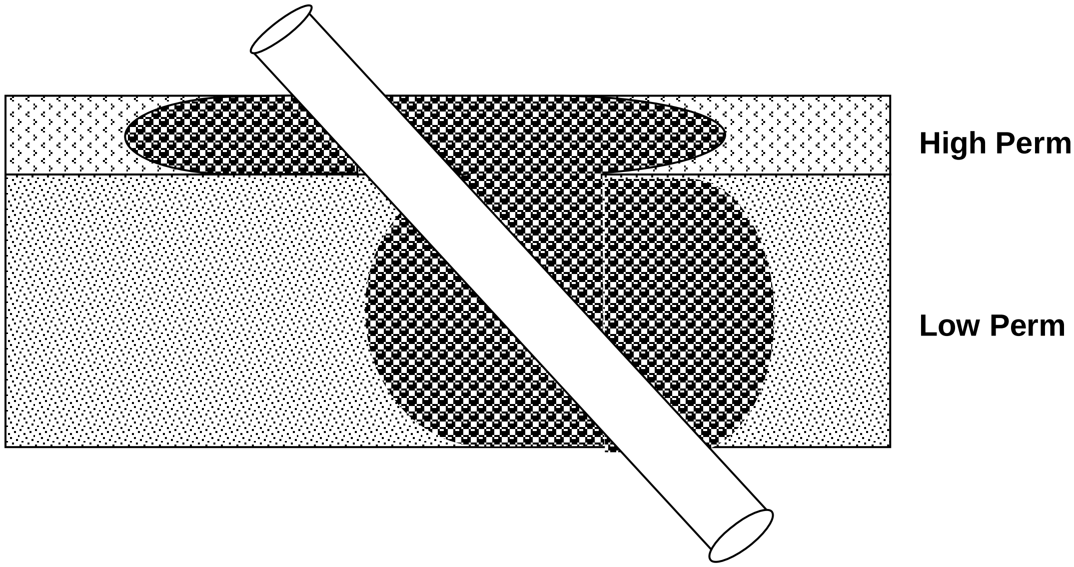

Fig. 3 — Possibility of Screenout Due to High Permeability Zones

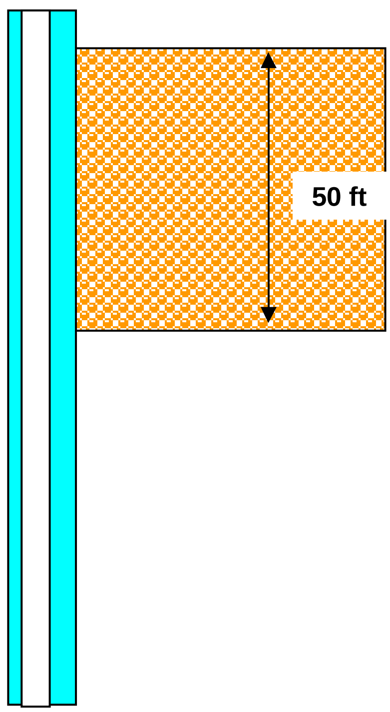

Fig. 4 — Model for Bridged Zone

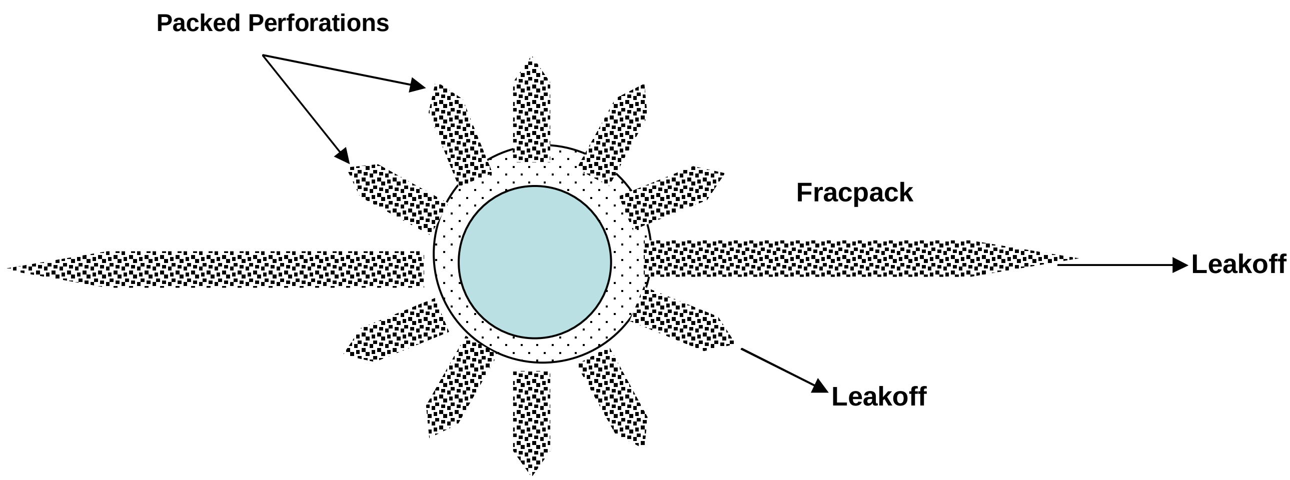

Fig. 5 — Radial View of Leakoff After Screenout

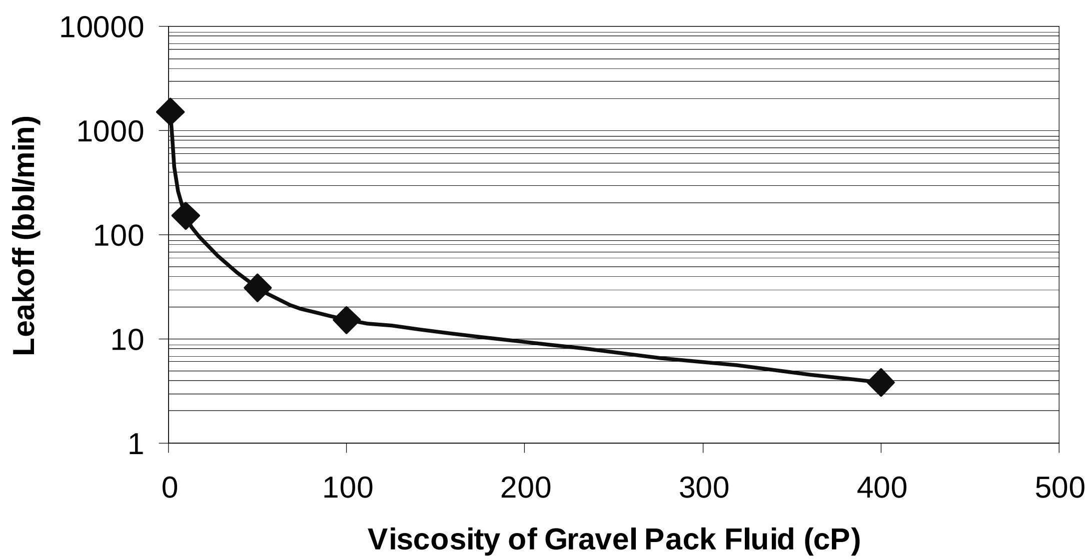

Fig. 6 — Leakoff through a set of packed perforations as a function of the fluid viscosity

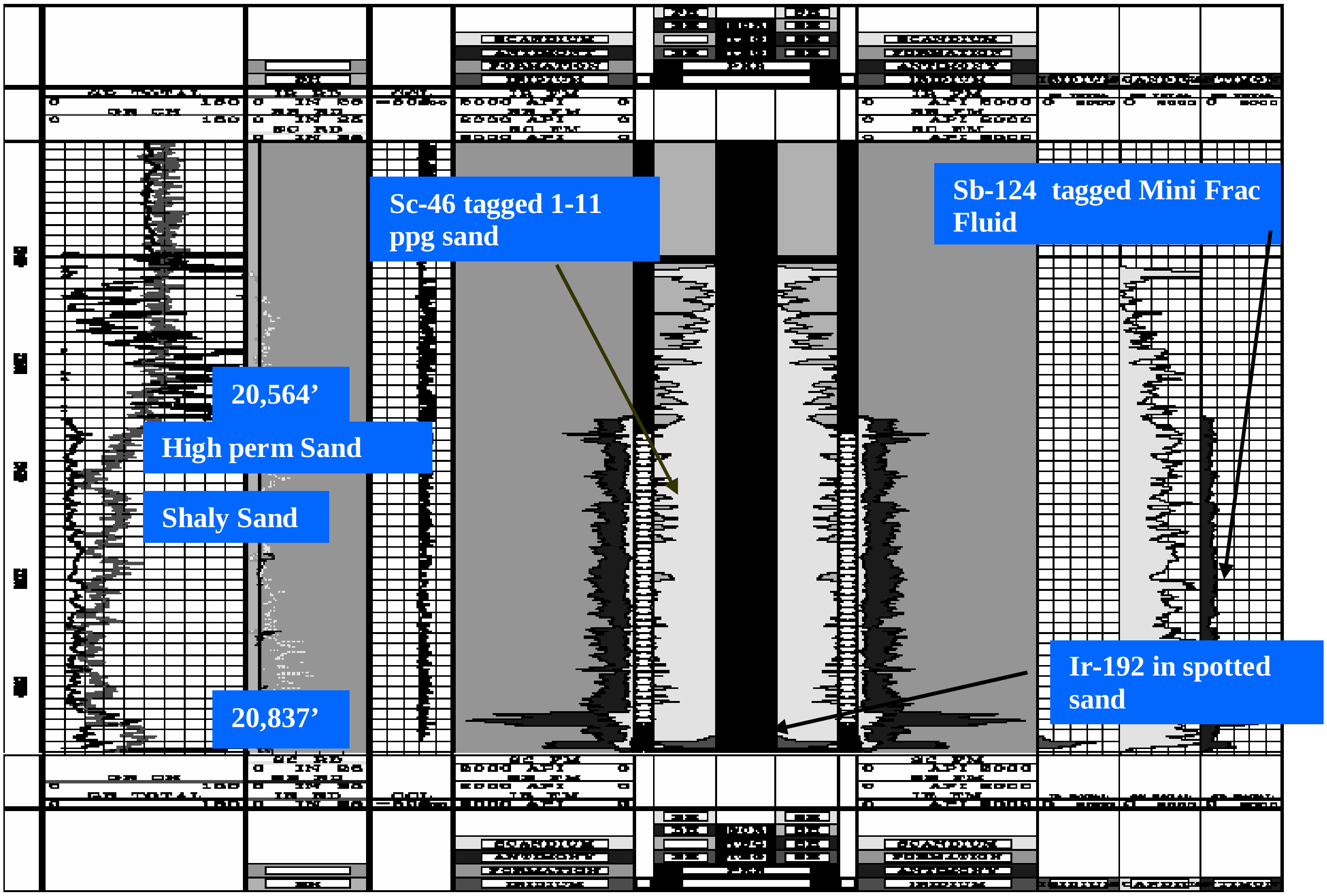

Fig. 7 — Tracer Log of Fracpack for Case History 1

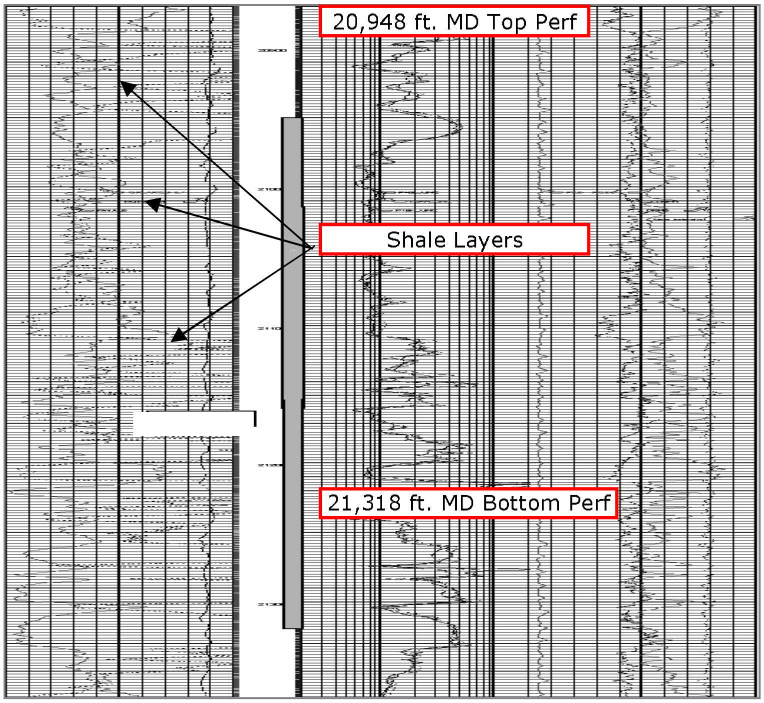

Fig. 8 — Log of Zone for Case History 2

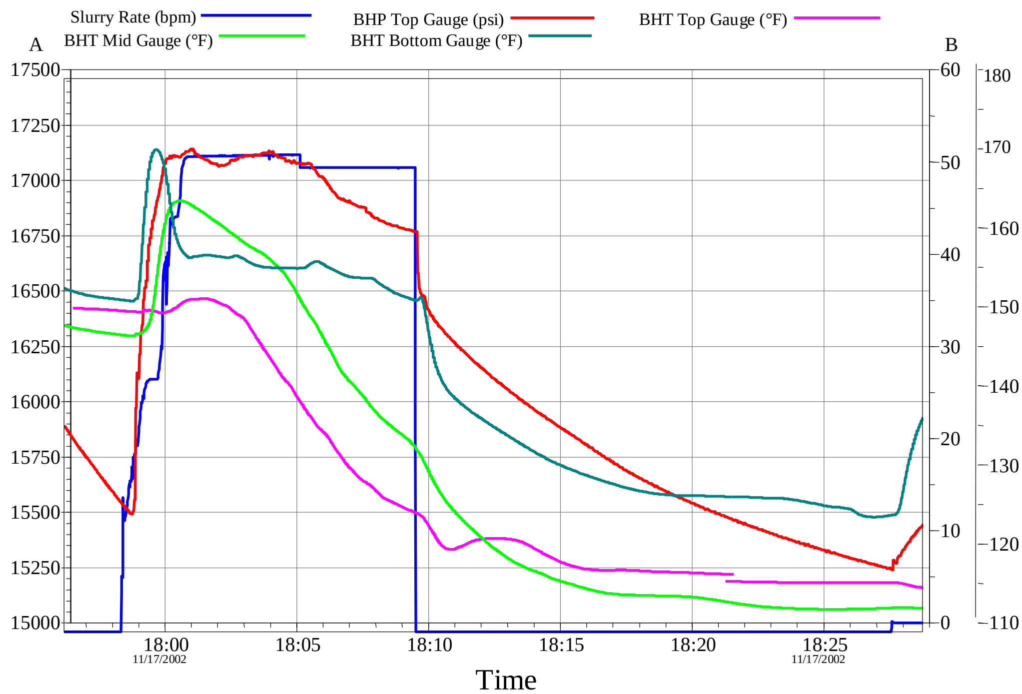

Fig. 9 — Minifrac Data for Treatment

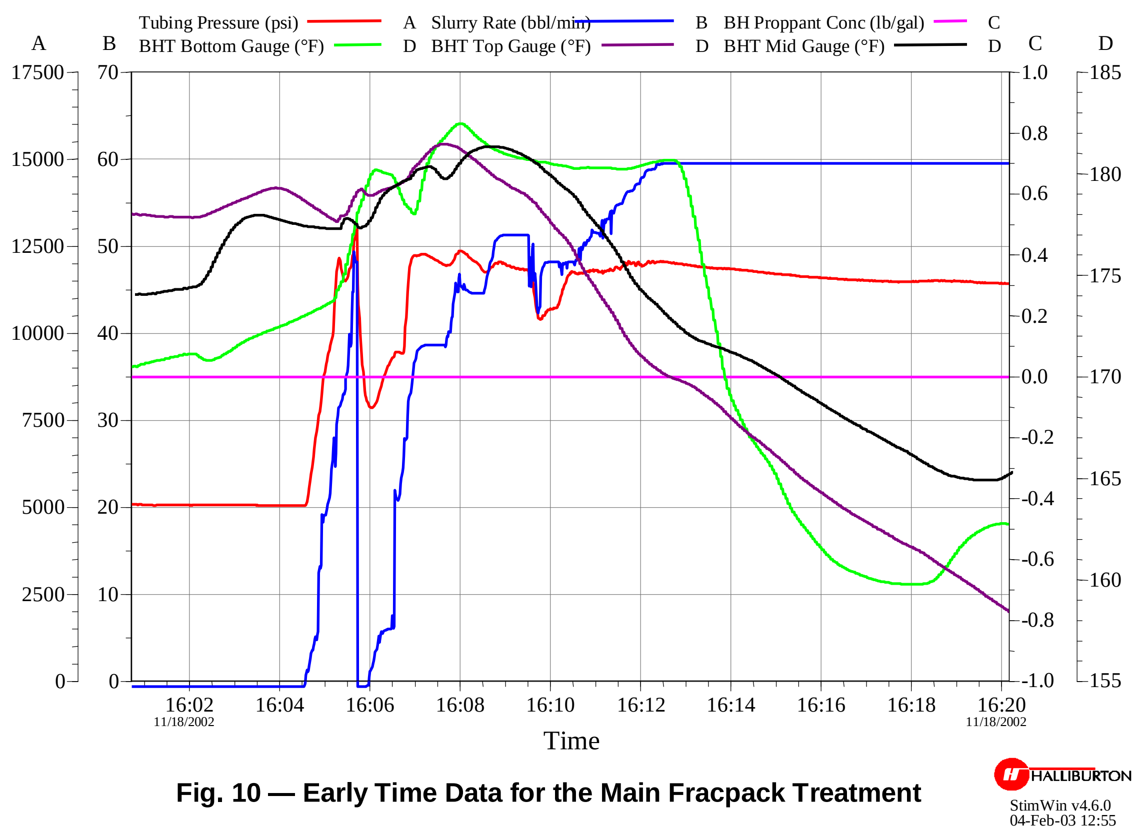

Fig. 10 — Early Time Data for the Main Fracpack Treatment

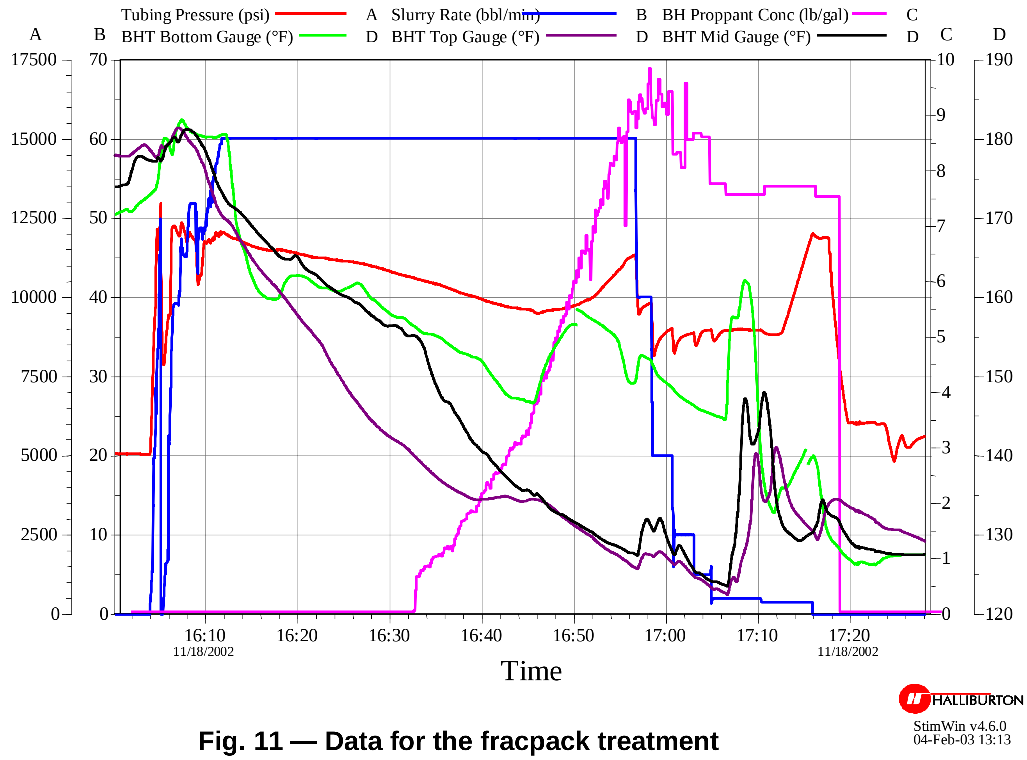

Fig. 11 — Data for the fracpack treatment

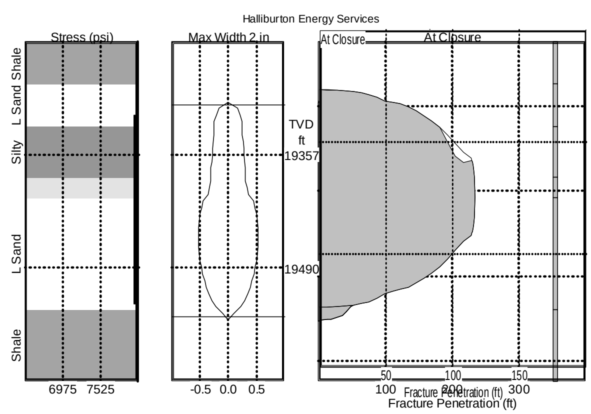

Fig. 12 — Estimated Geometry for the Zone

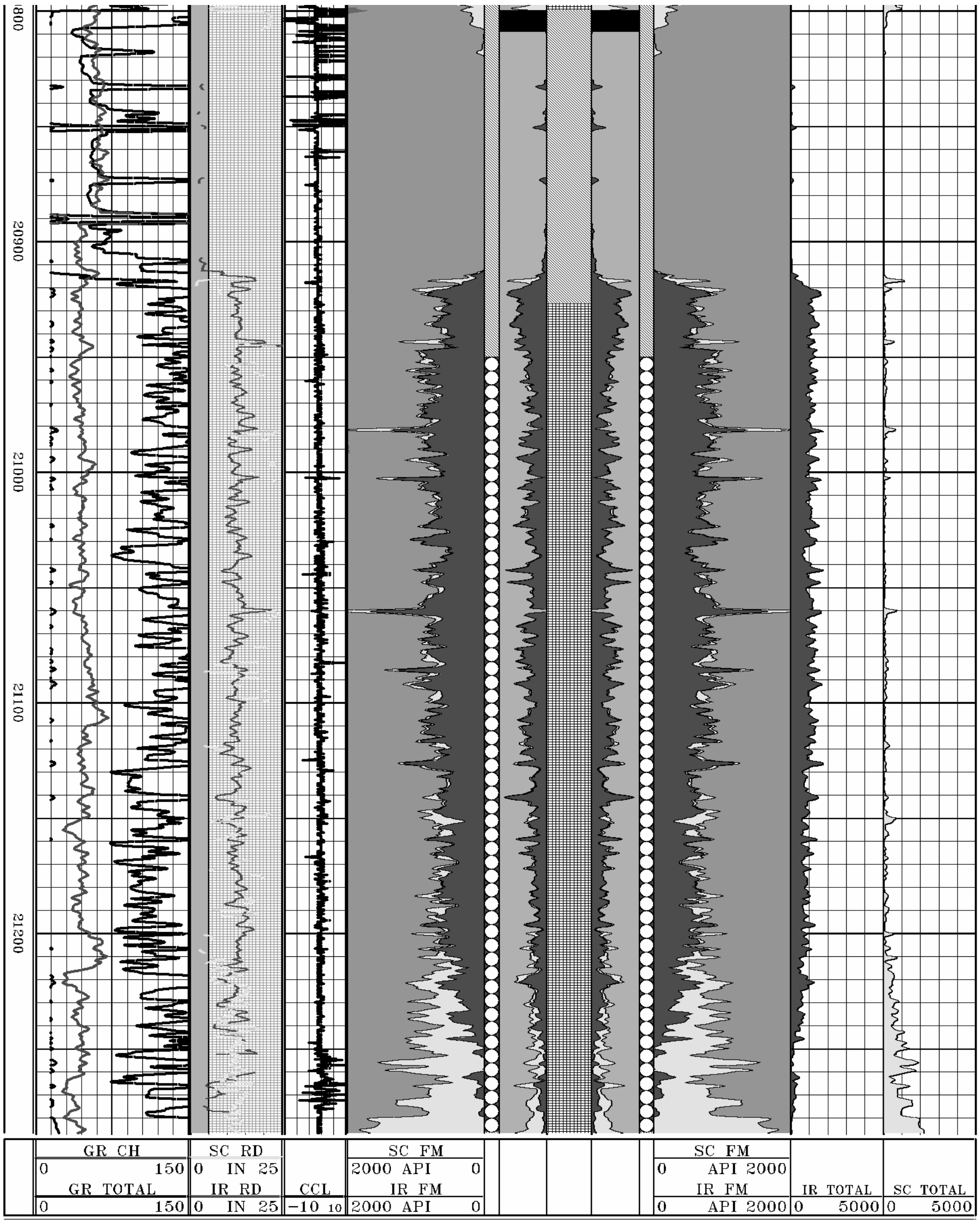

Fig. 13 — Tracer Log for Case History 2

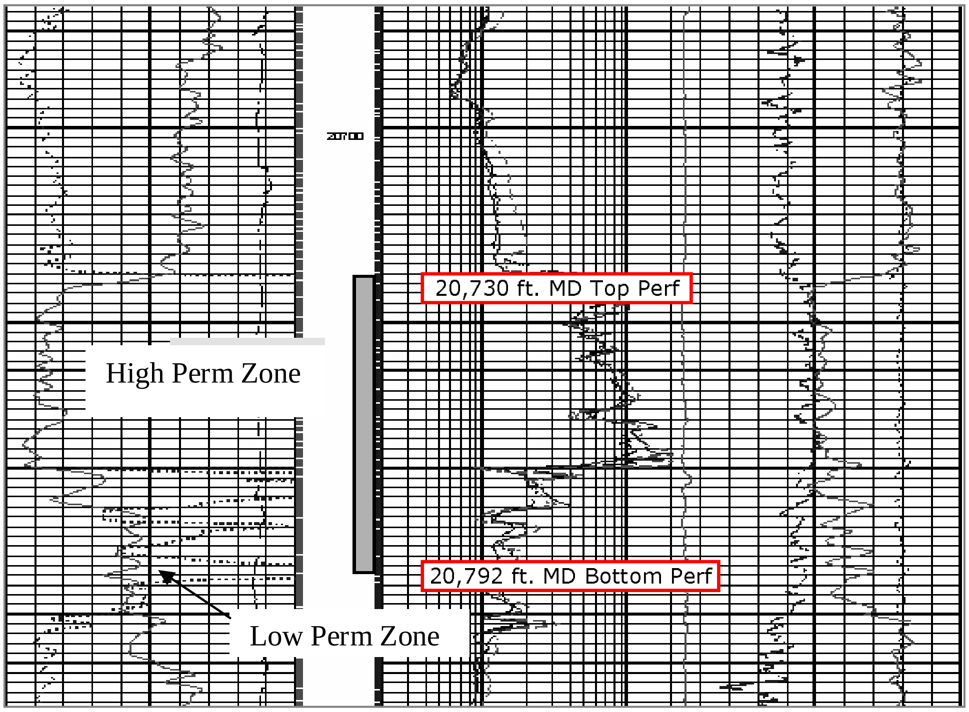

Fig. 14 — Log for the Case History 3

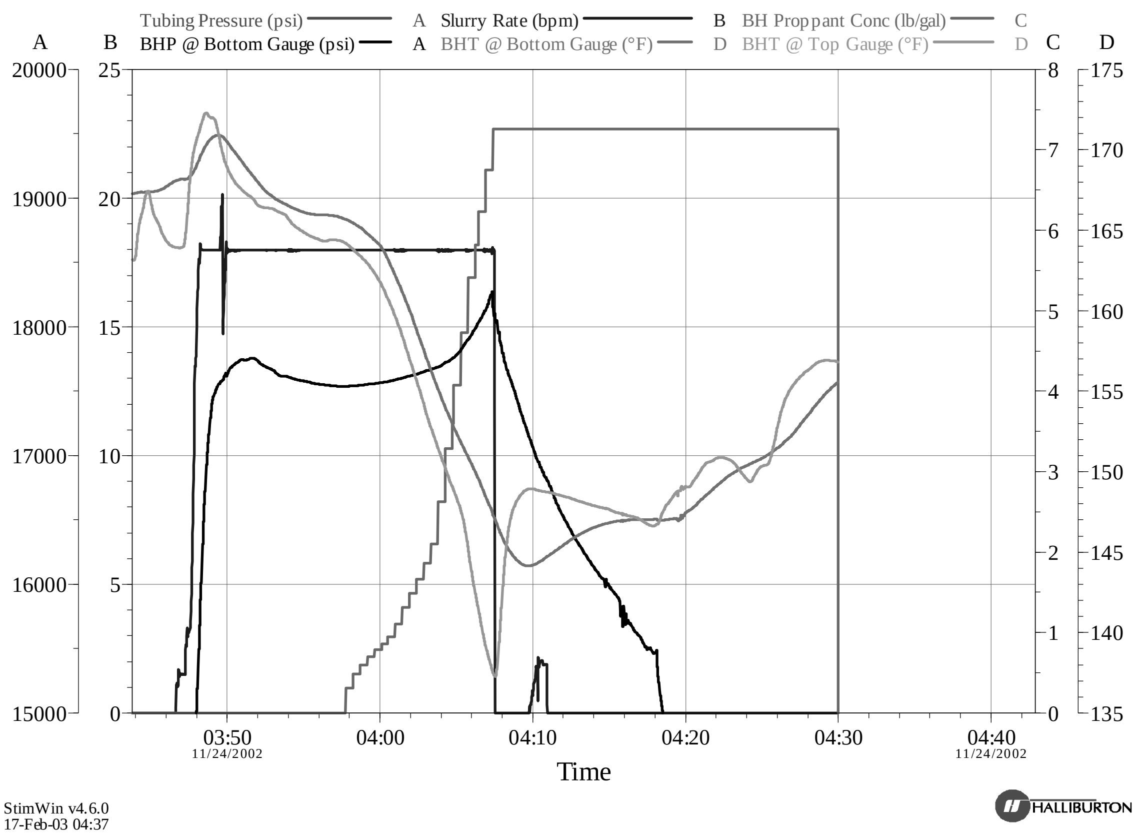

Fig. 15 — Summary of the FracPac for the Case History 3

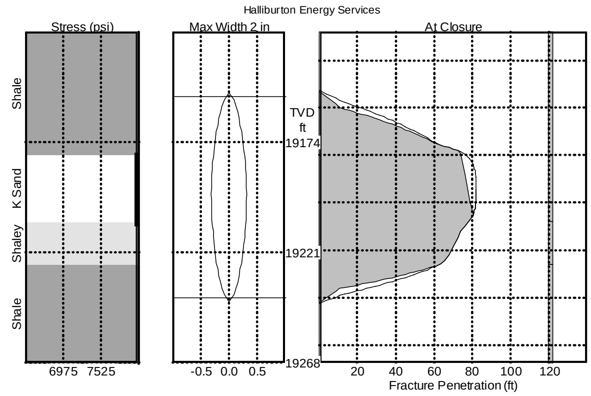

Fig. 16 — Calculated Geometry of FracPac for the Case History 3

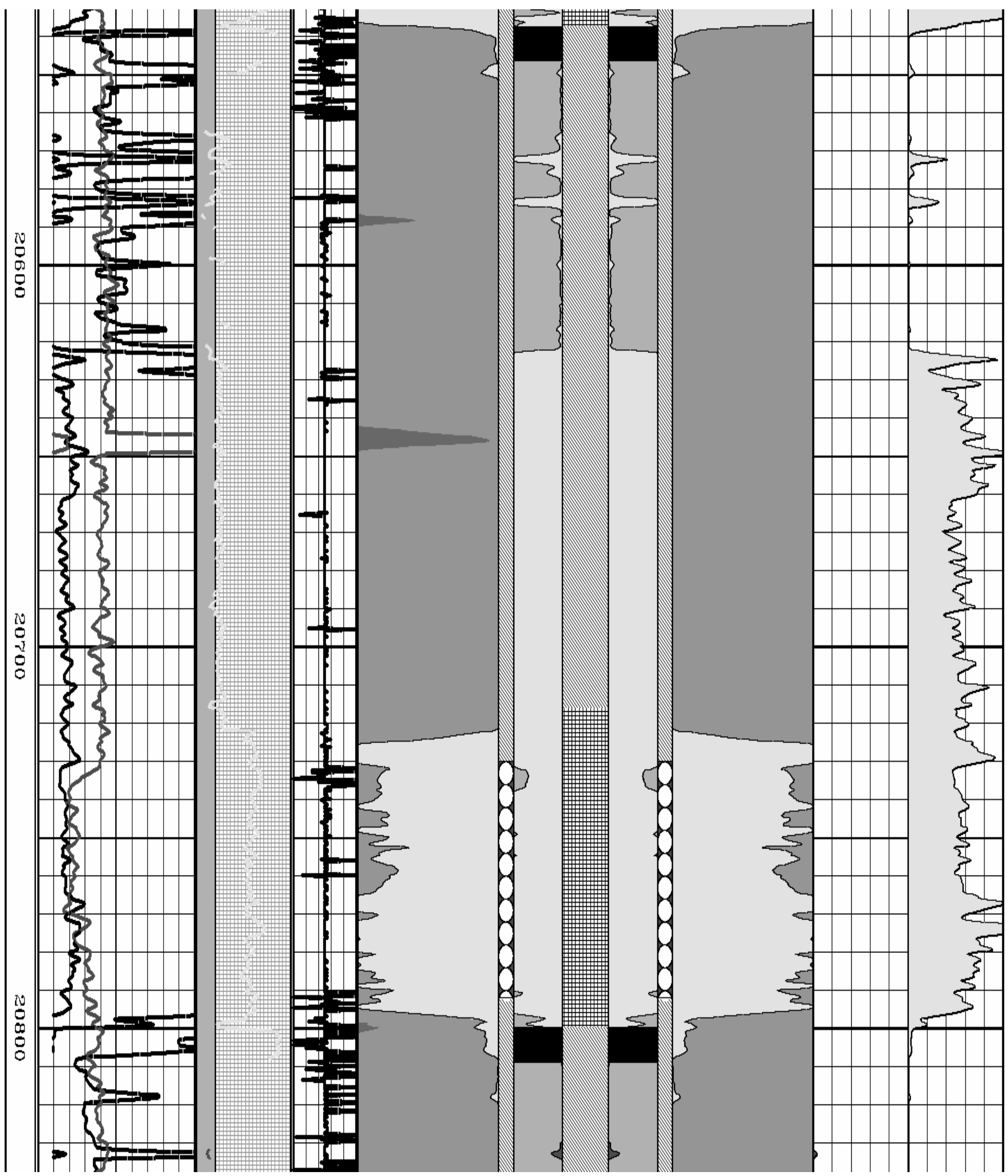

Figure 17 – Tracer Log for the Case History 3