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Integrating Wireline Data With Three-Dimensional Hydraulic Fracture Simulators in the Spraberry Trend

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Abstract

Two-dimensional hydraulic fracture simulators are used to design the majority of hydraulic fracture treatments in West Texas. These models assume a fixed hydraulic fracture height. In many cases, hydraulic fracture treatments often do not stay confined within a fixed height as the two dimensional models assume. In the Spraberry/Dean siltstones of West Texas there are no strong barriers to vertical fracture migration, and two dimensional models are clearly inappropriate. Three dimensional hydraulic fracturing simulators overcome this limitation of a fixed height by calculating the fracture height. The inputs required are considerably more involved, and the 3D models require data from both the pay sands and boundary layers. If the raw input data are not available or if sufficient engineering effort is not invested the model output may be misleading. Wireline logs can provide valuable inputs to these three dimensional simulators. These inputs will be discussed, along with case studies where the inputs helped optimize the completion design.

Introduction

The Spraberry Trend of West Texas is a low permeability siltstone oil reservoir located in the heart of the Midland Basin (Fig. 1). It is over 120 miles long and 30 miles wide in some portions, making it one of the world's largest oilfields. Well depths range from 7000 to 9500 ft., with well costs from $275,000 to $400,000. The average reserve recovery in Midland County is 70,000 BO over 25 years.[1] Most wells in the trend require hydraulic fracture treatments to produce economic quantities of oil and gas, with a typical job averaging 180,000 gal of fluid and 430,000 lb of sand. The range of matrix permeabilities encountered is from 0.01 to 0.05 Md in the Dean to 0.1 to 0.2 Md in the Upper Spraberry.[1] The boundary rock is primarily dirtier siltstone interspersed with 2 ft. to 4 ft thick carbonate stringers. A type log of the upper boundary for the Dean is shown as Fig. 2. Mechanical properties logs, tracer surveys, and pressure data all suggest that there is extensive vertical height growth during the treatment. A Poisson's ratio distribution can be seen in Fig. 3. This is supported by a post fracture radioactive tracer survey indicating the minimum height growth of the fracture (Fig. 4). The surface treating pressure profile and the corresponding decreasing pressure on a Nolte-Smith plot of calculated bottomhole pressure provides additional support. (Figs. 5 and 6). Similar pressure profiles have been observed on over 200 treatments over the last 8 years.

The mechanical properties contrast is similar to the Travis Peak, a formation studied extensively in the Gas Research Institute sponsored Staged Field Experiment. In the Spraberry/Dean the pay zones have a Poissons Ratio of 0.21 to 0.22 and the barriers have a Poisson's Ratio of 0.27 to 0.30. The Travis Peak sandstone pay zones have a Poisson's Ratio of 0.18 to 0.20 and the shale barriers have Poisson's Ratios of 0.28 to 0.30. The barriers in the Travis Peak are typically shales with a minimum of 4 ft thickness for downward growth restriction and 8 feet for upward growth restriction.[2] The barriers in the Spraberry/Dean range from 2 ft. to 4 ft. thick, as Fig. 3 illustrates. The majority of the barriers observed are in the 2 ft. category. Based on these comparisons, a Spraberry/Dean fracture should be expected to encounter even less confining stress than a Travis Peak fracture. Given the volumes of work that discuss the necessity and applicability of 3D models to the Travis Peak, the Spraberry/Dean is an even stronger candidate for the use of a 3D model.[3]

Three dimensional models have been used since the early 1980's. They are considerably more complex than 2D models, and initially required the use of mainframe computers to execute. With advances in microcomputer hardware in the mid 1980's, 3D models were ported to PC platforms and became more accessible to the practicing petroleum engineer.[4] As of this date, most major stimulation service company engineers and the majority of major oil company engineers have access to 3D models. Although the 3D models are readily available, a 1990 Gas Research Institute study indicated that only 15% of all treatments were being designed using 3D models and that 56% of engineers responding had never used a 3D model (Fig. 7).[3] This survey was conducted to evaluate the effectiveness of the technology transfer to industry from the GRI sponsored Staged Field Experiment. The Staged Field Experiment was a comprehensive study that focused on integrating geological, petrophysical, testing, and pumping inputs to optimize 3D stimulation designs in low permeability gas reservoirs. The GRI study indicated that only 15% of the survey respondents felt that they had sufficient expertise to accurately evaluate the created dimensions of a hydraulic fracture. The Staged Field Experiment provided an excellent framework for acquiring this expertise, and the methodology employed in this study is based on this framework.

The recommended inputs from the Staged Field Experiment for optimizing completions are discussed by Holditch.[5] The two principal inputs for the 3D models discussed were the permeability-thickness profile and the in-situ stress profile. The first objective of this study is to demonstrate that the critical 3D model inputs can be obtained from available data in the Spraberry trend. The second objective is to demonstrate that 3D models can help operators design better treatments in the Spraberry/Dean that will result in improved economics for the trend.

Critical Three Dimensional Model Inputs

Development of the Permeability Thickness Profile

In the Staged Field Experiment a comprehensive study was conducted to estimate permeability from wireline porosity data. Over 2000 core plugs were analyzed under simulated in-situ conditions to develop a correlation that could be used in a permeability thickness profile.[6] The relationship developed in the study for siltstones was:

$$k_{inf}\,NOB = 3.52*10^4 * PHIE^{5.81} \qquad (1)$$

where:

$k_{inf}\,NOB$ = gas permeability at net overburden

PHIE = Effective porosity

The conversion to brine permeability was made with the following relationship:

$$k_w NOB = 0.52* (k_{inf}\,NOB)^{1.13} \qquad (2)$$

where:

$k_w NOB$ = brine permeability at net overburden

A similar technique was employed in the Spraberry Trend.[1] The process involved the integration of openhole wireline data and production data, with the 3D hydraulic fracture model used to estimate the created fracture geometry to facilitate a history match. Decline data was used in lieu of core data or pressure transient data due to the difficulty in obtaining usable data. One of the history matches is shown in Fig. 8. Openhole density log and gamma ray data were used to estimate the effective porosity, and a modified Coates-Denoo relationship was used to estimate effective permeability. The basic relationship used was:

$$k=(C * PHIDCL^2 * (PHIDCL-BVW_{irr})/BVW_{irr}))^2 \qquad (3)$$

where:

k = effective permeability to fluids

C = constant

PHIDCL = clean density porosity

BVW_{irr} = Bulk Volume Water Irreducible

This permeability estimate is compared to the apparent effective permeability from a combination of the decline data, 3D hydraulic fracture geometry estimate, and a 2D reservoir simulator.[7] An example of the output for a Jo Mill well in Midland County is presented as fig Fig. 9. The permeability thickness profile indicates the permeable intervals for use in both fluid efficiency estimates and productivity estimates in the optimization process. The permeability to brine is used for leakoff estimation and the permeability to oil for productivity estimates.

Validation of the technique is the ability to predict production declines on offset wells. Three examples are presented from Martin, Midland, and Reagan Counties. In all three examples the log derived kh and the estimated fracture geometry from the treatments pumped treatment were combined to predict the initial production declines using the 2D reservoir simulator (Figs 10-12). Two additional examples from the Dean in Midland County are presented in Ref 1. In all examples the agreement is shown to be excellent.

Development of the In-Situ Stress Profile

If possible, a series of microfrac treatments should be conducted to determine the in-situ stress distribution the hydraulic fracture may encounter. This was done extensively in the Staged Field Experiment.[3] In most cases this is not available, and a correlation must be made to the information that is available. A model for estimating mechanical properties from petrophysical data was proposed by Ahmed et al (1985).[8] The Staged Field Experiment confirmed that excellent correlations could be obtained between petrophysical inputs and in-situ stress test data.[9] A poroelastic model was used that related an acoustically derived Poisson's Ratio and pore pressure to measured stresses. The same input data has been available for the Spraberry/Dean, with several studies available that validated the effectiveness of the technique.[10,11,12] The relationship used in the Spraberry/Dean is:

$$F.G. = v/(1-v)*OBG + (1-(v/1-v)) * Pp + Ptec \qquad (4)$$

where:

F.G. = Fracture gradient (psi/ft)
v = Poisson's Ratio
Pp = Pore pressure gradient (psi/ft)
Ptec = Tectonic offset
OBG =Overburden stress gradient (psi/ft)

The original studies relied extensively upon the use of full wave acoustic data,[8,9] however a re-evaluation of the data following analysis of over 600 mechanical properties logs indicated a strong correlation between lithology and Poisson's Ratio. Lithology has always been used as a quality control on the measured Poisson's Ratio from the full wave acoustic data. A summary of these correlations can be found in Fig. 13. Based on these observed correlations, a Poisson's Ratio distribution can be estimated for a Spraberry Trend well where sufficient log data are available to identify the carbonate stringers. This can be done in the Spraberry Trend due to the net pay and the majority of the boundary layers being comprised of siltstones, and the barriers being the carbonate stringers. In other sandstone formations with siltstone and shale barriers this correlation may not be valid due to the variation in Poisson's Ratio in siltstones in other areas. Zones with high gamma ray readings may not have a significant Poisson's Ratio contrast with zones that have a low gamma ray reading. This was observed extensively in the Travis Peak, where only the zones with close to 100% shale provided any significant stress contrast.[2]

Lithology estimation can usually be done with a neutron-density-gamma ray combination. If a bulk density measurement is available it can be used to estimate the overburden stress gradient. If it is not, an estimate of 1.0 psi/ft can be used. Using the inputs of Poisson's Ratio, overburden gradient, and pore pressure, it is possible to estimate the in-situ stress distribution above and below the perforations selected (Fig. 14). This estimate can be calibrated to shut in or microfrac data using the Ptec term in Eq. 4. Most often this estimate is compared to the ISIP in the pay zone and extrapolated to the boundary layers using the model. If there is a pore pressure variation between the pay zones and boundary layers this should be incorporated as well. This is critical at the interface between the Dean and the Wolfcamp, where the Dean typically has a 0.28 pore pressure gradient and the Wolfcamp carbonate has a 0.465 pore pressure gradient.

Young's Modulus and Fracture Toughness

From the full wave sonic data and bulk density data, an estimate of Young's Modulus can be made as well. The relationship used in the Spraberry/Dean is:

$$E_{log} = 2 * G * (1+v)$$

$$G = (1.34*10^{10})(RHOB/DTS^2)$$

$$E\ static = 0.70 * Elog$$

where:

E_{log} = Young's modulus (psi) from logs
G = Shear modulus (psi)
RHOB = Bulk density
E static =Young's Modulus model input

The value of 70% for a dynamic to static conversion is based on one comparison of triaxial core measurements with log data. If the triaxial data are available, a correlation can be made between the laboratory dynamic and static measurement and the field dynamic (log) measurement based. The 70% estimate may be high as some data from the GRI studies indicates 50% may be appropriate in some cases.[13] An error on the high side is conservative, though, as the higher number will predict a narrower fracture width and help prevent premature screenouts. Although the porous pay sands, surrounding tight siltstone layers, and tight carbonate layers have a range of Young's Moduli from 3.0 to 8.0 E^6 psi, the great majority of the fracture will be created in the tight siltstone layers. Thus the average value for the surrounding siltstones is probably the appropriate input, and it is routinely between 4E+6 psi in the Upper Spraberry to 4.5E+6 in the Dean.

Fracture toughness was derived from a core test from the Dean in the northern part of the trend. The average value observed was 2600 psi. Additional data are needed to confirm the applicability to the other zones. In the SFE 3 simulations a default value of 2000 psi was used for comparison to the estimate of 2600 psi used here.

Completion Design Considerations

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 300 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. This was observed in a horizontal core offsetting a hydraulically fractured well by Warpinski et al (1991).[15] Additional discussion of this was presented by Elbel (1991).[16] Further evidence can be found in multiple staged fracture treatments in the Spraberry Trend where the two stages are separated by less than 100-200 ft (although the predicted fracture height from the 3D model is 400 ft to 500 ft). This is a routine practice in Reagan County where the Jo Mill and Lower Spraberry are often staged separately. The net pressure profile on the Lower Spraberry stage gives no indication of communication with the Jo Mill stage on any of the treatments observed. A second area where this was observed was in Midland County in the Upper Spraberry. On one well the Upper Spraberry was treated in two stages only 74 ft apart with no evidence of communication on the second stage. The well performed significantly better than any offset wells with similar log derived kh, indicating a successful treatment. The deviated fracture theory is further supported by analysis of several core and formation imaging datasets in the Spraberry trend. **Fig. 15** presents one of these datasets from an oriented core in Reagan County. The figure illustrates the angle of the fractures from horizontal or the "dip". Fully 58% of the "vertical" fractures observed had deviations greater than 5 degrees off of vertical in the cores. Observations of formation imaging data from the Spraberry suggest that 2 to 4 degrees off of vertical is common when the "vertical" fractures are observed under in-situ conditions. If the wellbore is deviated, this can further cause the fracture to stray away from the wellbore. If two sets of perforations are placed 100 ft apart and the wellbore deviation is one degree, the two sets will be laterally displaced by 21 inches. When this is added to a natural fracture deviation of from 2 to 4 degrees, this can result in a lateral offset of from 5 to 9 ft between the two perforation sets and most likely separate fractures. In the Spraberry/Dean it is not uncommon to have over 300 feet between the top and bottom perforations, resulting in a 26 ft lateral offset between the top and bottom perforations if a 5 degree deviation from vertical is assumed. **Fig. 16** illustrates the relationship between deviation and the lateral offset.

Given the single wing geometry assumed in any fracture simulation model (2D or 3D), this offset could significantly complicate the resultant geometry. Elbel (1991) presented a model for estimating the relative distribution of fluid and proppant in these multiple fractures.[17] If a single fracture is assumed and this type of modeling is not done to account for possible multiple fractures, a significant risk exists that the lower stressed zones will receive larger amounts of pad and the higher stressed zones are likely to screen out prematurely. If interlayer crossflow through the wellbore during the pressure decline takes place, the potential for proppant removal exists and hence significant near-wellbore conductivity impairment. Perforating large intervals with limited entry thus increases the probability that the resultant propped fracture will not resemble the designed fracture in terms of length and conductivity. This can be costly in terms of lost production in a low permeability reservoir.

The recommended solution to this potential problem 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. 17). This figure displays data from Fig. 9 presented earlier. 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.

Stress Data Input to 3D Model

The in-situ stress profile and permeability inputs are combined to estimate the stress contrast in psi between the perforated interval and the boundary layers. A spreadsheet routine has been designed to accept inputs of depth, Poisson's Ratio, and pore pressure to output stress distribution above and below the perforated interval. Up to 45 depth intervals above and below the perforations are available with the current version of the 3D simulator,[18] and typically all of these will be used in a Spraberry/Dean design. The spreadsheet routine is used to calibrate the estimated closure stress to observed stresses. A typical undrained Dean zone will have a fracture gradient of 0.62 psi/ft, while an undrained Spraberry zone will have a gradient of 0.55 psi/ft. Offsets of 0.15 are frequently required in the Dean to match observed fracture gradients, with a value of 0.08 is commonly used in the Spraberry.

Sand and Fluid Schedule Optimization

The permeability distribution discussed earlier can be used to help estimate the fluid efficiency of the created fracture. In the 3D simulator used up to 7 layers can be used to estimate leakoff. Inputs are required for filter cake fluid loss coefficient (CIII), reservoir pressure, reservoir compressibility, reservoir and fracture fluid viscosities, and porosity. An estimate of leakoff height vs total height is input as well, and this is readily available from the permeability thickness profile. A minimal value for spurt loss is usually based on estimated matrix permeability. The effect of natural fractures should not be a concern as the hydraulic fracture should propagate in the same direction as the natural fractures. The hydraulic fracture surface area exposed to the natural fractures should be significantly less than the area exposed to the matrix. An example of a typical Upper Spraberry permeability distribution is provided in Fig.18.

The frac fluid properties are entered as well into the 3D simulator. Values are entered for n prime and k prime as a function of time. With crosslinked gel treatments the values are not changed as a function of sand concentration. The linear systems and polyemulsion systems require a separate n prime and k prime for each sand stage. Excellent agreement with field pressures has been achieved using the correlations proposed by Shah (1991).[19] An example of the effect of sand on n prime and k prime is shown in Figs. 19 and 20. Prior to using these correlations, the 3D simulations with linear gels routinely screened out prematurely even though the jobs have been successfully pumped. With the correlations, the jobs successfully execute and the field pressures agree reasonably well with the predicted pressures.

The type of fluid used varies among operators in the Spraberry Trend. The most commonly used fluid is linear gel, with the polymer loading between 30 and 40 lb/1000 gal depending upon temperature. Several operators use polyemulsion systems, and a few use crosslinked systems. A 70% damage factor is used with the linear systems and polyemulsions, with an 80% factor for the crosslinked systems. The proppant conductivity Additional research is recommended The pad volume is varied downward until a screenout occurs, then adjusted upward to provide a margin of safety. The optimum pad percentage varies as a function of permeability, fluid type, and rate. In all cases the minimum pad volume necessary is recommended.

The optimum fluid based on several comparative studies to date is the linear gel, with the polymer loading varied depending upon temperature. 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 3D model 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.

Regardless of the fluid used, it is recommended that as little as possible be left in the fracture after pumping. The success of the forced closure technique has been well documented in the literature.[20] The first benefit of forced closure would be to remove fluid from the fracture. A second finding of the horizontal core study by Warpinski (1991) was unbroken 40 lb crosslinked gel in the multiple fractures after 6 years of production.[15] This example reinforces the objective of minimizing the volume of fluid pumped provided adequate proppant is in place. The second benefit of forced closure would be to shorten the long (8-10 hour) closure times and keep more proppant in place above the perforations. These long closure times are supported by field data. In one Upper Spraberry workover a 5 PPG schedule with a 30 lb linear gel at 140F was interrupted for 3 hours due to a wellhead leak. Prior to the leak 110,500 lb of a 302,000 lb schedule was pumped. Pumping only one casing volume of pad (the flush pumped after the leak was discovered) the service company was able to immediately go to 5PPG again and pump an additional 191,500 lb of proppant prior to screening out. The fracture had probably remained open for the entire 3 hour period or it is unlikely that the 5PPG would have been accepted so readily, particularly with such a thin low efficiency fluid at the upper limits of its temperature range. The third benefit would be to create a "reverse gravel pack" behind the perforations to help minimize sand production following completion.[21] Sand production following completion is often a problem in the Spraberry Trend. Some operators overcome this by overflushing the fracture treatment. The fact that any production is established when this is done supports the crossflow after pumping cessation theory proposed by Elbel.[17] The "reverse gravel pack" is most likely taking place after the pumping ceases, with the zones that took the majority of the treatment expelling fluid to the wellbore and then into zones that were not pressurized by the frac fluid as extensively during the job. Other operators overcome this by pumping from above the top perforations. Forced closure appears to be a better option than these two, even with the risk of adding additional time and expense to the completion effort if the baffle rings are covered with sand. These wells are assets that will generate revenues of over $1.2 million and produce from 20 to 30 years and (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.

A possible solution to the operational difficulties of combining forced closure and baffle ring completions is the use of the "Pine Island" staging technique discussed by Holditch.[22] This would involve the use of produced sand from the previous stage to divert subsequent treatments. This would require maximum spacing between perforated stages, and would be impractical with the commonly used limited entry perforation techniques with large intervals perforated. With the limited interval perforating technique recommended in this paper the probability of success would be maximized. Implementation of this is being discussed with operators at this time.

The optimum sand schedules are based on a sensitivity of fracture conductivity to production, with permeability and fracture length held constant. This can be seen in Fig. 21. Once a minimum of 200-300 Md-ft is obtained the incremental recoveries are minimal. The jobs are typically designed to provide a minimum of 300 mdft, with more if possible. There is evidence that the permeability degrades with time in the Spraberry trend, and that this degradation is more severe with lower sand volumes.[23,24] The Spraberry/Dean siltstones are deposited in a deep marine environment (over 2000 ft of water depth) and are extremely fine grained. The closure stress encountered is at the higher end of the range for 20/40 Brady sand. These two factors increase the probability for fines to migrate from both the formation and from partial crushing of the proppant during production. It is a common practice to gradually ramp the sand up from 1 PPG to the final concentration, with a significant percentage of the sand pumped prior to the final concentration. In the case of the Dean formation in Midland County, the minimum conductivity of 300 Md-ft requires 5 to 6 PPG of sand in the pump schedule. This suggests that the lower concentrations during the schedule result in less than 300 Md-ft of conductivity, and should be more susceptible to completely plugging off when fines migrate.

To minimize the abovementioned problem, sand schedules should be steeply ramped to the optimum concentration early to minimize the length of the fracture that has below 300 Md-ft. In addition, with linear and polyemulsion systems the higher concentrations add viscosity to help maintain adequate fracture width and minimize proppant settling. The higher concentrations have resulted in larger total volumes of sand. A typical three stage job in Midland County in 1992 pumped 432,000 lb of sand and 180,000 gal of fluid. An optimized treatment in the same area would have over 900,000 lb of sand with 240,000 gal fluid. This is a 108% increase in sand volume while increasing fluid volume by only 33%. These large treatments have been successfully pumped in both the Dean and Upper Spraberry. In the Dean 320,000 lb of proppant was placed with 90,000 gal of fluid using a 40 lb linear system. The Dean frac was successfully pumped without any indication of premature screenout carrying 5 PPG sand through 66% of the pumping schedule. A graphical representation of the schedule used is shown in Fig. 22. To date over 50 jobs have been pumped using the more aggressive ramp schedule with no problems encountered in job execution.

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[25] or through a spreadsheet routine. 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. 23 and 24). The optimum job size can then be determined using the rate of return criteria.

Field Examples

Fig. 25 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 4 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. 10-12) and Ref. 1. 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. 27 and 28). The production comparison is shown in Fig. 29. 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

Three dimensional hydraulic fracturing models can help operators optimize their completion designs in the Spraberry trend. Inputs to the models can be acquired using existing technology and modified for input using the relationships presented in this study. The 3D model is the cornerstone of a completion optimization process involving the integration of wireline, reservoir, and completion inputs. The conclusions from this integrative process are as follows:

1. The Spraberry/Dean is a low permeability siltstone interspersed with thin carbonate barriers. Significant vertical height migration can be expected, and 3D hydraulic fracture models are clearly appropriate.

2. Productive intervals can be identified using openhole log data in the area. An estimate of permeability can be made based on integrating openhole data with production declines. This can be used to improve estimates of flow potential and fracture fluid efficiency.

3. The in-situ stress distribution can be estimated from Poisson's ratio based on lithology.

4. The perforated intervals should be selected based on log derived permeability and in-situ stress distribution. The perforated interval should be kept to a minimum to preserve fracture integrity. There is strong evidence that the fractures created are not vertical, and multiple fractures will probably be created when perforations are widely spaced.

5. The fracture treatment should be designed using the minimum pad volume and with sufficient proppant to obtain a minimum of 300 Md-ft of conductivity. This can result in sand volumes over 900,000 lb in some cases.

6. In most cases linear gels provide adequate proppant transport capability if high (5-6 PPG) sand concentrations utilized over the majority of the sand schedule.

7. Forced closure and sand plug diversion should be considered to minimize settling and to improve conductivity.

8. A rate of return and payout estimate can be obtained by combining the 3D hydraulic fracture model with a 2D reservoir simulator. This can help determine the optimum treatment design based on maximizing internal rate of return on total well investment.

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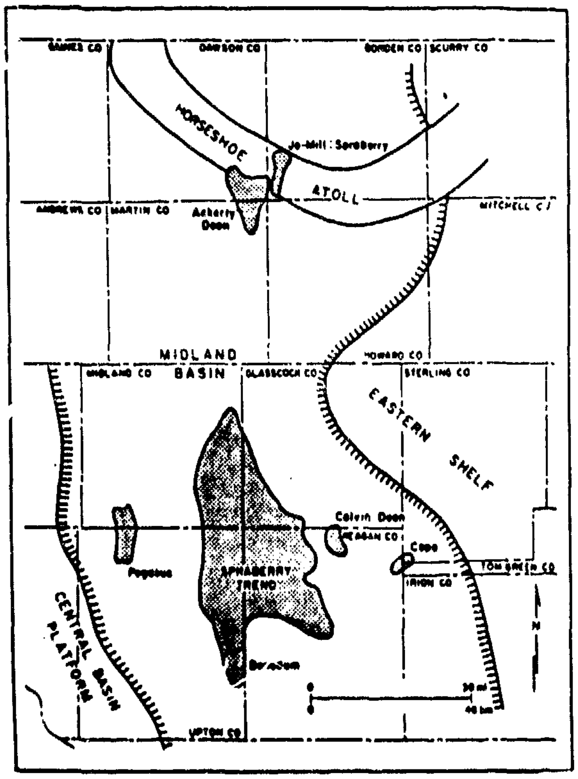

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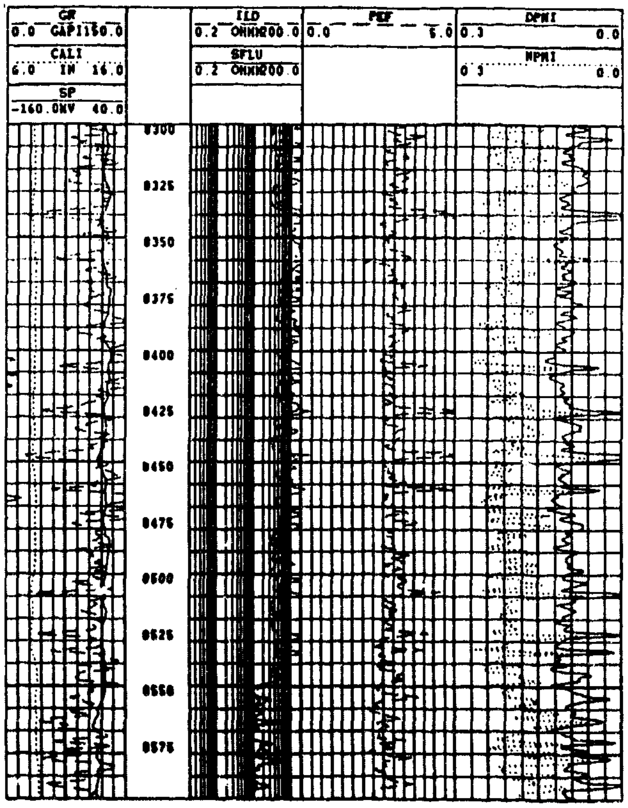

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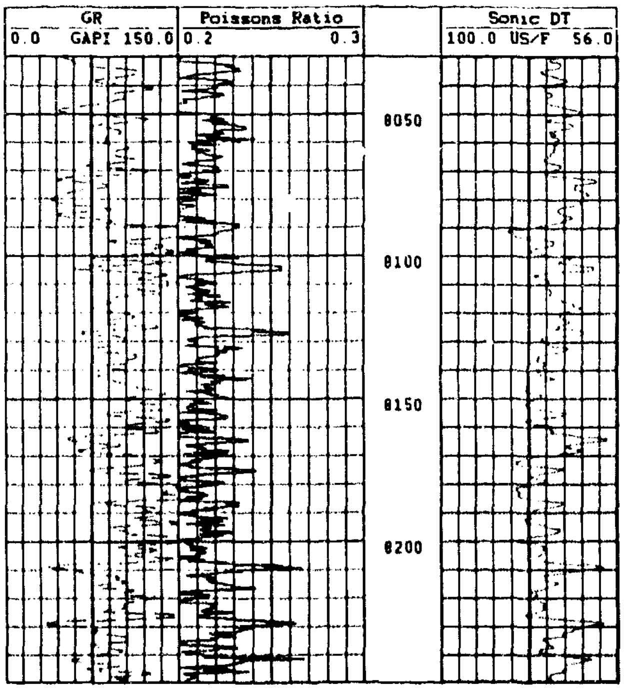

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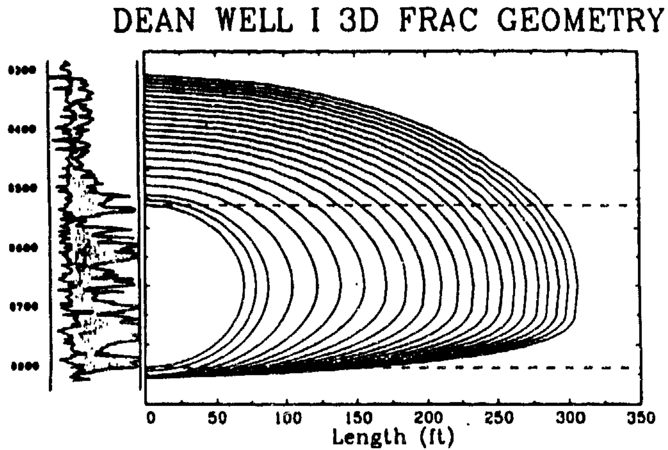

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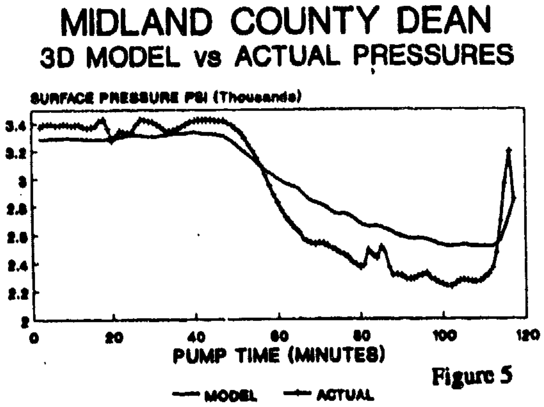

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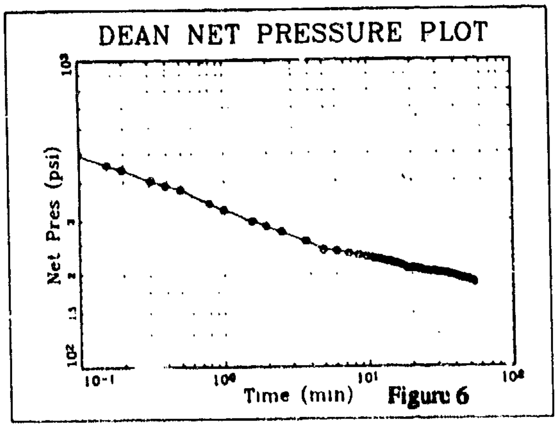

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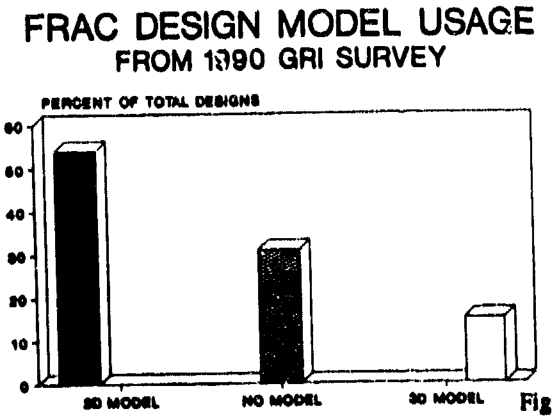

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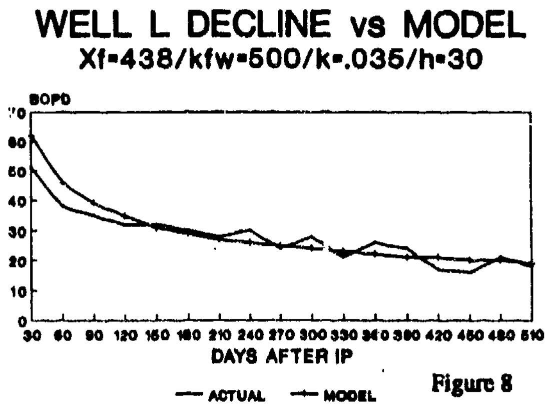

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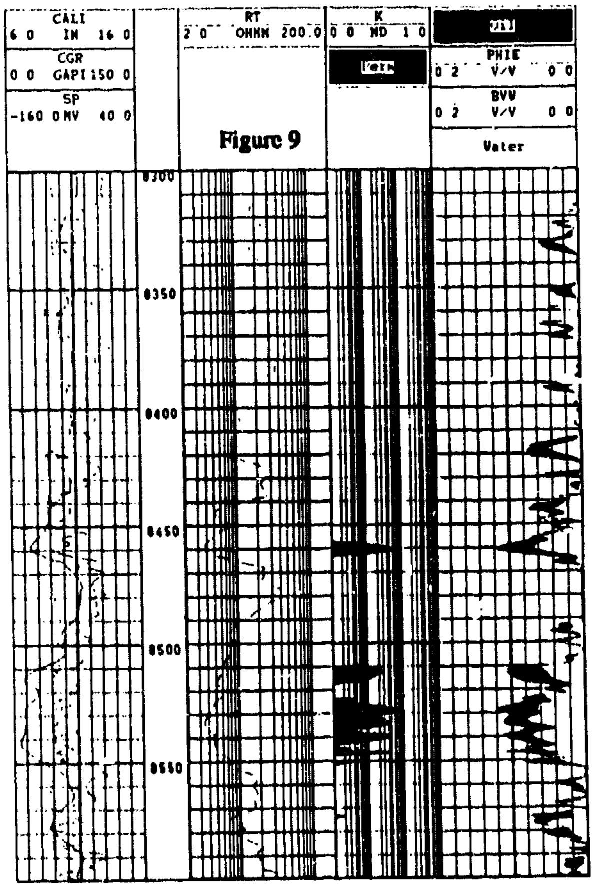

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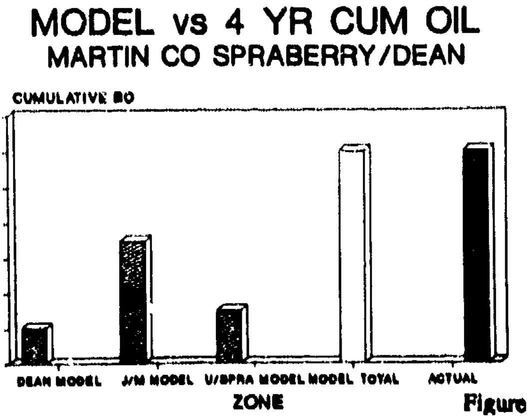

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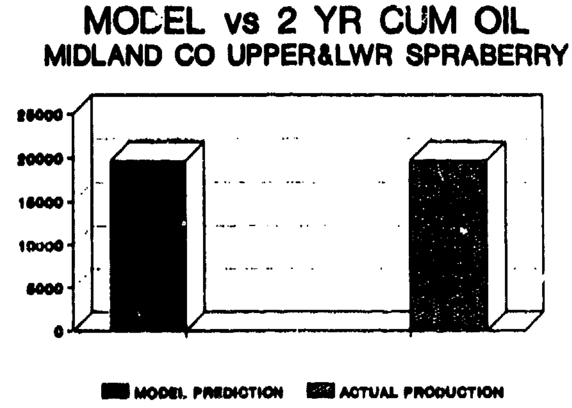
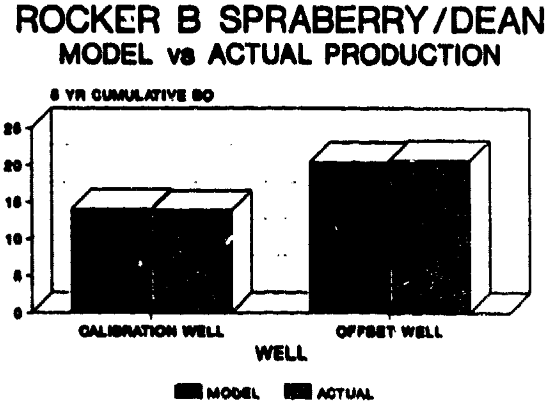


FROM 3D MODEL OF ORIGINAL FRAC

Figure 11



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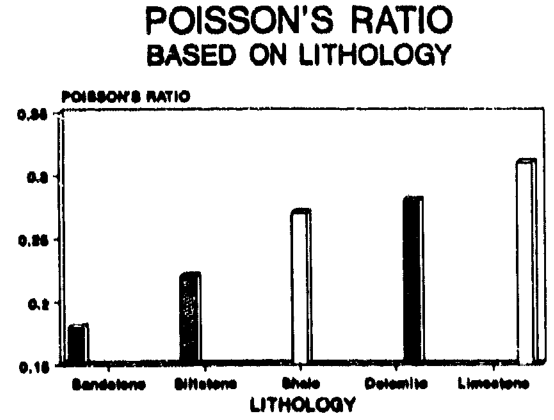
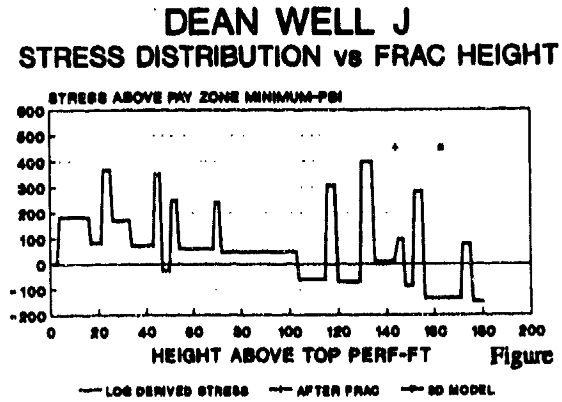


From Full Wave Sonic Data [illegible]rmian Basin

Figure 13



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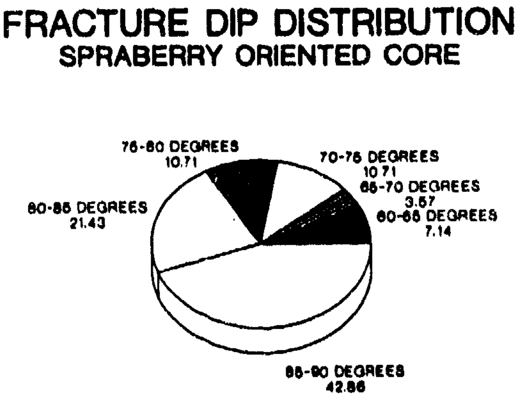
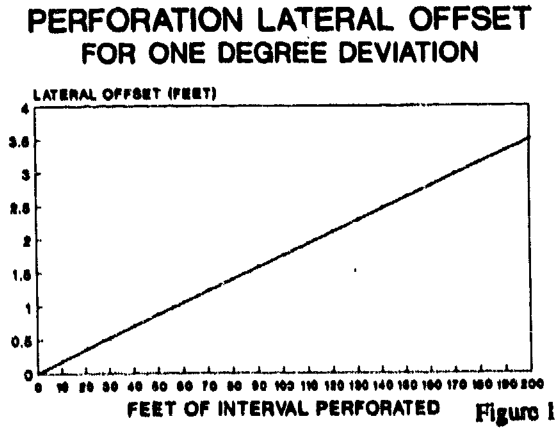


PERCENT OF FRACTURES OBSERVED

Figure 15



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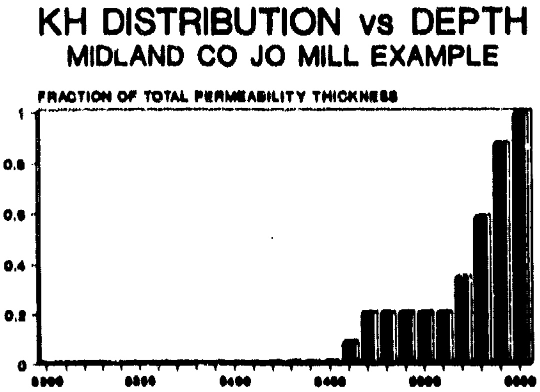

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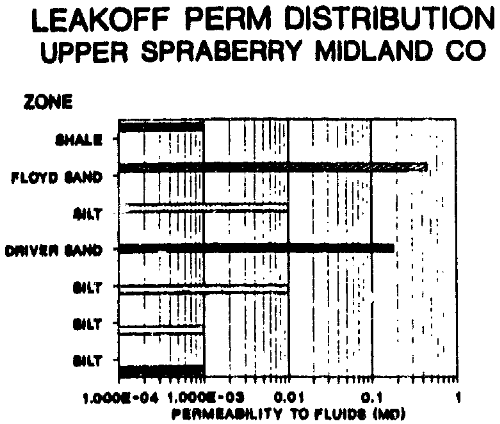
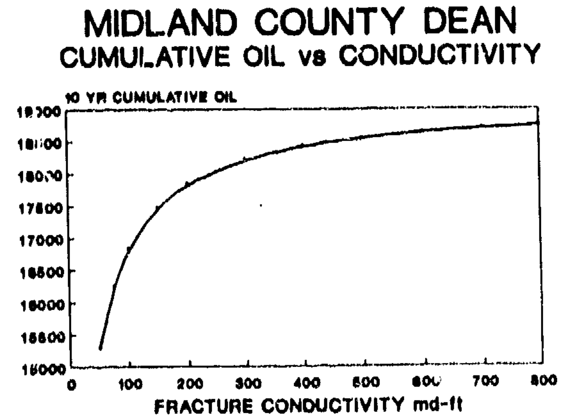


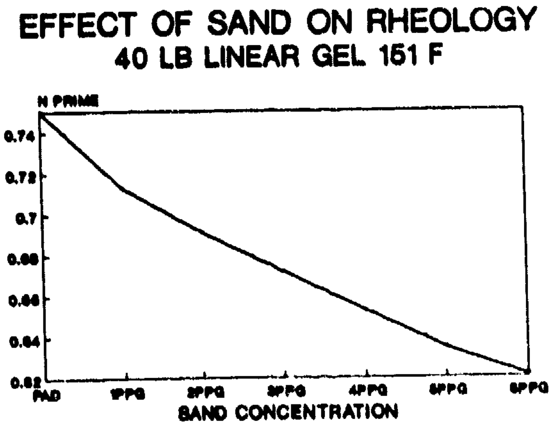
USING MFRAC-II 7 AVAILABLE LAYERS

Figure 18



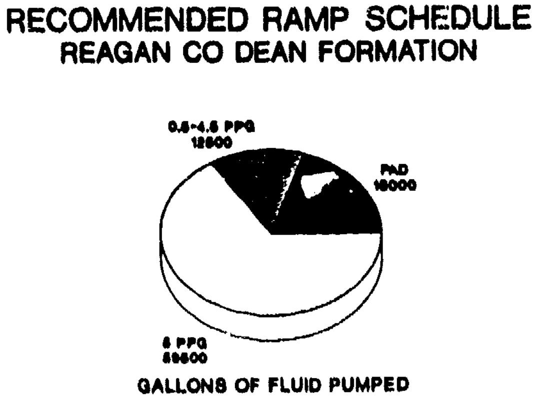
XI-300/K-.03MD/H-10/P--2400/PWF-300

Figure 21



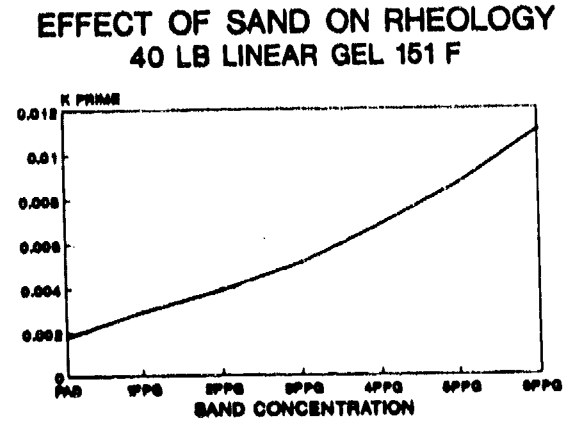
USING CORRELATIONS FROM SHAH SPE 22839

Figure 19



90,000 GAL 40LB LINEAR GEL 40 BPM

Figure 22



USING CORRELATIONS FROM SHAH SPE 22839

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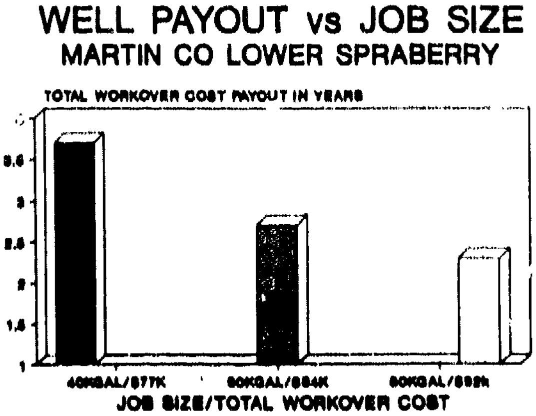
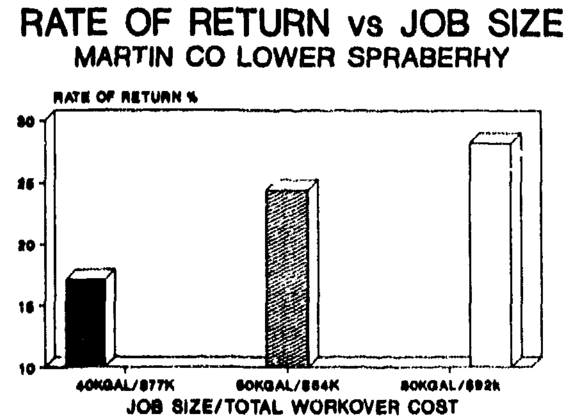


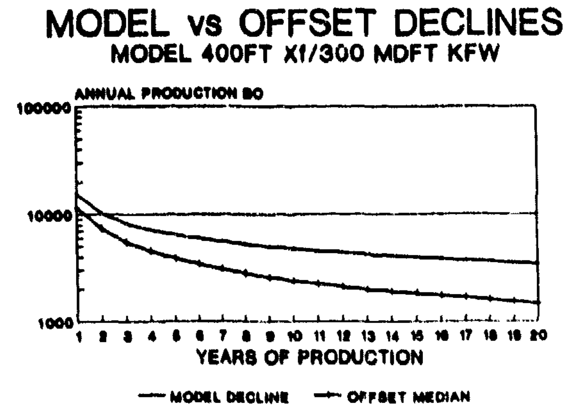
PERMEABILITY FROM LOG/PRODUCTION MATCH

Figure 23



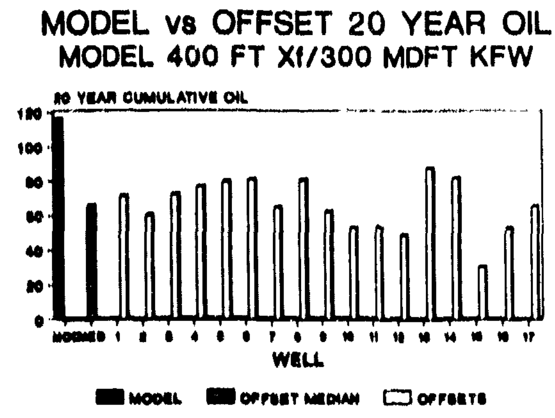
PERMEABILITY FROM LOG/PRODUCTION MATCH

Figure 24



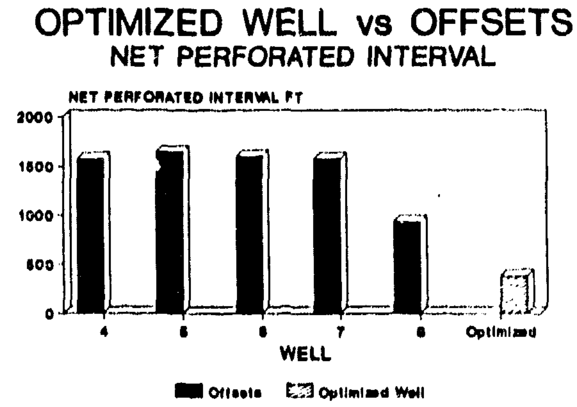
MEDIAN OF 17 OFFSET WELLS MIDLAND CO

Figure 25



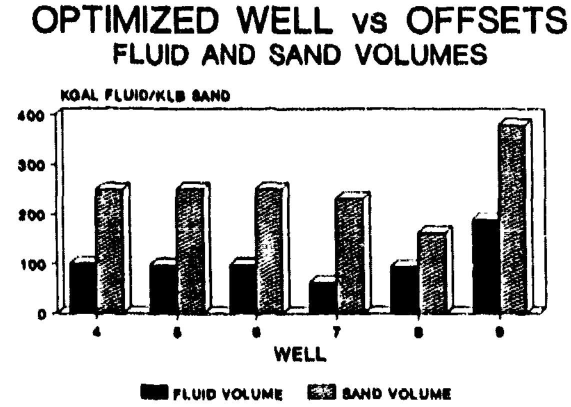
MIDLAND CO SPRABERRY/DEAN 3 STAGES

Figure 26



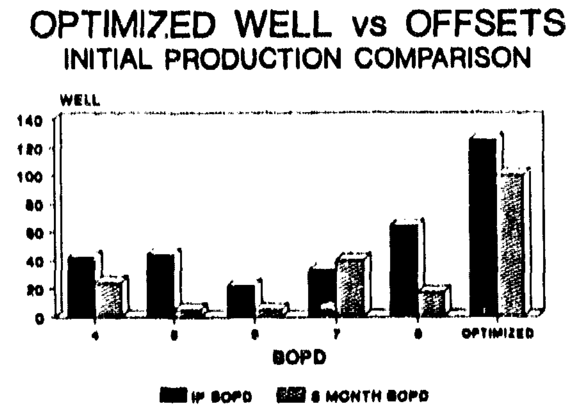
WELL 8 2 STAGES ONLY

Figure 27



IRION CO SPRABERRY/DEAN

Figure 28



IRION CO SPRABERRY/DEAN

Figure 29