Identification of Candidates for Massive Hydraulic Fracture Treatments in the Spraberry Trend

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Abstract

The first hydraulic fracture treatments in the Spraberry Trend consisted of 1500 gallons of refined oil carrying 1/4 lb per gallon of sand. Since then, the average size of hydraulic fracture treatments has increased significantly to 180,000 gal of fluid and 432,000 lb of sand. The indication from a detailed characterization of the reservoir suggests that in certain cases an increase to over 900,000 lb of sand may be justified to maximize rate of return on investment. This should be combined with limited interval perforating and forced closure to ensure successful execution. Justification for these recommendations will be provided with an integration of the reservoir characterization and 3-D hydraulic fracture simulators.

Introduction

Spraberry/Dean completions have changed little since the mid-1950's with the exception of increased volumes and shifting away from oil based fluids to gelled water. In 1954 a typical job was 21,000 gal of oil based fluid per stage carrying 31,500 lb of sand at 42-56 BPM into the Upper Spraberry open hole interval.[1] In 1975 an average 3 stage treatment consisted of 35,414 gal of gelled brine water per stage with 65,795 lb of sand, or if refined oil was used the average size was 27,033 gal per stage with 51,957 lb of sand.[2] Most operators perforated large intervals (up to 500 ft. per stage) with one shot per foot and treated at relatively high rates down casing to achieve limited entry. During that period the use of refined oil and gelled water was evenly split. In 1992 a typical job consisted of 63,333 gal of gelled water per stage carrying 144,000 lb of sand (**Fig.** 1). Other than the size of the treatment, the only change since then has been the increased use of gelled water. There have been significant advances in reservoir characterization and hydraulic fracture design optimization technology since the first treatments, however very little of this has been implemented in the Spraberry Trend.

The first major advance specific to the Spraberry trend has been a more complete characterization of the reservoir. There have been several studies that discuss this characterization.[3,4,5,6,7,8] The studies demonstrated that natural fractures had an insignificant role in the production of hydrocarbons, and that the matrix permeability and hydraulic fracture geometry determines the productivity. The stimulation treatment required to connect the wellbore to an existing natural fracture system is significantly different from a treatment required to substantially increase the effective wellbore radius. This was recognized by operators through field experience as evidenced by the significant increase in fracture fluid and sand volumes since the natural fractures closed. The second major advance has been the development of three dimensional hydraulic fracture simulators to estimate fracture geometry in reservoirs with weak fracture barriers. Since the mid-1980's these simulators have been available for use on personal computers.[9] When these simulators are combined with 2D reservoir simulators operators can then estimate fracture cost vs expected incremental production. If these two advances are properly applied, major changes in completion design are suggested. These are:

Perforating limited intervals with high shot densities vs limited entry with 1 SPF
Treating each major contributing sand separately
Using the propped fracture to drain minor contributing sands
Increasing sand volumes from 400-500,000 lb to over 900,000 lb
Utilization of forced closure techniques

These will be discussed in detail with supporting arguments.

Reservoir Characterization Advancements

Ref. 10 discussed the role of natural fractures in the productivity of the Spraberry/Dean. The study suggested that the natural fractures were initially open in the early days of development, however they closed as the pore pressure dropped from 0.34 psi/ft to 0.28 psi/ft. The actual performance and the modeling of the eight horizontal well attempts lended further credence to this theory. If the natural fractures were open, the horizontal attempts should have done significantly better than they did. Ref. 10 modeled the performance of some of the wells using matrix parameters alone. With natural fracture permeability relegated to an insignificant role in the deliverability equation, the productivity of the well can be determined by reservoir pressure, matrix permeability and the stimulation treatment. A model for estimating matrix permeability from openhole log data was proposed in **Ref.**

10. The relationship was tied to actual production decline data. A typical relationship for the Dean is provided as **Fig. 2**. **Ref. 10** provided examples in the Dean where this model was used to predict well production. The permeability information can be used to help predict fracture fluid efficiency as well. A distribution of permeability by zone for the Upper Spraberry in Midland County is presented in **Fig. 3**. Further support for this model is provided by several examples from the Spraberry/Dean. These examples can be seen in **Figs. 4** to **6**.

Modeling the Hydraulic Fracture

With the role of natural fractures eliminated and the matrix permeability determined to be relatively low, large hydraulic fracture treatments are necessary to recover economic quantities of oil and gas. The size of the treatment required to maximize the return on investment is a function of reservoir deliverability and fracture geometry. The deliverability of the reservoir with various fracture geometries can be compared to the cost associated with the geometries and an economic analysis made.

A major limiting factor in this process in the past has been the difficulty in estimating fracture geometry. The Spraberry/Dean has relatively few barriers to vertical fracture migration, and this significantly complicates the estimation of fracture geometry. The majority of job designs are made using 2D models and these models require a fixed fracture height input. The 3D models overcome this limitation, and are applicable to the Spraberry/Dean. Extensive work has been done on 3D modeling in the Travis Peak formation of East Texas as part of the Gas Research Institute's Staged Field Experiment. **Ref. 11** has a complete bibliography of the technical papers presented. The Travis Peak is analogous to the Spraberry/Dean in that the barriers are the thin shales, while in the Spraberry/Dean the barriers are thin carbonates. The stress contrasts in the Travis Peak were generally greater than those expected in the Spraberry/Dean, making the Spraberry/Dean an even more suitable candidate for 3D models. **Ref. 12** discusses the use of 3D models in the Spraberry/Dean.

The recommended inputs from the Staged Field Experiment for optimizing completions are discussed by Holditch.[13] The two principal inputs for the 3D models discussed were the permeability-thickness profile and the in-situ stress profile. The inputs for the permeability thickness profile have already been discussed in the reservoir characterization section. The development of the in-situ stress profile is discussed in detail in the Staged Field Experiment literature.[11] The development of an in-situ stress profile for the Spraberry/Dean is provided in Ref. 12.

Integrating the Reservoir Characterization with the 3D Model

Perforation Selection

Perforation recommendations are based on both log derived permeability and in-situ stress barriers. A summation of the log derived permeability values can provide an estimate of how much each porosity lens is contributing. The in-situ stress barriers indicate which lenses should be drained by the propped hydraulic fracture. Recommended perforation phasing has been 3 SPF 120 degree phased of 4 SPF 90 degree phased. This is to maximize the chance that the maximum horizontal in-situ stress plane will be perforated and thus the friction drop will be the lowest when the fracture is propagated. The entry path from the fracture to the perforation during the production phase is most direct as well with this geometry.[14] This is contrary to the common practice in the Spraberry Trend of limited entry perforating over a 200 to 400 ft gross interval with 12-16 holes at 1 SPF. With limited entry perforating over such a large interval, the risk of creating multiple fractures exists.

Creation of Multiple Fractures

The fracture geometries suggested by the 3D model typically approach an elongated penny shape, with higher growth upward than downward. In the example shown for the Dean, (**Fig. 7**), the predicted total height was 500 ft for a created half length of 300 ft. The simulation assumes a single wing on each side of the wellbore to achieve the length indicated. In the Spraberry/Dean length is critical to production due to the low matrix permeabilities. A sensitivity of cumulative production to length for a central Midland Co Jo Mill well is shown as **Fig. 8**. If the fracture fluid is diverted into more than one fracture, the probability is high that the design length will not be achieved. Recent studies have indicated that multiple fracture wings are the rule in treatments rather than the exception. In two studies a horizontal or high angle core was obtained perpendicular to the expected fracture "wing", and the propped fractures were directly observed. In study conducted by Warpinski, et al (1991), multiple fracture strands were observed in a horizontal core in the Mesaverde formation.[15]

In a similar study done by Mobil (Fast, et al) (1992) multiple strands were observed, with the strands perpendicular to the bedding planes and tilted 15 degrees from the vertical.[16] While no horizontal cores have been obtained in the Spraberry/Dean, evidence is abundant that suggests the hydraulic fractures are not vertical. This evidence is seen first in core data, and formation imaging data, both of which indicate that "vertical" fractures are at best 2 to 4 degrees off of vertical and often much higher.[12] (**Fig. 9**). The second set of evidence is in multiple staged fracture treatments where the stages are reasonably close together, yet no evidence of communication is observed on the subsequent stages. This is routine in Reagan County, where four stage and five stage treatments are successfully pumped even though each stage's fracture height overlaps the subsequent stage's by several hundred feet. In one Midland County well a two stage treatment was done in the Upper Spraberry with the stages only 74 ft apart. The second stage successfully pumped with no indication of communication with the first stage, and the well's performance suggested both stages were successfully treated.[12]

One solution to this is to attempt to model the multiple fractures, using techniques that estimate the relative volumes entering the various zones. Elbel (1991) provided a discussion of this.[17,18] Another option is a minimization of the perforated interval, including only the highest log derived permeability interval in each stage. With the use of the permeability thickness profile, the impact of this minimized interval can be estimated prior to the treatment. In many cases, over 80% to 90% of the permeability-thickness can be directly opened with a relatively short perforated interval (**Fig. 10**). This figure displays data from the log presented as **Fig. 11**. If the 40 ft interval from 8510 to 8550 is perforated over 80% of the permeability-thickness will be directly opened to the wellbore. Most operators in the area of this well perforate from 8320 to 8580 or a 260 ft gross interval. If the fracture grows vertically as expected the remaining 10% to 20% of the unperforated pay should be drained by the propped fracture without perforating this large interval and possibly compromising the integrity of the created fracture.

Effect of Proppant Settling

With limited interval perforating comes a potential drawback in the area of proppant settling. With the linear gel systems and long closure times the 2D proppant transport module of the 3D model suggests there is substantial settling, especially at concentrations below 6PPG. A comparison of final proppant distribution for several different job schedules is shown in **Figs. 12** through **14**. The figures illustrate that the percentage of the created fracture that is propped following closure ranges from 24% with a 2

PPG sand concentration to 95% for 6 PPG concentrations. **Fig. 15** summarizes the percentage of zone effectively propped for 2 PPG to 6PPG final concentrations for an 8500 ft Jo Mill zone. Most wells are fractured with a maximum of 4 PPG, resulting in only a 61% coverage of the created fracture. Operators that pump final concentrations less than 6 PPG probably achieve reasonable results in the Dean and Jo Mill due to the concentration of kh in the lower portion of the created fracture (**Fig 11**). **Figs. 16 and 17** illustrates the estimated conductivity profile for both the 2 PPG final concentration and the 6PPG concentration. The 2PPG final concentration achieves similar results in terms of both length and conductivity over the effective propped length. The primary difference is the 2 PPG treatment has a propped height of 127 ft compared to the 6 PPG treatment's 473 ft of propped height. Both treatments meet the requirements of a minimum of 300 Md-ft as demonstrated by **Fig. 18**. The increase in coverage by the higher sand concentrations is largely a result of the increased viscosity observed by Shah.[19] Shah proposed a series of correlations for linear gel systems, estimating the effect of sand concentration on both n prime and k prime. Application of these correlations has significantly improved the ability to model the performance of the linear systems. Prior to using the correlations, the 3D simulator routinely predicted premature screenouts with linear systems. With the correlations applied, excellent agreement has been obtained with predicted and actual job treating pressures.

With the commonly used multiple zone limited entry techniques all perforated zones are probably propped, however most have relatively short fracture lengths. The most likely scenario is an opening of all zones with fluid due to limited entry, with a screening out of zones with higher fracture gradients early in the sand schedule. With the limited interval perforating some upper unperforated zones may be unpropped. If the kh distribution indicates a major contribution, a separate stage may be warranted. If the kh distribution indicates a minor percentage of contribution from these upper zones, this may not be a major issue. If it falls somewhere in between, the limited interval perforating and normal settling may leave appreciable reserves behind.

There are two solutions to the settling problem expected with limited interval perforating. The first option is to increase the sand concentrations during the job as **Figs. 12 to 14** suggest. The second option is to conduct forced closure at the end of the job to speed the closure process. With the permeability inputs an estimate can be made of closure time, and in most cases the time is from six to ten hours even with low viscosity fluids. The concept of forced closure is discussed in **Refs. 20** and **21**. In addition to the minimization of proppant settling, forced closure creates a "reverse gravel pack" that minimizes sand production during the life of the well. Sand production after completion is a common problem, so much so that some operators have resorted to overflushing as a solution. The fact that wells produce any fluid at all following an overflush is evidence that post-flush crossflow is probably taking place between the multiple fractures. If only one fracture was created, the relatively incompressible frac fluid would be flowing back into a closed system created by the frac bomb sealing off the lower zone as the next stage was treated.

An additional benefit of forced closure is the removal of some of the potentially damaging gel from the fracture. A second finding of the horizontal core study done by Warpinski was unbroken 40 lb gel after 6 years of production.[15] Once the proppant has been placed the fluid serves no useful purpose, and as much as possible should be removed (provided the zone will flow back). In some cases zones will only flow back for a brief period prior to going on a vacuum. Given the volumes of fluid pumped, the low permeability matrix, and long closure times, a single fracture should have a significant increase in apparent pore pressure increase following the job that would provide sufficient energy to promote flowback at least enough to create the "reverse gravel pack" discussed earlier. The post-treatment crossflow between the multiple fractures created by limited entry most likely contributes to the limited flow back volumes observed at the surface.

The primary disadvantage is the entry of sand into the wellbore that can interfere with the baffle ring stage diversion operations. This is minimized when limited interval perforating is used, as it increases the separation between stages significantly. In a Midland County example the separation between the Jo Mill perforations and the Upper Spraberry was less than 200 ft with the conventional "limited entry" techniques but over 450 ft with limited interval technique. A possible option to consider instead of the baffle ring staging technique is the "Pine Island" technique discussed by Holditch.[22] This involves the use of sand plugs to divert subsequent stages. The sand produced with the forced closure technique could be used to initiate the plug, with additional sand added if necessary. Additional rig time may be involved to allow for the sand to settle, verify the sand placement with a wireline dummy run, and to perhaps clean out excess sand with tubing. These wells are assets that will generate revenues of over $1.2 million and produce from 20 to 30 years (based on the 70,000 BO average and associated gas revenues). Investing an additional $10,000 in rig time to ensure all zones are properly drained is worthy of consideration.

Fluid and Proppant Schedule Optimization

The optimum fluid based on several comparative studies to date is the linear gel, with the polymer loading varied depending upon temperature. Typically 40 lb systems are recommended in the Dean and Jo Mill in the deeper parts of the basin, with 30 lb systems satisfactory for the Upper Spraberry. A plot of temperature vs depth based on a regression of openhole log measured temperatures is provided as **Fig. 19**. The relatively low viscosities result in lower height growth than the crosslinked or polyemulsion systems, and if a high enough sand concentration is used the settling is minimized and adequate width is created. The linear systems are also less expensive than the crosslinked systems. The polyemulsion systems are less expensive than both water based systems, however the additional horsepower charges can offset the fluid cost savings. The rheological properties of the polyemulsions are not well characterized in the literature, particularly with regard to the effects of sand on viscosity. The integration of the 3D fracture design model with the reservoir characterization provides a platform to evaluate the impact of each of these variables, and comparisons can be made among the three fluids to determine the optimum for each situation.

The optimum proppant schedule can be determined using the previously discussed guidelines. A minimum of 300 to 400 Md-ft of conductivity should be planned over the maximum interval possible. As **Figs. 12** through **14** indicated, low sand concentrations are of limited value due to settling problems. The maximum concentration should therefore be attained as soon as possible following the pad. An example of such a ramp schedule is shown in **Fig. 20**. The maximum concentration required to obtain the target conductivity with minimum settling varies with depth and closure stress, however in general the Dean and Jo Mill/Lower Spraberry require at least 5.5 to 6 PPG and the Upper Spraberry 4.5 to 5 PPG. These relatively high concentrations are easier to pump with limited interval perforating than with limited entry perforating. Over 75 such steep ramps have been pumped to date with no premature screenouts.

Estimation of Internal Rate of Return

Using the above methodology a range of fracture treatment sizes are simulated. With each treatment a propped fracture length (defined as having more than 300 mdft of initial conductivity) and an average fracture conductivity are output. Using a combination of the permeability thickness profile and the propped fracture height, an estimate of effective permeability thickness drained is input to the 2D reservoir simulator. The PVT properties of the reservoir (producing both oil and water) are calculated using standard correlations. From these inputs a 10 year production decline is simulated using the effective permeability to reservoir fluids. Based on the expected average water cut in the area studied, a decline for the oil phase is forecast. Each size treatment has a corresponding cost involved, and this can be estimated through an economic module or through a spreadsheet routine.[23,24] The inputs required are proppant cost, fluid cost, horsepower cost, and miscellaneous fixed charges for each stage. The 3D fracture simulator can estimate the horsepower required to pump the stage in question, and the rest of the inputs can be obtained from the service company or the operator. The total well costs are input to the routine, along with expected lease operating expenses, severance taxes, and product prices. With multiple stages these costs are allocated based on expected reserve contributions. The output of the module is a rate of return on investment and payout for each job size considered in each stage (**Figs. 21 and 22**). The optimum job size can then be determined using the rate of return criteria. In most cases, zones with adequate permeability-thickness to merit completion have optimum lengths in excess of 400 feet. The fluid volumes required to achieve this length is typically from 70,000 to 90,000 gal per stage. Total sand volumes in excess of 900,000 lb are required to achieve a minimum of 300 Md-ft conductivity over the majority of the created fracture length. Not all wells are candidates for this size treatment, as the permeability-thickness varies significantly from area to area across the Spraberry Trend. The integrated analysis can identify the candidates for the larger treatments, and it can also identify which zones should not be completed. In several areas the recommendations have been made to avoid completion of zones with insufficient permeability to recover the cost of the stimulation. Notable examples have been the Upper Spraberry in certain parts of Martin County, the Dean in certain portions of Midland Co., and the Jo Mill in Glasscock and Eastern Reagan Counties.

Field Examples

Fig. 23 compares the actual production of 17 wells to simulated production using the log derived permeability and the 3D model inputs of conductivity and created length. All of the wells are in the same field over a four section area and a cross section of log derived permeability indicated homogeneity. Wells that were drained by offset production were not considered. The production model was developed from correlations near this field, and the ability to match production has been shown (**Figs. 4-6**) and **Ref. 10**. The log derived permeability distribution suggested a completion was warranted in the Jo Mill, Driver Sand, and Floyd Sand, with the Driver and Floyd sands in the Upper Spraberry. The Dean was not productive in the area. The 3D model suggests that a 400 ft fracture with 300 Md-ft of conductivity can be created with 190,000 gal of fluid and 719,000 lb of 20/40 sand. The model suggested that 20 year production from such a fracture geometry would be 116,222 BO. Several wells were within 20% of this in terms of extrapolated decline, but many are significantly lower. The median extrapolated production from the 17 offsets was 65,568 BO over 20 years, with a range from 30,159 BO to 87,092 BO. This is reasonably close to the 70,000 BO average 25 year production observed for all Midland County wells.[1] This comparison indicates significant potential for the area based on the proper application of the 3D technology and reservoir inputs. This is supported in part by the performance of one well in the field that was perforated and completed using the limited interval perforating technique and taking advantage of the deviated fracture theory. The well was completed in two stages 74 ft apart in the Upper Spraberry alone. All of the offsets were completed in one single stage over a 200 ft interval. The well has performed significantly better than offsets completed in all 3 main zones over the first 12 months of production.

The second example was an application of the 3D technology and the optimization process. The above methodology was employed on a well in Irion County, Texas. The well was the 9th well on a one section lease, replacing a 80 acre proration unit well that was prematurely plugged. Production was expected to be in the 30 to 40 BOPD range based on offset performance. The offset 80 acre development wells were treated in 3 stages with an average of 32,200 gal of fluid and 82,200 lb of sand per stage. The designs either used a 2D model with minimal height growth expected or no model. Each stage was perforated with 1 SPF using limited entry over a 519 ft average interval per stage. The optimized design using the 3D model recommended an average of 63,300 gal and 126,700 lb of sand over a 126 ft interval per stage perforated 3 SPF 120 degree phased (**Figs. 24 and 25**). The production comparison is shown in **Fig. 26**. The average 3 month production rate for the 5 offset wells was 18.2 BOPD compared to 100 BOPD for the optimized well. The combined production of all 5 offsets was 91 BOPD, or only slightly less than the total from the optimized well alone.

Conclusions

Candidates for massive hydraulic fracture treatments can be identified by integrating 3D hydraulic fracturing models with a characterization of the reservoir based on openhole log data in the area of proposed development. Wells that are suitable candidates should be completed using high shot densities over limited intervals. Limited entry is not recommended due to the high probability multiple fractures will be created. Whenever possible all major producing sands should be completed separately. High sand concentrations are recommended to minimize proppant settling and to provide adequate conductivity over the life of the reservoir. Forced closure should be considered to minimize settling, remove gel residue, and to limit sand production over the life of the well. The results of this integrative process can be more effective completions and improved recovery over the life of the well.

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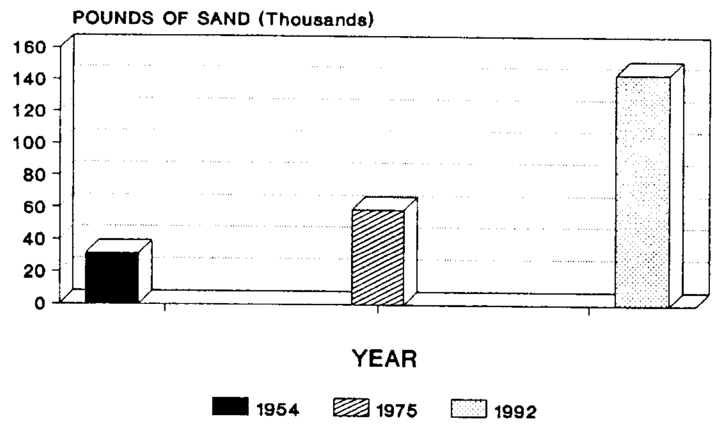
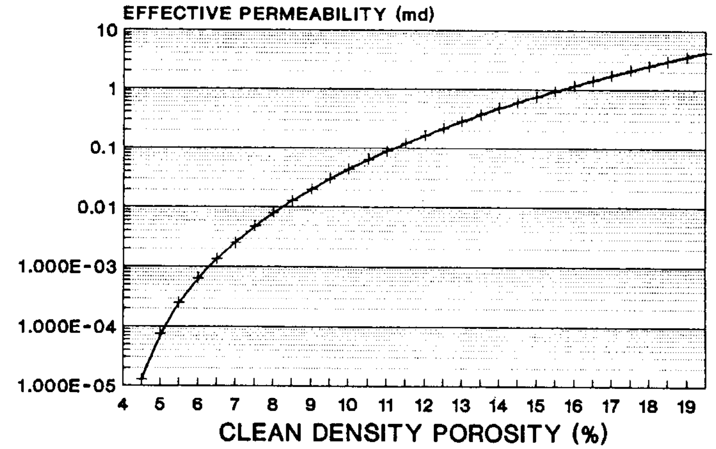


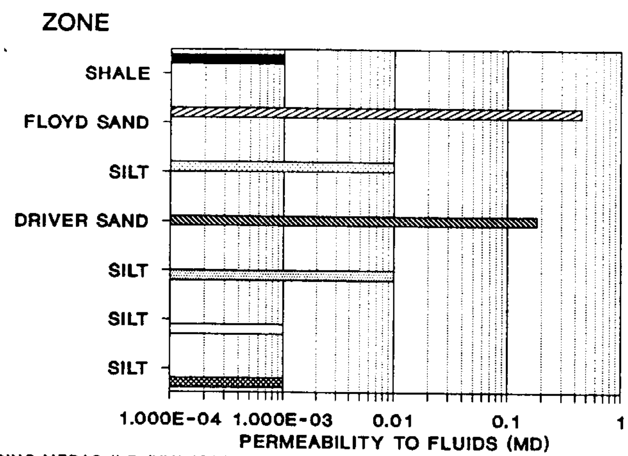
AVERAGE VOLUME PER STAGE

Figure 1 - Historical sand volumes
Midland basin Spraberry/Dean



FROM HISTORY MATCH TO PRODUCTION

Figure 2 - Dean porosity vs. permeability
Midland Co. 8500 ft



USING MFRAC-II 7 AVAILABLE LAYERS

Figure 3 - Leakoff perm distribution
Upper Spraberry, Midland Co.

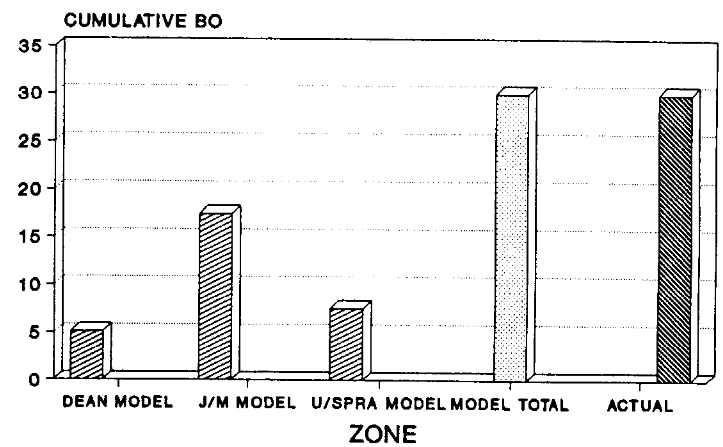


Figure 4 - Model vs. 4 yr. cum. oil
Martin Co. Sprayberry/Dean

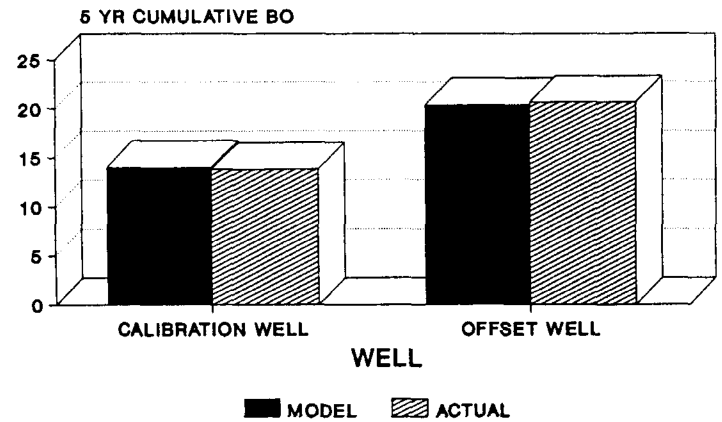


Figure 5 - Rocker B Spraberry/Dean model vs. actual production

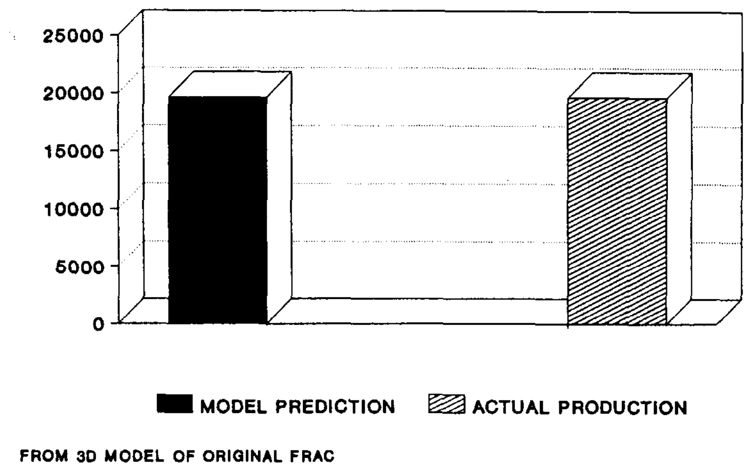


Figure 6 - Model vs. 2 yr. cum. oil Midland Co. Upper & Lower Spraberry

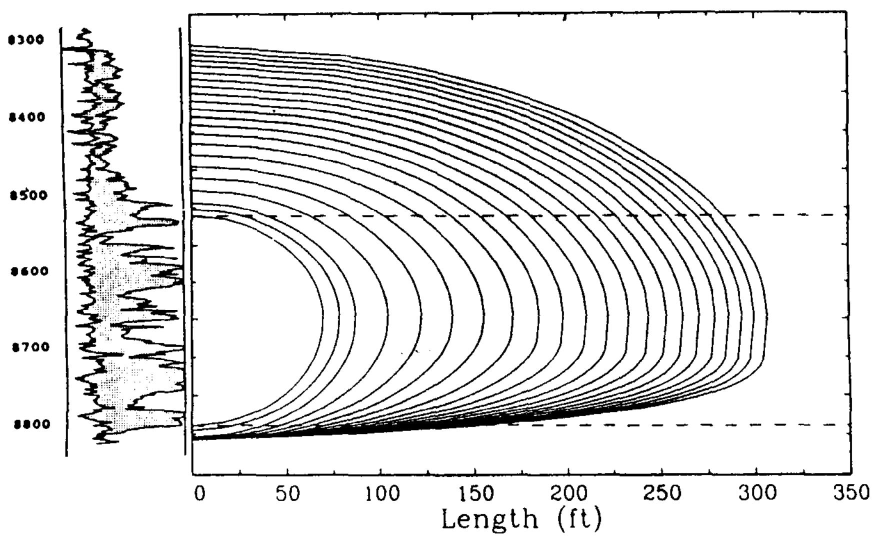


Figure 7 - Dean well I 3D frac geometry

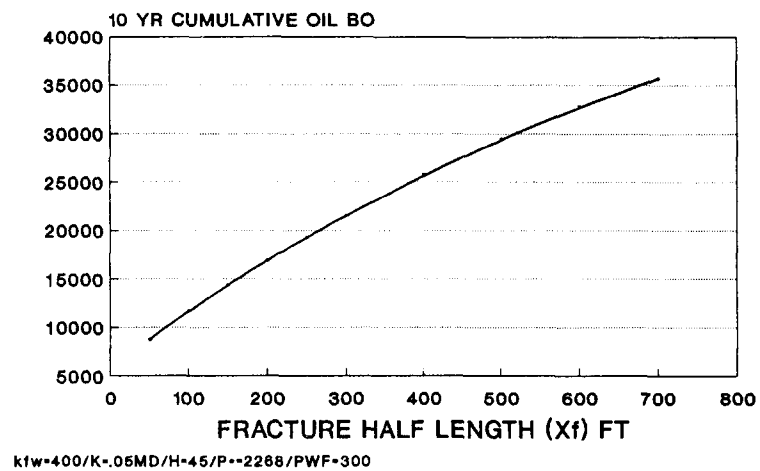


Figure 8 - Midland Co. Jo Mill cumulative oil vs. frac length

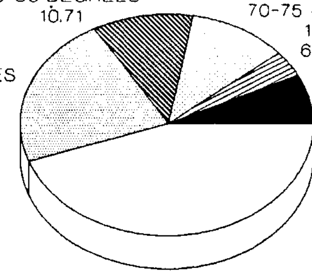


Figure 9 - Fracture dip distribution
Spraberry oriented core

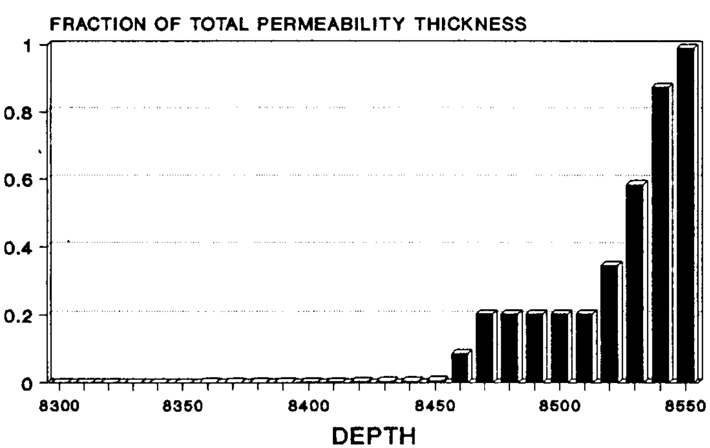


Figure 10 - KH distribution vs. depth
Midland Co. Jo Mill example

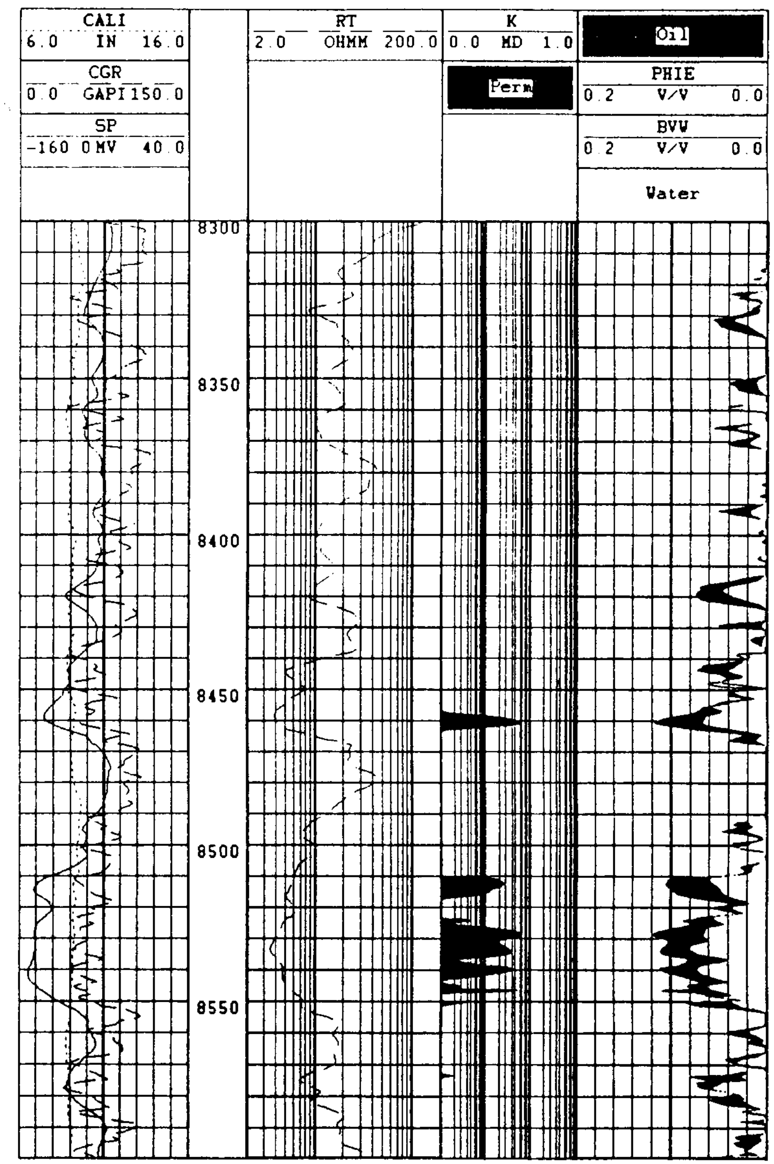


Figure 11

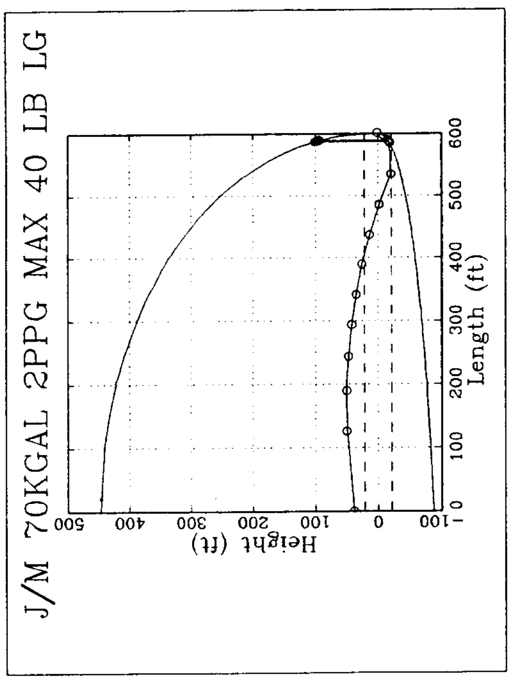


Figure 12

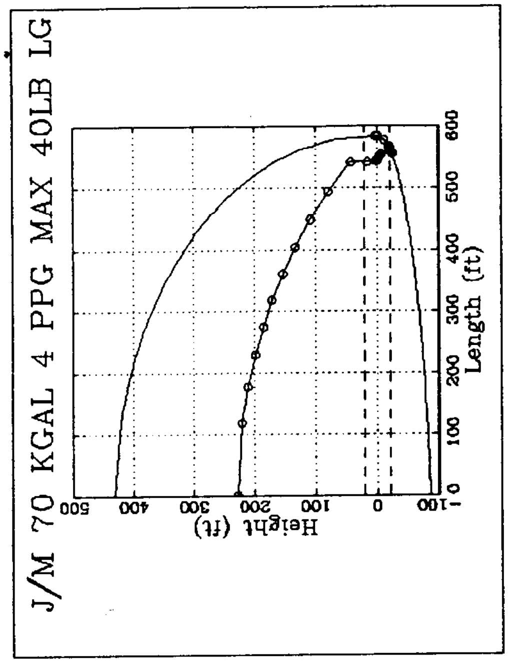


Figure 13

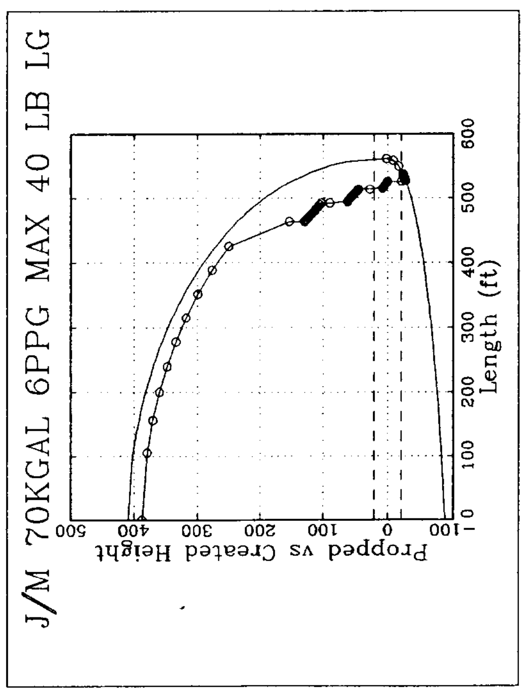


Figure 14

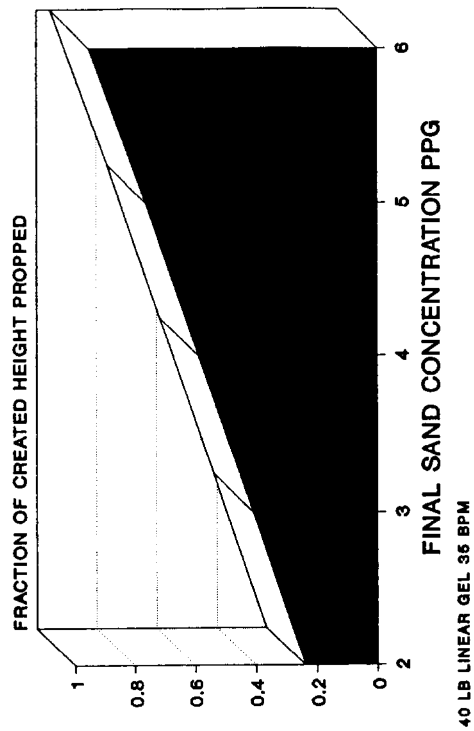


Figure 15 - Propped vs. created height
Midland County Jo Mill sand

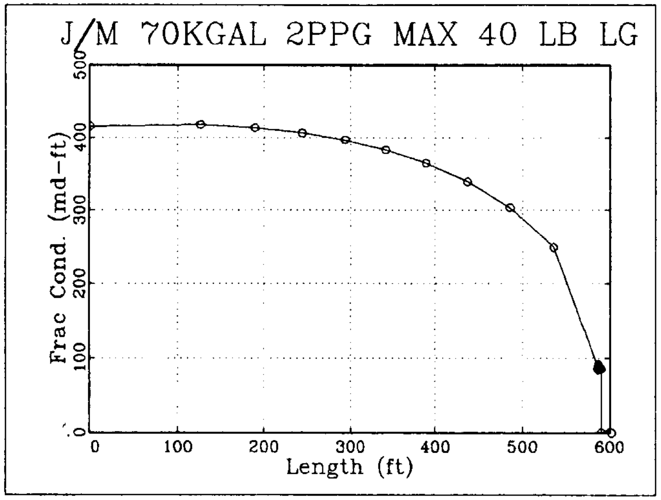


Figure 16

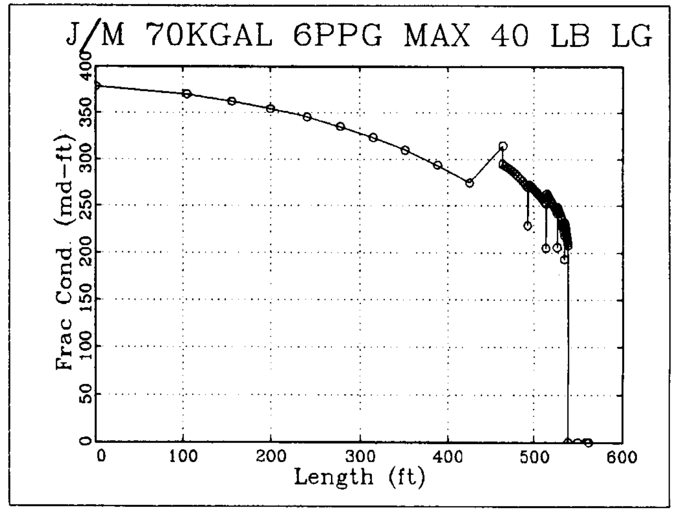


Figure 17

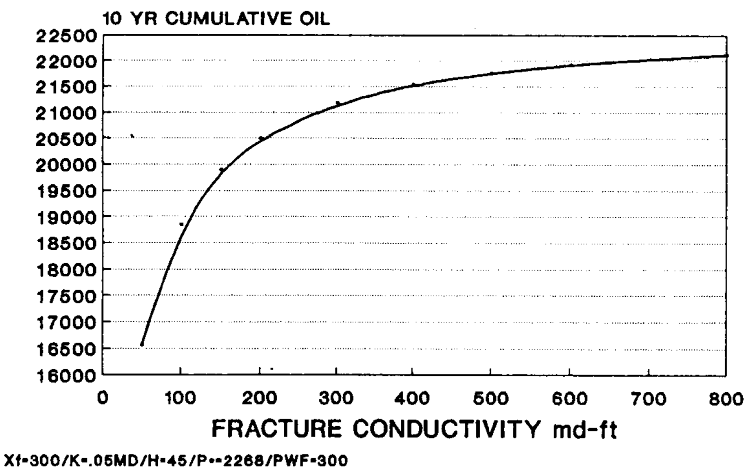


Figure 18 - Midland Co. Jo Mill
cumulative oil vs. conductivity

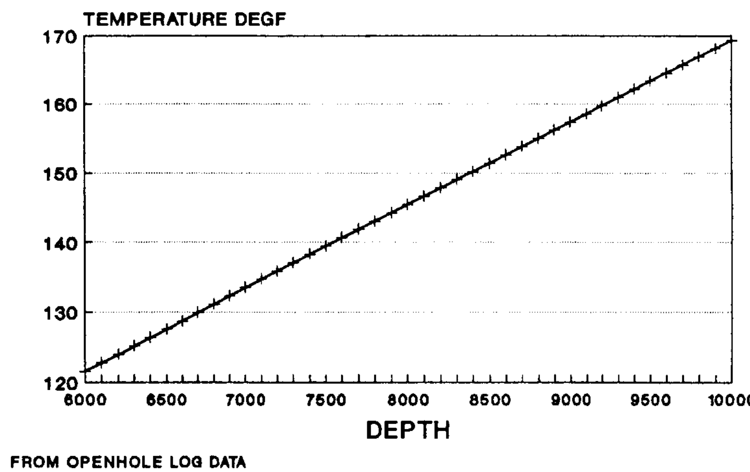
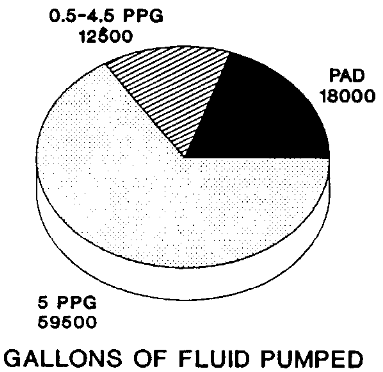
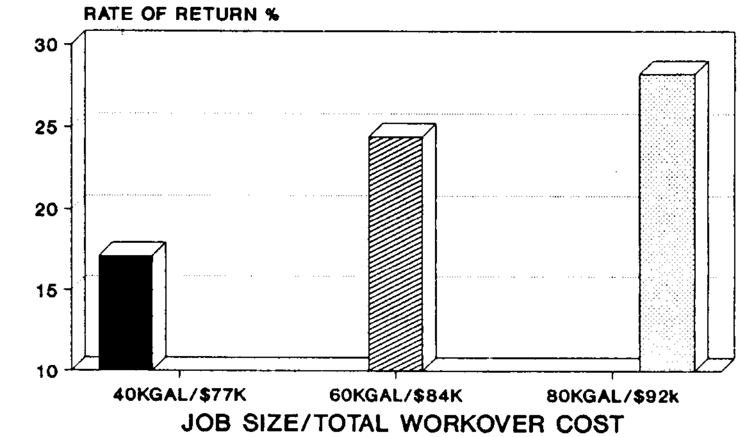


Figure 19 - Temperature vs. depth
Midland basin Sprayberry/Dean



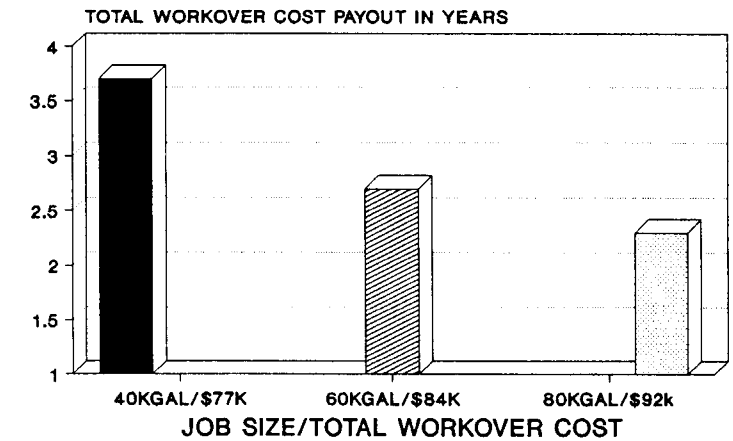
90,000 GAL 40LB LINEAR GEL 40 BPM

Figure 20 - Recommended ramp schedule
Reagan Co. Dean formation



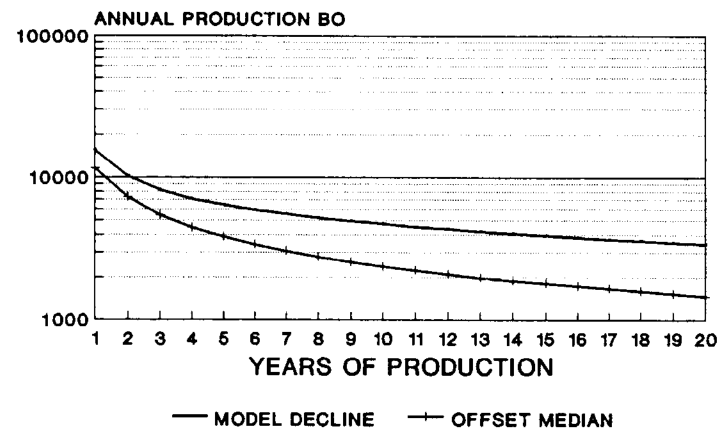
PERMEABILITY FROM LOG/PRODUCTION MATCH

Figure 21 - Rate of return vs. job size
Martin Co. Lower Spraberry



PERMEABILITY FROM LOG/PRODUCTION MATCH

Figure 22 - Well payout vs. job size
Martin Co. Lower Spraberry



MEDIAN OF 17 OFFSET WELLS MIDLAND CO

Figure 23 - Model vs. offset declines
Model 400 ft. Xf/300 MDFT KFW

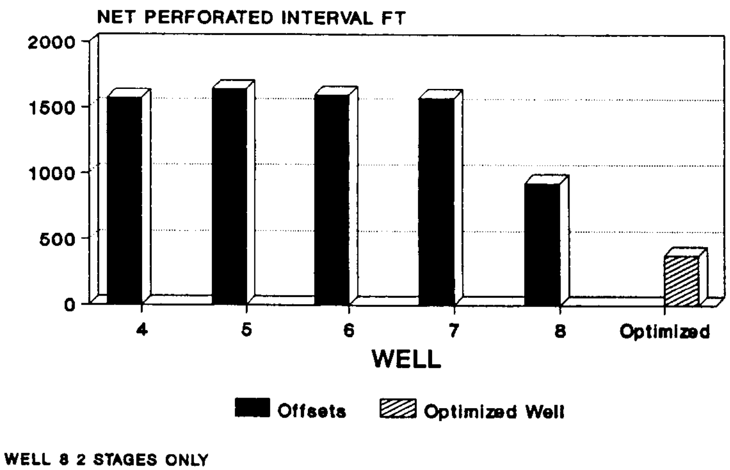


Figure 24 - Optimized well vs. offsets
net perforated interval

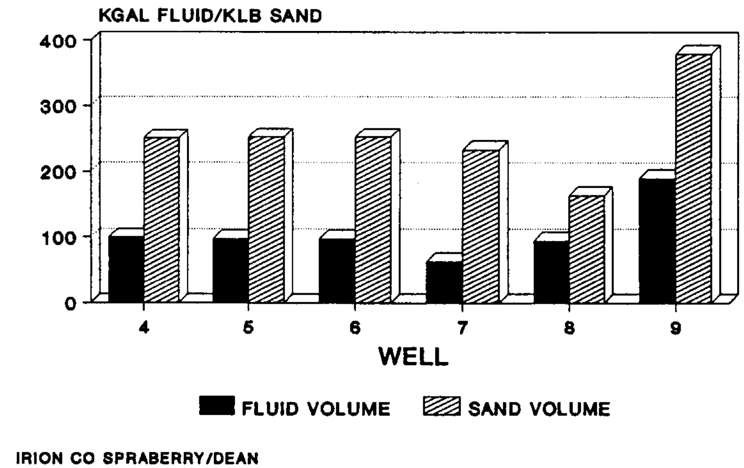


Figure 25 - Optimized well vs. offsets
fluid and sand volumes

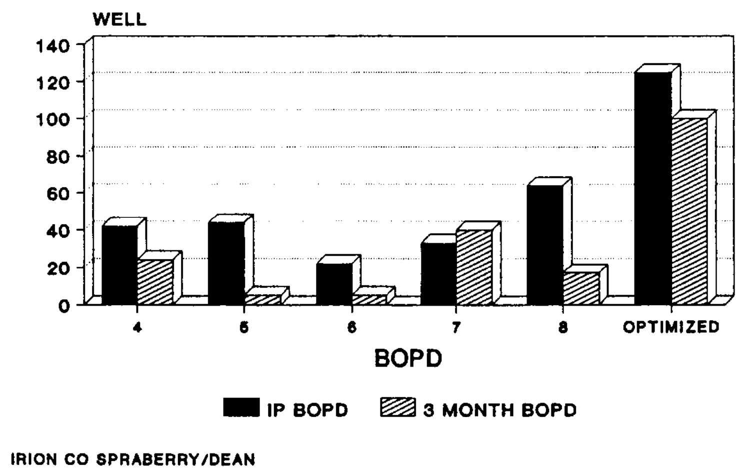


Figure 26 - Optimized well vs. offsets
initial production comparison