IMPROVED FORMATION EVALUATION FROM PRESSURE AND CONVENTIONAL CORES TAKEN WITH STABLE FOAM - BENNETT RANCH UNIT (WASSON FIELD)

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ABSTRACT:

Analysis of conventional and pressure cores taken with stable foam from the San Andres formation within the Bennett Ranch Unit of the Wasson Field provides a better means of formation evaluation. The pressure core data were used to correct conventional core oil saturations to in situ conditions. This oil saturation adjustment method corroborates similar procedures cited in the literature.

The pressure at the bit was controlled during the coring operation to minimize the possibility of core fluid saturation alteration. Nitrate was used as a tracer material and the nitrate analyses of the core waters confirmed the lack of filtrate invasion.

Calculations of pressure at the bit obtained during foam coring operations provides an accurate method of measuring the vertical cross section of bottomhole pressures in a thick formation consisting of lithologies of variable quality. This procedure provides another means of evaluating the volumes and paths of the injection waters for estimating the quantity of oil that may be contacted during tertiary recovery operations.

Introduction

Tertiary recovery operations require a large front-end investment in equipment and injectants. The prudent operator will pre-plan such operations to minimize risk and optimize the chance for success. The San Andres formation located in several counties of West Texas, and the Wasson (San Andres) Field in particular, is a target for tertiary CO_2 recovery projects.[1,2,3,4] Doscher and Wise[5] report that the Wasson Field has the highest CO_2 flooding potential of the 12 Grayburg-San Andres reservoirs listed in their paper. The Bennett Ranch Unit of the Wasson Field may also be a candidate for a tertiary flood using CO_2. A pilot area is under consideration and Sun is attempting to establish a credible data base prior to the implementation of such a project.

Simplistic material balance approaches, i.e. residual oil equals original oil in place less volume produced, do not provide the vertical and areal distributions of oil saturation. Log analysis, likewise, may not provide accurate hydrocarbon saturation information. Fluid saturation data from conventional cores seldom yields oil values that are representative of true in situ values. Pressure coring is a potential tool to provide insight regarding hydrocarbon saturation and its distribution. The pressure core barrel technique eliminates the reduction in oil saturation caused by gas expansion; however, misleading fluid saturation data may still result if the cores are flushed with drilling mud filtrate during the cutting of the cores. The ideal method is a core cut at "balanced" BHP conditions and brought to the surface without a reduction in the "capture" pressure.

If the BHP exceeds the pressure that can be obtained with minimally-weighted drilling fluids, a balanced drilling system may be designed. If the BHP is less than that from a normal water gradient, the use of most drilling fluid systems will result in an overbalanced condition during coring, and pore space flushing is likely to occur. Under these BHP conditions stable foam can be the ideal coring fluid.[6] The foam drilling fluid system, unlike conventional mud systems, can be modified almost instantaneously to achieve the desired physical properties, and the pressures required to balance the BHP are likewise easily attained.

BACKGROUND

The Wasson Field is located in Gaines and Yoakum Counties, Texas (Fig. 1) and encompasses some 68,500 acres. Production is from the San Andres dolomite at an average depth of 5100-5200 feet. The producing interval customarily is divided into an upper "First Porosity" zone and a deeper zone termed "Main Pay." The field was discovered in 1936, was largely developed by 1941 and waterflood operations started in 1964. Initial oil in place was in excess of 1.5 billion barrels and as of 1979 the remaining reserves were estimated at over 600 million barrels. Ghauri[4] and others[7] have provided descriptions of the geologic setting and Wasson Field core data.

The Bennett Ranch Unit is located in the northernmost tip of the Wasson Field (Fig. 1) and contains over 7000 productive acres. The unit was formed in 1964 and was operated by the Texas Pacific Oil Company, Inc. Currently the operator is Sun Exploration & Production Co. who acquired the Lower 48 assets of Texas Pacific in 1980.

Water injection for unitized waterflooding operations began in 1965. As of March 1, 1979, the cumulative oil production was 38.9 million barrels. The ultimate recovery (primary plus waterflood) is estimated at 104 million barrels (34 percent of OOIP).[7] Residual oil saturation at the end of the waterflood is expected to be 43 percent.[7] This is the target for tertiary recovery operations.

In 1979, Gruy Federal, Inc. under contract to DOE, participated with the Texas Pacific Oil Company in pressure coring operations on the BRU No. 310. Swift, et al[7,8] reported on these operations that were designed to provide engineering data necessary for the implementation of pilot CO_2 tests in carbonate reservoirs.

An infill drilling program has been implemented by Sun. As a part of a multi-well package it was decided to conventionally core the entire San Andres interval of the BRU #340 and to pressure core a 30' section of the "main pay" estimated to be approximately 100' thick. The pressure core section was selected based on correlations from nearby wells. It was thought that a successful pressure core might provide insight regarding vertical conformance and volumetric sweep efficiency. The BRU #340 was conventionally cored from 4985'-5162'. Thirty feet of pressure-retained core were cut from 5160'-5190' (a depth overlap is noted and could not be reconciled). Conventional coring was resumed from 5190'-5287'.

Nitrate was added to the foam make-up water as a "tracer" material to provide a means for evaluating changes in core saturations from coring fluid invasion. The results of the core invasion tests will be discussed later in the paper.

Bottomhole Pressure Observations During Coring

A critical part of the planning and implementation of the coring project was arriving at a reasonable estimate of the bottomhole pressure (BHP) at the BRU #340 location. The BRU #340 was scheduled to be drilled between two water injection wells (Fig. 2). These wells (numbers 156 and 158) were completed as injectors in December 1970. Cumulative injection as of November 1982 was 2,600,000 and 2,300,000 barrels respectively. Measurements from nearby wells indicated BHP's in the 2000 psi range while other data indicated somewhat lower pressures. It was desirable to achieve "balanced" drilling conditions during coring as the literature documents overbalance as one of the prime contributors to core fluid saturation alteration[9]. The uncertainty of the BHP value at the BRU #340 location influenced the decision to use stable foam as opposed to a water-base drilling fluid. With a normal drilling mud (e.g., 9 lb/gal) the fluid column at 5000 feet would exert a pressure of 2340 psi. Even a fresh water gradient would result in 2165 psi at 5000 feet. The stable foam system is extremely flexible in that means are available to control the pressure at the bit with effective foam densities ranging from less than 0.3 lb/gal to approximately 7 lb/gal[6], the latter being equivalent to an oil gradient.

The decision was made to start coring with a foam pressure of 1500 psi at the bit. If oil were not observed at the foam "blooie line" the pressure could be reduced in increments until an oil show was observed, indicating that underbalanced conditions prevailed. The pressure could then be adjusted accordingly. Table 1 lists the calculated pressures at the bit at various depths during the coring operation. The pressure at the bit is a function of several variables as discussed by Lorenz.[10].

They include depth, air and make-up water pumping rates, back pressure, etc. The conditions existing at the start of coring operations yielded a calculated pressure at the bit of 1482 psig. Since no oil was observed at the "blooie line," the pressure was reduced until an oil show was observed. The pressure required to balance the BHP (Table 1) was slightly in excess of 1300 psig. This held true for approximately 100 feet of coring. At 5120 feet oil was observed at the blooie line and the pressure was increased to about 1400 psig. The pre-selected depth for the pressure coring operations was approaching rapidly and the pressure required for balanced conditions was continuing to increase. The BHP was estimated by extrapolation based on the required pressure increases for the interval above the pressure core point. This extrapolation predicted the need for perhaps a 100-200# increase. The plans had called for cutting the 30 feet of pressure core at slightly overbalanced conditions to prevent expulsion of the fluids prior to capturing the cores under pressure. It was decided to adjust the foam system for 1900-2000 psi while cutting the two 15 foot pressure cores.

A reaming operation followed the pressure coring, and conventional coring was resumed. A pressure of approximately 1600# was apparently satisfactory to balance the BHP. This was about the same as that required prior to the pressure coring. In hindsight, the pressure cores could have been cut at approximately 1800# as opposed to the 2000# to guarantee slightly overbalanced conditions. The impact of coring at 400# of overbalance will be discussed in later sections of the paper.

Conventional Core Data Evaluation

Routine (basic) core data may have a wide range of applications in the reservoir management process. Normally only a small percentage of wells from a given field are cored; therefore, it behooves the user to glean as much information as possible from all core data. Prior to any extensive usage/extrapolation of the core data, the experienced core analyst will perform certain diagnostic procedures for quality control purposes. These procedures ensure that proper laboratory techniques were used and the experiments performed so as to yield the accepted degree of accuracy . There are certain relationships that may be anticipated between sets of core data from a given lithology, e.g., permeability normally increases with increasing porosity, water saturation may trend with rock quality, residual oil may or may not exhibit a trend with other core data, etc. Cross-plotting various of the data sets is one useful means of data evaluation.

Several such cross-plots were performed on the conventional core data from the BRU #340. Shown in Figure 3 is the plot of helium porosity versus horizontal (90°) permeability for 229 conventional core data pairs. Full diameter analyses of the BRU #340 cores yielded K_{max}, $K_{90°}$, and K_V permeabilities. The 90° values were plotted because they are more representative of the matrix permeability. While there was considerable data point scatter, a discernible trend was evident. An estimated best-fit line was drawn. The equation of the line is also shown which has potential application in computed log analysis where permeability values may be assigned on non-cored wells based on log-derived porosities[11].

Figures 4 and 5 show the relationship of residual oil with porosity and permeability. Both exhibited reasonable trends and indicate increasing residual oil saturations with increasing porosities and permeabilities. These trends are often not evident from data measured on cores taken at overbalanced drilling conditions with conventional water-based mud systems. The foam system eliminates or minimizes the flushing of the pore spaces and thereby eliminates one variable that impacts on core residual oil saturations.

Shown in Figure 6 is a plot of total water saturation versus porosity. A straight-line relationship is associated with the data pairs in the higher porosity ranges; however, at some lower limit of porosity (e.g., 6-7%) this relationship changes and the water saturation approaches an asymptotic value. This suggests that Wasson Field rock of poorer quality may exhibit a constant minimum or irreducible water saturation.

Total water saturation is plotted versus permeability in Figure 7. The trend was less well defined and the curved line relationship was drawn based on the previous relationship of water saturation and porosity.

In all water saturation plots the general trend is for the water saturation to decrease with increasing porosity and permeability. This would be the anticipated relationship as influenced by lower irreducible waters trending with better rock quality.

Since the anticipated relationships were observed, the conventional core data were assumed to be valid within normal tolerances. Later data treatments and comparisons with the pressure core data could then be made with confidence.

<u>Pressure Core Oil Saturation</u>

The data determined on the pressure cores is provided in Table 2. The on-site and laboratory core handling processes as well as the analytical techniques are quite involved[6,12] and will be discussed only to the extent required to explain data and interpretations.

Of particular significance are the oil saturations. Samples 1-3, exhibiting good permeability and porosity, indicate an average oil saturation of 64.4% with an associated average of 22% oil produced by pressure depletion. Comparable quality rock (samples 7-11 and 16-20) average only 26.1% oil saturation and 3.5% oil produced by pressure depletion. The last five pressure core samples (23-27) exhibit properties associated with reservoir-quality rock and the oil averages are 72% and 18.9%. The upper and lower portions of the pressure core interval appear to be at near virgin reservoir conditions while much of the section appears to have been depleted to residual oil conditions such as might be anticipated by waterflood.

Tracer Studies

Nitrate (NO_3) was added to the foam make-up water in an amount specified to yield a concentration in the 400-500 ppm NO_3 range. Samples of the make-up water were collected and analyzed. Shown in Table 3 are the results of nitrate analyses during the coring operation. The nitrate concentrations are within acceptable design specification limits.

A small portion of each foot of conventional core was broken off and maintained in a frozen condition. Past experience has shown that high nitrate concentrations in the contaminated core periphery can be transported to the center of the core through diffusion. The freezing immobilizes the fluids.

The conventional core basic data were reviewed and samples selected throughout the cored interval for nitrate analyses. Samples exhibiting a broad range of permeability, porosity and residual oil saturation were chosen. Samples from the center portions of the cores were analyzed and the results are given in Table 4. The extremely low nitrate levels indicate no invasion of the foam and therefore, the saturations were not altered during the coring process conducted at "balanced" pressure conditions.

Shown in Table 5 are the nitrate data determined on the pressure cores. These high nitrate concentrations can be explained by the fact that the pressure core analytical process involves the use of a frozen section of whole core. The core is allowed to thaw and the gases and other fluids are collected in appropriate lab equipment. The pressure cores were 2 1/2" in diameter while the conventional cores were 4" in diameter. The pressure cores were taken at "overbalanced" pressure conditions. The peripheral portions of the pressure cores were undoubtedly highly contaminated with nitrate and since the entire core was analyzed, the collected waters would have been expected to contain nitrate.

The commercial laboratory analyst was questioned regarding the pressure core nitrate concentrations being in some cases, higher than those measured on the foam make-up water. They reported that the nitrate was measured by a titration method. Water was leached from the conventional cores and the nitrate concentration was measured by the selected ion electrode technique with direct readout. Additional test work is underway in an attempt to resolve the accuracy of the two methods.

The 400# of overbalance did not cause pore space flushing throughout the 30' zone. Selective flushing throughout the 30 foot zone would be unlikely. This conclusion is primarily based on the fact that permeable sections of the pressure core interval exhibited oil saturations in the 64-72% range. The high nitrate concentrations resulted from the contaminated periphery of the 2 1/2" diameter core, which would influence the nitrate concentration in the total core waters to a greater degree than comparable invasion in a 4" diameter core.

OIL AND WATER SATURATION RELATIONSHIPS OF SPECIAL STUDY AREA

A 50 foot interval (5150-5200') was selected for detailed study. The pressure core section was located approximately in the middle of the interval. This section was chosen as the rock properties appeared to be comparable above and below the pressure core interval. Subsequent averaging and comparisons of data could be weighted equally between the pressure and conventional core data.

Water Saturation

The first area of study was the water saturations. Previous plots (Figures 6 & 7) indicated trends of decreasing water saturation with increasing permeability and porosity. The total waters measured on samples from 5150-5200' (Fig. 12) are plotted versus porosity and permeability in Figures 8 and 9 respectively. Note the absence of the trends previously discussed.

In both plots the majority of the pressure core water saturations are considerably higher than those for the conventional cores. Exceptions are the eight high oil saturation samples previously indicated as possibly being at initial discovery conditions, i.e., the waters for these samples may be reasonably representative of initial reservoir water saturations.

Another explanation for the "grouping" of the water saturations may be the conventional versus pressure coring process. If mobil water exists, the solution gas that evolves during the core lifting would cause expulsion of these waters. The pressure coring process locks all fluids in place until the analytical process begins.

Sparks[6] reported good agreement between pressure core water saturations and log values in the oil column and in the water-encroached areas. Full suites of logs were run on the BRU #340 and good quality data were obtained; however, calculated water saturation values could not be assigned with a high degree of confidence due to the uncertainty of the in situ water resistivity (R_w). As previously documented, the water volume injected in wells 156 and 158 has exceeded 5,000,000 bbls. This water has been fresh water, produced formation brine and various combinations of the two giving a wide range of R_w values that might apply to various intervals in the BRU #340. The sensitivity of R_w is such that calculated water saturations have larger accuracy tolerances than normal. Attempts at assigning water saturation values on the BRU #340 that are in close agreement with the pressure core data have not been successful. Swift, et. al.[7], studied the BRU #310 and reported that standard log analysis procedures lacked the desired precision.

Oil Saturation

The second area studied in the 5150-5200' interval was the oil saturations. Conventional core oil saturations are affected by the oil formation volume factor. Current PVT studies of BRU crude suggest a FVF of 1.17. There were 23 feet of conventional core in the 5150-5200' interval and the average oil saturation is 27.1%

(Table 6). If these data are multiplied by the FVF of 1.17 this average increases to 31.7%.

The pressure cores were allowed to pressure deplete and the "total" and "pressure depleted" oil values are listed in Table 6. The "total oil" less "depleted oil" (i.e., residual oil) for 24 feet of pressure core averaged 34.9% which should be comparable to the 27.1% residual oil value.

A "depletion ratio" was calculated for each foot of pressure core that was tested in this manner. The depletion ratio is defined as the (Total oil)/(Total oil -Oil by Pressure Depletion). The depletion ratio average for 23 feet of pressure core was 1.28 with a range from 1.08 to 1.74. Plots of these ratios versus porosity and permeability are shown in Figures 10 and 11 respectively. As may be noted, no correlations are evident. This indicates that the depletion ratio is not a function of rock quality but is controlled by other factors.

The conventional core residual oil saturations were multiplied by the depletion ratio of 1.28 and the average for 23 feet is 34.7%. The 26 feet of pressure core averaged 44.4% "total" oil. The combination of 49 samples, consisting of 26 feet of pressure core and 23 feet of conventional core multiplied by 1.28 yielded an average oil saturation of 39.8%. These data are tabulated in Table 6.

Discussion

Shown in Figure 12 is a Coregraph of the interval studied. (The footage discrepancy previously mentioned also exists in the plot.) An unoccupied pore volume or gas space $1-(S_o + S_w)$ is noted in the conventional core sections above and below the pressure core interval. The amount of gas space may be a function of (1) mobil waters expulsed during core lifting (2) a low "depletion ratio" multiplier or (3) a combination of the two.

Rathmell, et. al.[13], discuss "Shrinkage and Bleeding of Oil" and arrived at a suggested means for adjusting conventional core residual oil saturations to in situ values. In their paper data are furnished from laboratory tests conducted on cores from three unidentified reservoirs. The average oil saturation change from simulated lifting conditions was 10%. Their final recommendation for the oil adjustment on conventional cores consists of multiplying the surface oil saturation by B_oE, where B_o is the differential formation volume factor of the oil and E is the adjustment for bleeding. The suggested value for E is 1/(1 - .10) = 1.11. The adjustment for the BRU #340 case would be 1.17 x 1.11 = 1.30. This is in close agreement with the 1.28 average "depletion ratio" calculated from the data on 23 feet of BRU #340 pressure core.

A word of caution appears in order regarding the blanket use of the B_oE adjustment. Rathmell, et. al., state that the cores used in their experiments were water-wet sandstones. The San Andres is a carbonate with a non-sandstone type pore structure. Also, there is evidence to suggest that the Wasson (San Andres) Formation may be other than strongly water wet[7,14]. Both of these factors could influence the core bleeding characteristics. While good agreement was obtained for the BRU #340 case, it is possible that this is a coincidence. When at all possible, bleeding measurements should be made on cores from the reservoir under study[13]. Furthermore, the oil adjustment should be considered as an approximation and data from properly taken pressure cores would always be preferred.

CONCLUSIONS

1. Much of the "main pay" section of the BRU #340 is at, or approaching residual oil saturation. This conclusion is reinforced by the high water saturations in the pressure core interval that (1) are not in the field discovery water saturation range, and (2) are not a result of drilling fluid invasion.

2. The "depletion ratio" approach affords an objective means for adjusting conventional core oil saturations to in situ values.

3. The combination of coring with stable foam and the use of the pressure core barrel provided data regarding the vertical oil saturation distribution and a more precise estimate of reserves for the planning of a tertiary recovery project.

4. The stable foam drilling fluid system allowed for a means to determine the vertical profile of pressures in a thick formation with variable quality rock.

5. Data from non-invaded cores, captured at in situ pressure conditions, provides a means to evaluate log water saturation calculations when the resident water composition cannot be determined due to commingling of injection waters over a long period of time.

6. The nitrate tracer technique afforded a means to evaluate core fluid saturation alteration from drilling fluid invasion.

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Table 1
Distribution of Calculated Bit Pressures with Depth During Coring Operations

DEPTH (FEET)	OPERATION		CALCULATED PRESSURE AT BIT (PSIG)
5005	CONVENTIONAL	CORING	1482
5025	"	"	1448
5044	"	"	1316
5073	"	"	1303
5093	"	"	1308
5113	"	"	1314
5133	"	"	1408
5160	"	"	1581
5175	PRESSURE	CORING	1939
5190	"	"	2003
5202	CONVENTIONAL	CORING	1573
5251	"	"	1588
5260	"	"	1591
5285	"	"	1599

Table 2
Bennett Ranch Unit No. 340 Pressure-Retained Core Analysis

SAMPLE NO.	PERMEABILITY (MILLIDARCIES)	POROSITY (PERCENT)	OIL SATURATION PERCENT PORE VOLUME		WATER SATURATION PERCENT PORE VOLUME
			TOTAL OIL	BY PRESSURE DEPLETION	
1	14.0	16.1	65.6	22.0	33.5
2	10.0	12.3	63.1	20.1	34.4
3	8.2	13.8	64.5	23.9	32.1
4	0.2	8.0	40.7	6.1	57.5
5	0.3	9.4	49.1	6.8	44.1
6	2.3	14.1	40.2	6.7	55.3
7	12.0	15.2	30.6	N.A.	65.3
8	1.6	15.9	43.0	11.1	50.1
9	33.0	17.9	18.5	1.8	71.2
10	23.0	17.4	30.9	3.5	63.5
11	19.0	15.6	27.4	2.9	66.7
12	NO ANALYSIS	–	–	–	–
13	< 0.01	14.9	34.0	4.2	58.6
14	66.0	14.8	36.7	N.A.	62.4
15	87.0	18.0	29.1	4.1	67.8
16	3.2	11.1	30.0	2.2	65.4
17	9.3	14.9	28.1	0.0	69.9
18	23.0	20.0	29.2	4.7	67.9
19	38.0	19.0	22.5	2.9	73.4
20	4.9	12.2	31.6	2.7	62.8
21	38.0	11.4	38.9	11.0	52.2
22	570.0	19.3	39.4	16.8	57.6
23	3.9	12.9	78.5	25.3	18.8
24	2.9	15.8	75.3	24.5	23.2
25	4.5	15.9	73.0	18.6	20.0
26	4.9	15.3	64.6	10.5	24.7
27	20.0	15.1	68.8	15.5	23.1

Table 3
Foam Make-up Water Nitrate Concentrations During Coring Operations

CORE NUMBER	DEPTH (FEET)	SAMPLE NUMBER	NITRATE CONCENTRATION (PARTS PER MILLION)
1·	5160	1	454
1	5165	2	496
1	5170	3	446
1	5170	4	319
2·	5175	1	443
2	5180	2	428
2	5185	3	428
2	5190	4	502
6··	5190	1	428
6	5200	2	487
6	5202	3	419
7··	5202	1	449
7	5212	2	443
7	5222	3	390
7	5232	4	411
7	5242	5	440
7	5252	6	403
7	5262	7	458
8··	5262	1	320
8	5272	2	461
8	5282	3	428
8	5285	4	508

· PRESSURE CORE
·· CONVENTIONAL CORE

Table 4
Nitrate Analyses from Selected Conventional Core Samples

DEPTH (FEET)	NITRATE CONCENTRATION (PARTS PER MILLION)	PERMEABILITY 90° (MILLIDARCIES)	POROSITY (PERCENT)	OIL SATURATION (PERCENT)
4987-88	1.4	< 0.01	1.6	12.3
4993-94	1.3	0.02	8.1	23.4
5000-01	1.2	0.78	9.2	22.1
5029-30	1.4	0.89	14.0	31.2
5075-76	1.3	4.4	14.3	22.9
5085-86	1.0	0.05	10.8	26.1
5097-98	1.6	8.4	18.6	31.5
5112-13	1.0	5.4	13.8	23.1
5122-23	1.3	3.8	11.2	26.0
5127-28	1.4	19.0	18.4	32.4
5137-38	1.4	4.8	17.4	27.7
5151-52	1.4	6.7	20.0	29.1
5161-62	1.5	1.8	10.9	22.4
5190-91	1.2	9.3	13.9	22.3
5194-95	1.0	41.0	16.9	31.6
5197-98	1.1	2.5	16.0	28.1
5204-05	1.2	0.56	6.2	26.0
5210-11	1.2	0.07	3.3	4.5
5219-20	1.0	1.9	9.2	25.8

Table 5
Nitrate Concentrations with Depth from Pressure Core Samples

DEPTH (FEET)	NITRATE CONCENTRATION (PARTS PER MILLION)
CORE NO. 1	
5160-61	594
5162-63	465
5164-65	377
5167-68	439
5169-70	399
CORE NO. 2	
5175-76	284
5178-79	412
5180-81	252
5182-83	93
5184-85	691
5186-87	664

Table 6
Summary of Conventional and Pressure Core Average Oil Saturations from the Interval 5150 - 5200'

TYPE CORE	FEET	CONDITIONS	AVERAGE OIL SATURATION (PERCENT)
CONVENTIONAL	23	ROUTINE CORE ANALYSIS	27.1
CONVENTIONAL	23	S_o X 1.17 (*)	31.7
CONVENTIONAL	23	S_o X 1.28 (**)	34.7
PRESSURE	24	TOTAL-DEPLETION OIL	34.9
PRESSURE	26	TOTAL OIL	44.4
CONV. + PRESSURE	49	PRESS.(TOTAL) + S_o X 1.28	39.8

* FVF
** AVERAGE DEPLETION RATIO FROM PRESSURE CORE
(TOTAL OIL) ÷ (TOTAL OIL − OIL BY PRESSURE DEPLETION)

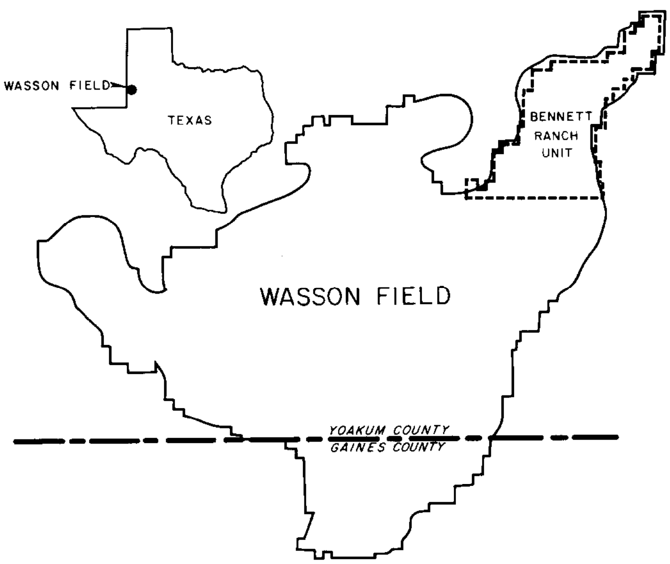

Figure 1 - Area map of Wasson Field

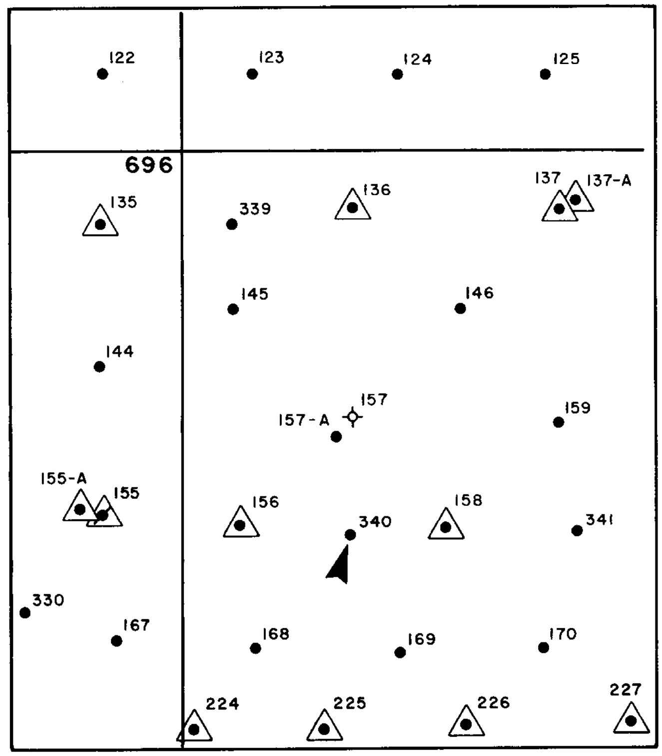

Figure 2 - Location of BRU No. 340 with respect to other production and injection wells

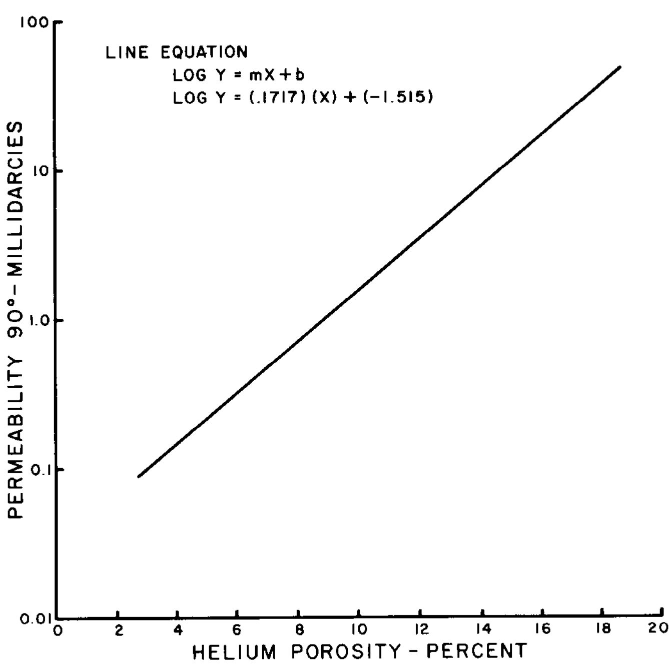

Figure 3 - Permeability-porosity relationship of conventional cores from the BRU No. 340

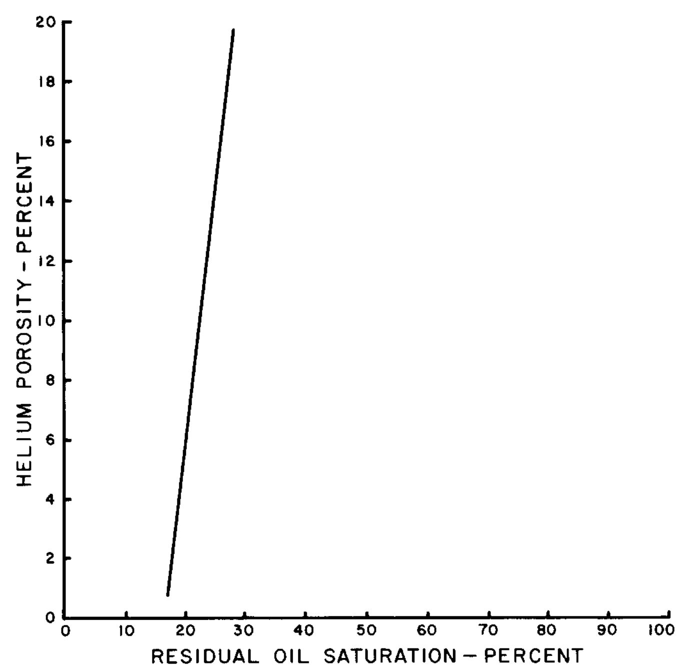

Figure 4 - Porosity-residual oil saturation relationship of conventional cores from the BRU No. 340

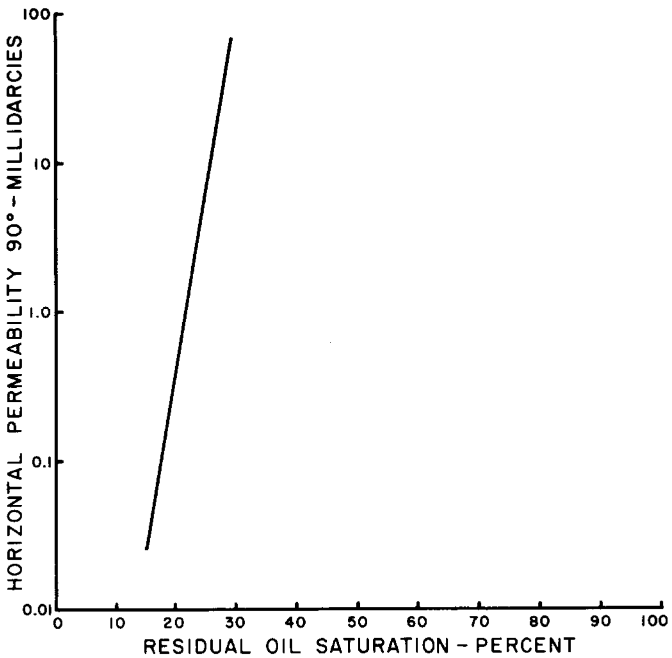

Figure 5 - Permeability-residual oil saturation relationship of conventional cores from the BRU No. 340

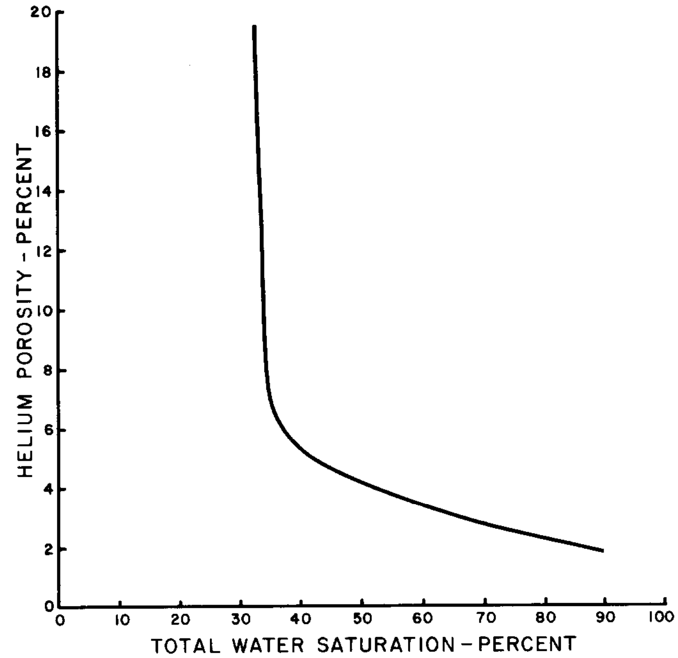

Figure 6 - Porosity-water saturation relationship of conventional cores from the BRU No. 340

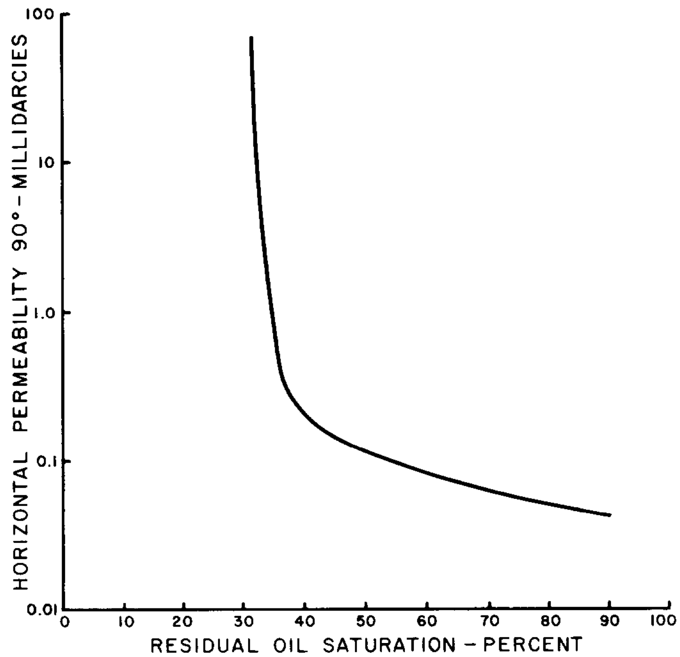

Figure 7 - Permeability-water saturation relationship of conventional cores from the BRU No. 340

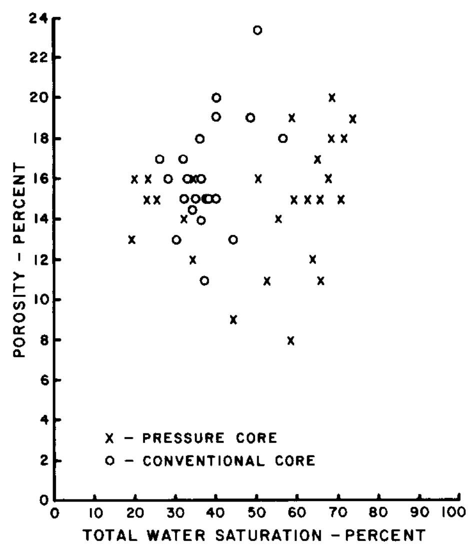

Figure 8 - Porosity-water saturation relationship of pressure and conventional cores from the special study interval (5150' - 5200')

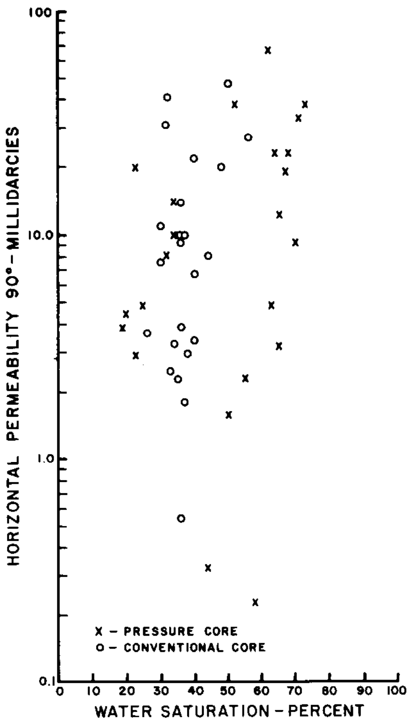

Figure 9 - Permeability-water saturation relationship of pressure and conventional cores from the special study interval (5150' - 5200')

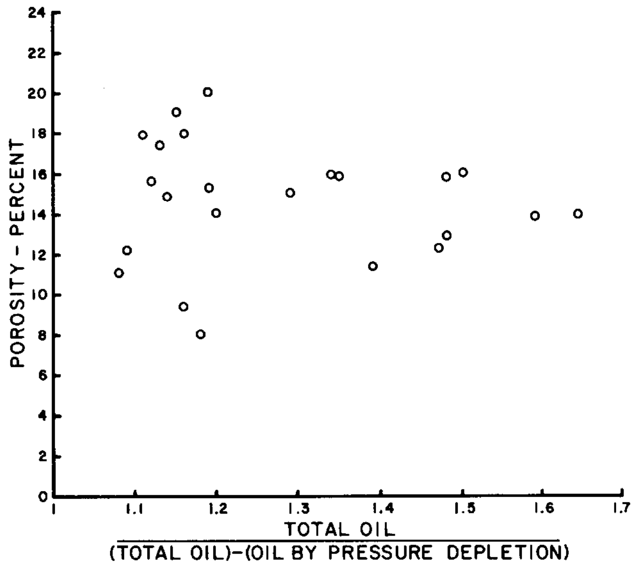

Figure 10 - Relationship of porosity-depletion ratio of pressure cores-BRU No. 340

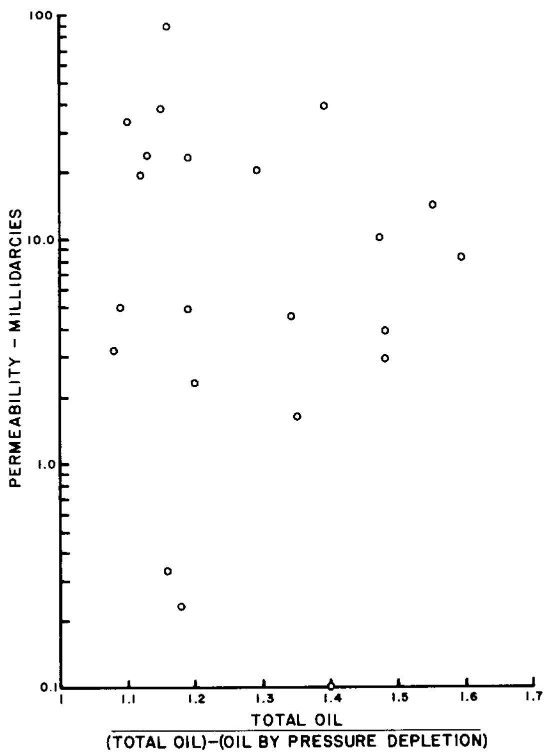

Figure 11 - Relationship of permeability-depletion ratio of pressure cores-BRU No. 340

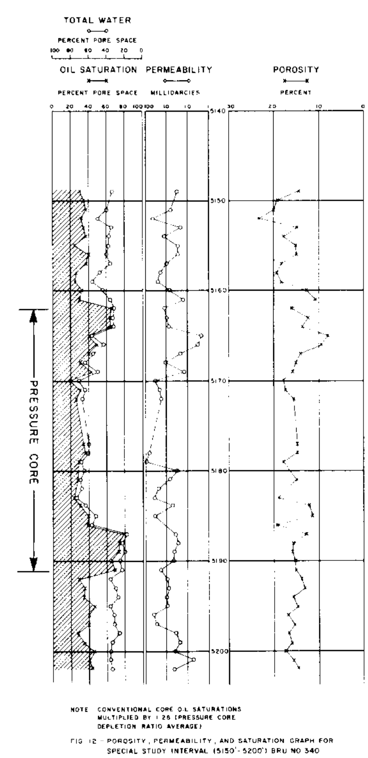

Figure 12 - Porosity, permeability and saturation graph for special study interval (5150'-5200') BRU No. 340