STATE OF NEW MEXICO

ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT

OIL CONSERVATION DIVISION

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November 12, 1992

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Attorneys at Law
P. O. Drawer 2265
Santa Fe, New Mexico 87504

RE: CASE NO. 10547
ORDER NO. R-9761

Dear Sir:

Enclosed herewith are two copies of the above-referenced Division order recently entered in the subject case.

Sincerely,

Florene

Florene Davidson
OC Staff Specialist

FD/sl

cc: BLM - Farminton
W. Carr
OCD Aztec Office

STATE OF NEW MEXICO
ENERGY, MINERALS AND NATURAL RESOURCES DEPARTMENT
OIL CONSERVATION DIVISION

IN THE MATTER OF THE HEARING
CALLED BY THE OIL CONSERVATION
DIVISION FOR THE PURPOSE OF
CONSIDERING:

CASE NO. 10547
ORDER NO. R-9761

APPLICATION OF BENSON-MONTIN-GREER DRILLING CORPORATION FOR A HIGH ANGLE/ HORIZONTAL DIRECTIONAL DRILLING PILOT PROJECT, RIO ARRIBA COUNTY, NEW MEXICO

ORDER OF THE DIVISION

BY THE DIVISION:

This cause came on for hearing at 8:15 a.m. on September 3, 1992, at Santa Fe, New Mexico, before Examiner Michael E. Stogner.

NOW, on this 12th day of November, 1992 the Division Director, having considered the testimony, the record and the recommendations of the Examiner, and being fully advised in the premises,

FINDS THAT:

(1) Due public notice having been given as required by law, the Division has jurisdiction of this cause and the subject matter thereof.

(2) At the time of the hearing, this matter was consolidated with Case No. 10548 for purposes of testimony.

(3) The applicant, Benson-Montin-Greer Drilling Corporation, seeks to initiate a high angle/horizontal directional drilling pilot project within a standard 640-acre oil spacing and proration unit in the West Puerto Chiquito-Mancos Oil Pool comprising all of Section 9, Township 27 North, Range 1 West, NMPM, Rio Arriba County, New Mexico.

(4) The proposed pilot project area is within the boundaries of the West Puerto Chiquito-Mancos Oil Pool and, as such, is subject to the Special Rules and Regulations for said pool as promulgated by Division Order No. R-6469-B, as amended, which provides for 640-acre spacing and proration units with an allowable of 800 barrels of oil per day and for all wells to be no closer than 1650 feet to the outer boundary of a proration unit nor closer than 330 feet to an inner quarter-quarter section line of sub-division inner boundary.

(5) The Niobrara interval of the Mancos shale is the productive zone of the West Puerto Chiquito-Mancos Oil Pool, which is characterized by tight, low permeability blocks interconnected by a high capacity fracture system.

(6) Past experience in said pool has shown that unless a conventionally drilled (vertical) well intersects such a fracture, the chance of obtaining commercial production is severely curtailed.

(7) By drilling a horizontal wellbore, the applicant is attempting to increase the probability of encountering several of these fractures, which may ultimately result in the recovery of a greater amount of oil, thereby preventing waste.

(8) The applicant proposes to drill vertically from a well to be located on the surface at an unorthodox surface oil well location 1050 feet from the North line and 2300 feet from the West line (Unit C) of said Section 9 to a depth sufficient to penetrate the base of the Mesaverde formation and then kick-off in a southerly direction, build angle and continue to drill horizontally in the Mancos formation. Further, the applicant proposes to keep the horizontal displacement of said well's producing interval within the allowed 1650-foot offset provisions for said pool, pursuant to said Order No. R-6469-B, as amended.

(9) Because the proposed wellbore will not encroach outside the allowed offset limits for said pool, correlative rights are protected.

(10) No offset operator appeared and objected to the proposed horizontal drilling project; however, American Hunter Exploration, Ltd., an operator in the subject pool, appeared through counsel and expressed concern about management of the reservoir.

(11) The applicant should be required to determine the actual location of the kick-off point prior to directional drilling operations. Also, the applicant should notify the supervisor of the Aztec District Office of the Division of the proposed direction of the deviated hole and of the date and time of the commencement of directional drilling operations in order that the same may be witnessed.

(12) The applicant should be required to conduct a directional survey on the lateral portion of the wellbore during or after completion of the drilling operations on the horizontal wellbore and submit a copy of said survey to both the Santa Fe and Aztec Offices of the Division.

IT IS THEREFORE ORDERED THAT:

(1) The application of Benson-Montin-Greer Drilling Corporation for a high angle/horizontal directional drilling pilot project within a standard 640-acre oil spacing and proration unit in the West Puerto Chiquito-Mancos Oil Pool comprising all of Section 9, Township 27 North, Range 1 West, NMPM, Rio Arriba County, New Mexico, is hereby approved.

(2) The applicant is further authorized to drill vertically from a well to be located at an unorthodox surface location 1050 feet from the North line and 2300 feet from the West line (Unit C) of said Section 9 and continue drilling in the unconventional manner as described in Finding Paragraph No. (8) in this order.

(3) The lateral extent of the horizontal wellbore in the producing interval shall be limited to an area which extends no closer than 1650 feet to the outer boundary of the spacing and proration unit.

(4) The subsurface location of the kick-off point for the proposed horizontal well shall be determined prior to directional drilling. Also, the operator shall notify the supervisor of the Aztec District of the Division of the proposed direction of the deviated hole and of the date and time of the directional drilling in order that the same may be witnessed.

(5) The applicant shall conduct a directional drilling survey on the well during or after completion of horizontal drilling operations.

(6) Upon completion of the horizontal drilling operations on the well, the applicant shall file a copy of said directional drilling survey along with a final report specifying the depth and location of the terminus of said horizontal wellbore to both the Santa Fe and Aztec Offices of the Division.

(7) Jurisdiction of this cause is retained for the entry of such further orders as the Division may deem necessary.

DONE at Santa Fe, New Mexico, on the day and year hereinabove designated.

STATE OF NEW MEXICO
OIL CONSERVATION DIVISION

WILLIAM J. LEMAY
Director

SEAL

Once a curve match has been obtained, then the total pore volume can be calculated. In the above example, $K_g h/\mu$ is 0.46 darcy-feet/cp and for C_T equal to 370×10^{-6} and the ratio of t to t_{DX_f} equal to 1/0.94, the total pore volume in the fracture block is calculated to be 28,000 bbl of hydrocarbon pore space (equivalent to 22,000 STB).

Although it is impossible to determine fracture length or unit pore volume from this information alone, it is possible to determine how the value of one is dependent on the other. Furthermore, the relation of the total fracture length, $2x_f$, to unit pore volume can be described. Figure 3-3 shows this limit of definition in determining fracture length or unit pore volume. If one knows the fracture length, the unit pore volume can be determined, or vice versa. In the absence of independent information as to one or the other, however, this relation—one variable dependent on the other—is the limit of definition that can result from analysis only of a build-up or fall-off test.

To make an independent determination of the length of the induced fracture, we analyze the frac treatment causing the induced fracture. Although aided by analysis of the frac treatment, the unknown quantities are such that it is impossible to construct a mathematically exact solution that will provide unit pore volume. Given the fact that maximum average pore volume is probably less than 2000 bbl per acre (from interference tests in West Puerto Chiquito), it is possible to combine information from the two sets of data to arrive at an approximate solution.

With respect to analysis of the frac treatment, we note that in other wells tested by radioactive tracer surveys following frac treatment, and by production testing with zones individually fractured, the results show that there is very little build-up of frac height during frac treatments using low viscosity fluids in the Niobrara. Rather, the frac appears to be confined to, if not the perforated interval, the particular zone (A, B, or C). For the subject well the perforated interval was 30 ft (9 m), and it is believed that the total frac treated interval could not exceed 50 ft (15 m).

The main variable in the instant case in estimating the length of the induced fracture is the leak-off of the frac fluid, or frac efficiency. Using frac efficiency as the variable, the fracture lengths were computed by the KGD model (Economides and Nolte, 1987) and the results for 30 ft (9 m) and 50 ft (15 m) fracture lengths displayed graphically (Figure 3-4).

These curves show the limit of definition in estimating frac length (one variable dependent on the other). Amount of leak-off, and efficiency, is next to impossible to determine. The relation does, however, provide an entirely independent method of estimating frac length. In calculating the curves by the KGD model, an oil viscosity of 3 cp, Young's Modulus of 5.6×10^{-6}/psi, frac treatment rate of 67½ BPM, and total volume of 3600 bbl were used.

With the knowledge that overall reservoir unit pore volume will probably not exceed the equivalent of 2000 STB/ac, this is used as the highest point on the ordinate of the plot in Figure 3-3. Using this information from Figure 3-3 and combining it with that of Figure 3-4 provides a method of estimating frac length as shown by reproducing the curves of Figures 3-3 and 3-4 on Figure 3-5. Although the maximum ordinate for the pressure fall-off test is only an estimate for the reservoir, it is a reasonable estimate. The result is not particularly sensitive to this estimated figure: If the correct figure were 1000 instead of 2000 bbl/ac, the consequence would be a reduction in pore volume of 50 to 100 bbl/ac.

From Figure 3-5, we determine the total frac length to be in the range of 700 to 800 ft (213-244 m), and the corresponding hydrocarbon pore volume to be 300 to 400 STB/ac. From this and the fracture block's

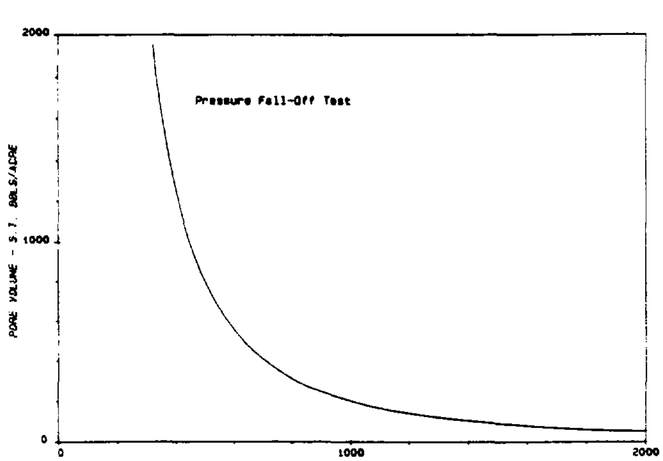

Figure 3-3. Relation of unit pore volume (stock tank barrels per acre) to fracture length of hydraulically induced fracture of the COU A-14 well determined from pressure fall-off test shown in Figure 3-2.

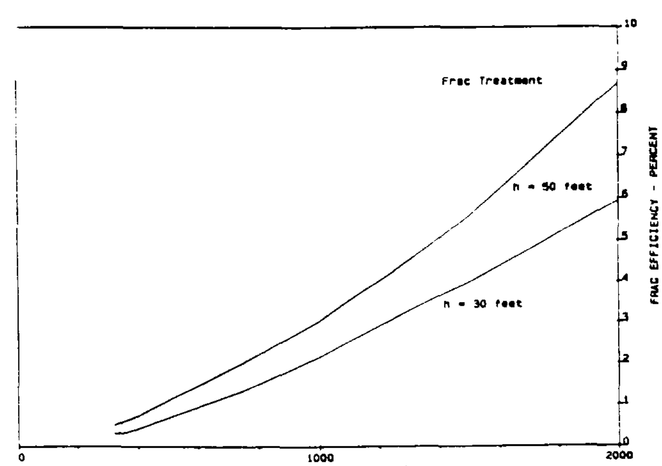

Figure 3-4. Relation of frac efficiency to total induced fracture length for hydraulic fracture treatment of the COU A-14 injection well calculated by the KGD and PKN methods.

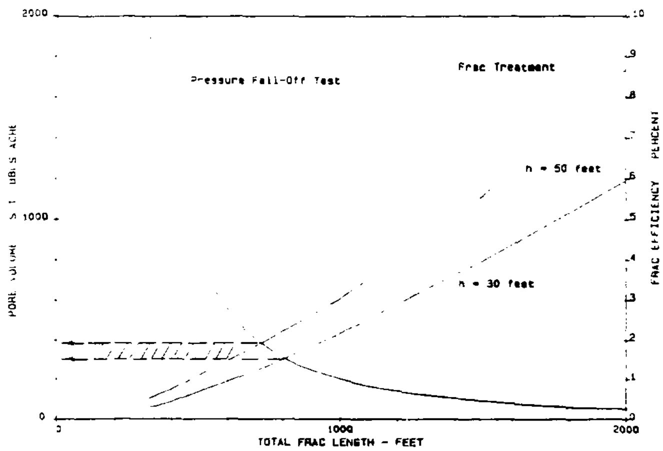

Figure 3-5. Combination of Figures 3-3 and 3-4 using arbitrarily selected maximum ordinate of 2000 stock tank barrels per acre for location of data of pressure fall-off test. Interpreted frac length 700 to 800 ft. Pore volume of well's low capacity fracture block approximately 300 to 400 barrels per acre using KGD method of hydraulic fracture analysis.

total pore volume, the minimum area occupied by the fracture block can be calculated; in this case, 55 to 75 ac.

Fracture lengths versus the frac efficiency were also calculated by the PKN method (Economides and Nolte, 1987). Using this method and a similar combination of data, the unit pore volumes are indicated to be in the range of 200 to 270 STB/ac with a fracture block size of 80 to 110 ac.

The 30 ft frac "height" line intersects the other at a fracture length of 800 ft (244 m) (Figure 3-5). For this fracture length, the fracture width is 0.19 in. This amounts to an effective sand volume supporting the propped fracture of ±44% of the 147,000 lb of frac sand used.

For the 50 ft (15 m) frac height line intersection at 730 ft fracture length, the average fracture width is 0.16 in., which indicates 58% of the sand volume is effective in propping the fracture.

As gas continues to be injected in this well, permeability to gas is increasing. The maximum value so far shown is a $K_g h$ of 0.015 darcy-feet. Since permeability to gas has increased approximately sevenfold since initial injection, it is reasonable to believe that K_{rg} is approaching a value of 0.5. *Kh* for this block would be 0.025 to 0.035 darcy-feet using a range of 0.4 to 0.6 for *K*. As noted above, the corresponding unit hydrocarbon pore volume is 200 to 400 STB/ac. From this ϕh = 0.033 to 0.067 and the resulting K/ϕ values range from 0.4 to 1.1. The corresponding average porosity values for the estimated 30 to 50 ft (9–15 m) of pay (and the 200 to 400 STB/ac determined above) range from 0.1 to 0.2%. These values (covering the ranges for both KGD and PKN models) are plotted in Figure 2-2 of Appendix 2 (example identified therein as A-14).

These porosity and corresponding permeability values for the A-14 fracture block converted to hydrocarbon pore volume (bbl/acre) are compared with those obtained in interference tests sampling large areas of the reservoir by displaying its field on a graph of capacity (*Kh*) versus unit pore volume in STB/ac (Figure 3-6).

On Figure 3-6, the basic X, Y, and Z lines derive from the porosity and permeability relations for the field identified as "some fracture systems" on Figure 2-2 of Appendix 2. The "probable upper limit for fracture porosity" is identified as the "A" relation, the lower part of the field as the "C" relation, and halfway in between, the "B" relation. Using these values and the number of feet of pay as shown on Figure 3-6, lines X, Y, and Z have been computed.

Figure 3-6 was prepared in 1969 (NMOCC, 1969) as a basis to work from in comparing unit pore volume as it might be dependent on *Kh*. Most of the test data were acquired by the operator of the Canada Ojitos Unit. *Kh* data for Boulder were from tests made by Standard of Texas (NMOCC, 1963). Location of the X, Y, and Z lines of Figure 3-6 is based on the premise that the thicknesses of the "pay zones," in this case the fractured reservoir units, are relatively uniform throughout the reservoir. Increases in pore volume between areas are caused by greater curvature (or bending stress) applied to the reservoir units, resulting in increased aperture width but relatively similar fracture density throughout. Thus, the ratio of oil in place of two areas varies as the cube root of the ratio of their respective capacities (*Kh*). Clearly we cannot expect this to be the case throughout; but it is surprising the number of tests that fall in the projected ranges.

The character of the fracture network makes unreliable such analyses as Horner plots where extrapolated to estimate reservoir pressure. One can be assured only that the reservoir pressure is as high as the last pressure measured. Extrapolation can be reliable only in the sense that it marks the maximum possible. Because of this infirmity, the Canada Ojitos Unit operator uses pressure fall-off tests following fracture treatment to estimate maximum reservoir pressure indicated by a well.

Numerous examples corroborate the existence of "tight" fracture blocks and nearby high capacity fracture systems. The Canada Ojitos Unit E-10, for example, was drilled through the pay zones with air. The flow stream analysis showed no hydrocarbons above that of the background overlying shales, and the well produced no oil or gas "natural." After frac treatment, however, it produced at high rates and has accumulated 2.3 million bbl. Clearly, the character of the formation in the bore-hole was not representative of the reservoir.

In conclusion, the reservoir geometry underscores the difficulty of attempting to analyze the reservoir through core analyses. The bulk of the recoverable reserves are probably located in open fractures of the high capacity fracture system. Reservoir property

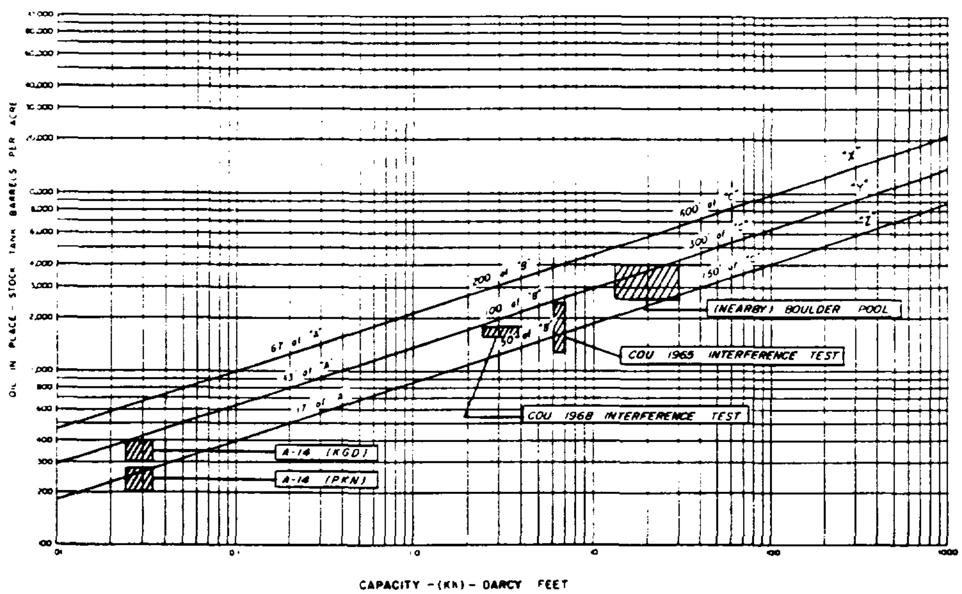

Figure 3-6. Plot of pore volume (stock tank barrels per acre) as dependent on capacity, *Kh*, determined from interference and pressure testing.

determination through core analyses of the low capacity "tight" block must be considered suspect. The properties of the high capacity system, from which the bulk of the reserves will come, are even more difficult to determine. Average characteristics reflected by interference and frac pulse testing, however, yield data useful in development planning and reservoir management.

Appendix 4. West Puerto Chiquito Fluid Property Data

Although in most solution gas drive reservoirs the process involves a mix of flash and liberation processes, in making our analyses we have used differential liberation fluid property data (Figure 4-1) since this more nearly represents the entire depletion process here. In support of this position, we offer the following observations.

With early free gas movement in a fractured solution gas drive reservoir, the free gas is removed from the system as soon as it reaches the wellbore. With early high GORs, this commences with first production, and the reservoir process is clearly one approaching strict differential liberation. Although liberated gas as it moves through the reservoir to the wellbore stays in contact with reservoir oil until it reaches the wellbore, so does gas liberated in the laboratory stay in contact with some oil for the length of the pressure "step" during the laboratory analysis. The laboratory simulation of the reservoir process may not be perfect, but values obtained from it are probably as accurate as the values determined for the other factors influencing a reservoir analysis. Most of the production in West Puerto Chiquito has been the consequence of gravity displacement: Here the liberated gas moves—not to the wellbore—but updip to form a gas cap, and the result is the same, differential liberation.

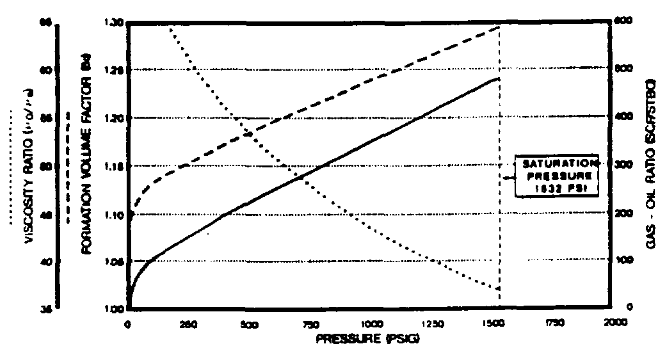

Figure 4-1. Fluid property data from COU K-13 well, Sec. 13, T25N, R1W, in West Puerto Chiquito field.

Since part of the recovery in West Puerto Chiquito will be by solution gas drive and most of the recovery in nearby fields will be by solution gas drive, we now review in more detail the influence of both differential and flash liberation characteristics for solution gas drive.

In estimating the portion of the overall depletion process that is influenced by differential and flash characteristics, it is instructive to review the mathematical relation of the various factors influencing solution gas drive depletion. This is most clearly accomplished by inspection of Muskat's method summarized in Appendix 5 (Muskat, 1945). The first step of equation (1) in Appendix 5 defines change in reservoir oil saturation with pressure decline. This step, as noted above, is clearly independent of flash data. Simply expressed, the gas and oil arrive at the wellbore by the differential depletion process, what happens thereafter will not have a retroactive effect on the reservoir's oil saturation.

The only effect of flash data lies in the determination of its share of the process which relates the volume of produced oil to the volume it occupied in the reservoir. Note that this produced volume is small (5 to 10% of oil-in-place for solution gas drive) compared to the remaining reservoir volume controlled by differential data. Furthermore, note that the fraction of the total stream that reaches the stock tank as oil depends on the "path" the mixture takes from the bottom hole of the well bore up the production string(s) to the stock tank. The paths taken by the production in the different wells may be different; but field-wide for the various operators the overall effect of the flash process modifying reservoir performance calculated by differential data will be small. In summary, it amounts only to the differences in amount of gas dissolved in oil at the stock tank for the different paths taken by the oil up the production strings. These different paths are defined by the production method used.

In our analyses, we use differential data all the way through. Not only is the reservoir process differential; but also we note that a substantial amount of a field's production as it moves from the bottom of the wellbore to the surface is differential liberation:

1. A large volume of oil has been produced in West Puerto Chiquito with submersible hydraulic pumps. Here as the produced oil moves to the surface, it is in continual contact with the power oil, and as gas comes out of solution from the produced oil, it immediately goes into solution in the power oil in a strictly differential liberation process. On flashing into the separator, the gas still in solution in the power oil prevents it from contacting the produced oil; so here again the process is still largely differential liberation.
2. Sometimes pumping wells are produced such that the gas is separated from the oil in the bottom of the well and moves up the annulus separate from the oil. Here the process is differential liberation until the two streams are combined in the separator.
3. In some of the wells that flow by gas lift by heads, the gas and oil are separated in the bottom of the wellbore and stay separated all the way to the stock tank—a form of the differential liberation process.

In summary, fluid sample data determined by the differential liberation process is appropriate for reservoir analyses at West Puerto Chiquito.

Appendix 5. Relative Permeability and Formation Compressibility

Fluid withdrawal from a closed reservoir causes pressures to decline and net overburden pressures to increase, resulting in a reduction in pore volume. Change in overburden pressure causing a reduction of as much as 50% of the pore space has been determined not to affect the ratio of relative permeabilities (gas to oil) in a sandstone (Fatt, 1953). In the absence of information to the contrary, we think it probable that the same will hold for a fractured reservoir.

Although this characteristic does not change, as pressure declines formation compressibility (C_f) causes a reduction in pore volume and, as a consequence, reduces the free gas saturation. Accordingly, the corresponding relative permeability ratio (k_g/k_o) will be smaller than that had the pore volume not been reduced. If the formation compressibility were of the same order of magnitude as system compressibility, it would have a marked effect on reservoir performance.

At West Puerto Chiquito and vicinity, neither the value of C_f nor that of k_g/k_o is precisely known. Since each property operates to influence the same factors controlling reservoir performance, we examine these two characteristics together.

Reported Formation Compressibilities

Three separate analyses for formation compressibility have been reported for West Puerto Chiquito and the offsetting pool, Gavilan:

1. Comparison of interference tests in West Puerto Chiquito at pressures above and below the bubble point.
2. Brine squeeze test of core samples from a Gavilan field well.
3. Special test to estimate fracture compressibility from cores of another Gavilan field well.

Remarks with respect to these tests follow.

1. An interference test that "sampled" several thousand acres in the Canada Ojitos Unit in West Puerto Chiquito in 1965 (NMOCC, 1966) when the oil was undersaturated and the formation compressibility was significant (with respect to system compressibility) showed reservoir volume of oil in place ranging from 1000 to 2500 STB/ac for the assumed range of formation compressibilities of 26×10^{-6}/psi to 6×10^{-6}/psi. Another interference test run in 1968 (NMOCC, 1969) in part of the area covered by the 1965 test showed stock tank oil-in-place volume approximating 1700 bbl/ac. This test was run when pressures were below the bubble point and the formation compressibility was believed to be relatively insignificant. A pore volume of 1700 bbl/ac shown by the second interference test approximates the average estimated from the first test. The formation compressibility would then be the average of 6×10^{-6}/psi and 26×10^{-6}/psi; or approximately 15 to 16×10^{-6}/psi.
2. Brine squeeze tests were run using cores from the Mobil B-38 well, Sec. 4, T24N, R2W (personal communication, Mobil to Gavilan Engineering Committee, 1986). From the plot of volume change versus applied pressure, the calculated compressibilities were determined to range from 6×10^{-6}/psi to 16×10^{-6}/psi.
3. Information from the special tests directed at estimating fracture compressibility from cores of the Mallon Davis Federal 3-15, Sec. 3, T25N, R2W, was reported for three samples (NMOCC, 1987). They were approximately 50×10^{-6}/psi, 100×10^{-6}/psi, and 150×10^{-6}/psi, a spread of 100×10^{-6}/psi. The laboratory qualified its results because of the difficulty in supporting the samples in such a fashion as to properly simulate reservoir conditions.

We believe the best information as to value of formation compressibility is the comparison of the interference tests. The brine squeeze tests, while yielding values approximating those of the interference tests, are subject to the same limitations inherent in all core analyses of this reservoir: Core samples are not representative of the producing reservoir (Appendices 2 and 3).

It is to be expected that compressibility will vary somewhat from one area to another. It is unlikely, however, that it will vary over the extreme ranges indicated in item 3 above. Even so, the study was expanded to include analyses involving the reported high compressibilities in order to cover completely the effect of such phenomena should they in fact exist.

"Critical Formation Compressibility"

For an overview of the effect of formation compressibility on solution gas drive performance, we inspect Muskat's basic formula (Muskat, 1945), equation (1) below. Note that the left-hand member of equation (1) is actually value ***per unit pore volume*** and has the same dimensions as formation compressibility. Note, also, early in the depletion cycle when free gas saturation and k_g/k_o are low, that $\Delta S_o/\Delta P$ approaches the value of lambda. Lambda is the dominant member of the two terms defining saturated oil compressibility (Ramey, 1964), which for the subject reservoirs is 200 to 300×10^{-6} (Figure 5-1). This is the same order of magnitude as the high values (100 to 150×10^{-6}/psi) of formation compressibility indicated by the tests of item 3 above. Thus, without analyses, but simply from inspection of the formula, it is clear that if formation compressibilities were in fact this high, they would modify significantly the otherwise normal reservoir performance.

For instance, if the initial value of $\Delta S_o/\Delta P$ were the same as that of formation compressibility, then the volume change of the oil saturation would be balanced by the pore volume change due to the formation compressibility and little free gas would evolve as oil is withdrawn. Gas oil ratios would decline initially and never reach high values with depletion. The fractures would contract such that the porosity would be significantly reduced from its original value. If the initial GORs were low, a very large part of the initial oil in place would have been expelled at depletion.

We refer here to the formation compressibility that initially balances $\Delta S_o/\Delta P$ as the "critical" formation compressibility. If, initially, formation compressibilities are above "critical," reservoir pressures will not decline on withdrawal of oil, and the solution gas drive process cannot take place. We have not included production behavior for such a situation, as we think

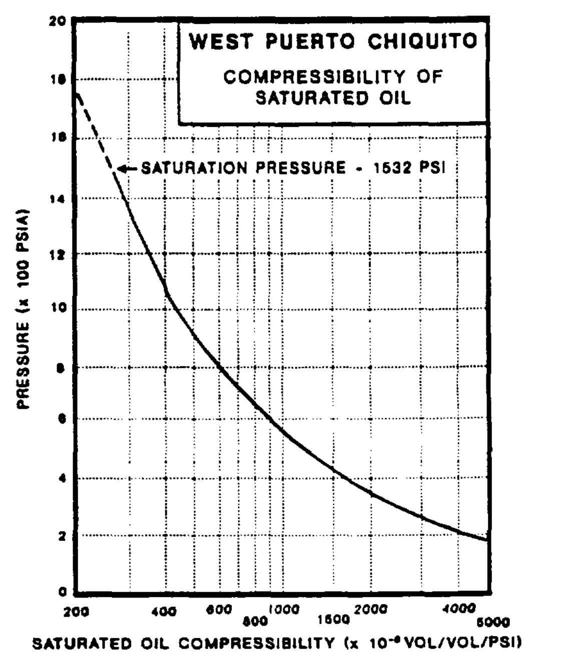

Figure 5-1. Compressibility of saturated oil from West Puerto Chiquito fluid property data.

it unlikely that it would actually occur. We make this note, however, since for one of the k_g/k_o curves studied herein, the critical formation compressibility approximates 100×10^{-6}/psi—well within the range of the 50 to 150×10^{-6}/psi reported for the special compressibility tests.

To illustrate production behavior where the value of formation compressibility approximates, but is slightly less than, "critical," as well as sensitivity of the production histories to different values of C_f, we present GOR histories utilizing three relative permeability ratio curves (curves I, II, and III of Figure 5-2). These three curves lie in the range indicated by laboratory measurements of relative permeability of fractured formations (Keeling et al., 1964, 1969). Curves I and II will "bracket" the characteristics on the high and low sides; and curve III lies in between these extremes.

Only GOR histories are displayed, since this provides a means of comparison with field performance from a minimum of data; namely, oil and gas production. In all of our determinations of sensitivity to formation compressibility, certain precautions were taken to insure that the differences in curves were indeed the consequence of changing C_f and not caused by mathematical inaccuracies. Straight line curves (saturation varies as the logarithm of k_g/k_o) were chosen since they permit precise calculation of k_g/k_o for any given saturation. Also the Muskat method, with formation compressibility recognized

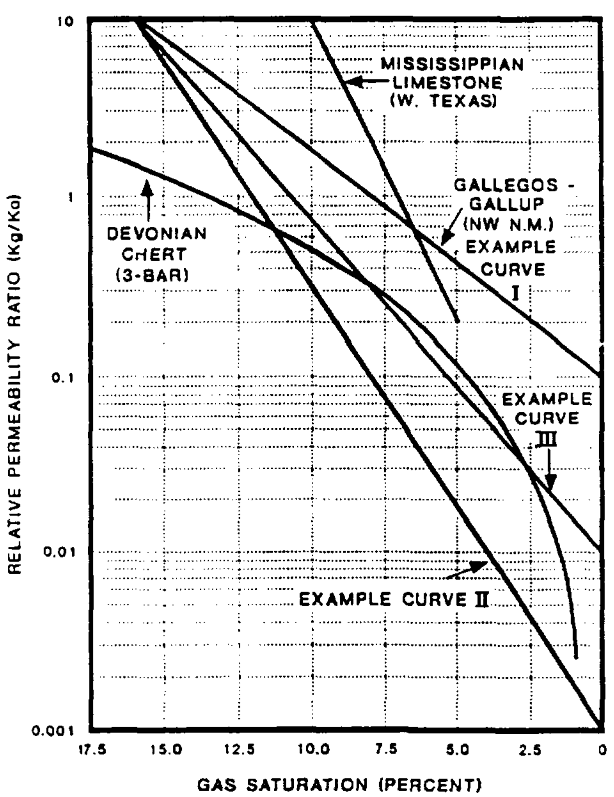

Figure 5-2. Ratio of relative permeability characteristics for some fractured reservoirs and example curves used in analyses.

(equations 5, 6, and 7 below), was used. Once composite functions have been determined for the average pressure of each step, there remain only two unknowns: oil (or free gas) saturation and the corresponding relative permeability ratio. Although in developing production histories of typical reservoirs it is possible to obtain acceptable results with this method by the direct calculation at each step from a reasonable projection of the average saturation for each preceding step, greater precision is reached by converging the saturation and relative permeability ratio values to exact matches. An integral part of the computer program used performs this convergence. Approximately 40 precise points were used to define each curve up to a free gas saturation of 20%. The program identifies and then makes a straight line interpolation between the relevant points to determine the convergence. Thus, although the k_g/k_o relations used do not exactly follow the curves, being instead a series of points on the curve with interconnecting straight lines, they are precisely the same for each set of C_f comparisons.

Fluid property data for West Puerto Chiquito (Appendix 4) were used along with 10% connate water saturation and an abandonment pressure of 125 psia. With these parameters the "critical formation compressibility" approximates the values in Table 5-1. (Higher water saturations would result in lower values for critical formation compressibilities.

Table 5-1

For curve (of Figure 5-2)	Initial k_g/k_o	Approximate "Critical" Formation Compressibility
I	0.1	100×10^{-6}/psi
II	0.001	300×10^{-6}/psi
III	0.01	230×10^{-6}/psi

Plots of GOR versus oil recovery in percent of oil in place are shown on Figure 5-3 for these three relative permeability curves and associated "critical" formation compressibility. Note the relatively high recoveries for curves II and III and the overall shape of the GOR curves: an initial decrease with only a slight increase over the depletion history. The curve shapes bear little resemblance to those of typical solution gas drive reservoirs.

Overview: Sensitivity of Oil Recovery to Formation Compressibility

An example of variation in oil recovery with C_f is demonstrated using relative permeability curve II of Figure 5-2. Here k_g/k_o and all parameters other than C_f are held constant. The results are displayed on Figure 5-4 where the GOR histories are plotted against cumulative recoveries in percent of oil in place for the several formation compressibilities shown.

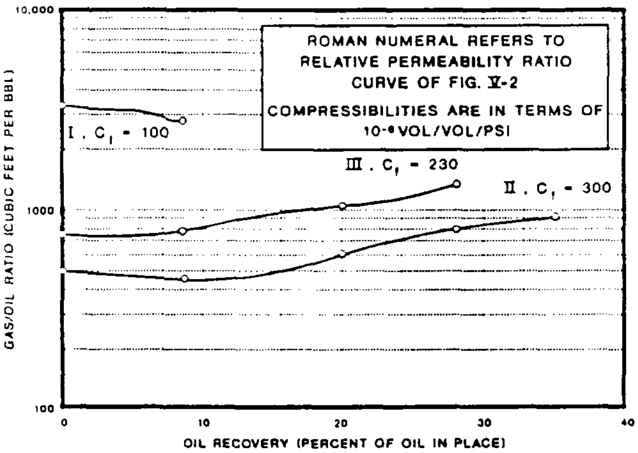

Figure 5-3. Solution gas drive GOR histories using "critical" formation compressibility. Note high recoveries for k_g/k_o curves II and III and that shape of all GOR curves bears no resemblance to that of typical solution gas drive reservoirs.

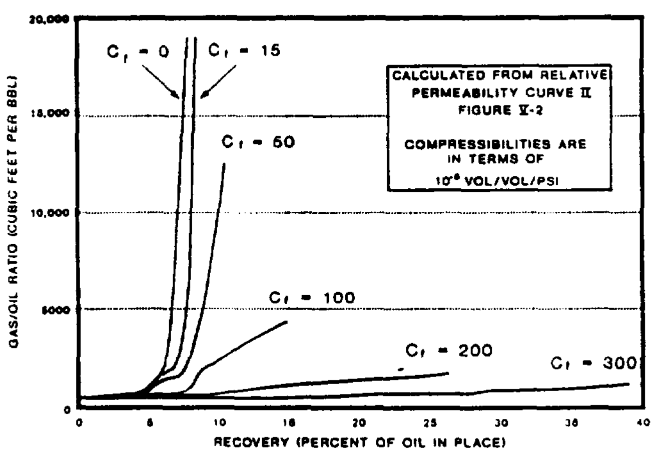

Figure 5-4. Solution gas drive recovery using relative permeability curve II and various formation compressibilities. Note extreme range of recoveries for the different compressibilities.

Here the ultimate recovery is identified by the end point of each GOR line. They show a range of recovery of five to one (confirming the observation that high C_f's would indeed be significant) for C_f ranging from the "critical" to zero (Table 5-2).

Estimate of Relative Permeability and Formation Compressibility through Comparison with Field Data

For purposes of comparison with calculated performance using the k_g/k_o curves and several values of C_f, we use the field performance of central Gavilan offsetting West Puerto Chiquito. Note that West

Table 5-2

C_f (10^{-6}/psi)	Ultimate Recovery of Oil in Place
0	8.8
15	9.2
50	11.0
100	15.7
200	28.0
300	41.6

Puerto Chiquito's pressure maintenance and relatively large amounts of gravity drainage preclude accurate determination of k_g/k_o from its production data. Although central Gavilan (Figure 2) has received substantial gravity drainage and support from migration, its dominant recovery mechanism, at least for the latter part of the depletion cycle, is solution gas drive. Analysis of solution gas drive provides k_g/k_o data.

In estimating relative permeability characteristics from central Gavilan production data, we note the following:

1. Because of the high conductivity of the fracture systems, significant gravity drainage has occurred (see "efficiency" above), even in areas of low dip. The result is lower GORs initially and apparently lower relative permeability ratio (k_g/k_o) than the reservoir's true character. In the latter stages of depletion, however, an effect of the earlier gravity drainage is to cause lower oil saturations than would be the case for pure solution gas drive. Therefore, the GORs and apparent relative permeability ratios will appear higher than had the process been pure solution gas drive. Gravity drainage, in other words, renders the determination of oil saturation associated with a given relative permeability ratio quite difficult.
2. Different areas of the reservoir will have different degrees of fracturing and may cause actual relative permeability ratios to be different in the different areas. The principal effect of the varying degrees of fracturing, however, will be reflected in the gravity drainage effects rather than difference in relative permeability ratios.
3. Even if reservoir pressures are reasonably well known and k_g/k_o can be calculated from GORs and estimated reservoir pressures, determination of the corresponding true oil saturation is more difficult, and sometimes the procedure cannot be completed. In Gavilan, where indefinite amounts of gravity drainage and regional migration have occurred, it is impossible to determine precisely the concurrent oil saturation. Regional migration precludes estimation of free gas saturation from the elementary relation of oil produced below the bubble point and an estimate of oil in place, along with formation volume factors. To enlarge the study area to include lands providing regional

migration in the analyses brings in complications more difficult to deal with: The Bear Canyon Unit (Figure 2) is downdip, with a lower well density, more efficient gravity drainage (a depletion process significantly different from Gavilan's), and migration from the east, where pressure maintenance support is involved. In spite of the problems of dealing with production above the bubble point, gravity drainage, and migration, the GOR history of Gavilan nevertheless provides some insight with respect to ratio of relative permeability and formation compressibility.

Since central Gavilan is essentially oil depleted (Figure 5-5), it is possible to make a reasonable projection of (economic) ultimate recovery: 5 million bbl. Any economically recoverable oil beyond that amount will be from stripper wells supported by gas sales or from "protected" wells still receiving gravity drainage. With an estimate of central Gavilan's ultimate recovery, it is possible to relate its GOR history to recovery in percent of ultimate. This provides one method of estimating C_f and k_g/k_o from a minimum of required field data; namely, oil and gas production.

Central Gavilan encompasses approximately 24,000 ac and has produced largely by solution gas drive from both high and low capacity wells with a high degree of communication. Although by no means a "perfect laboratory" for determining C_f and k_g/k_o, the overall production with appropriate adjustments should reveal nearly average formation properties.

k_g/k_o characteristics influence, and can be determined from, reservoir performance at pressures below the bubble point. Analysts have not agreed on Gavilan's bubble point pressure, but the highest reported (NMOCC, 1987) is 1660 psi. Approximately 1 million bbl were produced prior to the reservoir reaching this pressure.

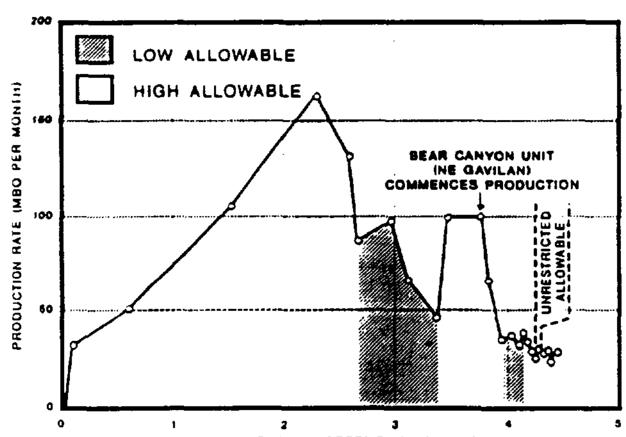

Figure 5-5. Plot of production rate versus cumulative recovery for central Gavilan. Periods of high and low allowables are identified along with one period of unrestricted allowable. Economic ultimate recovery of 5 million bbl estimated from this plot.

Statistics for central Gavilan's GOR history for production below this bubble point pressure are set out in Table 5-3. A plot of GOR versus ultimate recovery is shown in Figure 5-6. The first 65% of ultimate recovery reflects a smoothed curve of the published data (NMOCC, 1988) for production below the bubble point. Data for the rest of the curves come from monthly reports to the New Mexico Oil Conservation Commission.

The lower curve extending from this base ("all wells," Figure 5-6) derives from reported data for all wells in central Gavilan, while the upper curve ("all wells except two," Figure 5-6) excludes two wells (Hill Trust #1, Sec. 5, and High Adventure #1, Sec. 8; both in T25N, R2W). These two wells are still receiving substantial gravity drainage and do not reflect the relative permeability characteristics shown by the other approximately 60 wells. If the production of these wells were to be included in determining average GOR (and k_g/k_o values), the result would be values lower than the true average reservoir characteristics.

Similarly, other wells initially receiving gravity drainage and indicating k_g/k_o values lower than the true reservoir character will, in the later stages, exhibit higher gas saturations and k_g/k_o values than the true reservoir average. As a consequence, the curve for "all wells less 2" (Figure 5-6) shows higher GORs than would be the case in the absence of gravity drainage. We have therefore selected the GOR history between these two extremes ("average" curve of Figure 5-6) as more nearly representative of the actual relative permeability character for this part of the depletion cycle.

GOR histories for various formation compressibilities were calculated for the (straight line) k_g/k_o curves I, II, and III (Figure 5-2) and compared to the central Gavilan GOR history on Figures 5-7, 5-8, and 5-9. Clearly, the calculated curve forms for compressibilities exceeding 15×10^{-6}/psi bear no resemblance to the curve of field performance, forcing the preliminary conclusion that the value of C_f is probably low.

GOR histories using relative permeability ratio curves I and II (Figures 5-7 and 5-8) "bracket" the field data on both the high and low sides. As k_g/k_o characteristics move in the direction of a curve "match" (from curve II to curve III on Figures 5-8 and 5-9), the curves with higher C_f's show greater divergence at the latter part of the depletion cycle. Clearly, as convergence is approached between calculated and observed curves, values of C_f decrease, making it unlikely C_f will be greater than 15×10^{-6}.

Finally, use of k_g/k_o curve IV (Figure 5-10) with $C_f = 15 \times 10^{-6}$/psi results in an approximate match with field performance (Figure 5-11). Use of higher C_f values (not plotted) show greater divergence from field performance as the match improves. Moreover, for the reasons noted below, the true k_g/k_o relation is probably one that would shift the curves farther left (past a "match"), reducing even further the

Table 5-3. Central Gavilan gas-oil ratios and cumulative production

Date	Cumulative Oil Prod. (M Bbl)	Prod. below Bubble Point: Cumulative Less 1000 (M Bbl)	Prod. below Bubble Point: Ultimate Recovery (%)	Gas-Oil Ratios *: Central Gavilan (cf/bbl)	Gas-Oil Ratios *: Central Gavilan Less Two Wells ** (cf/bbl)	Gas-Oil Ratios *: Average (cf/bbl)
	0			550	550	550
07/85	1,000	0	0	850	850	850
12/85	1,500	500	12.5	1,100	1,100	1,100
06/86	2,000	1,000	25.0	1,400	1,400	1,400
08/86	2,500	1,500	37.5	2,000	2,000	2,000
01/87	3,000	2,000	50.0	3,150	3,150	3,150
08/87	3,500	2,500	62.5	4,600	4,600	4,600
05/88	4,050	3,050	76.3	8,000	9,600	8,800
07/88	4,100	3,100	77.5	9,000	11,600	10,300
10/88	4,200	3,200	80.0	10,800	15,200	13,000
01/89	4,300	3,300	82.5	13,000	18,800	16,000
		(4,000) ***	(100.0) ***			

* GORs are smoothed averages.
** Hill Trust #1 and High Adventure #1, Sec. 5 and 8, T25N, R2W.
*** Ultimate recovery for production below bubble point estimated at 4000 M bbl.

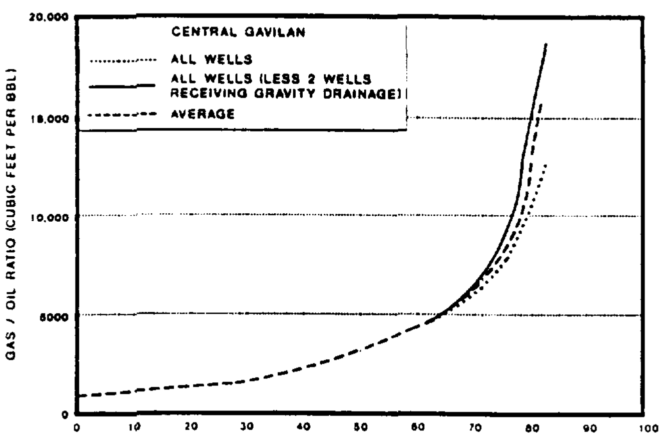

Figure 5-6. GOR history of central Gavilan from field data. Average curve is used in making comparisons of calculated histories with field performance. Percent of ultimate recovery is based on cumulative recovery of production below maximum assumed bubble point pressure of 1660 psi.

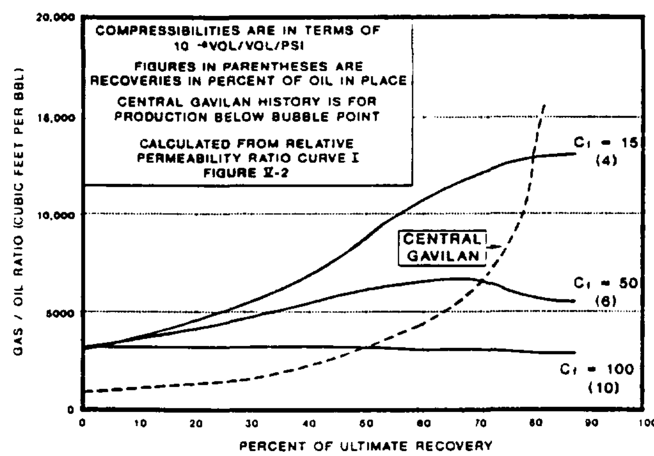

Figure 5-7. Calculated solution gas drive recoveries using k_g/k_o curve I of Figure 5-2 and various formation compressibilities. Histories are GOR versus ultimate recovery. Note failure of calculated curves to "match" field performance.

possibility that high formation compressibilities exist.

Gavilan's greater depths and higher temperatures would result in a higher bubble point than that determined for West Puerto Chiquito oil. Solution gas drive recoveries, however, are not sensitive to small differences in initial bubble point pressures; recognition of a different bubble point would not materially affect such analyses. Furthermore, a higher bubble point than that used would result in lower values of the composite function lambda and cause even greater divergence between the calculated curves using high formation compressibilities and the field data.

The foregoing analysis, while not completely definitive, clearly eliminates formation compressibilities in the range of 100 to 150 × 10^{-6}/psi. In fact, it is unlikely that C_f is higher than 15 × 10^{-6}/psi.

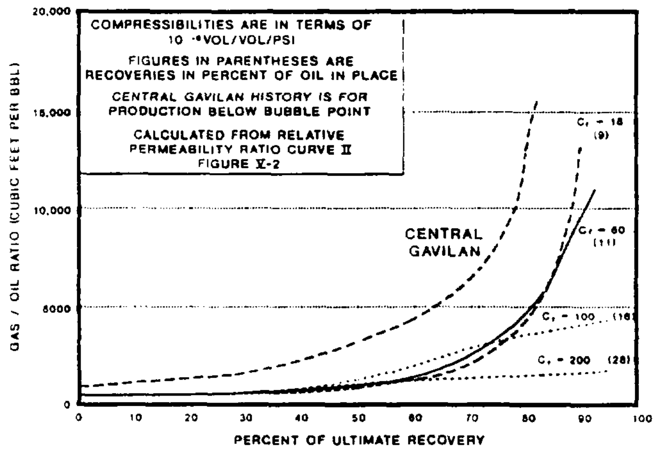

Figure 5-8. Calculated solution gas drive recoveries using k_g/k_o curve II of Figure 5-2 and various formation compressibilities. Note these curves fall below that of field performance. Note divergence from field data of curves for $C_f = 100$ and 200×10^{-6}.

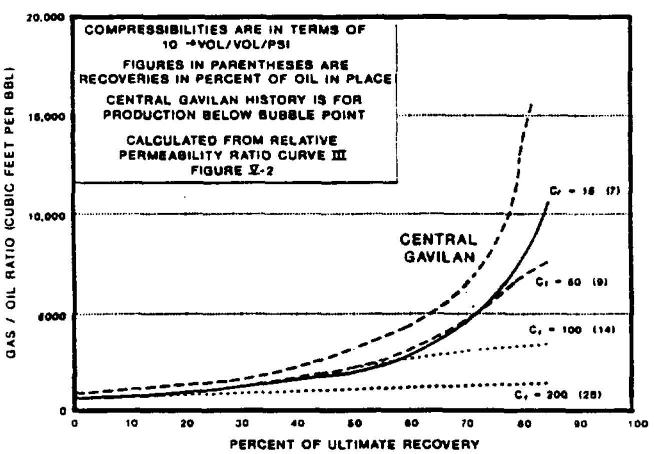

Figure 5-9. Calculated solution gas drive recoveries using k_g/k_o curve III of Figure 5-2 and various formation compressibilities. Note low value of maximum GORs for curves with C_f of 50×10^{-6} and greater.

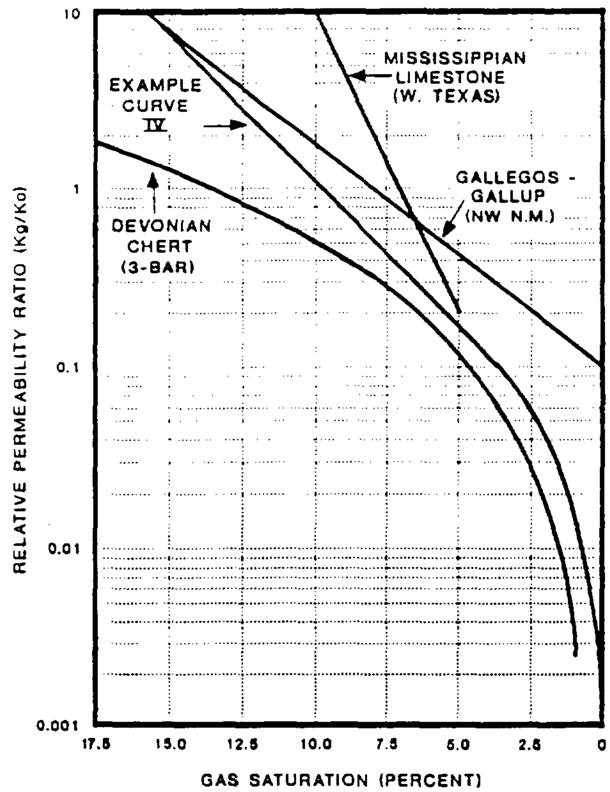

Figure 5-10. k_g/k_o example curve IV compared with those of some fractured formations.

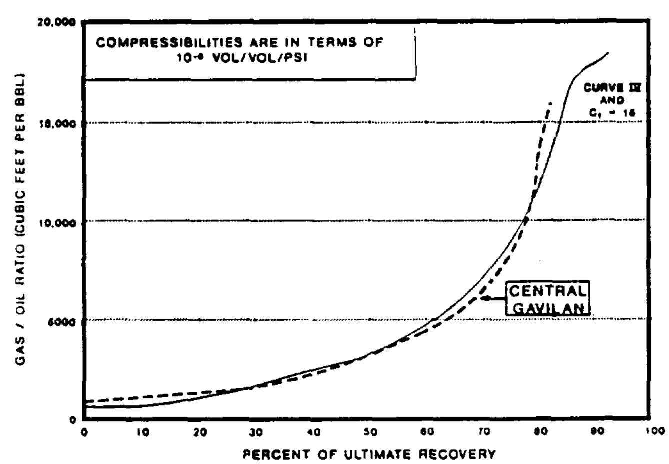

Figure 5-11. Calculated solution gas drive recoveries using k_g/k_o curve IV (Figure 5-10) and using formation compressibility of 15×10^{-6}. Despite apparent match authors believe true representation of k_g/k_o, in the absence of migration and gravity drainage, would be shifted to the left.

Data of this analysis, although adequate to eliminate high values of C_f as being appropriate, are not sufficiently precise to identify formation compressibility in the comparatively narrow ranges up to 15 or 20×10^{-6}/psi. For this definition we rely on the inherently more accurate results obtained from the interference test data.

Probable Range of "True" k_g/k_o Characteristics

An approximate match of GOR and percent ultimate recovery results from relative permeability curve IV and C_f of 15×10^{-6}/psi (Figures 5-10 and 5-11). No adjustment has been made to compensate for regional migration or gravity drainage effects early in the depletion cycle. Regional migration would have no effect on the shape of the curve if it were present *throughout* the depletion cycle. The effect in central Gavilan, however, where regional migration was substantial initially but decreased with time, is similar to that of gravity drainage when GORs are plotted against ultimate recovery: lower initial GORs than for no migration; then as migration is reduced, rising more steeply than had no migration been present.

In view of the above, curve IV, despite its apparent "match" with field performance, is somewhat optimistic for the "true" k_g/k_o relation. Curve IV represents limiting lower values of k_g/k_o; any adjustment for gravity drainage and migration would shift the k_g/k_o relation higher on the plot of Figure 5-10, at least for the early part of the curve. The latter part of the k_g/k_o curve (at higher gas saturations) would most likely "flatten" such that the probable range of "true" k_g/k_o values would assume a form within the shaded area shown on Figure 5-12.

The effect on ultimate solution gas drive recoveries of the different curves is shown by example:

At 175 psi abandonment pressure and $C_f = 15 \times 10^{-6}$/psi, curve IV yields a solution gas drive recovery of 5.94% of oil in place, while the curve represented by the extended shading results in a recovery of 5.65%. Apparently the k_g/k_o values for gas saturations greater than 10% have a minor effect on recovery. At a free gas saturation of 10%, the solution gas drive recovery using curve IV is 90% of ultimate recovery (recovery using the extended shading curve is 80% of its ultimate).

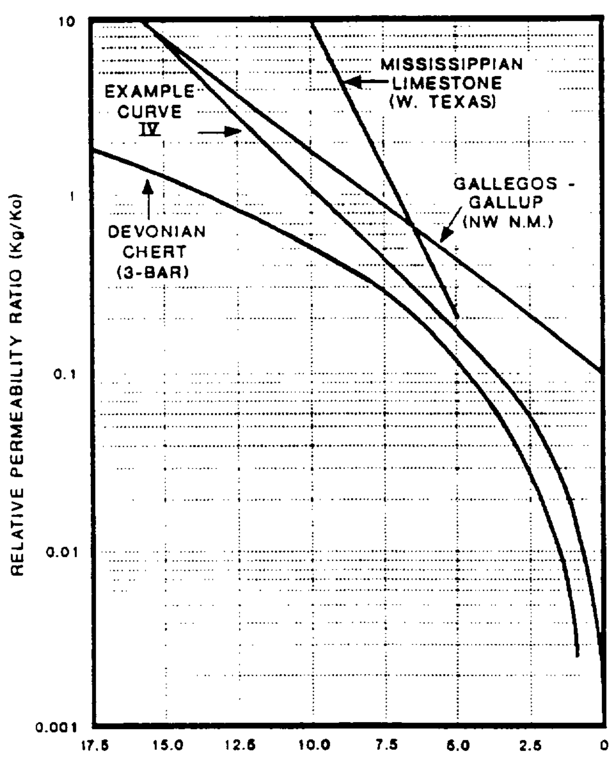

Figure 5-12. k_g/k_o curve IV showing adjustment (shaded area) in which true k_g/k_o relation should lie (after accounting for migration and gravity drainage).

In summary, we conclude that formation compressibility is that shown by the interference tests: approximately 15×10^{-6}. The exact shape of the k_g/k_o relation will turn on the indefinite amount of migration and gravity drainage of central Gavilan, with minimum values represented by curve IV (Figures 5-11 and 5-12). It is probable that true k_g/k_o fits in the shaded area of Figure 5-12. Whatever its exact shape, it appears that the resulting solution gas drive recovery will not exceed 6% of oil in place.

Muskat Method of Calculating Solution Gas Drive Performance

The Muskat method (Muskat, 1945), after substituting S for p, and R_s for S, can be described, in incremental form, as follows:

$$\Delta S_o/\Delta P = \frac{S_o\,\lambda + (1 - S_o - S_w)\,\varepsilon + S_o\,\eta\,(\psi)}{1 + (\mu_o/\mu_g)} \tag{1}$$

Gas Oil Ratio, $R = \alpha\,\psi + R_s$ (2)

Oil Recovery (fraction of initial pore space) =
$(S_{oi}/B_{oi}) - (S_o/B_o)$ (3)

Oil Recovery (fraction of initial oil in place) =
$(S_{oi}/B_{oi} - S_o/B_o)/(S_{oi}/B_{oi})$ (4)

where $\lambda(p) = (1/B_o\gamma)\,(dR_s/dp)$

$\varepsilon(p) = (1/\gamma)(d\gamma/dp)$

$\eta(p) = (1/B_o)(\mu_o/\mu_g)(dB_o/dp)$

$\alpha = (\gamma B_o)(\mu_o/\mu_g)$

S_o = oil saturation, fraction of pore space

S_w = water saturation, fraction of pore space

μ_o/μ_g = ratio of viscosity of oil to gas

ψ = relative permeability ratio

B_o = reservoir barrels of oil per stock tank barrel

γ = standard cubic feet of gas per reservoir barrel of oil

R_s = gas in solution in the oil at the subject pressure, cubic feet per barrel

i means initial conditions

(The derivatives dR_s/dp, $d\gamma/dP$, and dB_o/dP in the composite functions λ, ε, and η are determined by graphical, or numerical, integration.)

Recognition of Formation Compressibility Using the Muskat Method

Muskat treated formation compressibility as negligible. Recognition of formation compressibility is accomplished as follows:

Although the left-hand term of equation (1) shows $\Delta S_o/\Delta P$, actually it is change in oil saturation *per pore volume* per pressure differential, and as such, it has the same dimensions as formation compressibility, which in English units is $\Delta V/V$/psi. Accordingly, equation (1) becomes:

$$\Delta S_o/\Delta P = \frac{S_o \lambda + (1 - S_o - S_w)\,\varepsilon + S_o(\psi) - C_f}{1 + (\mu_o/\mu_g)(\psi)} \qquad (5)$$

where C_f = formation compressibility, $\frac{1}{\Delta}(\frac{\Delta V}{\Delta P})$

And since at the end of a pressure step, the pore volume has shrunk by an amount equal to formation compressibility times pressure change, $C_f \times (P_i - P_2)$, then the volume of oil remaining at the end of a pressure step (P_2) has likewise been decreased by formation compressibility in the same proportion, so equation (3) above becomes:

Oil Recovery, fraction of initial pore space:

$$S_{oi}/B_{oi} - (S_o/B_o)\,((1 - C_f(P_i - P_2)) \qquad (6)$$

where P_i = initial pressure

P_2 = pressure at end of a ΔP step

And accordingly, equation (4) above becomes:

Oil Recovery, fraction of initial oil in place:

$$\frac{S_{oi}/B_{oi} - (S_o/B_o)\,((1 - C_f(P_i - P_2))}{S_{oi}/B_{oi}} \qquad (7)$$

Appendix 6. Example of Development Forecast through Recognition of High Conductivity in a Reservoir Subarea (Recent Development South Part of West Puerto Chiquito)

The reservoir geometry that exists in the main West Puerto Chiquito reservoir (Appendix 3) has been found in nearby "subareas" of the field. The subareas may be in communication with each other through low permeability fractures, but the internal high capacity fracture network of one subarea may not be in close communication with other subareas. Within a subarea the interconnected fracture system can be revealed by interference, frac pulse, and occasionally shut-in pressure testing.

The pressure behavior of an individual well will often be defined by flow systems of "constant pressure at the boundary" (Appendix 3). Some will show influence of a nearby fault or fracture of high capacity. Typically, engineers do not attempt to analyze the "late time" portion of a pressure buildup. In the fractured Niobrara, however, with properly conducted tests, analysis of the late-time period of pressure build-up can be distinctive in assessing such reservoir character. Sensitive pressure gauges are desirable in acquiring late-time data.

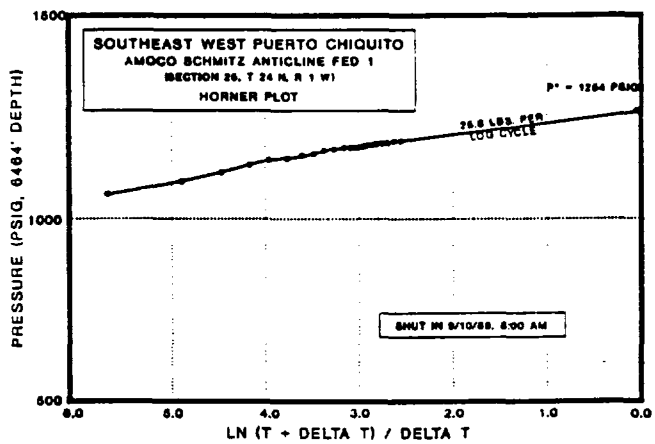

Figure 6-1. Plot of pressure buildup test of a well in southeast West Puerto Chiquito, a reservoir "subarea" first produced in 1985.

An example of pressure build-up revealing presence of a high capacity fault or fracture in southeast West Puerto Chiquito (NMOCC, 1989) occurs in the Amoco Schmitz Anticline No. 1 well, Sec. 25, T24N, R1W from tests conducted in September 1988 (Figures 6-1, 6-2, and 6-3). Figures 6-2 and 6-3 are expanded scale sections of Figure 6-1. Significant are the pressures from the 60th to the 116th hours of shut-in shown on the greatly expanded plat of Figure 6-3 and comparison with those just preceding. Although the pressures were not taken with a sensitive instrument, it is possible to average the points of equal pressure (scanner reads several points identically) and determine, as shown in Figure 6-3, that the pressures fall in a straight line, not at all like the "rounding" of pressures that occurs in a closed reservoir. Rather, the well test data indicate the presence of a linear high capacity fault or fracture.

Note that a straight line sealing fault will cause the slope of a pressure build-up curve to double. It can also be shown by the same type of analysis (method of images) that a linear fault or fracture of infinite capacity will cause the slope to decrease by one-half.

For the Schmitz well the slope of the build-up curve decreases by somewhat less than half (40.5 to 25.8

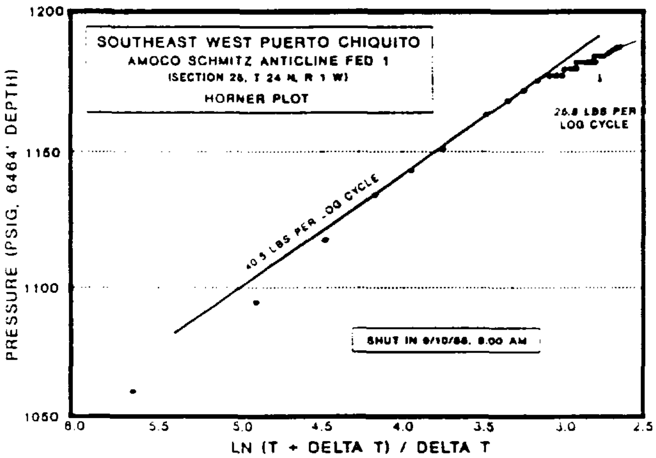

Figure 6-2. Plot of portion of pressure build-up (Figure 6-1) expanded to show that part of curve with a slope of 40.5 lb per log cycle.

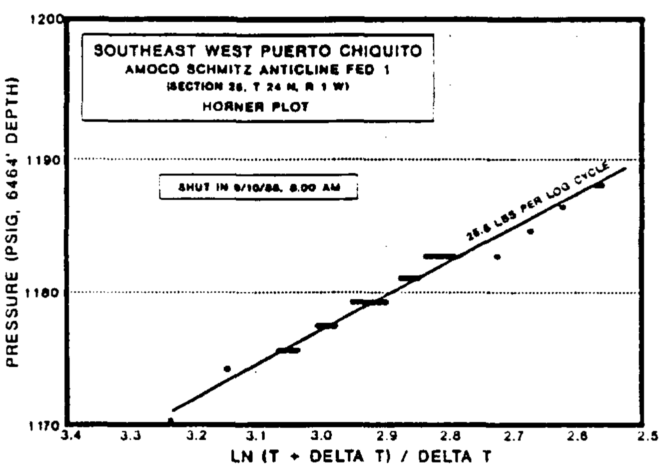

Figure 6-3. Plot of portion of build-up of Figure 6-1 greatly expanded to show "late-time" straight line slope of approximately 26 lb per log cycle, evidencing presence of high capacity fracture in well's immediate drainage area.

psi/log cycle), indicating a high capacity fault or fracture (but not one of infinite capacity). Surface fault orientations (**Figure** 6-4) suggest that the possible extension of the high capacity fracture system observed in the Schmitz well would extend to the vicinity of the second well drilled in this area, the Amoco C.C. State No. 1 (Sec. 26, T24N, R1W). Confirmation that an interconnected fracture system exists between the wells was observed in the production interference effects on the Schmitz well when the C.C. State went on production in February 1988 (Figure 6-5).

Thus, although no interference testing was available in southeast West Puerto Chiquito, the existence of a high capacity fracture system was established using:

1. The late-time straight line slope of pressure build-up.
2. Production interference effects.
3. Equalized pressure of high capacity and low capacity wells.

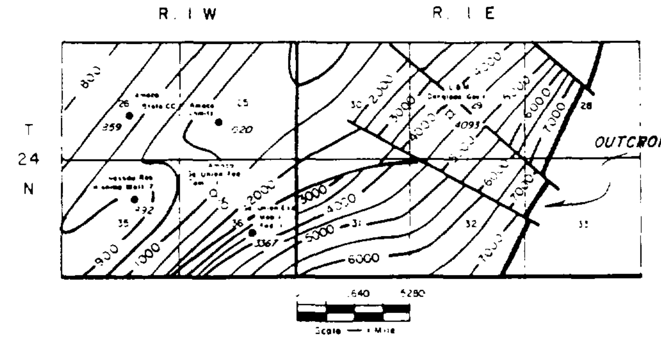

Figure 6-4. Plat showing structural contours and surface identified faults part of southeast West Puerto Chiquito "subarea" with northwest-southeast orientation.

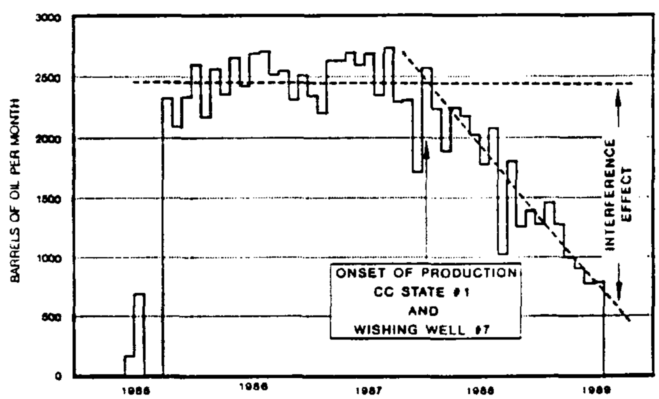

Figure 6-5. Production rate plot showing interference effect of new wells producing at high rates on stabilized production of existing wells.

Knowledge of the existence of the interconnecting fracture system permits forecast of the prospects of extension drilling as follows:

From pressure decline and production volumes for approximately four months, the indicated subarea reservoir volume is 2,500,000 STB. Pressure build-up showed a value of $kh/\mu = 1$ for the better wells.

In the absence of interference (or frac pulse) testing, pore volume per acre cannot be determined directly, nor can diffusivity, which depends on it. By assuming a series of reservoir per-acre volumes, calculating the diffusivity constant from these and Kh/μ, however, a plot can be made of reservoir unit pore volume versus two indicated areas: the area of the total reservoir oil volume; and the area that could be reached by steady state conditions (Figure 6-6).

The curve showing area that could be reached by steady state conditions in 120 days for $kh/\mu = 1$ approximates the curve for the reservoir volume area (lower two lines of Figure 6-6). If the subarea internal fracture system's diffusivity were the same as that of individual wells ($kh/\mu = 1$), then there would be no indication that the subarea reservoir was limited in size; extension drilling might provide similar wells.

If the subarea contains a high capacity fracture system, however, then the subarea's diffusivity and the area that could be reached by steady state conditions will be greater. An example is the upper curve in Figure 6-6, which results from a 3 to 1 ratio of reservoir Kh/μ to individual well Kh/μ. In West Puerto Chiquito and Gavilan, the Kh/μ for the high capacity fracture system is many multiples of that for individual wells. The same is probably true here.

Thus, for any assumed values of pore space per acre, the area that could be reached by steady state conditions is far greater than that indicated by reservoir volume. The surrounding area, therefore, must be of significantly lower permeability, and extension wells located therein will be limited in area drained to that of their own tracts. Recoveries, therefore, are expected to average 60,000 to 100,000 bbl per well. Further, since the permeability is known only to be significantly lower than for the existing wells, extension wells could very well be marginally economic, or nonpaying.

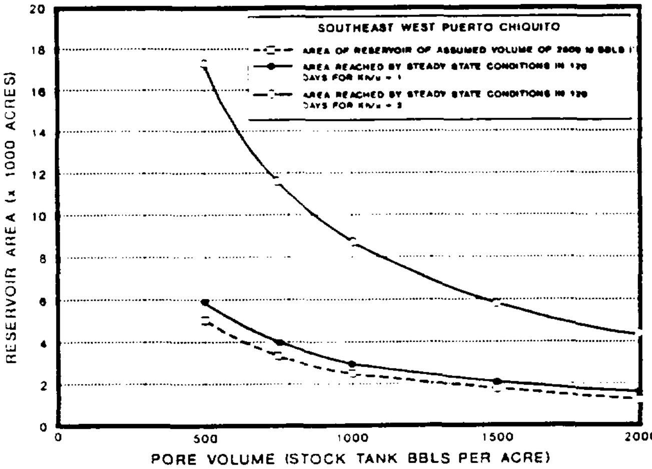

Figure 6-6. Plot showing reservoir area covering volume of 2.5 million bbl as dependent on per acre volume along with the concurrent area that could be reached by steady state conditions for the transmissibilities shown.

Another "tool" that may be of some use in evaluating a new subarea is Figure 3-6 of Appendix 3. Until information is available identifying existence of a high capacity fracture system, we suggest caution in assuming that the reservoir of a new area is of better quality than Figure 3-6 would imply.

Appendix 7. Field Description

Field name .... *West Puerto Chiquito field*

Ultimate recoverable reserves .... *15-20 million bbl (depending on future depletion method)*

Field location:

- **Country** .... *U.S.A.*
- **State** .... *New Mexico*
- **Basin/Province** .... *San Juan basin*

Field discovery:

- **Year first pay discovered** .... *Fractured Niobrara Member of U. Cretaceous Mancos Shale 1962*

Discovery well name and general location:

- **First pay** .... *No. K-13 Canada Ojitos Unit*

Discovery well operator .... *Bolack-Greer*

IP:

- **First pay** .... *15 BOPD and 6 MCF/D*

All other zones with shows of oil and gas in the field:

Age	Formation	Type of Show
Upper Cretaceous	*Mesa Verde*	*Gas*
	Pictured Cliffs	*Gas*
Lower Cretaceous	*Dakota*	*Gas*

Geologic concept leading to discovery and method or methods used to delineate prospect:
Postulated Niobrara fracture trap formed by Laramide development of basin-bounding monocline.

Structure:

Province/basin type .... *Colorado Plateau/Structural; Klemme IIB, Bally 222*

Tectonic history
Pre-Laramide faulting and uplift associated with development of Ancestral Archuleta anticlinorium rejuvenated during Eocene with vertical uplift and lateral shift, which created the Hogback monocline and a series of north-trending folds.

Regional structure
West-dipping flank of Hogback monocline and adjacent north-plunging structural "nose."

Local structure
5° homoclinal dip to west flattening to 0° at base to form synclinal flexure on west side.

Trap:

Trap type(s)
Fracture system isolated from outcrop by calcite vein-filling, and without connection to water.

Basin stratigraphy (major stratigraphic intervals from surface to deepest penetration in field):

Chronostratigraphy	Formation	Depth to Top in ft*
Tertiary	*Nacimiento, San Jose*	*Surface*
Upper Cretaceous	*Ojo Alamo*	*3000*
	Kirtland-Fruitland-PC	*3300*
	Lewis	*3700*
	Mesa Verde: Cliff House, Menefee, Pt. Lookout	*5200*
	Mancos	*6000*
	Niobrara	*7000*
	Sanostee, Carlile, Greenhorn, Graneros, Dakota	*7500*
	Entrada	*8300*

**Varies from 2000 ft shallower to 500 ft deeper than schedule depending on structural position and topography.*

W. P. CHIQUITO

Reservoir characteristics:

- **Number of reservoirs** ... *1*
- **Formations** ... *Niobrara Member of Mancos Shale; A, B, C lithologic units*
- **Ages** ... *Upper Cretaceous*
- **Depths to tops of reservoirs** ... *5000-7500 ft depending on structural position and topography*
- **Gross thickness (top to bottom of producing interval)** ... *250 ft*
- **Net thickness—total thickness of producing zones**
  - **Average** ... *50-100 ft*
  - **Maximum** ... *100-150 ft*
- **Lithology** ... *Highly laminated shale, siltstone, and minor limestone and dolomite sequence*
- **Porosity type** ... *Fracture*
- **Average porosity** ... *0.5-1.0%*
- **Average transmissibility** ... *Varies 1-50 darcy-feet*

Seals:

- **Upper**
  - **Formation, fault, or other feature** ... *Massive shale (Mancos) and loss of fractures*
  - **Lithology** ... *Shale*
- **Lateral**
  - **Formation, fault, or other feature** ... *Niobrara—loss of fractures*
  - **Lithology** ... *Shale*

Source:

- **Formation and age** ... *Niobrara (Upper Cretaceous)*
- **Lithology** ... *Shale*
- **Average total organic carbon (TOC)** ... *1-3%*
- **Maximum TOC** ... *NA*
- **Kerogen type (I, II, or III)** ... *NA*
- **Vitrinite reflectance (maturation)** ... $R_o = 0.77\text{-}0.90\%$
- **Time of hydrocarbon expulsion** ... *Tertiary*
- **Present depth to top of source** ... *5000-7000 ft*
- **Thickness** ... *300 ft*
- **Potential yield** ... *NA*

Appendix 8. Production Data

Field name ... *West Puerto Chiquito field*

Field size:

- **Proved acres** ... *80,000*
- **Number of wells all years** ... *40*
- **Current number of wells** ... *40*
- **Well spacing** ... *640 ac*
- **Ultimate recoverable** ... *15-25 million bbl*
- **Cumulative production** ... *10 million bbl*
- **Annual production** ... *0.5 to 1.0 million bbl*
- **Present decline rate** ... *
  - **Initial decline rate** ... *
  - **Overall decline rate** ... *

**Rates not meaningful because of pressure maintenance project, continuous development, gravity drainage.*

- **Annual water production** ... *Nil*
- **In place, total reserves** ... *50-100 million bbl*
- **In place, per acre foot** ... *NA*

Primary recovery ... *NA: pressure maintenance started early in life*
Secondary recovery ... *NA: see above*
Cumulative water production ... *Nil*

Drilling and casing practices:

Amount of surface casing set ... *500 ft*
Casing program
Early wells: 7⅝-in. intermediate through Mesa Verde, set from 100 ft to 500 ft above A zone, 5½-in. liner through pay
Later wells: 5½-in. intermediate from surface through pay
Drilling mud ... *Fresh water, viscosity 35 seconds shallow, 50-70 deep; water loss 4.8 though producing zones*
Bit program ... *Recent wells: 12¼-in. surface hole, 8¾-in. through Lewis shale, 7⅞-in. to TD*
High pressure zones ... *None*

Completion practices:

Interval(s) perforated ... *Primarily A, B, and C zones*
Well treatment ... *Sand frac*

Formation evaluation:

Logging suites ... *Induction-gamma ray, neutron density, some frac logs*
Testing practices ... *Open-hole: none; all testing done after running production casing*
Mud logging techniques ... *Sample logging, observation of lost circulation zones, occasionally gas monitoring*

Oil characteristics:

Type ... *NA*
API gravity ... *38-40°*
Base ... *Paraffin*
Initial GOR ... *480 ft^3/bbl (gas in solution)*
Sulfur, wt% ... *0*
Viscosity, SUS ... *0.62 cp at initial reservoir conditions*
Pour point ... *NA (low)*
Gas-oil distillate ... *NA*

Field characteristics:

Average elevation ... *Surface 7000-8000 ft*
Initial pressure ... *1620 psig at datum +1195*
Present pressure ... *2000 psi near injection wells, 1000 psi most remote wells*
Pressure gradient ... *0.313 psi/ft (initial reservoir conditions)*
Temperature ... *155-170°F*
Geothermal gradient ... *0.015-0.018°F/ft*
Drive ... *Solution gas*
Oil column thickness ... *Indeterminate*
Oil-water contact ... *None*
Connate water ... *Indeterminate*
Water salinity, TDS ... *NA*
Resistivity of water ... *NA*
Bulk volume water (%) ... *NA*

Transportation method and market for oil and gas:
90% moves through pipelines, remainder trucked.

United States Department of the Interior

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BUREAU OF LAND MANAGEMENT
Farmington Resource Area
1235 Laplata Highway
Farmington, New Mexico 87401

IN REPLY REFER TO:
Jicarilla Contract 404 (DL)
3162.2 (019)

OCT. 1 3 1992

CERTIFIED--RETURN RECEIPT REQUESTED
P 081 574 963

Mr. Bob Stovall
New Mexico Oil and Gas
Conservation Division
P. O. Box 2088
Santa Fe, NM 87504-2088

Dear Mr. Stovall:

The Farmington Resource Area (FRA) of the Bureau of Land Management has completed an analysis of 640-acre spacing in the Mancos formation in T. 27 N., R. 1 W., Rio Arriba County, New Mexico. The Mancos formation is a fractured shale with production from a gravity drainage mechanism. In this type of reservoir, an adequate size proration unit is necessary for economical production without waste.

Through numerous hearings before the New Mexico Oil Conservation Division, it has been determined that 640-acre spacing in the Mancos formation is necessary to economically produce this formation without waste of resources. After reviewing all of the data pertinent to these hearings, we found nothing to support a change in the current spacing.

The suspension of drilling in T. 27 N., R. 1 W., Rio Arriba County, New Mexico is hereby lifted and operations can resume in this area.

This letter has been sent to the following:

1. Jicarilla Indian Tribe, Oil & Gas Administration, Dulce, NM.
2. Bureau of Indian Affairs, Energy and Minerals Resource Assistance Office, Golden, CO.
3. Bureau of Indian Affairs, Jicarilla Agency, Dulce, NM.
4. New Mexico Oil and Gas Conservation Division, Aztec, NM.
5. Benson-Montin-Greer Drilling Corporation, Farmington, NM.
6. American Hunter Exploration Limited, Denver, CO.

Under provisions of 43 CFR 3165.3, you may request an Administrative Review of the order described above. Such request, including all supporting documents, must be filed in writing within 20 business days of receipt of this notice and must be filed with the State Director, Bureau of Land Management, P. O. Box 27115, Santa Fe, New Mexico 87502-0115. Such request shall not result in a suspension of the order unless the reviewing official so determines. Procedures governing appeals from instructions, orders or decisions are contained in 43 CFR 3165.4 and 43 CFR 4.400 *et seq.*

NORDHAUS HALTOM TAYLOR
TARADASH & FRYE

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Reply to Santa Fe Office

September 2, 1992

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SEP 02 1992

OIL CONSERVATION DIVISION

Mr. William J. LeMay
Oil Conservation Division
State Land Office Building
310 Old Santa Fe Trail, Room 219
Santa Fe, NM 87501

Re: Jicarilla 404 #3 (F-9) Well and Jicarilla 404 #2 (K-10) Well Applications of Benson-Montin-Greer Drilling Corp. for High Angle/Horizontal Direction Drilling Pilot Project, etc.

Hearing Date: September 3, 1992

Dear Mr. LeMay:

This firm represents the Jicarilla Apache Tribe, which is the landowner, lessor, royalty owner and governmental entity potentially affected by the applications identified above. This letter is submitted on behalf of the Jicarilla Apache Tribe on the conditions and for the purposes stated below. This letter should not be considered to be an entry of appearance by the Tribe in this proceeding, nor as an indication that the Tribe in any way submits itself to the jurisdiction of the Oil Conservation Division, nor as an indication that the Tribe will in any manner be bound by any decision to be rendered by the Division in this proceeding. The Tribe submits this letter solely for the purpose of providing the Division and all interested parties in this proceeding certain information directly relevant to the applications submitted by Benson-Montin-Greer Drilling Corp. (BMG). The Tribe provides this information solely as a courtesy to the Division and to carry out the government to government relationship existing between the State of New Mexico and the Jicarilla Apache Tribe.

The Tribe submits the following for the Division's consideration:

1. The State of New Mexico and its agencies do not have jurisdiction to authorize BMG to drill any well on the Jicarilla Apache Reservation over the objection of the Tribe or of the Federal Government. Any such interference in the management of the oil and gas

resources of the Tribe, held in trust by the United States, would be an infringement on tribal self-government and would be preempted by federal law. See, eg., Assiniboine and Sioux Tribes v. Board of Oil and Gas Conservation, 792 F.2d 782 (9th Cir. 1986) and Assiniboine and Sioux Tribes v. Calvert Exploration Co., 223 F.Supp. 909 (D.Mont. 1963), rev'd on jurisdictional grounds sub nom. Yoder v. Assiniboine and Sioux Tribes, 339 F.2d 360 (9th Cir. 1964).

2. The Tribe objects to the specific well locations proposed by BMG on the grounds that the locations are too close to the north boundary of Sections 9 and 10 and too close to the existing Tribal/American Hunter well located on Section 3. The proposed wells could result in drainage of the Jicarilla/American Hunter property and thereby cause economic injury to the Tribe, in violation of the Indian Mineral Leasing Act.

3. The Tribe objects to the wells proposed by BMG on the grounds that these additional wells should not be drilled until more information is available concerning formation pressure, gas-oil ratios, and optimal production rates to maximize long-term recovery of oil and gas from this reservoir. Any well in Section 9 or 10 would be premature and could result in permanent damage to the reservoir and waste of the Tribe's mineral resources.

4. The Tribe has requested two agencies of the Federal Government, the Bureau of Indian Affairs and the Bureau of Land Management, to conduct reservoir studies for the Tribe on an area including the 404 Lease held by BMG. The Farmington Resource Area Manager has informed the Tribe (by letter dated August 12, 1992) that the BLM will not approve any APD in the area included in the reservoir study until the study is completed. That study has not been completed and the BLM has not informed the Tribe of the date by which BLM expects to complete its study. Until the BLM and BIA reservoir studies are complete and the Tribe and the relevant federal agencies have reviewed those studies and determined appropriate spacing for this area (among other issues), there is no "acceptable well-spacing program" in effect for this area and no APD can be approved by BLM. See 43 CFR § 3162.3-1.

5. For the reasons stated above, any action taken by the Division at this time (before the BLM, BIA and Tribe have completed their reservoir studies) which purports to authorize BMG to drill the proposed wells, would have no legal effect and would amount to a futile act. Any action by the Division to authorize drilling of these wells at this time would precipitate an unnecessary and avoidable conflict between the State of New Mexico on the one hand and the Tribe and the Federal Government on the other.

6. On or about July 30, 1992 BMG applied to the Tribe for a permit to conduct a seismic survey on Sections 9 and 10 designed to locate potential well sites. The Tribe is