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Evaluating Horizontal Well Potential in the Spraberry Trend

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Abstract

Eight attempts have been made to drill and complete horizontal wells in the Spraberry trend of West Texas. The results have been disappointing to date. The production history of each attempt will be discussed, along with an economic analysis. By using the drainhole production and results from vertical well completions, a model for predicting the performance of these wells will be proposed. The key input to the model is a modified Coates-Denoo relationship between porosity and permeability that utilizes openhole wireline inputs. The model predictions will then be compared to actual performance and used to help predict the optimum completion strategy for wells in the Spraberry trend.

Spraberry Trend Background

The Spraberry trend of West Texas has been the target of extensive drilling since its discovery in 1949. Early wells in the trend were characterized by high initial flow rates after small stimulation treatments. The average initial potential from one study of 718 wells was 318 BOPD from open hole completions in the Upper Spraberry.[1] The high initial potentials had sparked a boom in the early 1950's, where up to 203 rigs were running by mid 1951. The reservoir extent seemed enormous, with production established over an area 150 miles long and 50 miles wide. Operators were convinced they had found "a potentially great source of oil reserves.."[2]

This boom was short lived, as the high potentials were accompanied by rapid declines. In three cases, wells produced from 26,000 to 40,000 BO in 15 to 17 months prior to abandonment.[1] The poor success in sustaining economic production rates led operators to try different techniques to improve productivity. The two major techniques employed by operators were hydraulic fracturing and waterflooding.

Early Productivity Enhancement Efforts

The earliest wells were open hole completed with a small cleanup "hydrafrac". A survey of 781 wells conducted in 1952 indicated that 92% of the wells in the survey were openhole completed, with the majority of the treatments consisted of 1500 gal of fluid or less.[1,3] As operators gained experience, the treatments increased to 4500 gal of oil based fluid carrying 2400 lb of 20/40 sand. The treatments were generally pumped down 2 3/8 in. tubing at an average injection rate of 5 bbl/min.[4]

These early treatments did not limit the steep declines, and by 1954 operators began to implement treatments with higher rates and volumes. In a series of re-fracture treatments documented by Geroldi there were substantial improvements in productivity with larger job sizes. A typical re-fracture treatment consisted of 21,000 gal of frac fluid carrying 31,500 lb of 20/40 sand at 42-56 bbl/min down casing. Several wells that were producing less than 10 BOPD were increased to over 100 BOPD. One well recovered 55,438 BO in 34 months after a 4500 gal fracture treatment. Prior to the re-fracture treatment the well was producing 1 BOPD. Following a re-fracture treatment consisting of 21,000 gal oil based fluid and 31,500 lb 20/40 sand the daily production rate increased to 355 BOPD and the well recovered an additional 34,155 BO in the next 18 months.[4]

In the period following the early 50's, waterflooding gained popularity as a means to improve recoveries. The declines in production rates were accompanied by rapid declines in reservoir pressure, and waterflooding was considered as a technique to reverse this decline in pressure and to sustain production. On 40 acre spacing the reservoir pressures declined 3.86 psi per day, while on 80 acre spacing the reservoir pressures declined 0.59 psi per day.[1] Brownscombe and Dye (1952) suggested that oil could be displaced in the Spraberry by capillary imbibition of water into the rock.[5,6] By 1953 it was suggested by Elkins that the low permeability matrix pores held the majority of the oil, and that the natural fractures provided flow channels for the oil to reach the wellbore.[7] The concept of waterflooding the Spraberry was proposed to help limit the decline in reservoir pressure and to displace the oil in the matrix.

The first pilot waterflood program was initiated by Atlantic in 1952. The results were encouraging but injection rates could not keep up with the high withdrawals. Humble implemented a five spot 80 acre pilot program in March 1955 and significantly increased the injection rate over the Atlantic test. The original reservoir pressure was restored and production significantly improved. The extensive nature of the fracture trend dictated that a large scale operation would be necessary to restore reservoir pressure across the trend. [8] Between July 1, 1960 and June 1, 1967 twelve waterflood units were formed in the Spraberry trend, encompassing 2214 total wells. Two of the twelve units documented increases in production. In the Sohio Driver unit a 1961 field test covering 39 wells in a 4 sq mile area the oil production increased from 350 BOPD to 1050 BOPD in just 10 days.[8] Oil production in the Driver unit increased from 2620 BOPD to a peak of 5171 BOPD with an average of 3370 BOPD. In the Mobil E.T. O'Daniel project the 15 well lease was producing 50 BOPD at the start of injection. This production was raised to 345 BOPD once the waterflood response was seen. [9] Waterflooding ended in 1973 in the Driver Unit. Since then produced water has been disposed of in former water injection wells. [10]

By 1983 the estimated ultimate recovery from the Spraberry trend was 470 million barrels. The Bureau of Economic Geology estimated that this was only 5% of the estimated 9.4 billion barrels of oil in place. [11] On an individual basis, a 1984 study of 212 wells in Midland County estimated the average initial potential to be 60.5 BOPD, with a decline to 13 BOPD in 5 years.[12] Extrapolating this decline using average decline rates results in an estimated ultimate recovery 70,000 BO over 25 years. With the cost of a Spraberry/Dean well between $375,000 and $500,000, this led to some tight economics during oil price down cycles. The majority of operators elected to work with the cost side of the economic equation to improve their profitability, concentrating their efforts on reducing drilling costs, evaluation costs, and completion costs. On the revenue side, several operators believed that additional reserves could be recovered to improve the economics of the Spraberry/Dean by applying improved evaluation and completion techniques. The Bureau of Economic Geology reinforced this with several studies in the mid 1980's.[13] With the growing interest in horizontal well technology in the mid-1980's, several operators saw horizontal wells as a means to improve recoveries. This was reinforced in a study of horizontal opportunities in Texas. The Spraberry/Dean was identified as a candidate for horizontal development, most likely due to its characterization as a naturally fractured reservoir with a low recovery efficiency.[14]

Role of Natural Fractures

The presence of natural fractures in the Spraberry was evident throughout the drilling, core analysis, logging, cementing, stimulation, and waterflooding processes. The wells would frequently lose circulation while drilling, requiring mud weights as low as 8.3 lbm/gal and lost circulation material.[15] When the wells were cored, the cores often fell apart into several pieces. [16] Open fractures could be clearly identified on dipmeter logs and on electrical images of the borehole.[17,18] Following the cementing process cement was frequently found up to 100 ft below TD when wells are drilled deeper to the lower Spraberry. On one job in the Pembrook area 4000 sacks of cement were lost during the cementing of a 7100 ft upper Spraberry well.[19] When the wells were hydraulically fractured, high injection rates were necessary to prevent premature job screenouts. Analysis of core matrix permeability suggests that the high leakoff encountered is unlikely to be a result of the matrix permeability.[20] The pilot waterflood studies showed substantial permeability anisotropy, suggesting an extensive natural fracture system.[21] The waterflood response of the Spraberry Driver Unit pilot mentioned earlier further reinforced the presence of a high permeability fracture system in the Spraberry. [8]

Completion techniques focused on connecting the wellbore to this natural fracture system with hydraulic fractures in order to drain the tight matrix. The hydraulic fracture will propagate perpendicular to the minimum principal horizontal stress and parallel to the maximum principal horizontal stress.[22] In most cases, the natural fractures will have their maximum aperture in the direction of the minimum principal horizontal stress and will tend to be closed in the direction of the maximum principal horizontal stress.[23] This limits the effective drainage of the natural fracture system by hydraulic fractures, as the two systems will usually parallel each other. It was this limitation that led operators to consider horizontal wells drilled perpendicular to the natural fracture system.

Horizontal Well Efforts in the Spraberry/Dean

The concept of drilling a horizontal well in the Spraberry trend was proposed as early as September 1951 by Legendre. [24] He mentioned that one operator was planning a drainhole in the Spraberry, however any such early attempts went unrecorded in the literature. Interest in the Spraberry/Dean was limited until the advent of medium radius drilling in 1985. These wells could reach out from 1000 to 3000 ft, substantially adding to the effective drainage area of a naturally fractured reservoir.[25] By early 1935 the first horizontal test of the Dean was underway in Glasscock County.

The locations of the eight horizontal attempts are shown in **Fig. 1**. **Table 1** is a summary of production results and economic projections for the eight wells. From **Table 1**, it can be seen that none of the horizontal wells were economic successes. All of the wells received hydraulic fracture treatments, with wells A, B, and G receiving a single stage frac. The remaining wells were fractured in separate stages similar to the technique discussed in Ref. 26. **Fig. 2** and **Fig. 3** compare the production declines of the horizontal attempts with offset vertical wells.

The distribution of drainhole azimuths is shown in **Table 1**. The most likely natural fracture azimuth range is N75E to N85E.[17] Economides suggested that severe near-wellbore skin problems can result when the hydraulic fracture is not perpendicular to the minimum in-situ stress vector.[27] The one Dean well drilled perpendicular to this vector performed better than the 2 Dean wells not drilled perpendicular to the minimum in-situ stress. Spraberry Well C ignored the N75E fracture trend and did well, while Well F honored the trend and did poorly. Well G ignored the fracture trend and did poorly. Well H honored the fracture trend and had the highest initial fluid production of all Spraberry/Dean horizontal wells.[26] The intersection of an offset well drainage pattern during the second of 5 stages (with the offset well 1420 ft away bearing N75E) further confirmed the azimuth proposed in Ref 17. The intersection of a second well drainage pattern (with the offset well 2180 ft away bearing N63E) by the fourth stage suggested that the stress field may have been altered by the previous 3 stages. The wells drilled perpendicular to the assumed trend of N75E did better as a group, however the excellent performance of Well C and the poor performance of Well F indicates that this azimuth is not the only factor controlling production.

The expectations of the operators drilling the eight horizontal wells were clearly not met. While a poor choice of azimuth may be a contributing factor, this did not affect the performance of all wells. The models used to estimate the producibility of the Spraberry/Dean are worthy of a closer look, along with their input assumptions.

Spraberry/Dean Producibility Model

The first area to investigate is natural fracture conductivity. A decrease in conductivity with a decrease in pore pressure was first noted by Elkins and Skov in the early 1960's. A series of buildup tests were run in July 1962 in the Driver Unit. The apparent effective permeabilities from the tests ranged from 2 to 40 md-ft, compared to 800 to 1000 md-ft calculated in 1953 on the same wells.[6] The 72 hour shut in pressure of the wells tested in 1962 equated to a pore pressure gradient of approximately .24 psi/ft. In the 1953 tests pore pressure gradients were in the .31 to .33 psi/ft. range.[7] In falloff tests in the Driver Unit in 1961 wells that were in the fracture pattern had a 1000 to 1400 psi difference in pressure and a significant difference in conductivity as well. The higher pressure wells had an apparent conductivity of 245 md-ft whereas the lower pressure wells had a conductivity of 34 md-ft.[6] A more dramatic example of the loss of fracture conductivity with reservoir pressure was seen in the reservoir performance of the three Tex Harvey wells discussed in the introduction. If these wells lost reservoir pressure at a rate of 0.59 psi/day for wells on 80 acre spacing, this equates to a drop in pore pressure gradient from .327 psi/ft to .28 psi/ft in 18 months.[1] This corresponds roughly to the flow period of the three Tex Harvey wells prior to cessation of flow rates from an essentially unstimulated completion. The .28 psi/ft pore pressure gradient also corresponds to the maximum pore pressure gradient encountered today in 80 acre infill development in the Spraberry trend.[8] Warpinski, Teufel, and Graf (1991) observed a relationship between effective stress and natural fracture conductivity in the laboratory, with decreases in pore pressure resulting in decreases in permeability.[28] A similar phenomenon was reported by Canadian Hunter in the Bakken Shale, where fracture conductivity was observed to be directly related to pore pressure .[29]

A confusing issue has been the observation of fractured reservoir behavior during drilling, logging, and stimulation. Drilling and logging are normally conducted with at least a .433 psi/ft fluid gradient., and stimulation is often performed with a .55 to .65 psi/ft fluid pressure gradient. Although it is apparent that the natural fractures were open during these operations, they were clearly no longer open when normal reservoir conditions were restored. This observation allows us to shift the emphasis from natural fracture permeability to matrix permeability in the development of a productivity model.

Determination of Matrix Permeability

The two parameters sought from an analysis of the matrix are permeability and pay thickness. A link between pay thickness and productivity was first suggested by Guevara and Tyler (1986). They demonstrated a strong correlation between well productivity and sand thickness.[13] Several examples have been published linking porosity and core permeability. Oguen and Locke (1952) presented a semilog plot of core porosity vs core permeability for the Upper Spraberry.[20] Their correlation linked 10 percent core porosity to 0.68 md core permeability to air. Guevara (1988) presented a comparison of core porosities and permeabilities for the Spraberry Driver Unit.[10] The correlation made from this core data linked a core porosity of 10% to a range of 0.16 to 0.18 md. Although helpful in providing an upper limit, these values are to air at surface conditions and not directly correlative to in-situ permeabilities to reservoir fluids. Several authors have presented correlations to adjust surface values to in-situ values.[30,31,32,33] These were primarily done in single phase tight gas reservoirs with stressed core data. The Spraberry produces oil, water, and gas, and stressed core data are not readily available. The source of permeability data suggested in this environment is with a dynamic measurement observing the pressure transient response of the reservoir to either a pressure buildup or by history matching to the drawdown represented by the decline curve.

Dyes and Johnston (1953) observed permeabilities of 0.36 to 6.9 md to reservoir fluids when the Spraberry had virgin reservoir pressures.[34] It is likely that the measurements obtained were a combination of fracture permeability and matrix permeability. Elkins and Skov (1962) observed apparent effective permeabilities of from .051 md to .076 md in buildup tests conducted after the fracture system had closed.[8] While establishing an approximate range of effective permeabilities to expect, these observations fall short of establishing a direct quantitative relationship between measured porosity and dynamic test permeability. This can be best done with the direct integration of well logs with well tests.

Howard (1988) demonstrated that a reasonable correlation could be obtained between well test kh and well log kh using a modified Coates-Denoo relationship in the Travis Peak[32] Barba, Chaney, and Darling (1991) demonstrated that well log kh data calculated from the Coates-Denoo porosity-permeability relationship can be correlated to well test kh in the Miocene and Wilcox.[35,36] Aisquith (1989) proposed the use of the Fertl (1975) relationship for water saturation and effective porosity in the Spraberry.[37,38] The effective porosity is based on a non-linear shale correlation and a bulk density measurement. The equation proposed to link porosity to effective permeability in the Spraberry trend is:

$$k = ((C * PHIDC^2 * (PHIDC-BVWirr)/BVWirr)^2 \quad (1)$$

The log derived kh from Eq 1 can then be compared to effective permeability-thickness from a dynamic measurement. The "C" factor can be varied until a match was obtained between the dynamic kh estimate and the log derived kh estimate.

The determination of a dynamic kh estimate is less direct. The technique employed by Howard (1988) and Ref. 36 relied on obtaining permeability data from transient pressure analysis.[32,36] Well tests to determine permeability are rarely conducted in the Spraberry/Dean either before or after stimulation. A series of post-frac pressure buildup tests in the Dean and Upper Wolfcamp were analyzed by Barba (1988).[39] The wells were not in pseudoradial flow even after 11 to 14 days of testing. Post stimulation measurements added the additional variables of fracture length and conductivity to the test interpretation equations, and without pre-frac buildup data the uniqueness of the post-frac analysis was in question. Due to this uncertainty, the principal method of analysis utilized in Ref. 39 was a history match to production drawdown using assumptions of fracture geometry, two dimensional hydraulic fracture models, and a finite conductivity production model. The ability of the two-dimensional models to accurately model the geometry of the fracture has been questioned in areas where in-situ stress barriers are known to be weak.[40] Subsequent analysis of the well dataset used in Ref. 39 suggested this was the case in the Dean, and that the fracture treatments were not confined. This study utilized a three-dimensional hydraulic fracture simulator to refine the history match and obtain a new range of permeability values.

The data that were available on these wells included openhole log data, full wave sonic data, stimulation data, and production data. Five wells were evaluated, with four in the Dean in Midland County and one in the Spraberry/Dean in Martin County. Wells I and J had after frac tracer surveys available in addition to the above data. Stress distribution was calculated on all 5 wells using a transversely elastic model and a modified

fracture mechanics model for frac pressure vs. depth. [41] The digitized logs were analyzed using the formation evaluation model recommended by Aisquith and used Eq. 1 to calculate net pay and estimate log derived permeability.[44] A pseudo 3D hydraulic fracture simulator was used to predict the length, height, width, and conductivity of the created fracture along with a simulation of surface and bottomhole fracture pressures.[42] The simulated results were compared to net pressures observed in the field and after frac tracer surveys on Wells I and J to support the accuracy of the model. An excellent match was obtained between the model predicted pressures and field pressures. The agreement between the model predicted height and the tracer surveys was also excellent. It was substantially higher than the input height to the two-dimensional models used in Ref. 39. The 3D model lengths were substantially shorter than the 2D model lengths, with the 3D estimates averaging 50% less than the 2D estimates. The net pressure results were compared for Wells K and L, and Wells K and L were used to conduct the production history match. Well M was used to illustrate the applicability of the technique to the Spraberry/Dean.

Field Examples

Table 2 shows the input parameters used for the simulations. Fig. 4 shows the stress distribution inputs for Well I to the model, and Fig. 5 shows the predicted Nolte-Smith plot (Fig. 5).[43] Fig. 6 shows the predicted geometry, and Fig. 7 shows the comparison with the tracer survey. Experience with over 20 previous jobs with similar pumping schedules indicated a slightly positive Nolte-Smith plot up to 300-400 psi net pressure, and this was the model's prediction. Fig. 8 shows the effective stresses input for Well J. Fig. 9 shows the predicted net pressure plot. Fig. 10 shows the predicted geometry. The observed net pressure profile was again in agreement with the predicted profile. Fig. 11 shows a comparison with the tracer survey run.

The same methodology was used on Wells K and L to predict the created geometry. The inputs from the fracture simulator were input into a finite conductivity fractured reservoir production model, and a history match was made to production using the inputs in Fig 12.[44] The predicted fracture length was held constant, and a sensitivity to variations in conductivity was run. Conductivity data was based on recent laboratory studies with damage factors varied from 50 to 90 percent. [45] While variations in conductivity affected the initial potential over a 10 BOPD range, the effect on the overall 18 month production decline curve was minimal once the conductivity exceeded 200-300 md-ft. This is seen in Fig. 13. The history match for Wells K and L can be seen in Fig14 and Fig.15. The relationship proposed from the history match is shown in Fig. 16. The permeability listed is the permeability to total fluid production.

In the study area, the effective porosity in the best Dean sand ranged from 8.5% to 14.5%, with a maximum thickness of 5 ft. If these porosity values are entered into Eq. 1 and the resultant permeability values are then input into a simulator, the estimated 14 year estimated cumulative production can be seen in Fig. 17. The simulation assumes a 1600 ft infinite conductivity drainhole, vertical permeability equal to horizontal permeability over the 5 ft. reservoir interval, and zero skin. The cumulative production estimates can be compared to the performance of Wells B and D. The average permeability thickness encountered in offsets to Wells B and D ranged from 0.1 to 0.3 md-ft. This compares to recoveries of from 15,000 BO to 35,000 BO, or the range expected from Wells B and D (see Table 1).

Fig. 17 also demonstrates the maximum permeability thickness expected from this maximum porosity. It is unlikely that any of the wells will encounter 5 ft. of 14.5% porosity and 2.985 md-ft of permeability, however this should provide an upper limit for what could be expected. With this optimistic scenario, a well encountering 2.985 md-ft of matrix permeability should produce 134,839 BO in 14 years. With a $1.2 million well cost, this well has a 10.7% before tax rate of return and a discounted payout (at 10%) of 12.8 years. This is barely over the 10% hurdle rate used for the wells in Table 1. A simulation of multiple staged hydraulic fractures was not conducted for this evaluation, however the permeability transform proposed in Eq. 1 can be used to estimate the expected productivity. If the present value of the expected recoveries do not exceed the present value of the134,839 BO in 14 years expected from the unfractured simulator, and the cost is over the $1.2 million base case used, the economics will be marginal. The best performance to date for a multiple staged fractured well is an estimated 104,878 BO over 24 years.

While the economics appear to be marginal even for a multiple staged fractured horizontal well, the economics of a multiple staged fractured vertical well are not. Table 1 illustrated the rates of return for a 75,000 to 80,000 BO EUR well to be in the 20 to 25% range with a $450,000 cost and $20 flat oil price. The producibility model proposed here provides a tool to estimate the rate of return prior to completion as a function of various fracture treatment designs. Ref. 46 discusses this optimization process and provides an example where it was used to significantly improve recoveries in a marginal Martin County Spraberry/Dean prospect (Well M). Well M was located in an area where offset wells were not paying out. Openhole logs were run on the well and full wave acoustic data was available for in-situ stress estimation. The data presented in Ref. 46 was re-processed using the 3D hydraulic fracture model. The optimum length in the Dean was determined to be 700 ft. using the permeability relationship from Ref. 39 and a 2D fracture design model. The 100,000 gal. per stage pumped to achieve this design length resulted in an estimated length of 345 ft. using the 3D model. This was shorter than the 2D model design length, however it was 38% to 97% longer than the offset job predicted lengths. The offset job volumes (ranging from 30,000 gal to 60,000 gal per stage) were estimated to create a maximum length of from 175 to 250 ft. using the 3D model. A comparison of two month production from Well M with 25 offset wells is shown in Fig. 18. A comparison of estimated ultimate recoveries is shown in Fig. 19. Well M is expected to recover 71,500 BO, compared to 31,300 BO for the closest offset well. The offset well is not expected to pay out, while the optimized well should pay out in 5.47 years with an 13.22% before tax rate of return. This was based on a $500,000 well cost to account for the added cost of openhole evaluation, rig time, and the larger job size. While not a spectacular rate of return, the well was in an area where offset wells had negative rates of return. The comparison suggests that the economics of a Spraberry/Dean well can be improved by applying the optimization techniques in vertical wells.

Conclusions

None of the eight horizontal attempts have been economic successes. The horizontal attempts have helped confirm the orientation and conductivity of the natural fracture trend. The attempts have demonstrated the value of fully characterizing a reservoir prior to attempting an expensive completion effort. With the porosity-permeability relationship proposed in this study, a more complete characterization can now be made. An estimate can be made of vertical well productivity given various stimulation treatments, and the optimum completion design can be selected based on a rate of return criterion. An optimized vertical completion is recommended in lieu of horizontal completions in the Spraberry trend.

Nomenclature

k	=	permeability to reservoir fluids (md)
C	=	Scale factor (dimensionless)
PHIDC	=	Clean density porosity (v/v)
BVWirr	=	Bulk Volume Water Irreducible (v/v)

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46. Barba, R.E., Denoo, S., and Donovan, M.P.:" A PC-Based Solution to the Completion Optimization Problem," presented at the Permian Basin Applications of Microcomputers in Petroleum Exploration and Development Conference, Midland, Nov. 1989 pp. 73-80.

Table 1- Economic Summary

Horizontal Wells

Well	IP Date	Zone	Length Ft.	Azimuth	IP BOPD	IP BWPD	EUR Oil BO	Producing Life Years	Before Tax Rate of Return	Discounted Cash Flow $ 10% (NPV)
A	4/85	Dean	332	NA	2.4*	1	NA	2	Negative	NA
B	2/86	Dean	1626	N64W	53	24	38,752	22	Negative	NA
C	1/86	L/Spra	891	N65W	80.6**	NA	95,406	16	2.03%	-284,908
D	12/86	Dean	1588	N34W	80	46	21,669	13	Negative	NA
E	6/87	Dean	1672	N15W	15.3**	NA	104,878	23.5	2.14%	-457,459
F	9/87	L/Spra	1423	N18W	40	110	29,872	9.2	Negative	-911,328
G	2/88	L/Spra	1457	N82W	30	100	39,131	14.3	Negative	NA
H	10/88	L/Spra	1728	N20W	69	326	NA	NA	NA	NA

Vertical Offsets

Dean					51	9	75,760	23.4	24.6	183,132
Spraberry/Dean					70	210	80,528	23.2	20.95	163,905

* From Annual Well Test Report (8 months after IP)
** After stimulation. Well C: IP 14 BOPD and 9 BWPD after initial completion. Well E: IP 5 BOPD and 9 BWPD after completion.

Assumptions:

$20 flat oil price, $800 flat lease operating expenses, $1.2 million cost for horizontal wells, $450,000 cost for vertical wells.

Table 2

Parameters Used in Simulators

Pseudo-3D Frac Model

n'	0.44
K'	0.112
Young's Modulus	$4.7E^6$ psi
Poisson's Ratio	.219
Total Fluid Loss Coefficient	.0012 ft/sq. rt. min
Spurt Loss	.025 gal./ft^2
Closure Pressure	5063 psi

Production Simulator-Dean Formation

Reservoir Pressure	2800 psi
Bottomhole Flowing Pressure	100 PSI
Reservoir Temperature	148 deg F
Total Compressibility	7.3015 E-5 psi^{-1}
Water Cut	15%
GOR	850
Oil Gravity	39.3
Gas Gravity	0.93
Water Saturation	68.6%
Average Porosity	7.5%
Well Spacing	160 Acres
Formation Volume Factor	1.431 RB/STB

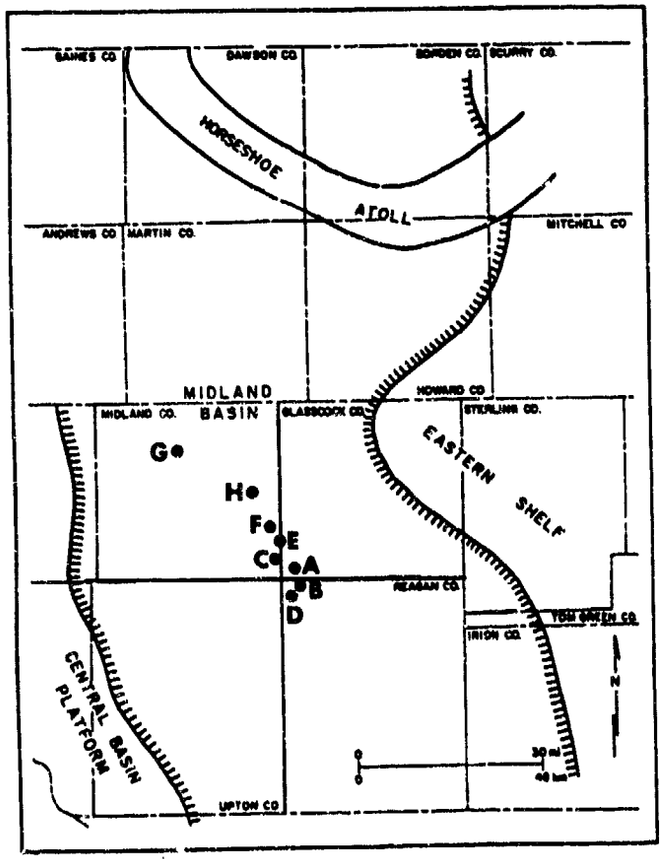


Figure 1

Horizontal Well Locations

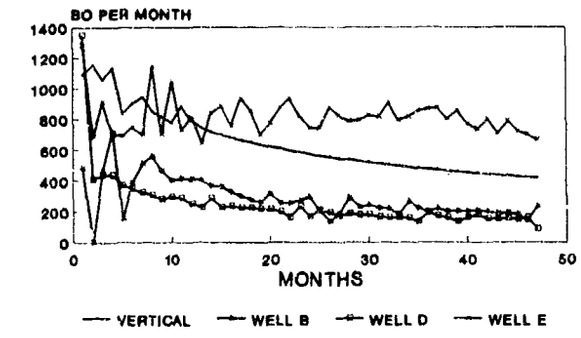


Figure 2

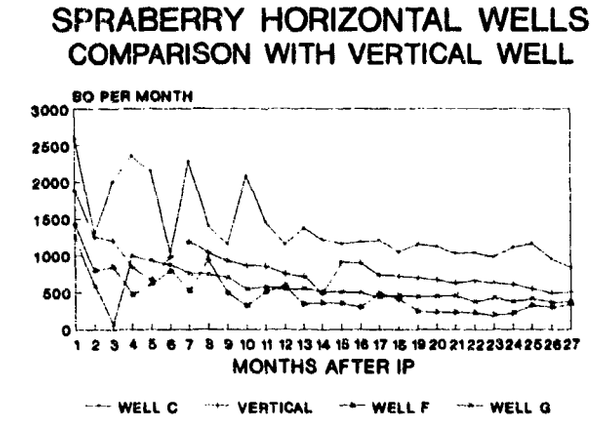


Figure 3

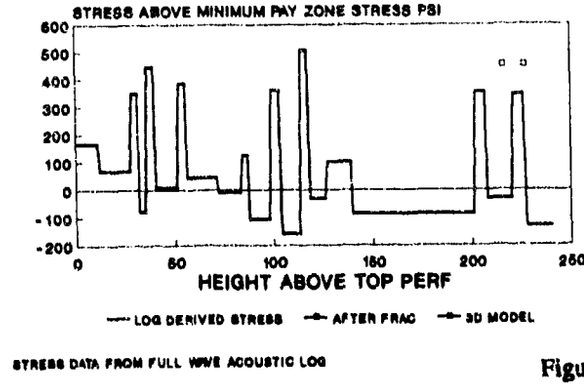
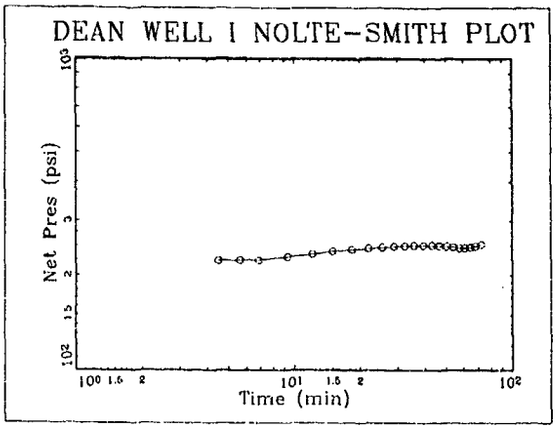


Figure 4



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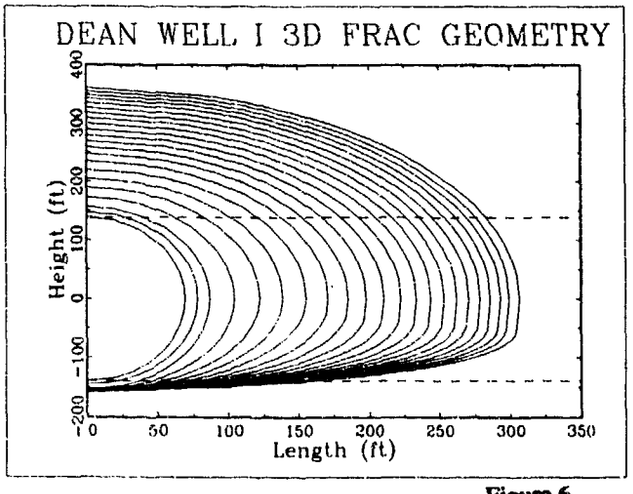

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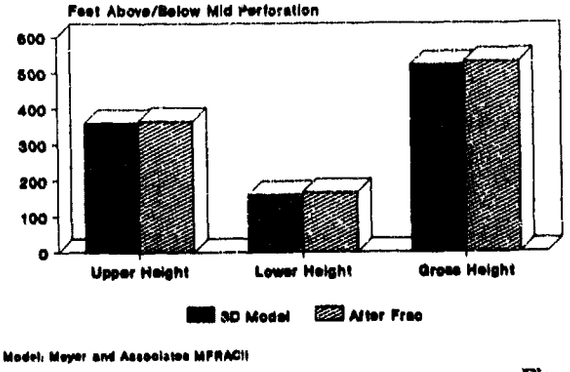
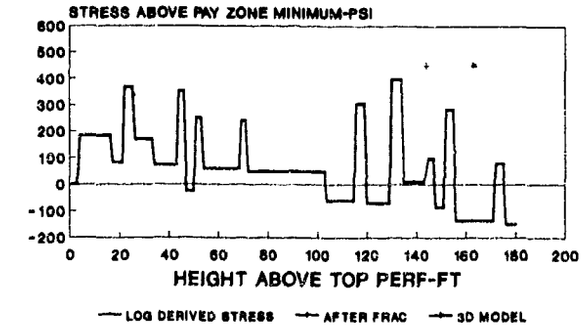


Figure 7

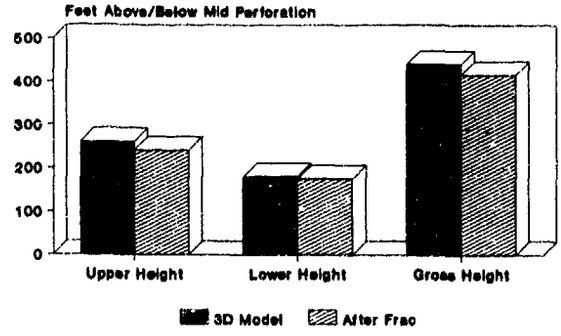
DEAN WELL J
STRESS DISTRIBUTION vs FRAC HEIGHT



STRESS DATA FROM FULL WAVE ACOUSTIC LOG

Figure 8

DEAN WELL J
3D Model Comparison With Tracer



Model: Meyer and Associates MFRACII

Figure 11

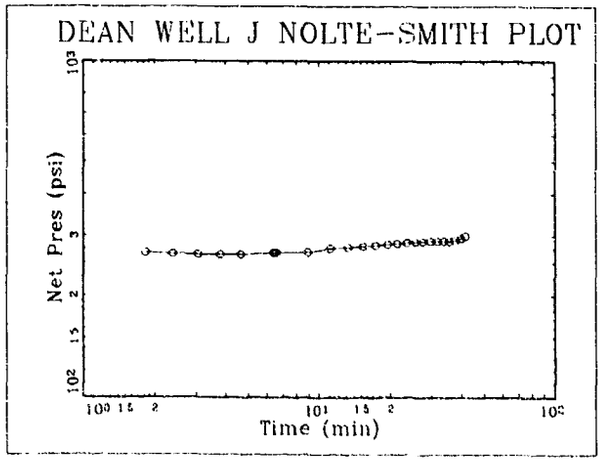


Figure 9

DEAN FRAC PREDICTIONS
Based on MFRAC-II 3D Model

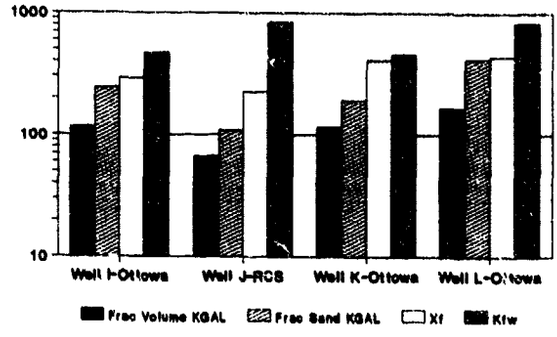


Figure 12

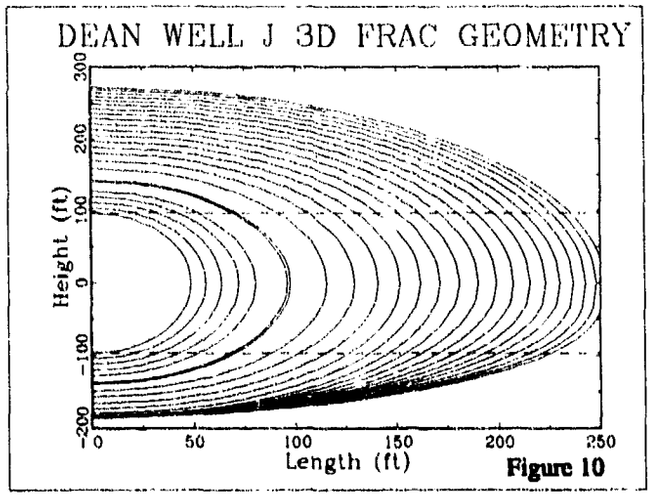
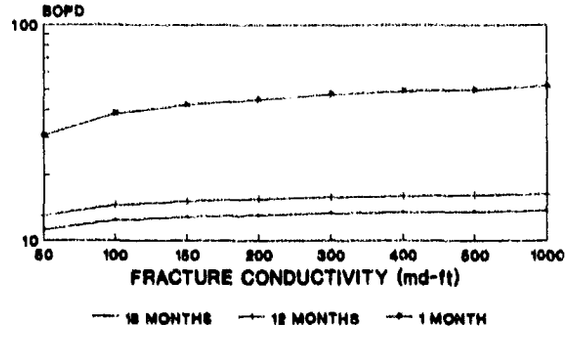


Figure 10

DEAN WELL K PRODUCTION
BOPD vs CONDUCTIVITY



Xf=410/kh^.47

Figure 13

WELL K DECLINE vs MODEL
Xf=409/kfw=300/k=.015/h=34

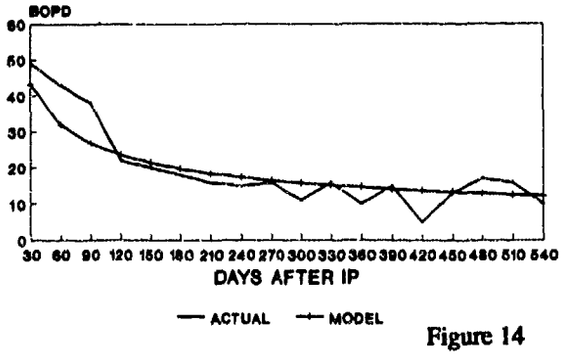


Figure 14

WELL L DECLINE vs MODEL
Xf=438/kfw=500/k=.035/h=30

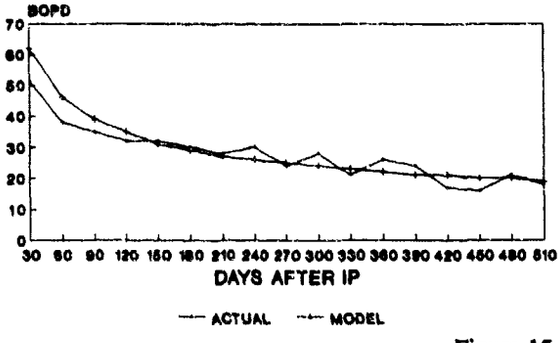
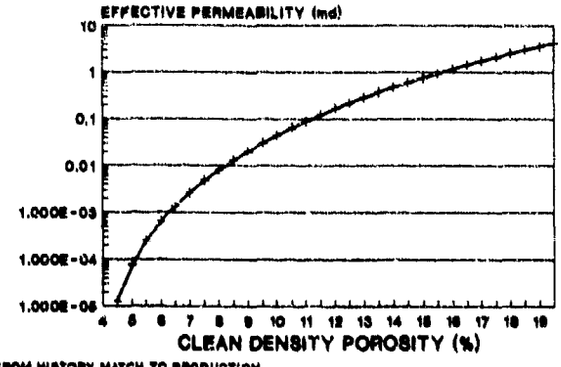


Figure 15

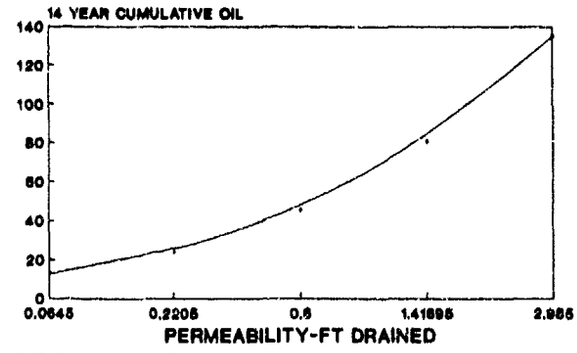
DEAN POROSITY vs PERMEABILITY
C=14/BVWirr=.04



FROM HISTORY MATCH TO PRODUCTION

Figure 16

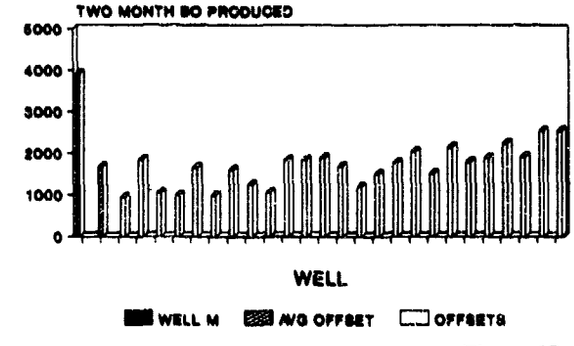
DEAN HORIZONTAL WELL
14 YR BO vs PERMEABILITY-FT



1600 FT LENGTH/C=14/6.5 TO 14.5% PHI

Figure 17

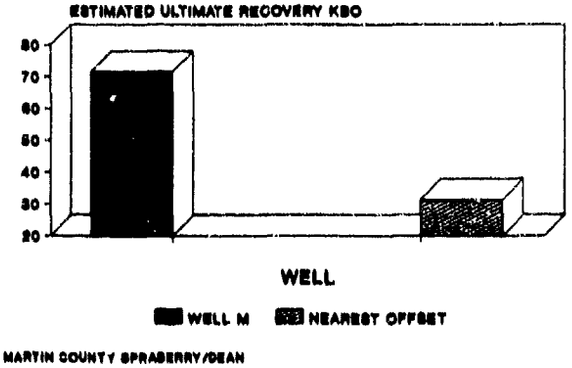
PRODUCTION COMPARISON
WELL M vs OFFSETS



MARTIN COUNTY SPRABERRY/DEAN

Figure 18

PRODUCTION COMPARISON
WELL M vs NEAREST OFFSET



MARTIN COUNTY SPRABERRY/DEAN

Figure 19