IMPROVING PRODUCTION IN THE SPRABERRY TREND WITH WIRELINE INPUTS

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ABSTRACT

The Spraberry trend of west Texas is a low-porosity naturally fractured reservoir, traditionally completed in the Upper Wolfcamp carbonate, Dean sand, Lower Spraberry sand, and Upper Spraberry sand zones. The overall interval is from 1200 to 1500 ft. thick, with completions encompassing from two to four stages. In all cases the wells require large hydraulic fracture treatments to produce economic quantities of oil and gas. The most common method of perforation selection involves correlating from well to well using cased hole gamma ray/neutron logs and drilling time. The large majority of the wells in the Spraberry trend have been perforated using this technique. The small minority of wells that have used openhole data have relied heavily on basic porosity and water saturation data to select perforations. Recent data suggest that production can be improved significantly by using VOLAN*, CFI*, and FracHite* data to select the perforated intervals. A group of 10 Dean/Wolfcamp wells that used the combination package of VOLAN/CFI/FracHite had a 103 percent increase in initial oil potential over 11 offset Dean/Wolfcamp wells that used basic openhole porosity and water saturation data. In addition, the well group with VOLAN/CFI/FracHite data produced 73 percent more oil over the initial four months of production than the offset wells. A discussion of the methodology follows, along with the production results of the 21 wells in the study.

BACKGROUND

The Spraberry trend covers a large portion of the Midland basin of west Texas, encompassing over 500,000 acres of productive acreage. A map is shown in fig. 1. The trend contains a tremendous volume of oil in place. The University of Texas Bureau of Economic Geology estimates 9.4 billion barrels are in place in the trend. Through 1981, there have been 457 million barrels recovered, and it was estimated then that an additional 13 million barrels can still be recovered.[1] This is a recovery factor of five percent, compared to the accepted average of ten percent for most solution gas-drive reservoirs. This relatively poor recovery is often attributed to the low porosity, low permeability, high water saturation, and the solution gas drive. Thus far, the completion methodology used on the overwhelming majority of the wells producing the 457 million barrels has been ignored as a factor in this poor recovery performance. This aspect deserves a closer analysis.

The completion technique used on the great majority of Spraberry trend wells involves plotting drilling time versus depth and observing fresh or brine water samples for hydrocarbon shows. Sample observation is generally not done in proven areas of production. Fresh water is used as the drilling fluid in the northern part of the trend and brine water is used in the southern part. A mud system is rarely used because mud slows the drilling rate significantly. With water systems a typical 9400 ft. Midland County well can be drilled in 10 to 14 days. Most wells then have $4\frac{1}{2}$ in. production casing set, with $5\frac{1}{2}$ in. occasionally used. Once casing is set, a gamma ray/neutron survey (fig. 2) is run and correlated with drilling time and hydrocarbon shows. Perforations are chosen from this data, with a strong tendency to use offset well perforated intervals for guidance. When open surveys are run, the typical criteria for

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perforation selection involve clean density/neutron log porosity over 10 percent, SP development, and bulk volume water values under 10 percent. A density/neutron log from the Dean and Upper Wolfcamp is shown in fig. 3, with typical perforations indicated. The wells are always treated with large hydraulic fracture treatments, averaging 60,000 gal. of fluid and 120,000 lb. of sand per stage in Midland County. Normally, the stages involved are the Wolfcamp, Dean, Jo-Mill and Lower Spraberry (together), and the Upper Spraberry. The average Midland County well completed in all four zones between 1975 and 1982 has an initial potential of 60.5 BOPD and an EUR of approximately 60,000 barrels over 17-25 years, based on a decline curve study of 212 wells.**

CONVENTIONAL COMPLETION DESIGN LIMITATIONS

There are several inherent limitations to this conventional design. The first is the assumption that productive and nonproductive intervals can be correlated over a local area. Once a well has been succcessfully completed in an area, there is a strong tendency to perforate the offsets in what appears to be correlative zones. For this to be a valid technique the reservoir should have a high degree of homogeneity. Extensive research conducted by the Bureau of Economic Geology suggests strongly that there is substantial heterogeneity in the Spraberry trend, both vertically and horizontally. This conclusion was from a study of more than 800 wells over a 160-square-mile area in the center of the trend. Their research strongly suggests that a substantial amount of oil has been left behind by not recognizing this heterogeneity.[2] It presents a strong argument for evaluating and completing each well based on its individual merits. This is not the case with the conventional completion design.

The second major limitation is the lack of permeability data, either from the rock matrix or fractures. This information is difficult, at best, to obtain once casing is set. For matrix permeability some limited information can be inferred from cleanliness of the gamma ray and neutron porosity, combined with drilling break information. In terms of fracture permeability, however, it is difficult to infer this with simple correlation and porosity logs once casing is in the ground.

The third major limitation is the lack of fracture gradient data. Spraberry trend wells will not produce without a large hydraulic fracture treatment. To maximize the length of any hydraulic fracture treatment, perforations should be placed between barriers that provide resistance to vertical height migration. In addition, if the perforated zones have different hydraulic fracture gradients the treatment will seek the path of least resistance. This information is not available from conventional cased hole correlation and porosity wireline evaluation programs. It could be obtained by perforating and treating every porosity zone and every barrier, but this is generally not economically feasible.

The fourth major limitation is the identification of pore space fluids. This cannot be accomplished through casing with simple porosity/correlation devices. The mud log can occasionally provide good data, assuming circulation is maintained. A large percentage of Spraberry/Dean wells have lost-circulation problems. In addition, in the naturally fractured zones residual hydrocarbons can be flushed away from the wellbore and difficult to circulate up.

** Barba, R.E., "A Statistical Economic Analysis of Spraberry/Dean Logging and Completion Methods," Schlumberger Well Services GFE paper, presented May 1984.

These limitations apply to the majority of wells completed in the trend since over 95 percent were completed using cased hole porosity and correlation log data. When conventional openhole logs (density/neutron/gamma ray/dual induction logs) are run, the permeability and pore space fluid limitations are less severe. The other limitations (permeability from natural fractures and hydraulic fracture gradient data) are still present. However the limitations are most evident in the Dean and Wolfcamp, since obvious porosity zones are usually not present. In Midland County, a productive Wolfcamp zone can average 5 percent clean porosity or less with matrix permeability of less than 0.1 md. In the Dean, it is not uncommon to recover significant reserves from sands with 6.5 percent average clean porosity and 0.1 to 0.4 md matrix permeability. In the Upper and Lower Spraberry a generally accepted clean porosity cutoff is 10 percent, unless natural fractures are present to aid the recovery efficiency.

OPENHOLE WIRELINE EVALUATION METHODOLOGY

To minimize these limitations, a major oil operator solicited a program to evaluate a series of wells proposed in southeastern Midland County. The wells were to be drilled to the upper Wolfcamp and completed in the Dean/Wolfcamp. The two main Spraberry zones were unitized in the area and thus could not be included. There were a number of successful Dean/Wolfcamp producers in the area, along with an even larger number of marginal wells. With a conventional openhole log suite (density/neutron/gamma ray dual induction) there were no obvious differences between the good wells and the marginal wells. On the previous 11 wells drilled in the program, the perforations were selected based on clean porosity from the density/neutron/gamma ray log, shown in fig. 3. The dual induction log was not relied upon heavily because water production was not a problem in this area, and water saturations were not helpful in selecting perforations.

It was recommended to the operator that natural fracture data and hydraulic fracture gradient data be acquired in addition to a basic porosity and resistivity suite. The eight button Dual Dipmeter* tool was added to detect natural fractures and to obtain a fracture identification map (FILMAP*), shown in fig. 4. A more complete discussion of FILMAP application in the Spraberry trend is found in (3). The LSS* (long spaced sonic tool) was added to obtain the hydraulic fracture gradient distribution with the FracHite log (4), shown in fig. 5. In addition, it was recommended that a VOLAN computation (5) be performed to better define the reservoir rock quality (fig. 6). This involved the replacement of the FDC* tool with the Litho-Density* tool.

After the first two wells, it was observed that a fair correlation was obtained between the Dual Dipmeter FILMAP data and the LSS shear and compressional energy attenuation, shown in fig. 7. In comparisons with the Dual Dipmeter/FILMAP data over the entire Spraberry/Dean/Wolfcamp interval, there was a 83 percent correlation of LSS energy attenuation events to Dual Dipmeter/FILMAP events. On two later wells the Formation Microscanner* tool (FMS) was run and there was a 80 percent correlation between LSS energy attenuation events and FMS vertical fractures. A Midland County Dean FMS example of a vertical fracture is shown in fig. 8. The Long Spaced Sonic energy data was attenuated by other events in the well (such as borehole rugosity, vugs, and damaged shales). By using the VOLAN computation in conjunction with the LSS data the bettter quality reservoir rock could be discriminated from the shales. Since the price of oil had recently fallen there was a strong effort to economize wherever possible. Thus, on the remaining 8 wells in the 10-well package the LSS energies and the VOLAN data were used for natural fracture detection, even though it was known that some natural fractures would not be detected using these data alone. This information was displayed as a fracture probability curve (called the composite fracture intensity or CFI curve) on the VOLAN presentation. A Dean VOLAN/CFI presentation is shown in fig. 9.

Once the information was collected, the perforation selection process began. The initial task was to identify potential permeability channels using natural fracture and matrix permeability indications. Cores from the area indicated that matrix permeability in the better zones was from 0.1 md to 0.4 md, so even minor indications of permeability were flagged. Once the permeability channels were identified, the FracHite log was used to place perforations where these channels could be best stimulated. This involved perforating in low stress regions between higher stress barriers and treating zones between the same barriers with single perforations. The VOLAN log was used to ensure that the perforations were placed in the better quality reservoir rock. Once the initial perforations were in place, a second FracHite pass was run to measure the hydraulic fracture gradient difference between the perforations in terms of fracture extension pressure. With this difference, a chart using the Bundy limited entry equation (6) was used to set a minimum friction pressure across the perforations to help balance the treatment among all of the intervals (7). A chart illustrating the relationship between flow rate, perforation size, and perforation friction pressure is shown in fig. 10 (8). A qualitative factor to allow for perforation erosion was applied whenever possible. The bottom line was to treat the maximum number of productive intervals with the minimum number of perforations. Once the perforations were finalized, the FracHite log was used to obtain a height, Poisson's ratio, and Young's modulus to refine the hydraulic fracture model. The FracHite log was also used to pick an adequate high stress barrier between the upper and lower stages to prevent the two stimulated intervals from communicating.

The lower stage would then be perforated with a casing gun one shot per foot using 0.3 in. perforations. The perforations were then treated with a matrix acid volume, with ball sealers used to evenly distribute the acid. The lower stage was then treated with an average of 94,000 gal. of oil/water emulsion and 169,000 lb. of 20/40-mesh sand. The treatment rate down $5\frac{1}{2}$ in. casing was in the 30-35 bbl/min range. The stages were then mechanically separated with a wireline frac bomb or bridge plug. The procedure was repeated for the upper interval, using an average of 128,000 gal. of oil/water emulsion and 245,500 lb. of 20/40-sand. The treatment rate was again in the 30 to 35 bbl/min range. The lower stage averaged 18.2 perforations and the upper stage averaged 19 perforations.

DISCUSSION OF RESULTS

To validate the theory, a comparison of production results is in order. A group of 10 wells that used a combination of VOLAN/CFI/FracHite data was compared to 11 direct offset wells. A location map is shown in fig. 11. The wells were located in the center of the Spraberry trend near the four corners intersection of Midland, Glasscock, Upton, and Reagan counties. All 21 wells were completed in the Dean/Wolfcamp only, with the two Spraberry zones left behind casing. The 11 offset wells used density/neutron/gamma ray data to pick perforations, with an average of 49.75 holes over a gross interval of 411.3 ft. The wells were then treated with an average of 244,070 gal. of crosslinked gel and 497,360 lbs. of sand. On the 10 newer wells, the VOLAN/CFI/FracHite information was used to pick the perforations, with an average of 37.2 perforations over a gross interval of 621.5 ft. These wells were treated with an average of 221,950 gal. of water/oil emulsion and 414,500 lb. of sand. The VOLAN/CFI/FracHite group (also referred to as the "Spraberry Package" group) thus had 25.2 percent fewer perforations over a 51.1 percent larger interval. These wells also used 9 percent less frac fluid volume and 16.6 percent less sand (fig. 11). The fluid type was the only other difference between the two groups. The operator changed from crosslinked gel to emulsions at the same time the logging program changed. Two separate multiple well studies in the area indicated that Spraberry/Dean Wolfcamp wells treated with emulsions do not perform any better than wells treated with water based gels. The results of a 100 well study conducted in northern Midland and southern Martin Counties is shown in fig. 12. In this study the wells treated with water based gels produced 6 percent more oil over a 6 month period than the wells treated with emulsions. All wells were completed in the Spraberry/Dean/Wolfcamp with no significant difference in fluid volumes. A second study conducted in Reagan County gave similar results with 19 crosslinked water frac wells producing an average of 55 percent more oil than 22 emulsion frac wells over a 36 month period.*** In many cases, emulsions are chosen for their lower effective cost as oil purchasers will frequently loan the oil to the operator. In this case, the operator suspected a clay sensitivity problem, and chose to try an emulsion system primarily for that reason. This was done at the same time the new logging program was finalized. Once the initial results of the combined VOLAN/CFI/FracHite/emulsion package were in, it was decided to not experiment further with either the logging program or the fracture fluid program, particularly since the emulsion system was lower in effective cost. All 10 wells with VOLAN/CFI/FracHite data were completed using emulsions, and since the first 10 an additional 12 wells have been completed using the VOLAN/CFI/FracHite/emulsion combination. The results of the first 10 will be discussed here, as their production history is established.

PRODUCTION COMPARISON

In terms of initial potential, the 10 Spraberry Package wells averaged 104.5 BOPD versus 51.5 BOPD for the 11 offsets with density/neutron/gamma ray data. This is shown in fig. 13, along with the monthly well test average for the two groups over a 4 month period. In terms of monthly production, the Spraberry Package wells averaged 1929 barrels of oil per month over the 4 month period, while the offsets averaged 1121 barrels of oil per month over the 4 month period. The monthly production distribution can be seen in fig. 14. The average increased production per well over the 4 month period was 3233 barrels of oil, or an average increase of $36,371 per well using a $15 oil price and 75 percent NRI. These two comparisons are graphically illustrated in fig. 15 and 16. Although only an estimate, the operator places the EUR of the 10 Spraberry Package wells at an average of 188,200 barrels, compared to an EUR average of 111,000 barrels for the direct offsets. The average Midland County Spraberry trend well completed in all four producing zones has an EUR of 60,000 barrels. Again, the wells in this study were completed in only the lower two zones.

CONCLUSIONS

The wells completed with the VOLAN/CFI/FracHite/emulsion package performed significantly better than those with density/neutron/gamma ray/crosslinked gel package. With other studies that used frac fluids alone as a variable in production comparison, it can be said that the fluid type probably did not make a significant difference in the production increase. The wells with VOLAN/CFI/FracHite data used fewer perforations, less volume, and covered more interval than the offset wells. A strong case is made for applying the VOLAN/CFI/FracHite technology to help accomplish a more efficient and more productive completion in the Spraberry trend. This is particularly valid in areas where the Dean/Wolfcamp can make a contribution to production.

*** Hoel, Mark, Spraberry Trend Completion Technique vs. Production Study, Smith Energy Services, internal paper, December 1986.

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8. "Friction Pressure and Limited Entry": B.J. Hughes Inc. publication BJ-455 (September 1979) Figure 1-D.

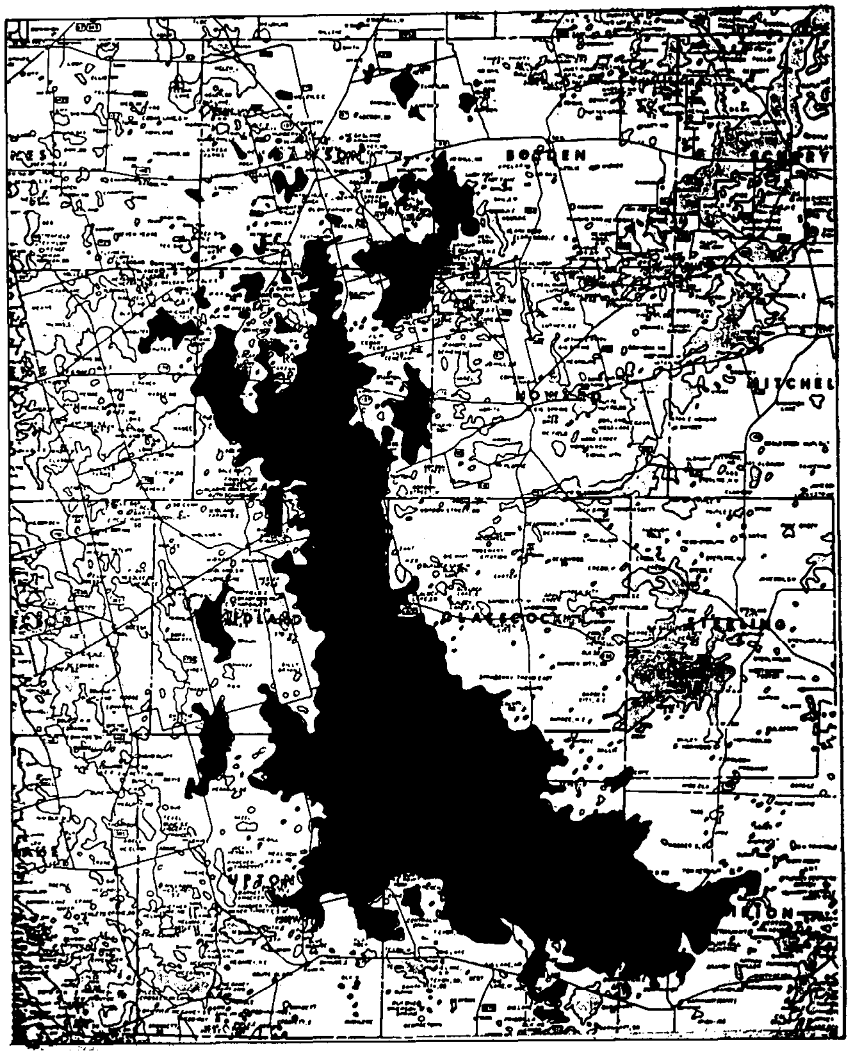

Figure 1—The Spraberry trend

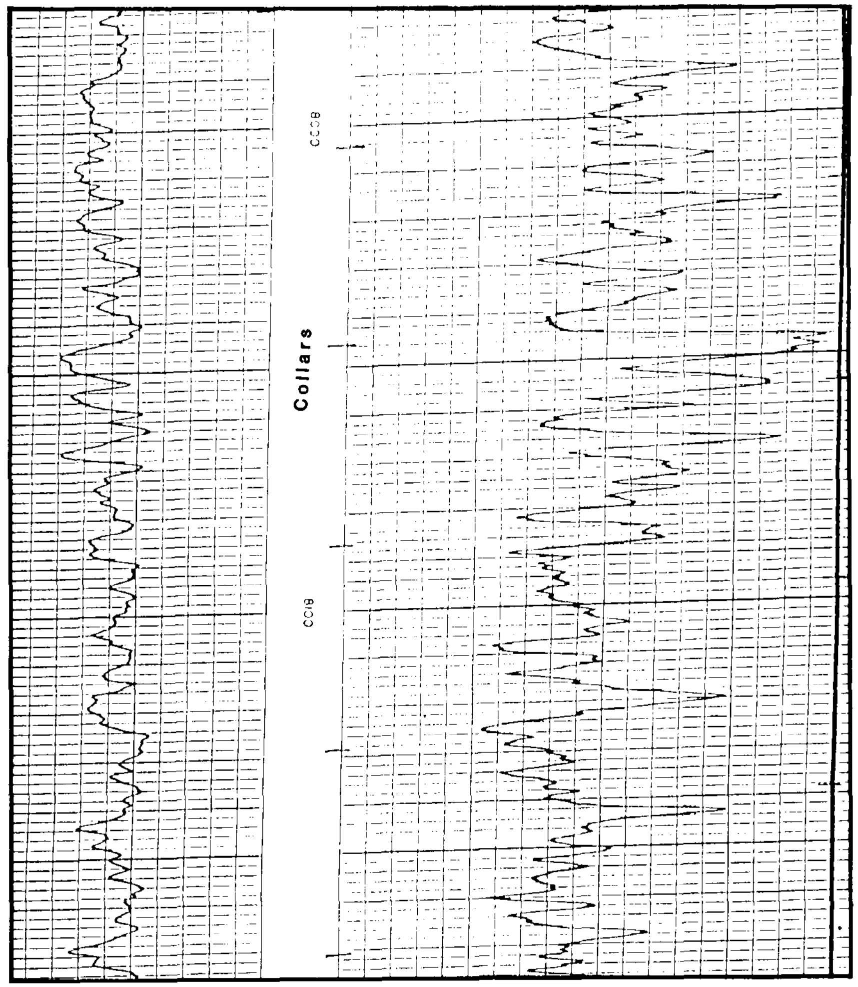

Figure 2—The gamma ray/neutron log

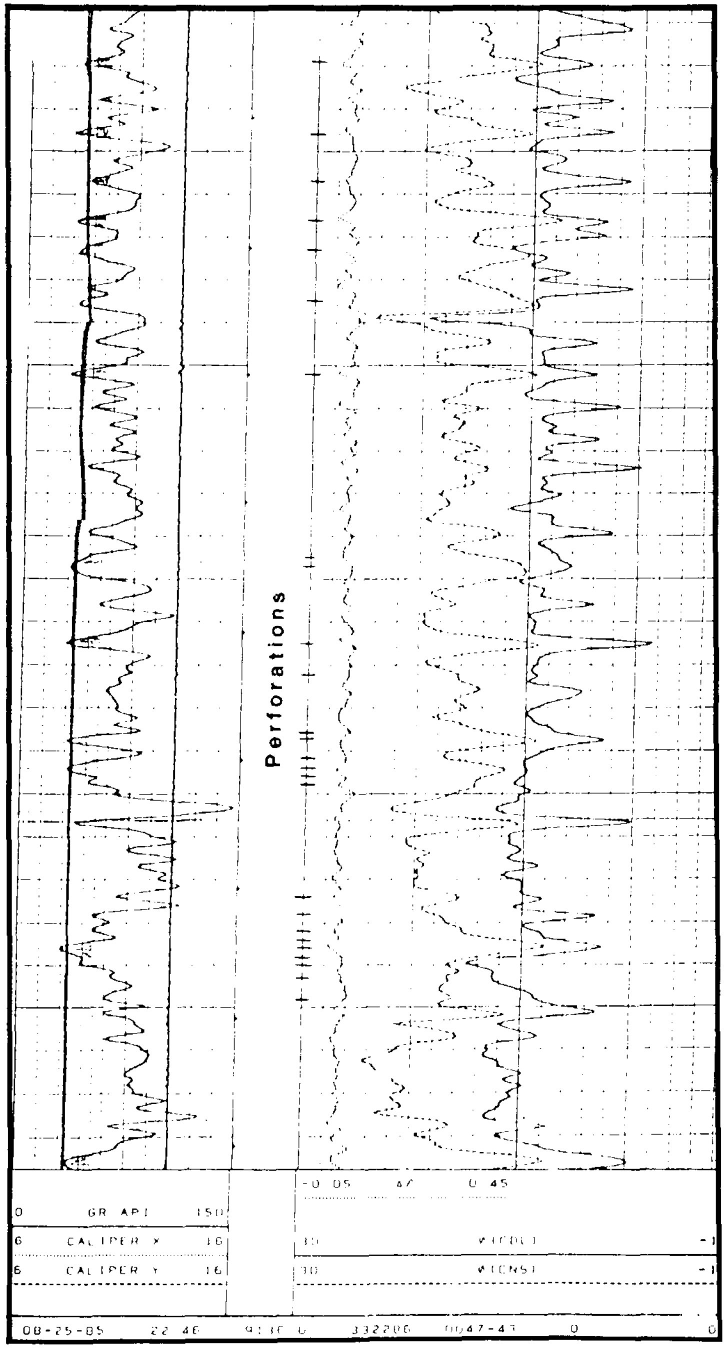

Figure 3—The FDC/CNL/GR log

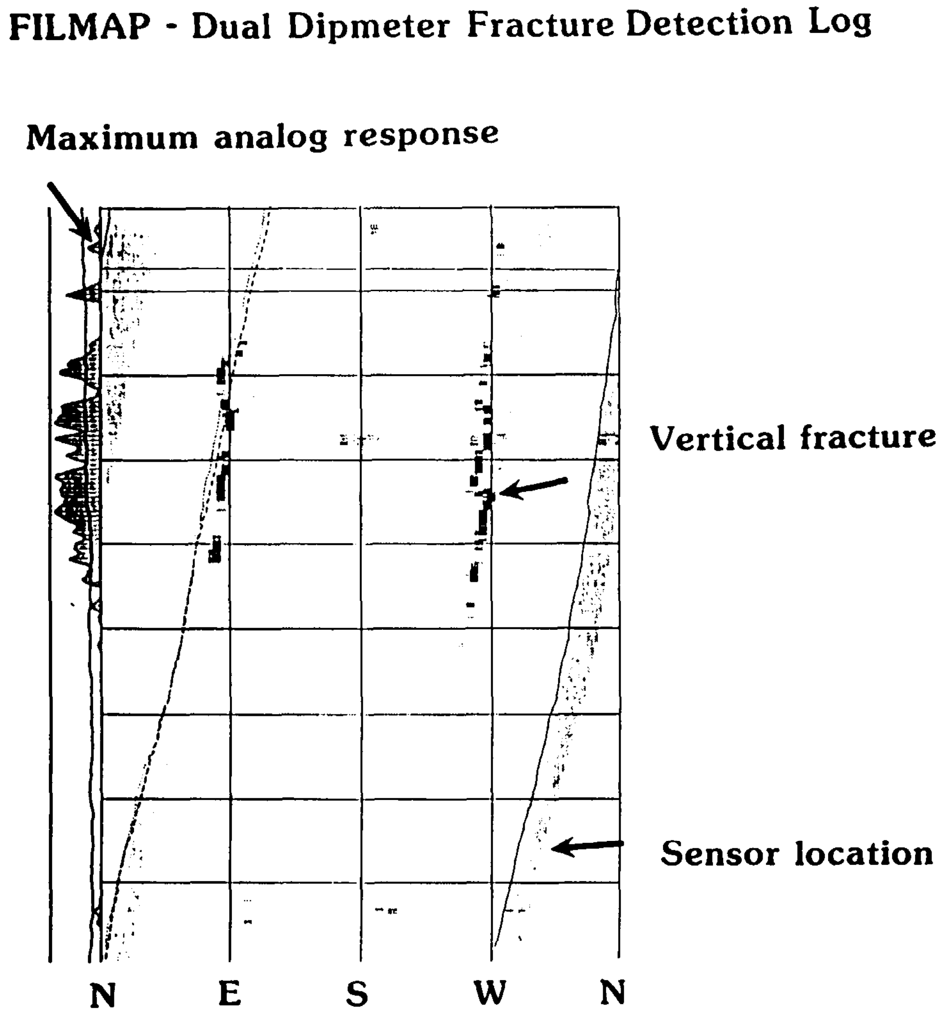

Figure 4—The FILMAP

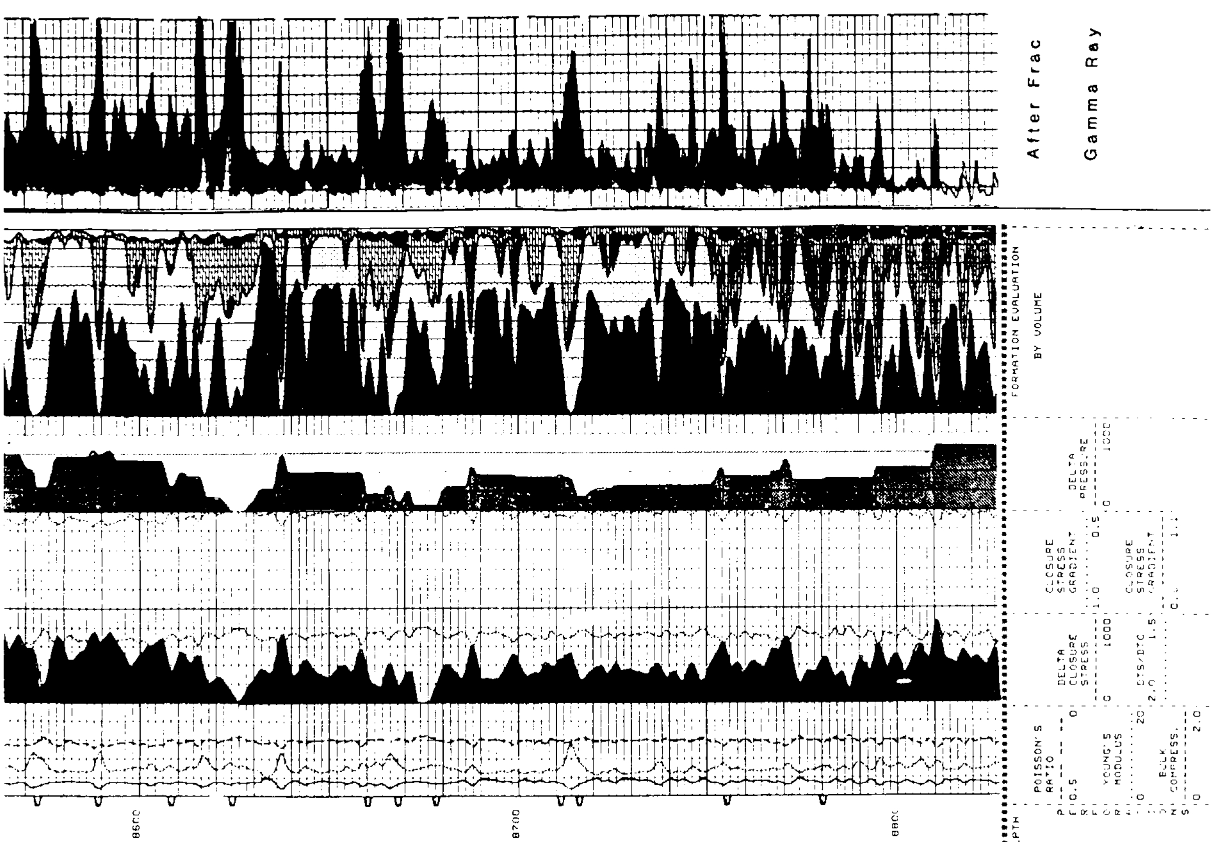

Figure 5—The FracHite log

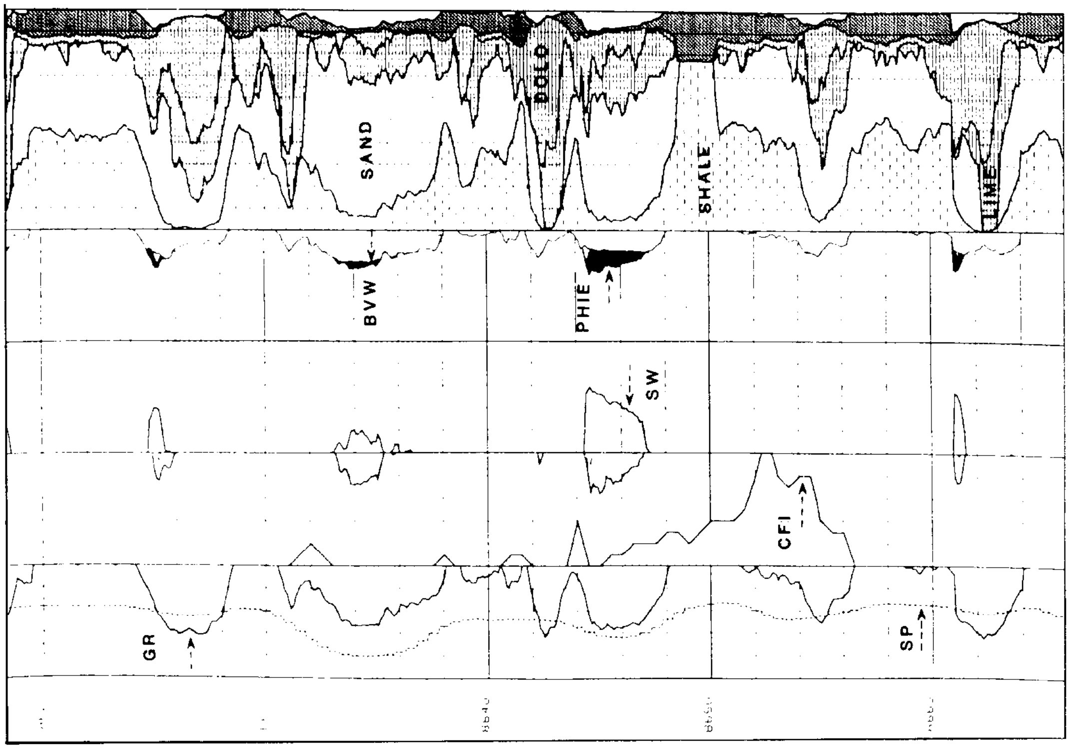

Figure 6—The Volumetric Analysis (VOLAN) presentation

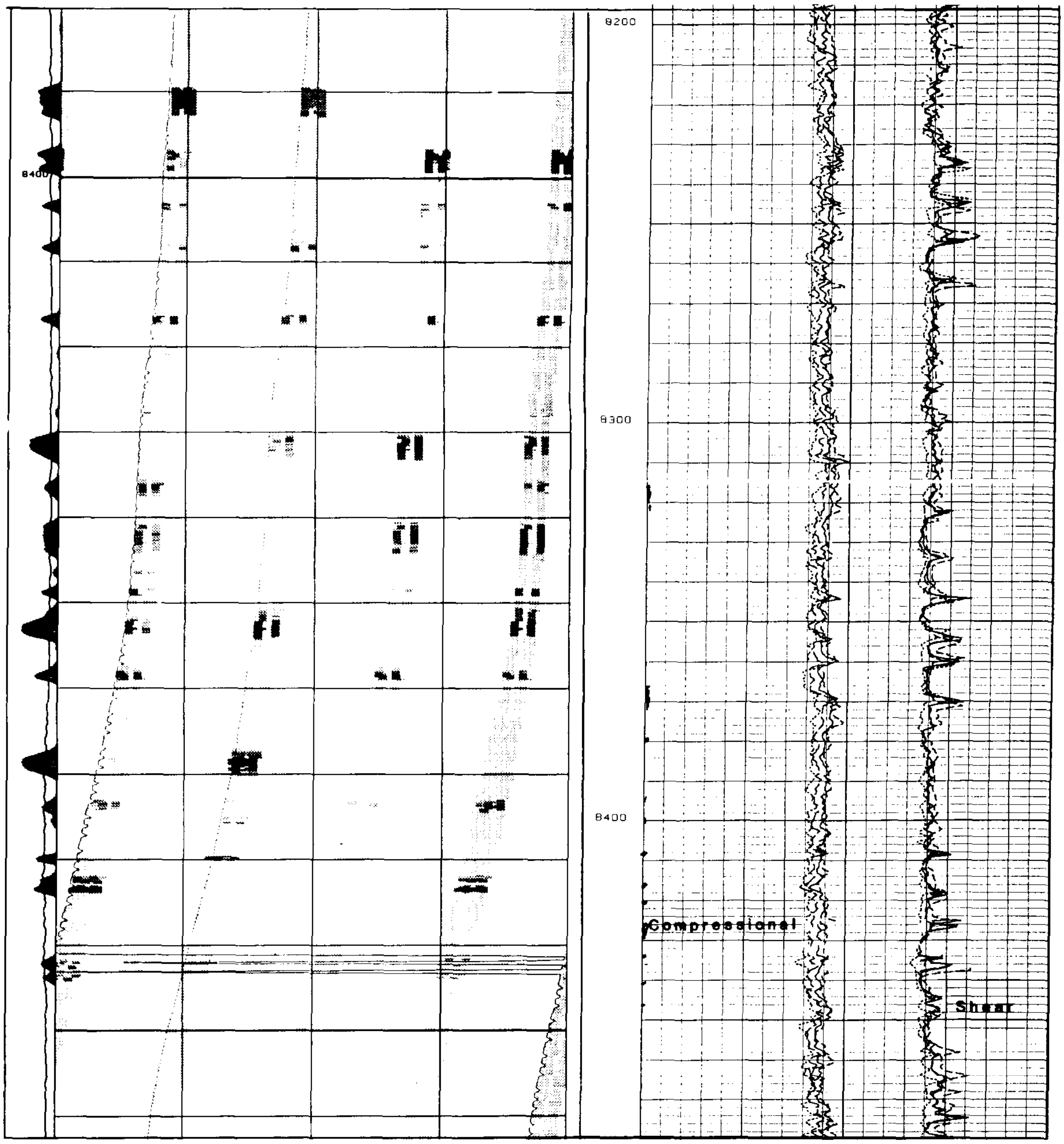

Figure 7—Dual Dipmeter FILMAP (L) vs. LSS energy attenuation (R)

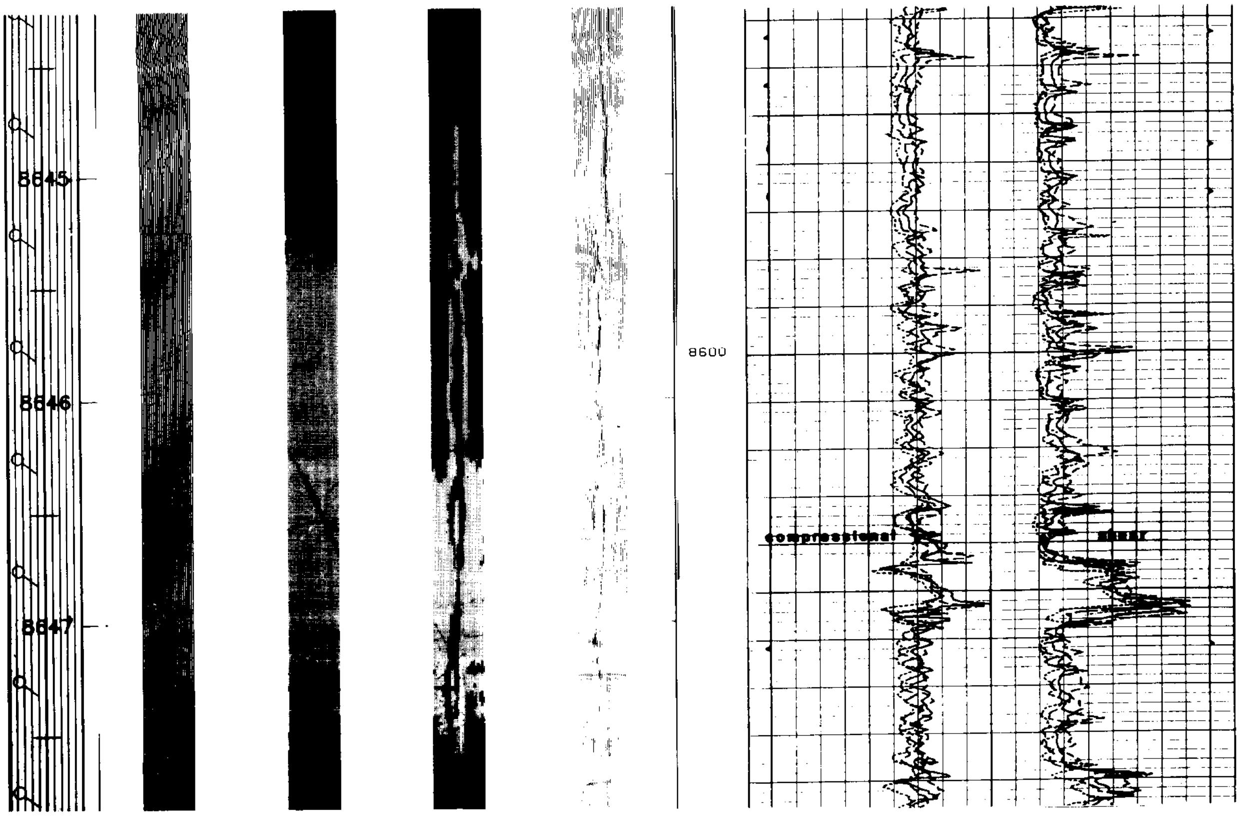

Figure 8—FMST (L) presentation vs. LSS energy attenuation (R)

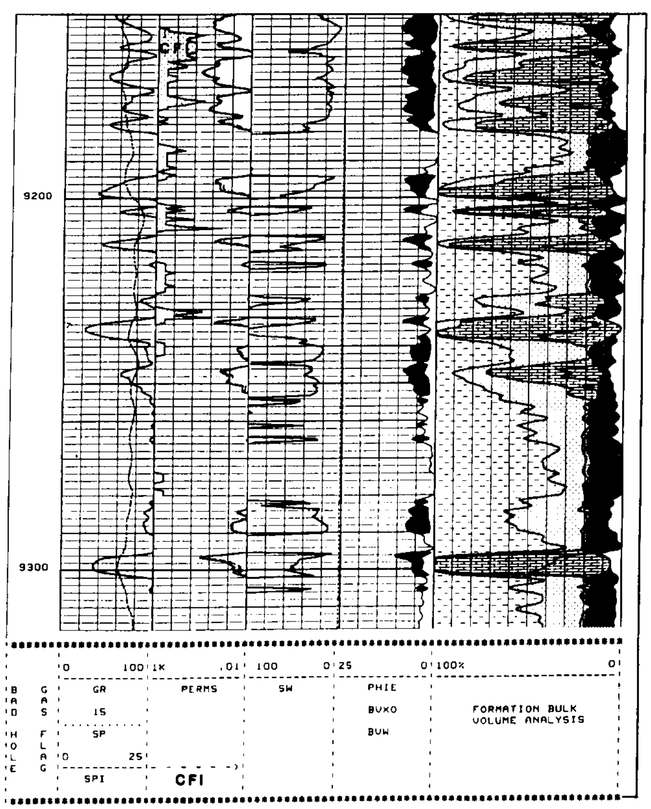

Figure 9—VOLAN with CFI (Composite Fracture Intensity) flag

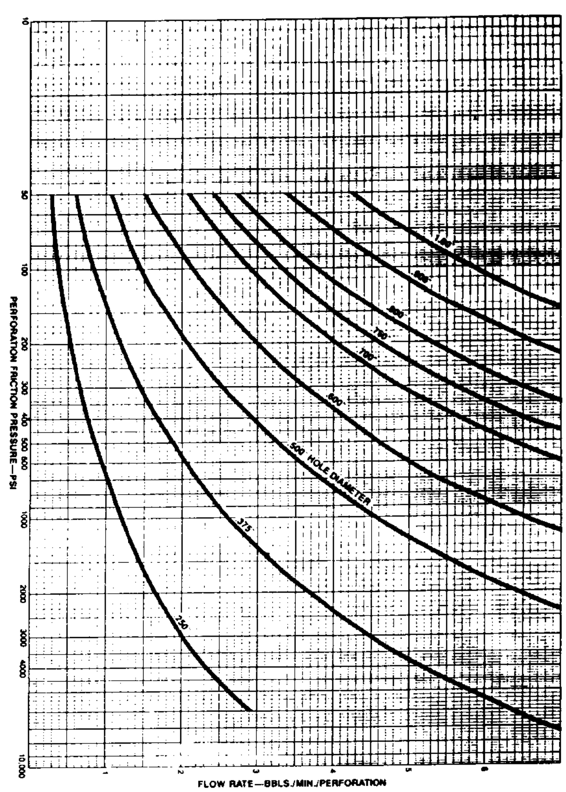

Figure 10—Flow rate vs. perforation friction pressure chart

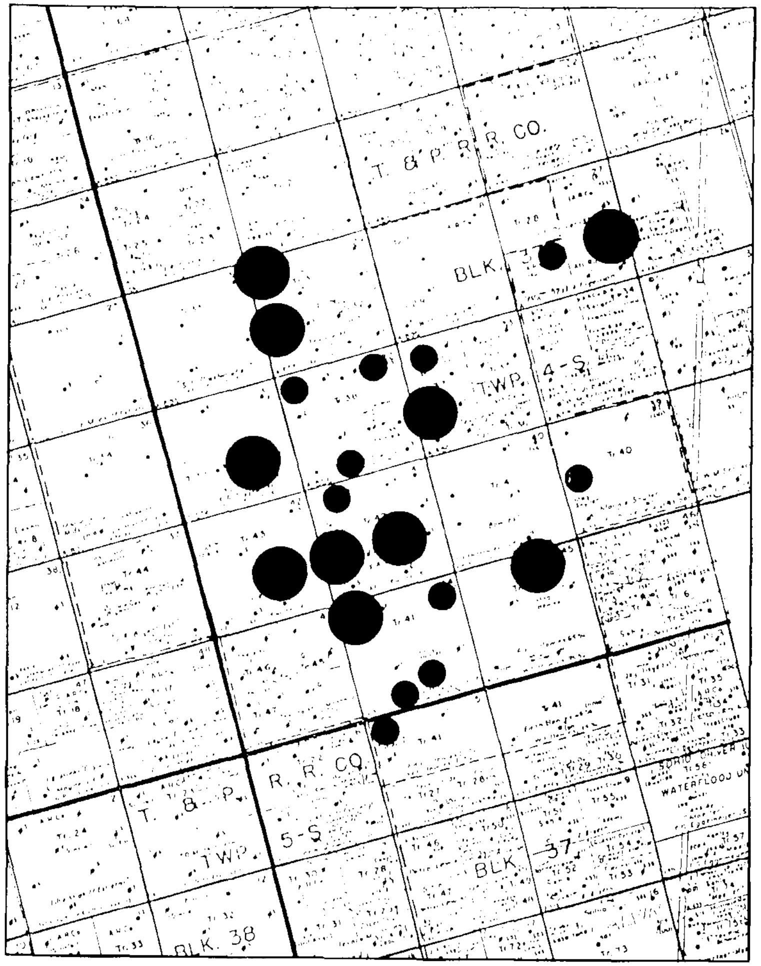

Figure 11—Well locations. Large dots used VOLAN/CFI/FracHite package, small dots used FDC/CNL/GR

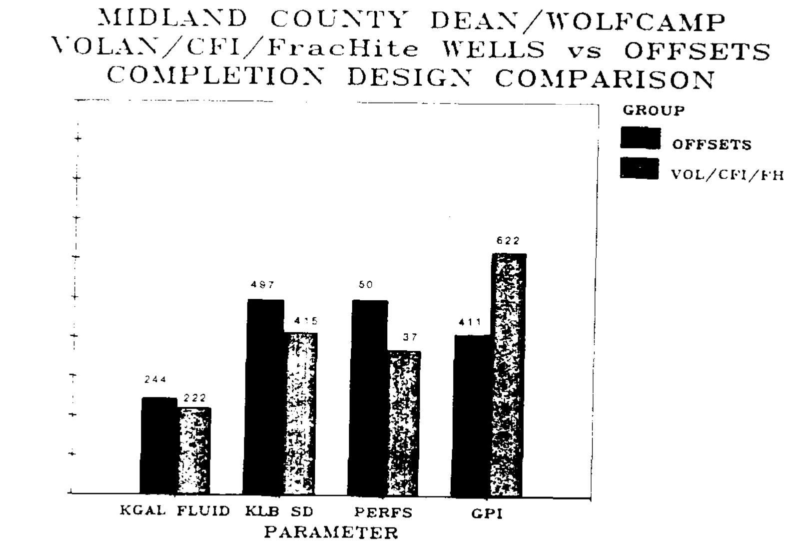

Figure 11A—Average volume, perforation, and gross perforated interval comparison

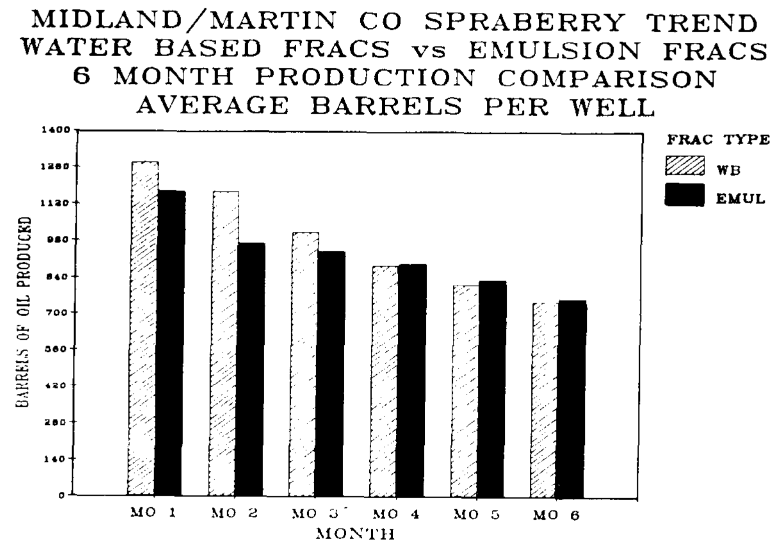

Figure 12—Production comparison, 62 water-based frac wells vs. 38 emulsion frac wells

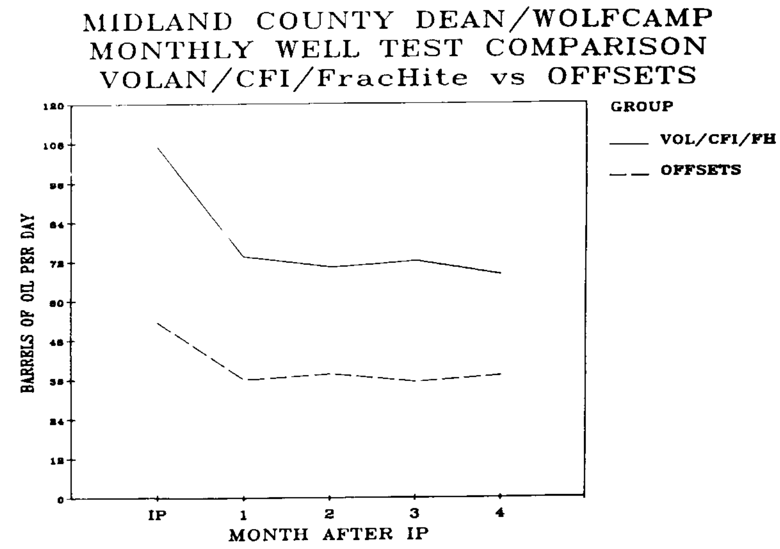

Figure 13—Average monthly well test comparison

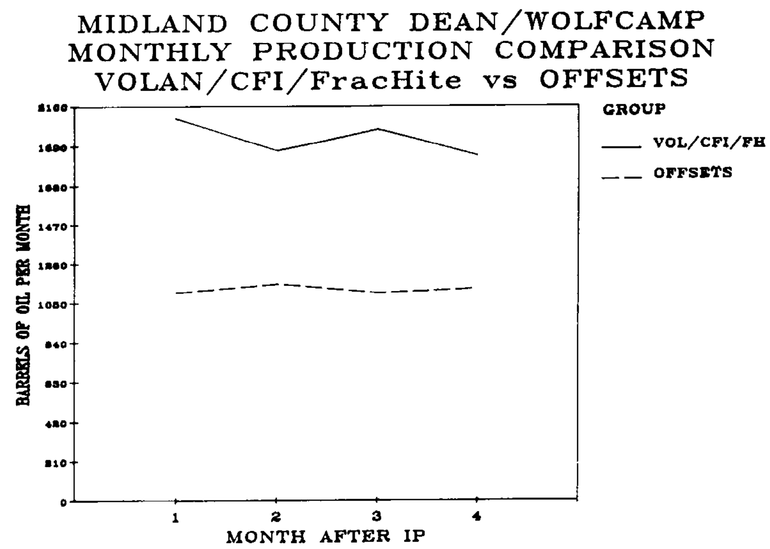

Figure 14—Average monthly production comparison

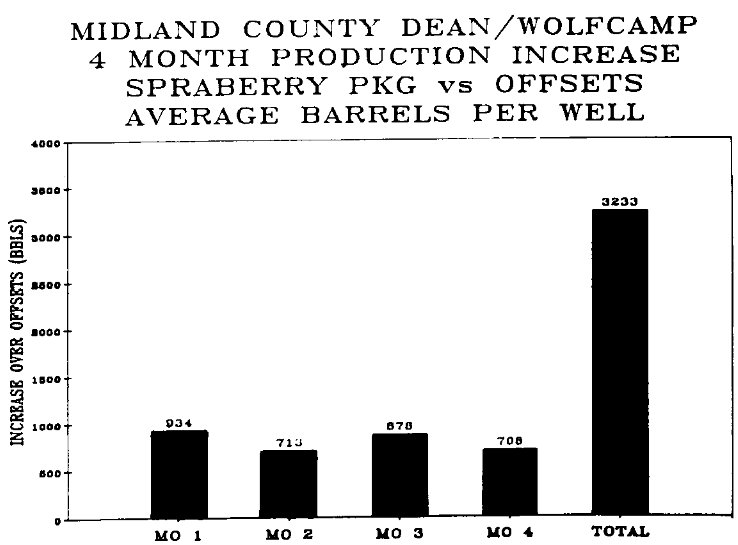

Figure 15—Average monthly production difference per well

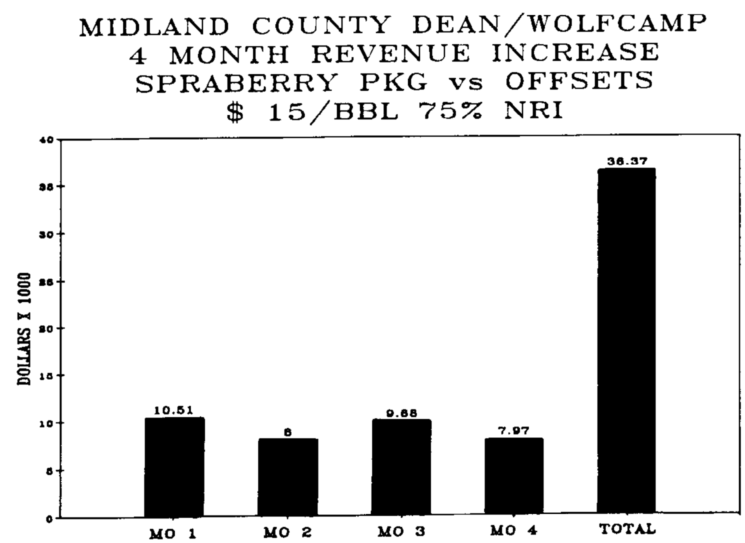

Figure 16—Average monthly revenue difference per well