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FRACTURES AND STRESSES IN BONE SPRING SANDSTONES

1989 ANNUAL REPORT

by

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ABSTRACT

This project is a collaboration between Sandia National Laboratories and Harvey E. Yates Company being conducted under the auspices of the Oil Recovery Technology Partnership. The project seeks to apply perspectives related to the effects of natural fractures, stress, and sedimentology to the stimulation and production of low-permeability gas reservoirs to low-permeability oil reservoirs as typified by the Bone Spring sandstones of the Permian Basin, southeast New Mexico. This report presents the results and analyses obtained in 1989 from 233 ft of oriented core, comprehensive suite of logs, various in situ stress measurements, and detailed well tests conducted in conjunction with the drilling of two development wells. Natural fractures were observed in core and logs in the interbed carbonates, but there was no direct evidence of fractures in the sandstones. However, production tests of the sandstones indicated permeabilities and behavior typical of a dual porosity reservoir. A general northeast trend for the maximum principal horizontal stress was observed in anelastic strain recovery measurements and in strikes of drilling-induced fractures; this direction is subparallel to the principal fracture trend observed in the interbed carbonates. Many of the results presented are believed to be new information for the Bone Spring sandstones.

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EXECUTIVE SUMMARY

This cooperative project between Sandia National Laboratories and the Harvey E. Yates Company (Heyco), Roswell, NM is one of the first projects being conducted under the new Oil Recovery Technology Partnership. The project seeks to apply specific Sandia technologies and experience developed in low-permeability gas reservoirs to low-permeability oil reservoirs in the Permian Basin. The target is sandstones of the Bone Spring Formation, thick, tight, light-oil reservoirs which contain an estimated 25 to 35 million barrels of oil per section. Production is erratic, however, and shows that the effective drainage of each well averages about 5 acres and that less than 6% of the original oil-in-place is being recovered.

The project is assessing the in situ stresses and the importance of natural fractures in these oil reservoirs in southeastern New Mexico. This reservoir has been postulated to be a naturally fractured play, but few data exist to prove or disprove the presence of fractures, or to document their character, relative importance, and orientation. Moreover, little is known about the magnitudes and orientations of the in situ stresses in this region and in the different strata. Subsequently, these findings will be used in the design and execution of stimulation and completion practices that will lead to improved production.

These questions were addressed by the acquisition of quality, nonroutine data from two new Heyco wells: the AJ 11 Federal No. 1 (Section 11, T31E, R18S, Eddy Co., NM) and the Cal-Mon 15 State No. 1 (Section 15, T33E, R18S, Lea Co., NM).

The AJ 11 Federal No. 1 was drilled to a depth of 8960 ft in April 1989, and 233 ft of core and a comprehensive suite of logs were obtained. Some problems with the coring operations were encountered, but sufficient data were obtained to answer many of the questions. The results from the

"main pay" carbonate and three benches of the Second Bone Spring sandstone include:

Core No. 1: "Main pay" carbonate, 8123 to 8172 ft, 44 ft recovered. Coring was stopped when the core barrel jammed due to abundant natural fractures in the core. The orientation survey worked, but because of fracturing, much of the core was rubblized. Thirteen oriented natural fractures and five oriented induced fractures were recovered in this carbonate interval.

Core No. 2: Above the First Bench sandstone, 8263 to 8267 ft, 4 ft recovered. The attempt to core the upper contact of the first Bone Spring sandstone was thwarted by a core bit dulled by reaming an undergauge hole in very hard rock during reentry with the coring assembly. Coring was stopped when penetration rates decreased to 2 hr/ft. Seven oriented natural fractures and two oriented induced fractures were recovered from this siliceous carbonate interval above the reservoir.

Core No. 3: Second Bench sandstone, 8529 to 8590 ft, 61 ft recovered. It was decided to forego a further attempt to core the First Bench sandstone, and this core was started 23 ft below the top of the Second Bench sandstone. Good core recovery and good orientation survey data were canceled in part by a wildly rotating scribe line. Although this loss of orientation data was not crucial because no natural or induced fractures were found in this core, the ASR tests could not be oriented.

Core No. 4: Second Bench sandstone and underlying carbonate, 8590 to 8649 ft, 62 ft recovered. The decision was made to core the lower contact of this reservoir, and coring continued immediately below core No. 3. The scribe line rotation problem was corrected, but the battery pack in the orientation tool shorted out, and no orientation data were recovered. However, significant bedding inclinations could be correlated between the core and the oriented FMS log, and five natural fractures observed in the carbonate could be oriented by this method.

Core No. 5: Overlying carbonate and top of the Third Bench sandstone, 8649 to 8709 ft, 62 ft recovered. Coring continued immediately below core No. 4. All components worked on this run: 12 oriented natural fractures in the carbonate and 19 oriented induced fractures were recovered.

Core Gamma: All recovered core was logged in the field on Sandia's core gamma machine. The core gamma log was reduced to the scale of the downhole geophysical logs and gave insight into shale content (low) and position in the hole of these cores.

Reservoir Properties: Each of the four principal core runs (Nos. 1, 3, 4, 5) was sampled in three places for laboratory tests on reservoir properties performed by Core Laboratories. These core analyses show that matrix permeabilities to gas of the sandstones are very low (0.2 to 11 μ d at 3500 psi confining stress), and that vertical permeabilities are lower than horizontal permeabilities by a factor of 2 to 3. Permeabilities to brine are on the order of a microdarcy or less. Porosities of these samples range from 2% to 7%, oil saturations from 0 to 39%, and water saturations from 21% to 93%. The low permeabilities and varying saturations indicate that relative permeabilities will play an important role in production.

Anelastic Strain Recovery (ASR): ASR tests were performed on 12 samples (three from each of the principal cores). These tests did not have the resolution anticipated due to long coring times and software problems. Nevertheless, results from six sandstone samples suggest that the principal stress is vertical, and that the maximum principal horizontal stress is approximately northeast.

Core Velocity Anisotropy (CVA): CVA tests were performed on 4 samples and velocity anisotropies of 3% to 11% were found. Orientations of minimum velocity (maximum stress direction) ranges from northeast to east for three sandstone samples.

Core Fractures: Two classes of fractures—induced and natural—were noted in these cores. Induced fractures normally strike parallel to the

maximum horizontal compressive stress, and the 19 most reliable induced fractures (from core No. 5) corroborate the generally northeast trend for this stress component derived from ASR tests. The less reliable and more erratic induced fractures noted in cores No. 1 and No. 2, however, may suggest a northwest trend in this shallower part of the hole. Natural fractures in the "main pay" carbonate (13 oriented from core No. 1) show several intersecting sets, the dominant set trending slightly east of north. No dominant trend was noted in core run No. 2 (7 fractures). The natural fractures in the Bone Spring sandstone interval cored in core run Nos. 3, 4, and 5 all occur in the interbedded carbonates: No fractures were recorded in the sandstones in either geophysical logs or core. However, fractures in the associated carbonates (five from core No. 4 and 12 from core No. 5) show a dominant northeast to north-northeast trend, subparallel to the measured present-day maximum horizontal stress in this zone.

Thin Section Petrography: Results indicate that the sandstone benches of the second Bone Spring sandstone are primarily siltstones, predominantly composed of quartz. Other components include 2% to 10% potassium feldspar, 11% to 18% plagioclase, 13% to 17% dolomite cement, <2% pyrite, and 4% to 7% clay (primarily illite, but with <1% iron chlorite). The clays may be a significant source of reservoir damage, as they appear to be highly reactive to fresh water. Clay-rich, salty efflorescences are commonly noted on core that has been wetted for sedimentologic study.

Sedimentology Studies: Sedimentary structures and assemblages of these structures suggest that the Bone Spring sandstones are not turbidite deposits as they have commonly been interpreted to be. Rather, they are thin repetitive laminae (<1 mm to ~1 cm thick) that settled out from suspension. Secondary, deep-marine currents reworked many of the laminae into thin rippled beds; current indicators show an east to northeast paleoflow. Two types of invertebrate traces are present in the upper sections of the reservoir: bedding-plane tracks and trails, and horizontal burrowing. These disrupt the strong primary horizontal layering, probably enhancing local vertical permeability.

Geophysical Logging: Nine different logs were run in this well by two different companies (Schlumberger and Western Atlas Wireline Services). Three borehole televiwer logs, a dipmeter log, a sonic log, a nuclear petrology lithology tool, and the formation microscanner (FMS) were run in addition to the lithodensity and dual laterolog tools normally run in Heyco wells. Two of these were developmental logs run by the companies at no cost to the project. The logs showed extensive fracturing in the "main pay" carbonate, but none in the sandstone intervals. The FMS log was useful in orienting core No. 4 where the orientation survey did not work. Limited data on breakouts, which reflect horizontal stress directions, were obtained from these logs.

Breakdown and Testing: Mud-log shows, geophysical logs, and oil-bleeding core suggested that the Bone Spring sandstones in the AJ 11 Federal No. 1 well had reservoir potential. The Second Bench sandstone was perforated from 8517 to 8618 ft with 19 shots placed at indications of high porosity and the interval was treated initially with 4000 gal of 2% KCl water with clay inhibitor. Water recovery was good, but after 4 days of no shows of oil or gas, the well was again treated with 3500 gal of mixed treatment fluids (NARS). Recovery percentage and rates of the fluids were also good, but no oil was recovered. After four days, 4500 gal of 7-1/2% HCl acid was injected and recovered, but still no oil was produced. With no oil production, the planned well tests could not be performed. The well was completed in the "main pay" carbonate, and focus of this study was shifted to another development well 11 miles to the east.

The Cal-Mon 15 State No. 1: This well was completed June 24, 1989, and was used for well and fracturing tests in the Second Bone Spring sandstone. This well has good development of both log porosity and thickness of the Bone Spring sandstones. The mud log indicated good hydrocarbon shows. Twenty-four drilled sidewall cores were taken between depths of 8973 and 9444 ft in all three sandstones. Some of these 1-in. plugs were sealed and sent to Core Laboratories for reservoir analysis. Others went to Sandia and Heyco for comparative sedimentologic and reservoir analysis. Results suggest that similar reservoir properties and depositional environment

occur in this well as in the AJ 11 Federal No. 1 well.

Well Testing: The Cal-Mon 15 State No. 1 well was perforated at high-porosity locations at 9005, 9023, and 9027 ft in the First Bench sandstone, and at 9345, 9359, 9403, 9407, and 9423 ft in the Third Bench sandstone. The six Third Bench sandstone perforations were treated as a group with 1800 gals of HCl acid. The well was swabbed on and off for five days at an average rate of 2 bpd. CER Corporation was contracted to run a buildup test using a quartz pressure gauge and a bottomhole closure tool to minimize wellbore storage effects. The buildup was run for 10 days with no problems or leaks. The data were unusual as they showed a dual-storage behavior in the wellbore for the first 80 hours, no clear straight line on the Horner plot, and a decreasing derivative curve throughout the test (after wellbore storage). Interpretation of the well test data yields a 10 to 15 μ d reservoir with probable dual-porosity behavior, which may be the result of either natural fractures or permeable layers.

Microinjections: After the well test was completed, a series of KCl injection tests were conducted in the Third Bench to determine closure stress and other reservoir parameters. CER Corporation's pressure gauge was placed downhole in an open-ended tubing string for accurate bottomhole pressure measurements. Injections consisted of three small-column stress tests, a 70-bbl pump-in/shut-in test, a step-rate/flow-back test and two pump-in/flow-back tests. The tests gave a closure stress of 6665 ± 70 psi (approximately 0.71 psi/ft) and an apparent leakoff permeability of 4 μ d.

Minifrac: After completion of the microinjections, the upper three perforations were acidized with 7.5% HCl and a minifrac consisting of 25,000 gal of 45-lb/1000 gal HPG linear gel with 3% HCl was conducted in both zones together. Analysis of the minifrac was difficult because no bottomhole pressure measurement was possibly due to operational constraints. The calculated leakoff coefficient was 0.0005 ± 0.0002 ft/ $\sqrt{\text{min}}$. Based on the pressure behavior data, the fracture height appeared to grow

to the full height of the individual sandstone benches. There was no indication of natural fractures having any effect on the minifrac behavior.

Fracture Treatment: Immediately after the minifrac, Heyco treated the perforations with 115,000 gal of 45-lb/1000 gal HPG and 3% HCl and 100,000 lb of intermediate strength proppant. The well was then put on production on pump.

Conclusions: Nonroutine, detailed data were obtained from two Heyco development wells during the year. Preliminary conclusions based upon the first year of study are listed below:

No natural fractures were seen in core or logs in the sandstone benches of the Second Bone Spring sandstone. In addition, they did not appear to have a major influence on the well testing or the fracturing tests. Nevertheless, natural fractures may still be important for three reasons. First, they may still be the cause for localized good production observed in other Bone Spring sandstone wells. Second, measured effective permeability is much greater than the permeability of the matrix rock. Finally, if present, they are marginal i.e., narrow, widely spaced, poorly-interconnected) and are easily damaged, significantly affecting production.

The core properties indicate very low permeability matrix rock (0.2 to 11 μ d to gas at in situ stress), with low porosities (2 to 7%) and variable oil (0 to 39%) and water (21 to 93%) saturations. The matrix permeability will be still lower at reservoir saturations.

The Bone Spring Sandstones are predominantly siltstones and they contain moderate amounts (4 to 7%) of clay, mostly illite. They were deposited as thin repetitive laminae that settled out from suspension and appear reworked by secondary, deep-marine currents and portions contain invertebrate traces; they do not have features typical of turbidite deposits, as they have commonly been interpreted to be.

Stress indicators (e.g., ASR, CVA, and drilling-induced fractures) suggest that the maximum principal horizontal stress over the cored interval is northeast to east, although the accuracy is less than desired. Small volume injection tests gave a closure stress of 6665 ± 70 psi, approximately a 0.71 psi/ft gradient.

Log-derived porosities were found to be about 2 to 3 porosity percent higher than core-derived porosities. This has probably caused an over estimate of the amount of oil in place.

Reservoir permeability was measured to be 10-15 μ d based upon a 10-day buildup test. This is at least an order of magnitude greater than the in situ matrix permeability estimated from core data. This difference indicates that natural fractures, high permeability streaks, or some other mechanism contribute to production.

These results represent a wealth of new information that was not previously available for the Bone Spring sandstones and they present new insight into these reservoirs.

The above results are not as definitive with respect to the role of natural fractures and in situ stresses as was hoped at the start of this project. The AJ 11 Federal No. 1 was not productive from the Bone Spring sandstone, and the Cal-Mon 15 State No. 1 was a below-average producer. Thus, the data presented here may not be typical of those for good Bone Spring sandstone production. Natural fractures may still be important if they can be shown to be present in a good producing well. Damage appears to be a significant factor as evidenced in production behavior and by the high skins found in well tests. The depositional environment appears very different than previously thought, thus presenting a new perspective on these reservoirs. These areas form the focus for additional work in the coming year.

1.0 INTRODUCTION

This cooperative project between Sandia National Laboratories and the Harvey E. Yates Company (Heyco), Roswell, NM, is one of the first projects being conducted under DOE's new Oil Recovery Technology Partnership. The project seeks to apply specific Sandia technologies and experience developed in low permeability gas reservoirs to low permeability oil reservoirs in the Permian Basin. The target is the Second sandstone of the Bone Spring Formation, a thick, tight, light-oil reservoir which contains an estimated 25 to 35 million barrels of oil per section. Production is erratic and results show that the effective drainage of each well averages about five acres, and that less than 6% of the original oil-in-place is being recovered.

The permeability of this formation is marginal and some form of stimulation is required to obtain production. While initial production rates of 50 to 200 BOPD are common, within 1 to 2 years the rates decline to 20 BOPD or less. Gas-oil ratios are initially 500 to 1000, but they increase to 2000 to 2500 within the first year or two. Water is produced in only small amounts (<2 BWPD). Only small amounts of clays are found in the sandstones and surrounding rocks, but some, such as chlorite, are acid sensitive. No natural fractures have been seen in the few cores which are available, but the abundance of such fractures in the overlying and underlying carbonates, as well as the rapid decline curves, have prompted speculation that the production is controlled by natural fractures.

The project is assessing the in situ stresses and the importance of natural fractures in these oil reservoirs in southeastern New Mexico. This reservoir is postulated to be a naturally fractured play, but few data exist to prove or disprove the presence of fractures, or to document their character, relative importance, and orientation. Moreover, little is known about the magnitudes and orientations of the in situ stresses in this

region and in the different strata. Subsequently, these findings will be used in the design and execution of stimulation and completion practices that will lead to improved production.

These questions were addressed by the acquisition of nonroutine core, log and well test data from two Heyco development wells. The AJ 11 Federal No. 1 well (Section 11, T31E, R18S, Eddy Co., NM) was drilled March to April 1989 (Figure 1.1). This was the primary well for this project and extensive core was taken and an extensive log suite was run over the intervals shown in Figures 1.2 to 1.4. However, after several attempts to break down and produce the well in the Second sandstone, there was no oil production (but good water production) and further work in this interval was abandoned. Another development well, the Cal-Mon 15 State No. 1 (Section 15, T33E, R18S, Lea Co., NM) located about 11 miles to the east, was chosen as the project well for the remaining tests. Sidewall cores were cut and well injection tests were performed in the Second sandstone interval described in Figures 1.5 to 1.7.

This report presents the data and analyses which resulted from the nonroutine activities conducted in 1989 under this Oil Recovery Technology Partnership project on these two development wells. In general, the focus is upon the Second sandstone and work conducted by Sandia National Laboratories. However, some results are presented for the "main pay" carbonate and from Heyco activities. In any event, none of the work presented here would have been possible without the enthusiastic support and cooperation of Heyco and its personnel.

Figure 1.1 Generalized Geologic Section

A.J. 11 FEDERAL #1

Figure 1.2 Interval of Interest and Core Runs

Figure 1.3 Electrical Logs—AJ 11 Federal No. 1

Figure 1.4 Density Logs—AJ 11 Federal No. 1

CAL MON 15 STATE #1

Figure 1.5 Interval of Interest, Perforations, and Sidewall Cores

Figure 1.6 Electrical Logs—Cal-Mon 15 State No. 1

Figure 1.7 Density Logs—Cal-Mon 15 State No. 1

2.0 CORING AND ANALYSES

2.1 Core

The AJ 11 Federal No. 1 was drilled to a depth of 8960 ft in April 1989 and 233 ft of core and a comprehensive suite of logs were obtained over the "main pay" carbonate and three Benches of the Second Bone Spring sandstone (Figure 1.2). Some problems with the coring operations were encountered, but sufficient data were obtained to answer many of the questions. The results include:

Core Run No. 1: "Main pay" carbonate, 8123 to 8172 ft, 44 ft recovered. Coring was stopped when the core barrel jammed due to abundant natural fractures in the core. The orientation survey worked, but because of fracturing, much of the core was rubblized. Thirteen oriented natural fractures and five oriented induced fractures were recovered in this carbonate interval.

Core Run No. 2: Above the First Bench sandstone, 8263 to 8267 ft, 4 ft recovered. The attempt to core the upper contact of the First Bench sandstone was thwarted by a core bit dulled by reaming an undergauge hole in very hard rock during reentry with the coring assembly. Coring was stopped when penetration rates decreased to 2 hr/ft. Seven oriented natural fractures and two oriented induced fractures were recovered from this siliceous carbonate interval above the reservoir.

Core Run No. 3: Second Bench sandstone, 8529 to 8590 ft, 61 ft recovered. It was decided to forego a further attempt to core the First sandstone, and this core was started 23 ft below the top of the Second sandstone. Good core recovery and good orientation survey data were canceled in part by a wildly rotating scribe line. Although this loss of orientation data was not crucial because no natural or induced fractures were found in this core, the ASR tests could not be oriented.

Core Run No. 4: Second Bench sandstone and underlying carbonate, 8590 to 8649 ft, 62 ft recovered. The decision was made to core the lower contact of this reservoir, and coring continued immediately below core No. 3. The scribe line rotation problem was corrected by lowering mud-pump pressure and weight on bit, but the battery pack in the orientation tool shorted out, and no orientation data were recovered. However, significant bedding inclinations could be correlated between the core and the oriented FMS log, and five natural fractures observed in the carbonate could be oriented by this method.

Core Run No. 5: Overlying carbonate and top of the Third Bench sandstone, 8649 to 8709 ft, 62 ft recovered. Coring continued immediately below core No. 4. All components worked on this run: 12 oriented natural fractures in the carbonate and 19 oriented induced fractures were recovered.

A general description of core run Nos. 3, 4, and 5 showing sedimentary structures and sample locations is given in Figure 2.1.

2.2 Core Gamma Log

All recovered core was logged in the field on Sandia's core gamma machine. The core gamma log was reduced to the scale of the downhole geophysical logs for comparison with the well logs. Core gamma logs from the five cored runs are shown in Figures 2.2 and 2.3. The very low gamma spikes mark locations where cores were taken for testing. The high spikes are shaley areas and these were matched to the wireline gamma ray log for depth correlation.

2.3 Anelastic Strain Recovery (ASR) and Core Velocity Anisotropy (CVA)

ASR tests were performed on 12 samples (three from each of the principal core runs). The ASR results were disappointing, primarily because of the long time intervals between when the cores were cut and when the cores were instrumented (8 to 25 hrs) and because of some resolution problems

with the data logging software. Figure 2.4 shows an example of the type of data obtained from one of the cores. The lower plot adds a least-squares polynomial fit of the data that was made to extract orientations. The error on the orientation is about $\pm 15^\circ$ because of the poor resolution of the logging software. Table 2.1 gives the ASR orientations from the cores that were analyzable. Results from the "main pay" carbonate were questionable because of orientation difficulties, tectonic fractures, vugs, and the large grain size. Results of the ASR tests suggest that the principal stress is vertical, and that the maximum principal horizontal stress is approximately northeast.

CVA tests were performed on four core samples, three from the sandstones and one from the "main pay" carbonate. Figures 2.5 to 2.8 show the velocity results along with a nonlinear regression fit of the data using a theoretical $\cos(2\theta) + \cos(4\theta)$ model. Velocity anisotropies were 3 to 11% for these samples. Orientations of the minimum velocity direction (maximum stress direction if the anisotropy is due to stress relaxation) ranged from northeast to east for the sandstone samples. The minimum velocity in the carbonate sample (8123 ft) was oriented southeast, but its large grain size, vugginess, and natural fractures yield little confidence for this sample.

The stress results for the Bone Spring sandstones are shown on Figure 2.9. The maximum stress orientation is generally in the NE quadrant, but the scatter in the data prevents any additional interpretation.

2.4 Reservoir Properties

Samples, both sealed and unsealed, were selected from each of the four principal coring run (Nos. 1, 3, 4, and 5) for reservoir property analyses. The studies performed by Core Laboratories were:

- (a) Routine Dean-Stark saturation and porosity analyses on full-diameter core (Table 2.2) and permeability measurements under

confining stress for 1-in. diameter plug samples cut both vertically and horizontally (Table 2.3) and cut vertically and in two orthogonal horizontal directions (Table 2.4) (File 57181-15821; June 1, 1989).

- (b) Additional permeability and porosity measurements under confining stress on 1-in.-diameter plug samples cut vertically and in two orthogonal horizontal directions for two adjacent samples--one homogenous in appearance and the other with laminations (Table 2.5) (File No. SCAL-89121; July 11, 1989).
- (c) Routine saturation and porosity analyses and permeability measurements on sidewall core plugs from the Cal-Mon 15 State No. 1 well (Table 2.6) (File No. SCAL-89121; August 1, 1989).
- (d) Basic saturation, porosity, and permeability measurements on two additional AJ 11 Federal No. 1 samples and one additional Cal-Mon 15 State No. 1 sample (Table 2.7). Air-brine centrifuge capillary pressure measurements on a sample from each well (Figure 2.10). A USBM wettability test was attempted (File No. SCAL-89121; December 5, 1989).
- (e) A summary of AJ 11 Federal No. 1 core properties in relation to the resistivity log is given in Table 2.8.

Overall, the results show that matrix permeabilities to nitrogen gas are very low: from a few tenths microdarcy up to 10 μ d at 3500 psi confining pressure. Vertical permeabilities are generally lower than horizontal permeabilities by a factor of two to three. The permeabilities are so low that a USBM wettability test could not be performed and a decision made not to measure permeabilities to oil at this time. Porosities are generally in the 4 to 7% range and decrease noticeably with increasing confining pressure. Generally, the degree of permeability decrease with confining pressure is proportioned to the decrease of porosity with confining pressure. Oil saturations range from 0 to about 40% and water saturations range from around 20% to greater than 90%. Generally, the results of these routine analyses were quite similar for the "main pay"

carbonate from the AJ 11 Federal No. 1 well or Second sandstone samples from both wells.

A few directional permeabilities were measured as a function of horizontal plug azimuth. Orthogonal horizontal plugs were taken at 30° and 120° east of north to see if there was a directional effect on permeability caused by stress-relaxation-induced microcracks (Section 2.3). There was no noticeable anisotropy.

Air-brine capillary pressure measurements were performed on a Second sandstone sample from each well, and there is a noticeable difference (Figure 2.10). The effective capillary pressures for core with residual brine saturations of 70% to 90%, typical of the AJ 11 Federal No. 1 samples, are of the order of 100 to 200 psi. The brine saturations in the Cal-Mon 15 State No. 1 samples are lower, probably closer to irreducible water saturation, and capillary pressures can approach 1000 psi. Of note, the AJ 11 Federal No. 1 well had high water production upon stimulation while the Cal-Mon 15 State No. 1 well had high oil production with very little water production.

The AJ 11 Federal No. 1 preserved sample chosen for capillary pressure measurements was flushed with brine prior to testing and an effective permeability to brine at residual oil saturation was found to be 1 micro-darcy.

2.5 Core Fractures

Two classes of fractures—coring induced and natural—were noted in the core from the AJ 11 Federal No. 1 well.

Coring induced fractures normally strike parallel to the maximum horizontal compressive stress, and the 19 most reliable induced fractures (from core No. 5) corroborate the generally northeast trend for this stress component derived from ASR tests (Figure 2.11A). The less reliable and more erratic induced fractures noted in cores No. 1 and No. 2, however, may suggest a northwest trend in this shallower part of the hole (Figure 2.11B).

Natural fractures in the "main pay" carbonate (13 oriented from core No. 1) show several intersecting sets, the dominant set trending slightly east of north. No dominant trend was noted in core run No. 2 (seven fractures). The fractures in the Second sandstone interval cored in core run Nos. 3, 4, and 5 all occur in the interbedded carbonates. No fractures were recorded in the sandstones in either geophysical logs or core. However, fractures in the associated carbonates (five from core No. 4 and 12 from core No. 5 as shown in Figure 2.12) show a dominant northeast to north-northeast trend, subparallel to the measured present-day maximum horizontal stress in this zone.

2.6 Petrography

Petrographic studies were conducted on four samples from the AJ 11 Federal No. 1 well and one sample from the Cal-Mon 15 State No. 1 well. Tests included thin section petrography, bulk and clay X-ray diffraction, scanning electron microscopy (SEM), and diagenetic analyses (Core Laboratories, File No. 189173; July 20, 1989). Of particular interest was verifying the apparent uniformity of the Second Bench of the Second sandstone in the AJ 11 Federal No. 1 well seen in the well logs and confirming the similarity of the intervals of interest in the two wells.

The general descriptions from this action analyses are given in Table 2.9. Of particular note, is that the rocks in the Second sandstone are primarily siltstones. X-ray diffraction (Table 2.10) and thin section (Table 2.11) composition analyses indicate that the samples are similar and are composed of quartz (58 to 62%) feldspar (16 to 25%), dolomite cement (4% to 17%), and clay (4% to 8%).

Illite is the dominant clay in these samples but there are traces of chlorite in the pores of these sandstones. The one SEM sample (AJ 11 Federal No. 1 at 8613 ft) indicates the presence of authigenic, thread-like illite in the pores of the sample. The presence of trace amounts of chlorite, the thread-like illite in the pores, as well as the extremely

high salinity of connate waters suggest that this matrix rock may be susceptible to common forms of damage, reducing the effective permeability of the rock. An electron dispersion spectrum (EDS) analysis (Figure 2.13) of the dolomite cement in the SEM sample shows that the iron content, at least in this sample, is negligible.

Special preparation was used on two samples to detect the presence of water-soluble halite as salty efflorescences were commonly noted on core that had been wetted for sedimentologic study. No halite was found in these two samples. (The connate water is very saline with concentrations on the order of 23,000 ppm Ca, 63,000 ppm Na, and 140,000 ppm Cl). However, halite was observed in a subsequent SEM study (Section 2.8).

A diagenetic history derived by Core Laboratories is given in Table 2.12. All samples were found to have the same history.

2.7 Sedimentology

A detailed sedimentologic study was performed on core run Nos, 3, 4, and 5 from the AJ 11 Federal No. 1 well. Sedimentary structures and assemblages of these structures suggest that the Second sandstones (at least in this well) are not turbidite deposits as they have commonly been interpreted to be. Rather, they are thin repetitive laminae (<1 mm to ~1 cm thick) that settled out from suspension (Figure 2.14). Secondary, deep-marine currents reworked many of the laminae into thin rippled beds, and current indicators show an east to northeast paleoflow (Figure 2.15). Two types of invertebrate traces are present in the upper sections of the reservoir: bedding-plane tracks and trails, and horizontal burrowing (Figure 2.16). These disrupt the strong primary horizontal layering, probably enhancing local vertical permeability. Where the laminations are relatively isolated, near the base of the sandstones, they commonly show a grading from siltstone upward into silty dolomite (Figure 2.17). Other laminations show a distinct draping of microtopography created by isolated current-formed ripples (Figure 2.18).

Draping and fining upward grain-size trends support a depositional mechanism of vertical settling from suspension. The common ripple bedding, however, suggests that gentle bottom currents existed concurrently with sediment settling, producing interbedded current and suspension deposits. The dominant ripple azimuths (Figure 2.15) suggest that currents flowed subparallel to the basin margin, and at approximately right angles to the local sea floor slope (east-southeast as indicated by the dips of slump beds in Figure 2.19).

The absence of regular vertical successions and trends of sedimentary structures argue against a turbidite-fan depositional model. Rather, these deposits are inferred to record eolian transport of silt during dust storms, from the adjacent exposed shelf areas and into this marine setting, during sea level lowstands. There were numerous lowstands during Bone Spring time, possibly up to nine depending on the reconstruction (Figure 2.20). A plot of 54 successive sedimentary cycles from the basal 12 ft of one sand/siltstone bench (Figure 2.21) supports an eolian model in that it shows a highly irregular vertical trend, more consistent with irregular climatic variability (dust storm frequency) than with a regularly prograding turbidite fan. Moreover, the range of grain sizes (sorting) is compatible with known dust storm sediments such as loess.

Turbidite-fan deposits such as suggested by Cawloski may exist in other areas of the Bone Spring Formation, but there is no evidence for them in core from the AJ 11 Federal No. 1 well. If the Bone Spring sandstones turn out to be wholly, or even partially composed of combined vertical suspension and bottom current deposits, the rationale for exploration for thicker sandstone developments will need to be modified. Instead of slope-parallel, linear, channel-axis thickenings, exploration may have to rely on less well-developed concepts of current-formed, large-scale ripple bedding. In this regard, it is of interest to note that the 12 1-in.-diameter side-wall cores from the Cal-Mon 15 State No. 1 well, located about 11 miles to the east-southeast of the AJ 11 Federal No. 1 well, were sedimentologically and mineralogically identical to the core features described above.

A detailed log of the sedimentology of the core taken from the Second Bench of the second sandstone of the Bone Spring limestone is given in Figure 2.22.

2.8 Core Analyses in Support of Stimulation

Heyco sent samples of core from the AJ 11 Federal No. 1 well to Halliburton, Dowell Schlumberger, the Western Company, Smith Energy Services, and B. J. Titan. These cores were for analyses which would lead to recommendations for stimulation treatments. Both Heyco and Sandia were involved in the discussions with the field engineers and the research laboratories of these companies. These discussions involved the possible influence of natural fractures in producing this formation as well as the potential for damage to these fractures during stimulation. Core Laboratories data on the AJ Federal No. 1 well (Section 2.4) was sent to all parties to facilitate their analyses.

Reports from four companies are available. Salient results from each are summarized here.

(a) Halliburton Report dated August 6, 1989, 8546 to 8548 ft

- X-ray diffraction analysis results are similar to those of Core Laboratories. Illite, mixed-layer clays, and chlorite are seen. SEM shows a quartz framework with dolomite cement and clay covering the grains and present in the pores.
- Unconfined Young's moduli are around 3.2×10^6 psi.
- Regained permeability measurements were made on four core plugs, two where 2% KCl water was used, two where a 70% CO₂ foam was used, all with various frac fluid additives. First, nitrogen permeability to dry core plugs was obtained in one direction.

The plugs were then saturated with brine-based "frac fluids" from the opposite direction and finally they were cleaned up by flowing nitrogen in the original direction. The core plugs used for the CO₂ foam tests and the one test where only brine with additives was used regained most permeability in 24 hours.

(b) Dowell Schlumberger Report dated November 18, 1989, 8544 to 8546 ft

- The mineralogical analyses were the same as Core Laboratories with one major exception. Massive or cubic halite was seen in the pore throats in the SEM sample. Whether this halite is a result of evaporation of connate waters or actually exists in situ is not known at this time.
- Permeabilities to nitrogen were about 0.5 microdarcies.
- There was less than 25% proppant embedment using 20 to 40 Ottawa sand in tests done on dry samples at 4000 psi confining stress.
- Treatment by HCl or HCl/HF seems to cause irreversible damage due to the formation of insoluble precipitates. HF alone seems to remove clays and enhance porosity.
- A mildly reactive frac solution is recommended to enhance porosity by removing and fusing pore-blocking clays and silicates.

(c) B. J. Titan Laboratory Report, August 29, 1989, 8552 to 8555 ft

- The mineralogical analysis was consistent with that from Core Laboratories, except that traces of gypsum were seen.
- Water sensitivity to this formation can be controlled with KCl and clay control agents.

- Acid flow studies with an HCl acid system yielded little (~40%) matrix permeability improvement.
- Higher proppant loading yielded better conductivity. Sand or medium strength proppant seem satisfactory. Little or no proppant embedment was seen.
- A wide, deep, penetrating, non-acid fracture is recommended because of low matrix permeability.

(d) Smith Energy Services Report, December 21, 1989, 8549 to 8551 ft

- The mineralogical analysis was consistent with that from Core Laboratories. No unobstructed porosity was observed with thread-like illite bridging the pores.
- Damage to matrix rock from a variety of frac fluid combinations, mostly acidic, at 2000 psi confining pressure was about 50% or larger.

Table 2.1 ASR Stress Results

Depth (ft)	ASR Orientation	CVA Orientation
8123	-	N134°E
8125	-	
8143	-	
8536	N16°E	
8565	N31°E	N92°E
8581	-	
8597	-	
8641	N48°E	
8641	-	
8673	N42°E	
8693	N31°E	N48°E
8708	N1°W	N69°E

Table 2.2

FULL DIAMETER CORE ANALYSIS (AMBIENT CONDITIONS)

SAMPLE NUMBER	DEPTH	HELIUM POROSITY	GRAIN DENSITY	So	Sw	DESCRIPTION
R1	8123.0-23.3	6.2	2.84	17.0	21.0	Dol, p.p.
R2	8132.6-32.9	2.7	2.82	15.2	36.2	Dol, shly
R3	8152.9-53.2	3.5	2.85	17.4	23.4	Dol, anhy, VF
R4	8564.8-65.1	6.6	2.71	7.3	73.8	Sand
R5	8564.5-64.7	6.8	2.69	23.5	69.1	Sand
R6	8556.4-56.7	7.0	2.69	19.0	71.4	Sand, shly
R7	8629.9-30.2	6.8	2.70	39.3	49.8	Sand
R8	8608.2-08.4	3.5	2.62	0.0	74.0	Sand, v shly
R9	8696.3-96.5	6.4	2.71	2.9	72.3	Sand, shly
R10	8708.3-08.5	3.7	2.68	0.0	93.4	Sand, shly
R11	8673.0-73.3	2.0	2.66	28.0	46.7	Sand, shly
R12	8692.5-92.7	2.0	2.71	0.0	76.3	Sand, shly

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Table 2.3

NON-DIRECTIONAL DATA

SAMPLE DEPTH	CONFINING STRESS (PSI)	PORE VOLUME (CC)	POROSITY	KL (KLINK) (MD)	K _{air} (MD)	GRAIN DENSITY (G/CC)
R-1-H	800	0.848	6.1	0.0103	0.0258	2.83
8123.0-23.3	3500	0.796	5.7	0.0051	0.0133	
	5000	0.776	5.6	0.0037	0.0097	
R-1-V	800	1.319	6.2	0.0171	0.0421	2.83
8123.0-23.3	3500	1.239	5.9	0.0111	0.0263	
	5000	1.243	5.9	0.0093	0.0219	
R-2-H	800	0.426	3.0	0.0137	0.0200	2.82
8132.6-32.9	3500	0.380	2.7	0.0045	0.0078	
	5000	0.363	2.5	0.0032	0.0057	
R-2-V	800	0.496	2.5	0.0003	0.0014	2.81
8132.6-32.9	3500	0.184				
	5000	0.265				
			BELOW ACCURATE RANGE LIMITS			
R-5-H	800	1.236	6.6	0.0069	0.0242	2.69
8564.5-64.7	3500	1.168	6.2	0.0034	0.0120	
	5000	1.142	6.1	0.0025	0.0092	
R-5-V	800	1.042	5.9	0.0017	0.0064	2.69
8564.5-64.7	3500	0.876	5.0	0.0002	0.0018	
	5000	0.797	4.6	0.0002	0.0011	
R-6-H	800	1.212	6.5	0.0069	0.0250	2.69
8556.4-56.7	3500	1.121	6.0	0.0026	0.0107	
	5000	1.094	5.9	0.0019	0.0080	
R-6-V	800	0.929	6.7	0.0055	0.0167	2.69
8556.4-56.7	3500	0.858	6.2	0.0019	0.0079	
	5000	0.839	6.1	0.0014	0.0064	

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PERMEABILITY MEASUREMENTS PERFORMED ON PLUG SAMPLES

H = HORIZONTAL, V = VERTICAL

Table 2.4

DIRECTIONAL DATA

SAMPLE DEPTH	CONFINING STRESS (PSI)	PORE VOLUME (CC)	POROSITY	KL (KLINK) (MD)	K _{air} (MD)	GRAIN DENSITY (G/CC)
R-4-V	800	1.229	5.9	0.0019	0.0073	2.69
8564.8-65.1	3500	1.025	4.9	0.0003	0.0017	
	5000	0.951	4.6	0.0002	0.0011	
R-4-H-30	800	1.127	6.2	0.0062	0.0195	2.69
8564.8-65.1	3500	1.027	5.7	0.0011	0.0055	
	5000	0.996	5.5	0.0007	0.0038	
R-4-H-120	800	0.735	5.8	0.0052	0.0163	2.69
8564.8-65.1	3500	0.665	5.3	0.0007	0.0048	
	5000	0.644	5.1	0.0004	0.0032	
R-7-V	800	1.183	6.1	0.0044	0.0126	2.69
8629.9-30.2	3500	1.068	5.6	0.0007	0.0039	
	5000	1.009	5.3	0.0005	0.0030	
R-7-H-30	800	1.475	6.5	0.0671	0.0256	2.69
8629.9-30.2	3500	1.342	6.0	0.0025	0.0101	
	5000	1.335	5.9	0.0619	0.0072	
R-7-H-120	800	0.799	7.0	0.0095	0.0275	2.69
8629.9-30.2	3500	0.692	6.0	0.0028	0.0113	
	5000	0.665	5.9	0.0619	0.0085	
R-10-V	800	0.704	4.7	0.0005	0.0018	2.69
8708.3-08.5	3500	0.394	2.7	0.0002	0.0008	
	5000	0.413	2.8	0.0001	0.0006	
R-10-H-30	800	0.850	4.4	0.0005	0.0033	2.69
8708.3-08.5	3500	0.714	3.7	0.0002	0.0010	
	5000	0.653	3.4	0.0001	0.0008	
R-10-H-120	800	0.614	4.6	0.0007	0.0041	2.69
8708.3-08.5	3500	0.513	3.9	0.0001	0.0014	
	5000	0.464	3.5	0.0001	0.0008	
R-12-V	800	0.742	4.6	0.0006	0.0027	2.69
8692.5-92.7	3500	0.618	3.9	0.0007	0.0009	
	5000	0.567	3.6	0.0001	0.0007	
R-12-H-30	800	0.810	5.1	0.0016	0.0065	2.69
8692.5-92.7	3500	0.673	4.3	0.0007	0.0018	
	5000	0.608	3.9	0.0005	0.0015	
R-12-H-120	800	0.733	4.8	0.0028	0.0086	2.69
8692.5-92.7	3500	0.584	3.9	0.0006	0.0024	
	5000	0.515	3.4	0.0002	0.0017	

H = HORIZONTAL, V = VERTICAL * DENOTES POSSIBLE SAMPLE FRACTURING

HEYCO
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Table 2.5

SUMMARY OF BASIC CORE PROPERTIES

Sandia National Laboratories
 Heyco A. J. 11 Federal #1 Well
 Eddy County, New Mexico

<u>Sample ID</u>	<u>Depth, feet</u>	<u>Orientation</u>	<u>Confining Stress, psi</u>	<u>Klinkenberg Permeability, millidarcies</u>	<u>Porosity, percent</u>
1V	8613.6- 8613.7	Vertical	800	0.0032	5.8
			3500	0.0006	5.3
			5000	0.0006	5.0
<u>Horizontal Plugs - "Homogeneous Portion"</u>					
4H	8613.7	30°	800	0.0087	7.2
			3500	0.0035	6.7
			5000	0.0026	6.6
5H	8613.7	120°	800	0.0084	7.0
			3500	0.0033	6.5
			5000	0.0026	6.3
<u>Horizontal Plugs - "Laminated Portion"</u>					
2H	8613.8	30°	800	0.0098	7.1
			3500	0.0043	6.6
			5000	0.0034	6.5
3H	8613.8	120°	800	0.0098	7.1
			3500	0.0047	6.7
			5000	0.0038	6.6

Table 2.6

SUMMARY OF TEST RESULTS

Sandia National Laboratories
Calmon 15 State Number 1 Well

BASIC CORE PROPERTIES

<u>Sample I.D.</u>	<u>Confining Stress, psi</u>	<u>Klinkenberg Permeability, millidarcies</u>	<u>Porosity, percent</u>
9023	800	0.0061	5.5
	3500	0.0005	4.8
	5000	0.0003	4.6
9329	800	0.0040	5.3
	3500	0.0003	4.2
	5000	0.0002	3.7
9440	800	0.0081	7.0
	3500	0.0011	6.3
	5000	0.0007	6.1

DEAN-STARK ANALYSIS

<u>Sample I.D.</u>	<u>Porosity, percent ambient</u>	<u>Fluid Saturations, percent pore space</u>	
		<u>brine</u>	<u>oil</u>
9023	5.7	44.5	40.9
9329	5.8	74.6	23.2
9440	7.5	64.7	28.5

A density of 1.036 grams/cm³ was used in the brine saturation calculation.

An oil density of 0.830 grams/cm³ was used to calculate oil saturations.

Table 2.7

SUMMARY OF BASIC PROPERTIES

Sandia National Laboratories
 Heyco A. J. 11 Federal No. 1 Well

Sample I.D.	Depth, feet	Orientation	Confining Pressure, psi	Klinkenberg Permeability, millidarcies	Porosity, percent	Fluid Saturations,* percent pore space Brine Oil
S3-V	8585.5-86.2	Vertical	800 3500 5000	0.018 0.0088 0.0077	8.5 8.2 8.1	85.9 9.9
S3-H1	8585.5-86.2	Horizontal	800 3500 5000	0.017 0.011 0.010	8.6 8.2 8.1	76.1 12.3
S3-H2	8585.5-86.2	Horizontal	800 3500 5000	0.020 0.012 0.011	8.6 8.1 8.0	89.9 10.2
S3-H3	8585.5-86.2	Horizontal	800 3500 5000	0.026 0.015 0.013	9.2 8.7 8.6	- -
S7-V	8604.8-05.2	Vertical	800 3500 5000	0.016 0.0012 0.0006	6.7 6.2 6.0	91.5 8.5
S7-H1	8604.8-05.2	Horizontal (30°)	800 3500 5000	0.0072 0.0007 0.0004	5.7 5.2 5.0	87.0 12.3
S7-H2	8604.8-05.2	Horizontal (120°)	800 3500 5000	0.013 0.0028 0.0021	6.8 6.3 6.2	82.6 13.2
9440	9440	Horizontal	800 3500 5000	0.023 0.0047 0.0047	7.7 6.6 6.4	- -

*Brine Density: 1.036 grams/cc
 Oil Density: 0.830 grams/cc

TABLE 2.8

Summary of Core Properties (AJ 11 Federal No. 1)

Depth (ft)	ϕ (percent)	S_o (percent)	S_w (percent)	K @ 3500 psi (μ d)
8123	6.2	17	21	5.1
8133	2.7	15	36	4.5
8153	3.5	17	23	-

8556	7.0	19	71	2.6
8565	6.6-6.8	7-23	69-74	0.7-3.4
8585	8.1-8.2	10	90	11-12
8605	5.2-6.3	12-13	83-87	0.7-2.8
8608	3.5	0	74	0.1-0.2
8630	6.8	39	50	2.5-2.8
8673	2.0	28	47	-
8693	2.0	0	76	0.6-0.7
8696	6.4	3	72	-
8708	3.7	0	93	-

Table 2.9

HEYCO A.J. 11 Federal No.1 Well
Bone Spring Limestone

THIN SECTION ANALYSES: GENERAL DESCRIPTION

Sample Depth (Feet):		8536.8-37.0	8561.2-61.5	8569.5-69.7
Rock Type:	Siltstone	Siltstone	Siltstone	Siltstone
Rock Name				
Folk (1980):	Subarkosic siltstone	Subarkosic siltstone	Subarkosic siltstone	Arkosic siltstone
Pettijohn et al. (1972):	Subarkosic siltstone	Subarkosic siltstone	Subarkosic siltstone	Subarkosic siltstone
Grain Size:				
Maximum:	0.080mm (very fine sand)	0.085mm (very fine sand)	0.085mm (very fine sand)	0.085mm (very fine sand)
Minimum:	0.025mm (medium silt)	0.030mm (medium silt)	0.030mm (medium silt)	0.015mm (medium silt)
Average:	0.047mm (coarse silt)	0.052mm (coarse silt)	0.052mm (coarse silt)	0.045mm (coarse silt)
Sorting:	Good	Good	Good	Good
Textural Maturity:	Submature	Submature	Submature	Submature
Grain Orientation:	Subtle subparallel alignment of elongate grains	Subtle subparallel alignment of elongate grains	Subtle subparallel alignment of elongate grains	Subtle subparallel alignment of elongate grains
Grain Angularity:	Average is subangular	Average is subangular	Average is subangular	Average is subangular
Grain Contacts:	Long > concavo-convex > point > sutured > floating	Long > concavo-convex > point > sutured > floating	Long > concavo-convex > point > sutured > floating	Long > concavo-convex > point > sutured > floating
Porosity Types:	Rare intergranular and intragranular pores	Intergranular and lesser intragranular pores	Intergranular and lesser intragranular pores	Trace of intergranular pores
Pore Network:	Isolated and poorly interconnected	Poorly interconnected	Poorly interconnected	Isolated
Comments:	-----	Uncommon stringers of detrital clay	Uncommon stringers of detrital clay	Uncommon stringers of detrital clay

Table 2.9
(continued)

HEYCO A.J. 11 Federal No.1
Bone Spring Limestone

THIN SECTION ANALYSES: GENERAL DESCRIPTION

Sample Depth (Feet):		8613.8	HEYCO Calmon 15 State No.1 Well Bone Spring Limestone	9440.0
Rock Type:	Siltstone	Siltstone		
Rock Name	Subarkosic siltstone	Arkosic siltstone		
Folk (1980):	Subarkosic siltstone	Subarkosic siltstone		
Pettijohn et al. (1972):	Subarkosic siltstone			
Grain Size:				
Maximum:	0.02mm (medium silt)	0.02mm (medium silt)		
Minimum:	0.12mm (very fine sand)	0.13mm (very fine sand)		
Average:	0.05mm (coarse silt)	0.05mm (coarse silt)		
Sorting:	Moderate to good	Moderate to good		
Textural Maturity:	Submature	Submature		
Grain Orientation:	Subtle subparallel alignment of elongate grains	Subtle subparallel alignment of elongate grains		
Grain Angularity:	Average is subangular	Average is subangular		
Grain Contacts:	Long > concavo-convex > point > sutured > floating	Long > concavo-convex > point > sutured > floating		
Porosity Types:	Trace of intergranular pores	Intergranular pores; trace of fractures and intragranular pores		
Pore Network:	Isolated; patchy	Moderately interconnected to isolated pores		
Comments:	Thin, parallel, clay laminations	Pore interconnections appear better parallel to stringers of clay and long axes of grains		

Table 2.10 X-ray Diffraction Analyses (weight percent)

Well	Depth (feet)	Quartz	K feldspar	Plagioclase	Dolomite	Pyrite	Total Clay	Clay Minerals		
								Illite	Fe-Chlorite	
HEYCO A.J. 11 Federal No. 1	8536.8-37.0	58	4	12	17	2	7	7	0	
HEYCO A.J. 11 Federal No. 1	8561.2-61.5	59	2	18	13	1	7	7	0	
HEYCO A.J. 11 Federal No. 1	8569.5-69.7	59	10	11	15	1	4	3	1	
HEYCO A.J. 11 Federal No. 1	8613.8	62	15	10	4	1	8	8	trace	
HEYCO Calmon 15 State No. 1 Wells	9440.0	61	12	10	9	1	7	7	0	

Table 2.11

THIN SECTION ANALYSES : COMPOSITION

HEYCO A.J. 11 Federal No.1 Well
 HEYCO Calmon 15 State No.1 Well
 Bore Spring Limestone

Sample I.D. Depth (feet)	1 8536.8	2 8561.2	3 8569.5	4 (3H) 8613.8	5 9440.0
FRAMEWORK GRAINS	76.8	74.4	65.6	81.2	72.4
Quartz	56.8	52.4	46.4	58.4	50.0
Monocrystalline	53.2	47.6	40.4	51.6	45.6
Polycrystalline	3.6	4.8	6.0	6.8	4.4
Feldspar	17.2	16.8	16.0	18.8	17.6
Alkali feldspar	10.8	9.6	12.0	11.2	9.6
Plagioclase	6.4	7.2	4.0	7.6	8.0
Rock fragments	0.8	2.8	2.4	0.4	2.8
Metamorphic	0.0	0.0	0.0	0.0	0.4
Schistose quartz	0.0	TR	0.0	0.0	0.4
Sedimentary	0.8	2.8	2.4	0.4	2.4
Argillite	0.0	0.4	0.4	0.4	0.0
Chert	0.8	2.4	2.0	0.0	2.4
Accessory Grains	2.0	2.4	0.8	3.6	2.0
Biotite	0.0	0.0	6.0	1.2	0.0
Muscovite	2.0	2.4	0.8	2.4	2.0
Tourmaline	TR	TR	TR	TR	TR
Zircon	TR	TR	TR	TR	TR
MATRIX	6.8	2.4	6.8	6.8	6.8
Detrital	4.4	2.4	5.6	6.8	6.8
Undifferentiated	2.4	0.0	1.2	0.0	0.0
AUTHIGENIC CEMENT	16.4	20.8	27.6	12.0	20.0
Quartz	TR	TR	TR	TR	TR
Dolomite	13.2	18.4	0.0	8.4	15.6
Pyrite	1.2	1.6	0.4	2.0	2.8
Titanium-oxide	0.8	0.8	1.2	0.4	0.0
Organic material	0.8	0.0	1.2	1.2	1.6
POROSITY	TR	2.4	TR	TR	0.8
Intergranular	0.0	2.0	0.0	0.0	0.8
Dissolution	TR	0.4	TR	TR	TR
Intragranular	TR	0.4	TR	TR	TR
Fracture	0.0	0.0	0.0	TR	TR
Shrinkage	0.0	0.0	0.0	0.0	0.0
TOTAL	100.0	100.0	100.0	100.0	100.0

Table 2.12

HEYCO A.J. 11 Federal No.1 Well
HEYCO Calmon 15 State No.1 Well

GENERALIZED DIAGENETIC HISTORY
Bone Spring Limestone

TIME ----->	
Compaction	-----
Pyrite Precipitation	-----
Titanium-oxide Precip.	-----
Quartz Cementation	? ----- ?
Grain Dissolution	? ----- ?
Dolomite Cementation	? ----- ?

Figure 2.1 Generalized Description of Core Runs No. 3-5

Core Run #4

Sandstone, v.f.g.
finely laminated, alternates with
thin massive zones.
starved ripples
rare burrows

Gray laminated Ss

Cyclic sedimentation: ~30 cycles

Laminated Ss to massive Ss

Each cycle fines upward,
but entire interval
becomes sandier upward

Laminated dolo/siltst

Figure 2.1 Continued

Figure 2.1 Continued

ss, laminated and
burrowed--also
diagonally sheared--in 2 directions
main shears dip toward 170° true
secondary shears dip toward 350° true

Figure 2.1 Continued

Figure 2.2 Core Gamma Logs.

Upper: Core Run No. 1; Lower: Core Run No. 2

Figure 2.3 Core Gamma Logs. Core Runs No. 3, 4, 5

Figure 2.4 ASR Data (upper) and Polynomial Fit (lower)

AJ11 FED#1 8123 FT BONE SPRING CARBONATE

Figure 2.5 CVA Results

RJ11 FED#1 8565 FT BONE SPRING 2ND SAND

Figure 2.6 CVA Results

AJ11 FED#1 8693 FT BONE SPRING 2ND SAND

Figure 2.7 CVA Results

AJ11 FED#1 8708 FT BONE SPRING 2ND SAND

Figure 2.8 CVA Results

STRESS ORIENTATION

Figure 2.9 Stress Orientation Results—Bone Spring Sandstone

Heyco A. J. 11 Federal No. 1 Well

Calmon 15 State No. 1 Well

Figure 2.10 Air-Brine Centrifuge Capillary Pressure Measurements

Figure 2.11 Coring Induced Fracture Azimuths

Figure 2.12 Natural Fracture Azimuths in Abutting Carbonates

EDS SPECTRUM OF DOLOMITE
IN A DOLOMITE-CEMENTED SILTSTONE

This EDS spectrum of a rhombohedral crystal of dolomite (shown in Plate 6B) contains prominent calcium (CA) and magnesium (MG) peaks. This EDS spectrum indicates that the iron (FE) content of this dolomite crystal is negligible. The silicon (SI) and aluminum (AL) peaks are from nearby silicate minerals. The gold (AU) and palladium (PD) peaks result from the thin gold-palladium coating applied to the sample to enhance conductivity.

Figure 2.13

Figure 2.14 Sedimentary Structure (slabbed core)

N

Ripple Azimuths

n = 72

Figure 2.15 Rippled Beds and Azimuths

Figure 2.16 Invertebrate Traces (slabbed core)

Figure 2.17 Grading of Laminations (slabbed core)

Figure 2.18 Example of Draping (slabbed core)

**Bedding-Plane Slump Azimuths:
Core Run #4**

Figure 2.19 Slump Beds and Azimuths

(FROM ROSS AND ROSS, 1987)

Figure 2.20 Sea Level Variations during Bone Spring Time

Figure 2.21 Sedimentary Cycles

Figure 2.22 Detailed Core Sedimentology

Figure 2.22 Continued

Figure 2.22 Continued

Figure 2.22 Continued

Figure 2.22 Continued

Figure 2.22 Continued

Figure 2.22 Continued

Figure 2.22 Continued

Figure 2.22 Continued

Figure 2.22 Continued

Figure 2.22 Continued

Figure 2.22 Continued

3.0 LOGGING AND ANALYSES

3.1 AJ 11 Federal No. 1

The suite of logs run in the AJ 11 Federal No. 1 well was extensive and included a number of developmental logs that were run at no cost to the project. Nine different logs were run in this well by two different companies. These logs are discussed below:

- (a) Schlumberger Compensated Neutron/Lithodensity Log (Neutron 0 to 8963 ft; density 2349 to 8963 ft). This log is normally run by Heyco and is shown for the interval of interest in Figure 1.4. A new high-resolution porosity display was included at no charge. Some apparently large, open fractures are detected with this porosity presentation. Log porosities average 8% to 10%, and approach 10% to 11%, in the Second Bench of the Second Bone Springs sandstone. (Measured core porosities are actually lower, maximum core porosities are around 7%). The log porosities average 1% to 2% less in the other two benches of this sandstone. The porosity display across the Second Bench is essentially uniform.
- (b) Schlumberger Dual Laterolog/Micro SFL Log (2449 to 8964 ft). This log is normally run by Heyco and is shown for the interval of interest in Figure 1.3. The displays of the electrical logs are also uniform across Second Bench. The displays of the log across the upper and lower bench are less uniform and the resistivities are somewhat smaller.
- (c) Schlumberger Formation Microscanner (FMS) Log run for Sandia (7490 to 8969 ft). Two passes were made with the FMS; this provided coverage of around 40% of the borehole well. In the interval that a repeat pass was also made (8520 to 8720 ft) 70% of the borehole was covered.

A thorough study was made of the Second Bone Springs sandstone from preliminary displays of the FMS data and from enhanced displays provided at the Schlumberger (Dallas) Data Center. No natural fractures were seen in any of the three benches of the Second Bone Spring sandstones although a few natural fractures were seen in the dolomitic mudstones abutting the three benches. The "main pay" carbonate is highly fractured and a representation of that log provided by the Schlumberger Data Center is shown in Figure 3.1.

An excellent structural representation of the formation was obtained from the FMS log. In fact, this representation was used to orient core run No. 4 after making a correction from log to core depths with the aid of the core and well gamma logs. Figure 3.2 shows a near horizontal bedding in the First Bench while Figure 3.3 shows distinct irregular bedding features which were used to orient the core in the Second Bench. These particular figures were provided by the Schlumberger Data Center.

- (d) Schlumberger Experimental and Commercial Televiewers run for Sandia (7500 to 8960 ft). The displays from both of these televiewers was disappointing. The resolution of these particular logs was on the order of 6 in., very good for the study of wellbore breakouts but not good enough to provide information on natural fractures. The wellbore breakouts in and around the Second Bone Spring sandstone were tabulated and a display of principal stress directions from analyses of breakouts is given in Figure 3.4. The data in Figure 3.4 suggest a predominant maximum stress azimuth in the northwest-southeast direction. A secondary direction appears to be east of north. The velocity, ASR, and natural fracture data suggest that the principal stress is east of north. Since few breakouts occur in the region where the core data were taken, a direct comparison between core and log results cannot be made.

- (e) Western Atlas Circumferential Borehole Imaging Log (CBIL) run for Heyco (5200 to 5400, 6340 to 6540, 7450 to 7550 ft, 7700 to 8900 ft). This log was the most promising of the televiwer type logs run. Considering cost, use of this log may provide a cost-effective way to examine the borehole for special features such as natural fractures. Basically, the analyses of this log provided the same conclusion as the analyses of the FMS log: there are no fractures in the sandstone benches of the Second Bone Springs sandstone, although a few fractures exist in the materials abutting some of the benches of this sandstone and the "main pay" carbonate is very fractured.

Figure 3.5 gives the CBIL display of this tool in the "main pay" carbonate over approximately the same interval as shown in the FMS log from Figure 3.1. Figures 3.6 and 3.7 give the CBIL display over approximately the same intervals shown for the FMS log in Figure 3.2 (flat bedding, no fractures) and Figure 3.3 (contorted bedding, no fractures). A listing of some fractures observed in the region of (but not within) the Second Bone Springs sandstone is given in Table 3.1. In each case, Western Atlas applied its software package, VISION, to enhance and analyze the displays from the CBIL.

- (f) Western Dipmeter run for Heyco (7900 to 8800 ft). This log was run to complement the Western Atlas CBIL log. The displays of this log showed fractures in the "main pay" carbonate, but not in the sandstone benches. Western Atlas' dipmeter software, DIPU, can be combined with that from the VISION formalism to analyze intervals logged by both the CBIL and dipmeter logs.
- (g) Schlumberger Digital Sonic Log run for Sandia (4700 to 4850, 7900 to 8937 ft). High velocities (1.5×10^4 ft/sec) were encountered in Bone Spring sandstones and still higher (1.75×10^4 ft/sec) velocities were encountered in the dolomitic siltstones/mudstones

abutting the Benches. A mechanical rock properties computation/presentation was derived from this log and the Schlumberger density logs. No rock property measurements at confining pressure are available for comparison. Figure 3.8 shows the display of compressional and shear velocities between 8100 and 8700 ft. Perturbances in the shear velocity display are both expected and observed over the region of the "main pay" carbonate.

- (h) Schlumberger (prototype) Nuclear Petrology Tool (NPLT) run for Heyco (7900 to 8900 ft) at no cost. This log is a combination of lithodensity, spectral gamma, fast and epithermal neutron tool. This tool is being developed as a new generation lithology tool. The neutron generator portion of the tool did not function in this test, and there were other problems also. At any rate, no information was obtained from this trial run.

3.2 Cal-Mon 15 State No. 1

Only the routine Schlumberger compensated neutron/lithodensity log and dual laterolog/micro SFL log were run in this well. The logs over the interval of interest are shown in Figures 1.6 and 1.7.

Table 3.1

Natural Fractures in the CBIL Log (AJ 11 Federal No. 1)

<u>Depth</u> <u>(ft)</u>	<u>Azimuth(s)</u> <u>(° from N)</u>
8007	30
8009	65
8023	60
8025	85, 145
8150	90
8200	80, 85
8201	90
8393	48
8414	125
8419	75
8505	100
8667	70
8741	30

Figure 3.1 FMS Log of Fractured "Main Pay" Carbonate

Figure 3.2 FMS Log Detail: Horizontal Bedding

Figure 3.3 FMS Log Detail: Irregular Feature

Figure 3.4 Orientation of Wellbore Breakouts from Televiewer Log

Figure 3.5 CBIL Display of Fractured "Main Pay" Carbonate

Figure 3.6 CBIL Detail: Horizontal Feature

Figure 3.7 CBIL Detail: Irregular Feature

Figure 3.8 Digital Sonic Log

Figure 3.8 Continued

Figure 3.8 Digital Sonic Log

4.0 WELL TESTING

4.1 Breakdown and Testing (AJ 11 Federal No. 1)

Mud-log shows, geophysical logs, and oil-bleeding core suggested that the Bone Spring sandstones have reservoir potential. The Second Bench sandstone was perforated from 8517 to 8618 ft with 19 shots placed at indications of high porosity and the interval was treated initially with 4000 gal of 2% KCl water with clay inhibitor. Water recovery was good, but after 4 days of no shows of oil or gas, the well was again treated with 3500 gal of mixed treatment fluids (NARS). Recovery percentage and rates of the fluids were also good, but no oil was recovered. After 4 days, 4500 gal of 7-1/2% HCl acid was injected and recovered, but still no oil was produced. With no oil production, the planned well tests could not be performed. The well was completed in the "main pay" carbonate, and focus of this study was shifted to another development well 11 miles to the east.

4.2 Well Testing (Cal-Mon 15 State No. 1)

The Cal-Mon 15 State No. 1 was completed June 24, 1989, and was used for well and fracturing tests in the Second Bone Spring sandstone. This well has good development of both porosity and thickness of the Bone Spring sandstones. The mud log indicated good hydrocarbon shows. Twenty drilled sidewall cores were taken between depths of 8973 and 9444 ft in all three sandstones. Five of these 1-in. plugs were sealed and sent to Core Laboratories for reservoir analysis. Ten went to Sandia and five to Heyco for comparative sedimentologic and reservoir analysis. Results suggest that the same depositional environment occurs in this well as in the AJ 11 Federal No. 1 well, but with improved local porosities of up to 15%.

The Cal-Mon 15 State No. 1 well was perforated at high-porosity locations at 9005, 9023, and 9027 ft in the First Bench sandstone, and at 9345, 9359, 9403, 9407, and 9423 ft in the Second Bench sandstone (Figure 1.5). The six sandstone perforations were treated as a group with 1800 gals of HCl acid. The well was swabbed on and off for 5 days at an average rate of

2 bpd. CER Corporation was contracted to run a buildup test using an HP pressure gauge and a bottomhole closure tool to minimize wellbore storage effects (Section 4.3).

The buildup was run for 10 days with no problems or leaks. The data were unusual as they showed a dual-storage behavior in the wellbore for the first 80 hours and a decreasing derivative curve throughout the test (after wellbore storage). Preliminary interpretation of the well test data yields a 10 to 15 μ d reservoir with either dual-porosity or boundary behavior. The dual porosity may be the result of either fractures or layers. The boundary, if it exists, is at most a few tens of feet away from the wellbore.

4.3 CER Corporation's Report

CER Corporation's report of the buildup test and the analysis of the data are presented as a direct copy which begins on the next page and extends through page 4.22.

1.0 Introduction

A 10-day, bottomhole pressure buildup test of the oil-bearing, Bone Spring 2nd Sand was performed in the HEYCO CAL-MON State No. 1 well. The test began July 6, 1989, following almost 5 days of intermittent swab production, and concluded 10 days later on July 16, 1989. The primary objectives of this pre-stimulation well test was to provide quantitative information concerning certain reservoir properties, especially average permeability, k , areal delineation and near wellbore damage or skin effects, s . In addition, since the Bone Spring Sand in and around CAL-MON State No. 1 is presumed to contain natural fractures, CER planned to assess the influence that this fracture system might have on production and, if possible, determine the magnitude of fracture conductivity, k_{fwf} .

2.0 Summary

The pressure buildup data from the HEYCO CAL-MON State No. 1 well was evaluated using both Horner analysis and modified analytical solutions. The evaluation indicated an average reservoir flow capacity of approximately 1 md-ft and a skin ranging from 9 to 11.4. Based on a perforated height of 86 ft, the calculated average reservoir permeability is 0.012 md. The extrapolated pressure from Horner analysis, p^* , is 3,650 psi.

There were two complicating factors in the analysis of the pressure buildup data:

1. The existence of an initially segregated two-phase wellbore volume that transitioned into a single-phase wellbore volume.
2. The exhibition of complex reservoir characteristics in the later time buildup data, which was especially evident in the log-log pressure derivative curve.

Both of these factors were evaluated in the analysis. The early time pressure buildup data was successfully matched using a variable wellbore storage constant, while the complex, later time behavior could be matched using either dual porosity or a no-flow boundary. Preliminary review of the reservoir and well test data appears to indicate that dual porosity behavior is the most probable mechanism for production in the HEYCO CAL-MON State No. 1.

3.0 Well Test Operations

Figure 1a is a schematic of the wellbore tubulars and tool configuration that was employed during the buildup testing period. Table 1 provides a tabular summary of pertinent bottomhole configuration data. A surface recording bottomhole pressure / temperature gauge was set at the lowest point possible in the well, just above the tubing packer at 9,304 ft. The use of this highly accurate, quartz pressure gauge assures that the measured pressures are accurately acquired and most representative of the perturbed reservoir. The tubing packer provided isolation between the large annular wellbore volume and the perforated intervals. The pressure gauge is affixed to a specialized seating nipple that, along with the tubing mandrel, constitutes a bottomhole shut-in device. Using this shut-in device insures that the wellbore storage volume is as small as possible, thus minimizing storage effects. Employing this bottomhole shut-in device is especially important during the very early portion of the buildup test when reservoir fluid flow is most affected by the natural fractures and is therefore best observed. Without the bottomhole shut-in tool, wellbore storage might totally mask the important natural fracture / matrix transition period thus limiting the engineering interpretation of the data.

Spontaneous oil flow from the reservoir into the wellbore was initially found to be negligible and was supplemented using a wireline swab to encourage production. Swabbing began at 8 p.m. on July 1, 1989, and continued intermittently for the next 5 days until 5 p.m., July 6, 1989. During the 117 hrs of intermittent production, approximately 10 BBL of oil were produced along with a small but unmeasured amount of gas. The average oil production rate is then taken to be, $q_o = 2$ BOPD.

At the end of the production period, the bottomhole pressure gauge and shut-in nipple assembly were lowered into the well. At 5:38 pm, July 6, the pressure and nipple assembly were set in the bottomhole mandrel. Sealing this assembly involves maintaining the hydrostatic pressure above the assembly higher than the pressure that is building in the bottomhole below the assembly. This pressure differential assures that the nipple and mandrel will create a gas tight seal. Increasing hydrostatic pressure was accomplished by rapidly filling the tubing with water. Five BBL of water were initially pumped into the well thus increasing the pressure on the bottomhole shut-in tool by about, 560 psi. At 9:45 p.m., July 6, an additional 20 BBL of water were added to the tubing, thus increasing the hydrostatic pressure on the bottomhole assembly to about 3,100 psi. Bottomhole pressure at that time was only about 1,000 psi and thus the large pressure difference across the shut-in tool was more than adequate to maintain a gas tight seal.

Figure 2 is a graphic presentation of measured test pressures as a linear function of time. Zero time, t_0 , is referenced at 5:38 p.m., July 6, the time when the bottomhole pressure gauge was seated in the nipple and the pressure buildup began. Figure 2 depicts bottomhole pressure from the quartz pressure gauge as well as surface readings of casing (annulus) pressure and tubing pressure from analog pressure transducers. Note that the casing which had previously been filled with water was subsequently pressurized and held about 80 psi above hydrostatic throughout the entire test period. The tubing was ultimately filled with water and pressurized the following day, July 7, at about 11:20

a.m. (19 hrs) and 12:30 a.m. (20 hrs). During the periods when the tubing and casing pressures were being altered, the bottomhole pressure was carefully monitored for any indication of pressure communications. Bottomhole pressure measurements never demonstrated that any leak might have occurred between either casing and bottomhole or tubing and bottomhole. Thus, CER is reasonably confident that from the time the bottomhole assembly was sealed, 0 hrs, the bottomhole was isolated from the casing and tubing.

3.1 WELL TESTING ANALYSIS

To determine average reservoir production capacity, kh , a Horner plot was developed. The flow period was taken to be the entire 117-hr swabbing period and the average flow rate, $q_0 = 2$ BOPD. Figure 3 is the resulting Horner plot along with the superimposed straight line. The slope of this straight line, $m = 230$ psi / cycle, was assumed to be the best available pick for deriving average reservoir capacity. Note that the early time portion of the buildup showed significant deviation from the late time straight line and indicates the presence of a positive skin and wellbore storage.

Average reservoir flow capacity, kh , is derived from Horner and amounts to:

$$kh = 162.6 q_0 \mu B_0 / m \quad \text{Eq. 1}$$

where,

kh = average reservoir flow capacity, md-ft
 q_0 = average flow rate, 2 BOPD
 μ = fluid viscosity, 0.53 cp
 B_0 = reservoir volume factor, RB / STB, and
 m = slope of the Horner straight line, 230 psi / cycle.

Substituting these values (see Table 2) into Equation 1 yields,

$$\begin{aligned} kh &= 162.6 \cdot 2.0 \cdot 0.53 \cdot 1.45 / 230 \\ &= 1.087 \text{ md-ft.} \end{aligned}$$

Since there was a small perforation breakdown procedure performed in this well prior to the buildup test, it is assumed that the full perforated interval contributes to production. Without a clear delineation from logging information as to the net productive interval, net height, h , was selected to be equivalent to the total perforated interval, $h = 86$ ft. Thus, average oil permeability is then given by,

$$k = kh / h = 1.087 / 86 = 0.0126 \text{ md} = 12.6 \mu\text{d.}$$

Extrapolation of the Horner straight line to infinite shut-in time or a Horner time of 1, yields the pressure, p^* ,

$$p^* = 3,650 \text{ psi.}$$

For an infinite reservoir, p^* is essentially initial reservoir pressure, p_i . Skin factor, s , is also calculated from an extrapolation of the Horner straight line.

From Figure 3, s is calculated using the standard Van Everdingen and Hurst solution:

$$s = 1.151 \{ [p_{1hr} - p_{wf}] / m - \log(k / \phi \mu c_t r_w^2) + 3.23 \} \quad \text{Eq. 2}$$

where,

- s = Van Everdingen and Hurst skin factor, s
- p_{1hr} = pressure at 1 hr after shut in, psi
- p_{wf} = pressure at shut in, psi
- ϕ = porosity
- c_t = total system compressibility, 1 / psi
- r_w = wellbore radius, ft

Substituting in the measured, derived and estimated values it is found that

$$\begin{aligned} s &= 1.151 \{ [3180 - 292] / 230 - \log(0.0126) / (0.06 \cdot 0.53 \cdot 12.9 \cdot 10^{-6} \cdot \\ &\quad (2.446 / 12)^2) + 3.23 \} \\ &= 11.41. \end{aligned}$$

This is a rather large value for skin and suggests that oil production was most probably markedly reduced as a result of this apparent damage.

A log-log / derivative plot was created as a means of assessing the various flow regimes that occur both within the limited size wellbore volume and the reservoir itself. Figure 4 is a composite log-log / derivative curve derived from the bottomhole pressure buildup data. The ordinate is delta pressure for the log-log curve and a complex pressure derivative group that results in delta pressure for the derivative group while the abscissa is buildup time. Delta pressure is determined by taking buildup pressure minus the final flowing pressure, or $p_{ws} - p_{wf}(\Delta t = 0)$. The final flowing pressure was taken to be $p_{wf}(\Delta t = 0) = 292$ psi. The unit slope shown on the log-log plot indicates that the system response is dominated by wellbore storage. As seen in Figure 4, this storage period indicated by the unit slope, $m = 1$, appears to end at about 2.5 to 3 hrs after shut in. However, note that after this initial storage period, the pressure buildup is seen to rise even faster. This suggests that the reservoir is not responding in a way that would suggest normal behavior, such as pseudo radial flow or a transition period involving natural fracture and matrix flow.

To determine the mechanism associated with this irregular, log-log, early time pressure behavior, consider the bottomhole wellbore configuration as shown in Figures 1a and 1b. For these illustrative purposes, consider that the oil level in the annular region between the tail pipe is initially unknown. Since bottomhole pressure during the production period was on the order of 300 psi, which was well below the bubble point, 2,350 psi, then solution gas entering the wellbore would find its way into the tail pipe annular region.

Once gas entered this annular region, it became trapped and began to displace oil and thus lowering the liquid level present in the annular region. Figure 1a suggests that gas may have displaced oil from the bottom of the packer assembly, 9,310 ft to about 9,322 ft, a total of 12 ft; volume displacement is then calculated from the volume capacity for the annular region and the displaced length, or

$$V_g = 0.0178 \text{ BBL / ft} \cdot 12 \text{ ft} = 0.214 \text{ BBL.}$$

With such a wellbore configuration, two separate wellbore storage periods can be expected and result in a change in storage constant. The first storage period will be controlled by the influx of oil required to fill the 0.214 BBL annular volume and the compressibility of trapped gases. In this case, the wellbore storage constant will be given by:

$$C_2 = 144 \cdot V_u \cdot g_c / g \cdot 1 / \rho + V_g \cdot c_g \quad \text{Eq. 3}$$

where,

- C_2 = wellbore storage constant, BBL / psi
- V_u = annular volume capacity, BBL / ft
- g_c = units conversion factor, (lb_m-ft) / (lb_f-sec²)
- g = acceleration of gravity, ft / sec²
- ρ_o = oil density, lbm / ft³
- V_g = gaseous wellbore volume, BBL
- c_g = gas compressibility, 1 / psi

The latter term involving gas compressibility will dominate the above expression and thus control this storage constant.

The second storage period will begin after the annular region is essentially filled with oil, as shown in Figure 1b. In that case, the wellbore storage constant is primarily dependent only on the compressibility of oil and given by:

$$C_1 = V_w \cdot c_o \quad \text{Eq. 4}$$

where,

- C_1 = wellbore storage constant, BBL / psi
- V_w = total wellbore storage volume, BBL
- c_o = compressibility of oil, 1 / psi.

Estimates of C_2 and C_1 were created and superimposed on the HEYCO field data and shown in Figure 5. Note that C_1 is less than C_2 and that the curves display quite similar behavior to the theoretical curves shown in Reference 1. Refer to Reference 1 for more details on this phenomena of changing storage constant.

The somewhat irregular, early time, pressure buildup behavior from the HEYCO test was most probably related to the decreasing storage phenomena suggested above. The time

for the first storage period to effectively diminish can be estimated by considering the gas annular volume, V_g , and the average oil production rate, q_o . This time is then given by,

$$t_1 = V_g / q_o = 0.214 \text{ BBL} / 2 \text{ BOPD} = 0.107 \text{ days}$$

or,

$$t_1 = 0.107 \text{ days} * 24 \text{ hr / day} = 2.6 \text{ hrs}$$

This is in good agreement with the time when the data begins to deviate from the unit slope as seen in Figure 4, about 2.5 to 3 hrs. Following this wellbore filling period and gas compression stage, bottomhole pressure then showed signs of a transition period in response to the second storage mechanism that was controlled by oil compressibility. This second storage period which is the normal storage period generally discussed in the literature is rather ill defined as can be seen in Figure 4. However, all the wellbore storage effects appear to be totally diminished after about 15 to 20 hrs into the buildup as noted by the transition of the derivative curve.

Published type curves which are used in the analysis of pressure buildup behavior do not accommodate a varying wellbore storage constant. For purposes of this analysis, various solutions to the diffusivity equation were generated which allow for variation of the wellbore storage constant with time. These solutions were generated to investigate the anomalous behavior of the buildup data during storage and to determine potential causes for the behavior of the buildup curve during reservoir dominance. Solutions which were generated include those for finite reservoir-no flow outer boundary, finite reservoir-no flow outer boundary, and infinite reservoir-dual porosity. These solutions are described in the Appendix.

As seen in Figure 4, the derivative curve, based on the buildup data, transitions from wellbore storage into a reservoir dominated portion which decreases in value with time. The cause of this phenomenon was investigated using the above referenced diffusivity equation solutions.

Finite Reservoir - No Flow Outer Boundary

Figure 6 illustrates the predicted versus actual buildup and derivative group performance based on a varying wellbore storage constant and an assumed no-flow outer boundary. The match parameters were:

$$\begin{aligned} kh &= 0.955 \text{ md-ft} \\ skin &= 9.0 \\ r_e / r_w &= 250 \end{aligned}$$

The wellbore storage constant varied linearly between $1.61 \cdot 10^{-4}$ and $8.03 \cdot 10^{-4}$. Although the match appears reasonable, the possibility that a no-flow outer boundary exists in this case is questionable due to the small value of r_e / r_w which resulted from

the match. Assuming a wellbore radius ratio of 250, the resulting r_e of 62.5 ft is small and may not be of practical consideration.

Infinite Reservoir - Dual Porosity

Figure 7 illustrates the predicted versus actual buildup and derivative group performance based on a varying wellbore storage constant and an infinite reservoir which exhibits dual porosity behavior. The match parameters were:

$$\begin{aligned} kh &= 1.032 \text{ md-ft} \\ skin &= 9.0 \\ \lambda &= 5 \cdot 10^{-7} \\ \omega &= 0.01 \end{aligned}$$

The wellbore storage constant varied linearly between $1.61 \cdot 10^{-4}$ and $8.03 \cdot 10^{-4}$. It should be noted that the match illustrated in Figure 7 is non-unique. The test did not run long enough to uniquely determine the combination of flow capacity, λ , and ω , which might represent the reservoir. It is apparent from the log-log / derivative curves, however, that dual porosity behavior could be present during this test.

It should be noted that in the two matches presented above, the early time wellbore storage behavior was matched by letting the wellbore storage coefficient vary linearly.

Table 3 summarizes the results from the well test analysis.

4.0 References

1. Earlougher, R.C. Jr.: Advances in Well Test Analysis, Monograph Series, SPE, Dallas (1977).
2. Bourdet, D., T.M. Whittle, A.A. Douglas and Y.M. Pirard: "A New Set of Type Curves Simplifies Well Test Analysis," World Oil (May 1983).
3. Warren J. and P. Root: "The Behavior of Naturally Fractured Reservoirs," SPEJ (Sept. 1963) p.245-255.

Appendix

Applying mass balance and Darcy's law, the following is a diffusivity equation in a radial coordinate:

$$(1/r)[(\partial/\partial r)(\partial p/\partial r)] = (\phi\mu c_t/k)(\partial p/\partial t)$$

where:

- p = pressure, psi
- ϕ = porosity
- μ = viscosity, cp
- c_t = reservoir total compressibility, 1/psi
- k = reservoir permeability, md
- r = radial coordinate, ft
- t = time.

To solve the diffusivity equation, the following boundary conditions (B.C.) and initial conditions (I.C.) are needed:

Initial conditions:

$$p = p_i \text{ @ } t = 0;$$

Inner B.C.:

$$[-C(dp_{wf}/dt) + (2\pi krh/\mu)\partial p/\partial r]_{r=r_w} = q, \text{ and}$$

$$p_{wf} = [p - \bar{s} \cdot r_w \cdot p/\partial r]_{r=r_w};$$

Outer B.C.:

(1) For infinite reservoir:

$$p = p_i \text{ as } r \rightarrow \infty;$$

(2) For closed reservoir:

$$[\partial p/\partial r]_{r=r_e} = 0;$$

(3) For constant pressure outer boundary:

$$p = p_i \text{ @ } r = r_e;$$

where,

- p_i = initial reservoir pressure, psi
- r_e = reservoir drainage radius, ft
- $\bar{s}$ = skin
- C = wellbore storage coefficient, BBL/psi.

Define the following dimensionless variables:

Dimensionless pressure:

$$p_D = 2\pi kh(p_i - p) / qB\mu;$$

Dimensionless radial:

$$r_D = r / r_w, r_{eD} = r_e / r_w;$$

Dimensionless time:

$$t_D = kt / \phi\mu c_f r_w^2;$$

Dimensionless wellbore storage coefficient:

$$C_D = C / 2\pi\phi k c_f r_w^2.$$

If the equations and I.C. and B.C. are put into dimensionless space, then.

$$\partial^2 p_D / \partial r_D^2 + 1 / r_D \cdot \partial p_D / \partial r_D = \partial p_D / \partial t_D;$$

I.C.:

$$p_D = 0 \text{ @ } t_D = 0;$$

Inner B.C.:

$$C_D \cdot \partial p_{wD} / \partial t_D - \partial p_D / \partial r_D \big|_{r_D=1} = 1, \text{ and}$$

$$p_{wD} = [p_D - \bar{s} \cdot \partial p_D / \partial r_D]_{r_D=1} = 1;$$

Outer B.C.:

$$(1) \quad p_D = 0 \text{ as } r_D \rightarrow \infty;$$

$$(2) \quad [\partial p_D / \partial r_D]_{r_D=r_{eD}} = 0 \text{ @ } r_D = r_{eD};$$

$$(3) \quad p_D = 0 \text{ @ } r_D = r_{eD}.$$

Applying Laplace transform and Bessel functions, the following are solutions for different outer B.C.s in Laplace space:

(1) Infinite reservoir:

$$p_{wD} = 1 / s \cdot [k_0(\sqrt{s}) + \sqrt{s} \cdot \bar{s} \cdot k_1(\sqrt{s})] / [(1 + C_D \cdot \bar{s} \cdot s) \sqrt{s} \cdot k_1(\sqrt{s}) + C_D \cdot s \cdot k_0(\sqrt{s})];$$

(2) Closed reservoir:

$$P_{WD} = 1/s \{ \} \cdot \{ k_1(r_{eD}\sqrt{s})I_0(\sqrt{s}) + I_1(r_{eD}\sqrt{s})k_0(\sqrt{s}) - \bar{s}\sqrt{s}k_1(r_{eD}\sqrt{s})I_1(\sqrt{s}) + \bar{s}\sqrt{s}I_1(r_{eD}\sqrt{s})k_1(\sqrt{s}) \};$$

where,

$$\{ \} = (1 + C_D \cdot s \cdot \bar{s})\sqrt{s}k_1(\sqrt{s})I_1(r_{eD}\sqrt{s}) + C_D s k_0(\sqrt{s})I_1(r_{eD}\sqrt{s}) - (1 + C_D \cdot s \cdot \bar{s})\sqrt{s}I_1(\sqrt{s})k_1(r_{eD}\sqrt{s}) + C_D s I_0(\sqrt{s})k_1(r_{eD}\sqrt{s});$$

(3) Constant pressure outer boundary:

$$P_{WD} = 1/s \{ \} \cdot \{ I_0(r_{eD}\sqrt{s})k_0(\sqrt{s}) - I_0(\sqrt{s})k_0(r_{eD}\sqrt{s}) + \bar{s}\sqrt{s}I_1(\sqrt{s})k_0(\sqrt{s}r_{eD}) + \bar{s}\sqrt{s}I_0(r_{eD}\sqrt{s})k_1(\sqrt{s}) \};$$

where,

$$\{ \} = (1 + C_D \cdot s \cdot \bar{s})\sqrt{s}I_1(\sqrt{s})k_0(r_{eD}\sqrt{s}) - C_D s I_0(\sqrt{s})k_0(r_{eD}\sqrt{s}) + (1 + C_D \cdot s \cdot \bar{s})\sqrt{s}k_1(\sqrt{s})I_0(r_{eD}\sqrt{s}) + C_D s k_0(\sqrt{s})I_0(r_{eD}\sqrt{s}).$$

For simplicity, the solution of Warren & Root's³ dual porosity model is given:

$$P_{WD} = 1/s \cdot [k_0(\sqrt{s}\sqrt{f}) + \bar{s} \cdot \sqrt{s}\sqrt{f} \cdot k_1(\sqrt{s}\sqrt{f})] / [(1 + C_D \cdot \bar{s} \cdot s)\sqrt{s}\sqrt{f} \cdot k_1(\sqrt{s}\sqrt{f}) + C_D \cdot s \cdot k_0 \cdot \sqrt{s}\sqrt{f}], \text{ and}$$

$$f = [\omega(1-\omega)s + \lambda] / [(1-\omega)s + \lambda];$$

where,

ω = storativity ratio at fracture system to total system and

λ = Interporosity pseudo-steady state flow parameters.

All the above solutions in Laplace space are numerically converted into real time by Stehfest algorithm.

*Table 1 Wellbore Configuration for Pressure Buildup Test
of the Bone Spring 2nd Sand*

Casing:	5.5" O.D, 17#, 4.892" I.D., Surface - 9,450 ft
Tubing:	2.375" O.D., 4.7 EUE J55, 1.995" I.D., Surface - 9,304 ft
Packer:	Set at 9,308 ft (center)
Seating Nipple:	9,304 ft
Tail Pipe:	9,310 to 9,338 ft
Perfs:	9,345 ft 9,359 ft 9,404 ft 9,407 ft 9,423 ft 9,431 ft

*Table 2 PVT Data of the Bone Spring 2nd Sand Oil
(from Sandia National Laboratories)*

API gravity	37° API
GOR	600 ft ³ / STB
c _o	12.9 • 10 ⁻⁶ 1 / psi
B _o	1.45 RB / STB
p _o	0.69 at 2,940 psi 0.697 at 2,400 psi
p _b	2,400 psi

Pressure, psi	Oil Viscosity, μ _o cp
0	1.65
223	0.90
470	0.81
817	0.72
1,136	0.64
1,560	0.58
1,823	0.55
1,970	0.53
2,956	0.52
2,865	0.55
2,540	0.51
2,400	0.50

Table 3 Parameters Obtained from the Well Test

Analysis of HEYCO CAL-MON State No. 1 Well

Method Parameter	Horner	Analytical Solutions	
		Dual Porosity	No-Flow Boundary
k (μ d)	12.6	12.0	11.1
S	11.4	9.0	9.0
p* (psi)	3,650	N/A	N/A
C ₁ (BBL / psi)	N/A	$1.61 \cdot 10^{-4}$	$1.61 \cdot 10^{-4}$
C ₂ (BBL / psi)	N/A	$8.03 \cdot 10^{-4}$	$8.03 \cdot 10^{-4}$
Estimated Distance to No-Flow Boundary, ft	N/A	N/A	≈ 62.5

Figure 1 Bottomhole Tool and Tubular Configuration Used in the Pressure Buildup Tests of the Bone Spring 2nd Sand in HEYCO CAL-MON State No. 1 Well (a) Gas Partly Filling the Annular Region of the Bottomhole Creating a Large Wellbore Storage Constant, C_2 (b) Oil Filled Wellbore Volume After the Gas is Compressed into a Small Portion of the Annular Volume (thus decreasing the storage constant, C_1)

Figure 2 Bottomhole, Surface Casing and Tubing Pressures Measured During the Buildup Test of the Bone Spring 2nd Sand

Figure 3 Horner Plot from the Bottomhole Pressure Buildup with $t_f = 117$ Hours and $q_0 = 2 \text{ BOPD}$ (the late time slope is $m = 230 \text{ psi/cycle}$)

Figure 4 Log-Log/Derivative Curve for the Bottomhole Pressure Buildup Test Performed in the Bone Spring 2nd Sand

Figure 5 Theoretical Log-Log Curve Depicting a Case with Decreasing Wellbore Storage and Analogous to the Data from Figure 1

Figure 6 Log-Log/Derivative Match Using Finite Reservoir with No Flow Out: Boundary at $r_e = 62.5$ Ft

Figure 7 Log-Log/Derivative Matches Using Infinite Reservoir with Dual Porosity Behavior

5.0 FRACTURING

5.1 Microfracs

On July 18, 1989, microfrac injection tests were performed in the Cal-Mon 15 State No. 1 well. These tests were conducted in order to obtain accurate closure stress measurements for a subsequent minifrac and to obtain some initial information about fracture behavior and leakoff conditions. The zone that was tested was the Third Bench of the Bone Spring Second sandstone at a depth of about 9400 ft. The tests conducted included the following:

- 3 micro-injections
- 1 pump-in/shut-in test
- 1 step-rate/flow-back test
- 2 pump-in/flow-back tests.

Figure 5.1. shows a brief description of the well layout, including the location of the bottomhole pressure gauge relative to the perforations. The center of the perforated interval is at 9388 ft. All tests were pumped down the annulus while the pressure gauge was located in the tubing dead string. Treating fluid was 1% KCl water. The correction for the tool location relative to the center of the perforated interval is 235 psi, using a 0.435 psi/ft gradient. CER Corporation ran the pressure tool and Dowell-Schlumberger pumped the treatments.

Figure 5.2 shows the bottomhole pressures for the initial three micro-injections; note that these pressures have not been corrected to zone depth. ISIP values for these three tests are 6350, 6350, and 6370 psi, respectively. ISIP's on these small micro-injections are usually a good estimate of the closure pressure (normally within 100 psi).

The micro-injections were followed by a pump-in/shut-in test to determine additional fracture characteristics. The bottomhole pressure from the entire test and the Nolte-Smith log-log plot from the injection part of the

test are shown in Figure 5.3. The log-log plot of the treatment pressure shows a fairly constant slope of 0.3 for the final 70% of the injection; this is a little higher than the expected value for a Newtonian fluid (0.2) but this may be due to an overestimate of the perforation pressure drop or the closure stress (6430 psi). If the perforation correction (105 psi) is neglected entirely, the slope is 0.19. This low slope indicates that there was minimal height growth. Radial growth appears to have occurred for only the first 2 to 3 min of the injection. Such behavior suggests that there are some boundaries, at least for this low pressure injection.

The most useful part of this test is the pressure falloff behavior, shown in the square-root-of-time and G-function plots of Figure 5.4. The end of the initial straight line segment of both of these plots is usually a good measure of the closure stress, being about 6430 psi for the $\sqrt{t}$ time and about 6420 for the G-function. However, in this case the straight line segment is not particularly clear and one could reasonably pick either higher or lower values. The negative of the slope of the G-function plot through the initial straight line segment is also equivalent to Nolte's P^* in the pressure decline analysis. The derivative curve, showing this initial constant slope behavior, and the formal Nolte type curve analysis are shown in Figure 5.5. Both analyses give a clear P^* value of 30 psi.

We can use the P^* value to calculate the leakoff coefficient, by

$$C = \frac{P^* H^2 \beta_s}{H_p E' \sqrt{t_o}}$$

where the nomenclature and values for these parameters are given in Table 5.1. Note that the leakoff coefficient is particularly sensitive to the total fracture height; our only estimate of this value comes from the temperature log. Figure 5.6 shows a section of the temperature logs that were run after these tests. The total fracture height appears to be on the order of 100 ft. The leakoff height was taken from the porosity log, using a cutoff value of 10%. We used 10% because we believe that the log-derived

porosity is about 3% higher than core values. The actual porosity cutoff is then 7%. Using these values, the coefficient of leakoff for KCl water is 0.00015 ft/ $\sqrt{\text{min}}$, an extremely low value for an oil reservoir. Since there is no wall-building properties with KCl water, the permeability can be estimated from this coefficient. The permeability can be calculated from either

$$k = \left[\frac{C}{0.0469} \right]^2 \frac{\mu}{\phi \Delta P} ,$$

for a permeability-dominated leakoff in an evacuated media, or

$$k = \left[\frac{C}{0.0374 \Delta P} \right]^2 \frac{\mu}{\phi c} ,$$

for permeability-dominated leakoff in a liquid filled reservoir. Both value should be calculated and the higher one used (usually, one is an order of magnitude higher than the other). Table 5.2 gives the best estimates for values needed in these equations. The permeability-dominated leakoff into an evacuated medium gives a permeability of 0.000026 md for water leakoff, which is obviously too low. Leakoff of liquid frac fluid into an evacuated medium is generally more typical of gas reservoirs than oil reservoirs.

The permeability-dominated leakoff into a liquid reservoir yields a permeability of 0.0046 md for all water in the formation and 0.0007 md for all oil in the formation. In this case, the leakoff is water, but it must push oil out of the way, so some combination of fluids is really required. We believe, however, that the water case should be pretty close to the overall behavior; thus the permeability calculated from leakoff is about 0.004 md or 4 μd . This is a really tight reservoir with no sign of natural fractures in the leakoff behavior.

We can also use Nolte's analysis to estimate the fracture length. In this case it comes out to 140 ft. This suggests that we might try a radial fracture geometry for this analysis, but it yields 0.00016 ft/ $\sqrt{\text{min}}$ for the leakoff coefficient, almost the same value as the constant height model.

A step-rate/flow back was conducted next. The overall pressure behavior and the step-rate graph are shown in Figure 5.7. The step-rate graph has the actual pressure and a corrected pressure, in which the perforation pressure drop is subtracted out. We assumed that all six perforations were opened, the perf diameter was 0.38 in and the flow coefficient was 0.95, yielding the perf pressure drop curve shown in the insert. The step-rate results suggest that fracturing extension pressure is about 6430 psi, nearly the same as the closure pressure. Most likely, a couple of the perforations are in a little lower stress interval, and these start taking fluid first. Otherwise, the fracture created by the acid breakdown must be fairly wide and porous.

The flow-back data from the step-rate/flow-back test are shown in Figure 5.8. The figure shows the actual data and a least-squares polynomial fit of the data, so that derivatives can be calculated from smooth data. During a flowback, the point of fracture closure should cause an inflection in the pressure curve. An inflection point has a zero second derivative, which can be easily found from the polynomial fit. In this test the inflection occurs at 38 min, but possibly as late as 46 min, since the fit is never totally accurate. This yields a pressure range of 6450 to 6492 psi for the closure stress. Five-point regressions are also conducted on the raw data, but these regressions are often quite noisy and they are not shown here. It is interesting to note that Shell people tend to take the point where the pressure begins to fall over as the closure pressure. This is about 6350 psi, which agrees with the micro-injection ISIP values.

The first pump-in/flow-back test was conducted next; the pressure data are shown in Figure 5.9. Data and derivatives from the flow-back are shown in Figure 5.10. The closure occurs at about 23 min and the stress appears to be about 6485 psi, based on the inflection point. The Shell value would again be about 6350 psi.

The second pump-in/flow-back test is shown in Figure 5.11. Data and derivatives are shown in Figure 5.12. The closure occurs between 19 and 23 min for a stress range of 6460 to 6502 psi, based on the inflection point. The Shell value is again about 6350 psi.

All of the closure stress results are summarized in Table 5.3. It is generally best to pick lower values when a range is present. In this case, we believe that the closure stress is about 6430 psi $\pm$ 70 psi. When the correction to the depth of the perforations is added, the closure stress is 6665 psi $\pm$ 70 psi, for a gradient of 0.71 psi/ft.

5.2 Minifrac

On July 24, 1989, a minifrac was conducted on Heyco's Cal-Mon 15 State No. 1 well. The purpose of this test was to obtain additional information about reservoir parameters and fracture behavior in the First and Third Benches of the Bone Spring Second sandstone. This test was pumped by Dowell-Schlumberger, followed later in the day by the actual stimulation.

The well configuration for this test is shown in Figure 5.13. Because of casing constraints, there was no bottomhole pressure measurement and bottomhole pressures were calculated from surface pressures. There were nine perforations scattered in two separate sandstone benches, over a 500-ft interval. Perforations were 0.38 in diameter. The minifrac fluid was a 45 lb/1000 gal HPG with 3% HCl acid.

The surface pressure and gel flow rate from the minifrac are shown in Figure 5.14. The flow rate is not exactly correct, as it does not show the acid rate, which is about 10% of the gel rate. Between 10 and 27 min, the total rate is about 24 bpm. After 27 min, we were injecting casing flush volume; since we did not want acid sitting in the casing for a couple of hours while we were monitoring the pressure decline, the acid injection was stopped and the gel injection was increased to keep the same total flow rate. The faster increase in the surface pressure after this change is due primarily to the change in fluid viscosity. Prior to the change, a 48 lb/1000 gal gel was mixed with the acid, resulting in a net 45 lb/1000 gal gel. After the change, a straight 48 lb/1000 gal gel was pumped downhole. It appears that the total rate was also slightly greater. There is initially KCl water in the casing, and gel hits the perforations at about 13 min. The total gel pump time is about 23 min.

Figure 5.15 shows the calculated bottomhole pressure during the pressure decline (surface pressure + hydrostatic) and the resulting Nolte type curve from this pressure decline. The data are relatively coarse because the resolution of the surface gauge is about 5 psi, resulting in the stair-step behavior in the bottomhole pressure. The type curve results are also a bit strange, with a significant deviation from expected behavior after about 1.5 pump times (about 35 min). This may be because of closure and will be discussed more later. The type curves give a reasonable match over a range of P^* values from 40 to about 120. We chose the P^* value of 55 as a best fit primarily because it agreed with the square-root-of-time analysis as to the time of apparent fracture closure.

Figure 5.16. shows the calculated bottomhole pressure as a function of Nolte's G-function, as well as a least-squares polynomial fit of the curve. The fit data is used to smooth out the stair-step behavior in order to get the dP/dG plot (also shown in Figure 5.16) for a second method of estimating P^* . One usually searches for a flat dP/dG interval, with the negative of that dP/dG value being equivalent to P^* . In this case there is no flat interval and P^* could have a value anywhere between 30 and 70 psi. This behavior is similar to the type curve behavior discussed earlier. We tried using pressure sensitive leakoff analyses to get flatter dP/dG behavior, but those analyses did not improve the data. The pressure sensitive leakoff does not appear to be the problem here.

Using a P^* of 55 psi, the leakoff coefficient of this fluid can be calculated if the total height and leakoff height are known. Unfortunately, we could not get a temperature log because of wellhead problems, so there is no direct measurement of the fracture height. Table 5.4 gives values or ranges of values that we considered in calculating the leakoff coefficient for this test. The maximum fracture area occurs for an equivalent fracture height, H , of 300 ft, while the expected minimum fracture height would be about 150 ft, based on the geology. The leakoff height, H_p , on the other hand, might be as little as 82 ft (the net porosity thickness) or as much as 150 ft. Using these ranges of values, the leakoff

coefficient can be calculated from

$$C = \frac{s P^* H^2 \beta}{H_p E' \sqrt{t_o}}$$

With these numbers, a leakoff range of 0.00015 to 0.0011 ft./min is calculated. As will be shown later, further analyses will help to narrow this range. For comparison, the KCl pump-in/shut-in test resulted in a leakoff coefficient of 0.00015 ft./min.

The only additional data that we have to narrow down the range of the calculated leakoff coefficients are the pressures during the treatment. Figure 5.17 shows D-S's calculated bottomhole pressures on a log-log plot, but these numbers do not account for the perforation friction pressures (at our request) and there appears to be some other errors. For example, at 27 min, there is a 150 psi drop in pressure followed by a fairly fast increase. What actually happened here is the switch from acid to no acid. However, the gel rate was increased to compensate for the acid rate, but the calculations apparently did not pick this up. The increase that follows is due to the slight rheology change in the casing, from a 45 lb/1000 gal to a 48 lb/1000 gal system. This apparently was also not incorporated in the calculations.

Our corrections of these errors and our estimate of the perforation friction pressures yield the bottomhole pressures shown in Figure 5.18. This is the pressure seen at the interface between the fracture and the perforations; however, we do not have a lot of confidence in these numbers since there are a lot of approximations and estimations made in getting them. Also shown in Figure 5.18 is our estimate of the log-log plot. This plot is started when the gel first hits the perfs (about 13 min into the job), yielding the shorter pump time than shown in D-S's graph. The slope here is about 0.15, a little smaller than would be expected for a fluid with $n' = 0.5$, and is probably due to the large amount of height growth during the treatment.

With the net pressure plot, we can also perform some pressure-history modeling to estimate parameters. In this case, there are so many uncer-

tainties in the values, that we did not feel it was worth trying anything elaborate. However, a simple constant height calculation to match the final treatment pressure provided some interesting results. Figure 5.19 shows the final treatment pressures for this pump, given the values in Table 5.5, as a function of fracture height and leakoff coefficient. Over the range in leakoff values calculated with the minifrac, the total fracture height is fairly constrained if the correct net pressure is to be reached. In this case, the height should be about 220 ft $\pm$ 30 ft. Because the leakoff values are relatively low, fracture height tends to dominate the net pressure behavior during the injection, and, as a first order approximation, we can ignore the leakoff coefficient to get the height.

Using this value of fracture height, a new range of leakoff coefficients can be calculated for the minifrac. This range is 0.00033 to 0.00064 ft/ $\sqrt{\text{min}}$. A realistic value is 0.0005 $\pm$ 0.0002 ft/ $\sqrt{\text{min}}$. This value is interesting because it is higher than the leakoff for the KCl pump; usually the gels will have lower leakoff coefficients. This discrepancy is likely due to the acid and the additional permeability created by the acid.

The total height of 220 ft is also an interesting number. It is clear that there are two separate fractures and in Nolte's analysis, with more than one fracture, 220 ft is the height of a single elliptic fracture having the same area as the sum of the separate fractures. For such a case,

$$H = \sqrt{H_1^2 + H_2^2} ,$$

where H is 220 ft and H_1 and H_2 are the heights of the two separate fractures. Of course, this is a gross approximation and does not take into account different closure stresses in the two layers or different frictional resistance. In this case, the 220 ft height is equivalent to two fractures of 90 and 200 ft, just the thicknesses of the two sand benches, although this agreement is likely serendipity.

The square-root-of-time plot for the pressure decline, shown in Figure 5.20, indicates that there was some significant change in fracture closure behavior at about a value of 6 (or 36 min after shut in). Also shown is a least-squares polynomial fit and the resulting derivative. The derivative result also shows that the slope changes and becomes fairly flat after 40 min or so. This change occurs at a pressure of 6780 psi, about 100 psi higher than the closure stress of the lower sand, as measured in the microinjection tests. The closure may reflect a different stress level in the upper sand, which closes first, or, more likely, is due to different stress levels in different layers of the sand benches. It could be due to back stresses (poroelastic stress changes due to leakoff), but this is an extremely large back stress for such a small treatment in such a tight reservoir.

In summary, it looks like the leakoff coefficient for this frac fluid is quite low, at about 0.0005 ft³/min. The injection pressure indicates that there must be considerable height associated with this fracture, resulting in relatively low net injection pressures. Because the injection pressures are low, if there are any stress boundaries, they may be fairly effective. Also, with such low injection pressures, other containment features such as bedding, material property differences, and gravity effects can help retard fracture growth.

There is nothing in any of these data to suggest that natural fractures have a large effect in either the leakoff or the injection behavior. If fractures exist in this reservoir, they are probably tight and widely spaced.

Although these data have been useful for giving a first look at the reservoir and fracture behavior, there are many uncertainties associated with this data set. If we are to really get high quality data for a complete minifrac analysis, we need to have a measured bottomhole pressure and a separate height measurement, such as a temperature log. Additionally, the high perforation pressure drop associated with so few perforations

makes it difficult to estimate the true injection pressure. Finally, we need to look at one sandstone bench at a time to avoid the multiple fracture, multiple closure phenomena. Some of these changes would be helpful for any follow-on work.

5.3 Fracture Treatment

Immediately after the minifrac, Heyco treated the perforations with 115,000 gal of 45 lb/1000 gal HPG and 3% HCl and 100,000 lb of intermediate strength proppant. The well was then put on production on pump.

Table 5.1

Properties Used in Pressure-Decline Analysis

n'	consistency index	1.0
β_s	pumping coefficient	0.8
t_o	pump time	10.3 min
H_p	leakoff height	66 ft
H	total frac height	100 ft
E	Young's modulus	7.0×10^6 psi
ν	Poisson ratio 0.23	
E'	plane-strain E	7.4×10^6 psi

Table 5.2

Properties for Leakoff Calculations

Δp	pressure differential	2700 psi
ϕ	porosity	12 %
μ	viscosity	
	water	0.8 cp
	oil	0.5 cp
c	compressibility	
	water	3.3×10^{-6} psi ⁻¹
	oil	13×10^{-6} psi ⁻¹

Table 5.3

Closure Stress Data

<u>TEST</u>	<u>ISIP</u>	<u>SHUT-IN DATA</u>		<u>FLOW-BACK DATA</u>	
		<u>$\sqrt{t}$</u>	<u>Q</u>	<u>REGRESSION</u>	<u>FIT</u>
Microinjection #1	6350				
Microinjection #2	6350				
Microinjection #3	6370				
Pump-in/shut-in	6510	6430	6420		
Step-rate/flow-back	6550			-	6450-6492
Pump-in/flow-back #1	6550			6480-6500	6485
Pump-in/flow-back #2	6550			6480-6501	6460-6502

Best estimate: closure stress = 6430 psi $\pm$ 70 psi
 Corrected to depth: = 6665 psi $\pm$ 70 psi

Table 5.4

Values for Minifrac Leakoff Calculations

n'	0.5
β_s	0.67
E'	7.4×10^6 psi
t_o	23 min
H	150-300 ft
H_p	82-150 ft

Table 5.5

Values for Pressure History Calculations

E	7.0×10^6 psi
ν	0.23
C	0.0001, 0.0005 and 0.001 ft/ $\sqrt{\text{min}}$
S _p	0.001 gal/ft ²
n'	0.5
k'	0.014 lb-sec ^{n'} /ft ²
Q	24.2 bpm
t _{pump}	23 min

CAL-MON 15 STATE # 1

PUMP DOWN ANNULUS
1.5 % KCL WATER

BHP TOOL Ø 8850 FT
TUBING TAIL Ø 8900 FT
PERFS Ø 9345, 59
9403, 07, 23, 31

Figure 5.1 Well layout

Figure 5.2 Micro-injections

Figure 5.3 Pump-in/shut-in data

Figure 5.4 Shut-in data

Figure 5.5 Pressure decline data

Figure 5.6 Temperature Logs

**STEP-RATE TEST
CAL-MON 15 STATE #1**

Figure 5.7 Step-rate/flow-back data

Figure 5.8 Flow-back data

Figure 5.9 Pump-in/flow-back test #1

Figure 5.10 Flow-back data

Figure 5.11 Pump-in/flow-back #2

Figure 5.12 Flow-back data

Figure 5.13 Well layout

Fractec*

Pumping Parameter Recorder

TREATMENT REPORT

24 Jul 89

Customer: HEYCO

Well Name: CALMON 15 ST. #1

District: 0506-5403

*Trademark and Service Mark of Dowell Schlumberger

Figure 5.14 Injection data

Figure 5.15 Pressure decline data

Figure 5.16 G-function data

Customer: HEYCO
Well Name: CALMON 15 ST. #1
District: 0506-5403

24 JUL 89

*Trademark and Service Mark of Dowell Schlumberger

Figure 5.18 Corrected bottom-hole pressure data

NET PRESSURE VS FRAC HEIGHT AND LEAKOFF

Figure 5.19 Pressure match results

Figure 5.20 Square-root-of-time data

6.0 CONCLUSIONS AND RECOMMENDATIONS

Nonroutine, detailed data were obtained from two Heyco development wells during the year. Preliminary conclusions based upon the first year of study are listed below:

No natural fractures were seen in core or logs in the sandstone benches of the Second Bone Spring sandstone. In addition, they did not appear to have a major influence on the well testing or the fracturing tests. Nevertheless, natural fractures may still be important for three reasons. First, they may still be the cause for localized good production observed in other Bone Spring sandstone wells. Second, measured effective reservoir permeability is much greater than the permeability of the matrix rock. Finally, if present, they are marginal (i.e., narrow, widely spaced, poorly interconnected) and are easily damaged, significantly affecting production.

The core properties indicate very low permeability matrix rock (0.2 to 11 μ d to gas at in situ stress), with low porosities (2% to 7%) and variable oil (0% to 39%) and water (21% to 93%) saturations. The matrix permeability will be still lower at reservoir saturations.

The Bone Spring Sandstones are predominantly siltstones and they contain moderate amounts (4% to 7%) of clay, mostly illite. They were deposited as thin repetitive laminae that settled out from suspension and appear reworked by secondary, deep-marine currents and portions contain invertebrate traces; they do not have features typical of turbidite deposits, as they have commonly been interpreted to be.

Stress indicators (e.g., ASR, CVA, and drilling-induced fractures) suggest that the maximum principal horizontal stress over the cored interval is northeast to east, although the accuracy is less than desired. Small volume injection tests gave a closure stress of 6665 ± 70 psi, approximately a 0.71 psi/ft gradient.

Log derived porosities were found to be about 2 to 3 porosity percent higher than core-derived porosities. This has probably caused an overestimate of the amount of oil in place.

Reservoir permeability was measured to be 10-15 μ d based upon a 10-day buildup test. This is at least an order of magnitude greater than the in situ matrix permeability estimated from core data. This difference indicates that natural fractures, high permeability streaks, or some other mechanism contribute to production.

These results represent a wealth of new information that was not previously available for the Bone Spring sandstones and they present new insight into these reservoirs.

The above results are not as definitive with respect to the role of natural fractures and in situ stresses as was hoped at the start of this project. The AJ 11 Federal No. 1 was not productive from the Bone Spring sandstone, and the Cal-Mon 15 State No. 1 was a below-average producer. As such, the data presented here may not be typical of those for good Bone Spring sandstone production. Thus, the following areas form the focus for additional work in the coming year.

Natural fractures may still be important if they can be shown to be present in a well with good production from the Bone Spring sandstone. Thus, if another well is planned in a more productive location, then additional efforts are warranted to take core and run fracture-identification logs, and to make anelastic strain recovery and other stress-related techniques to determine fracture/stress relationships. Another high-quality well test should also be conducted. If fractures are not important, then the mechanism for production from this low matrix permeability reservoir must be determined in additional studies.

Damage appears to be a significant factor, as evidenced in production behavior and by the high skins found in most well tests. This damage may

be due to compatibility problems with the acids and liquids used in most completions. However, it may also be due to more subtle effects such as relative permeability effects in the tight matrix, or gel or liquid damage to existing natural fractures. First consideration should be given to evaluating a nondamaging breakdown of the perforations such as perforating with the well pressurized with nitrogen gas. Other approaches to minimize damage are to use a gelled oil to minimize relative permeability problems, to try a nitrogen foam in order to minimize liquids and gels, or possibly to combine both in a nitrogen/oil foam frac. Both the nitrogen breakdown and a foam frac will require higher strength casing than normally used.

Geologic studies on the depositional environment and structural controls on the reservoir are necessary. A reconciliation between the variability in sandstone thickness noted between wells (on 40-acre spacing) and the low-energy sedimentary structures observed in core is needed. Core from a well with good production is needed in order to assess any possible sedimentary reasons for differences between wells with poor production (such as the AJ 11 Federal No. 1) and wells with higher potential. Additionally, well-log studies are needed of the section-scale geometries of individual sandbodies (benches) within the second Bone Spring sandstone interval. There are about five such sandstones, and their patterns of thinning and thickening in relation to each other and to other local structural and sedimentary features should enhance the understanding of the reasons for these patterns. Such understanding could ultimately lead to an exploration rationale based on a well-supported sedimentary model.

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END

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