PROPOSED SOUTH JUSTIS UNIT

TECHNICAL COMMITTEE REPORT

JUSTIS BLINEBRY AND JUSTIS TUBB/DRINKARD FIELDS

LEA COUNTY, NEW MEXICO

BEFORE EXAMINER CATANACH
OIL CONSERVATION DIVISION
ARCO EXHIBIT NO. 20
CASE NO. 10552, 10553, 10554

TABLE OF CONTENTS

TABLE OF CONTENTS
(Continued)

Tables **Page**

Figures

TABLE OF CONTENTS
(Continued)

TABLE OF CONTENTS
(Continued)

TABLE OF CONTENTS
(Continued)

TABLE OF CONTENTS
(Continued)

INTRODUCTION

Efforts to unitize the Justis Blinebry and Justis Tubb/Drinkard Fields in southeastern Lea County, New Mexico, for the purpose of conducting waterflood operations, have been ongoing since 1984. A Technical Committee was formed and elected to hire a local consulting firm, T. S. Hickman and Associates, to conduct a feasibility study of secondary recovery operations in the Justis fields. The Hickman report was published in August 1987 and Hickman recommended forming two units, the North Justis Unit and the South Justis Unit. Based on that recommendation, ARCO announced in February 1988 its intention to expedite the formation of the proposed South Justis Unit. A meeting with working interest owners was held in March 1988 and a five-part charge to the Technical Committee was approved. Since that time, ARCO has conducted a study to supplement the Hickman feasibility study and to address the charges made to the Technical Committee.

The Technical Report for the proposed South Justis Unit is attached. The geological characteristics of the Blinebry and Tubb/Drinkard are similar due to similar depositional environments. The major differences are that the Blinebry is 200' thicker than the Tubb/Drinkard and covers a broader area than the Tubb/Drinkard. Correlating individual zones on logs from both reservoirs proved to be very difficult over two to three 40-acre well locations. As is typical with other carbonate reservoirs, individual pay members are continuous only over limited distances.

A data base was established with yearly production statistics from 1957 through 1989 for each well completed in the Justis Blinebry and Justis Tubb/Drinkard. The plots generated from the data base helped address questions such as water and gas production from the Blinebry. No evidence of a strong water drive exists in the Blinebry although cumulative water production exceeds 15 MMBW. Approximately 12% of the wells located along the western and southern edges of the structure have recovered 40% of the water but only 16% of the oil. The evidence suggests that a weak edge water drive exists in some zones, but that flooding operations will not be adversely affected.

The Blinebry has produced approximately 12 BCFG more than the volumetrically calculated original gas in place. A data base of production statistics for the overlying Justis Glorieta gas wells was created. Plots based on this data indicate that some Blinebry wells which were perforated between 5000' and 5100' may have been influenced by wellbore communication with the Glorieta.

Seven nearby Clearfork waterfloods that are well documented have been surveyed. The compiled data became the basis for reserve recovery estimates and production forecasts under two development plans. The expected secondary to primary ratio (S/P) for 80-acre line drive development is 0.85:1 and the reserve estimate is 22 MMBO. The S/P ratio for 40-acre five-spot development is 1.15:1 and the overall reserve estimate is 34 MMBO. Flooding with 80-acre line drive patterns is characterized by low total injectivity, delayed responses, a low peak rate that does not occur for more than 20 years after injection begins, high operating costs, and marginal economics. Infill drilling to 20 acres and flooding with 40-acre five-spots is characterized by higher unit injectivity, quicker response time, a higher peak rate, a higher initial rate due to the recovery of additional primary reserves, and more favorable economics.

The two development plans require capital investments of $34.0MM ($1.55/BO) for 80-acre line drive patterns and $69.7MM ($2.05/BO) for 40-acre five-spots. Generic AFIT project economics for the 80-acre line drive development show a present worth discounted at 10% of -$13.8MM. For the 40-acre five-spot plan, the PW_{10} is $44.6MM. The development plans utilized by most of the operators of other Clearfork floods include infill drilling to 20-acre spacing.

A table of possible participation parameters is included in this study. Insufficient tract working interest ownership data has been received to generate accurate participation parameters by working interest owner.

CHARGE TO THE TECHNICAL COMMITTEE

PROPOSED SOUTH JUSTIS UNIT

A. Prepare a map of the proposed Unit Area with boundary lines showing each tract in the Unit.

B. Define the Unitized interval with a description of the upper and lower limits of the interval and with specific log markers from a certain well log adequately referenced.

C. Develop an improved recovery plan for the area along with the economics of such a plan for presentation to the Working Interest Owners.

D. Prepare a tabulation of values of the following parameters under the plan presented for each tract. The tract parameter values will be used for negotiating a Tract Participation Formula.

    1. Cumulative oil and gas production
    2. Current oil and gas production
    3. Remaining primary oil and gas reserves
    4. Improved recovery oil reserves
    5. Other parameters deemed necessary by the Technical Committee

E. Investigate and evaluate any other factors pertinent to allowing an improved recovery program to be carried out for the area.

AGREE:______________________

NAME:______________________

COMPANY:______________________

DATE:______________________

CONCLUSIONS

1. The Justis Tubb/Drinkard reservoir has similar porosity and permeability characteristics to the Justis Blinebry reservoir due to similar depositional environments. The major differences between the two are that the Blinebry is a thicker reservoir and has a greater areal extent than the Tubb/Drinkard.

2. The stratigraphy of the Blinebry and Tubb/Drinkard is a complex sequence of interfingering reservoir and non-reservoir dolomitic rock units. The reservoir units are generally discontinuous laterally between two to three 40-acre well locations. No evidence exists to support systematic vertical permeability.

3. The Justis Blinebry and Justis Tubb/Drinkard reservoirs originally contained approximately 207,950 MBO in the proposed South Justis Unit area. Through December 31, 1989, the cumulative production from these reservoirs was 28,693.8 MBO, 176,373.3 MMCFG, and 18,776.6 MBW.

4. Approximately 1668 MBO of primary reserves remain to be recovered from the Justis Blinebry and the Justis Tubb/Drinkard reservoirs. The ultimate primary recovery is 30,361 MBO, or 14.6% of the original oil in place (OOIP).

5. The cumulative water production from the Justis Blinebry area was 15,734.0 MBW through December 31, 1989. The 18 wells with the highest Blinebry water recoveries comprise 12% of all Blinebry wells and have recovered 40% of the water but only 16% of the oil. A partial edge water drive may exist along the southern and western flanks of the Blinebry structure, but it is not expected to adversely impact flooding operations.

6. The cumulative gas production from the Justis Blinebry through December 31, 1989 was 138.3 BCF and exceeds the volumetrically calculated original gas in place (OGIP) of 126.6 BCF. Evidence suggests that some wells completed near the top of the Blinebry may have communicated with the overlying Justis Glorieta gas field.

7. A study of seven mature and well-documented Clearfork waterfloods provides a basis to estimate reserves associated with various spacing densities and also a means to time rate the reserve recovery for economic evaluations.

8. The proposed South Justis Unit is quite similar to the other Clearfork waterflood projects reviewed, particularly Mobil's Russell (Clearfork 7000') Unit in Gaines County, Texas.

9. The expected secondary to primary ratio associated with flooding on 40-acre spacing is 0.85:1 and the secondary reserves are 22 MMBO.

10. The expected secondary to primary ratio associated with flooding on 20-acre spacing is 1.15:1 and the total recovery is expected to be 34 MMBO.

11. The estimated costs to develop the proposed South Justis Unit on 80-acre and 40-acre patterns are $34,035M ($1.55/BO) and $69,737M ($2.05/BO), respectively.

12. Due to low total injectivities and long response times, the economics of flooding on 80-acre patterns are unprofitable.

13. Infill drilling and flooding on 40-acre patterns is expected to result in additional primary recovery, shorter waterflood response times, higher peak rates, and better economics.

14. The unitized interval for the proposed South Justis Unit should extend from the top of the Justis Blinebry as defined by the NMOCD to the top of the Abo.

RECOMMENDATIONS

1. Compile an accurate list of working interest owners in each tract and begin immediate negotiations on a unit participation formula.
2. Prepare the proper instruments for unitizing the South Justis Unit and obtain the necessary federal, state, royalty owner and working interest owner approval to form the unit.
3. Conduct 20-acre infill drilling operations and waterflood the proposed South Justis Unit with 40-acre five-spot patterns. The infill wells should primarily be water injectors and conversions of old wells to injectors should be minimized.

RESERVOIR GEOLOGY

Summary

A geological study was undertaken to compare the reservoir quality of the Blinebry with that of the Tubb/Drinkard and to evaluate pay continuity. Based on log surveys and core descriptions, the lithologies of the two zones are very similar due to similar depositional environments. The Blinebry is about 200' thicker than the Tubb/Drinkard and is about one-half mile longer and wider. Attempts to correlate porous zones throughout the Blinebry and Tubb/Drinkard intervals over distances of two or three well locations were generally unsuccessful due to the complex sequence of depositional settings and subsequent modification by dolomitization. Several stick cross sections which show the original zones of completion and subsequent workover zones as well as two core descriptions are included in Appendix A.

Geological Analysis

The Justis Field is located in south central Lea County, New Mexico, on the Central Basin Platform. The field is an elongated north-south trending anticline which is about two miles wide and nine miles long. Figure 1A is a structure map contoured on the top of the Blinebry formation which shows the area of interest. At the Blinebry level, the field has about 250' of structural closure. Details of the lithology and stratigraphy have been reported by S. J. Mazzullo in a study conducted by Hickman and Associates (dated August 27, 1987).

The Blinebry-Tubb/Drinkard formations, which are of Leonard age (lower Permian), produce from a complex dolomite facies which has a gross thickness of about 1200'; the gross thicknesses of the Blinebry and Tubb/Drinkard are about 700' and 500', respectively. The sequence was deposited in a broad flat, shallow-shelf setting which persisted on the Central Basin Platform throughout Leonardian time. Subsequent to deposition, the area was deformed into the configuration as mapped. Deposition was controlled by fluctuating sea level conditions which probably began during Abo time and continued in this area throughout Leonardian and Guadalupian time. The resulting stratigraphic intervals consist of a complex sequence of reservoir and non-reservoir rock types. The primary facies are eolian, intertidal to supratidal, shallow subtidal, and deeper subtidal. The productive facies are the intertidal to shallow subtidal intervals; the other facies are tight non-reservoir rock types. The units combine to form a complex interfingering sequence of reservoir and non-reservoir rock types, such that the reservoir components are generally separated laterally and vertically from each other.

The reservoirs are primarily dolomites which were originally fine to medium grained calciclastics with primary porosity and permeability. The dolomitization process modified (increased or decreased) the original reservoir properties masking the original rock fabric. Reservoir conditions are similar across the area regardless of structural position and characterized as pinpoint biomoldic to leached matrix type porosity. Locally, the reservoir is enhanced by vugs and micro fractures. Reservoir distribution is generally discontinuous (except locally) in both lateral and vertical directions.

Log and Core Analysis

Electric logs, cores, and well samples were analyzed in the South Justis area in an attempt to better understand the issues of reservoir continuity and lithological differences between the Blinebry-Tubb/Drinkard formations. Figure 1A (Blinebry structure contour map) in Appendix A shows the location of a series of six East-West stick cross sections (labeled A-A' through F-F') which provide a framework for stratigraphic correlation as related to perforated intervals in the Blinebry-Tubb/Drinkard formations. Well sample and core descriptions were provided on selected wells by S. J. Mazzullo which are included in a report by Hickman and Associates (dated June 26, 1987). Two Blinebry cores, one from ARCO's Justis Federal #2 located in Section 11-T25S-R37E and the other from ARCO's Langlie Federal #2 located in Section 14-T25S-R37E, were described and are included (Figures 8A and 9A) in this report. Thin sections were also prepared from selected intervals of the core and are available for examination. Based on the analysis conducted by Hickman on the limited core data available, the average porosity is estimated to be 5.4%. The average permeability is 3 md with a range of .1 md to 50 md.

Pay Continuity

A series of E-W stick cross sections, hung stratigraphically, was constructed and shows the productive zones. Noted are the original completion intervals and subsequent workover zones. The original perforated intervals, generally considered to represent the better reservoirs, occur at various stratigraphic levels at different locations across the field. Reservoir continuity relationships can be determined by examining the series of E-W stick cross sections (Figures 2A through 7A) and mapping the various reservoir groups.

The stick cross sections were initially constructed to show the structural and stratigraphic framework, and originally included all formations from surface to TD with subsequent focus on the Blinebry-Tubb/Drinkard. The results showed that individual reservoir zones are only locally correlative and that they would not have communication laterally with other Blinebry-Tubb/Drinkard intervals more than one-quarter to one-half mile away. In addition, no evidence was found to suggest the existence of a systematic fracture network also precluding vertical communication between reservoir units. It was also concluded that, in any given wellbore, the better reservoir intervals were properly evaluated and included in the original completion programs. Generally, subsequent workover projects produced only a fraction of the oil recovered from initial completion work and are generally characterized by fairly rapid decline rates.

All rock samples and log data indicate the Blinebry and Drinkard formations to be very similar lithologically. The two dolomite units are separated from each other by the Tubb formation which is described as a sandy dolomite. In both formations, the reservoir units are encased in tight dolomite or dolomitic limestones which contain varying amounts of anhydrite. The significant difference between the Blinebry formation and the Tubb/Drinkard formation is the extent of reservoir development which controls the limits of productivity. The Tubb/Drinkard reservoirs are not as well developed as the Blinebry reservoirs. The Tubb/Drinkard Field limits range from 1/2 to 1-1/2 miles wide by 6-1/2 miles long, whereas the Blinebry Field ranges from 1-1/2 to 2 miles wide by 9 miles long. The cumulative recovery from the Tubb/Drinkard is significantly less than that of the Blinebry.

Conclusions

A preliminary geological evaluation has been conducted which provides a structural and stratigraphic understanding of the South Justis area. Further geological studies are planned as the unitization efforts proceed. This phase of the evaluation involved approximately 1/4 of the 200 wells in the subject area. Conclusions of the preliminary evaluation are:

(1) The stratigraphy is a complex sequence of interfingering reservoir and non-reservoir dolomitic rock units.

(2) The reservoir units are generally laterally discontinuous, except locally, with no evidence to support systematic vertical permeability.

(3) The best reservoirs are generally included in the original completion interval, disregarding reservoir pressure decline.

(4) The lithologies of the Blinebry and Tubb/Drinkard units are very similar due to similar environments of deposition.

(5) The Blinebry reservoirs are 200' thicker with a larger areal distribution than those in the Tubb/Drinkard.

PRIMARY PERFORMANCE

Yearly oil, water, and gas production data from 1957 (year of discovery) through 1989 for each well in the entire Justis Blinebry and Justis Tubb/Drinkard Fields were entered into a database. Table 1 lists yearly oil, gas, and water production by reservoir for wells in the proposed unit area. Table 2 lists the same information for the combined reservoirs. Table 3 lists cumulative production data through 1989 by reservoir, operator, and well for the South Justis Unit.

Figures 1, 2, and 3 are historical plots of oil, gas, and water production for the Blinebry, Tubb/Drinkard, and combined reservoirs, respectively. There are 123 active Blinebry and Tubb/Drinkard completions currently in the unit. The cumulative production through December 31, 1989 from the tracts in the proposed unit is 28,694 MBO. The remaining primary oil (from January 1, 1990) is 1668 MBO. The ultimate primary oil recovery from the area in the proposed unit should be 30,361 MBO. Hickman's volumetrically calculated OOIP for all of the South Justis area (209,540 MBO) was reduced using the same primary recovery factor (0.146) to 207,952 MBO. Table 4 summarizes the primary performance of the tracts in the proposed unit.

Based on the results of a regional Clearfork study that will be presented later in this report, a primary recovery efficiency of ±15% under 40-acre development is a reasonable recovery for a Clearfork reservoir and verifies the accuracy of Hickman's volumetric OOIP. An attempt was made to verify the OOIP with a material balance but the results were inconsistent and are not considered a reliable indicator of the OOIP. Factors which may make utilizing material balance equations an inadequate tool to describe the Justis reservoir include poor pressure decline data, water influx data, and gas production data. Also, most material balance models assume a radial reservoir which is not applicable at Justis.

BLINEBRY WATER PRODUCTION

Significant water production (15.7 MMBW cumulative as of January 1, 1990) from the Blinebry in the South Justis area has been observed. In 1989, the average water production rate from the Blinebry in the unit area was 1078 BPD, or only about 9 BPD/well. Most of the water has been produced along the western and southern edge of the structure (Figure 4). Table 5 ranks the cumulative water produced by the top water producing wells with the cumulative oil produced and provides the running totals. The top 12% of the wells which have recovered the most water (18 of a total of 154 wells in the field) have produced 40% of the total water cumulative (6.4 MMBW) but only 15.7% of the total oil cumulative (3.4 MMBO). A plot of this data is presented in Figure 5.

A strong edge water drive does not appear to exist. A strong edge water drive would have exhibited pressure support and a gradation in water cut and cumulative up the flank of the structure. Also, substantially higher current water rates would have been observed if a strong water drive existed. Tubb/Drinkard production below the Blinebry has not been affected by a strong water drive. The producing histories suggest that water is encroaching into some Blinebry wells through individual stringers along the western and southern edges of the reservoir. This is not expected to adversely impact potential waterflood operations.

BLINEBRY GAS PRODUCTION

T. S. Hickman's study reported that the Blinebry in the South Justis area had produced more gas than was volumetrically possible (page 12 and Table 7, Volume I). Based on Hickman's volumetric OOIP (154,047 MBO) and the original gas-oil ratio (822 SCF/STB) for the Blinebry, the original solution gas in place should be 126.6 BCF. The Blinebry has produced 138.3 BCF as of January 1, 1990 from the unit area.

PVT evidence suggests that a gas cap did not originally exist. The estimated original reservoir pressure of 2500 psig is based on initial pressure tests of the discovery wells. The bubble point pressure determined from a recombined sample from Gulf's Learcy McBuffington #6 is only 2170 psig which indicates an undersaturated reservoir.

To explain the excessive gas production from the Blinebry, Hickman suggested the formation of secondary gas caps shortly after development began and/or wellbore communication with an overlying gas zone, the Glorieta formation. A study was undertaken to evaluate the relationship between the Glorieta and the excessive gas production from the Blinebry. Fifteen Glorieta completions have been reported along the Justis structure (Figure 6) in the unit area. The total cumulative production from these wells through December 31, 1989 is 64 BCF. Individual decline curves for each Glorieta well showing gas, water, and oil production along with tubing pressures (Appendix B, Figures 1B through 15B) were generated. Histories of the Blinebry wells offsetting the Glorieta wells were compiled and summaries of stimulations were added to the production plots.

In some instances, a correlation appears to exist between the addition of perforations between 5000' and 5100' in a Blinebry well and a change in the production decline and/or pressure decline in the nearby Glorieta well. Examples include ARCO's Eaton B #1, Chevron's Ramsay F #3, and El Paso's Langlie #1. Since numerous Blinebry wells have been completed near the top of the zone, it is possible that Glorieta production could be a factor behind the apparent excessive Blinebry gas production. The apparent communication of the Blinebry and the Glorieta in individual wellbores will influence the completion techniques and injection well design procedures in secondary operations.

A higher OOIP than the volumetrically derived value could be an alternate explanation for the large Blinebry gas production. Material balance calculations, although derived from insufficient data, suggest that the OOIP in the Blinebry is greater than the volumetrically calculated OOIP which could account for the extra gas production.

REGIONAL CLEARFORK STUDY

Summary

Several West Texas Clearfork waterfloods on the Central Basin Platform close to Justis were studied to evaluate the technical success of waterflooding the Clearfork, which correlates to the Blinebry, Tubb, and Drinkard in southeast New Mexico. The seven units for which the most information was available were Amoco's Northeast Prentice Unit, Chevron's C. A. Goldsmith Unit, Exxon's Fullerton Clearfork and Robertson Clearfork Units, Mobil's Russell (Clearfork 7000') Unit, Shell's Flanagan Unit, and Unocal's Dollarhide Clearfork Unit (Appendix C, Figure 1C). Each Unit was characterized and compared to the proposed South Justis Unit. Mobil's Russell Unit appears to be most like the South Justis Unit.

A key correlation was developed relating 40-acre primary recovery efficiency to secondary/primary ratios for 20- and 40-acre spacing (Figure 19C). Approximately 4.4 MMBO of reserves around the edge of the proposed unit will not be available for recovery because peripheral development is not justified. For the South Justis Unit, the expected primary recovery is 30.4 MMBO, or 14.6% of the OOIP. The expected S/P ratios and recoveries are 0.85 (22 MMBO) for 40-acre spacing and 1.15 (34 MMBO) for 20-acre spacing. Time rating curves (Figure 21C) were also developed for 20- and 40-acre spacing and incorporated into the unit forecasts of performance.

Introduction

The South Justis Field reservoirs (Blinebry and Tubb/Drinkard) are similar in age and lithology to a number of Clearfork reservoirs in West Texas. Several of these West Texas reservoirs have been waterflooded and infill drilled. There is enough performance information to suggest that these reservoirs are somewhat predictable even though their reservoir properties, operations, and performance have varied considerably. Based on correlations developed from these other floods, a reasonable estimate for the waterflood and infill drilling performance and for related reserve recovery for the proposed unit has been determined.

The South Justis Blinebry and Tubb/Drinkard Fields in the proposed unit have an estimated OOIP of 208 MMBO. Nearly 31 MMBO, or 14.6% of the OOIP, should be produced under 40-acre primary development. The following study shows that 22 MMBO of additional recovery, or 10.6% of the OOIP, is the expected benefit from waterflooding on 40-acre spacing. Also, full 20-acre development under secondary operations should increase recovery by an additional 12 MMBO, or 5.8% of the OOIP.

Discussion

The Justis Field Blinebry and Tubb/Drinkard reservoirs are very difficult to describe physically because both continuity and the relationship between porosity and permeability, which are critical in characterizing the reservoir, vary too widely to define accurately on a reservoir-wide basis. Because of the difficulty of using reservoir parameters to project the secondary and infill drilling project performance, it was determined that a regional study of the Blinebry and Tubb/Drinkard (Clearfork) reservoirs would provide the most reliable indication of how the South Justis project would perform.

Data Collection

As many as 17 Clearfork projects were identified with various levels of secondary operations and infill drilling. A number of these projects were eliminated because waterflooding was implemented too recently or the nature of the project made the data difficult to use and compare with other projects. As a result, seven projects were used and studied in great detail and are reviewed in this discussion. The seven projects that were utilized, as well as the proposed South Justis Unit, are shown geographically on Figure 1C.

Once the key projects were selected, the parameters that would be used to characterize the reservoirs and related operations were identified. The projects were characterized using three general categories, namely: reservoir description, production performance, and operating scheme.

The reservoir description parameters included basic data such as net pay, average porosity, and permeability as well as more interpretive data, such as vertical permeability variation, continuity, and aquifer contribution. Also, reservoir fluid and end-point saturation information was obtained whenever it was available. The sources for this data includes: SPE papers, working interest owner reports, Secondary Recovery Hearings from the TRC, and direct contact with the operator. Generally, the reservoir parameters vary considerably from project to project and cannot be relied on for performance projections. Not only are the reservoirs themselves varied but the methods used to generate the data no doubt varied from project to project. Figures 2C through 6C summarize the important reservoir data for each project.

The second type of information assembled for this study was the production performance data. This data is the most valuable for two reasons: (1) it is the most reliable since these values are public record and not based on interpretation, and (2) it provides the best correlation among the projects for predicting waterflood and infill drilling results. All oil production and water injection data was compiled for the seven key projects from the beginning of water injection. Also, well count information was noted throughout the life of these waterfloods. Figures 7C through 10C summarize production characteristics of the various projects.

The last type of information extracted from the various sources was related to the operation of the projects. This includes details such as injection pattern, well spacing, and injection pressures, among other items. Observations regarding operation of the seven projects are reviewed later in this report.

Characterizing the Projects

Once all the data was collected, the performance of the units was characterized to determine if that performance could have been predicted accurately from pre-waterflood information. This characterization took the form of a dimensionless plot of recovery efficiency versus displaceable hydrocarbon pore volume injected. Figure 11C shows the performance history of the seven projects. It is apparent that all the projects are relatively mature and are performing well, with the possible exception of the Robertson Clearfork Unit.

To define the reserve benefits of waterflooding and infill drilling separately at Justis Field, it was critical to first determine these separate benefits for the seven projects in this study. Fortunately, Barbe and Schnoebelen with Exxon documented a detailed quantitative analysis of the separate benefits of waterflooding and infill drilling at the Robertson Clearfork Unit (JPT, December 1987). In their analysis, they segmented the ultimate production into the following categories: 40-acre primary, 40-acre secondary, 20-acre primary, 20-acre secondary, 10-acre primary, and 10-acre secondary recoveries. This was done by using a nonlinear regression analysis on the performance data. The validity of the regression was verified in this study and it appears to be reasonable. Once the ultimate contribution of each category was known, it was possible to generate the curves in Figure 12C which shows the performance of waterflooding and infill drilling separately. Using a similar approach for the remaining six projects yielded Figures 13C through 18C. Note that all the other projects were developed on 20-acre spacing except for two projects. The Flanagan Unit still remains on 40-acre spacing, and the C. A. Goldsmith Lease had very limited 10-acre development. While this technique appears to give reasonable results, it is an estimate. Even so, it is important to keep in mind that several of the curves in each of these figures are based on projections of historical data. For example, there was usually sufficient data to comfortably extrapolate by constant percentage decline analysis the recoveries from 40-acre primary, 40-acre secondary, and 20-acre secondary phases. The result of this effort provides characterizations of these seven projects which were used to develop a performance prediction model for all Clearfork projects.

The Prediction Model

To develop a predictive model, it was necessary to determine if any pre-waterflood information (i.e., reservoir data, primary production) consistently foretold waterflood and infill drilling performance. Primary oil production proved to be the most reliable pre-waterflood indicator of waterflood and infill drilling performance. Figure 19C shows the relationship between secondary to primary ratio (20- and 40-acre spacing) and 40-acre primary recovery efficiency. The two lines on the plot represent the best fit for the projects in this study, not including the Robertson Clearfork Unit. The Robertson Clearfork Unit was not included because the reservoir was much more discontinuous than the other projects' reservoirs, as evidenced by its very low primary recovery. The nature of the two lines on the plot suggests that a higher S/P ratio would be expected in the case of lower primary recovery. It is likely that these cases had lower initial reservoir energy compared to the high primary recovery cases which probably had a greater primary or secondary gas cap or aquifer support, which reduced the benefit for secondary operations. Also, reservoir discontinuities may have impacted recoveries.

Figure 19C can be used to forecast secondary reserves on any Clearfork project, including South Justis, where ultimate primary recovery efficiency is known. An exception to this would be a project with a particularly discontinuous reservoir, or one of poor quality. To determine the S/P ratio on 40-acre well development for the Justis Field, simply enter the X-axis at 14.6% recovery efficiency and read the S/P ratio associated with the 40-acre S/P ratio line. The S/P ratio is about 0.85 in this case. Using the same process on 20-acre spacing yields an S/P ratio of about 1.15. Note that the S/P ratios would be greater if the OOIP has been underestimated, and the ratios would be reduced if OOIP has been overestimated. Historically, Clearfork reservoir OOIP estimates have increased as projects develop.

To complete the estimate of secondary and infill drilling reserves, it was necessary to determine how much to expect from the primary recovery mechanism with 20-acre spacing. Once again, 40-acre primary recovery efficiency (RE) provides an indication of expected 20-acre recovery. Figure 20C reflects this relationship. Figure 20C might suggest that a higher 40-acre primary recovery efficiency would result in a higher 20-acre primary recovery efficiency. However, the projects with high 20-acre RE's were also those projects with 20-acre development on a reduced and selective scale. Only the better part of these units had infill drilling. Therefore, these properties showed higher RE's for the limited level of 20-acre development as compared to those units that were fully developed on 20-acre spacing. Since this study assumes full field development at the South Justis Field, it is necessary to weigh more heavily those projects (i.e., Robertson, NE Prentice) that also were fully developed on 20 acres. Based on Figure 20C, South Justis may expect a 2.5% RE from the primary mechanism on 20-acre spaced wells. If selective 20-acre development were implemented at Justis, the affected OOIP would be reduced, but the RE would improve because the best part of the reservoir would be developed.

The total primary production under 40-acre and 20-acre spacing for South Justis would be 17.1% (14.6% + 2.5%) of the OOIP. Using the 1.15 S/P ratio from Figure 19C for 20-acre spacing indicates the total secondary performance will yield 16.8% (14.6% x 1.15) of the OOIP. However, as was pointed out, 12.4% (14.6% x 0.85) of the OOIP could have been recovered by secondary operations on 40-acre spacing. Therefore, the difference in 16.8% and 12.4%, or 4.4% of the OOIP, yields an apparent incremental secondary recovery for 20-acre spacing. Based on the reservoir characterization plots, most of the projects recover no more than 33% of the OOIP. From the above analysis and the upper limit for overall recovery, the expected secondary recovery from 20-acre spacing is about 3.5% of the OOIP.

Time Rating Reserves

For South Justis, it has been shown that 40-acre primary, 40-acre secondary, 20-acre primary, and 20-acre secondary will provide estimated recoveries of 14.6%, 12.4%, 2.5%, and 3.5% of the OOIP, respectively (Table 6). The maximum overall recovery is estimated to be 33% of the OOIP. These reserves were time rated so that a revenue forecast could be generated for the economic analysis. A comparative analysis among all seven projects was done to determine which type of response, as seen in Figures 13C through 18C, might be expected at South Justis Field.

Prior to actually comparing the character of the oil recovery curves, there were two units that were considered the most likely to be the model for Justis: Dollarhide and Russell. The Dollarhide Unit was attractive because of its proximity to Justis Field while the Russell Clearfork Unit was attractive because many of its reservoir characteristics were similar to those of South Justis.

When the various curves were overlaid (Figure 11C), it was obvious that the Dollarhide Unit was not very representative of the group of projects, primarily because the early injection efficiency problems resulted in a very sluggish waterflood response. These injection containment problems were addressed in a Unocal study that justified an attempt to correct the problem. Apparently, the problem was corrected because the project is currently enjoying very good secondary and infill drilling response. Certainly water injection containment should be a priority at Justis Field.

The time rating of the Russell curves appeared to be one of the most representative of the group of projects as a whole. This, coupled with the reservoir similarities between the Russell Clearfork Unit and South Justis, suggested that the "Russell type" response would be most appropriate. Figure 21C illustrates the time rated responses to waterflooding and infill drilling as a fraction of total expected recovery based on the Russell Clearfork Unit response. Note that there are two 20-acre infill curves: one to represent concurrent waterflood and drilling projects and another to represent infill drilling delayed until after fill-up. Delayed drilling has no apparent advantage.

General Information

During the data gathering phase of this study, additional information was found that is worth mentioning in a qualitative fashion. First, all seven projects claimed to have limited or no aquifer support whatsoever as is the case with Justis. Also, the projects' operators claimed that no primary gas cap existed. It follows that solution gas drive was the predominant primary mechanism in the seven projects studied. However, at Justis, there has been a tremendous volume of gas produced either from a gas reservoir source connected behind pipe or at the top of the Blinebry structure. Regarding injection patterns, they varied between five spots and nine spots while two projects had a portion of the field with a line drive scheme. A directional permeability with a northeast-southwest orientation was mentioned in a few project studies and is expected at Justis. This was considered during the design of the South Justis waterflood pattern. Finally, it appeared that with most projects, the estimates of OOIP increased as time progressed and infill wells were drilled.

Conclusions

This regional study provides one approach to forecasting waterflood and infill drilling response in Clearfork reservoirs and particularly, Justis Field. The approach is supported by performance from seven mature and well documented Clearfork projects. A method is provided to determine the reserves associated with various levels of development and also to time rate the reserves for economic evaluations.

Using a value for OOIP of 208 MMBO for the South Justis area, an estimated 34 MMBO (16.4%) can be assigned to full unit 20-acre development.

The South Justis Blinebry and Tubb/Drinkard reservoirs are quite similar to the other projects reviewed in this study and should perform in the fashion this study predicts. The only important difference is the relatively large volume of gas produced in the Justis Blinebry Field. This may not be a problem if this gas has been produced behind pipe from the Glorieta reservoir as is currently believed. If this is the case, then a completion philosophy that addresses the gas channeling should resolve this issue.

SECONDARY FORECASTS

Two development plans were investigated during this study: 80-acre line drive and 40-acre five-spots. Hickman's normalized injectivity model (Figure 7) formed the basis for predicting how individual injectors would perform after injection began. Based on core analysis, an average KH of 485 md-ft is expected for a Blinebry-Tubb/Drinkard well. Since not all injectors will include the Tubb/Drinkard, a weighted average KH of 448 md-ft per well was used to estimate injectivity on a unit basis. The S/P and time rating curves provided by the regional Clearfork study (Figures 19C through 21C) became the basis for predicting the amount of secondary reserves and the timing of their recovery for both development plans.

An attempt to forecast the secondary response with a simplistic five-spot model was made and the results were too optimistic. Modeling carbonate reservoirs usually yields poor results due to optimistic sweep efficiencies built into the model and discontinuities in the reservoir.

80-Acre Line Drive

The Hickman study only addressed an 80-acre line drive development (Figure 8) in which there were 70 producers and 65 injectors. The calculated total pore volume of 48,305 acre-feet (Table 3, Volume I - Hickman Study), and fluid saturations were used to estimate a displaceable pore volume of 187,375 MRVB. Table 7 is the projected secondary recovery versus pore volume injected. The following reservoir parameters from PVT data were used to calculate a fill-up volume (75 MMRVB) and an ABAR (the ratio of the gas saturation at the time of waterflooding to the original oil saturation) of 0.4.

Boi = 1.4
Box = 1.2
Scw = 0.22
Sor = 0.28

The total KH for the unit's 65 injectors is 29,120 md-ft. The calculated initial injectivity (87.4 MBWPD) is greater than the proposed plant capacity (71 MBWPD for the 80-acre line drive case) and was reduced. Injectivity falls below plant capacity during the first year of waterflooding. An injection efficiency of 60% was assumed and the initial net injection is 42.6 MBWPD. Net injection was projected to decline to 19 MBWPD within four years with fill-up expected to occur in about 18 years.

The time rating plot in the regional Clearfork study forecasted insignificant secondary recovery on 40-acre spacing until almost 40% of the displaceable pore volume is injected (Figure 21C). This is projected to occur in about nine years. Data generated by a pilot test at the Central Drinkard Unit (which is about 25 miles north of Justis) was utilized to time rate the recovery of reserves (Figure 9). The two time rating forecasts closely resemble each other and validates the use of this technique.

A correlation between primary recovery efficiency and S/P ratio (Figure 19C) developed in the regional Clearfork study is the basis for the secondary reserve estimate. The primary recovery efficiency expected in the unit (14.6%) should result in an S/P ratio of 0.85, or 22 MMBO of secondary reserves for 40-acre spacing. Table 7 summarizes the details of the injection and production forecasts for 80-acre line drive patterns and Figure 10 presents the forecasts. The GOR profile in Figure 10 reflects the recovery of approximately 16 BCF of remaining primary gas during waterflood operations. Make-up water should satisfy the unit's injection requirements during the early life of the project. By the time 70% of the reserves are recovered, produced water should match injectivity (20 MBWPD) and make-up water should no longer be needed. Because Clearfork floods exhibit low injectivities on 40-acre patterns, peak rates are low and project lives are extended.

40-Acre Five Spot

Most of the waterfloods investigated in the regional Clearfork study are developed on 20-acre spacing and generally with 40-acre five spots. A similar infill program for the proposed South Justis Unit was investigated (Figure 11). After careful review of several plans of development, the Technical Committee recommended developing the unit on 20-acre spacing by drilling mainly new injectors. Because of efficiency and environmental concerns, converting old wells to injectors will be minimized.

Time rating of the reserves for 40-acre five-spot patterns is based on the upper curve of the regional study forecast (Figure 21C). There should be 102 injectors and initial injectivity is estimated to be 137 MBWPD. Most injection needs will be met with make-up water. Injection efficiency is predicted to be 85% with fill-up occurring in about five years. Table 8 summarizes the injectivity and recovery forecasts for 40-acre five-spot patterns and Figure 12 presents the forecasts. The four proposed infill producers are expected to produce 50 BOPD per well initially (based on production results from other Clearfork floods) and increase overall unit production by ±200 BOPD. The GOR for the new wells should be approximately 5000:1 and the expected gas recovery during secondary operations for all wells is 42 BCF.

The injection plant for the 40-acre five spot case is designed to supply 123 MBWPD at 1500 psig discharge pressure to the Unit. For 40-acre five-spot development, three multi-stage centrifugal pumps with 1500 HP electric motors will be utilized. The expected initial injectivity of the unit of 137 MBWPD decreases to less than 100 MBWPD within one year of startup. The plan is designed to economically meet injection needs of the unit during startup and to provide a back-up pump once injectivity has stabilized.

Mobility Ratio

The mobility ratio (M) is a ratio of the relative permeability to viscosity ratio of the displacing phase to the displaced phase and can be used to predict the success of a waterflood. No relative permeability data has been gathered at Justis. Based on correlations, the mobility ratio is estimated to lie in a range of 0.6 and 1.0. Mobility ratios less than 1.0 are considered favorable for waterflooding.

ECONOMICS

Uninflated economic projections were made for both development plans using the costs which are provided later in this report. The results conclusively demonstrate that infill drilling and flooding on 40-acre five-spots can be a very profitable investment. The Clearfork has a proven record of successful secondary recovery operations. However, due to the heterogenous nature of the reservoir rock, infill drilling on 20-acre spacing will be essential to an economical project. Closer spaced wells result in higher injection rates into the reservoir and quicker fill up, a higher production rate as infill wells recover additional primary reserves, quicker response times and a higher peak response rate, improved sweep efficiencies, better conservation of resources, and prudent management of assets in the field.

Cash flow projections for both development plans are shown in Appendix D with 100% working interest and 87.5% net revenue interest. The following assumptions were made:

Severance Taxes	3.75%
Ad Valorem Taxes	3.54%
Oil Price	$18.00/BO
Gas Price	$2.00/MCF
Overhead	$400/well/month
Operating Cost	$2000/well/month - producers $500/well/month - injectors
Water Cost	8¢/BW
Unitization	1-1-91
Initial Injection	1-1-92

Projections were made for non-unitized primary operations and for unitized operations. The difference between the two is the incremental cash flow for secondary recovery operations. The incremental economics for 80-acre line drive and 40-acre five-spot development are the following:

	80-Acre Line Drive	40-Acre Five-Spot
Total Cost (MM$)	34.00	69.70
Incremental Reserves (MMBO)	22.00	34.00
Development Cost ($/BO)	1.55	2.05
Investor's Rate of Return (%)	2.90	15.50
Expected Payout (Years)	29.63	8.15
Expected Present Worth (M$)		
As of 1/1/91 (AFIT)		
Undiscounted	41,093.5	218,213.6
At 6%	-16,802.2	78,523.6
At 10%	-24,389.8	34,050.3
At 15%	-26,628.1	2,409.6
At 25%	-26,060.9	-25,642.7

DEVELOPMENT COSTS

New Wells, Workovers, Conversions

The estimated cost to develop both the Blinebry and Tubb/Drinkard reserves (22 MMBO) in the unit on 80-acre line drive patterns is $34,035M, or $1.55/BO. The estimated cost for 40-acre five-spot development (34.0 MMBO) is $69,737M, or $2.05/BO (Table 9). Generic workover procedures, WIW conversion procedures, and drilling prognoses are included in Appendix E along with their cost estimates. Due to the lack of good geological data, cores are planned for five wells and repeat formation tests are planned for 20 wells. A suite of modern porosity and resistivity logs are planned for new wells. Also, all wells will be tested for casing integrity and repaired as needed.

For comparison purposes, the estimated cost to develop the Blinebry is 90-95% of the cost to develop both the Blinebry and Tubb/Drinkard depending on the waterflood pattern (Table 10). The latest cumulative production data from the proposed unit area (Blinebry - 20.9 MMBO, Tubb/Drinkard - 7.8 MMBO) suggests that the Tubb/Drinkard contains approximately 27% of the recoverable reserves, assuming that the recovery efficiencies and production lives are the same. On 20-acre spacing, the estimated overall recoverable reserves are 34 MMBO. Approximately 27%, or 9.2 MMBO, are estimated to be recoverable from the Tubb/Drinkard. The incremental cost to develop those reserves on 40-acre five-spots is $4533M, or 49¢/BO.

Facilities

Preliminary designs were centered around four plans of development: (1) 80-acre line drive, (2) 80-acre five-spot, (3) 40-acre five-spot/80-acre line drive, and (4) 40-acre five-spot. Options 2 and 3 were not viable because of their inefficiencies and lack of flexibility. The cost summaries for two cases are shown in Figure 1F. Optional items (Figure 2F) include positive displacement pumps, a filtration system, and a spare pump rotor. No optional equipment was included in the economics. The cost estimate to equip each producing well is $46.3M (Figure 3F).

Once the project is approved and all governmental approvals have been obtained, final design, equipment selection, bid awards, equipment fabrication, and facility installation will take about one year (Figure 4F).

Injection Water

Most of the water can be supplied by either Texaco's Jal Salt Water Supply System or Capitan Enterprises' West Texas Water Supply System. Texaco's Jal system appears to be the most viable option. However, no negotiations have been undertaken with any water suppliers. The injection system will also utilize produced Blinebry and Tubb/Drinkard water along with water from the Fusselman. Initially, Blinebry, Tubb/Drinkard, and Fusselman water sources should provide 3,000-5,000 BWPD. Analysis of all of these waters indicates they are all compatible (Figure 13). Presently, Blinebry and Tubb/Drinkard production is commingled in numerous wellbores and the waters are compatible.

Texaco's Jal system can supply 120 MBWPD for approximately 8¢/BW. For 40-acre five-spot development, initial injectivity for the reservoir (137 MBWPD) is expected to exceed the produced water plant capacity (123 MBWPD) for the first three months of injection. After that, plant capacity exceeds the injectivity and the need for large volumes of Jal water should decrease. The line to Texaco is sized to handle 120 MBWPD.

The Jal water system is utilized at the nearby Seven Rivers Queen Unit with good results. No filtration other than settling tanks upstream of the pumps and strainers at the wellhead are planned. Sand filters are not considered necessary and are not planned for the South Justis Unit.

Engineering Design and Construction

1. Introduction and General Assumptions

Only start-up spares have been included (no long term or warehouse spares). An optional price will be provided for one (1) spare centrifugal rotating pump element. No office or dog house facilities have been provided at any of the batteries or the water plant with the exception of the field office. No sales gas distribution facilities have been provided, i.e., all gas sales will take place at the battery limits of the satellite batteries and the central battery. It was also assumed that no sweetening or compression will be required. None of the injection water supply, injection water distribution system, or production gathering system pipelines contain pigging facilities.

There has not been any consideration in the design of any of the pipeline and facility systems for any future tertiary recovery, i.e., handling of CO_2, etc. The pipeline and facility materials assumed in the estimate could handle CO_2 with little cost impact. However, no consideration has been given to the different flow and pressure requirements for the use of CO_2 in a tertiary recovery scheme. All materials of construction will meet NACE MR-01-75 requirements for the production equipment and gathering system as the hydrocarbon production contains 5,000 to 10,000 ppm of H_2S. There is a negligible CO_2 contained in the hydrocarbon production.

2. Field Office and Lay Down Yard

The office and adjoining lay down yard will be located south of and adjacent to State Highway 128 at the intersection of an existing lease road. The fenced lay down yard will be two acres in size.

3. Electrical Power Distribution System

Southwestern Public Service Company has a 115 KV transmission system and sub-station six miles northwest of the proposed Unit. It is assumed that Southwestern Public Service will serve the waterflood unit at 12.47 KV and provide service at the northwest corner of the unit. A single meter will be provided by the power company at that point. A 477 MCM ACSR express feeder will be run from the service point down to the water injection central battery facility. From that point, all new overhead distribution to all producing wells and production facilities will be provided. This will include all new transformers and services to producing wells. The field and plant loads will be segregated into three sections. The field will be separated into a northern and southern section and the central facility will be on the third section. A maximum 60 hp load at each producing well was assumed. For the largest load case at the water injection plant, 4500 hp was assumed (3-1500 hp machines). At this time, it is assumed that the system can handle the starting of these 3-1500 hp motors.

For operators on Unit property who operate facilities not included in the Unit, the existing power service will remain unchanged. The exception will be where a portion of the Operator's facilities are in the Unit and a portion are not. In this case, the portion belonging to the Unit will be disconnected and power will be supplied by the new Unit power distribution system. The estimate assumes power is existing at the Fusselman leases (ARCO's State "Y" and Wimberly leases for instance) for the new booster pumps.

4. Injection Water Supply to Plant (Texaco and Fusselman)

Produced water from Fusselman sources and the Unit production will be supplemented by a supply of salt water from Texaco or from Capitan Enterprises. The supply line from Texaco will require 25,300' of 10" polylined carbon steel piping to deliver this water from Texaco's tie-in point to the water injection plant. The line has been sized for 120,000 barrels of water per day. It was assumed that the supply pressure at the Texaco tie-in point is 125 psig and that no booster pumps will be required. Water from the Fusselman sources will be delivered in 8000' of 6" fiberglass pipeline. It was assumed that this water will be taken from an existing atmospheric storage tank and that booster pumps will be required to pressure the water from the Fusselman sources to the injection water plant. This line has been sized for 6000 barrels of water per day.

5. Injection Plant

This plant will be located approximately 1/4 mile south of State Highway 128 adjacent to an existing lease road. This plant will supply pumps and tankage to take injection water supply from atmospheric tanks up to 1500 psig discharge pressure for distribution to the injection wells. The plant will be manned eight hours per day, seven days per week.

There are three sources of injection water. The first source would be the produced water from the Unit. The second source would be from leases producing from the Fusselman. The balance of the water will be supplied from an outside supply system. Various laboratory tests have been conducted on these waters and it was assumed that there would be no compatibility problems with mixing these three waters.

The base estimate assumed the use of three centrifugal electric motor driven pumps operating in parallel. Additional cost savings could be realized by using two centrifugal pumps in parallel. However, due to flexibility considerations, it was thought that the three pump case would be more appropriate as the estimate basis. Optional prices have been provided for each case using the required number of 600 hp positive displacement pumps. The use of centrifugal pumps is recommended due to capital and operating cost considerations as well as potential pulsation problems. For the initial design rates, no spare pumps are included in the estimate scope. Pump discharges are designed for 900 ANSI.

A pump building will be supplied to house the injection pumps, booster pumps, plant switch-gear and injection water headers. The prime consideration in supplying a building was freeze protection. The building will be a steel frame building on a concrete slab. It will be uninsulated but will contain catalytic heaters for low ambient temperature conditions. A bridge crane and overhead doors will be provided for ease of pump maintenance. Suction and discharge headers will be located in trenches in the concrete slab. Three 50% booster pumps will be provided to supply NPSH requirements for the injection pumps.

Injection water lines will either be insulated or underground. No heat tracing has been provided. Above ground piping will be on sleepers. All piping will be I.P.C. carbon steel.

In the event of increasing water level in the tanks due to pump shut-down, etc., a level control system will gradually shut-off water supply from Texaco via an inlet control valve. If the level continues to rise in the tank, next the Fusselman will gradually be shut-off by an inlet control valve. Finally, the level controller will shut-off the water supply from the central battery by an inlet control valve which will cause produced water to overflow from the skim water tank to the emergency pit. This will allow lead time prior to production being shut-in from the Unit.

A single pad mounted 5 MVA transformer feeding a lineup of 5 KV Class motor control center was assumed for the water injection pumps. The motor control center would be housed in a separate room in the pump house. 480 volt distribution for all facilities would come from pole top mounted distribution transformers at each facility feeding a lineup of motor control and distribution equipment.

No filters have been included in the estimate. However, an optional price will be provided. Orifice meters will be provided on both north and south trunk lines. The plant will be fenced-in with the central battery. The plant will contain area lighting and will utilize local contracts. Tanks will be internally coated.

6. Injection Water Distribution System (To Wells)

The waterflood pumps will be centrally located in the Unit. For lines 6" and greater in size, carbon steel poly-lined pipe will be used with a design pressure rating of 2000 psig. For lines less than 6" in size, fiberglass pipe with a 2000 psig design pressure rating will be used. These lines will all be buried 3' deep. No cathodic protection system will be required provided, however, that anytime the steel trunk line's path crosses another steel line, a 32# magnesium anode shall be installed (cost approximately $100 per anode).

7. Injection Well Hook-up/Metering Assembly

Each injection well will be provided with a prefabricated injection assembly. It will utilize screwed fittings and a 1" Halliburton turbine meter with totalizer. Control of the flow of water to each injection well will be accomplished at satellite injection manifolds.

8. Central Battery

The central battery will receive produced water and crude from each of the satellite batteries in the Unit. It will be located one-quarter mile south of State Highway 128 adjacent to the water injection plant. It will be manned eight hours per day, seven days per week. The crude is assumed to be 32° API gravity. The allowable BS&W content is 1%. Two 100% trains of treating will be provided to handle the crude. In-line booster pumps will be provided to boost pressure as required from the gathering system. With the exception of the produced fluid booster pumps, the pumps in the central battery will not have installed spares.

The earthen fire wall around the three storage tanks are sized for 1.5 times the total tankage volumes. All piping inside the central battery limits will be above ground on sleepers and will be I.P.C. carbon steel construction. Production gathering and injection water trunk lines will run north/south through the pipeway between the injection plant and the central battery. Electrical power service, motor control, etc. is common with the injection plant. A description of the system is provided in the injection plant section. The area of the central battery and the injection water plant will be fenced. A remote vent with a berm is included. The plant will contain area lighting. Four H_2S monitors and alarms will be provided with remote annunciation to the field office. Instrument air compressor will be supplied. Sweet fuel gas will be brought to the central battery via 2000' of 2" carbon steel line from the ARCO Wimberly Lease. This fuel will be used for blanket gas and chemelectric treater fuel. The central battery will utilize local controls. In the event of an ESD of the central battery, pressure will be allowed to build-up back to the satellites which will in turn shut in the satellites and individual wells. All vessels and tanks will be internally coated. It is assumed that the crude and gas purchasers will take custody at the central battery limits. No compression or sweetening has been allowed for.

9. Satellite Batteries

Skid mounted satellite batteries will be located at seven locations throughout the field. Each satellite will handle production from approximately 20 wells. Each well will have individual flowlines (flowline costs are included in the production gathering system). Manual well tests will be performed with two test separators. Each separator will handle approximately ten of the wells. However, all wells will be manifolded to each test separator. The group separator and the two test separators will dump oil and produced water into the production gathering system trunk lines. No blowcase has been provided; however, booster pumps will be provided at the central battery which will boost pressure as required in the gathering trunk lines from the satellite batteries. The gas purchaser will take custody of the gas at each satellite battery limit. No compression or sweetening has been included in the estimate. A remove vent has been included. No area lighting has been included. Piping inside the battery limits will be carbon steel construction and mounted above ground on sleepers. The batteries will utilize local controls. Net oil computers will be provided on each separator. All steel piping inside battery limits will be IPC (internally plastic coated). A visual alarm light will be provided. An instrument air compressor has been included.

10. Production Gathering System

The production gathering system consists of individual flow lines from each well to a satellite battery and a trunk line system from the satellite batteries to the central battery. One trunk line gathers production from the northern satellite batteries and one trunk line gathers production from the southern satellite batteries.

11. Data Acquisition System

A solar powered RTU will be mounted outdoors at each satellite battery to provide for group separator oil and water volumes. An RTU will be mounted outdoors at the central battery to provide for water volumes, LACT data, and 32 digital alarm points, which will remotely annunciate at the field office. A PC and printer will be supplied at the field office for alarm annunciation. An auto-dialer will be provided for automatic dial-up during unmanned periods. The system is radio based. Automatic well testing is part of the RTU base level automation. A separate PC-based system is planned to monitor production pumps and provide pump-off controls.

UNIT BOUNDARY

The unit includes tracts which have a reasonable chance of contributing economically recoverable reserves to the waterflood. The tracts removed from Hickman's original study area have low primary recoveries or plugged wellbores that are not currently usable by the unit. Table 11 lists the tracts that were included. The revised unit area contains approximately 5360 acres. The following lists the tracts removed from Hickman's area of study:

Operator	Lease	Location	Cum. Recovery MBO (1-1-90)
UTP	2 States Stuart #1	L-11	24.1
Rhodes	Corrigan #1 (SWD)	M-11	8.4
Rice	SWD Well #B-12	G-12	0.4
Amoco	Langlie B #5 & #6	L,M-14	1.0
Westbrook	Buffington C #1	M-18	26.0
Leeser	El Paso Fed #2	N-23	75.7
UTP	Sunray #1	K-26	4.5
ARCO	Gregory Fed #1	I-35	37.8
Fina	Ginsberg #13	K-31	10.0
Texaco	Riggs A #3	C-1	24.6
Texaco	Riggs B #7	H-1	93.3
Maralo	Self #5 & #6	D,E-6	167.0
Total			472.8

UNITIZED INTERVAL

The vertical limits of the unitized interval will extend from the top of the Justis Blinebry Field to the base of the Justis Tubb/Drinkard Field. The NMOCD defined the top of the Justis Blinebry in 1961 as 4980' on the electrical log of Amerada's Ida Wimberley #4 (Figure 15). Previously, the NMOCD had designated the top of the Justis Drinkard at 5784' of the log from Amerada's Ida Wimberley #5. The base of the Tubb/Drinkard rests on top of the Abo at 6180' in the Wimberley #4.

PARTICIPATION PARAMETERS

Potential tract participation parameters are assembled in Table 1 of Appendix G. The active well count is as of March 1990. A cross reference between the South Justis Unit Technical Committee tract numbers and the Hickman study's tract numbers is provided. A participation parameter table sorted by working interest owner will be generated after the working interest of each individual tract has been collected and verified.

Individual tract production plots are included in Appendix H. Production histories (BOPD, BWPD, MCFD, and the GOR) were obtained from NMOCD supplied data and downloaded to a personal computer. A graphics package was used to plot data from 1970 through March 1990. The historical gas-oil ratios were used to calculate an oil production rate equivalent to 2 BOE per day per active well. A gas equivalency of 10 MCF/BO was used. The production history indicates a solution gas drive reservoir, and a constant percent decline analysis was performed to determine remaining oil and gas reserves for each tract. Results are tabulated on each of the tract production plots.

TABLES

TABLE 1
SOUTH JUSTIS UNIT
YEARLY PRODUCTION HISTORY BY RESERVOIR

RESERVOIR	YEAR	OIL (BBLS)	GAS (MCF)	WATER (BBLS)	UNIT
BB	1958	17,921	4,000	560	2
	1959	168,299	570,320	10,485	2
	1960	530,219	977,660	46,578	2
	1961	716,434	1,588,416	81,801	2
	1962	829,263	1,949,091	106,988	2
	1963	1,105,396	2,488,945	176,540	2
	1964	1,273,399	3,333,577	321,207	2
	1965	1,307,973	4,030,262	456,326	2
	1966	1,529,389	5,226,001	460,693	2
	1967	1,433,665	6,927,439	455,679	2
	1968	1,194,679	7,290,770	465,268	2
	1969	1,195,204	7,811,783	739,020	2
	1970	1,011,869	8,843,009	738,588	2
	1971	990,776	8,950,735	772,187	2
	1972	926,911	8,107,564	672,877	2
	1973	781,405	7,547,967	574,621	2
	1974	803,756	7,312,408	633,012	2
	1975	703,321	7,149,412	617,247	2
	1976	581,923	5,950,691	603,571	2
	1977	470,377	4,912,336	528,074	2
	1978	457,472	4,514,951	550,801	2
	1979	401,412	4,166,282	504,641	2
	1980	369,847	4,080,085	558,592	2
	1981	336,852	3,653,313	490,986	2
	1982	288,589	3,364,234	458,231	2
	1983	265,813	3,108,502	403,099	2
	1984	238,973	2,813,743	370,799	2
	1985	222,067	2,616,449	363,905	2
	1986	216,097	2,486,442	410,360	2
	1987	203,989	2,472,166	492,988	2
	1988	180,129	2,140,054	363,891	2
	1989	166,829	1,938,000	393,711	2
*TOTAL BB		20,920,248	138,326,607	13,823,326	
TD	1957	978	0	0	2
	1958	111,205	11,449	9	2
	1959	405,335	403,220	21,048	2
	1960	697,297	1,232,571	61,456	2
	1961	780,020	2,169,483	170,377	2
	1962	714,250	2,326,345	149,879	2
	1963	632,991	2,325,001	187,442	2
	1964	590,251	2,649,629	221,626	2
	1965	544,757	2,489,112	212,575	2

TABLE 1
SOUTH JUSTIS UNIT
YEARLY PRODUCTION HISTORY BY RESERVOIR

RESERVOIR	YEAR	OIL (BBLS)	GAS (MCF)	WATER (BBLS)	UNIT
TD	1966	530,926	2,292,735	237,088	2
	1967	442,380	2,154,574	226,566	2
	1968	312,040	1,931,284	226,950	2
	1969	213,933	1,409,216	178,681	2
	1970	124,660	903,256	177,759	2
	1971	133,093	1,079,379	127,894	2
	1972	118,587	1,006,486	119,535	2
	1973	121,986	1,200,549	108,328	2
	1974	109,816	967,439	80,347	2
	1975	93,247	857,689	92,006	2
	1976	123,245	1,404,235	163,295	2
	1977	108,158	1,204,671	133,817	2
	1978	104,050	1,141,245	130,066	2
	1979	80,365	975,299	132,181	2
	1980	83,454	835,026	169,841	2
	1981	83,324	742,827	146,939	2
	1982	77,350	706,724	171,460	2
	1983	74,721	655,493	172,506	2
	1984	70,994	618,691	214,708	2
	1985	68,793	479,779	193,220	2
	1986	64,403	563,668	182,645	2
	1987	58,066	484,176	173,094	2
	1988	50,259	396,278	197,908	2
	1989	48,623	429,144	172,070	2
*TOTAL TD		7,773,557	38,046,673	4,953,316	
TOTAL		28,693,805	176,373,280	18,776,642	

TABLE 2
SOUTH JUSTIS UNIT
YEARLY PRODUCTION HISTORY
COMBINED RESERVOIRS

YEAR	OIL (BBLS)	GAS (MCF)	WATER (BBLS)	UNIT
1957	978	0	0	2
1958	129,126	15,449	569	2
1959	573,634	973,540	31,533	2
1960	1,227,516	2,210,231	108,034	2
1961	1,496,454	3,757,899	252,178	2
1962	1,543,513	4,275,436	256,867	2
1963	1,738,387	4,813,946	363,982	2
1964	1,863,650	5,983,206	542,833	2
1965	1,852,730	6,519,374	668,901	2
1966	2,060,315	7,518,736	697,781	2
1967	1,876,045	9,082,013	682,245	2
1968	1,506,719	9,222,054	692,218	2
1969	1,409,137	9,220,999	917,701	2
1970	1,136,529	9,746,265	916,347	2
1971	1,123,869	10,030,114	900,081	2
1972	1,045,498	9,114,050	792,412	2
1973	903,391	8,748,516	682,949	2
1974	913,572	8,279,847	713,359	2
1975	796,568	8,007,101	709,253	2
1976	705,168	7,354,926	766,866	2
1977	578,535	6,117,007	661,891	2
1978	561,522	5,656,196	680,867	2

TABLE 2
SOUTH JUSTIS UNIT
YEARLY PRODUCTION HISTORY
COMBINED RESERVOIRS

YEAR	OIL (BBLS)	GAS (MCF)	WATER (BBLS)	UNIT
1979	481,777	5,141,581	636,822	2
1980	453,301	4,915,111	728,433	2
1981	420,176	4,396,140	637,925	2
1982	365,939	4,070,958	629,691	2
1983	340,534	3,763,995	575,605	2
1984	309,967	3,432,434	585,507	2
1985	290,860	3,096,228	557,125	2
1986	280,500	3,050,110	593,005	2
1987	262,055	2,956,342	666,082	2
1988	230,388	2,536,332	561,799	2
1989	215,452	2,367,144	565,781	2
TOTAL	28,693,805	176,373,280	18,776,642	

TABLE 3
SOUTH JUSTIS UNIT
CUMULATIVE PRODUCTION BY WELL
THROUGH 1989

OPERATOR	RESERVOIR	WELL	CUM OIL	CUM GAS	CUM WATER	UNIT	ARCO TRACT
AMER EXPL	BB	EPASO F 1	159,682	542,340	412,869	2	32
*TOTAL RESERVOIR BB			159,682	542,340	412,869		
*TOTAL OPERATOR AMER EXPL			159,682	542,340	412,869		
AMER HESS	BB	IDA WM 10	257,626	1,379,481	109,601	2	34
		IDA WM 11	171,837	1,009,263	50,393	2	34
		IDA WM 13	71,078	219,517	40,901	2	34
		IDA WM 14	70,434	603,573	33,067	2	34
		IDA WM 15	111,971	837,230	42,325	2	34
		IDA WM 16	79,544	750,604	43,307	2	34
		IDA WM 17	109,893	2,996,052	65,963	2	34
		IDA WM 9	146,296	1,808,762	74,950	2	34
		STUART 1	217,403	1,190,260	271,918	2	17
*TOTAL RESERVOIR BB			1,236,082	10,794,742	732,425		
	TD	IDA WM 10	73,899	229,818	26,157	2	34
		IDA WM 3	141,168	214,182	66,883	2	34
		IDA WM 4	167,984	696,189	230,357	2	34
		IDA WM 5	81,331	574,126	21,995	2	34
		IDA WM 6	126,679	637,633	52,204	2	34
		IDA WM 7	74,647	667,434	41,413	2	34
		IDA WM 8	100,646	478,294	29,447	2	34
		IDA WM 9	75,487	322,470	18,297	2	34
*TOTAL RESERVOIR TD			841,841	3,820,146	486,753		
*TOTAL OPERATOR AMER HESS			2,077,923	14,614,888	1,219,178		
AMOCO	BB	ST AJ 5	125,133	534,913	54,679	2	46
		ST AJ 6	95,204	200,299	88,685	2	46
*TOTAL RESERVOIR BB			220,337	735,212	143,364		
	TD	ST AJ 5	16,062	22,546	7,794	2	46
*TOTAL RESERVOIR TD			16,062	22,546	7,794		
*TOTAL OPERATOR AMOCO			236,399	757,758	151,158		
ARCO	BB	CARL AF 1	77,335	478,854	68,256	2	31
		CARL AF 2	96,420	293,998	87,055	2	31
		CARL F 1	158,592	2,092,022	55,020	2	41
		CARL F 2	196,857	2,289,458	77,355	2	41
		CARLSON 1	154,705	567,012	150,794	2	39
		CARLSON 2	105,160	499,036	186,669	2	39

TABLE 3
SOUTH JUSTIS UNIT
CUMULATIVE PRODUCTION BY WELL
THROUGH 1989

OPERATOR	RESERVOIR	WELL	CUM OIL	CUM GAS	CUM WATER	UNIT	ARCO TRACT
ARCO	BB	ETON NW14	158,459	417,761	65,582	2	10
		ETON NW15	89,004	275,627	192,316	2	9A
		ETON NW16	178,662	829,928	68,853	2	9A
		ETON NW17	73,263	275,166	85,263	2	9A
		ETON SE12	80,289	308,011	52,392	2	15
		ETON SE13	26,400	136,490	33,086	2	14
		ETON SW 8	197,564	1,425,722	56,869	2	12
		ETON SW 9	156,764	1,220,800	44,762	2	11
		ETON SW10	229,217	1,147,773	64,255	2	13
		ETON SW11	226,014	1,321,228	113,347	2	11
		FED 35 1	139,318	237,902	61,116	2	47
		JAL 2	252,947	1,056,404	90,495	2	5
		JAL 3	97,531	1,989,674	99,301	2	5
		JUST F 2	182,244	656,225	25,437	2	8
		JUST F 3Y	98,403	494,211	60,453	2	8
		LGL AF 1	244,496	1,136,217	36,062	2	20
		LGL AF 2	287,161	1,391,336	24,134	2	20
		LGL B 1	206,683	909,092	74,886	2	6
		LGL B 2	119,861	2,422,575	133,956	2	6
		LGL BF 1	121,386	512,589	9,796	2	19
		LGL BF 2	130,268	475,644	142,685	2	19
		LGL F 1	285,320	2,135,722	37,176	2	21
		LGL F 2	291,912	1,632,813	65,996	2	21
		STATE Y 3	120,229	2,046,708	24,591	2	43
		STATE Y 6	114,216	708,088	24,424	2	43
		STATE Y 7	171,307	1,382,706	13,957	2	43
		STATE Y 8	8,710	89,758	47	2	43
		STUART 1	100,110	327,712	86,551	2	4
		STUT AWN2	139,821	487,181	177,052	2	16
		WIMB WN 3	122,585	2,380,481	25,146	2	26
		WIMB WN 5	102,411	1,726,726	36,907	2	26
		WIMB WN 6	124,627	503,488	12,022	2	26
		WIMB WN 7	271,703	1,913,197	47,010	2	26
		WIMB WN 8	219,176	772,810	223,016	2	26
		WIMB WN 9	84,219	297,057	47,186	2	26
		WIMB WN10	146,131	554,720	376,596	2	26
		WIMB 2	240,458	2,513,060	93,847	2	29
		WIMB 3	240,168	2,318,326	115,783	2	30
*TOTAL RESERVOIR BB			6,868,106	46,651,308	3,567,502		
	TD	CARL AF 1	54,618	253,688	24,488	2	31
		CARL AF 2	45,033	111,141	167,944	2	31
		CARL F 1	75,097	238,426	2,882	2	41
		CARL F 2	80,267	354,705	36,802	2	41

TABLE 3
SOUTH JUSTIS UNIT
CUMULATIVE PRODUCTION BY WELL
THROUGH 1989

OPERATOR	RESERVOIR	WELL	CUM OIL	CUM GAS	CUM WATER	UNIT	ARCO TRACT
ARCO	TD	CARLSON 1	2,171	4,741	46,615	2	39
		ETON NW14	23,301	149,114	9,009	2	10
		ETON NW15	13,747	20,349	23,421	2	9B
		ETON SE12	26,273	60,588	7,888	2	15
		ETON SW 8	76,000	305,173	34,329	2	12
		ETON SW 9	17,752	127,230	11,072	2	11
		ETON SW10	43,399	327,121	52,122	2	13
		ETON SW11	77,319	371,885	42,201	2	11
		FED 35 1	14,238	0	0	2	47
		JA STUT 1	17,957	29,258	2,348	2	4
		JAL 2	166,346	1,201,533	69,162	2	5
		JAL 3	99,718	395,278	96,941	2	5
		LGL AF 1	31,651	64,543	14,506	2	20
		LGL B 1	86,068	497,710	43,935	2	6
		LGL B 2	73,008	635,928	47,819	2	6
		LGL BF 1	2,540	7,984	1,101	2	19
		LGL F 1	10,276	14,534	9,142	2	21
		STATE Y 5	69,083	1,148,078	908	2	43
		STATE Y 8	80,827	217,548	81,813	2	43
		STATE Y 9	27,910	573,941	309	2	43
		STATE Y10	17,661	321,787	15,852	2	43
		STUT AWN2	23,533	61,998	27,676	2	16
		WIMB WN 2	154,243	882,428	38,660	2	26
		WIMB WN 3	121,628	384,357	25,088	2	26
		WIMB WN 4	99,293	256,920	33,666	2	26
		WIMB WN 6	60,094	552,573	17,672	2	26
		WIMB WN 7	51,065	207,877	31,688	2	26
		WIMB WN10	586	2,076	1,765	2	26
		WIMB WN11	9,013	49,366	30,085	2	26
		WIMB 2	51,508	502,823	35,391	2	29
		WIMB 3	129,938	919,171	100,208	2	30
*TOTAL RESERVOIR TD			1,933,161	11,251,872	1,184,508		
*TOTAL OPERATOR ARCO			8,801,267	57,903,180	4,752,010		
BRUNO	BB	CARLB25 2	182,868	1,589,587	34,099	2	44
		CARLB25 5	161,947	1,169,338	13,950	2	44
		CARLB25 6	80,145	1,223,418	76,328	2	44
		CARLB26 5	184,615	692,157	98,177	2	40
		CARLB26 6	167,622	546,573	25,272	2	40
		CARLB26 7	39,903	108,152	48,458	2	40
*TOTAL RESERVOIR BB			817,100	5,329,225	296,284		
	TD	CARLB25 2	94,633	543,621	28,680	2	44

TABLE 3
SOUTH JUSTIS UNIT
CUMULATIVE PRODUCTION BY WELL
THROUGH 1989

OPERATOR	RESERVOIR	WELL	CUM OIL	CUM GAS	CUM WATER	UNIT	ARCO TRACT
BRUNO	TD	CARLB25 3	86,369	313,689	106,525	2	44
		CARLB25 4	169,137	613,460	73,182	2	44
		CARLB25 5	135,351	415,485	1,845	2	44
		CARLB26 5	74,613	297,847	156,008	2	40
		CARLB26 6	84,527	245,732	1,150	2	40
*TOTAL RESERVOIR TD			644,630	2,429,834	367,390		
*TOTAL OPERATOR BRUNO			1,461,730	7,759,059	663,674		
CHEVRON	BB	JA STUT 8	56,880	93,183	211,583	2	1
		L MCBUF 4	118,629	693,742	30,835	2	24
		L MCBUF 5	133,619	2,367,950	14,409	2	24
		L MCBUF 6	221,727	2,001,522	16,878	2	24
		L MCBUF 9	13,782	1,078,711	4,448	2	24
		L MCBUF10	163,301	916,879	29,136	2	24
		L MCBUF12	131,005	642,803	35,949	2	24
		L MCBUF13	187,879	2,543,080	39,282	2	24
		L MCBUF14	138,463	1,100,480	10,308	2	24
		L MCBUF15	20,422	1,954,705	9,979	2	24
		RAMSY B 1	70,327	167,475	464,713	2	50
		RAMSY B 6	217,097	588,241	124,927	2	50
		RAMSY B 7	196,701	748,043	198,260	2	50
		RAMSY B 8	196,336	887,181	73,192	2	50
		RAMSY B 9	100,810	560,439	209,517	2	50
		RAMSY B10	158,188	688,763	175,380	2	50
		RAMSY B11	93,149	432,718	337,937	2	50
		RAMSY B12	215,256	604,623	68,042	2	50
		RAMSY F 4	225,558	1,067,674	68,386	2	49
		RAMSY F 5	119,807	783,482	126,148	2	49
		RAMSY F 6	245,436	3,059,053	255,613	2	49
		RAMSY F 7	111,279	475,422	181,358	2	49
		RAMSY F 9	173,323	1,056,115	122,514	2	49
		RAMSY F10	212,939	470,332	250,717	2	49
		RAMSY F11	183,543	647,429	80,812	2	49
		RAMSY F12	127,338	413,260	128,711	2	49
*TOTAL RESERVOIR BB			3,832,794	26,043,305	3,269,034		
	TD	JA STUT 8	48,505	109,407	233,325	2	1
		L MCBUF 3	42,752	317,258	22,488	2	24
		L MCBUF 4	8,978	94,337	0	2	24
		L MCBUF 7	107,693	445,516	7,066	2	24
		L MCBUF10	114,466	538,846	10,838	2	24
		L MCBUF11	14,832	120,161	4,706	2	24
		L MCBUF14	11,952	58,968	3,783	2	24

TABLE 3
SOUTH JUSTIS UNIT
CUMULATIVE PRODUCTION BY WELL
THROUGH 1989

OPERATOR	RESERVOIR	WELL	CUM OIL	CUM GAS	CUM WATER	UNIT	ARCO TRACT
CHEVRON	TD	RAMSY B 6	53,166	108,350	52,793	2	50
		RAMSY B 7	148,290	668,052	63,852	2	50
		RAMSY B 8	132,634	528,655	17,508	2	50
		RAMSY B 9	18,573	25,633	1,212	2	50
		RAMSY B10	13,031	17,186	1,551	2	50
		RAMSY B11	6,980	8,016	4,791	2	50
		RAMSY B12	10,887	15,654	38,960	2	50
		RAMSY F 4	55,442	178,952	12,777	2	49
		RAMSY F 5	50,246	105,105	37,075	2	49
		RAMSY F 6	45,784	142,708	6,494	2	49
		RAMSY F 7	32,832	143,300	6,392	2	49
		RAMSY F 9	55,689	262,245	66,132	2	49
		RAMSY F11	20,764	218,096	3,312	2	49
		RAMSY F12	21,594	35,021	6,242	2	49
		RAMSY F13	26,289	104,772	73,535	2	49
*TOTAL RESERVOIR TD			1,041,379	4,246,238	674,832		
*TOTAL OPERATOR CHEVRON			4,874,173	30,289,543	3,943,866		
FINA	BB	GIBRG F 8	82,770	94,433	103,267	2	51
		GIBRG F 9	123,496	277,308	185,865	2	51
		GIBRG F10	123,624	265,419	124,514	2	51
		GIBRG F11	77,190	666,378	92,841	2	51
*TOTAL RESERVOIR BB			407,080	1,303,538	506,487		
	TD	GIBRG F 9	11,758	64,182	32,089	2	51
		GIBRG F11	55,462	121,580	32,132	2	51
*TOTAL RESERVOIR TD			67,220	185,762	64,221		
*TOTAL OPERATOR FINA			474,300	1,489,300	570,708		
PAC E	BB	CARLA23 1	21,310	70,232	49,063	2	27
		CARLB13 5	78,923	365,118	21,614	2	25
		CARLB13 6	112,388	709,483	98,210	2	25
		CARLB13 7	117,756	540,346	62,273	2	25
		CARLB13 8	7,616	63,019	27,622	2	25
*TOTAL RESERVOIR BB			337,993	1,748,198	258,782		
	TD	CARLB13 5	73,300	580,309	15,521	2	25
		CARLB13 8	5,648	54,007	10,223	2	25
*TOTAL RESERVOIR TD			78,948	634,316	25,744		
*TOTAL OPERATOR PAC E			416,941	2,382,514	284,526		

TABLE 3
SOUTH JUSTIS UNIT
CUMULATIVE PRODUCTION BY WELL
THROUGH 1989

OPERATOR	RESERVOIR	WELL	CUM OIL	CUM GAS	CUM WATER	UNIT	ARCO TRACT
TEXACO	BB	A COAT C8	38,435	719,116	14,655	2	35
		A COAT C9	13,808	363,029	11,260	2	35
		A COATC10	52,600	1,440,729	33,507	2	35
		A COATC14	113,413	1,389,908	35,800	2	35
		A COATC16	41,790	604,810	57,799	2	35
		A COATC18	190,302	1,046,057	102,755	2	35
		A COATC19	100,765	795,283	32,574	2	35
		A COATC21	67,629	539,144	7,574	2	35
		A COATC22	134,077	546,837	21,572	2	35
		A COATC23	139,163	742,382	34,201	2	35
		A COATC24	148,743	938,859	9,713	2	35
		A COATC25	91,554	572,981	14,106	2	35
		A COATC26	128,166	1,497,024	13,967	2	35
		A COATC27	144,111	2,888,834	95,845	2	35
		A COATC28	48,250	684,830	36,899	2	35
		A COATD03	110,722	414,875	28,323	2	36
		HOBBS A 6	142,704	442,467	56,599	2	45
		HOBBS A 7	153,465	400,355	101,350	2	45
		LCRUCS C1	303,983	1,546,594	256,785	2	28
		PENNEYF 6	50,200	93,503	13,651	2	37
		PENNEYF 7	55,222	87,605	46,924	2	37
		RIGGS B 6	147,303	702,407	225,406	2	52
		RIGGS B 8	136,946	511,461	286,356	2	52
*TOTAL RESERVOIR BB			2,553,351	18,969,090	1,537,621		
	TD	A COATC 6	4,183	174,347	5,182	2	35
		A COATC 7	9,981	58,181	12,397	2	35
		A COATC 8	86,899	176,781	67,825	2	35
		A COATC 9	101,948	298,959	17,790	2	35
		A COATC11	281,804	1,943,939	244,156	2	35
		A COATC12	242,582	1,610,270	521,836	2	35
		A COATC14	181,826	813,406	44,149	2	35
		A COATC16	154,507	1,364,263	77,701	2	35
		A COATC18	70,631	223,522	50,773	2	35
		A COATC19	24,617	296,586	11,371	2	35
		A COATC21	238	1,003	21,605	2	35
		A COATC23	94,821	345,080	21,686	2	35
		A COATC24	56,417	236,601	4,503	2	35
		A COATC25	93,107	646,866	11,617	2	35
		A COATD 2	137,800	1,912,292	393,373	2	36
		HOBBS A 6	77,686	336,226	24,378	2	45
		HOBBS A 7	81,099	212,959	37,547	2	45
		L BUF B 2	1,497	2,723	2,325	2	38
		LCRUCS C1	93,403	246,872	27,713	2	28

TABLE 3
SOUTH JUSTIS UNIT
CUMULATIVE PRODUCTION BY WELL
THROUGH 1989

OPERATOR	RESERVOIR	WELL	CUM OIL	CUM GAS	CUM WATER	UNIT	ARCO TRACT
TEXACO	TD	PENNY F 4	18,961	19,632	14,505	2	37
		PENNY F 6	18,994	11,507	1,526	2	37
		RIGGS B 8	6,417	11,899	10,465	2	52
*TOTAL RESERVOIR TD			1,839,418	10,943,914	1,624,423		
*TOTAL OPERATOR TEXACO			4,392,769	29,913,004	3,162,044		
UN TEX	BB	BLOCKER 4	46,339	967,730	27,410	2	23
		BLOCKER 5	244,357	1,763,595	25,626	2	23
		BLOCKER 6	161,364	1,228,244	23,307	2	23
		BLOCKER 7	196,223	1,604,680	49,547	2	23
		BUFFTN B3	107,894	485,715	49,172	2	38
		BUFFTN B4	64,251	119,160	49,712	2	38
		CARL A 1	20,751	168,672	10,741	2	42
		CARL A 3	250,426	2,715,201	97,657	2	42
		CARL A 4	228,040	2,358,534	152,417	2	42
		CARL A 5	146,528	979,491	59,789	2	42
		CARL A 6	149,716	1,153,721	50,685	2	42
		CARL B 1	260,597	1,497,289	106,889	2	33
		CARL B 2	269,457	1,337,837	62,894	2	33
		GRERY AF1	133,314	364,668	314,550	2	48
		JUSTIS 1	133,057	434,781	22,235	2	7
		JUSTIS 2	122,989	817,718	24,484	2	7
		LGL B 1	362,020	2,142,775	124,872	2	22
		LGL B 2	348,696	2,780,473	129,601	2	22
		LGL D 1	213,508	678,068	350,889	2	18
		LGL D 2	165,912	444,285	370,634	2	18
		O STUART1	4,067	0	444	2	3
		O STUART2	78,631	253,857	177,507	2	3
		STUART 6	342,650	1,165,469	213,540	2	2
		STUART 7	274,758	521,493	81,972	2	2
		STUART 8	162,178	226,193	522,384	2	2
*TOTAL RESERVOIR BB			4,487,723	26,209,649	3,098,958		
	TD	BLOCKER 4	71,629	251,498	37,716	2	23
		BLOCKER 5	38,095	156,109	6,260	2	23
		BLOCKER 6	76,022	379,117	7,168	2	23
		BLOCKER 7	19,827	99,749	67,571	2	23
		BUFFTN B3	49,045	97,321	18,536	2	38
		BUFFTN B4	17,897	39,489	2,771	2	38
		CARL A 1	77,165	109,016	15,354	2	42
		CARL A 3	64,559	173,384	48,961	2	42
		CARL A 4	92,813	576,773	41,865	2	42
		CARL A 5	83,157	238,719	20,387	2	42

TABLE 3
SOUTH JUSTIS UNIT
CUMULATIVE PRODUCTION BY WELL
THROUGH 1989

OPERATOR	RESERVOIR	WELL	CUM OIL	CUM GAS	CUM WATER	UNIT	ARCO TRACT
UN TEX	TD	CARL AF 2	23,172	31,829	264	2	42
		CARL AF 6	24,519	230,648	607	2	42
		CARL B 1	61,706	360,511	30,622	2	33
		CARL B 2	124,686	428,220	26,949	2	33
		JUSTIS 1	79,303	201,937	19,600	2	7
		JUSTIS 2	65,272	171,907	16,521	2	7
		LGL B 1	88,232	240,260	10,579	2	22
		LGL B 2	52,852	104,591	28,081	2	22
		O STUT 1	5,380	7,548	430	2	3
		O STUT 2	23,742	98,664	76,412	2	3
		STUART 6	76,085	234,701	18,113	2	2
		STUART 7	95,740	280,054	22,884	2	2
*TOTAL RESERVOIR TD			1,310,898	4,512,045	517,651		
*TOTAL OPERATOR UN TEX			5,798,621	30,721,694	3,616,609		
TOTAL			28,693,805	176,373,280	18,776,642		

TABLE 4

SOUTH JUSTIS UNIT
PRIMARY RECOVERY SUMMARY
BLINEBRY AND TUBB/DRINKARD RESERVOIRS

Cumulative Oil Production (1-1-90)	28,693.8 MBO
Cumulative Gas Production (1-1-90)	176,373.3 MMCF
Cumulative Water Production (1-1-90)	18,776.6 MBW
Remaining Primary Oil (1-1-90)	1,668 MBO
Remaining Primary Gas (1-1-90)	17,981 MMCF
Ultimate Primary Oil	30,361 MBO
Ultimate Primary Gas	194,354 MMCF
Estimated Original OOIP	207,952 MBO
Primary Recovery Factor	.146

TABLE 5
SOUTH JUSTIS AREA
RUNNING TOTAL WATER & OIL CUMS (BBLS) FOR BLINEBRY WELLS RANKED BY HIGHEST CUM WATER PRODUCTION

UNIT	ARCO TRACT	OPERATOR	WELL	CUM WATER	CUM OIL	WATER % OF TOTAL	RUNNING TOTAL WATER	CUM % WTR	RUNNING TOTAL OIL	CUM % OIL
2	00	MARALO	MD SELF 6	694,300	80,068	4.41	694300	4.41	80068	.37
2	2	UN TEX	STUART 8	522,384	162,178	3.32	1216684	7.73	242246	1.13
2	50	CHEVRON	RAMSY B 1	464,713	70,327	2.95	1681397	10.68	312573	1.46
2	00	LEESER	EPASO F 2	463,425	75,759	2.95	2144822	13.63	388332	1.81
2	32	AMER EXPL	EPASO F 1	412,869	159,682	2.62	2557691	16.25	548014	2.56
2	26	ARCO	WIMB WN10	376,596	146,131	2.39	2934287	18.64	694145	3.24
2	18	UN TEX	LGL D 2	370,634	165,912	2.36	3304921	21.00	860057	4.02
2	4	ARCO	STUART 1	358,469	317,513	2.28	3663390	23.28	1177570	5.50
2	18	UN TEX	LGL D 1	350,889	213,508	2.23	4014279	25.51	1391078	6.50
2	50	CHEVRON	RAMSY B11	337,937	93,149	2.15	4352216	27.66	1484227	6.94
2	48	UN TEX	GRERY AF1	314,550	133,314	2.00	4666766	29.66	1617541	7.56
2	52	TEXACO	RIGGS B 8	286,356	136,946	1.82	4953122	31.48	1754487	8.20
2	22	UN TEX	LGL B 2	263,557	468,557	1.68	5216679	33.16	2223044	10.39
2	28	TEXACO	LCRUCS C1	256,785	303,983	1.63	5473464	34.79	2527027	11.81
2	49	CHEVRON	RAMSY F 6	255,613	245,436	1.62	5729077	36.41	2772463	12.96
2	49	CHEVRON	RAMSY F10	250,717	212,939	1.59	5979794	38.00	2985402	13.96
2	52	TEXACO	RIGGS B 6	225,406	147,303	1.43	6205200	39.43	3132705	14.65
2	26	ARCO	WIMB WN 8	223,016	219,176	1.42	6428216	40.85	3351881	15.67
2	2	UN TEX	STUART 6	213,540	342,650	1.36	6641756	42.21	3694531	17.27
2	1	CHEVRON	JA STUT 8	211,583	56,880	1.34	6853339	43.55	3751411	17.54
2	50	CHEVRON	RAMSY B 9	209,517	100,810	1.33	7062856	44.88	3852221	18.01
2	22	UN TEX	LGL B 1	199,758	568,703	1.27	7262614	46.15	4420924	20.67
2	50	CHEVRON	RAMSY B 7	198,260	196,701	1.26	7460874	47.41	4617625	21.59
2	9A	ARCO	ETON NW15	192,316	89,004	1.22	7653190	48.63	4706629	22.01
2	00	MARALO	MD SELF 5	187,282	86,696	1.19	7840472	49.82	4793325	22.42
2	39	ARCO	CARLSON 2	186,669	105,160	1.19	8027141	51.01	4898485	22.91
2	51	FINA	GIBRG F 9	185,865	123,496	1.18	8213006	52.19	5021981	23.49
2	49	CHEVRON	RAMSY F 7	181,358	111,279	1.15	8394364	53.34	5133260	24.01
2	3	UN TEX	O STUART2	177,507	78,631	1.13	8571871	54.47	5211891	24.38
2	16	ARCO	STUT AWN2	177,052	139,821	1.13	8748923	55.60	5351712	25.03
2	50	CHEVRON	RAMSY B10	175,380	158,188	1.11	8924303	56.71	5509900	25.77
2	00	TEXACO	RIGGS B 7	166,130	93,382	1.06	9090433	57.77	5603282	26.21
2	42	UN TEX	CARL A 4	152,417	228,040	.97	9242850	58.74	5831322	27.28
2	39	ARCO	CARLSON 1	150,794	154,705	.96	9393644	59.70	5986027	28.00
2	19	ARCO	LGL BF 2	142,685	130,268	.91	9536329	60.61	6116295	28.61
2	49	CHEVRON	RAMSY F12	128,711	127,338	.82	9665040	61.43	6243633	29.21
2	00	C RHODES	CORRGN 1	126,853	8,392	.81	9791893	62.24	6252025	29.25
2	49	CHEVRON	RAMSY F 5	126,148	119,807	.80	9918041	63.04	6371832	29.81
2	50	CHEVRON	RAMSY B 6	124,927	217,097	.79	10042968	63.83	6588929	30.82
2	51	FINA	GIBRG F10	124,514	123,624	.79	10167482	64.62	6712553	31.40
2	49	CHEVRON	RAMSY F 9	122,514	173,323	.78	10289996	65.40	6885876	32.21
2	30	ARCO	WIMB 3	115,783	240,168	.74	10405779	66.14	7126044	33.33
2	00	UN TEX	SUNRAY 1	114,258	4,555	.73	10520037	66.87	7130599	33.35

TABLE 5
SOUTH JUSTIS AREA
RUNNING TOTAL WATER & OIL CUMS (BBLS)
FOR BLINEBRY WELLS RANKED BY
HIGHEST CUM WATER PRODUCTION

UNIT	ARCO TRACT	OPERATOR	WELL	CUM WATER	CUM OIL	WATER % OF TOTAL	RUNNING TOTAL WATER	CUM % WTR	RUNNING TOTAL OIL	CUM % OIL
2	11	ARCO	ETON SW11	113,347	226,014	.72	10633384	67.59	7356613	34.41
2	34	AMER HESS	IDA WM 10	109,601	257,626	.70	10742985	68.29	7614239	35.61
2	33	UN TEX	CARL B 1	106,889	260,597	.68	10849874	68.97	7874836	36.83
2	51	FINA	GIBRG F 8	103,267	82,770	.66	10953141	69.63	7957606	37.22
2	35	TEXACO	A COATC18	102,755	190,302	.65	11055896	70.28	8147908	38.11
2	45	TEXACO	HOBBS A 7	101,350	153,465	.64	11157246	70.92	8301373	38.83
2	5	ARCO	JAL 3	99,301	97,531	.63	11256547	71.55	8398904	39.29
2	25	PAC E	CARLB13 6	98,210	112,388	.62	11354757	72.17	8511292	39.82
2	40	BRUNO	CARLB26 5	98,177	184,615	.62	11452934	72.79	8695907	40.68
2	42	UN TEX	CARL A 3	97,657	250,426	.62	11550591	73.41	8946333	41.85
2	35	TEXACO	A COATC27	95,845	144,111	.61	11646436	74.02	9090444	42.52
2	29	ARCO	WIMB 2	93,847	240,458	.60	11740283	74.62	9330902	43.64
2	51	FINA	GIBRG F11	92,841	77,190	.59	11833124	75.21	9408092	44.00
2	5	ARCO	JAL 2	90,495	252,947	.58	11923619	75.79	9661039	45.18
2	46	AMOCO	ST AJ 6	88,685	95,204	.56	12012304	76.35	9756243	45.63
2	31	ARCO	CARL AF 2	87,055	96,420	.55	12099359	76.90	9852663	46.08
2	9A	ARCO	ETON NW17	85,263	73,263	.54	12184622	77.44	9925926	46.42
2	2	UN TEX	STUART 7	81,972	274,758	.52	12266594	77.96	10200684	47.70
2	49	CHEVRON	RAMSY F11	80,812	183,543	.51	12347406	78.47	10384227	48.56
2	41	ARCO	CARL F 2	77,355	196,857	.49	12424761	78.96	10581084	49.48
2	44	BRUNO	CARLB25 6	76,328	80,145	.49	12501089	79.45	10661229	49.85
2	34	AMER HESS	IDA WM 9	74,950	146,296	.48	12576039	79.93	10807525	50.53
2	50	CHEVRON	RAMSY B 8	73,192	196,336	.47	12649231	80.40	11003861	51.45
2	9A	ARCO	ETON NW16	68,853	178,662	.44	12718084	80.84	11182523	52.29
2	49	CHEVRON	RAMSY F 4	68,386	225,558	.43	12786470	81.27	11408081	53.34
2	31	ARCO	CARL AF 1	68,256	77,335	.43	12854726	81.70	11485416	53.70
2	50	CHEVRON	RAMSY B12	68,042	215,256	.43	12922768	82.13	11700672	54.71
2	21	ARCO	LGL F 2	65,996	291,912	.42	12988764	82.55	11992584	56.07
2	34	AMER HESS	IDA WM 17	65,963	109,893	.42	13054727	82.97	12102477	56.58
2	10	ARCO	ETON NW14	65,582	158,459	.42	13120309	83.39	12260936	57.32
2	13	ARCO	ETON SW10	64,255	229,217	.41	13184564	83.80	12490153	58.39
2	33	UN TEX	CARL B 2	62,894	269,457	.40	13247458	84.20	12759610	59.65
2	25	PAC E	CARLB13 7	62,273	117,756	.40	13309731	84.60	12877366	60.20
2	47	ARCO	FED 35 1	61,116	139,318	.39	13370847	84.99	13016684	60.85
2	8	ARCO	JUST F 3Y	60,453	98,403	.38	13431300	85.37	13115087	61.31
2	42	UN TEX	CARL A 5	59,789	146,528	.38	13491089	85.75	13261615	61.99
2	35	TEXACO	A COATC16	57,799	41,790	.37	13548888	86.12	13303405	62.19
2	12	ARCO	ETON SW 8	56,869	197,564	.36	13605757	86.48	13500969	63.11
2	45	TEXACO	HOBBS A 6	56,599	142,704	.36	13662356	86.84	13643673	63.78
2	41	ARCO	CARL F 1	55,020	158,592	.35	13717376	87.19	13802265	64.52
2	46	AMOCO	ST AJ 5	54,679	125,133	.35	13772055	87.54	13927398	65.10
2	15	ARCO	ETON SE12	52,392	80,289	.33	13824447	87.87	14007687	65.48
2	00	TEXACO	RIGGS A 3	52,003	24,598	.33	13876450	88.20	14032285	65.59

TABLE 5
SOUTH JUSTIS AREA
RUNNING TOTAL WATER & OIL CUMS (BBLS)
FOR BLINEBRY WELLS RANKED BY
HIGHEST CUM WATER PRODUCTION

UNIT	ARCO TRACT	OPERATOR	WELL	CUM WATER	CUM OIL	WATER % OF TOTAL	RUNNING TOTAL WATER	CUM % WTR	RUNNING TOTAL OIL	CUM % OIL
2	42	UN TEX	CARL A 6	50,685	149,716	.32	13927135	88.52	14182001	66.29
2	34	AMER HESS	IDA WM 11	50,393	171,837	.32	13977528	88.84	14353838	67.09
2	38	UN TEX	BUFFTN B4	49,712	64,251	.32	14027240	89.16	14418089	67.39
2	23	UN TEX	BLOCKER 7	49,547	196,223	.31	14076787	89.47	14614312	68.31
2	38	UN TEX	BUFFTN B3	49,172	107,894	.31	14125959	89.78	14722206	68.81
2	27	PAC E	CARLA23 1	49,063	21,310	.31	14175022	90.09	14743516	68.91
2	40	BRUNO	CARLB26 7	48,458	39,903	.31	14223480	90.40	14783419	69.10
2	26	ARCO	WIMB WN 9	47,186	84,219	.30	14270666	90.70	14867638	69.49
2	26	ARCO	WIMB WN 7	47,010	271,703	.30	14317676	91.00	15139341	70.76
2	37	TEXACO	PENNEYF 7	46,924	55,222	.30	14364600	91.30	15194563	71.02
2	00	ARCO	GREGORY 1	46,765	37,869	.30	14411365	91.60	15232432	71.20
2	11	ARCO	ETON SW 9	44,762	156,764	.28	14456127	91.88	15389196	71.93
2	34	AMER HESS	IDA WM 16	43,307	79,544	.28	14499434	92.16	15468740	72.30
2	34	AMER HESS	IDA WM 15	42,325	111,971	.27	14541759	92.43	15580711	72.82
2	34	AMER HESS	IDA WM 13	40,901	71,078	.26	14582660	92.69	15651789	73.15
2	24	CHEVRON	L MCBUF13	39,282	187,879	.25	14621942	92.94	15839668	74.03
2	21	ARCO	LGL F 1	37,176	285,320	.24	14659118	93.18	16124988	75.36
2	26	ARCO	WIMB WN 5	36,907	102,411	.23	14696025	93.41	16227399	75.84
2	35	TEXACO	A COATC28	36,899	48,250	.23	14732924	93.64	16275649	76.07
2	20	ARCO	LGL AF 1	36,062	244,496	.23	14768986	93.87	16520145	77.21
2	24	CHEVRON	L MCBUF12	35,949	131,005	.23	14804935	94.10	16651150	77.82
2	35	TEXACO	A COATC14	35,800	113,413	.23	14840735	94.33	16764563	78.35
2	35	TEXACO	A COATC23	34,201	139,163	.22	14874936	94.55	16903726	79.00
2	44	BRUNO	CARLB25 2	34,099	182,868	.22	14909035	94.77	17086594	79.85
2	35	TEXACO	A COATC10	33,507	52,600	.21	14942542	94.98	17139194	80.10
2	14	ARCO	ETON SE13	33,086	26,400	.21	14975628	95.19	17165594	80.22
2	34	AMER HESS	IDA WM 14	33,067	70,434	.21	15008695	95.40	17236028	80.55
2	35	TEXACO	A COATC19	32,574	100,765	.21	15041269	95.61	17336793	81.02
2	24	CHEVRON	L MCBUF 4	30,835	118,629	.20	15072104	95.81	17455422	81.57
2	24	CHEVRON	L MCBUF10	29,136	163,301	.19	15101240	96.00	17618723	82.33
2	36	TEXACO	A COATD03	28,323	110,722	.18	15129563	96.18	17729445	82.85
2	25	PAC E	CARLB13 8	27,622	7,616	.18	15157185	96.36	17737061	82.89
2	23	UN TEX	BLOCKER 4	27,410	46,339	.17	15184595	96.53	17783400	83.11
2	23	UN TEX	BLOCKER 5	25,626	244,357	.16	15210221	96.69	18027757	84.25
2	00	UN TEX	2ST STRT1	25,446	24,088	.16	15235667	96.85	18051845	84.36
2	8	ARCO	JUST F 2	25,437	182,244	.16	15261104	97.01	18234089	85.21
2	40	BRUNO	CARLB26 6	25,272	167,622	.16	15286376	97.17	18401711	85.99
2	26	ARCO	WIMB WN 3	25,146	122,585	.16	15311522	97.33	18524296	86.56
2	43	ARCO	STATE Y 3	24,591	120,229	.16	15336113	97.49	18644525	87.12
2	7	UN TEX	JUSTIS 2	24,484	122,989	.16	15360597	97.65	18767514	87.69
2	43	ARCO	STATE Y 6	24,424	114,216	.16	15385021	97.81	18881730	88.22
2	20	ARCO	LGL AF 2	24,134	287,161	.15	15409155	97.96	19168891	89.56
2	23	UN TEX	BLOCKER 6	23,307	161,364	.15	15432462	98.11	19330255	90.31

TABLE 5
SOUTH JUSTIS AREA
RUNNING TOTAL WATER & OIL CUMS (BBLS) FOR BLINEBRY WELLS RANKED BY HIGHEST CUM WATER PRODUCTION

UNIT	ARCO TRACT	OPERATOR	WELL	CUM WATER	CUM OIL	WATER % OF TOTAL	RUNNING TOTAL WATER	CUM % WTR	RUNNING TOTAL OIL	CUM % OIL
2	7	UN TEX	JUSTIS 1	22,235	133,057	.14	15454697	98.25	19463312	90.93
2	25	PAC E	CARLB13 5	21,614	78,923	.14	15476311	98.39	19542235	91.30
2	35	TEXACO	A COATC22	21,572	134,077	.14	15497883	98.53	19676312	91.93
2	00	FINA	GIBRG F13	20,043	10,005	.13	15517926	98.66	19686317	91.98
2	24	CHEVRON	L MCBUF 6	16,878	221,727	.11	15534804	98.77	19908044	93.02
2	35	TEXACO	A COAT C8	14,655	38,435	.09	15549459	98.86	19946479	93.20
2	24	CHEVRON	L MCBUF 5	14,409	133,619	.09	15563868	98.95	20080098	93.82
2	35	TEXACO	A COATC25	14,106	91,554	.09	15577974	99.04	20171652	94.25
2	35	TEXACO	A COATC26	13,967	128,166	.09	15591941	99.13	20299818	94.85
2	43	ARCO	STATE Y 7	13,957	171,307	.09	15605898	99.22	20471125	95.65
2	44	BRUNO	CARLB25 5	13,950	161,947	.09	15619848	99.31	20633072	96.41
2	37	TEXACO	PENNEYF 6	13,651	50,200	.09	15633499	99.40	20683272	96.64
2	26	ARCO	WIMB WN 6	12,022	124,627	.08	15645521	99.48	20807899	97.22
2	35	TEXACO	A COAT C9	11,260	13,808	.07	15656781	99.55	20821707	97.28
2	42	UN TEX	CARL A 1	10,741	20,751	.07	15667522	99.62	20842458	97.38
2	24	CHEVRON	L MCBUF14	10,308	138,463	.07	15677830	99.69	20980921	98.03
2	24	CHEVRON	L MCBUF15	9,979	20,422	.06	15687809	99.75	21001343	98.13
2	19	ARCO	LGL BF 1	9,796	121,386	.06	15697605	99.81	21122729	98.70
2	35	TEXACO	A COATC24	9,713	148,743	.06	15707318	99.87	21271472	99.40
2	00	AMOCO	LGL BF 6	7,825	847	.05	15715143	99.92	21272319	99.40
2	35	TEXACO	A COATC21	7,574	67,629	.05	15722717	99.97	21339948	99.72
2	00	WBROOK	L BUFFTN1	6,318	26,274	.04	15729035	100.01	21366222	99.84
2	24	CHEVRON	L MCBUF 9	4,448	13,782	.03	15733483	100.04	21380004	99.90
2	3	UN TEX	O STUART1	444	4,067	.00	15733927	100.04	21384071	99.92
2	00	AMOCO	LGL BF 5	194	131	.00	15734121	100.04	21384202	99.92
2	43	ARCO	STATE Y 8	47	8,710	.00	15734168	100.04	21392912	99.96

TABLE 6

Recovery Estimates
20-Acre Secondary Development

OOIP - 208 MMBO

Development	Recovery Efficiency % OOIP	Reserves (MMBO)
40-Acre Primary	14.6	30.4
40-Acre Secondary*	10.3	21.4
20-Acre Primary	2.5	5.2
20-Acre Secondary	3.5	7.3
Total	30.9	64.3

*Reduced by 4.4 MMBO of peripheral reserves unavailable for recovery.

TABLE 7
SECONDARY RECOVERY VS PVI
SOUTH JUSTIS UNIT
80 ACRE LINE DRIVE

DISPLACEABLE PORE VOL = 50% GROSS PORE VOLUME
GROSS PV = 374,750 MRVB; DISP PV = 187,375 MRVB
AVERAGE KH = 448 MD-FT/WELL

PLANT CAPACITY = 71000 BWPD
INITIAL INJECTIVITY = 87,400 BWPD (65 WELLS)
ULTIMATE SECONDARY = 22 MMBO
S/P=.85

GROSS PVI	DISPL PVI	CUM DISPL PVI	TOTAL KH	INJ (BPD/KH)	AVG INJ (BPD/KH)	AVG INJ (BWPD)	INJ EFF. (FRAC.)	NET INJ (BWPD)	TIME (YRS)	SEC REC FRAC	SEC REC (MBO)	CUM SEC REC (MBO)	RATE (BOPD)
0.000	0.00	0	29120	3.00	3.000	71000	0.6	42600	0.0	0.0000	0	0	0
0.030	0.06	11243	29120	2.23	2.615	71000	0.6	42600	0.7	0.0000	0	0	0
0.050	0.10	18738	29120	2.00	2.115	61589	0.6	36953	1.3	0.0022	48	48	239
0.075	0.15	28106	29120	1.80	1.900	55328	0.6	33197	2.1	0.0050	62	110	218
0.100	0.20	37475	29120	1.00	1.400	40768	0.6	24461	3.1	0.0094	97	207	253
0.125	0.25	46844	29120	0.97	0.985	28683	0.6	17210	4.6	0.0150	123	330	226
0.150	0.30	56213	29120	0.95	0.960	27955	0.6	16773	6.1	0.0250	220	550	394
0.175	0.35	65581	29120	0.93	0.940	27373	0.6	16424	7.7	0.0350	220	770	386
0.200	0.40	74950	29120	0.90	0.915	26645	0.6	15987	9.3	0.0500	330	1100	563
0.225	0.45	84319	29120	0.89	0.895	26062	0.6	15637	10.9	0.0650	330	1430	551
0.250	0.50	93688	29120	0.87	0.880	25626	0.6	15375	12.6	0.0800	330	1760	542
0.275	0.55	103056	29120	0.86	0.865	25189	0.6	15113	14.3	0.1000	440	2200	710
0.300	0.60	112425	29120	0.85	0.855	24898	0.6	14939	16.0	0.1200	440	2640	702
0.325	0.65	121794	29120	0.83	0.840	24461	0.6	14676	17.8	0.1400	440	3080	689
0	0.70	131163	29120	0.80	0.815	23733	0.6	14240	19.6	0.1700	660	3740	1003
5	0.75	140531	29120	0.78	0.790	23005	0.6	13803	21.4	0.2000	660	4400	972
0.400	0.80	149900	29120	0.75	0.765	22277	0.6	13366	23.4	0.2300	660	5060	942
0.425	0.85	159269	29120	0.74	0.745	21694	0.6	13017	25.3	0.2600	660	5720	917
0.450	0.90	168638	29120	0.73	0.735	21403	0.6	12842	27.3	0.3000	880	6600	1206
0.475	0.95	178006	29120	0.71	0.720	20966	0.6	12580	29.4	0.3500	1100	7700	1477
0.500	1.00	187375	29120	0.70	0.705	20530	0.6	12318	31.4	0.3800	660	8360	868
0.525	1.05	196744	29120	0.69	0.695	20238	0.6	12143	33.6	0.4300	1100	9460	1426
0.550	1.10	206113	29120	0.69	0.690	20093	0.6	12056	35.7	0.4800	1100	10560	1415
0.575	1.15	215481	29120	0.68	0.685	19947	0.6	11968	37.8	0.5000	440	11000	562
0.600	1.20	224850	29120	0.68	0.680	19802	0.6	11881	40.0	0.5200	440	11440	558
0.625	1.25	234219	29120	0.67	0.675	19656	0.6	11794	42.2	0.5900	1540	12980	1939
0.650	1.30	243588	29120	0.66	0.665	19365	0.6	11619	44.4	0.6100	440	13420	546
0.675	1.35	252956	29120	0.66	0.660	19219	0.6	11532	46.6	0.6400	660	14080	812
0.700	1.40	262325	29120	0.65	0.655	19074	0.6	11444	48.8	0.6800	880	14960	1075
0.725	1.45	271694	29120	0.65	0.650	18928	0.6	11357	51.1	0.7000	440	15400	533
0.750	1.50	281063	29120	0.65	0.650	18928	0.6	11357	53.4	0.7200	440	15840	533
0.775	1.55	290431	29120	0.64	0.645	18782	0.6	11269	55.6	0.7500	660	16500	794
0.800	1.60	299800	29120	0.64	0.640	18637	0.6	11182	57.9	0.7700	440	16940	525
0.825	1.65	309169	29120	0.64	0.640	18637	0.6	11182	60.2	0.7900	440	17380	525
0.850	1.70	318538	29120	0.64	0.640	18637	0.6	11182	62.5	0.8100	440	17820	525
0.875	1.75	327906	29120	0.63	0.635	18491	0.6	11095	64.8	0.8200	220	18040	261
0.900	1.80	337275	29120	0.63	0.630	18346	0.6	11007	67.2	0.8400	440	18480	517
0.925	1.85	346644	29120	0.63	0.630	18346	0.6	11007	69.5	0.8500	220	18700	258
0.950	1.90	356013	29120	0.63	0.630	18346	0.6	11007	71.8	0.8600	220	18920	258
5	1.95	365381	29120	0.62	0.625	18200	0.6	10920	74.2	0.8700	220	19140	256
1.000	2.00	374750	29120	0.61	0.615	17909	0.6	10745	76.6	0.8900	440	19580	505

TABLE 8
SECONDARY RECOVERY VS PVI
SOUTH JUSTIS UNIT
40 ACRE 5 SPOT

DISPLACEABLE PORE VOL = 50% GROSS PORE VOLUME	PLANT CAPACITY = 123000 BWPD	
GROSS PV = 337,000 MRVB; DISP PV = 168,500 MRVB	INITIAL INJECTIVITY = 137,000 BWPD (102 WELLS)	ULT. SEC.=34 MMBO
AVERAGE KH = 448 MD-FT/WELL		S/P=1.15

GROSS PVI	DISPL PVI	CUM DISPL PVI	TOTAL KH	INJECTIVITY (BPD/KH)	AVG INJECTIVITY (BPD/KH)	AVG INJ. (BWPD)	INJECTION EFFICIENCY (FRACTION)	NET INJ. (BWPD)	TIME (YRS)	SEC REC FRAC	SEC REC (MBO)	CUM SEC REC (MBO)	RATE (BOPD)
0.000	0.00	0	45696	3.00	3.000	123000	0.85	104550	0.0	0.000	0	0	0
0.030	0.06	10110	45696	2.17	2.585	118124	0.85	100406	0.3	0.010	340	340	3377
0.050	0.10	16850	45696	2.00	2.085	95276	0.85	80985	0.5	0.015	170	510	2043
0.075	0.15	25275	45696	1.80	1.900	86822	0.85	73799	0.8	0.022	238	748	2085
0.100	0.20	33700	45696	1.00	1.400	63974	0.85	54378	1.2	0.030	272	1020	1756
0.125	0.25	42125	45696	0.97	0.985	45011	0.85	38259	1.8	0.035	170	1190	772
0.150	0.30	50550	45696	0.95	0.960	43868	0.85	37288	2.5	0.040	170	1360	752
0.175	0.35	58975	45696	0.93	0.940	42954	0.85	36511	3.1	0.070	1020	2380	4420
0.200	0.40	67400	45696	0.90	0.915	41812	0.85	35540	3.7	0.100	1020	3400	4303
0.225	0.45	75825	45696	0.89	0.895	40898	0.85	34763	4.4	0.120	680	4080	2806
0.250	0.50	84250	45696	0.87	0.880	40212	0.85	34181	5.1	0.150	1020	5100	4138
0.275	0.55	92675	45696	0.86	0.865	39527	0.85	33598	5.8	0.180	1020	6120	4068
0.300	0.60	101100	45696	0.85	0.855	39070	0.85	33210	6.5	0.220	1360	7480	5361
0.325	0.65	109525	45696	0.83	0.840	38385	0.85	32627	7.2	0.280	2040	9520	7900
0.350	0.70	117950	45696	0.80	0.815	37242	0.85	31656	7.9	0.340	2040	11560	7665
0.375	0.75	126375	45696	0.78	0.790	36100	0.85	30685	8.7	0.400	2040	13600	7430
0.400	0.80	134800	45696	0.75	0.765	34957	0.85	29714	9.4	0.470	2380	15980	8394
0.425	0.85	143225	45696	0.74	0.745	34044	0.85	28937	10.2	0.520	1700	17680	5839
0.450	0.90	151650	45696	0.73	0.735	33587	0.85	28549	11.0	0.580	2040	19720	6913
0.475	0.95	160075	45696	0.71	0.720	32901	0.85	27966	11.9	0.610	1020	20740	3386
0.500	1.00	168500	45696	0.70	0.705	32216	0.85	27383	12.7	0.650	1360	22100	4420
0.525	1.05	176925	45696	0.69	0.695	31759	0.85	26995	13.6	0.670	680	22780	2179
0.550	1.10	185350	45696	0.69	0.690	31530	0.85	26801	14.4	0.700	1020	23800	3245
0.575	1.15	193775	45696	0.68	0.685	31302	0.85	26606	15.3	0.730	1020	24820	3221
0.600	1.20	202200	45696	0.68	0.680	31073	0.85	26412	16.2	0.770	1360	26180	4264
0.625	1.25	210625	45696	0.67	0.675	30845	0.85	26218	17.0	0.800	1020	27200	3174
0.650	1.30	219050	45696	0.66	0.665	30388	0.85	25830	17.9	0.830	1020	28220	3127
0.675	1.35	227475	45696	0.66	0.660	30159	0.85	25635	18.8	0.840	340	28560	1035
0.700	1.40	235900	45696	0.65	0.655	29931	0.85	25441	19.7	0.850	340	28900	1027
0.725	1.45	244325	45696	0.65	0.650	29702	0.85	25247	20.7	0.855	170	29070	509
0.750	1.50	252750	45696	0.65	0.650	29702	0.85	25247	21.6	0.860	170	29240	509
0.775	1.55	261175	45696	0.64	0.645	29474	0.85	25053	22.5	0.875	510	29750	1517
0.800	1.60	269600	45696	0.64	0.640	29245	0.85	24859	23.4	0.890	510	30260	1505
0.825	1.65	278025	45696	0.64	0.640	29245	0.85	24859	24.4	0.895	170	30430	502
0.850	1.70	286450	45696	0.64	0.640	29245	0.85	24859	25.3	0.900	170	30600	502
0.875	1.75	294875	45696	0.63	0.635	29017	0.85	24664	26.2	0.905	170	30770	498
0.900	1.80	303300	45696	0.63	0.630	28788	0.85	24470	27.2	0.910	170	30940	494
0.925	1.85	311725	45696	0.63	0.630	28788	0.85	24470	28.1	0.915	170	31110	494
0.950	1.90	320150	45696	0.63	0.630	28788	0.85	24470	29.0	0.920	170	31280	494
0.975	1.95	328575	45696	0.62	0.625	28560	0.85	24276	30.0	0.930	340	31620	980
1.000	2.00	337000	45696	0.61	0.615	28103	0.85	23888	31.0	0.940	340	31960	964
1.100	2.20	370700	45696	0.61	0.610	27875	0.85	23693	34.9	0.970	1020	32980	717
1.200	2.40	404400	45696	0.61	0.610	27875	0.85	23693	38.8	1.000	1020	34000	717

JUSTPVIR 07-Jan-91

TABLE 9

Cost Summaries
Blinebry and Tubb/Drinkard Development

80-Acre Line Drive

Item	Per Well Cost (M$)	Tangibles (M$)	Intangibles (M$)	Total (M$)
Stimulate 70 Producers	97.65	308.0	6,527.5	6,835.5
Convert 65 Wells	105.95	1,774.5	5,112.3	6,886.8
Equip 70 Producers	46.30	3,241.0	0	3,241.0
Facilities	0	17,072.0	0	17,072.0
Total		22,395.5	11,639.8	34,035.3

40-Acre Five-Spot

Item	Per Well Cost (M$)	Tangibles (M$)	Intangibles (M$)	Total (M$)
Stimulate 125 Producers	97.65	550.0	11,656.3	12,206.3
Drill & Complete 4 Producers	348.30	369.2	1,024.0	1,393.2
Convert 11 Producers	105.95	300.3	865.2	1,165.5
Drill and Complete 86 Injectors	299.00	8,092.6	17,621.4	25,714.0
Core and Complete 5 Injectors	397.10	537.0	1,448.5	1,985.5
RFT 20 wells	4.00	0	80.0	80.0
Equip 129 Producers	46.30	5,972.7	0	5,972.7
Facilities	0	21,220.0	0	21,220.0
Total		37,041.8	32,695.4	69,737.2

TABLE 10

Cost Summaries
Blinebry Development Only

80-Acre Line Drive

Item	Per Well Cost (M$)	Tangibles (M$)	Intangibles (M$)	Total (M$)
Stimulate 70 Producers	79.95	252.2	5,344.3	5,596.5
Convert 65 Wells	95.00	1,591.1	4,583.9	6,175.0
Equip 70 Producers	46.30	3,241.0	0	3,241.0
Facilities	0	17,072.0	0	17,072.0
Total		22,156.3	9,928.2	32,084.5

% of Blinebry and Tubb/Drinkard Development - 94.3

40-Acre Five-Spot

Item	Per Well Cost (M$)	Tangibles (M$)	Intangibles (M$)	Total (M$)
Stimulate 125 Producers	79.95	550.0	9,443.8	9,993.8
Drill & Complete 4 Producers	292.70	19.2	1,151.6	1,170.8
Convert 11 Producers	95.00	11.2	1,033.8	1,045.0
Drill & Complete 86 Injectors	277.90	7,791.6	16,107.8	23,899.4
Core & Complete 5 Injectors	366.60	415.5	1,417.5	1,833.0
RFT 20 Wells	3.50	0	70.0	70.0
Equip 129 Producers	46.30	5,972.7	0	5,972.7
Facilities	0	21,220.0	0	21,220.0
Total		35,980.2	29,224.5	65,204.7

% of Blinebry and Tubb/Drinkard Development - 93.5

TABLE 11

PROPOSED SOUTH JUSTIS UNIT TRACTS AND CURRENT OPERATORS

TRACT NO.	OPERATOR	LEASE NAME
1	Chevron USA, Inc.	J. A. Stuart
2	Union Texas Petroleum Corp.	Stuart
3	Union Texas Petroleum Corp.	Olsen Stuart
4	ARCO Oil and Gas Company	J. A. Stuart
5	ARCO Oil and Gas Company	Jal
6	ARCO Oil and Gas Company	Langlie "B" (JH)
7	Union Texas Petroleum Corp.	Justis
8	ARCO Oil and Gas Company	Justice
9A	ARCO Oil and Gas Company	Eaton, N.W. (JH) Nos. 15, 16, and 17 (Bly)
9B	ARCO Oil and Gas Company	Eaton, N.W. (JH) Nos. 15, 16, and 17 (T/D)
10A	ARCO Oil and Gas Company	Eaton, N.W. (JH) No. 14 (Bly)
10B	ARCO Oil and Gas Company	Eaton, N.W. (JH) No. 14 (T/D)
11	ARCO Oil and Gas Company	Eaton, S.W. (JH) Nos. 9 and 11
12A	ARCO Oil and Gas Company	Eaton, S.W. (JH) No. 8 (Bly)
12B	ARCO Oil and Gas Company	Eaton, S.W. (JH) No. 8 (T/D)
13	ARCO Oil and Gas Company	Eaton, S.W. (JH) No. 10
14	ARCO Oil and Gas Company	Eaton, S.E. (JH) No. 13
15	ARCO Oil and Gas Company	Eaton, S.E. (JH) No. 12
16	ARCO Oil and Gas Company	Stuart "A" WN
17	Amerada Hess Corp.	W. F. Stuart
18	Union Texas Petroleum Corp.	Langlie "D"
19	ARCO Oil and Gas Company	Langlie "B" Federal
20	ARCO Oil and Gas Company	Langlie "A" Federal
21	ARCO Oil and Gas Company	Langlie Federal
22	Union Texas Petroleum Corp.	Langlie "B"
23	Union Texas Petroleum Corp.	Blocker
24	Chevron USA, Inc.	Learcy McBuffington
25	Pacific Enterprises	Carlson "B" 13
26	ARCO Oil and Gas Company	Wimberly WN
27	Pacific Enterprises	Carlson "A"-23
28	Texaco Inc.	Las Cruces "C"
29	ARCO Oil and Gas Company	Wimberly (JH) No. 2
30	ARCO Oil and Gas Company	Wimberly (JH) No. 3
31	ARCO Oil and Gas Company	Carlson "A" Federal
32	American Exploration	El Paso Federal
33	Union Texas Petroleum Corp.	Carlson "B"
34	Amerada Hess Corp.	Ida Wimberley
35	Texaco Inc.	A. B. Coates "C"
36	Texaco Inc.	A. B. Coates "D"

TABLE 11

PROPOSED SOUTH JUSTIS UNIT TRACTS AND CURRENT OPERATORS
(continued)

TRACT NO.	OPERATOR	LEASE NAME
37	Texaco Inc.	C. E. Penny Federal NCT 4
38A	Union Texas Petroleum Corp.	Buffington "B"
38B	Texaco Inc.	L. M. Buffington B
39	ARCO Oil and Gas Company	Carlson (JH)
40	Bruno, Earl R.	Carlson "B"-26
41	ARCO Oil and Gas Company	Carlson Federal
42	Union Texas Petroleum Corp.	Carlson "A"
43	ARCO Oil and Gas Company	State "Y"
44	Bruno, Earl R.	Carlson "B"-25
45	Texaco Inc.	Hobbs "A"
46	Amoco Production Company	State "AJ"
47	ARCO Oil and Gas Company	Federal 35
48	Union Texas Petroleum Corp.	Gregory "A" Federal
49	Chevron USA, Inc.	Arnott Ramsay NCT "F"
50	Chevron USA, Inc.	Vinson Ramsay NCT "B"
51	Fina	Ginsberg Federal
52	Texaco Inc.	G. D. Riggs "B"

FIGURES

SOUTH JUSTIS UNIT AREA
BLINEBRY PRODUCTION

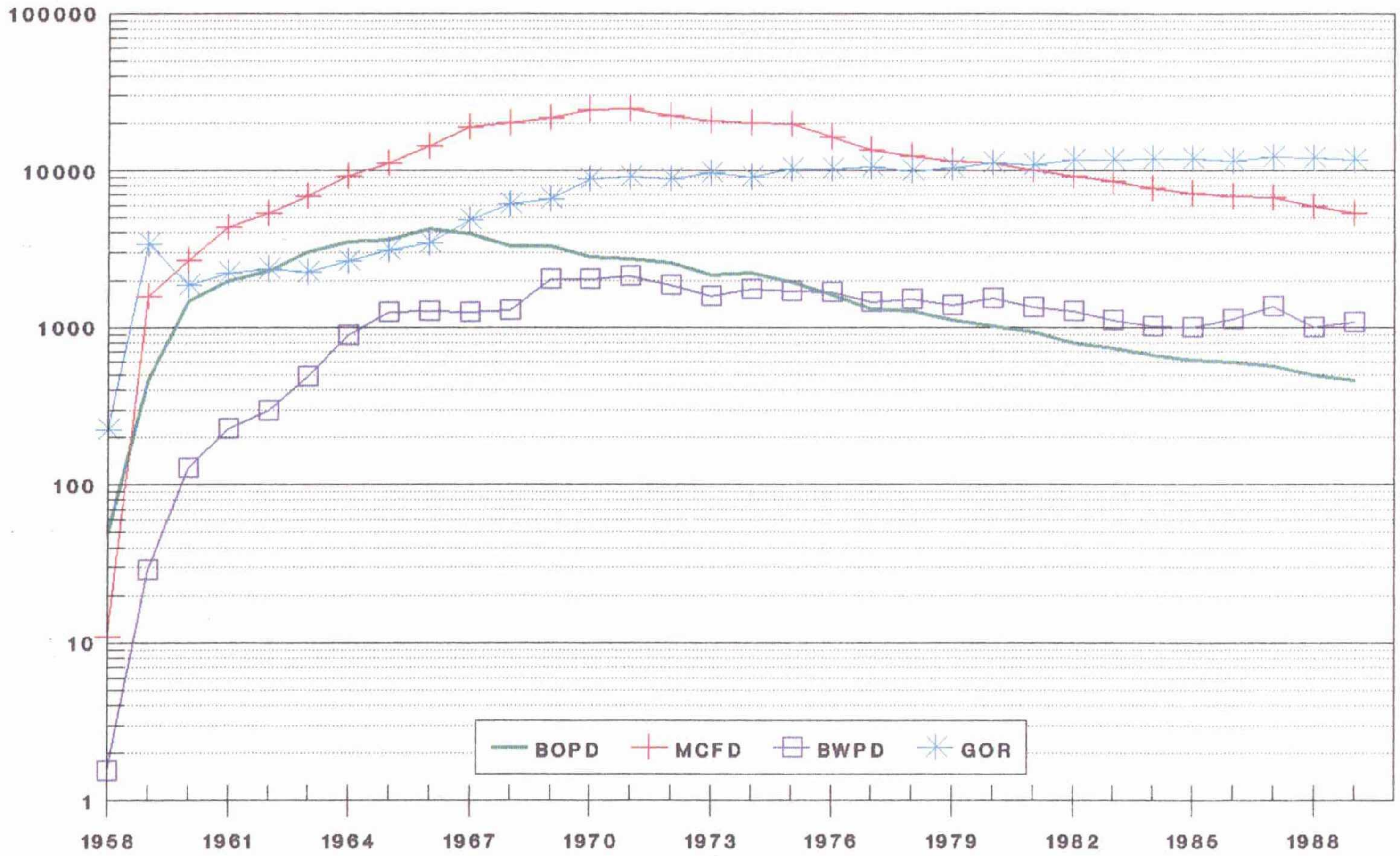


FIGURE 1

RSP/EEG SJUBLBY 12/27/90

SOUTH JUSTIS UNIT AREA
TUBB/DRINKARD PRODUCTION

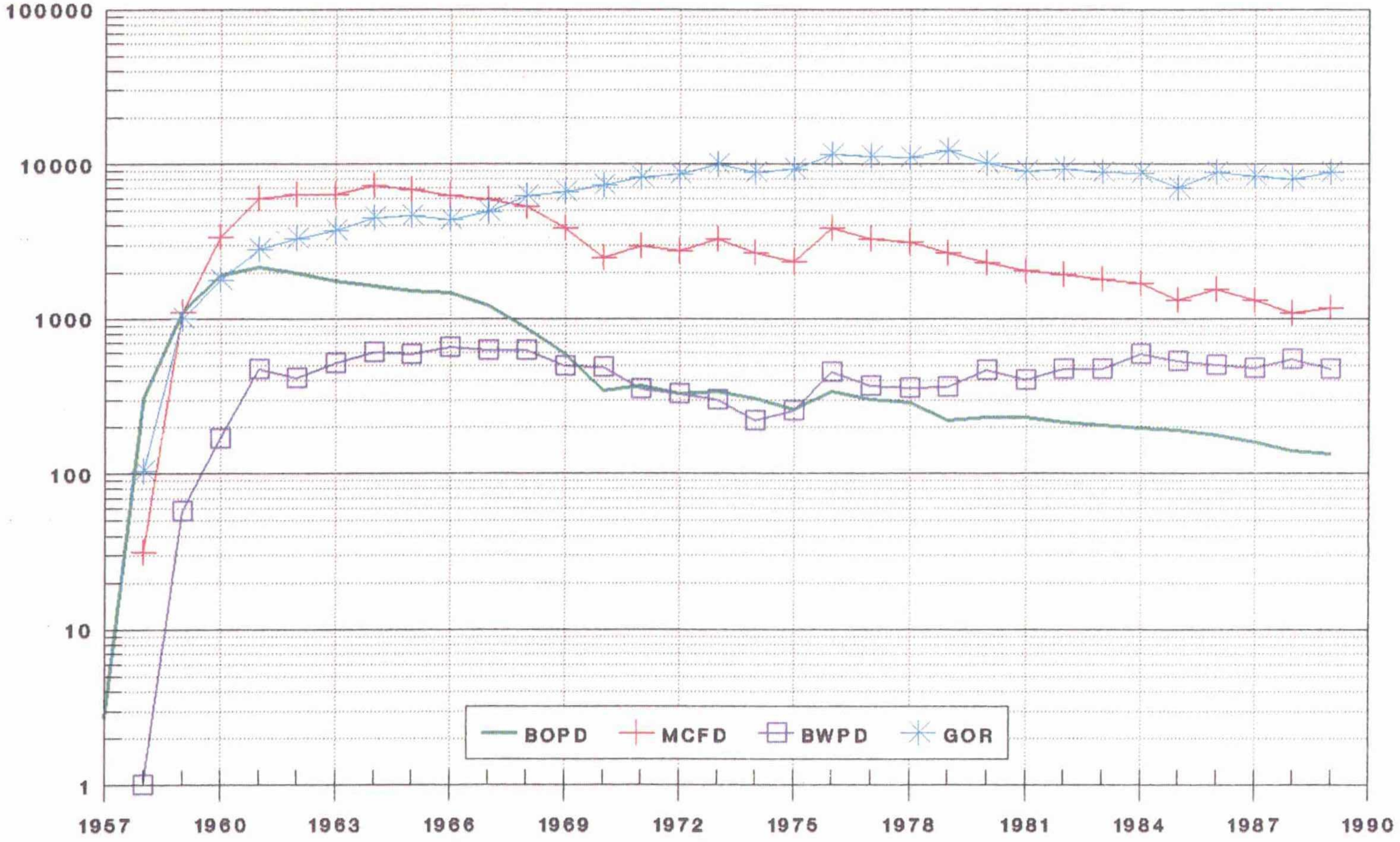


FIGURE 2

RSP/EEG SJUTBDRK 12/28/90

PRIMARY PERFORMANCE HISTORY
SOUTH JUSTIS UNIT - LEA COUNTY, NM
BLINEBRY & TUBB/DRINKARD RESERVOIRS

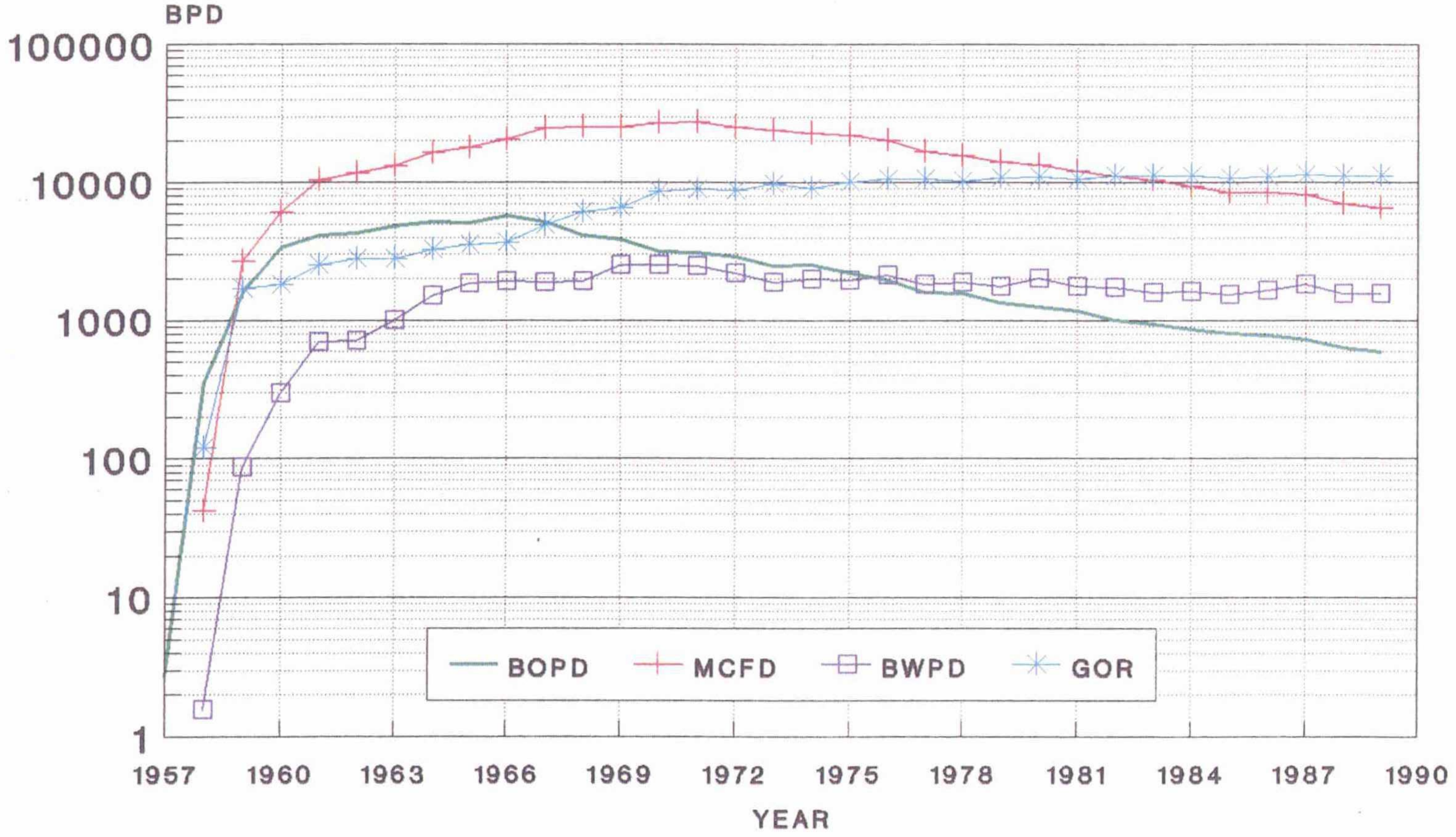


FIGURE 3

RSP/EEG PRICOMB 12/27/90

A COMPARISON OF CUM. OIL & WATER PROD.

FOR WELLS RANKED BY HIGHEST WATER PROD.

Blinebry Field - South Justis Unit

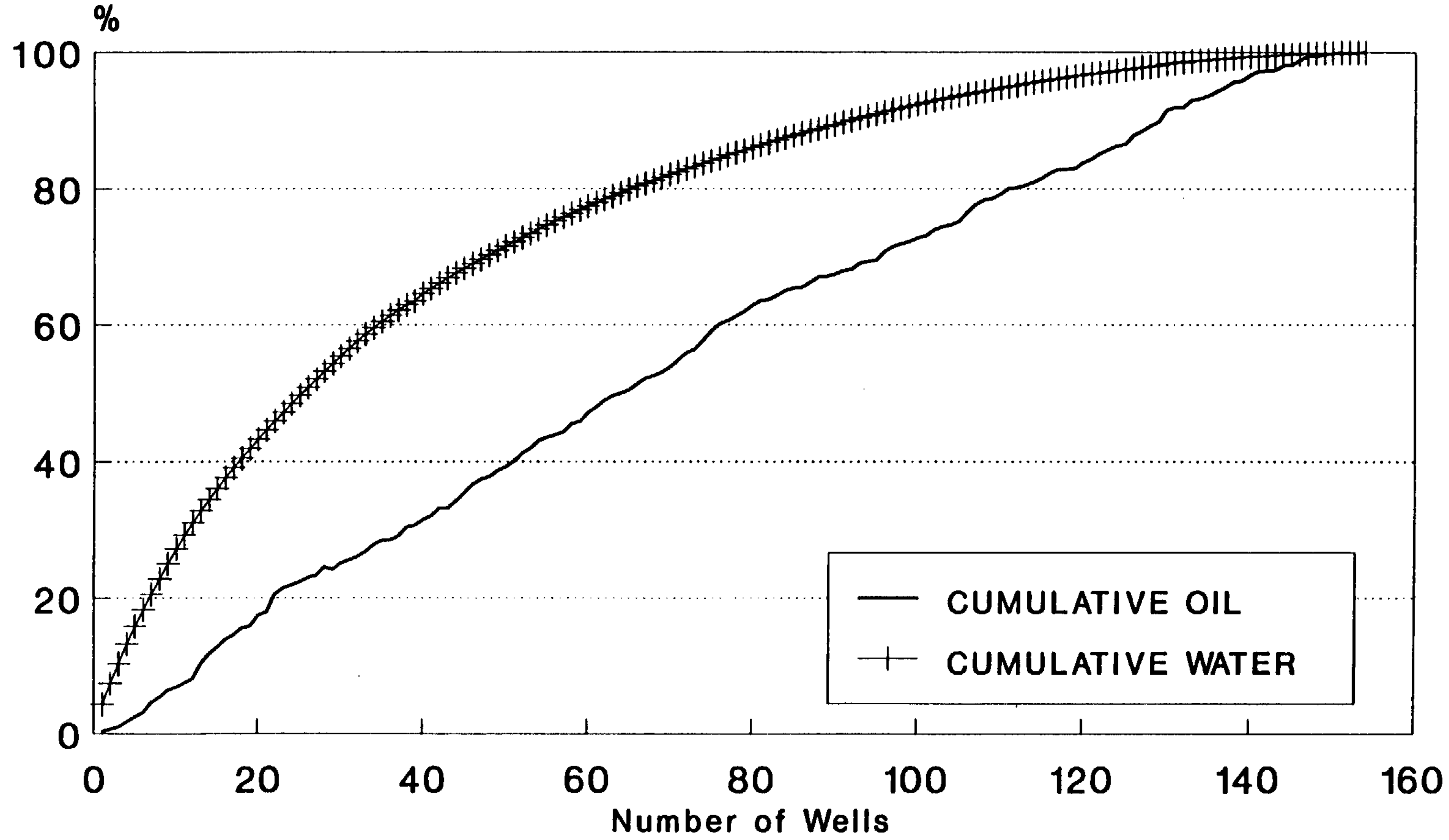


FIGURE 5

RSP/EEG 10/23/89

INJECTIVITY VS.
GROSS PORE VOLUME INJECTED
JUSTIS FIELD, LEA COUNTY, NM

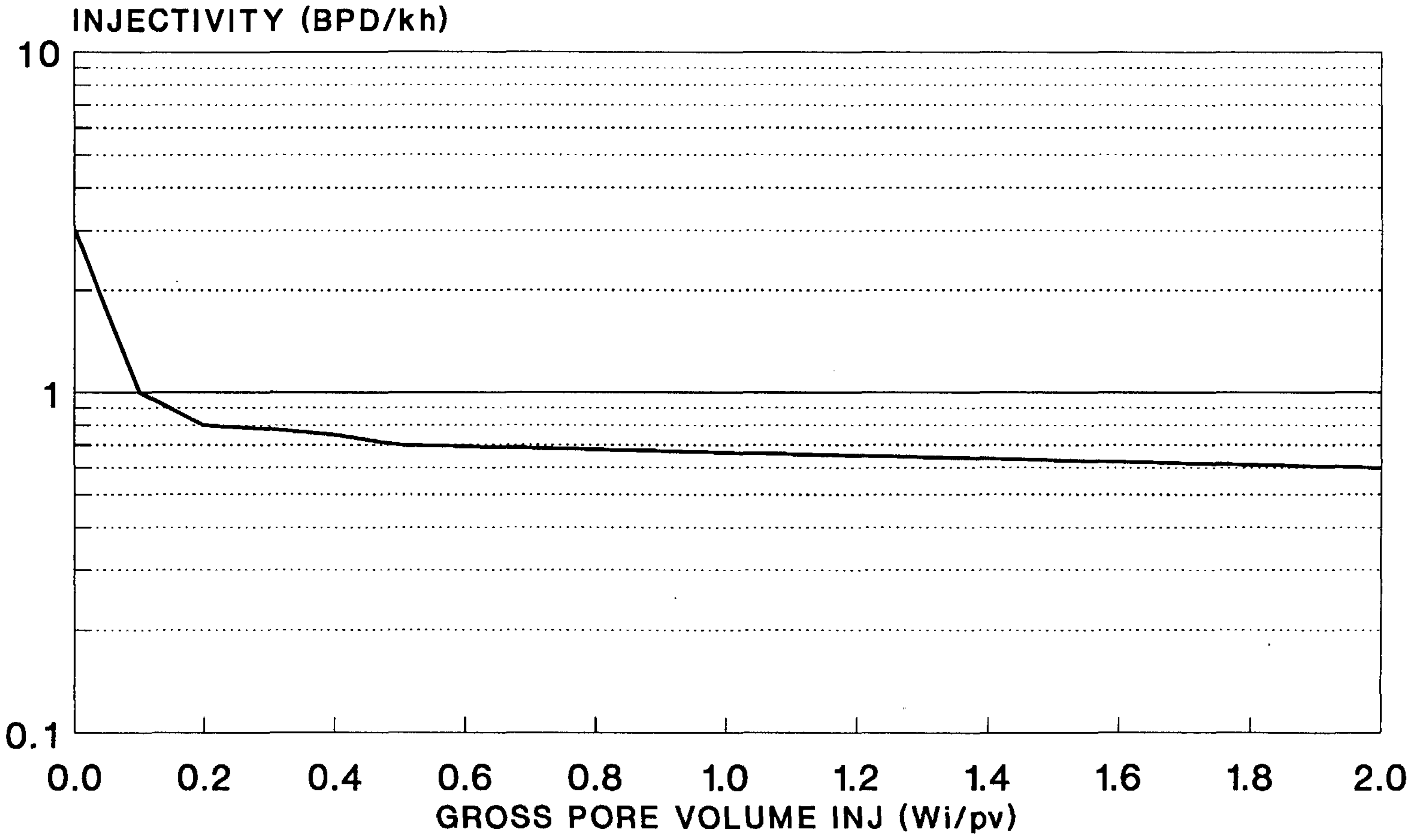


FIGURE 7

RSP/EEG 10/23/89

SECONDARY RECOVERY VS. PORE VOLUME INJECTED CENTRAL DRINKARD UNIT

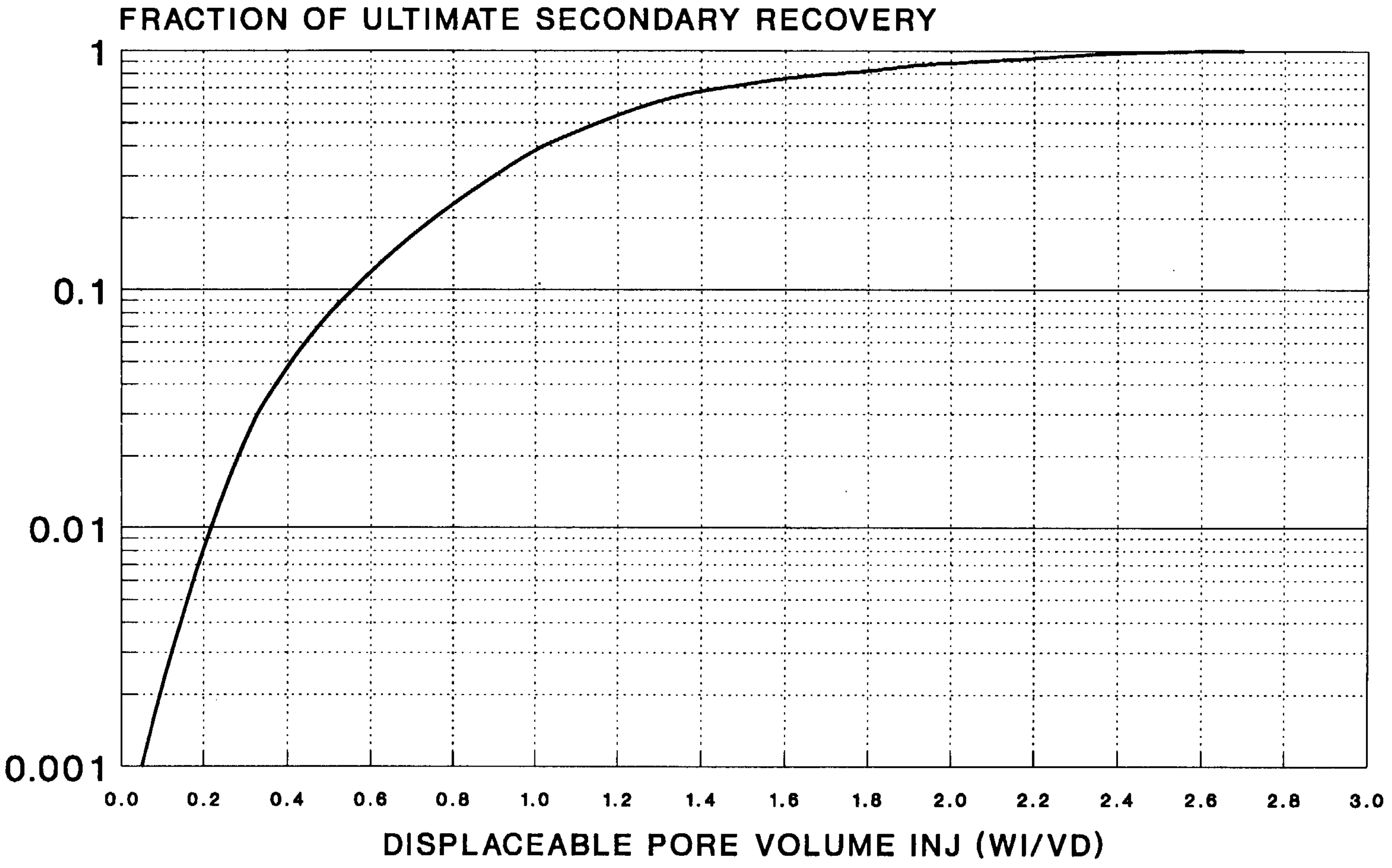


FIGURE 9

CWE/RSP/EEG 10/23/89

PROPOSED SOUTH JUSTIS UNIT
80-ACRE LINE DRIVE
REGIONAL STUDY FORECAST

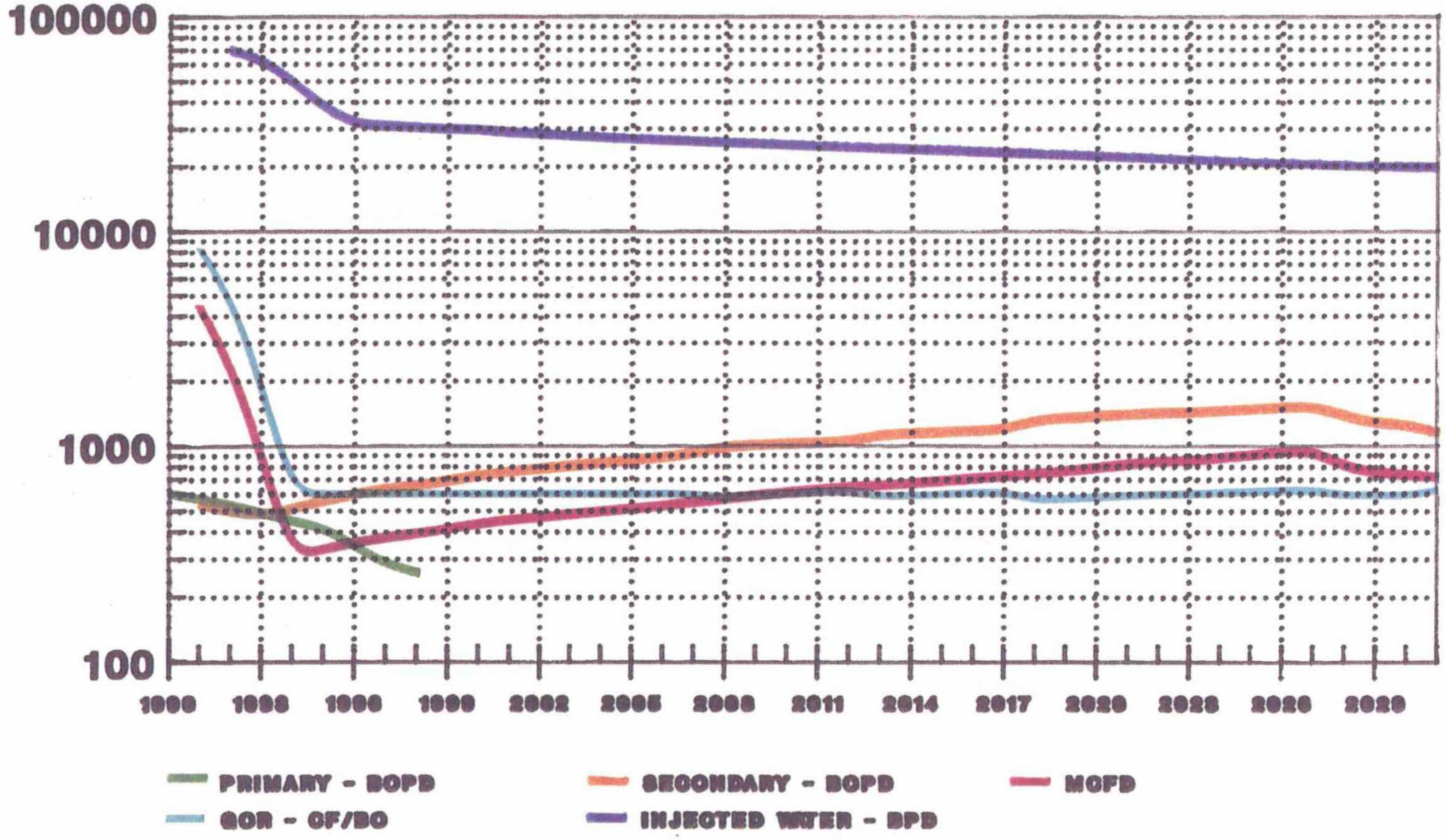


FIGURE 10

RSP/EEG 80ACRE 01/17/91

PROPOSED SOUTH JUSTIS UNIT
40-ACRE 5-SPOTS
REGIONAL STUDY FORECAST

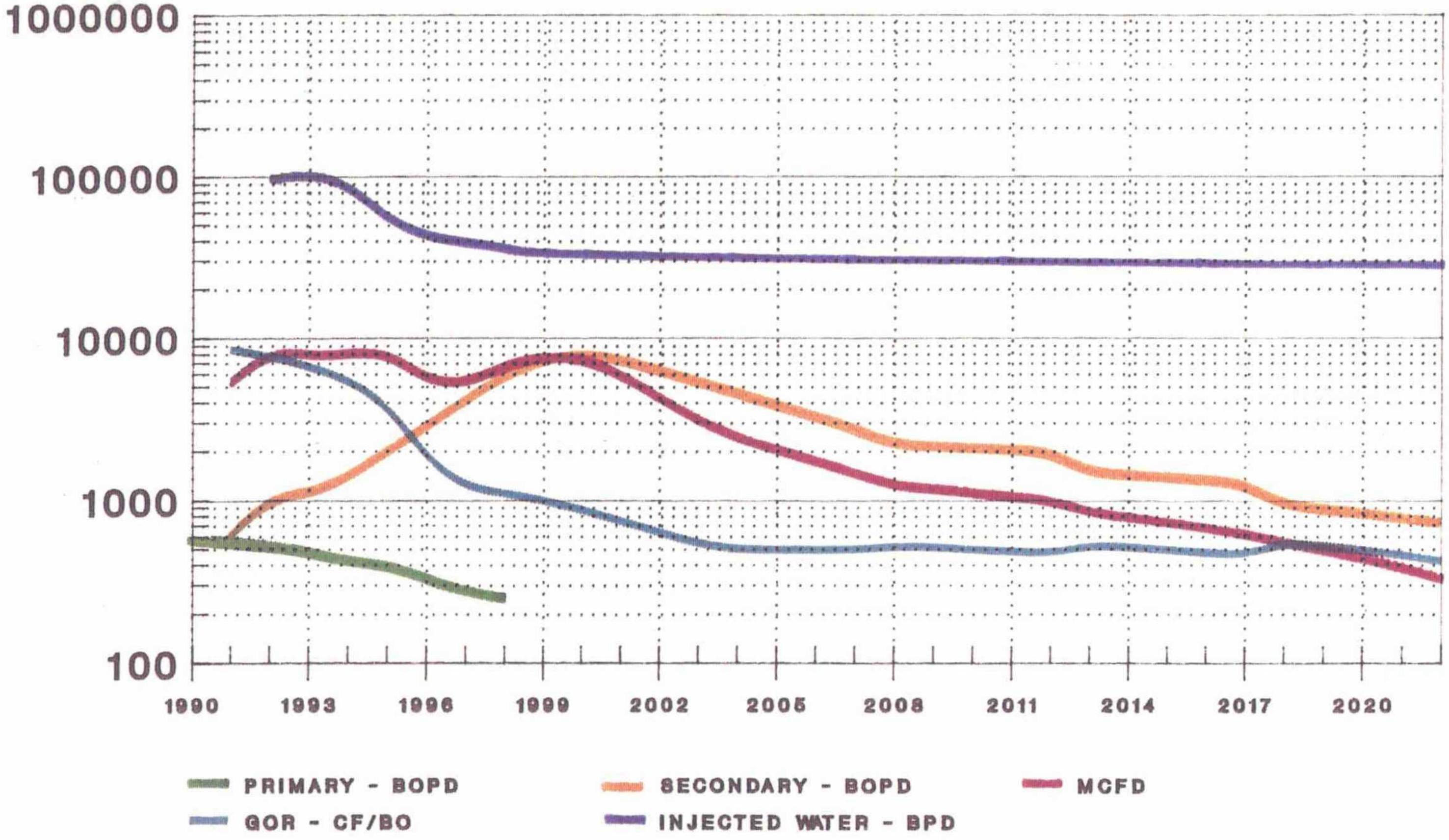


FIGURE 12

RSP/EEG 40ACRE 11/29/90

FIGURE 13

Martin Water Laboratories, Inc.
WATER CONSULTANTS SINCE 1953
BACTERIAL AND CHEMICAL ANALYSES

P.O. BOX 1468
MONAHANS, TEXAS 79756
PH. 943-3234 or 563-1040

709 W. INDIANA
MIDLAND, TEXAS 79701
PHONE 683-4521

July 21, 1988

Mr. Randy Thompson
ARCO Oil & Gas Company
P.O. Box 949
Andrews, Texas 79714

Dear Mr. Thompson:

The objective of this letter is to respond to your request to evaluate certain compatibilities regarding the waters represented in the discussion below.

The primary need for compatibility is understood to be between your State "Y" Fusselman water and Texaco's Jal Water System water. In order to represent Fusselman, we have utilized records of State "Y" #5 and #8 reported on laboratory #588105 (5-16-88); and for Texaco's Jal Water System water, we have utilized records reported to them last February. In comparing these records, we have encountered no evidence of any incompatibility between the Fusselman water and Texaco's water. Therefore, we would classify these two waters to be compatible without reservation.

Also, we have studied the possibility of including your Wimberly Fusselman, Blinebry, and Tubb-Drinkard waters as represented from wells #6, #10, and #11 respectively and reported on laboratory #1087236 (10-28-87). We have examined these waters regarding their compatibility with your State "Y" Fusselman and also Texaco's water. Again, we have encountered no evidence of any incompatibility between these Wimberly waters and either the State "Y" Fusselman water or the Texaco water. However, in this comparison, we do have one mild concern in that a majority of our Blinebry records show slight hydrogen sulfide as does the Wimberly #10 water, but we have a few records which do not show sulfide. In the absence of sulfide, it would be possible that the Blinebry water might have some soluble iron. However, based on records available, this is very unlikely but would lead us to suggest that the composite Blinebry water that might be combined with the other waters in this study should be re-checked to confirm this aspect of this water.

Very truly yours,

Waylan C. Martin

WCM/sn

cc: Mr. Robert Patterson,
Texaco @ Eunice

P. O. BOX 1468
MONAHANS, TEXAS 79756
PH. 943-3234 OR 563-1040

Martin Water Laboratories, Inc.

709 W. INDIANA
MIDLAND, TEXAS 79701
PHONE 683-4521

RESULT OF WATER ANALYSES

LABORATORY NO. 1087236

TO: Mr. Arley Stafford
P.O. Box 949, Andrews, Texas

SAMPLE RECEIVED 10-23-87

RESULTS REPORTED 10-28-87

COMPANY ARCO Oil & Gas Company

LEASE Wimberly

FIELD OR POOL Justice

SECTION ____ BLOCK ____ SURVEY ____ COUNTY Lea STATE NM

SOURCE OF SAMPLE AND DATE TAKEN:

NO. 1 Produced water - taken from Wimberly #6. 10-22-87

NO. 2 Produced water - taken from Wimberly #10. 10-22-87

REMARKS: 1. Fusselman 2. Blinbry Blinebry

CHEMICAL AND PHYSICAL PROPERTIES

	NO. 1	me/l	NO. 2	me/l
Specific Gravity at 60° F.	1.0478		1.0675	
pH When Received	7.60		7.30	
Carbonate as CO_3	0	0.0	0	0.0
Bicarbonate as HCO_3	1,013	16.6	714	11.7
Supersaturation as $CaCO_3$	130		75	
Undersaturation as $CaCO_3$	----		----	
Total Hardness as $CaCO_3$	10,900		17,300	
Calcium as Ca	2,780	139.0	4,760	238.0
Magnesium as Mg	960	79.0	1,312	108.0
Sodium and/or Potassium	21,365	929.0	31,208	1,356.9
Sulfate as SO_4	2,829	58.9	1,869	38.9
Chloride as Cl	37,995	1,071.5	58,591	1,652.3
Iron as Fe	0.24	0.0	0.40	0.0
Barium as Ba				
Turbidity, Electric				
Color as Pt				
Total Solids, Calculated	66,942		98,454	
Temperature °F.				
Carbon Dioxide, Calculated				
Dissolved Oxygen, Winkler				
XXXXXn Sulfide - Total	437		3.8	
Resistivity, ohms/m at 77° F.	0.127		0.096	
Suspended Oil				

Results Reported As Milligrams Per Liter

Additional Determinations And Remarks

Form No. 2

By ____

P. O. BOX 1468
MONAHANS, TEXAS 79756
PH. 943-3234 OR 563-1040

Martin Water Laboratories, Inc.

709 W. INDIANA
MIDLAND, TEXAS 79701
PHONE 683-4521

RESULT OF WATER ANALYSES

LABORATORY NO. 1087236 (Page 2)
SAMPLE RECEIVED 10-23-87
RESULTS REPORTED 10-28-87

TO: Mr. Arley Stafford
P.O. Box 949, Andrews, Texas

COMPANY ARCO Oil & Gas Company LEASE Wimberly
FIELD OR POOL ~~Justice~~ Justis
SECTION ___ BLOCK ___ SURVEY ___ COUNTY Lea STATE NM
SOURCE OF SAMPLE AND DATE TAKEN:
NO. 1 Produced water - taken from Wimberly #11. 10-22-87
NO. 2

REMARKS: Tubb-Drinkard

CHEMICAL AND PHYSICAL PROPERTIES

	NO. 1	me/l	NO. 2	me/l
Specific Gravity at 60° F.	1.0857			
pH When Received	7.50			
Carbonate as CO_3	0	0.0		
Bicarbonate as HCO_3	506	8.3		
Supersaturation as $CaCO_3$	85			
Undersaturation as $CaCO_3$	----			
Total Hardness as $CaCO_3$	21,700			
Calcium as Ca	5,640	282.0		
Magnesium as Mg	1,847	152.0		
Sodium and/or Potassium	38,997	1,695.6		
Sulfate as SO_4	1,844	38.4		
Chloride as Cl	73,860	2,082.8		
Iron as Fe	5.12	0.2		
Barium as Ba				
Turbidity, Electric				
Color as Pt				
Total Solids, Calculated	122,694			
Temperature °F.				
Carbon Dioxide, Calculated				
Dissolved Oxygen, Winkler				
XXXXX Sulfide - Total	52.5			
Resistivity, ohms/m at 77° F.	0.081			
Suspended Oil				

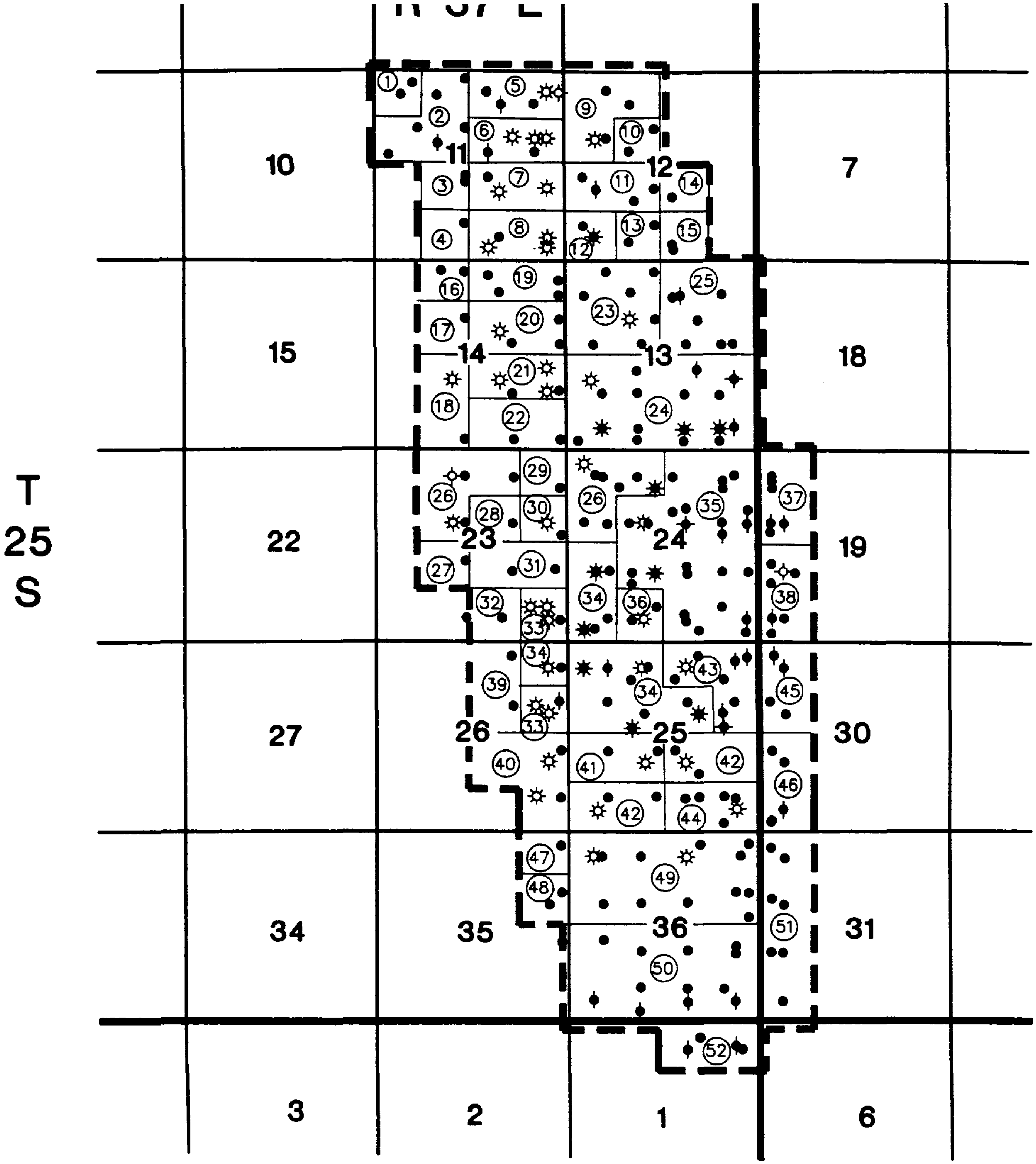
Results Reported As Milligrams Per Liter

Additional Determinations And Remarks In comparing the results of these analyses, we see no evidence of any incompatibility between any combination of the waters represented herein. This is to say that a combination of the waters should not cause any precipitation, scaling, or other detrimental condition.

Form No. 2

cc: Mr. Dick Prentice, Midland
Mr. R.D. Thompson, Andrews
Mr. Jim Ellis, Jal
Central File System, Midland

By Waylan C. Martin, M.A.



— — — **Unit Boundary**

(51) **Tract Number**

Figure 14

ARCO Oil and Gas Company
Division of AtlanticRichfieldCompany
Central District Midland, Texas

Proposed South Justis Unit

Lea County, New Mexico

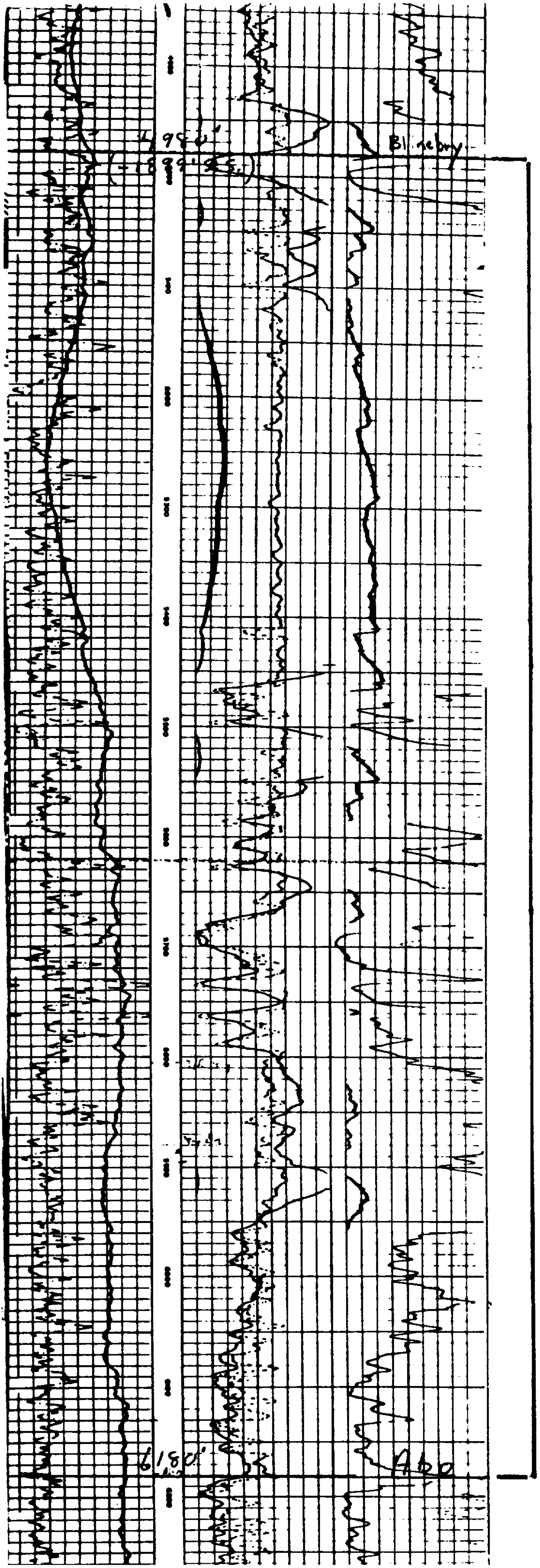
Scale: 1"=4000'

By:	R. Alletag	Drawn By: RGJ	Date: 12-90
Date:	12-90	Revised By: A.M.C.	Date: 1/91
Dept:	Land	Dwg No.: NM/SMPLT02	PSJU3725

Type Log

Amerada Hess

Ida Wimberly #4
Schlumberger Electrical Log
Sec. 24-T25S-R37E
DF 3079'
660' FSL, 990' FWL
Figure 15



Unitized Interval

Top 4980'

Bottom 6180'

FIGURE 8A

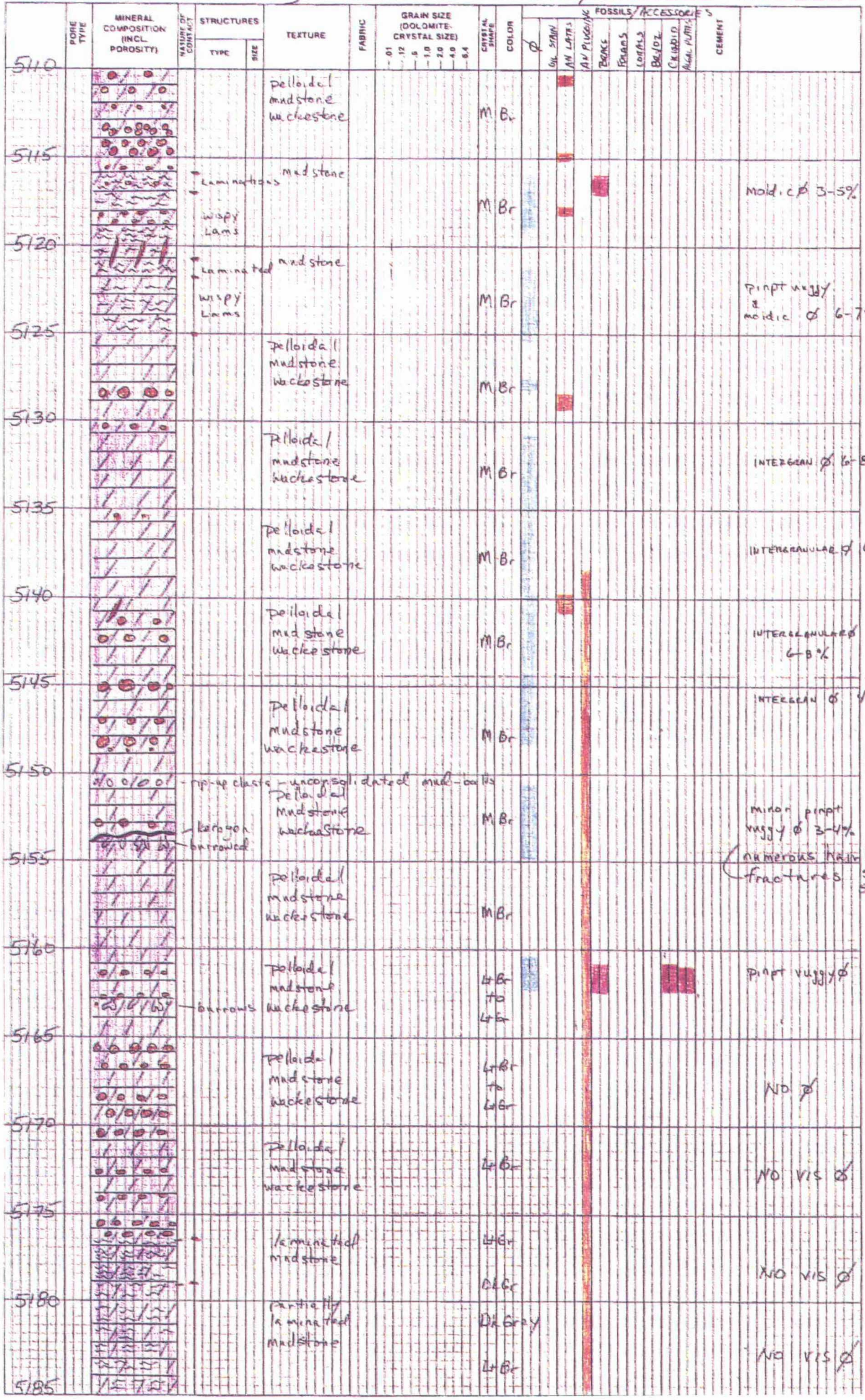
1

Sec 11 T25S R 37E

6605 1980E

WELL ARCO JUSTIS # 2 COUNTY Lea STATE N. Mex

STRATIGRAPHIC INTERVAL BLINEBRY LOGGED BY QST DATE 9-9-88



	STRUCTURES TYPE	TEXTURE	CRYSTAL SHAPE	COLOR	
5110–5115		pelloidal mudstone wackestone	M	Br	
5115–5120	Laminations wispy Lams	mudstone	M	Br	Moldic Ø 3-5%
5120–5125	Laminated wispy Lams	mudstone	M	Br	pinpt vuggy & moldic Ø 6-7%
5125–5130		Pelloidal mudstone wackestone	M	Br	
5130–5135		Pelloidal mudstone wackestone	M	Br	INTERGRAN Ø 6-8%
5135–5140		pelloidal mudstone wackestone	M	Br	INTERGRANULAR Ø 6-8%
5140–5145		pelloidal mudstone wackestone	M	Br	INTERGRANULAR Ø 6-8%
5145–5150		Pelloidal mudstone wackestone	M	Br	INTERGRAN Ø 4-5%
5150–5155	rip-up clasts - unconsolidated mud-balls kerogen burrowed	Pelloidal Mudstone wackestone	M	Br	minor pinpt vuggy Ø 3-4% (numerous hairline fractures 54-57 57-77')
5155–5160		pelloidal mudstone wackestone	M	Br	
5160–5165	burrows	pelloidal mudstone wackestone		Lt Br to Lt Gr	pinpt vuggy Ø
5165–5170		pelloidal mudstone wackestone		Lt Br to Lt Gr	NO Ø
5170–5175		Pelloidal Mudstone wackestone		Lt Br	NO VIS Ø
5175–5180		laminated mudstone		Lt Gr Dk Gr	NO VIS Ø
5180–5185		partially laminated mudstone		Dk Grey Lt Br	NO VIS Ø

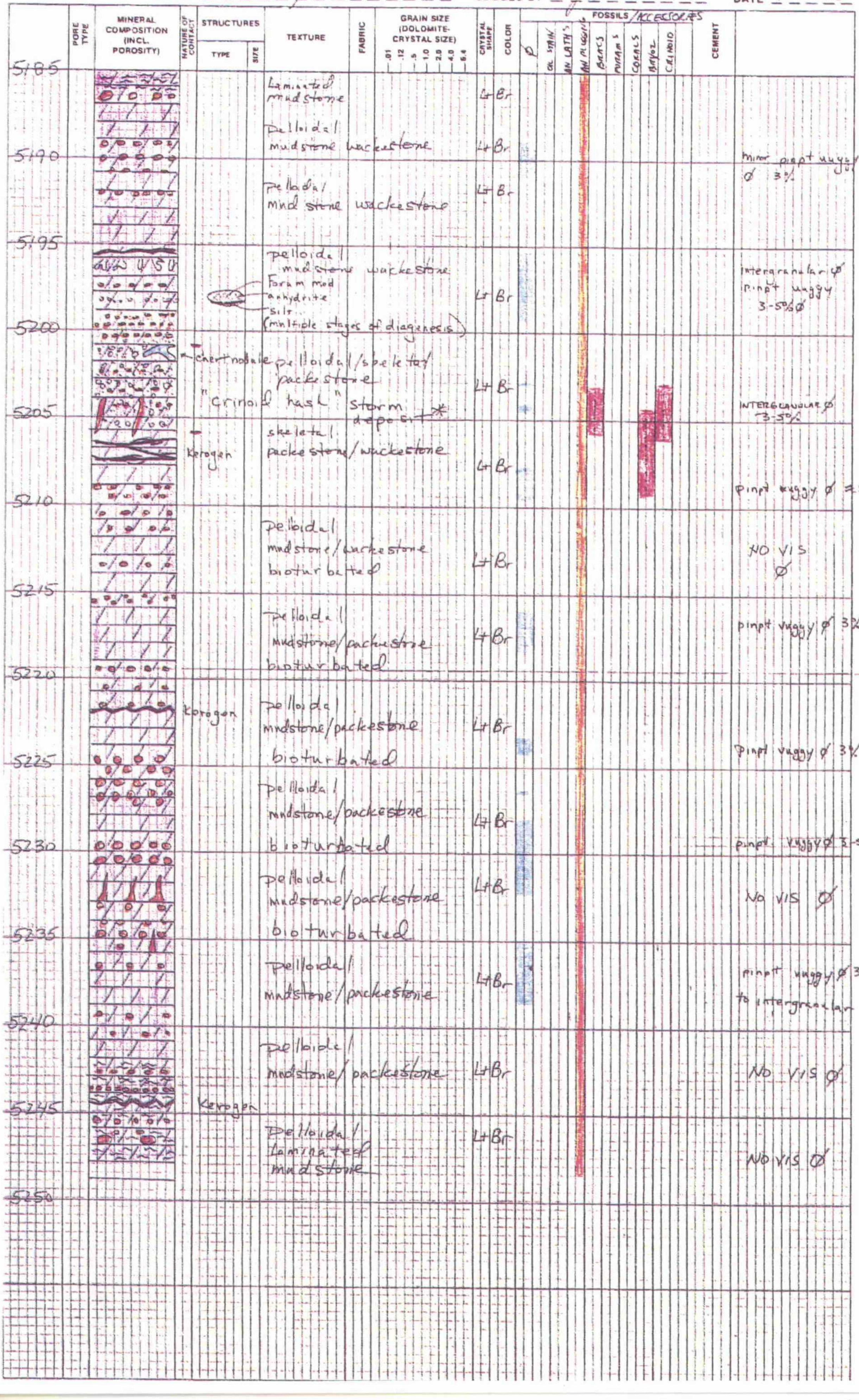
Sec 11 T25S R37E
660S 1980E

FIGURE 8-A

2

WELL ARCO JUSTIS #2 COUNTY Lea STATE N. Mex

STRATIGRAPHIC INTERVAL BLINEBRY LOGGED BY JST DATE 9-9-88



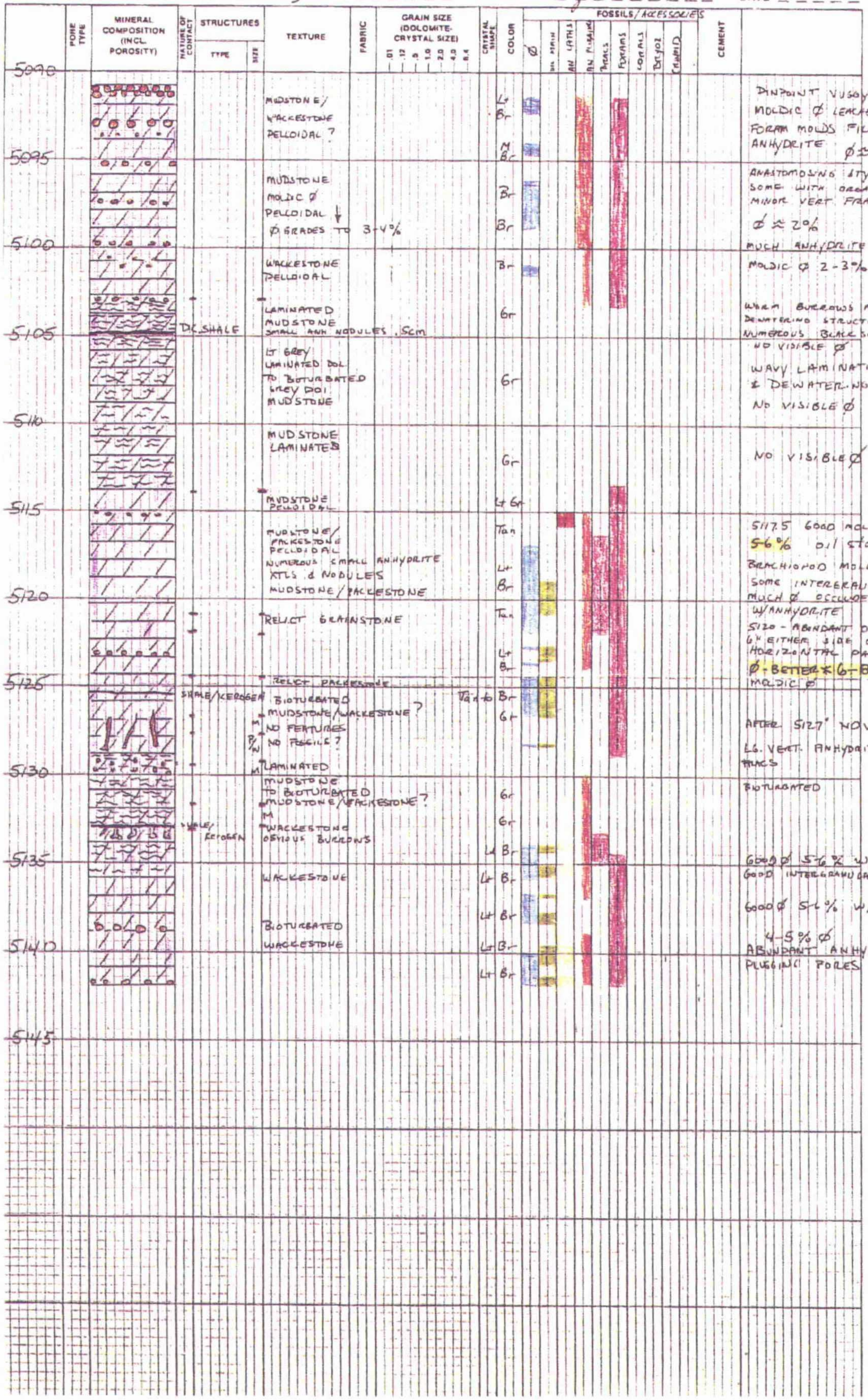
STRUCTURES TYPE	TEXTURE	COLOR	
	Laminated mudstone	Lt Br	
	Pelloidal mudstone wackestone	Lt Br	minor pinpt vuggy Ø 3%
	pelloidal mud stone wackestone	Lt Br	
	pelloidal mudstone wackestone Foram mod anhydrite silt (multiple stages of diagenesis)	Lt Br	intergranular Ø pinpt vuggy 3-5% Ø
chert nodule	pelloidal/skeletal packestone "crinoid hash" storm deposit *	Lt Br	INTERGRANULAR Ø 3-5%
Kerogen	skeletal packestone/wackestone	Lt Br	pinpt vuggy Ø ≈5%
	Pelloidal mudstone/wackestone biturbated	Lt Br	NO VIS Ø
	Pelloidal mudstone/packestone bioturbated	Lt Br	pinpt vuggy Ø 3%
Kerogen	Pelloidal mudstone/packestone bioturbated	Lt Br	pinpt vuggy Ø 3%
	Pelloidal mudstone/packestone bioturbated	Lt Br	pinpt vuggy Ø 3-5%
	pelloidal mudstone/packestone bioturbated	Lt Br	No VIS Ø
	pelloidal mudstone/packestone	Lt Br	pinpt vuggy Ø 3-5% to intergranular
	pelloidal mudstone/packestone	Lt Br	No VIS Ø
Kerogen	Pelloidal/laminated mudstone	Lt Br	NO VIS Ø

Sec 14 T25S R37E

WELL ARCO LANGUE FEDERAL #2 1650 S & E COUNTY LEA STATE N. Mex

FIGURE 9A

STRATIGRAPHIC INTERVAL BLINEBRY LOGGED BY JST DATE 9-8-88



	STRUCTURES	TEXTURE	COLOR	
5090		MUDSTONE/ WACKESTONE PELLOIDAL ?	Lt Br M Br	PINPOINT VUGGY ϕ TO MOLDIC ϕ LEACHED FOSSILS FORAM MOLDS FILLED WITH ANHYDRITE ϕ≈2%
5095		MUDSTONE MOLDIC ϕ PELLOIDAL ↓ ϕ GRADES TO 3-4%	Br Br	ANASTOMOSING STYLOLITES SOME WITH ORGANIC LAMINAE MINOR VERT FRACS ϕ ≈ 2% MUCH ANHYDRITE PLUGGING
5100	DK SHALE	WACKESTONE PELLOIDAL LAMINATED MUDSTONE SMALL ANH NODULES .5cm	Br Gr	MOLDIC ϕ 2-3% WORM BURROWS FLATTENED DEWATERING STRUCTURES NUMEROUS BLACK SH LAMINAE
5105		LT GREY LAMINATED DOL TO BIOTURBATED GREY DOL MUDSTONE	Gr	NO VISIBLE ϕ WAVY LAMINATIONS & DEWATERING STRUCTURES NO VISIBLE ϕ
5110		MUDSTONE LAMINATED MUDSTONE PELLOIDAL	Gr Lt Gr	NO VISIBLE ϕ
5115		MUDSTONE/ PACKESTONE PELLOIDAL NUMEROUS SMALL ANHYDRITE XTLS & NODULES MUDSTONE/PACKESTONE	Tan Lt Br	5117.5 GOOD MOLDIC ϕ 5-6% oil stained BRACHIOPOD MOLDS SOME INTERGRANULAR ϕ MUCH ϕ OCCLUDED W/ANHYDRITE
5120		RELICT GRAINSTONE RELICT PACKESTONE	Tan Lt Br	5120 - ABUNDANT OIL STAIN 6" EITHER SIDE OF HORIZONTAL PARTING ϕ - BETTER ≈ 6-8% 5121-24 MOLDIC ϕ
5126	SHALE/KEROGEN	BIOTURBATED MUDSTONE/WACKESTONE ? M NO FEATURES P/W NO FOSSILS ?	Tan to Br Gr	AFTER 5127' NO VISIBLE ϕ LG. VERT. ANHYDRITE FILLED FRACS
5130	SHALE/ KEROGEN	M LAMINATED MUDSTONE TO BIOTURBATED MUDSTONE/WACKESTONE ? M WACKESTONE OBVIOUS BURROWS	Gr Gr Lt Br	BIOTURBATED GOOD ϕ 5-6% W/OIL STAIN
5135		WACKESTONE BIOTURBATED WACKESTONE	Lt Br Lt Br Lt Br	GOOD INTERGRANULAR ϕ GOOD ϕ 5-6% W/OIL STAIN 4-5% ϕ ABUNDANT ANHYDRITE
5140			Lt Br	PLUGGING PORES

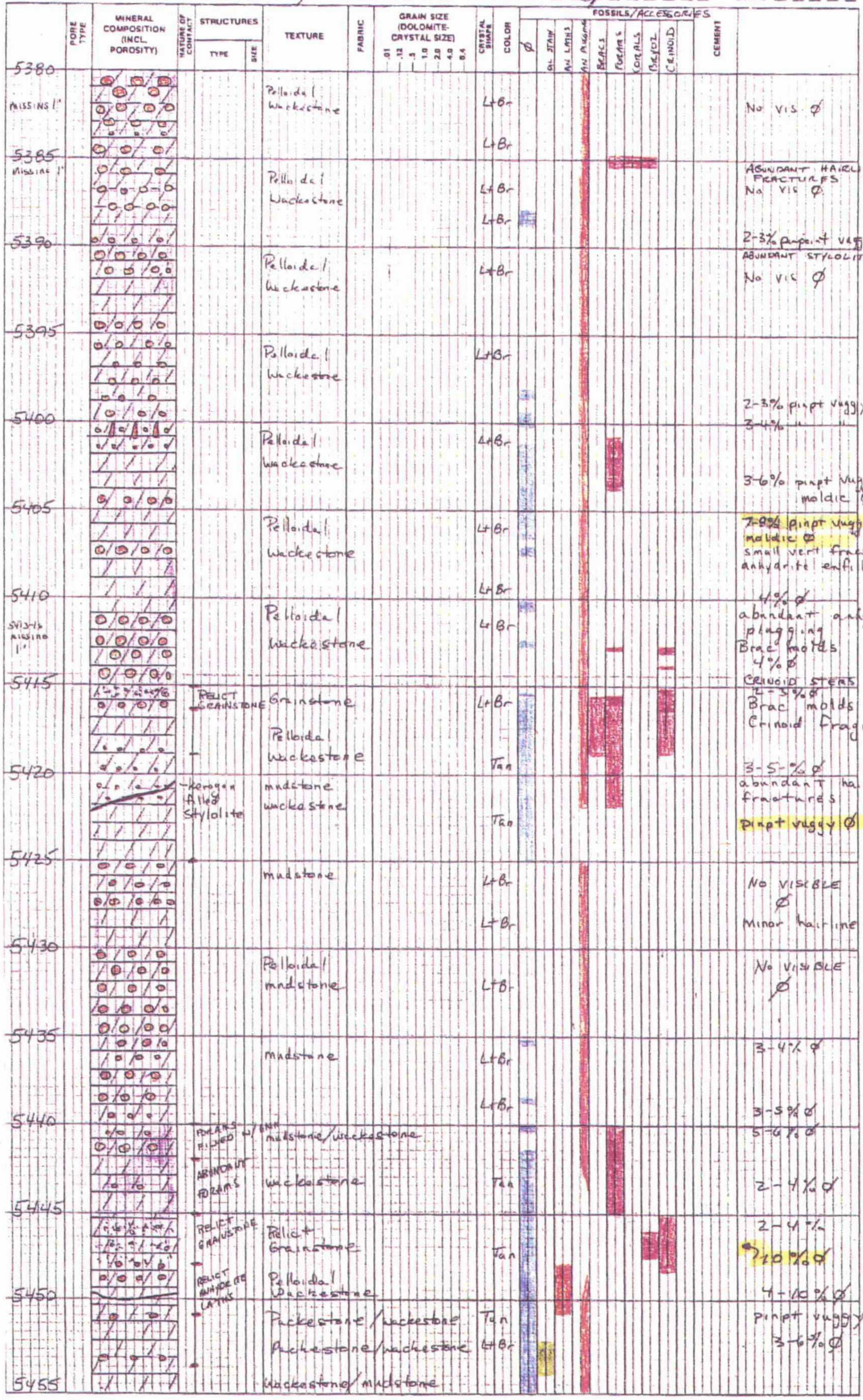
FIGURE 9A

2

sec 14 1255 R37E
1650 S & E

WELL ARCO LANGLIE FEDERAL #2 COUNTY LEA STATE N. Mex

STRATIGRAPHIC INTERVAL BLINEBRY LOGGED BY QST DATE 9-8-88



5380 – MISSING 1" – Pelloidal Wackestone – LtBr – LtBr – No vis Ø

5385 – Missing 1" – Pelloidal Wackestone – LtBr – LtBr – ABUNDANT HAIRLINE FRACTURES; No vis Ø; 2-3% pinpoint vuggy Ø

5390 – Pelloidal Wackestone – LtBr – ABUNDANT STYLOLITES; No vis Ø

5395 – Pelloidal Wackestone – LtBr – 2-3% pinpt vuggy Ø; 3-4% " " "

5400 – Pelloidal Wackestone – LtBr – 3-6% pinpt vuggy to moldic Ø Fossils

5405 – Pelloidal Wackestone – LtBr – LtBr – 7-8% pinpt vuggy to moldic Ø; small vert fracs; anhydrite enfilled pores; 4% Ø

5410 – 5413-14 missing 1" – Pelloidal Wackestone – LtBr – abundant anhydrite plugging; Brac molds; 4% Ø; CRINOID STEMS - SOLITARY

5415 – RELICT GRAINSTONE – Grainstone – LtBr – 2-3% Ø; Brac molds; Crinoid Fragments; Pelloidal Wackestone – Tan – 3-5-% Ø

5420 – Kerogen filled Stylolite – mudstone wackestone – Tan – abundant hairline fractures; pinpt vuggy Ø ≈ 10%

5425 – mudstone – LtBr – LtBr – NO VISIBLE Ø; Minor hairline fracs

5430 – Pelloidal mudstone – LtBr – No VISIBLE Ø

5435 – mudstone – LtBr – LtBr – 3-4% Ø; 3-5% Ø

5440 – FORAMS FILLED w/ ANH – mudstone/wackestone – 5-6% Ø; ABUNDANT FORAMS – wackestone – Tan – 2-4% Ø

5445 – RELICT GRAINSTONE – Relict Grainstone – Tan – 2-4% ; ?10% Ø; RELICT ANHYDRITE LATHS – Pelloidal Wackestone – 4-10% Ø ??

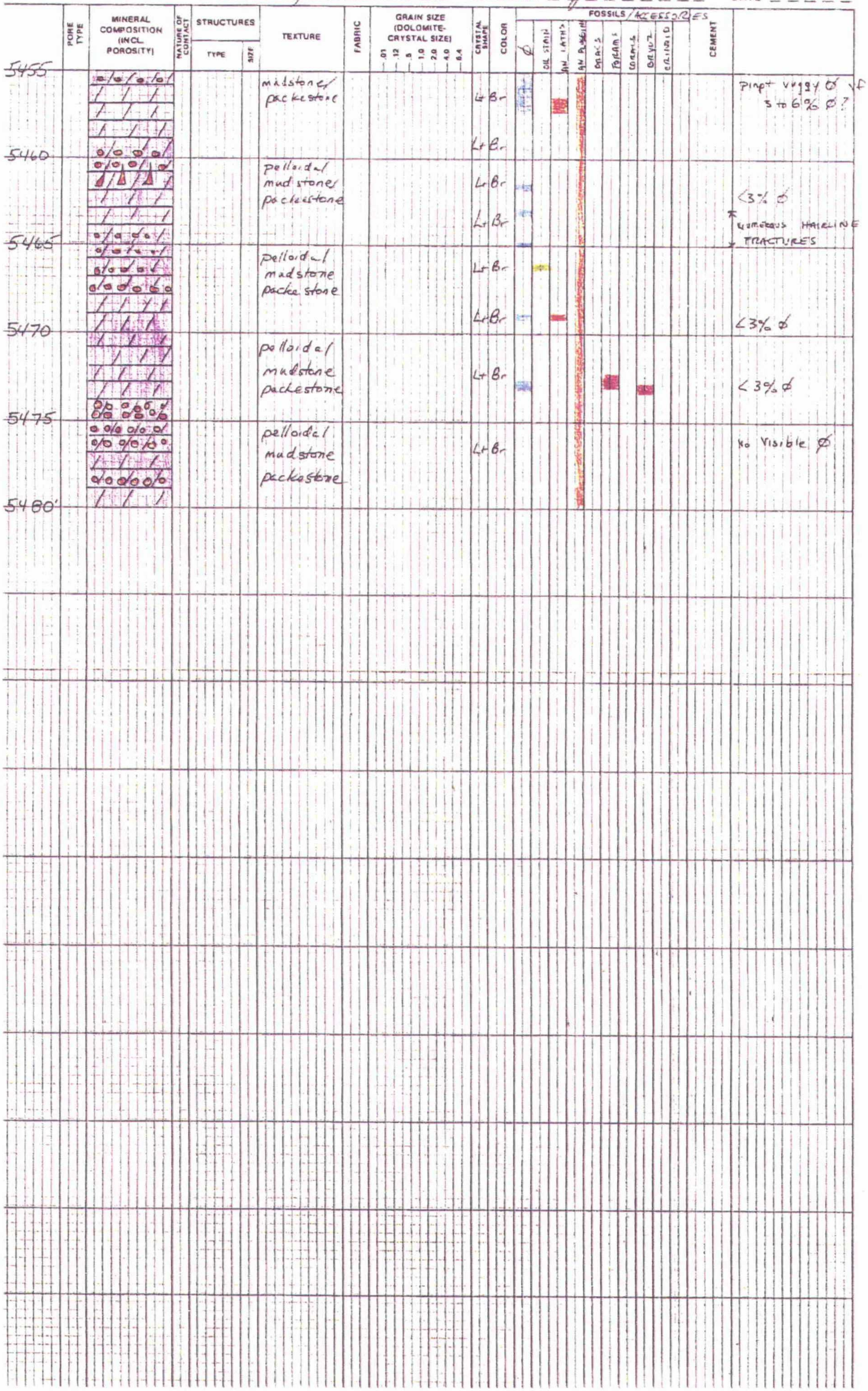
5450 – Packestone/wackestone – Tan – pinpt vuggy vf intergran; Packestone/wackestone – LtBr – 3-6% Ø; Wackestone/mudstone

FIGURE 9

sec 14 125S R37E
1650S & E

WELL ARCO LANGLIE FEDERAL #2 COUNTY LEA STATE N. MEX

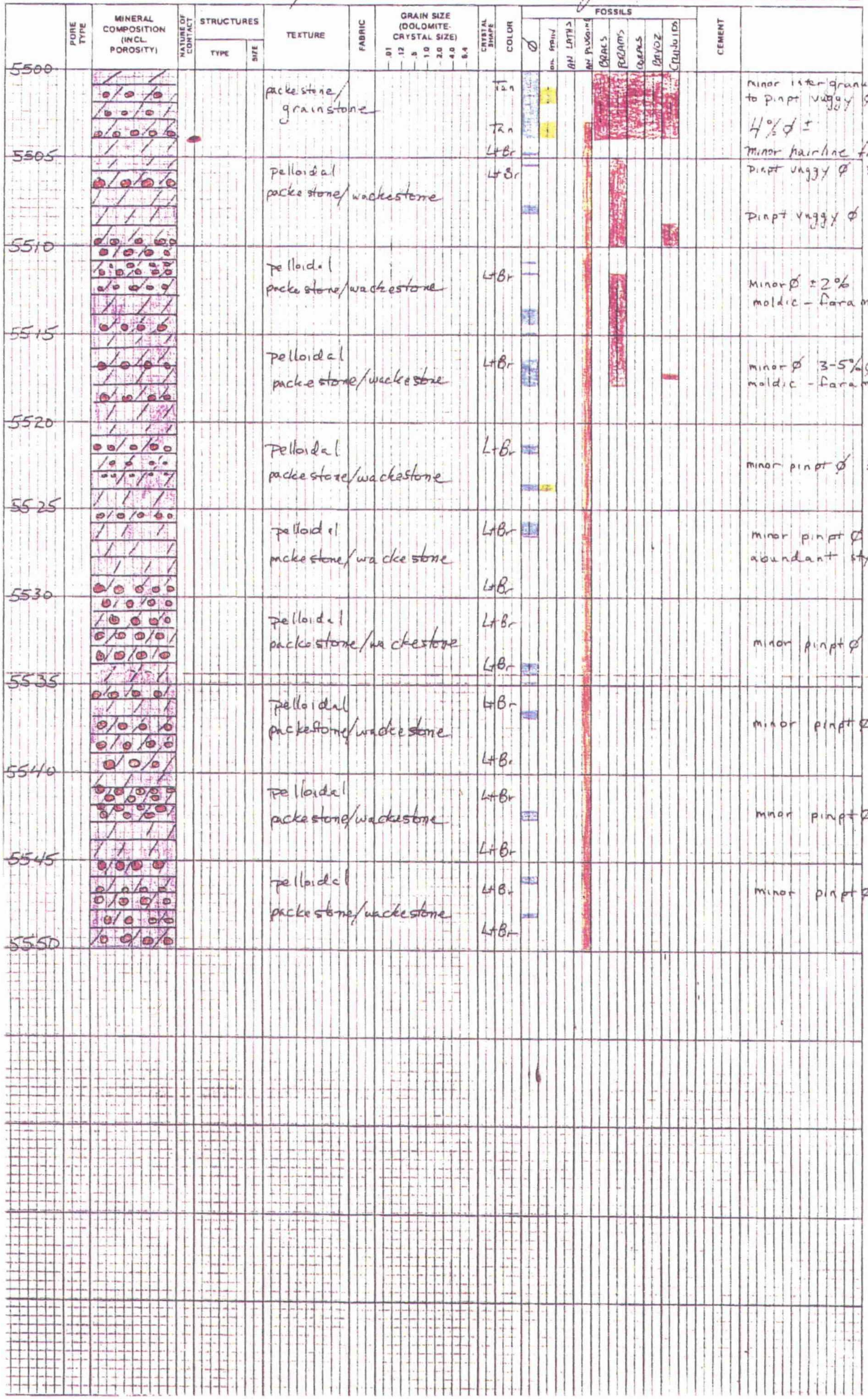
STRATIGRAPHIC INTERVAL BLINEBRY LOGGED BY JST DATE 9-8-88



WELL ARCO LANGLIE FEDERAL #2 1650'S & E COUNTY LEA STATE N. Mex

STRATIGRAPHIC INTERVAL BLINEBRY LOGGED BY JST DATE 9-8-88

FIGURE 9



	TEXTURE	COLOR	
5500	packestone/ grainstone	Tan Tan LtBr	minor intergranular to pinpt vuggy Ø 4% Ø ± minor hairline fracs
5505	pelloidal packestone/wackestone	LtBr	pinpt vuggy Ø 3-4% pinpt vuggy Ø 3-4%
5510	pelloidal packestone/wackestone	LtBr	Minor Ø ±2% moldic - forams
5515	pelloidal packestone/wackestone	LtBr	minor Ø 3-5% Ø moldic - forams
5520	Pelloidal packestone/wackestone	LtBr	minor pinpt Ø 3%±
5525	pelloidal packestone/wackestone	LtBr LtBr	minor pinpt Ø 3%± abundant stylolites
5530	pelloidal packestone/wackestone	LtBr LtBr	minor pinpt Ø 3%±
5535	Pelloidal packestone/wackestone	LtBr LtBr	minor pinpt Ø 3%±
5540	Pelloidal packestone/wackestone	LtBr LtBr	minor pinpt Ø 3%±
5545	pelloidal packestone/wackestone	LtBr LtBr	minor pinpt Ø 3%±
5550			

APPENDIX A

Appendix A - Geological Data