TECHNICAL REPORT

PART II

WATERFLOOD PLAN AND ECONOMICS

FOR

THE PROPOSED

BLINEBRY-DRINKARD UNIT

LEA COUNTY, NEW MEXICO

DECEMBER 1985

Northeast Drinkard Unit
Exhibit Twenty-Two
Cases 9230
9231
9232

<u>TECHNICAL REPORT</u>

<u>PART II</u>

WATERFLOOD PLAN AND ECONOMICS

FOR

THE PROPOSED

BLINEBRY-DRINKARD UNIT

LEA COUNTY, NEW MEXICO

DECEMBER 1985

TABLE OF CONTENTS

LIST OF TABLES

LIST OF TABLES

(Cont).

LIST OF FIGURES

LIST OF FIGURES

(Cont.)

SECTION I.

INTRODUCTION

Formal unitization efforts were initiated in October 1984 to form the proposed Blinebry-Drinkard Unit in Lea County, New Mexico for the purpose of implementing a waterflood program. The Working Interest Owners' "Charge" to the Technical Committee included the development of a waterflood plan with an economic evaluation of conducting such an operation under various premise scenarios. This report documents the Technical Committee's recommended waterflood plan, the predicted oil recoveries, the required investment, and resulting profitability.

SECTION II.

SUMMARY

The productive oil limits of the Blinebry, Tubb, and Drinkard zones within the proposed 5200 acre unit area (Figure 1) are developed on 40 acre spacing. Utilizing the available wells, it is estimated that 15.265 million barrels of incremental supplemental oil recovery can be obtained under unitized waterflood operations. With the individual leases currently in the latter stages of primary depletion, formation of the unit and implementation of the waterflood will permit development of the secondary and possible tertiary oil potential for the area. Results of the economic analyses indicate the secondary recovery project to be a very attractive venture. Key parameters from the study are summarized below.

Cumulative oil production thru 5/31/85	28.134 MMB
Remaining primary oil after 5/31/85	2.396 MMB
Ultimate primary oil recovery	30.530 MMB
Secondary-to-primary ratio	0.50
Incremental waterflood oil reserves	15.265 MMB
Total injection water requirement	296 MMB
Make-up source water requirement	216 MMB
Reinjected produced water	80 MMB

(Cont.)

Initial investment	$27.0 MM
Future investment (current dollars)	$7.3 MM
Total investment	$34.3 MM
Unit development cost	2.25 $/BBL
Profitability - 5%/year inflation case	
Present value (7/85) profit AFIT discounted	
@ 10% nominal	$35.6 MM
Percent present value profit	133%

SECTION III.

CONCLUSIONS AND RECOMMENDATIONS

The Technical Committee has concluded that the proposed Blinebry-Drinkard Unit should be a successful waterflood candidate. The oil reservoirs are in the late stages of primary depletion under a solution gas drive recovery mechanism, with significant secondary oil potential remaining. A geological evaluation of the proposed unitized interval, combined with an ongoing successful waterflood in the Drinkard formation immediately to the southwest (Figure 2) and a long history of successful waterfloods in the equivalent Clearfork formation in West Texas confirm the floodability of the proposed area. Difficulties associated with waterflooding reservoirs containing non-associated gas intervals will be approached with careful profile control efforts.

The Technical Committee, therefore, recommends that the proposed Blinebry-Drinkard Unit be formed and a waterflood program implemented. All available wellbores will be effectively utilized in order to: 1) maximize development of secondary reserves with an eighty acre five-spot injection pattern, 2) deplete the remaining primary gas reserves from the Blinebry and Tubb non-associated gas zones, 3) obtain optimum profile control by using twin, single zone injectors where possible and dual injectors where not possible, and 4) develop the San Andres water source with existing producers thus avoiding significant capital requirements associated with drilling new wellbores.

Facilities have been designed to permit reinjection of produced water. However, to prevent scale precipitation, the make-up and produced waters will be gathered and injected separately. In addition to the waterflood system, facilities have been provided to produce the remaining primary gas reserves during waterflood operations.

SECTION IV.

GEOLOGY

The reservoir for the proposed Blinebry-Drinkard Waterflood Unit is comprised of the Blinebry, Tubb and Drinkard members of the Yeso Formation, a Permian (Leonardian) carbonate sequence deposited on the Central Basin Platform (Figure 3). This vertical sequence is approximately 1300 feet thick (Figure 4). The Blinebry and Drinkard are stratigraphically equivalent to the Upper and Lower Clearfork respectively in West Texas.

A petrophysical study was conducted as part of the "Feasibility Study for the Proposed Blinebry-Drinkard Waterflood Unit". The study concluded that there is a large degree of uncertainty associated with the log-core relationship which has a significant impact on evaluation of individual wells. Considering the sensitivity of OOIP calculations to porosity, it was recommended that log derived parameters of SoØh should not be used in determining working interest owner equities. No further petrophysical evaluation of logs has been conducted in conjunction with this report.

STRUCTURE

The structure in the proposed unit area is part of the NNW-SSE trending anticline of the Penrose-Skelly trend that parallels the western edge of the Central Basin Platform. The area encompassed by the proposed waterflood unit is a broad anticline with approximately 300 feet of structural relief at the top of the Blinebry (Figure 5). Dips are low, generally 1° to 2°. This structure is repeated in the Tubb and Drinkard members because the thicknesses of the Blinebry and Tubb remain relatively constant.

RESERVOIR CHARACTERISTICS

In order to understand reservoir quality rock types, lithologies and textures, Blinebry and Drinkard core material was examined from three wells in the proposed unit area. These include:

Shell Western Coll No. 2 Sec. 12, T21S, R37E (Non-Unit Well)	Blinebry	250'
Shell Western State "2" No. 19 Sec. 2, T21S, R37E	Blinebry	250'
Shell Western Taylor-Glenn No. 10 Sec. 3, T21S, R37E	Blinebry Drinkard	72' 170'

Core material from the Tubb was not available for examination from any well in the proposed unit area. Core analysis data were available from five additional wells in the proposed unit area and include:

Exxon Blinebry-Tubb Gas No. 1 Sec. 10, T21S, R37E (Non-Unit Well)	Blinebry Tubb	200' 191'
Conoco Hawk "B-10" No. 10 Sec. 10, T21S, R37E	Tubb	108'
Conoco Hawk "B-3" No. 16 Sec. 3, T21S, R37E	Tubb	150'

Conoco Hawk "B-3" No. 18 Sec. 3, T21S, R37E	Blinebry	290'
Arco Sarkeys No. 4 Sec. 23, T21S, R37E	Blinebry	359'

All core analyses are displayed in Figures 6-15. These plots of porosity-permeability versus depth also show the appropriate stratigraphic markers as interpreted from log correlation.

Blinebry

The Blinebry is a tan to gray dolomite with varying amounts of nodular, replacement and pore-filling anhydrite. Shale and "organic-rich" material are rare, but occur in very thin beds. Limestone and bedded anhydrite are also rare and generally occur in thin beds. The vertical sequence consists of thin bedded porous reservoir quality rock interbedded with dense, generally thicker bedded non-reservoir rock.

Reservoir quality rock consists of grain-supported dolomite packstone. The packstones are generally pelletal with varying amounts of skeletal debris. The reservoir quality rock is oil stained and contains visible interparticle, intercrystal (sucrosic) and moldic porosity. Even though this is the best reservoir lithology in the Blinebry, the measured air permeability rarely exceeds 1 millidarcy (17% of the available core analyses). Intervals which do exceed 1 millidarcy in permeability average less than 2 feet in thickness. The average air permeability measured on Blinebry core from six wells in the proposed unit area (Table 1) is 2.45 millidarcies for samples having measured air permeability greater than or equal to 0.1 millidarcy.

Non-reservoir quality rock consists of mud-supported dolomite and lime wackestone and mudstone. The wackestones are skeletal or contain intraclasts and the mudstones range from being featureless, to well burrowed or algal laminated. Visible porosity consists of moldic along with trace amounts of vug porosity. These pore systems are poorly connected and generally exhibit measured air permeability of less than 0.1 millidarcy.

Bioturbation is common in the Blinebry and burrowed zones have high anisotropic permeability. Matrix permeability is enhanced by short <u>hairline</u> natural fractures. There is not, however, enough evidence to suggest that natural fracturing has imposed any significant directional permeability that will affect waterflood performance.

Individual porosity zones in the Blinebry reservoir have significantly different hydrocarbon fluid (Figure 16). Across nearly all of the proposed unit area, Zone I of the Blinebry is gas bearing. Zone II also produces gas and 55° API gravity condensate over much of the area. The maximum depth of gas and associated condensate production is approximately -2250. The three lower zones (III, IV, V) produce 38-40° API gravity oil and associated gas with a high GOR.

Tubb

Shell Western has no Tubb core material for examination in conjunction with this study. Arco, however, in their unitization report (Proposed Blinebry Unit Waterflood Study) of 1971, has described the Tubb as a gray, fine-grained, silty sandstone interbedded with brown, finely sucrosic sandy dolomite. This basic description is confirmed by the mudlog of the recently drilled (1984) Shell Western Livingston No. 14, Section 3, T21S, R37E.

Both oil and gas are produced from the Tubb reservoir, with oil production from perforations as high as -2750 and gas production from perforations as low as -3050. This suggests that the Tubb reservoir intervals are extremely discontinuous, with individual pay lenses differing in their original hydrocarbon composition (oil or gas).

The Tubb appears to have lower permeability than the Blinebry or the Drinkard. Only 6.5% of the core analyses available for this study have measured air permeability greater than or equal to 1 millidarcy. Intervals which do exceed 1 millidarcy in permeability average less than 2 feet in thickness. The average air permeability measured on Tubb core from three wells in the proposed unit area is 1.19 millidarcies for samples having measured air permeability greater than or equal to 0.1 millidarcy (Table 2).

Drinkard

The Drinkard is a tan to dark gray limestone and dolomite. Pore-filling and replacement anhydrite are most common in the limestone and nodular anhydrite is most common in the dolomite. Limestone and dolomite can both be reservoir quality rock, however, limestone is most common.

Reservoir quality rock consists of skeletal lime grainstone and minor amounts of lime packstone. These rock types are oil stained and contain visible interparticle and moldic porosity. Dolomite pelletal packstone is a less common reservoir lithology with skeletal fragments being rare. These intervals are also oil stained and contain interparticle, inter-crystal (sucrosic), moldic and trace amounts of intraparticle porosity. Approximately 23% of the core samples have measured air permeability greater than or equal to 1 millidarcy. Intervals which do exceed 1 md in permeability average less than 2 feet in thickness. The average air permeability measured on Drinkard core from one well in the proposed unit area is 2.45 millidarcies for samples having measured air permeability greater than or equal to 0.1 millidarcy (Table 3).

Non-reservoir quality rock consists of mud-supported dolomite and lime wackestone and mudstone. The wackestones are skeletal or contain intra-clasts and the mudstones are massive, burrowed or most commonly algal laminated. Visible porosity consists of moldic and vug pore types. These pore types are poorly connected as evidenced by measured air permeability of less than 0.1 millidarcy.

Short, open natural fractures also provide permeability enhancement in the Drinkard and burrowed intervals can have high anisotropic permeability.

All zones within the Drinkard produce oil with a high GOR along with some water.

Depositional Environment

The vertical lithologic sequence in the proposed area is interpreted to represent a series of thin regressive depositional cycles. These cycles are characterized (from bottom to top) as subtidal (marine) changing upward to intertidal and supratidal. The best reservoir quality rock in both the Blinebry and Drinkard is contained within the marine intervals. The intertidal and supratidal intervals can be moderately porous but generally have low permeability.

These regressive cycles do not follow a predictable pattern when related to log response. That is, the high resistivity intervals are not generally dense supratidal rock and the low resistivity intervals are not completely porous marine lithologies.

STRATIGRAPHY AND WELLBORE UTILIZATION

The cyclic nature of the Blinebry, and to a lesser extent the Drinkard, is evident from stratigraphic correlation of logs throughout the proposed unit area. There are five cycles recognized in both the Blinebry and Drinkard. The Blinebry cycles are most important from a fluid distribution standpoint and will be discussed. Some cycles contain both oil and gas at different locations within the proposed unit boundary. It is important to understand these cycles in order to properly plan well completions (producer, injector, etc.). The Drinkard cycles are less important for planning well completions and will not be considered in this report.

The Blinebry cycles are best recognized from electric log response. Porous intervals show up as areas of low resistivity separated by high resistivity dense intervals. This cyclic character is also recognized on the available sonic and neutron logs with porous intervals alternating with non-porous intervals. After a thorough examination of three cored wells (742' of Blinebry and Drinkard core) from the proposed unit area, it was found that log response (electric and neutron) has little relationship to environmental interpretation but generally confirms the presence or absence of reservoir quality lithologies. Therefore, the observed cyclic log response cannot be directly related to major regressive cycles of deposition even though the log correlations can be easily carried across the field. The cycles observed during core examination are minor when compared to the scale of log correlation field wide.

No attempt has been made to correlate individual porosity streaks within each zone due to the poor log quality field wide. Thus no estimate has been made of continuity. Gulf's experience with flooding the Drinkard (Central Drinkard Unit) along with the overall gross correlation among zones strongly supports the potential for both the Blinebry and Drinkard as floodable units. The Tubb, on the other hand, is expected to be only locally floodable because of the apparent patchy distribution of porous zones and hydrocarbon fluid type.

Wellbore selection and utilization was determined by several factors: 1) the need to control water injection with dual injectors, 2) available wellbores contributed by the various companies, 3) the need to produce Tubb gas from separate wellbores and 4) the need to inject water in the Tubb oil areas and not in the gas areas. This resulted in 14 different types of wellbore completions throughout the proposed unit area (Figure 17).

The lateral and vertical relationships between well types, geologic structure and stratigraphy are illustrated in a series of block-panel diagrams that cover the entire proposed unit area (Figures 18-23). These diagrams not only show the surface configuration of the various well types, but include a fence-type illustration of each individual well along north-south lines of section. The isometric view of the various parallel panels gives one a sense of the three-dimensional relationships among the wellbores as well as the structural variation and stratigraphic correlation on a field wide scale.

SECTION V.

PRIMARY PERFORMANCE

The Drinkard Field was discovered in October 1944 with the completion of Gulf Oil Company's Vivian No. 1. Field development of the numerous productive oil and gas zones has continued field wide until present date, with the major activity occurring between 1948 and 1958. The productive zones in this field are the Brunson Ellenburger, Hare Simpson, Fusselman, Wantz Abo, Drinkard, Tubb, Blinebry, Penrose-Skelly and San Andres. The Drinkard Field is developed on 40-acre spacing.

Completion techniques varied from lease to lease in the Drinkard Field. Within the proposed 5200 acre unit area, the most common completion method was to selectively perforate through casing. Several wells, however, were completed open-hole. Most of the wells were acidized and/or fracture treated with oil treatments ranging from 5000-90,000 gallons. Remedial work has consisted mainly of treating existing zones, perforating additional pay, and recompleting new zones. Since the mid-1970's, oil production from the proposed unitized interval has been downhole commingled. The combinations were, and are currently threefold: Blinebry and Tubb, Tubb and Drinkard, or Blinebry and Drinkard.

The proposed unitized interval (Blinebry, Tubb, and Drinkard) consists of several pay zones separated by dense, tight streaks. In general, the upper two zones in the Blinebry reservoir are gas bearing producing under a simple pressure depletion primary recovery mechanism. The lower three zones in the Blinebry reservoir are generally oil bearing, and are being depleted under a solution gas drive type mechanism. The gas zones and oil zones are separated by 20 to 40 feet of tight rock. These individual depositional cycles (zones) of the Blinebry reservoir produce significantly different hydrocarbon fluids. Across nearly all of the proposed unitized area Zone I produces mainly gas. Zone II also produces gas and 55° API gravity condensate over much of the area. The maximum depth of the gas and associated condensate production is approximately -2250. The lower three cycles of the Blinebry interval, Zones III thru V, produce 38-40° API gravity oil and associated gas with a high GOR. The Tubb reservoir, directly underlying the Blinebry reservoir, is primarily gas bearing; however, it is oil bearing over a portion of the proposed unit area, producing under solution gas drive. The Tubb reservoir is gas productive from perforations as low as -3050 and oil productive from perforations as high as -2750; indicating that the Tubb pay intervals are extremely discontinuous. Injector and producer locations have been selected to maximize the Tubb waterflood oil reserves, as well as, effectively deplete the remaining Tubb gas zone reserves. Water injectors will be located only in the oil productive areas. A Tubb production surveillance study, and the resulting waterflood plan is further discussed in Section VI of this report.

The five depositional cycles (Zones I thru V) of the Drinkard reservoir are oil bearing, producing under a solution gas drive type mechanism. All of these zones, or cycles, produce 38-40° API gravity oil and associated gas with a high GOR. The Drinkard reservoir does not appear to have separate upper gas bearing zones as observed in the Blinebry reservoir. A schematic cross section of reservoir development and hydrocarbon accumulations in the Blinebry, Tubb, and Drinkard is shown in Figure 16.

Cumulative oil production from the proposed unitized interval for all individual leases within the unit area through May 31, 1985 was 28,134 MBO. The remaining primary oil recovery after May 31, 1985 was estimated at 2,396 MBO. The primary oil reserves were determined by adding together each lease's remaining primary obtained from individual lease exponential (constant percentage) decline curve analysis. Nominal decline factors for each lease were determined by performing a least squares fit through actual historical production data within a representative time interval. The average nominal decline factor for the leases was approximately 9.5% per year. With an expected ultimate primary oil recovery from the proposed unitized interval of 30,530 MBO, the Blinebry, Tubb, and Drinkard primary oil is about 92% depleted.

Unit wide oil production from the proposed unitized interval has followed a constant, shallow decline since 1970, as shown in Figure 24. Some periods of increased production are evident due to remedial workovers or recompletions. However, the unit wide oil production does return to its historical decline rate of approximately 9.5% per year. Based on this historical decline, remaining primary reserves as of January 1, 1987 were estimated at 1,993 MBO. The unit wide remaining primary production forecast (oil and gas) is listed by year in Table 4. These yearly remaining primary oil and gas production volumes were incorporated in the economic analyses discussed further in Section XI of this report.

The primary oil production performance has been indicative of a solution gas drive type mechanism. The average reservoir pressure has declined to approximately 400 psi. The GOR performance and very low water production also support the solution gas drive mechanism. The GOR increased steadily through most of the productive life of the Blinebry/Tubb/Drinkard. When these zones were about 85-90% depleted, the GOR peaked and started declining at its present rate. Some water is produced from the proposed unitized interval, but there is no evidence of an active water-drive.

SECTION VI.

WATERFLOOD PLAN AND EXPECTED PERFORMANCE

The Chevron (formerly Gulf) operated Central Drinkard Unit, the proposed Conoco operated East Blinebry Unit and the proposed Sun operated North Drinkard Unit flood or plan to flood portions of the same correlative interval evaluated for the proposed Blinebry-Drinkard Unit waterflood. The Central Drinkard Unit touches the southwest corner of the proposed Blinebry-Drinkard Unit, while the proposed East Blinebry and North Drinkard Units directly offset the eastern and western boundaries, respectively, of the proposed unit (Figure 2). Valuable performance data and other information obtained from these existing and proposed units were incorporated into the overall waterflood plan and expected performance for the proposed unit.

WATERFLOOD OPERATING PLAN

Due to the varying reservoir characteristics, as well as the non-associated gas zones within the proposed unitized interval, all available wellbores must be effectively utilized in order to: 1) maximize development of secondary reserves with an 80-acre five-spot injection pattern, 2) deplete the remaining primary gas reserves from the Blinebry and Tubb non-associated gas zones, 3) obtain optimum profile control by using twin, single zone injectors where possible and dual injectors where not possible, and

4) develop the San Andres water source with existing producers thus avoiding significant capital requirements associated with drilling new wellbores.

The Central Drinkard Unit (analog field) operated by Chevron has been successfully waterflooding the Drinkard reservoir with an 80-acre five-spot injection pattern since 1967. An 80-acre five-spot injection pattern is also planned for flooding the Blinebry reservoir of the proposed East Blinebry Unit. It is therefore, recommended that the proposed Blinebry-Drinkard Unit be developed with an 80-acre five-spot injection pattern, which would be a continuation of the offsetting waterflood pattern planned for the East Blinebry Unit. A row of buffer producers will be located on all remaining unit borders. With Sun currently in the early stages of forming their proposed North Drinkard Unit, buffer producers are initially planned for this common boundary. However, a cooperative leaseline injection pattern will be arranged upon completion of Sun's unitization efforts.

The oil bearing zones of the Blinebry and Drinkard reservoirs will be flooded over the entire unit area. Only the oil bearing areas of the Tubb reservoir will be flooded in the the proposed unit. The Tubb oil bearing areas occur generally in Section 2 and the north half of Section 10 and are discussed further in the "Tubb Surveillance" portion of this section.

It is recommended that production from the Blinebry oil zones and Drinkard zones be commingled during waterflood operations to efficiently utilize existing wellbores. Within the Tubb oil productive areas, commingled Blinebry oil zones , Tubb, and Drinkard production is recommended. Buffer commingled Blinebry, Tubb, and Drinkard oil producers will also be located around these areas. This will minimize oil resaturation losses into the Tubb gas productive areas. In the Tubb gas productive areas, available twin wellbores will be used to deplete the remaining non-associated Tubb gas zone reserves.

To prevent loss of waterflood response oil to the low pressure Blinebry gas zones, as well as possible water block damage to these gas zones, Blinebry gas zone gas will not be commingled with the Blinebry and Drinkard oil and water production. Rather, Blinebry and Drinkard commingled oil producers with vent strings will be used to deplete the non-associated Blinebry gas zones, and will be located every 160 acres within the unit area. This will ensure that the non-associated Blinebry gas reserves will be recovered during waterflood operations. Shell Western has successfully used vent string completions for producing gas zones in the Vacuum field, New Mexico (discussed further in Section VII).

It is also recommended that twin, single zone injectors be used where possible, and dual injectors where not possible, for optimum profile control during waterflood operations. As mentioned earlier, the varying reservoir characteristics of the Blinebry/Drinkard and Tubb reservoirs, as well as the non-associated gas zones of the Blinebry and Tubb reservoirs within the proposed unitized interval support the need for increased profile control measures. Both the Blinebry and Drinkard have average permeabilities of approximately 2.45 md, while the Tubb average permeability is about one-half of this, or 1.19 md (see Section IV). In addition, careful profile control efforts should further ensure that water is injected only into the oil bearing zones of the Blinebry, Tubb, and Drinkard formations. Subsequent to initiating water injection, periodic surveillance including evaluations of profile surveys will be conducted to ensure that proper profile control is being achieved. Twin, single zone injectors and dual injectors (as opposed to single injectors injecting commingled in all three formations) involve higher initial investments, increased operational costs, and additional routine maintenance. However, the increased effective profile control achieved with twin and dual injectors should result in a more successful, efficient, and higher oil recovery waterflood, thus resulting in a more profitable plan of operation over the long term. Shell Western has used dual injector completions with 2-1/16" tubing strings in the Big Mineral Creek field. These completions have operated essentially trouble free for over twenty years (discussed further in Section VII).

A 1,200 psi injection pressure is recommended, based on the New Mexico Oil Conservation Commission's regulation of 0.2 psi/ft of depth.

The Technical Committee also recommends that the San Andres water source be developed with existing twin, shallow wellbores (penetrating only the Blinebry formation) located in Sections 2 and 3 within the proposed unit area. It is estimated that ten wellbores will provide the make-up requirements. The initial San Andres completions will verify the actual number of source water producers required to provide sufficient make-up water for field wide injection. In addition, a testing program will be conducted prior to implementing source water facilities, to confirm the San Andres reservoir as a viable and adequate water source. Injection water requirements and the water source are further discussed in Section VIII of this report.

The overall waterflood plan including the proposed injection pattern and the utilization [commingled oil (Blinebry/Tubb/Drinkard) producer, gas (Tubb) producer, single (Blinebry) injector, etc.] of wellbores to be included in the unit are illustrated on Figure 17. Figures 18 thru 23 further illustrate three-dimensionally how each well will be utilized to waterflood the oil bearing zones while effectively depleting primary non-associated gas from gas bearing zones, which is the ultimate goal of the overall waterflood plan for the proposed Blinebry-Drinkard Unit.

EXPECTED WATERFLOOD RECOVERY AND PERFORMANCE

Ultimate Waterflood Recovery

As mentioned earlier in this section, the Chevron (formerly Gulf) operated Central Drinkard Unit, which adjoins the southwest corner of the proposed unit boundary was used as the analog to predict the proposed

Blinebry-Drinkard Unit's waterflood recovery and performance. Only the Drinkard formation is under flood in the analog unit and over twenty years of waterflood performance is available. A secondary to primary recovery ratio (S/P) of 0.50 was calculated based on actual production data from the analog unit supplied by Chevron. Certain assumptions were made when estimating the waterflood reserves for this Drinkard waterflood. The assumptions used to predict future performance, along with information concerning the current and past performance and history of the Central Drinkard Unit are further discussed in the "Analog Field" portion of this section. The proposed Conoco operated East Blinebry Unit, located directly adjacent to the proposed eastern unit boundary, will flood only the Blinebry formation. Conoco calculated a secondary to primary ratio (S/P) of 0.635, based on a combination of material balance and volumetric equations using reservoir and fluid parameters from the East Blinebry Unit, and assuming a primary recovery efficiency of 20% of the original oil in place (OOIP). Theoretical calculations were used to estimate areal and vertical sweep efficiencies.

Applying Conoco's methodology to the Central Drinkard Unit to verify the assumptions made when predicting the unit's waterflood performance, a 0.53 S/P was calculated. A 20% OOIP primary recovery efficiency was also assumed, but the sweep efficiency was discounted to account for resaturation losses. A 0.54 S/P was calculated for the proposed Blinebry-Drinkard Unit, again using the methodology described above and incorporating the same assumptions. Therefore, a secondary to primary ratio of 0.50 to predict the ultimate waterflood recovery of the proposed Blinebry-Drinkard Unit should be a realistic estimate. In addition, a 0.50 S/P is a typical average of many mature waterfloods in the Upper and Lower Clearfork formations in West Texas , which are stratigraphically equivalent to the Blinebry and Drinkard formations in New Mexico. The 0.50 S/P ratio results in an estimated ultimate waterflood recovery of 15.265 MMSTB for the proposed unit.

Expected Waterflood Performance

The Blinebry oil zones are expected to respond to water injection in a manner similar to the Drinkard zones. This should be a reasonable assumption since the permeability and reservoir pressure characteristics are similar for both the Blinebry and Drinkard formations. The average permeability calculated with available core data for both formations is estimated to be 2.45 md. Average permeabilities are discussed further in Section IV, and are listed in Tables 1 thru 3. Although limited current pressure data are available, previous detailed reservoir studies by Shell Western of the Drinkard field estimated the average reservoir pressure for both the Blinebry and Drinkard formations to be approximately 400 psi. Other average reservoir rock and fluid properties estimated for the Blinebry and Drinkard formations are also similar: the average porosity, water saturation, and oil gravity are approximately 9.0%, 25%, and 38-40° API for each, respectively (Tables 5 and 6). The assumption was also made that permeability and reservoir pressure characteristics of the Blinebry and Drinkard formations in the proposed unit are similar to those of the Drinkard formation in Chevron's Central Drinkard Unit. Core data and pressure data from the analog unit were not available for Shell Western to verify this assumption. However, with the existing and proposed unit directly offsetting one another, and the five depositional cycles of the Drinkard formation easily correlated across the field, the assumption that reservoir characteristics are similar for the Drinkard formation in both units seems reasonable.

Therefore, the oil and water production and injection forecasts during waterflood operations were predicted using the full-scale performance of Chevron's successful waterflood project.

The gas production during water injection cannot be predicted with the analog field performance. The Blinebry and Tubb gas zones do not exist in the Central Drinkard's unitized interval, since only the Drinkard formation was unitized, as they do in the proposed Blinebry-Drinkard's unitized interval. Therefore, another approach was taken to estimate the gas production performance for the proposed unit. The total gas production consists of two parts: 1) the Blinebry and Tubb gas zone gas production, which will continue to be produced under a pressure depletion type mechanism during waterflood operations and 2) the solution gas associated with the Blinebry, Tubb, and Drinkard oil production, which is expected to respond to water injection in the typical waterflood response manner.

The oil production forecast, along with the gas zone, solution, and total gas production forecasts, are tabulated in Table 7. The anticipated performance under waterflood operations is plotted in Figure 25. The date of unitization and initiation of water injection was assumed to be January 1, 1987 and January 1, 1988, respectively, for predicting future performance.

Water injectivity estimates were also based on historical performance from Chevron's Central Drinkard Unit. The predicted Drinkard formation injectivities were based directly on injection performance of the Drinkard injectors in Chevron's unit. The average initial Drinkard injectivity should be approximately 750 BWPD per well, declining to approximately 250 BWPD per well as the reservoir approaches fillup. The Blinebry and Tubb formations injectivities were derived using the following approximation:

$$\frac{\text{Blinebry (or Tubb) formation Average permeability-thickness product (md-ft)}}{\text{Drinkard formation Average permeability-thickness product (md-ft)}} \times \text{Drinkard formation Injectivity (BWPD)}$$

The initial Blinebry formation injectivity should be approximately 600 BWPD per well, declining to approximately 200 BWPD per well as the reservoir approaches fillup. This estimate of initial Blinebry formation injectivity is consistent with actual injection performance for two Conoco operated lease co-op Blinebry injectors located in the northern part of the proposed Unit. Conoco commenced water injection into the

Conoco Hawk B-3 No. 15 and the Southland Royalty State Sec. 2 No. 6 in 1983. Average stabilized water injection rates for these two wells have been 422 BWPD and 787 BWPD, respectively. The initial Tubb formation injectivity should be approximately 225 BWPD per well, declining to approximately 75 BWPD per well. As mentioned earlier in this section, the Blinebry and Drinkard formations have similar permeability and reservoir pressure characteristics. However, the Tubb formation has an average permeability of 1.19 md, approximately one-half that of the Blinebry and Drinkard formations. No current pressure data is available for the Tubb formation.

Ten injection locations (one dual injector or two twin injectors) will be injecting water in the Blinebry, Tubb, and Drinkard formations. These injection locations will be on 40-acre spacing in Section 2 and the north half of Section 10. These areas are mainly oil productive in the Tubb formation, and are discussed further in the Tubb surveillance portion of this section. Each of these 10 injection locations will initially inject approximately 1,575 BWPD, declining to approximately 525 BWPD. The remaining 36 injection locations will be injecting water in the Blinebry and Drinkard oil bearing formations only. Each of these injection locations will be on 40-acre spacing over the entire unit area (with the exception of Section 2 and the north half of Section 10), and will initially inject approximately 1,350 BWPD, declining to approximately 450 BWPD. The water injection for the total unit and for average injection locations (one dual injector or two twin injectors) are listed by year in Tables 8 and 9.

ANALOG FIELD

As mentioned earlier, the Central Drinkard Unit, currently operated by Chevron, was used as the analog to predict the proposed Blinebry-Drinkard Unit's waterflood performance. An 80-acre five-spot injection pattern is being used to flood only the Drinkard formation in Chevron's 2,560-acre unit, located to the southwest of the proposed unit. Buffer producers are located on all but the western border. Gulf Oil Corporation initiated the flood with a six injector pilot in 1967, expanding to full scale in 1972. An ultimate primary recovery estimated at 9,690,160 barrels, was included as part of the data submitted to the New Mexico Oil Conservation Commission (NMOCC) for the unitization hearing held in April, 1965 (Case No. 3241). Chevron's (formerly Gulf's) waterflood has shown excellent response. The peak oil production rate held constant at 15,000 BOPM for over five years, then began increasing in early 1982 from 15,000 to 18,000 BOPM by late 1984. The main reasons for this second oil production rate increase, as disclosed by Chevron, was twofold: 1) The Drinkard formation was fracture treated in several wells resulting in the majority of the unit wide oil production rate increase during this time period and 2) several gas wells drilled in 1979 were recompleted to the Drinkard oil zones during the latter part of this two year time period. These recompletions resulted in both increasing the unit wide oil production rate and reducing the well spacing to 20 acres in some areas of the unit. These recompletions began around mid-1983. Since for our study the 40 acre waterflood performance of the analog field was of major importance, the production data only through mid-1983 was included in the ultimate waterflood calculation. After mid-1983, the waterflood reserves were estimated, and using this approach, only the production increase due to the fracture treating program was incorporated into the reserve estimate with no production increase due to the gas well recompletions to Drinkard oil wells being included.

From early 1983 to late 1984, the average daily oil production rate in the Central Drinkard Unit increased over 2,000 BOPM; from just under 16,000 BOPM to over 18,000 BOPM. Both the fracture treating program and the gas well to oil well recompletion program were being conducted simultaneously during this period. It was assumed that each program contributed approximately 50% of the increase to the unit wide oil production rate during this two year time period. Only the increase in oil production rate due to the fracture treating program was included in the remaining waterflood reserves estimate, since only the 40-acre waterflood performance of the analog unit was being considered. This resulted in the peak oil production rate increasing only 1,000 BOPM to 17,000 BOPM by mid-1984. Assuming the 17,000 BOPM peak rate will be maintained through 1988 and then decline at approximately 10% per year to economic depletion, the ultimate waterflood recovery was calculated to be 4,815,159 BBL. This results in a secondary to primary recovery ratio of 0.497 for the Central Drinkard Unit.

TUBB SURVEILLANCE

A production surveillance study of the Tubb formation was conducted to determine the Tubb oil productive areas to be waterflooded for recovery of incremental secondary reserves, and the Tubb gas productive areas which will require continued depletion of the remaining primary gas reserves. The Tubb reservoir is very discontinuous, with more localized distribution of hydrocarbons than either the Blinebry or Drinkard reservoirs. For example, the Tubb formation is oil productive from perforations as high as -2,750 and gas productive from perforations as low as -3,050, thus indicating extreme discontinuities. Also illustrating the discontinuous nature of the Tubb is the wide range of gas to oil ratios (GOR's) of Tubb producers: Tubb oil producers* with GOR's of 10,000-20,000 SCF/STB located directly adjacent to Tubb gas producers* with GOR's of 200,000-500,000 SCF/STB are not uncommon.

Due to the extreme discontinuities and the varying localized oil and gas distributions, the Tubb reservoir was not considered for a field wide waterflood as were the Blinebry and Drinkard reservoirs. However, waterflooding the oil bearing portions for additional incremental secondary reserves while depleting the gas bearing portions for remaining primary gas reserves appears feasible.

* Tubb producers are classified as oil or gas wells by the New Mexico Oil Conservation Commission (NMOCC) depending on the gas/oil ratio: oil well - $<$ 50,000; gas well - $\geq$ 50,000.

The oil and gas productive areas could not be identified with available log data. The log quality is very poor field wide. Most of the logs available are older vintage electrical surveys; the main porosity tool being the older vintage cased hole neutron log. Alternative data sources were therefore utilized to conduct the Tubb surveillance study. These data sources included: 1) oil and gas initial and current producing rates and cumulative production data, 2) drill stem test data, 3) gas to oil ratios (GOR's) and/or NMOCC well classifications, and 4) °API gravity data of produced liquid hydrocarbons to differentiate between crude oil and condensate production. Taking all available data into consideration, the oil productive areas of the Tubb reservoir are limited mainly to all of Section 2 and the north half of Section 10. The remaining sections within the proposed boundary produce mainly gas with some limited scattered oil.

Within the oil productive areas mentioned above, the oil well GOR's are all under 20,000 SCF/STB. Within the mainly gas productive areas, the GOR's are generally 500,000 SCF/STB or higher for the gas wells, with exceptions for the few scattered oil wells. The °API gravities for liquid hydrocarbon production range from 38-41° for the oil productive areas and from 38-54° for the mainly gas productive areas. Additional Tubb production data are shown on Figures 26 and 27.

Based on the Tubb production surveillance, ten injectors (either single or dual) perforated in the Tubb formation will be located only in Section 2 and the north half of Section 10, as illustrated on Figure 17. Commingled oil

(Blinebry/Tubb/Drinkard) producers will be located within these Tubb oil productive areas, as well as around these areas as buffer producers to prevent oil resaturation losses and injection water from migrating into the gas productive areas. This extra precaution is being taken in case the oil and gas productive areas identified are not well isolated due to discontinuities as believed.

SECTION VII.

WELL WORKOVERS AND PRODUCER-TO-INJECTOR CONVERSIONS

Fourteen different well configurations are necessary to meet the production/injection needs for the Blinebry, Tubb and Drinkard formations. See Table 10. As a result, each of the proposed producers, injectors and source water wells will require workovers depending on the current status of the wells. A general outline is presented below describing the different completions as well as cost estimates for the various well preparations and/or conversions.

Estimated costs to prepare each wellbore for production average $30,000. This includes rig time, clean out, perforating, stimulating, and miscellaneous expenses such as rentals and transportation. Note that 30% of the proposed producers will initially require artificial lift installations. These will be supplied by newly converted injectors at a capital cost of $5,000/well.

OIL PRODUCERS

Most oil producers will be completed with conventional pumping well equipment. This consists of the typical completion where the tubing and pump are run to the lower portion of the producing interval to maintain a "pumped off" condition in the wellbore. Sucker rods are run from the pump to surface where the pumping unit provides the lifting mechanism. Some oil producers may be flowing well completions where artificial lift is not needed. In this case, a packer is set above the producing interval with tubing run to surface.

OIL/GAS PRODUCERS

Some oil producers have a gas zone at the uppermost interval. In this situation, a (dual) packer will be set just below the gas zone to protect it from the waterflooded the oil zones. If there exists questionable cement behind casing, a block squeeze will be done below the gas zone to prevent water and oil migration behind the casing string. The dual packer will have production tubing (typically 2-7/8" O.D.) running above and below it. Tubing below the packer will contain the pump at the lower oil producing interval with sucker rods running to the pumping unit at surface. The second production string is a 1" string to be used as a vent. This "vent string" allows the gas produced from the oil zones to reach surface without interfering with the pump. The gas zone above the packer will be produced through the annulus. Additional costs for the dual packer, vent string and installation costs are estimated at $15,000/well. This "vent string" design is necessary to exploit the field's gas reserves with the limited number of available wells. There are 32 oil/gas producers with the "vent string" design. SWEPI has wells with this completion in the Vacuum field which have proved to be reliable for many years.

GAS WELLS

Thirteen wells will produce only gas. These will be completed with a typical flowing well design where a packer will be set above the producing formation (Tubb) with tubing run to surface. If cement behind casing is questionable, a block squeeze will be performed above and/or below the gas interval to isolate it from the Blinebry and Drinkard zones being waterflooded above and below, respectively.

SOURCE WATER PRODUCERS

Ten source water wells will be completed in the San Andres reservoir. Because the water bearing San Andres reservoir has not been currently tested (last test 1965), it was assumed that the source water wells will require submersible pumps; this will be confirmed upon completion of the San Andres testing/development program subsequent to unitization. Experience in the offsetting Chevron operated Central Drinkard Unit (analog field) supports this assumption. The San Andres source water wells in Chevron's unit are currently being submersibly pumped. In the proposed unit, the submersibly pumped well design will consist of a downhole centrifugal pump and an electric motor run on tubing from surface to the producing interval. The submersible pump will be set at the lower portion of the water producing interval with controls and power source at surface.

WATER INJECTION WELLS

The water injectors may be single or dual. Single injectors will have a packer set above the zone of interest with a single tubing string run to surface. Dual injectors will have two packers and two strings of tubing to selectively inject water into more than one zone. The lower packer will be set just above the lowest zone of interest with tubing running to the upper packer and onto surface. The upper packer is a dual design. It maintains integrity of the "long string" and has the "short string" for water injection into upper zone(s) of interest. Dual injectors are used where two individual wells are not available for each water injection interval in a given forty acre tract.

Twenty-five of the dual injectors will be completed in 5-1/2" casing making for relatively tight clearances. In this case, each tubing string will be limited to 2-1/16" O.D., with one string having integral joints for easier installation. The 2-1/16" tubing is sufficiently large for log/survey tools as well as for water injection requirements. SWEPI's experience with this design in the Big Mineral Creek Unit has shown it to be reliable for over twenty years. The rest of the proposed dual injection wells will be completed in 7" casing providing enough space to run 2-7/8" tubing strings. Note that all water injection tubing strings will be internally plastic coated (IPC) for corrosion protection. Also, block squeezes will be done where cement behind pipe is questionable for profile control of the injected water.

Basic Steps for Preparation of Producers

1. Pull out of hole with all production equipment
2. Clean out hole.

Basic Steps for Preparation of Producers (Cont.)

3. Squeeze or TA (temporarily abandon with CIBP) open zones not of interest; pressure test.

4. Check well files for cement bond logs and/or indications of cement behind pipe quality; block squeeze as needed.

5. Perforate as necessary with casing gun.

6. Acid treat zone(s) of interest as necessary with 15% HCl using diverter.

7. Run production equipment

8. Report production rates until well stabilizes.

Basic Steps for Producer to Injector Conversion

1. Pull out of hole with all production equipment.

2. Clean out hole.

3. Squeeze or TA open zones not of interest; pressure test.

4. Check well files for cement bond logs and/or indications of cement behind pipe quality; block squeeze as needed.

5. Perforate as necessary with casing gun.

6. Acid treat zone(s) of interest with 15% HCl using diverter.

7. Run packer(s) and IPC tubing string(s).

   Note: Each packer will have a seating nipple and on-off tool above it.
   Injection packers will be retrievable type.
   Dual injection wells will have the tubing between the two packers externally fiberglass coated for corrosion protection.

8. Pressure test packer(s).

9. Report injection rates and pressures until well stabilizes.

10. Run tracer and temperature profile surveys.

SECTION VIII.

WATER REQUIREMENTS AND SOURCE

The injection water requirement has been based on performance of Chevron's Central Drinkard Unit waterflood operation. Based on injection and production data supplied by Chevron, the projected barrels of injection water required per barrel of expected incremental waterflood oil for the Central Drinkard Unit will be between 19-20 BW/BBL incremental oil. Therefore, the total water requirement for the proposed Blinebry-Drinkard Unit waterflood operation is forecasted to be just under 300 MMBW, or more specifically, 296 MMBW over the project life.

It is recommended that produced water be reinjected to provide the most efficient and economical waterflood operating plan. The produced and make-up waters will be maintained in separate facilities to avoid possible scaling problems associated with the compatibilities of the two waters. Produced water should account for approximately 80 MMBW, or 27% of the total injection water requirement. The remaining 73% of the total injection water requirement, or 216 MMBW, will be provided by make-up water.

The source of make-up water will be from the water bearing San Andres reservoir. Chevron (formerly Gulf) has successfully used San Andres water in their Central Drinkard waterflood since 1967. In addition, Chevron recently conducted a production test of the San Andres reservoir in their newly formed (2/85) Eunice Monument South Unit. The submersibly pumped well produced over 10,000 BWPD. In 1965 Shell conducted a production test of the San Andres reservoir using the Turner #16 well located in the proposed unit . The well produced an average of 6,000 BWPD. Based on this test, it is estimated that ten San Andres source water producers should provide adequate make-up water for the proposed waterflood. The drilling of new source water producers will not be required, since a sufficient number of shallow wellbores located in the northern part of the proposed unit (currently single Blinebry producers) should be available for San Andres recompletions.

Although the water bearing San Andres reservoir will most likely provide sufficient make-up water for the proposed unit; alternative water sources are available, if the San Andres does not initially provide the large make-up water volumes required for fieldwide water injection. Alternative injection water sources investigated by Conoco for their proposed East Blinebry Unit included purchasing sewage effluent from the City of Hobbs at a source in Section 2 of T20S, R38E, approximately 7 miles north of both units. Also evaluated by Conoco was the possibility of purchasing water from Getty's JAL Water Supply System in Section 6 of T23S, R37E, approximately 13 miles southwest of both units.

SECTION IX.

WATERFLOOD FACILITIES

New surface facilities are required for the implementation of this waterflood plan. The facilities required include a production system, water handling/injection facilities, injection lines and flowlines, a source water system, and provisions for scale and corrosion control.

PRODUCTION SYSTEM

A production system of eight satellite facilities and one central facility is recommended for the proposed Blinebry-Drinkard Waterflood Unit (reference Figure 28). Each satellite will consist of one two-phase production gas/liquid separator and one three-phase metering test separator as shown in Figure 29. The oil, water, and gas production from each well will be tested monthly. The gas production from both oil producing and gas producing wells will be commingled at the satellites before processing and sales. The oil and water emulsion will be transferred via fiberglass transfer lines (Figure 34) to the central battery for processing and sales.

The central battery (Figure 30) will consist of a heated FWKO and wash tank for oil/water separation. A LACT unit will sell the oil from one of two oil stock tanks to the pipeline company. The produced water will be sent to the injection facilities where it will be reinjected when significant volumes become available. Until such time, the small water volumes will be trucked from the injection station to nearby existing water disposal systems.

WATER HANDLING AND INJECTION

The injection station (Figure 31) will be installed at a centrally located site adjacent to the central production facilities. The system will be designed to handle 65,000 BWPD at 1200 psig injection pressure. Five 500 HP vertical turbine pumps can provide the required rates and pressures. An additional 100 HP positive displacement pump is included in the estimate to provide the capability to inject low volumes of produced water at the onset of the flood.

Injection water will consist primarily of make-up water with produced water volumes increasing with time. Separate facilities are provided so that make-up water and produced water are not commingled thereby reducing the potential for scale formation. The benefits of separate water systems will be realized in lower equipment maintenance costs and reduced injection wellbore impairment. The make-up water will be obtained from the San Andres formation which was previously discussed in Section VIII of this report.

INJECTION LINES AND FLOWLINES

The proposed Blinebry-Drinkard injection system is illustrated in Figure 33. Four buried injection trunklines originate at the injection station and terminate at headers located at each of the injection/production satellites. The water will be transported from the headers to the injection wells via 2" buried lines. Injection lines of dual injectors will be split into 2 streams at the wellhead to permit independent pressure control (Figure 32). All wellhead injection pressures will be independently maintained at the wellhead using EDI pressure/flow controllers. The controllers will insure the surface injection pressure does not exceed .2 psi per foot of depth to the injection zone as required by the New Mexico Oil Conservation Commission.

The Blinebry-Drinkard Unit is a candidate for a possible future CO_2-tertiary recovery project; therefore, all lines will be internally protected with a CO_2 compatible plastic coating to allow for future conversion to this service. The plastic coating also benefits initial operation by retarding paraffin build-up in the production lines.

SOURCE WATER SYSTEM

The source water will be provided by 10 existing wells drilled through and recompleted in the San Andres formation. Submersible pumps will pump the water to the surface gathering system (Figure 35) where it will then be transferred to the injection station via a buried fiberglass line.

SCALE AND CORROSION CONTROL

As mentioned previously, scale precipitation in the water injection system will be reduced by a facilities design that prevents the commingling of make-up and produced waters. Any scale formation in the injector or producer wellbores will be monitored and treated as needed.

As a preventive measure against corrosion, all vessels, tanks and piping will be internally plastic coated. Furthermore, the oxygen content in the injection water will be monitored and treated if necessary and gas blankets will be kept on all water tanks.

Tubing and sucker rod corrosion will be controlled by periodic chemical batch treatments. Weight-loss coupons will be installed to monitor corrosion rates on each producing well and inspected periodically. Periodic inspections will be used to confirm batch treatment adequacies and to flag necessary treatment changes due to increasing water cuts.

Paraffin build-up will be controlled with paraffin solvents and by periodic hot-oiling.

SECTION X.

INVESTMENT AND OPERATING COSTS

CAPITAL INVESTMENT

The required initial investment to implement the proposed waterflood is $27.0 million (1985$). This initial investment, itemized in Table 11, includes production and injection facilities, source water facilities, electrical system modifications, well workovers (oil, gas, and source water producers) and producer-to-injector conversions (single and dual injectors). An estimated 75 percent of this initial investment will be spent during 1987, the year prior to water injection. The remaining 25 percent will be spent during 1988, the first year of water injection. Detailed cost estimates have been included (Tables 13 thru 23) for the initial investment to document the individual cost categories summarized on Table 12. These cost estimates will be used for preparation of initial AFE's which will be required prior to the effective date of the unit.

A future investment of $7.3 million (1985$) for greater capacity lift equipment will be spent during 1991-1994 in order to maintain productivity and keep the wells pumped off as the unit responds to the injection program. Cost estimates for future artificial lift requirements are summarized on Table 24.

The ultimate investment required to implement the proposed waterflood is, therefore, $34.3 million, without consideration for inflation.

This ultimate investment, which includes the initial and future expenditures, escalates to $36.9 million and $39.9 million for 5% and 10% per year inflation rates, respectively.

WELL CONVERSIONS

The estimated cost to prepare each wellbore for production averages $30,000 which covers rig time, perforating, and stimulation. Thirty percent of the proposed producers will require artificial lift installation which will be supplied from the newly converted injectors at a cost of $5,000/well. There are nine types of producing wells which are mostly conventional completions. See Table 10.

Initially, additional artificial lift equipment will not be required; but as producers respond to the waterflood and fluid production increases, higher volume equipment will be necessary. An average production of 150 BFPD is expected with 25% of the producers making 50 BFPD; 50% of the producers making 150 BFPD; and 25% of the producers making 250 BFPD. Producers making 50 BFPD will require installation of a larger pumping unit (228) at a cost of $35,000/well. Producers making 150 BFPD will require installation of a larger pumping unit (456) with associated control panel and motor, larger rods, larger tubing, and larger pump at a total cost of $100,000/well. Producers making 250 BFPD will require installation of a larger pumping unit (640) with associated control panel and motor, larger rods, larger tubing, and larger pump at a total cost of $110,000/well. Detailed costs are shown in Table 24.

Thirteen gas wells will be completed in areas where the Tubb zone is gas bearing. These producers will be single zone only and have a typical flowing well design requiring approximately $20,000/well for preparation costs.

Another type of producer not yet mentioned is the source water well. There are 10 source water wells which will cost approximately $35,000 each for recompletion in the San Andres formation. All of these wells are expected to require an additional $60,000 each to provide for a submersible pump installation. This additional capital requirement is included in the source water system facilities estimate discussed previously in Section IX of this report (Table 21).

Estimated cost to prepare each wellbore for injection ranges from $70,000 to $105,000 which will cover rig time, perforating, stimulation, logging, tubing, wellhead and injection packer(s). Single Blinebry and Drinkard injectors will cost $70,000 or $75,000 depending on formation depth. Dual Blinebry/Drinkard injectors will cost $105,000 due to additional costs for dual wellheads, extra tubing, and dual packers. Detailed costs are presented in Table 25.

OPERATING COSTS

Tables 26 and 27 summarize forecasted yearly operating costs for continued primary operations and waterflood operations, respectively. Historical data indicates that average operating cost for a commingled Blinebry, Tubb and Drinkard primary producer is $1,250/month (1985$). Under waterflood operations, a commingled Blinebry, Tubb and Drinkard producer is estimated to average $1,800/month. These primary and waterflood operating costs were used for all oil producers as well as oil and gas producers. Gas wells are expected to have an operating cost of $1,000/month. Source water well operating costs will be approximately $1,500/month. Single water injectors were estimated to have an operating cost of $1,000/month whereas dual zone injectors should require $2,000/month. All operating costs are summarized in Table 10.

SECTION XI.

ECONOMIC ANALYSIS

The Working Interest Owners have specifically requested that the economics for the waterflood program be evaluated under a range of inflation rates and discount factors. Three cases generated to satisfy the requested scenarios are defined as follows: 1) Case I was defined as a current dollar (1985$) no inflation scenario, 2) Case II was to reflect a constant five percent yearly inflation rate applied to future crude and gas prices, as well as, future investments and operating expenses, and 3) Case III was to reflect a constant ten percent yearly inflation rate applied to the same items as described for Case II. The profit after federal income tax (AFIT) was calculated at zero, 5%, and 10% nominal discount factors.

Typical incremental waterflood project analyses were conducted by subtracting the continued primary depletion case from the waterflood operations case. The yearly oil and gas production volumes for the remaining primary and waterflood performance, both discussed in previous sections, were used in the economic analyses and are shown in Tables 4 and 7, respectively. The initial and future investments incorporated in the economic analyses are summarized in Table 11. The associated yearly operating costs for the remaining primary and waterflood operations cases (Tables 26 and 27) have also been included in the economics. The assumptions and data used in all economic analyses are summarized in Table 28.

Results from the three described incremental waterflood cases analyzed are presented in Table 29. For Case I, the current dollar no inflation scenario, the resulting analysis reveals that the proposed waterflood program will add 15,265,126 barrels of supplemental oil and generate an undeferred AFIT profit of $100.9 million or 294% of the ultimate investment. Discounted economic analyses still yield attractive returns. If 5% and 10% discount factors are applied, the resulting present value profits AFIT are $38.8 and $12.7 million respectively, or 132% and 49% of the investment, respectively.

Case II, the economic analysis reflecting a 5% yearly inflation rate yields a higher profitability than the current dollar scenario. The undeferred profit AFIT increases to $226.6 million or 615% of the investment. The discounted economics result in a present value profit AFIT of $89.8 and $35.6 million or 288% and 133% of the investment for the 5% and 10% discount factors, respectively.

The scenario applying a 10% inflation rate per year, Case III, yields a higher profitability than both previous cases discussed. An undeferred profit AFIT of $505.4 million, or 1266% of the investment was generated for this case. The 5% and 10% discounted economics yielded profits AFIT of $195.9 and $80.5 million, or 588% and 284% of the investment, respectively. Attractive unit development costs between $2.25 and $2.62 per barrel were calculated for the three cases. Cases I, II, and III generated nominal earning powers of 16%, 21%, and 26%, respectively.

Payout times ranged from 7.0 to 8.1 years which are typical of waterflood projects. All economic parameters indicate a very attractive economic venture.

Based on the significant secondary oil potential and favorable economics, the Technical Committee recommends that the proposed Blinebry-Drinkard waterflood program be implemented.

TABLE 1

SUMMARY OF BLINEBRY CORE DATA

	≥ 0.01 md.			≥ 0.1 md.			≥ 1 md.			≥ 10 md.		
	Ø	perm.	n	Ø	perm.	n	Ø	perm.	n	Ø	perm.	n
Shell Western Taylor-Glenn No. 10	6.87	0.68	(55)	7.58	0.95	(39)	8.58	2.08	(13)			
Conoco Hawk "B-3" No. 18	5.65	0.80	(198)	7.18	1.46	(107)	9.30	3.96	(33)	12.38	12.50	(4)
Arco Sarkeys No. 4	5.58	0.92	(359)	6.60	1.41	(233)	8.96	4.57	(62)	11.56	13.86	(7)
Shell Western Coll No. 2	9.93	0.75	(250)	13.46	2.11	(88)	15.32	4.85	(34)	17.98	26.63	(3)
Shell Western State "2" No. 19	8.12	0.93	(250)	11.20	2.54	(90)	13.73	5.92	(36)	19.90	17.55	(6)
Exxon Blinebry-Tubb Gas Com. No. 1	8.00	2.37	(200)	12.70	6.20	(76)	14.50	10.45	(44)	18.37	26.31	(13)
Averages (number of samples)	7.36	1.08	(1312)	9.79	2.45	(633)	11.73	5.31	(222)	16.04	19.37	(33)

Waterflood Study
December 1985

TABLES

BNBQ8528003

TABLE 2

SUMMARY OF TUBB CORE DATA

	≥ 0.01 md.			≥ 0.1 md.			≥ 1 md.			≥ 10 md.		
	Ø	perm.	n	Ø	perm.	n	Ø	perm.	n	Ø	perm.	n
Conoco Hawk "B-3" No. 16	5.12	0.02	(150)	7.83	0.17	(10)						
Conoco Hawk "B-10" No. 10	4.28	0.47	(108)	5.07	0.74	(67)	6.12	1.78	(16)			
Exxon Blinebry-Tubb Gas Com. No. 1	5.70	0.41	(191)	11.93	2.65	(29)	13.46	5.33	(13)	16.47	13.33	(3)
Averages (number of samples)	5.03	0.30	(449)	8.28	1.19	(106)	9.79	3.56	(29)	16.47	13.33	(3)

Waterflood Study
December 1985

BNBQ8528003

TABLE 3

SUMMARY OF DRINKARD CORE DATA

	$\geq$ 0.01 md.			$\geq$ 0.1 md.			$\geq$ 1 md.			$\geq$ 10 md.		
	Ø	perm.	n	Ø	perm.	n	Ø	perm.	n	Ø	perm.	n
Shell Western Taylor-Glenn No. 10	7.27	1.36	(170)	11.00	2.45	(94)	15.74	5.38	(39)	21.22	16.17	(6)

TABLE 4

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

REMAINING PRIMARY PRODUCTION FORECAST

Year	Oil Production (STB)	Gas Zone Gas Production (MMCF)	Solution Gas Production (MMCF)	Total Gas Production (MMCF)	Solution GOR (SCF/STB)	Total GOR (SCF/STB)
1987	225,410	5,875	451	6,326	2,000	28,064
1988	204,981	5,318	410	5,728	2,000	27,944
1989	186,405	4,812	368	5,180	1,975	27,789
1990	169,511	4,355	331	4,686	1,950	27,644
1991	154,149	3,942	297	4,239	1,925	27,499
1992	140,179	3,567	266	3,833	1,900	27,344
1993	127,475	3,229	239	3,468	1,875	27,205
1994	115,922	2,922	214	3,136	1,850	27,053
1995	105,417	2,644	192	2,836	1,825	26,903
1996	95,863	2,393	173	2,566	1,800	26,767
1997	87,175	2,166	155	2,321	1,775	26,625
1998	79,275	1,960	139	2,099	1,750	26,477
1999	72,090	1,774	124	1,898	1,725	26,328
2000	65,557	1,606	111	1,717	1,700	26,191
2001	59,616	1,453	100	1,553	1,675	26,050
2002	54,213	1,316	89	1,405	1,650	25,916
2003	49,488	1,190	80	1,270	1,625	25,663
2004		1,078		1,078		
2005		976		976		
2006		882		882		
2007		798		798		
2008		723		723		
2009		654		654		
2010		592		592		
2011		536		536		
2012		486		486		
2013		440		440		
2014		398		398		
2015		360		360		
	1,992,726	58,445	3,739	62,184		

Waterflood Study
December 1985

BNBQ8528003

TABLE 5

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

TYPICAL RESERVOIR PROPERTIES

		Blinebry	Tubb	Drinkard
Area		5,200 Acres	5,200 Acres	5,200 Acres
h	72	gas-28.8 feet oil-43.2 feet (23-105)	34 feet (18-46)	54 feet (13-80)
Ø		9% (7.5-12)	8% (7-13)	9% (6-11)
Sw		25% (12-33)	25% (15-34)	25% (10-32)

Waterflood Study
December 1985

TABLE 6

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

TYPICAL CRUDE PROPERTIES

	Blinebry	Drinkard
Bo_i	1.4 RB/STB	1.5 RB/STB
P_i	2415 psi	2660 psi
$P_{current}$	~400 psi	~400 psi
°API	40	40
μo	0.9 cps	1.3 cps

TABLE 7

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

WATERFLOOD OIL AND GAS PRODUCTION FORECAST

Year	Oil Production (STB)	Gas Zone Gas Production (MMCF)	Solution Gas Production (MMCF)	Total Gas Production (MMCF)	Solution GOR (SCF/STB)	Total GOR (SCF/STB)
1987	184,071	5,670	368	6,038	2,000	32,803
1988	168,228	5,132	336	5,468	2,000	32,504
1989	206,503	4,645	309	4.954	1,500	23,990
1990	340,466	4,203	383	4,586	1,125	13,470
1991	485,978	3,804	409	4,213	843	8,669
1992	600,555	3,443	379	3,822	632	6,364
1993	742,144	3,116	351	3,467	474	4,672
1994	825,000	2,820	293	3,113	356	3,773
1995	825,000	2,552	220	2,772	267	3,360
1996	825,000	2,310	165	2,475	200	3,000
1997	825,000	2,091	165	2,256	200	2,735
1998	825,000	1,892	165	2,057	200	2,493
1999	825,000	1,713	165	1,878	200	2,276
2000	825,000	1,550	165	1,715	200	2,079
2001	825,000	1,403	165	1,568	200	1,901
2002	825,000	1,270	165	1,435	200	1,739
2003	825,000	1,149	165	1,314	200	1,593
2004	825,000	1,040	165	1,205	200	1,461
2005	825,000	942	165	1,107	200	1,342
2006	766,231	852	153	1,005	200	1,312
2007	660,953	771	132	903	200	1,366
2008	570,141	698	114	812	200	1,424
2009	491,806	632	98	730	200	1,484
2010	424,233	572	85	657	200	1,549
2011	365,945	518	73	591	200	1,615
2012	315,666	469	63	532	200	1,685
2013	272,294	424	54	478	200	1,755
2014	234,882	383	47	430	200	1,831
2015	202,610	347	41	388	200	1,915
2016	174,772	0	35	35	200	200
2017	150,374	0	30	30	200	200
	17,257,852	56,411	5,623	62,034		

Waterflood Study
December 1985

TABLE 8

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

WATERFLOOD OPERATIONS
WATER PRODUCTION AND INJECTION FORECAST

Year	Total Produced Water (MBW)	Total Produced Water (BWPD)	Produced Water Disposed of (MBW)	Produced Water Disposed of (BWPD)	Reinjected Produced Water (MBW)	Reinjected Produced Water (BWPD)	Injected Make-Up Water (MBW)	Injected Make-Up Water (BWPD)	Total Injected Water (MBW)	Total Injected Water (BWPD)
1987	58	159	58	159	-	-	-	-	-	-
1988*	56	154	56	154	0	0	23,504	64,350	23,504	64,350
1989	73	199	73	199	0	0	20,090	55,003	20,090	55,003
1990	132	362	132	362	0	0	17,172	47,014	17,172	47,014
1991	218	598	218	598	0	0	14,678	40,185	14,678	40,185
1992	323	885	323	885	0	0	12,546	34,349	12,546	34,349
1993	495	1,355	0	0	495	1,355	10,228	28,004	10,723	29,359
1994	703	1,924	0	0	703	1,924	8,463	23,171	9,166	25,095
1995	859	2,351	0	0	859	2,351	6,976	19,099	7,835	21,450
1996	1,050	2,875	0	0	1,050	2,875	6,785	18,575	7,835	21,450
1997	1,238	3,388	0	0	1,238	3,388	6,597	18,062	7,835	21,450
1998	1,467	4,016	0	0	1,467	4,016	6,368	17,434	7,835	21,450
1999	1,675	4,586	0	0	1,675	4,586	6,160	16,864	7,835	21,450
2000	1,925	5,270	0	0	1,925	5,270	5,910	16,180	7,835	21,450
2001	2,231	6,107	0	0	2,231	6,107	5,604	15,343	7,835	21,450
2002	2,613	7,153	0	0	2,613	7,153	5,222	14,297	7,835	21,450
2003	2,925	8,008	0	0	2,925	8,008	4,910	13,442	7,835	21,450
2004	3,300	9,035	0	0	3,300	9,035	4,535	12,415	7,835	21,450
2005	3,758	10,290	0	0	3,758	10,290	4,077	11,160	7,835	21,450

TABLE 8
PROPOSED BLINEBRY-DRINKARD UNIT
(Cont.)

Year	Total Produced Water (MBW)	Total Produced Water (BWPD)	Produced Water Disposed of (MBW)	Produced Water Disposed of (BWPD)	Reinjected Produced Water (MBW)	Reinjected Produced Water (BWPD)	Injected Make-Up Water (MBW)	Injected Make-Up Water (BWPD)	Total Injected Water (MBW)	Total Injected Water (BWPD)
2006	4,033	11,042	0	0	4,033	11,042	3,802	10,408	7,835	21,450
2007	4,092	11,203	0	0	4,092	11,203	3,743	10,247	7,835	21,450
2008	4,236	11,596	0	0	4,236	11,596	3,599	9,854	7,835	21,450
2009	4,052	11,094	0	0	4,052	11,094	3,783	10,356	7,835	21,450
2010	3,908	10,700	0	0	3,908	10,700	3,927	10,750	7,835	21,450
2011	3,807	10,423	0	0	3,807	10,423	4,028	11,027	7,835	21,450
2012	3,754	10,279	0	0	3,754	10,279	4,081	11,171	7,835	21,450
2013	3,761	10,297	0	0	3,761	10,297	4,074	11,153	7,835	21,450
2014	3,845	10,528	0	0	3,845	10,528	3,990	10,922	7,835	21,450
2015	4,044	11,071	0	0	4,044	11,071	3,791	10,379	7,835	21,450
2016	4,429	12,126	0	0	4,429	12,126	3,406	9,324	7,835	21,450
2017	5,174	14,165	0	0	5,174	14,165	2,661	7,285	7,835	21,450
2018	6,798	18,613	0	0	6,798	18,613	1,037	2,837	7,835	21,450
Total	81,032		860		80,172		215,747		295,919	

* Initial water injection assumed 1/1/88.

TABLE 9

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

WATERFLOOD OPERATIONS
AVERAGE INJECTION LOCATION PERFORMANCE FORECAST

Year	Total Water Injection (MBW)	Yearly Average (BWPD)	Number of Injection Locations (Bl/Dr)	(Bl/Tb/Dr)	Average Dual Injector (BWPD) (Bl/Dr)	(Bl/Tb/Dr)
1988	23,504	64,350	36	10	1,350	1,575
1989	20,090	55,003	36	10	1,154	1,346
1990	17,172	47,014	36	10	986	1,151
1991	14,678	40,185	36	10	843	984
1992	12,546	34,349	36	10	721	841
1993	10,723	29,359	36	10	616	719
1994	9,166	25,095	36	10	526	614
1995	7,835	21,450	36	10	450	525
1996	7,835	21,450	36	10	450	525
1997	7,835	21,450	36	10	450	525
1998	7,835	21,450	36	10	450	525
1999	7,835	21,450	36	10	450	525
2000	7,835	21,450	36	10	450	525
2001	7,835	21,450	36	10	450	525
2002	7,835	21,450	36	10	450	525
2003	7,835	21,450	36	10	450	525
2004	7,835	21,450	36	10	450	525
2005	7,835	21,450	36	10	450	525
2006	7,835	21,450	36	10	450	525
2007	7,835	21,450	36	10	450	525
2008	7,835	21,450	36	10	450	525
2009	7,835	21,450	36	10	450	525
2010	7,835	21,450	36	10	450	525
2011	7,835	21,450	36	10	450	525
2012	7,835	21,450	36	10	450	525
2013	7,835	21,450	36	10	450	525
2014	7,835	21,450	36	10	450	525
2015	7,835	21,450	36	10	450	525
2016	7,835	21,450	36	10	450	525
2017	7,835	21,450	36	10	450	525
2018	7,835	21,450	36	10	450	525
Total	295,919					

Waterflood Study
December 1985

TABLE 10

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

WELL CONFIGURATIONS AND COST ESTIMATES

	Description (# Wells)	Zones	Completion Type	Preparation Costs**	Operating Costs** Per Month
1.	Single Injector (10)	Blinebry-Oil	Injection Well Completion w/Packer Set Above Blinebry	$60,000 (Exp.) $10,000 (Cap.)	$1,000
2.	Single Injector (13)	Drinkard-Oil	Injection Well Completion w/Packer Set Above Drinkard	$65,000 (Exp.) $10,000 (Cap.)	$1,000
3.	Single Injector (3)	Blinebry/Tubb-Oil	Injection Well Completion w/Packer Set Above Blinebry	$60,000 (Exp.) $10,000 (Cap.)	$1,000
4.	Dual Injector (28)	Blinebry-Oil Drinkard-Oil	Two Tubing Strings w/Dual Packers	$80,000 (Exp.) $25,000 (Cap.)	$2,000
5.	Dual Injector (5)	Blinebry/Tubb-Oil Drinkard-Oil	Two Tubing Strings w/Dual Packers	$80,000 (Exp.) $25,000 (Cap.)	$2,000
6.	Single Producer (11)	Blinebry-Oil	Conventional Pumping or Flowing Well Design	$20,000 (Exp.) $5,000*(Cap.)	$1,250 (Primary) $1,800 (Secondary)
7.	Single Producer (4)	Blinebry-Oil, Gas	Pump Oil Below Packer w/1" Vent to Surface. Produce Gas Up Annulus Above Packer.	$35,000 (Exp.) $5,000*(Cap.)	$1,250 (Primary) $1,800 (Secondary)
8.	Single Producer (13)	Tubb-Gas	Flowing Well Completion w/Packer Set Above Tubb	$20,000 (Exp.)	$1,000

TABLE 10
PROPOSED BLINEBRY-DRINKARD UNIT
(Cont.)

	Description (# Wells)	Zones	Completion Type	Preparation Costs**	Operating Costs** Per Month
9.	Single Producer (1)	Tubb-Gas Drinkard-Oil	Pump Oil Below Packer w/1" Vent to Surface. Produce Tubb Gas Up Annulus Above Packer.	$35,000 (Exp.) $5,000*(Cap.)	$1,500 (Primary) $2,000 (Secondary)
10.	Commingled Producer (31)	Blinebry-Oil Drinkard-Oil	Conventional Pumping or Flowing Well Design	$25,000 (Exp.) $5,000*(Cap.)	$1,250 (Primary) $1,800 (Secondary)
11.	Commingled Producer (19)	Blinebry-Gas Blinebry-Oil Drinkard-Oil	Pumping Oil Below Packer w/1" Vent to Surface. Produce Blinebry Gas Up Annulus Above Packer.	$40,000 (Exp.) $5,000*(Cap.)	$1,250 (Primary) $1,800 (Secondary)
12.	Commingled Producer (11)	Blinebry-Oil Tubb-Oil Drinkard-Oil	Conventional Pumping or Flowing Well Design	$30,000 (Exp.) $5,000*(Cap.)	$1,250 (Primary) $1,800 (Secondary)
13.	Commingled Producer (8)	Blinebry-Gas Blinebry-Oil Tubb-Oil Drinkard-Oil	Pumping Oil Below Packer w/1" Vent to Surface. Produce Blinebry Gas Up Annulus Above Packer.	$45,000 (Exp.) $5,000*(Cap.)	$1,250 (Primary $1,800 (Secondary)
14.	Source Water Producer (10)	San Andres-Water	Submersible Pumping Design	$35,000 (Exp.)	$1,500 (Sub-Pumped)

Notes:
* Only 30% of the producers will require initial artificial lift installations.
** All costs are 1985$.

Waterflood Study
December 1985

BNBQ8528003

TABLE 11

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

WATERFLOOD INVESTMENT SCHEDULE

YEAR	ITEM	COST M$
	Initial Investment	
	Production Facilities	
	Central Battery	$ 1,210
	Satellites	1,900
	Flowlines	3,380
	Transfer Lines	615
	Injection Facilities	
	Injection Plant	4,010
	Satellites	1,158
	Trunklines	1,000
	Injection Lines	1,354
	Source Water Facilities	1,382
	Electrical System	1,670
	Damages	685
	108 Producer Workovers	
	85 Commingled Oil (Blinebry/Tubb/Drinkard)	2,680
	13 Gas (Tubb)	260
	10 Source Water (San Andres)	350
	59 Producer-to-Injector Conversions	
	33 Dual	3,465
	13 Single (Blinebry)	910
	13 Single (Drinkard)	975
	Total Initial Investment	$27,004
1987	75% Initial Investment	$20,253
1988	25% Initial Investment	$ 6,751
1991	Larger Lift Equipment	$ 1,837
1992	Larger Lift Equipment	$ 1,836
1993	Larger Lift Equipment	$ 1,836
1994	Larger Lift Equipment	$ 1,836
	TOTAL WATERFLOOD INVESTMENT	$34,349

Waterflood Study
December 1985

BNBQ8528003

WORK ORDER COST ESTIMATE

TABLE 12

FORM NO. EP-225 (4-66)

WORK ORDER DESCRIPTION

Blinebry/Drinkard Unitization
Estimate Summary

QUANTITY	DESCRIPTION	AMOUNT	TOTAL
	Production Facilities - Central Battery		$ 1,210,000
	Production Facilities - Satellites		1,900,000
	Production Flowlines		3,380,000
	Production Transfer Lines		615,000
	Injection Plant Facilities		4,010,000
	Injection Facilities - Satellites		1,158,000
	Injection Trunklines		1,000,000
	Injection Lines		1,354,000
	Source Water Facilities		1,382,000
	Electrical System		1,670,000
	Damages		685,000
		Total	$18,364,000

PREPARED BY	DATE PREPARED	A.F.E. NO.	WORK ORDER NO.
R. L. Wintermute	8/29/85		

BNBI8527403

WORK ORDER COST ESTIMATE

TABLE 13

FORM NO. EP-225 (4-66)

WORK ORDER DESCRIPTION

Blinebry/Drinkard Unitization
Production Facilities-Central Battery

QUANTITY	DESCRIPTION	AMOUNT	TOTAL
1	10'X 30' Free Water Knock Out		120,000
2	2000 Bbl-API 120 Steel Tank	$50,000	100,000
1	1000 Bbl Welded Steel Tank		40,000
1	LACT Unit		35,000
1	Air Compressor		25,000
1	Vapor Recovery Unit		35,000
2	Recirculation Pump	$ 3,000	6,000
1	Meter Run		5,000
1	Control/Annunciator Panel		25,000
1	Production Header		60,000
1	1500 Bbl Wash Tank		50,000
	Valves, Piping and Fittings		125,000
	Electrical		75,000
	Foundations, Dirtwork, Painting		50,000
	Labor		300,000
	Subtotal		$1,051,000
	Transportation and Contingencies (15%)		159,000
	Total		$1,210,000

PREPARED BY	DATE PREPARED	A.F.E. NO.	WORK ORDER NO.
R. L. Wintermute	8/6/85		

BNBI8527403

WORK ORDER COST ESTIMATE
TABLE 14

FORM NO. EP-225 (4-66)

WORK ORDER DESCRIPTION

Blinebry/Drinkard Unitization
Production Facilities-Satellites

QUANTITY	DESCRIPTION	AMOUNT	TOTAL
8	3'X 10' - 3Ø Test Separator	$25,000	$ 200,000
8	3'X 10' - 2Ø Production Separator	25,000	200,000
8	200 Bbl Steel Pump Tank	6,000	48,000
8	100 Bbl Steel Blowdown Tanks	5,000	40,000
8	Transfer Pumps	10,000	80,000
8	Recirculation Pumps	4,000	32,000
8	Production Manifolds	15,000	120,000
8	Meter Runs	5,000	40,000
	Valves, Piping and Fittings	15,000	200,000
8	Electrical	15,000	120,000
	Foundations, Dirtwork, Painting	10,000	80,000
	Labor	60,000	480,000
	Subtotal		$1,640,000
	Transportation and Contingencies (15%)		250,000
	Total		$1,900,000

PREPARED BY	DATE PREPARED	A.F.E. NO.	WORK ORDER NO.
R. L. Wintermute	8/6/85		

BNBI8527403

WORK ORDER COST ESTIMATE

TABLE 15

FORM NO. EP-225 (4-66)

WORK ORDER DESCRIPTION

Blinebry/Drinkard Unitization
Production Lines

QUANTITY	DESCRIPTION	AMOUNT	TOTAL
23,100'	Satellite #1, 2" Production Line	$10/ft.	
23,000'	Satellite #2, 2" Production Line	$10/ft.	
23,800'	Satellite #3, 2" Production Line	$10/ft.	
22,400'	Satellite #4, 2" Production Line	$10/ft.	
45,000'	Satellite #5, 2" Production Line	$10/ft.	
30,900'	Satellite #6, 2" Production Line	$10/ft.	
27,600'	Satellite #7, 2" Production Line	$10/ft.	
25,400'	Satellite #8, 2" Production Line	$10/ft.	
72,600'	Flowline for Blinebry gas producer	$10/ft.	
	every 160 acres (Ave. line length 2200')		
293,800	2" A106 GRB, IPC and Layed on surface	$10/ft.	$2,938,000
	Transportation and Contingencies (15%)		442,000
	Total		$3,380,000

PREPARED BY	DATE PREPARED	A.F.E. NO.	WORK ORDER NO.
R. L. Wintermute	8/28/85		

BNBI8527403

WORK ORDER COST ESTIMATE
TABLE 16

FORM NO. EP-225 (4-66)

WORK ORDER DESCRIPTION

Blinebry/Drinkard Unitization
Production Transfer Lines
(Buried Fiberglass Pipe)

QUANTITY	DESCRIPTION	AMOUNT	TOTAL
6650'	Sat. #1 - Sat. #4, 4" Transfer Line	$12/ft.	$ 80,000
4000'	Sat. #2 - Sat. #3, 4" Transfer Line	$12/ft.	48,000
4300'	Sat. #7 - Sat. #6, 4" Transfer Line	$12/ft.	52,000
6650'	Sat. #8 - Sat. #6, 4" Transfer Line	$12/ft.	80,000
4750'	Sat. #6 - Sat. #5, 6" Transfer Line	$16/ft.	76,000
2250'	Sat. #5 - CB, 6" Transfer Line	$16/ft.	36,000
2700'	Sat. #4 - CB, 6" Transfer Line	$16/ft.	43,000
7500'	Sat. #3 - CB, 6" Transfer Line	$16/ft.	$120,000
	SUBTOTAL		$535,000
	Transportation and Contingencies (15%)		80,000
	TOTAL		$615,000

PREPARED BY	DATE PREPARED	A.F.E. NO.	WORK ORDER NO.
R. L. Wintermute	8/20/85		

BNBI8527403

WORK ORDER COST ESTIMATE

TABLE 17

FORM NO. EP-225 (4-66)

WORK ORDER DESCRIPTION

Blinebry/Drinkard Unitization
Injection Plant Facilities

QUANTITY	DESCRIPTION	AMOUNT	TOTAL
5	V. T. Injection Pump w/ Motor	$116,000	$ 580,000
1	Skid-mounted 100 HP, Belt Driven Plunger Pump		50,000
1	Source Water Control Valve w/Actuator		25,000
5	Nema Size 6 Motor Starters	10,000	50,000
1	Produced Water Disposal Pump		10,000
1	Produced Water Control Valve w/Actuator		25,000
2	5000 Bbl Source Water Pump Tanks	80,000	160,000
1	5000 Bbl Overflow Tank		80,000
2	5000 Bbl Skim Tank	80,000	160,000
1	300 Bbl Skim Oil Tank		7,000
1	Injection Manifold	125,000	125,000
98	Injection Wellhead Connections	5,000	490,000
	Control Building		45,000
	Overhead Crane		60,000
	Miscellaneous Instrumentation		160,000
	Pipe, Valves, and Fittings		405,000
	Electrical Material and Construction		245,000
	Mechanical Construction (Labor)		810,000
	Subtotal		$3,487,000
	Transportation and Contingencies (15%)		523,000
	Total		$4,010,000

PREPARED BY	DATE PREPARED	A.F.E. NO.	WORK ORDER NO.
R. L. Wintermute	8/16/85		

BNBI8527403

WORK ORDER COST ESTIMATE

TABLE 18

FORM NO. EP-225 (4-66)

WORK ORDER DESCRIPTION

Blinebry/Drinkard Unitization
Satellite Injection Facilities and CAO Equipment

QUANTITY	DESCRIPTION	AMOUNT	TOTAL
8	Injection Header complete with valves	$25,000	$ 200,000
98	Injection Controllers	4,100	402,000
1	IBM PC		10,000
	Alarm System		35,000
80	Pump-Off Controllers	4,500	$ 360,000
	Subtotal		$1,007,000
	Transportation and Contingencies (15%)		151,000
	Total		$1,158,000

PREPARED BY	DATE PREPARED	A.F.E. NO.	WORK ORDER NO.
R. L. Wintermute	8/29/85		

BNBI8527403

WORK ORDER COST ESTIMATE

TABLE 19

FORM NO. EP-225 (4-66)

WORK ORDER DESCRIPTION

Blinebry/Drinkard Unitization
Injection Trunklines

QUANTITY	DESCRIPTION	AMOUNT	TOTAL
7,500'	Battery - Sat. #3, 6" Injection Trunkline	$27/ft.	$ 203,000
2,700'	Battery - Sat. #4, 6" Injection Trunkline	$27/ft.	73,000
2,250'	Battery - Sat. #5, 8" Injection Trunkline	$35/ft.	79,000
4,000'	Sat. #2 - #3, 4" Injection Trunkline	$18/ft.	72,000
6,650'	Sat. #1 - #4, 4" Injection Trunkline	$18/ft.	120,000
4,750'	Sat. #5 - #6, 6" Injection Trunkline	$27/ft.	128,000
4,300'	Sat. #6 - #7, 4" Injection Trunkline	$18/ft.	77,000
6,650'	Sat. #6 - #8, 4" Injection Trunkline	$18/ft.	120,000
38,800'	Subtotal		$ 872,000
	Transportation and Contingencies (15%)		128,000
	Total		$1,000,000
	All Pipe: A106-GRB, IPC. and Buried		

PREPARED BY	DATE PREPARED	A.F.E. NO.	WORK ORDER NO
R. L. Wintermute	8/15/85		

BNBI8527403

WORK ORDER COST ESTIMATE

TABLE 20

FORM NO. EP-225 (4-66)

WORK ORDER DESCRIPTION

Blinebry/Drinkard Unitization
Well Injection Lines

QUANTITY	DESCRIPTION	AMOUNT	TOTAL
12,500'	Satellite #1, 2" Injection Lines	$11/ft.	
8,000'	Satellite #2, 2" Injection Lines	$11/ft.	
10,500'	Satellite #3, 2" Injection LInes	$11/ft.	
16,500'	Satellite #4, 2" Injection Lines	$11/ft.	
14,000'	Satellite #5, 2" Injection Lines	$11/ft.	
15,500'	Satellite #6, 2" Injection Lines	$11/ft.	
13,500'	Satellite #7, 2" Injection Lines	$11/ft.	
11,500'	Satellite #8, 2" Injection Lines	$11/ft.	
5,000'	5% Extra Pipe		
107,000'			
	2" Nom-A106 GRB, IPC, and Buried	$11/ft.	$1,177,000
	Transportation and Contingencies (15%)		177,000
	Total		$1,354,000

PREPARED BY	DATE PREPARED	A.F.E. NO.	WORK ORDER NO.
R. L. Wintermute	8/15/85		

BNBI8527403

WORK ORDER COST ESTIMATE

TABLE 21

FORM NO. EP-225 (4-66)

WORK ORDER DESCRIPTION

Blinebry/Drinkard Unitization
Source Water Facilities

QUANTITY	DESCRIPTION	AMOUNT	TOTAL
	Water Gathering System		
16,200'	8" - Buried Fiberglass Pipe	$22/ft.	$ 356,000
4,000'	6" - Buried Fiberglass Pipe	$16/ft.	64,000
6,800'	4" - Buried Fiberglass Pipe	$12/ft.	82,000
	Subtotal		$ 502,000
	Source Water Electrical		
10	100KVA Transformer	$ 8,000	$ 80,000
10	Installation	$ 1,000	10,000
			$ 90,000
10	Submersible Pumps Installed @ 900'	$60,000	$ 600,000
	Subtotal		$1,192,000
	Transportation and Contingencies (15%)		190,000
	Total		$1,382,000

PREPARED BY	DATE PREPARED	A.F.E. NO.	WORK ORDER NO.
R. L. Wintermute	8/19/85		

BNBI8527403

WORK ORDER COST ESTIMATE

TABLE 22

FORM NO. EP-225 (4-66)

WORK ORDER DESCRIPTION

Blinebry/Drinkard Unitization
Electrical System

QUANTITY	DESCRIPTION	AMOUNT	TOTAL
134,000'	Powerline	$15/ft.	$ 670,000
80	75 KVA Transformers with Connections	7,500	600,000
3	500 KVA Transformers	10,000	30,000
5	Capacitors	10,000	50,000
	Survey and Stake	50,000	50,000
	Miscellaneous Electrical	50,000	$ 50,000
	Subtotal		$1,450,000
	Transportation and Contingencies (15%)		220,000
	Total		$1,670,000

PREPARED BY	DATE PREPARED	A.F.E. NO.	WORK ORDER NO.
R. L. Wintermute	8/21/85		

BNBI8527403

WORK ORDER COST ESTIMATE

TABLE 23

FORM NO. EP-225 (4-66)

WORK ORDER DESCRIPTION

Blinebry/Drinkard
Surface Damages

QUANTITY	DESCRIPTION	AMOUNT	TOTAL
9	8 Satellite Locations + 1 Central Battery	$5,000	$ 45,000
	Location		
294,000'	Flowlines (Damages)	$16.5/Rod	294,000
107,000'	Injection Lines (Damages)	$16.5/Rod	107,000
77,600'	Transfer Lines and Trucklines (Damages)	$16.5/Rod	78,000
27,000'	Source Water Gathering System (Damages)	$16.5/Rod	27,000
134,000'	Electrical Lines	$16.5/Rod	134,000
			$685,000

PREPARED BY	DATE PREPARED	A.F.E. NO.	WORK ORDER NO.
R. L. Wintermute	8/6/85		

BNBI8527403

TABLE 24

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

ARTIFICIAL LIFT REQUIREMENTS

DESIGN PARAMETERS:

Average Maximum Production/Well 150/BFPD 95% WC
40° API oil
1.1 SG H_2O
75% pump efficiency
80% timer

ASSUMPTION: Average maximum production/well fieldwide is composed of the following:

25% of producers	50 BFPD
50% of producers	150 BFPD
25% of producers	250 BFPD

I. 25% of producers will require only a pumping unit change.

Install C 228D-246-86 $35,000/well

II. 50% of producers will require complete lift equipment change to the following design.

Install C 456D-304-120	$ 45,370
30 HP electric motor	1,042
Panel/controller	1,513
6,700' 2-7/8" 6.5#/ft J-55 tbg	31,455
86 rod string	15,540
25-175 pump	1,740
Miscellaneous	3,340
Total	$100,000/well

III. 25% of producers will require complete lift equipment change to the following design.

Install C 640D-305-144	$ 53,350
50 HP electric motor	1,645
Panel/controller	3,000
6700' 2-7/8" 6.5#/ft J-55 tbg	31,455
86 rod string	15,540
25-200 pump	1,900
Miscellaneous	3,110
Total	$110,000/well

Waterflood Study
December 1985

TABLE 25

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

AVERAGE WELL PREPARATION COSTS

<u>Average Well Workover Costs</u>

<u>EXPENSE</u>: Oil Producer

Rig time (includes clean out)	$10,000
Perforating	5,000
Stimulating	10,000
Miscellaneous	5,000
Total	$30,000/well

<u>CAPITAL</u>: Oil Producer

30% of the producers will require initial artificial lift installations. 36% of the wells will be converted to injectors. Net initial artificial lift installation costs will be only the cost to move and reset units (assuming 70% of the injector conversions will provide lift equipment).

Average cost to set unit and provide electricity	$5,000/well

<u>EXPENSE</u>: Gas Producer

Rig time (includes clean out)	$8,000
Perforating	5,000
Stimulating	5,000
Miscellaneous	2,000
Total	$20,000/well

<u>EXPENSE</u>: Source Water Producer

Rig time	$10,000
Logging	3,000
Cement/CIBP	7,000
Perforating	3,000
Stimulating	6,000
Miscellaneous	6,000
Total	$35,000/well

Waterflood Study
December 1985

TABLE 25
PROPOSED BLINEBRY-DRINKARD UNIT
(Cont.)

CAPITAL: Source Water Producer

All of the source water wells are expected to require submersible pumps.

Average cost to install submersible pump, cable, control panel and provide electricity	$60,000/well

This capital has been included in the Source Water System facilities cost estimate.

Average Producer to Injector Conversion Costs

EXPENSE: Injector-Blinebry

Rig time	$10,000
Perforating	$5,000
Stimulation	8,000
Logging	2,000
Tubing (IPC)	30,000
Miscellaneous	5,000
Total	$60,000/well

CAPITAL: Injector-Blinebry

Wellhead and associated equipment	6,000
Injector packer	4,000
Total	$10,000/well

EXPENSE: Injector-Drinkard

Rig time	$10,000
Perforating	5,000
Stimulation	10,000
Logging	2,000
Tubing (IPC)	33,000
Miscellaneous	5,000
Total	$65,000/well

TABLE 25
PROPOSED BLINEBRY-DRINKARD UNIT
(Cont.)

CAPITAL:	Injector-Drinkard	
	Wellhead and associated equipment	6,000
	Injector packer	4,000
	Total	$10,000/well
EXPENSE:	Injector-Dual	
	Rig time	$10,000
	Perforating	5,000
	Stimulation	10,000
	Logging	3,000
	Tubing (IPC)	44,000
	Miscellaneous	8,000
	Total	$80,000/well
CAPITAL:		
	Wellhead and associated equipment	$ 9,000
	Injector packer and associated equipment	16,000
	Total	$25,000/well

TABLE 26

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

REMAINING PRIMARY OPERATIONS
OPERATING COST FORECAST
(1985$)

Year	Production Facilities O&M (M$)	Production Wells (M$)	Total Unit Operating Cost (M$)
1987	96	2,721	2,817
1988	96	2,721	2,817
1989	96	2,721	2,817
1990	96	2,721	2,817
1991	96	2,721	2,817
1992	96	2,721	2,817
1993	96	2,721	2,817
1994	96	2,721	2,817
1995	96	2,721	2,817
1996	96	2,721	2,817
1997	96	2,721	2,817
1998	96	2,721	2,817
1999	96	2,721	2,817
2000	96	2,721	2,817
2001	96	2,721	2,817
2002	96	2,721	2,817
2003	41	1,157	1,198
2004	16	372	388
2005	16	372	388
2006	16	372	388
2007	16	372	388
2008	16	372	388
2009	16	372	388
2010	16	372	388
2011	16	372	388
2012	16	372	388
2013	16	372	388

TABLE 27

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

WATERFLOOD OPERATIONS
OPERATING COST FORECAST
(1985$)

Year	Production Facilities O&M (M$)	Production Wells (M$)	Total Unit Operating Cost (M$)
1987	1,287	3,234	4,521
1988	1,179	3,234	4,413
1989	1,083	3,234	4,317
1990	998	3,234	4,232
1991	920	3,234	4,154
1992	833	3,234	4,067
1993	775	3,234	4,009
1994	726	3,234	3,960
1995	726	3,234	3,960
1996	726	3,234	3,960
1997	726	3,234	3,960
1998	726	3,234	3,960
1999	726	3,234	3,960
2000	726	3,234	3,960
2001	726	3,234	3,960
2002	726	3,234	3,960
2003	726	3,234	3,960
2004	726	3,234	3,960
2005	726	3,234	3,960
2006	726	3,234	3,960
2007	726	3,234	3,960
2008	726	3,234	3,960
2009	726	3,234	3,960
2010	726	3,234	3,960
2011	726	3,234	3,960
2012	726	3,234	3,960
2013	726	3,234	3,960
2014	726	3,234	3,960
2015	726	3,234	3,960
2016	726	3,234	3,960
2017	726	3,234	3,960
2018	726	3,234	3,960

TABLE 28

PROPOSED BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

ECONOMIC MODEL ASSUMPTIONS

Basic Data

Present Value Reference Time	July 1, 1985
Overhead on Capital and Operating	10%
Property Tax and Insurance	1%
Severance Tax	(oil) 6.5%
	(gas) 6.5%
Royalty Fraction	0.125
Current Crude Price	$26.89/STB
Tier 2 Base Crude Price/WPT Rate	$21.33/60%
Average Gas Price	$1.23/MMCF

Continued Primary Operations Data

Average Blinebry/Tubb/Drinkard Producer	
Operating Cost (includes R&R)	$1,250/Mo.
Electrical Cost	$0.05/Kw-Hr.

Waterflood Operations Data

Average Producer Operating Cost (includes R&R)	
Commingled Oil (Blinebry/Tubb/Drinkard)	$1,800/Mo.
Gas (Tubb)	$1,000/Mo.
Source Water (San Andres)	$1,500/Mo.
Average Injector Operating Cost (includes R&R)	
Dual	$2,000/Mo.
Single	$1,000/Mo.
Average Producer Workover Cost	
Commingled Oil (Blinebry/Tubb/Drinkard)	$30,000/Well
Gas (Tubb)	$20,000/Well
Source Water (San Andres)	$35,000/Well
Average Convert-to-Injector Cost	
Dual	$105,000/Well
Single Zone - Blinebry	70,000/Well
Single Zone - Drinkard	75,000/Well
Electrical Cost	$0.05/Kw-Hr.

TABLE 29

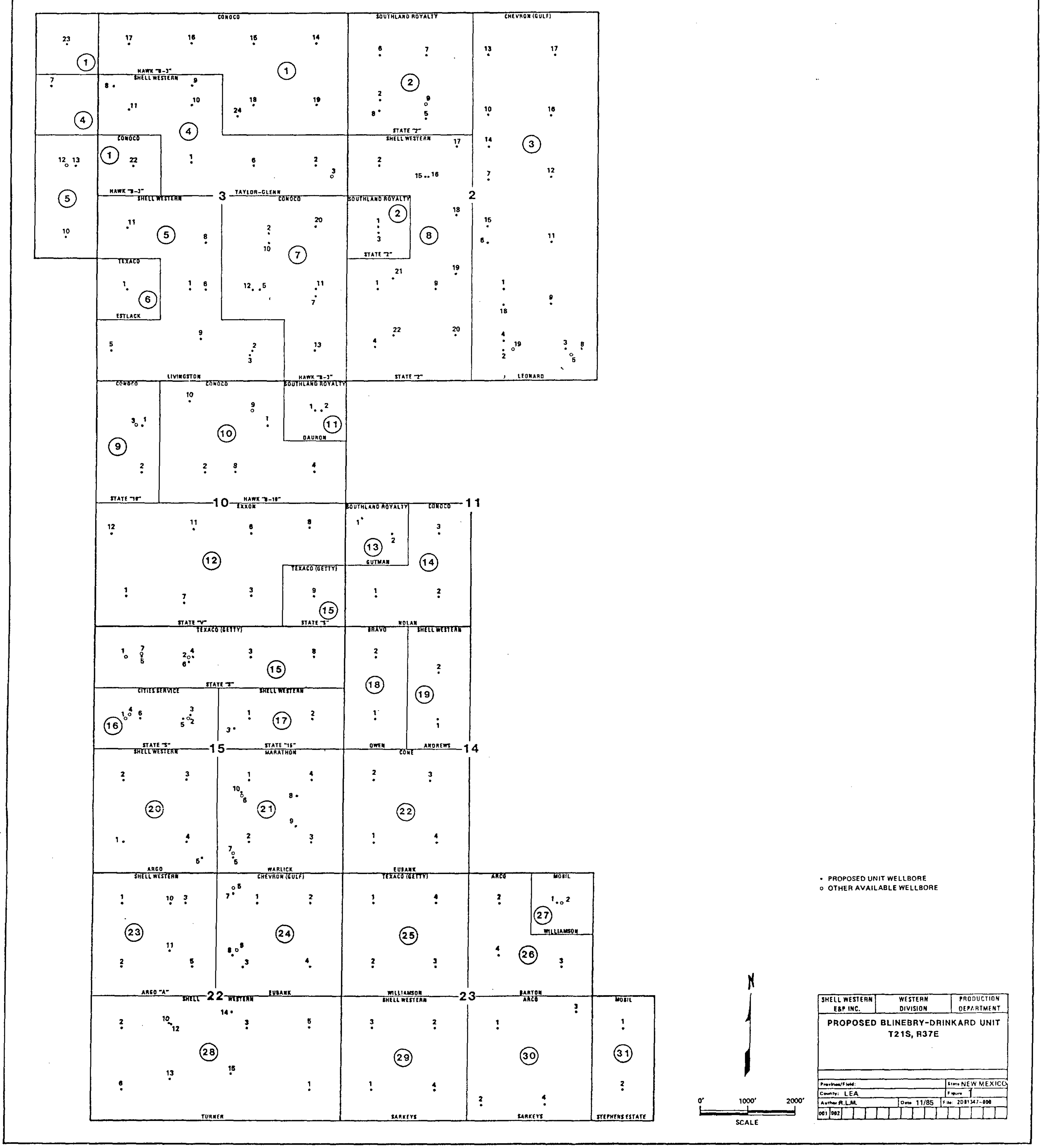
PROPOSED
BLINEBRY-DRINKARD UNIT
LEA COUNTY, NEW MEXICO

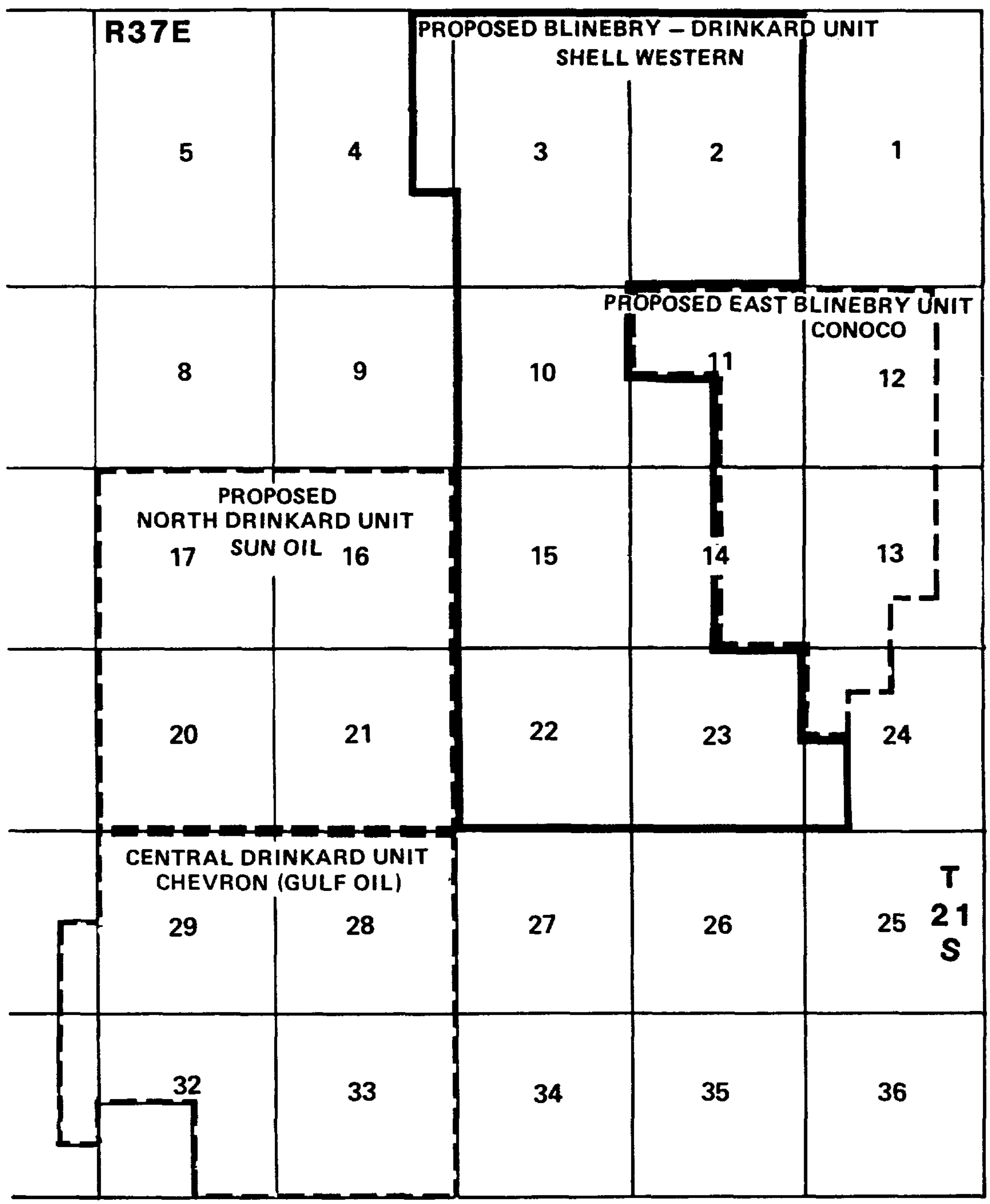
WATERFLOOD PROJECT
ECONOMIC ANALYSES

		Supplemental Reserve Additions		Investment		Undeferred Profit AFIT		PV Profit AFIT @ 5% DF		PV Profit AFIT @ 10% DF		Payout AFIT	Nominal Earning Power AFIT	Unit Development Cost
Case	Description	(MBO)	(MMCF)	Initial (M$)	Ultimate (M$)	(M$)	(%)	(M$)	(%)	(M$)	(%)	(Years)	(%)	($/STB)
I	1985$	15,265	-150	27,004	34,349	100,927	(294)	38,777	(132)	12,665	(49)	8.1	16	2.25
II	5%/Year Inflation Rate	15,265	-150	27,232	36,852	226,613	(615)	89,787	(288)	35,597	(133)	7.5	21	2.42
III	10%/Year Inflation Rate	15,265	-150	27,459	39,936	505,404	(1,266)	195,967	(588)	80,541	(284)	7.0	26	2.62

Waterflood Study
December 1985

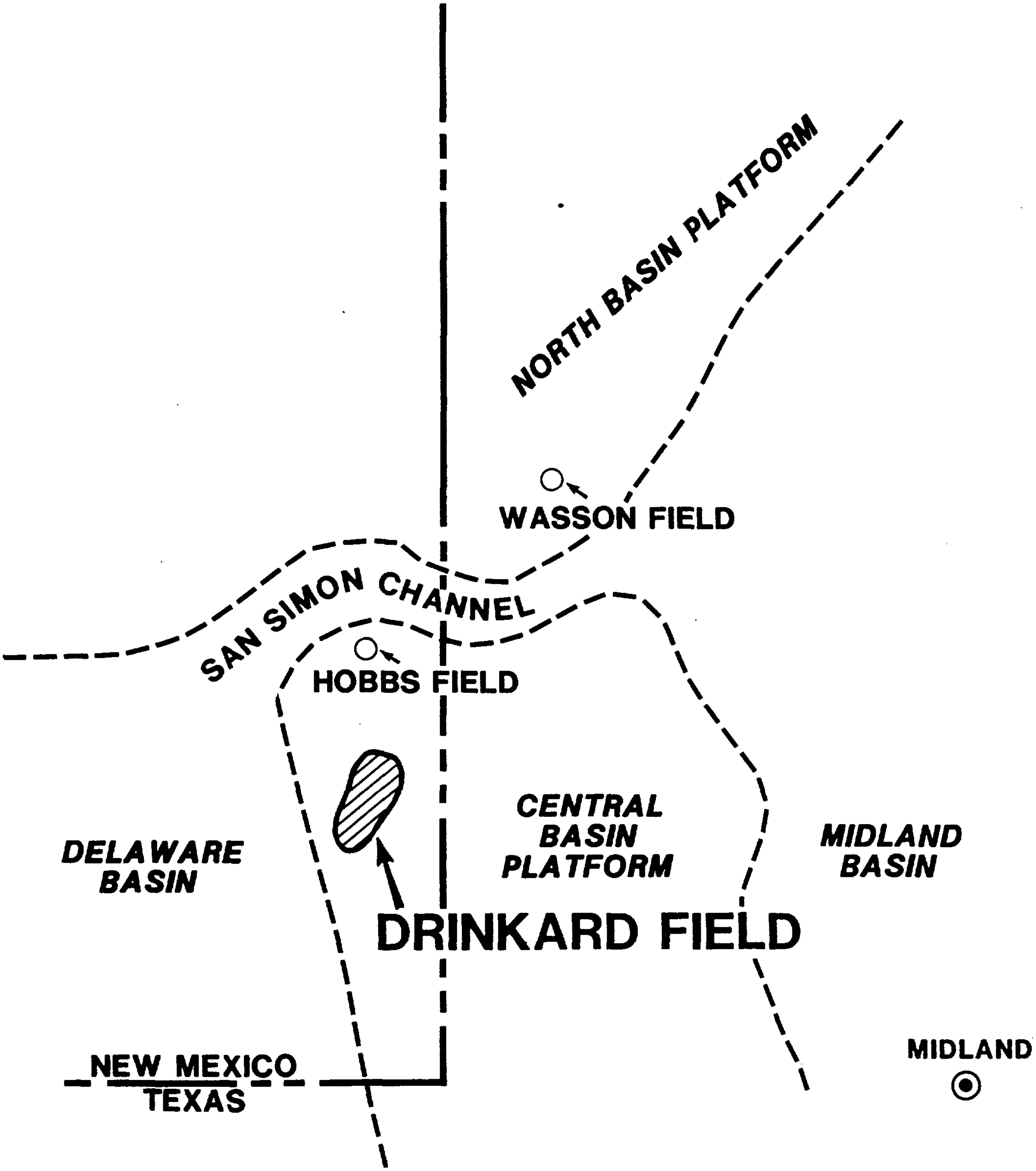
FIGURES


CONOCO
SOUTHLAND ROYALTY
CHEVRON (GULF)
SHELL WESTERN
TEXACO
TAYLOR-GLENN
LIVINGSTON
ESTLACK
LEONARD
DAURON
EXXON
GUTMAN
TEXACO (GETTY)
NOLAN
BRAVO
CITIES SERVICE
MARATHON
OWEN
CONE
ANDREWS
ARCO
WARLICK
EUBANK
MOBIL
WILLIAMSON
BARTON
TURNER
SARKEYS
STEPHENS ESTATE
• PROPOSED UNIT WELLBORE
o OTHER AVAILABLE WELLBORE
N
0' 1000' 2000'
SCALE
SHELL WESTERN E&P INC.
WESTERN DIVISION
PRODUCTION DEPARTMENT
PROPOSED BLINEBRY-DRINKARD UNIT
T21S, R37E
Province/Field:
State NEW MEXICO
County: LEA
Figure 1
Author R.L.M.
Date 11/85
File: 2D81347-000
001 002



PROPOSED BLINEBRY – DRINKARD UNIT
LEA COUNTY, NEW MEXICO
EXISTING AND PROPOSED
UNIT LOCATIONS
FIGURE 2

2VMC001538



PROPOSED BLINEBRY - DRINKARD UNIT
LOCATION MAP

MILES
0 5 10 15 20 25 30

FIGURE 3

2VMC001537

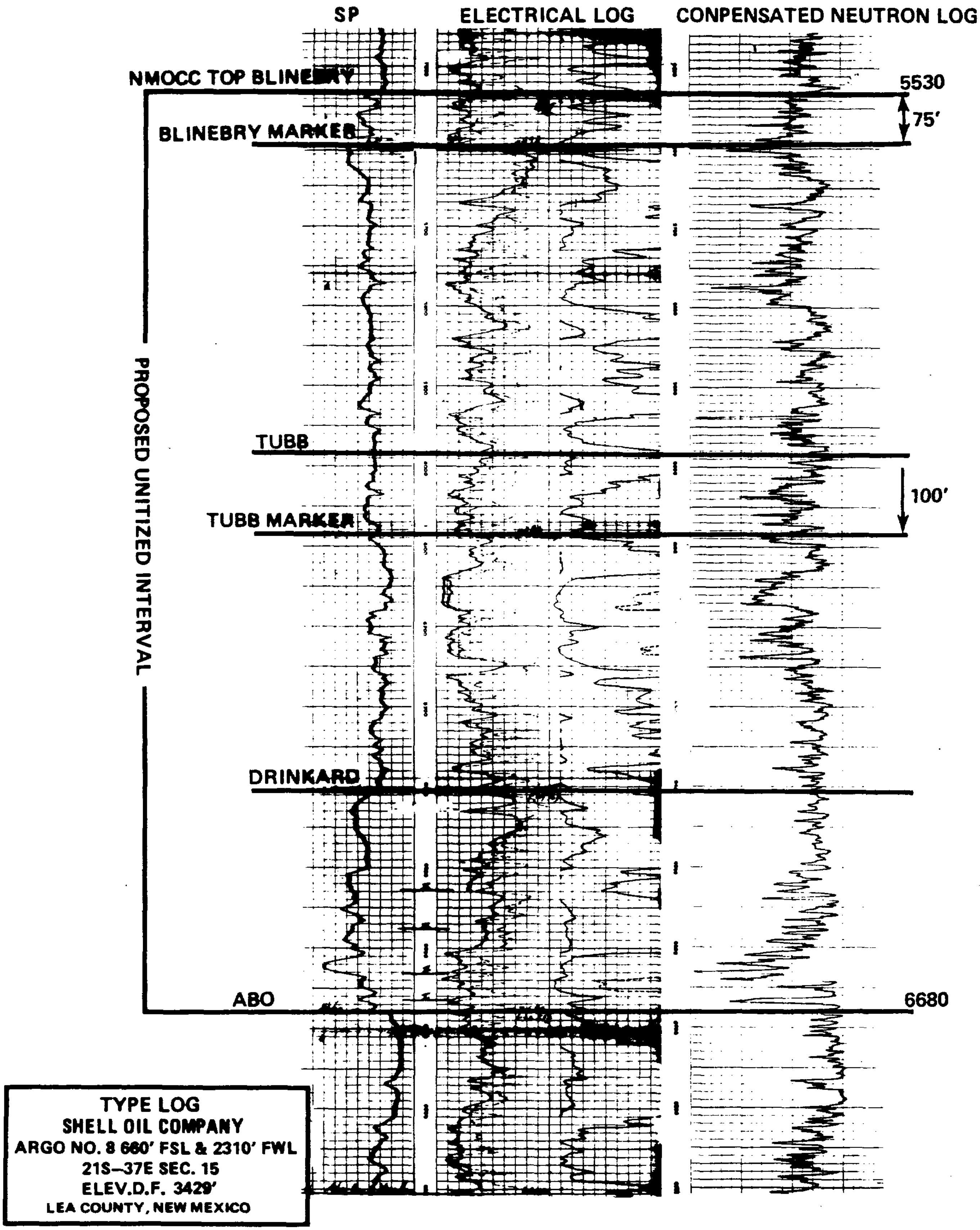
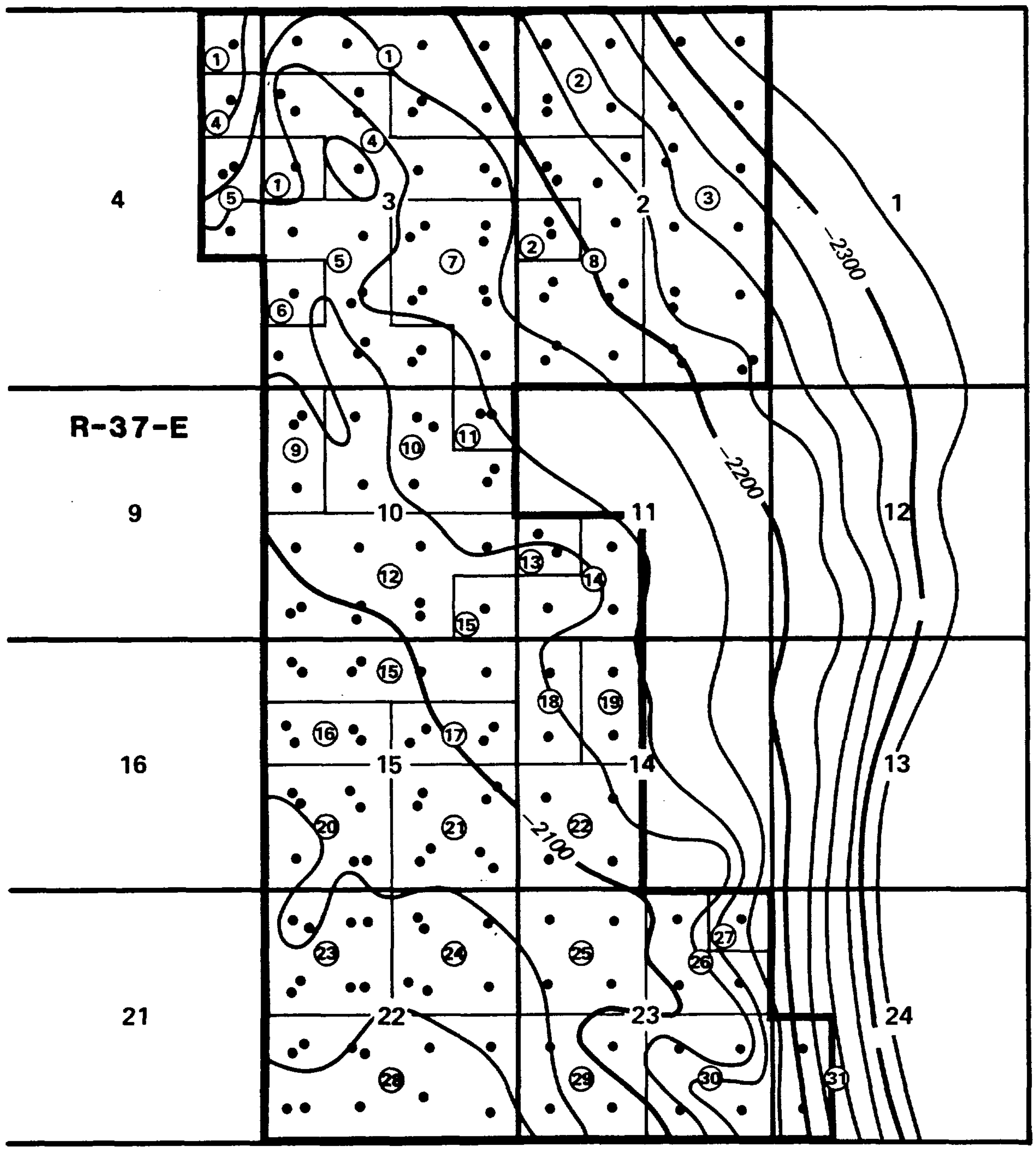

SP
ELECTRICAL LOG
CONPENSATED NEUTRON LOG
NMOCC TOP BLINEBRY
5530
75'
BLINEBRY MARKER
TUBB
100'
TUBB MARKER
DRINKARD
ABO
6680
PROPOSED UNITIZED INTERVAL
TYPE LOG
SHELL OIL COMPANY
ARGO NO. 8 660' FSL & 2310' FWL
21S–37E SEC. 15
ELEV.D.F. 3429'
LEA COUNTY, NEW MEXICO

FIGURE 4



LEGEND

- • PROPOSED UNITIZED WELLBORE
- 60 TRACT NUMBER

PROPOSED BLINEBRY – DRINKARD UNIT
LEA COUNTY, NEW MEXICO
STRUCTURE ON TOP OF BLINEBRY
CI=25'
FIGURE 5

2VMC001536

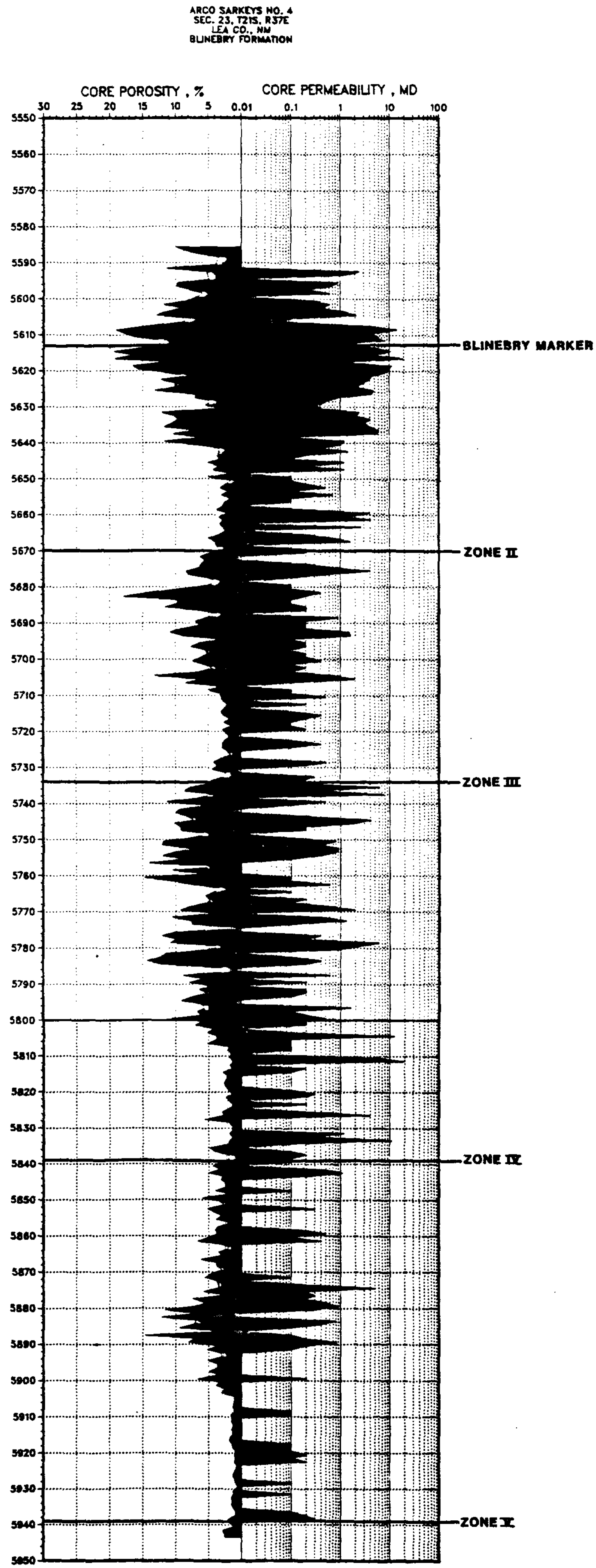

ARCO SARKEYS NO. 4
SEC. 23, T21S, R37E
LEA CO., NM
BLINEBRY FORMATION
CORE POROSITY , %
CORE PERMEABILITY , MD
30
25
20
15
10
5
0.01
0.1
1
10
100
5550
5560
5570
5580
5590
5600
5610
5620
5630
5640
5650
5660
5670
5680
5690
5700
5710
5720
5730
5740
5750
5760
5770
5780
5790
5800
5810
5820
5830
5840
5850
5860
5870
5880
5890
5900
5910
5920
5930
5940
5950
BLINEBRY MARKER
ZONE II
ZONE III
ZONE IV
ZONE V

FIGURE 6

LEA CO., NM
BLINEBRY FORMATION

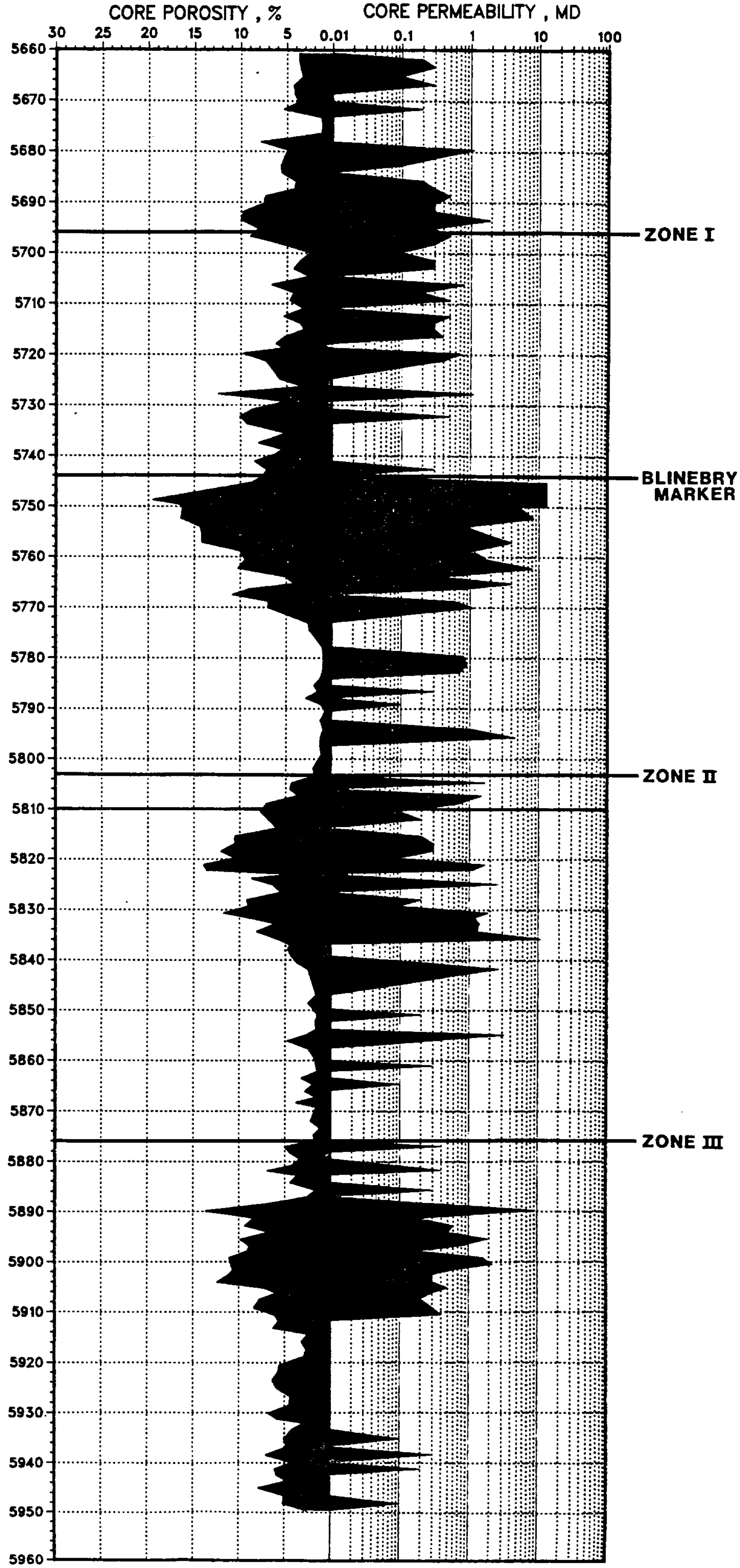


FIGURE 7

EXXON BLINEBRY-TUBB GAS COM NO. 1
SEC. 10, T21S, R37E
LEA CO., NM
BLINEBRY FORMATION

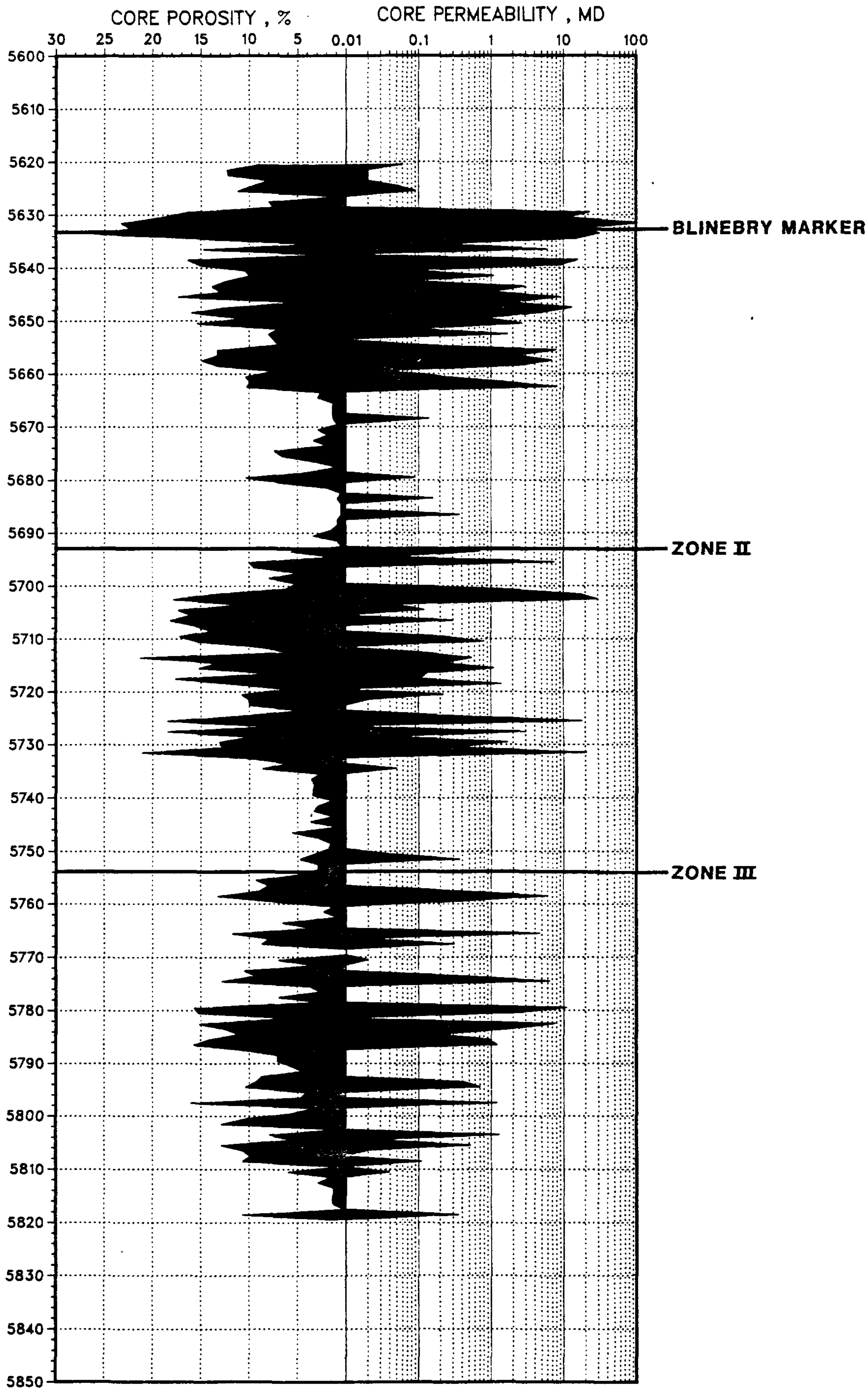


FIGURE 8

SHELL COLL NO. 2
SEC. 12, T21S, R37E
LEA CO., NM
BLINEBRY FORMATION

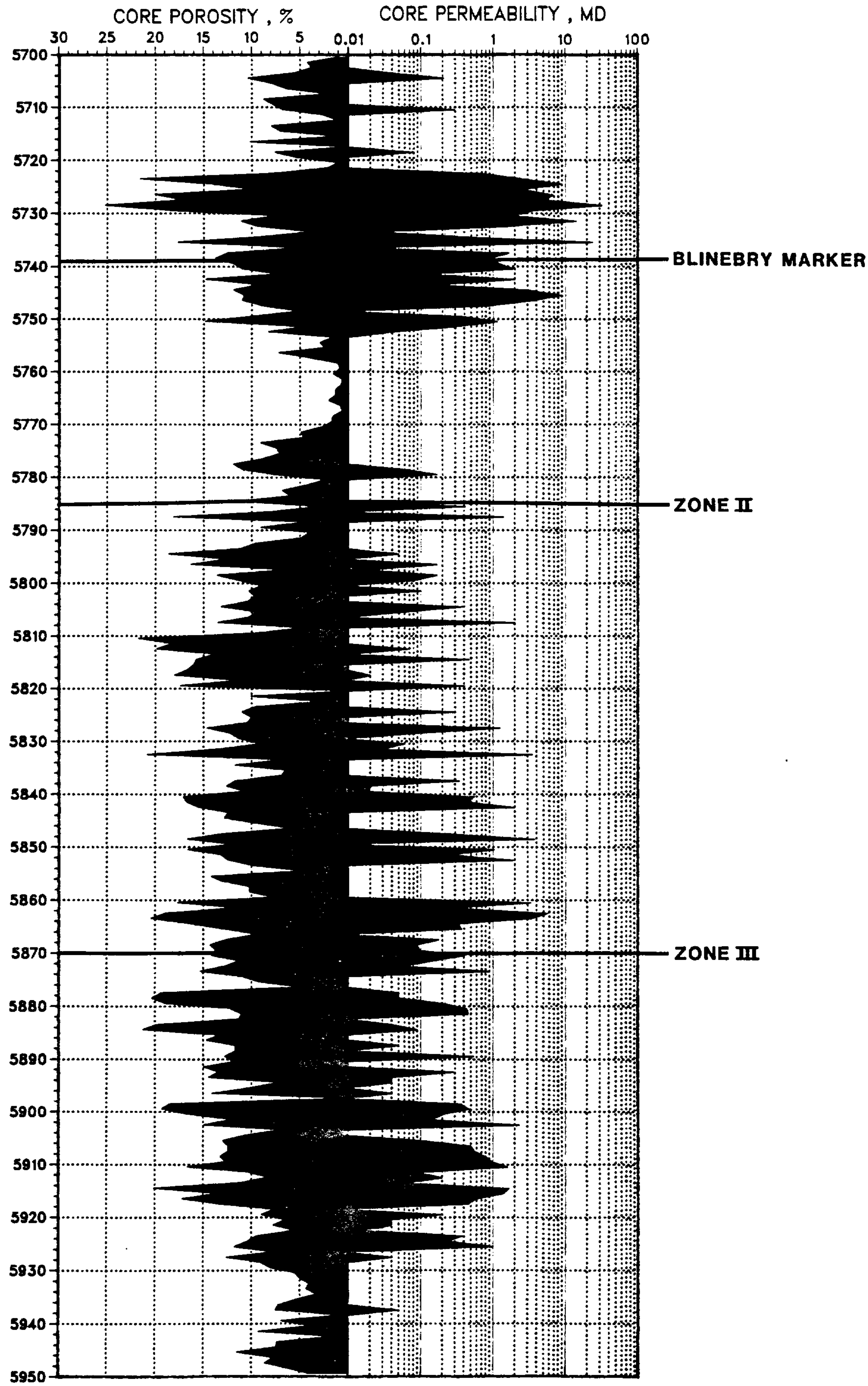


FIGURE 9

SHELL STATE NO. 19
SEC. 2, T21S, R37E
LEA CO., NM
BLINEBRY FORMATION

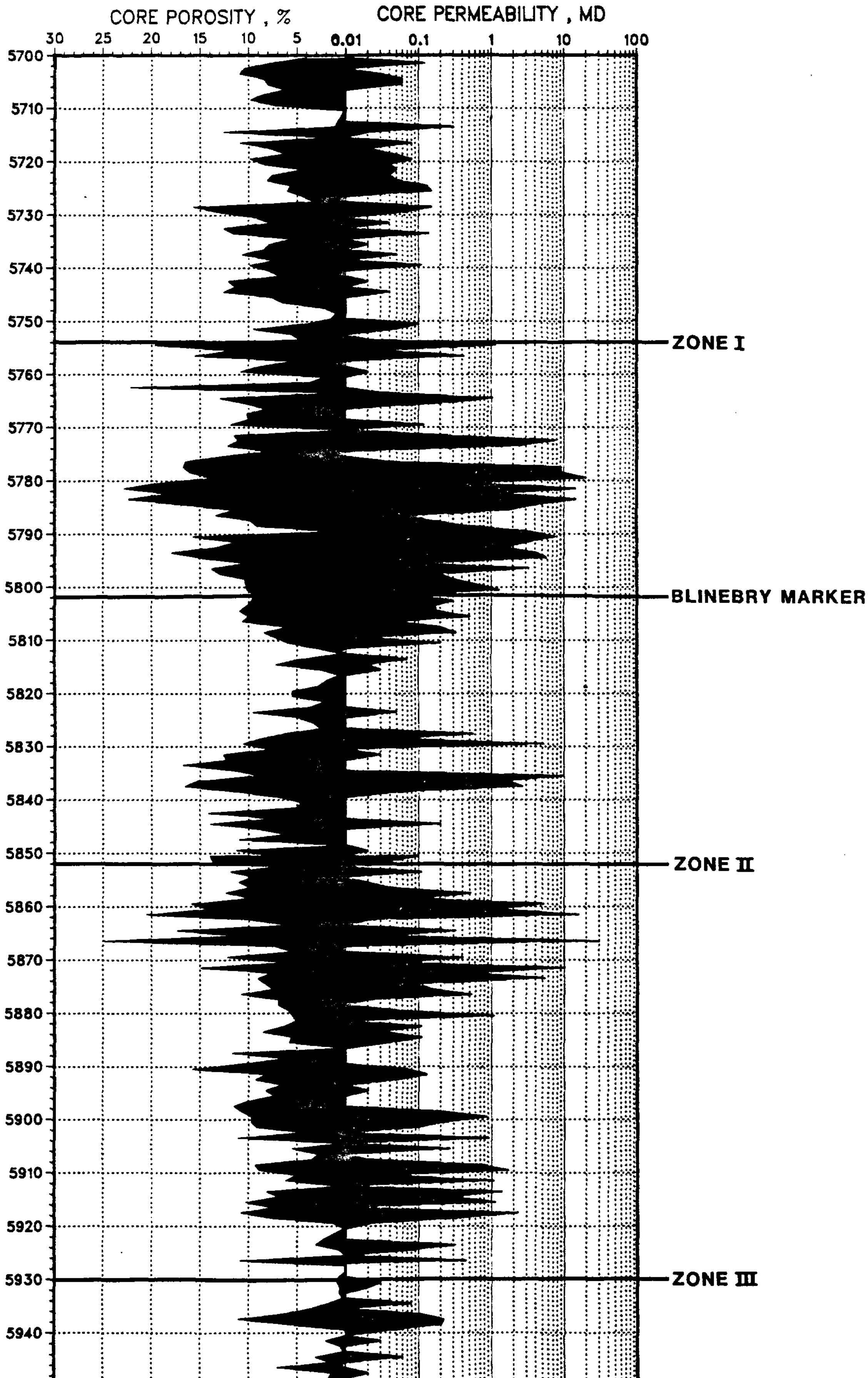


FIGURE 10

SHELL TAYLOR-GLENN NO. 10
SEC. 3, T21S, R37E
LEA CO., NM
BLINEBRY FORMATION

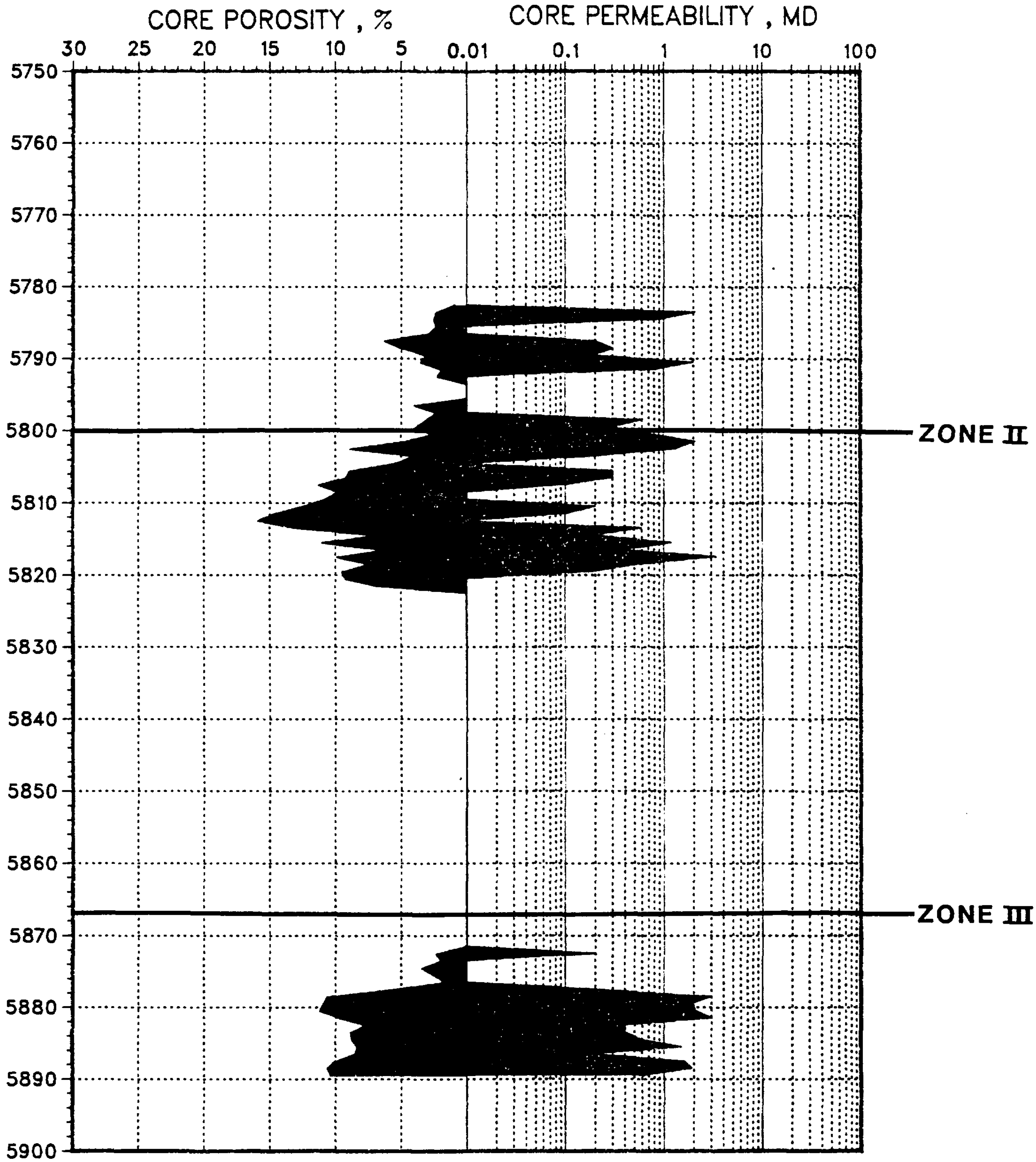


FIGURE 11

CONOCO HAWK B-3 NO. 16
SEC. 3, T21S, R37E
LEA CO., NM
TUBB FORMATION

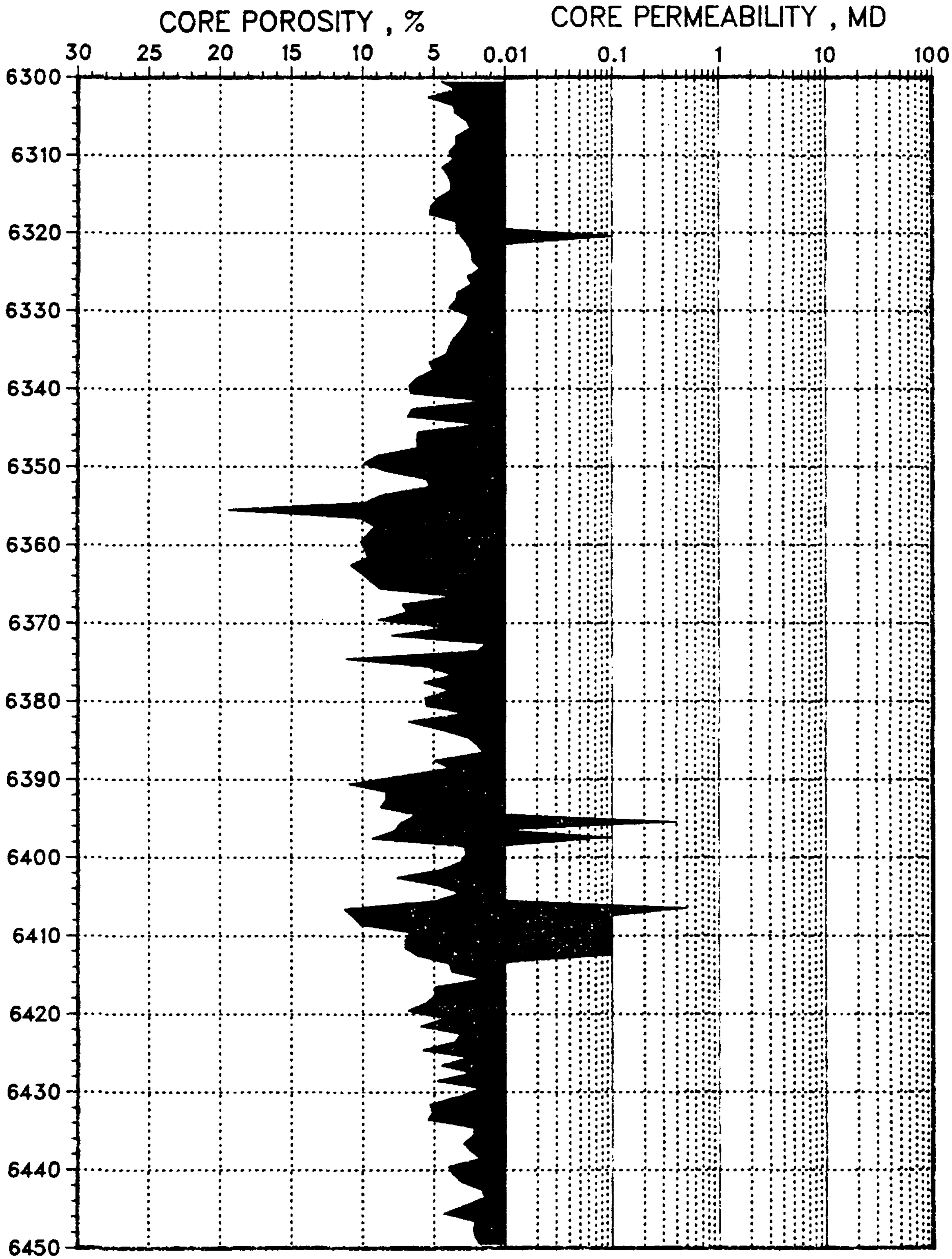


FIGURE 12

CONOCO HAWK B-10 NO. 10
SEC. 10, T21S, R37E
LEA CO., NM
TUBB FORMATION

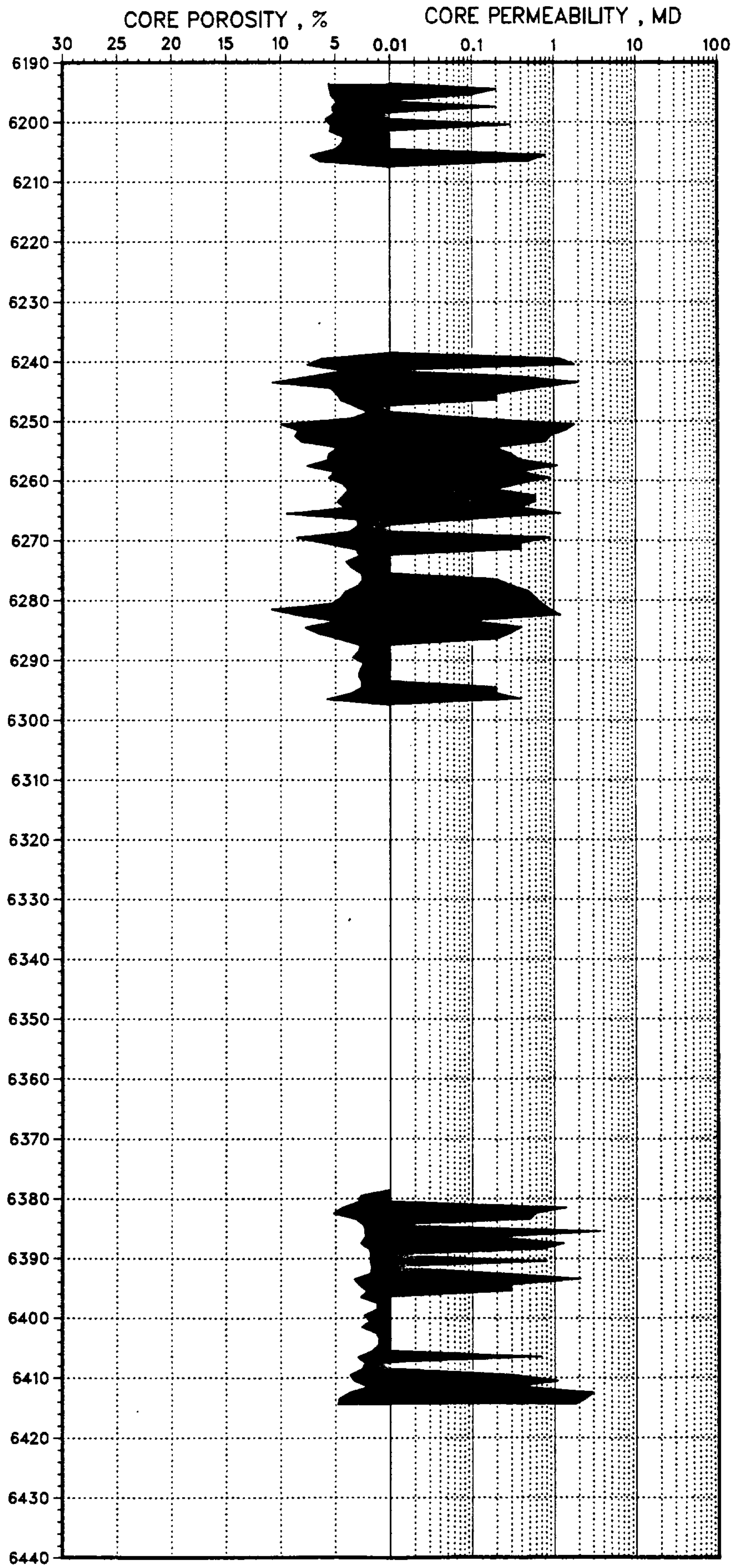


FIGURE 13

EXXON BLINEBRY–TUBB GAS COM NO. 1
SEC. 10, T21S, R37E
LEA CO., NM
TUBB FORMATION

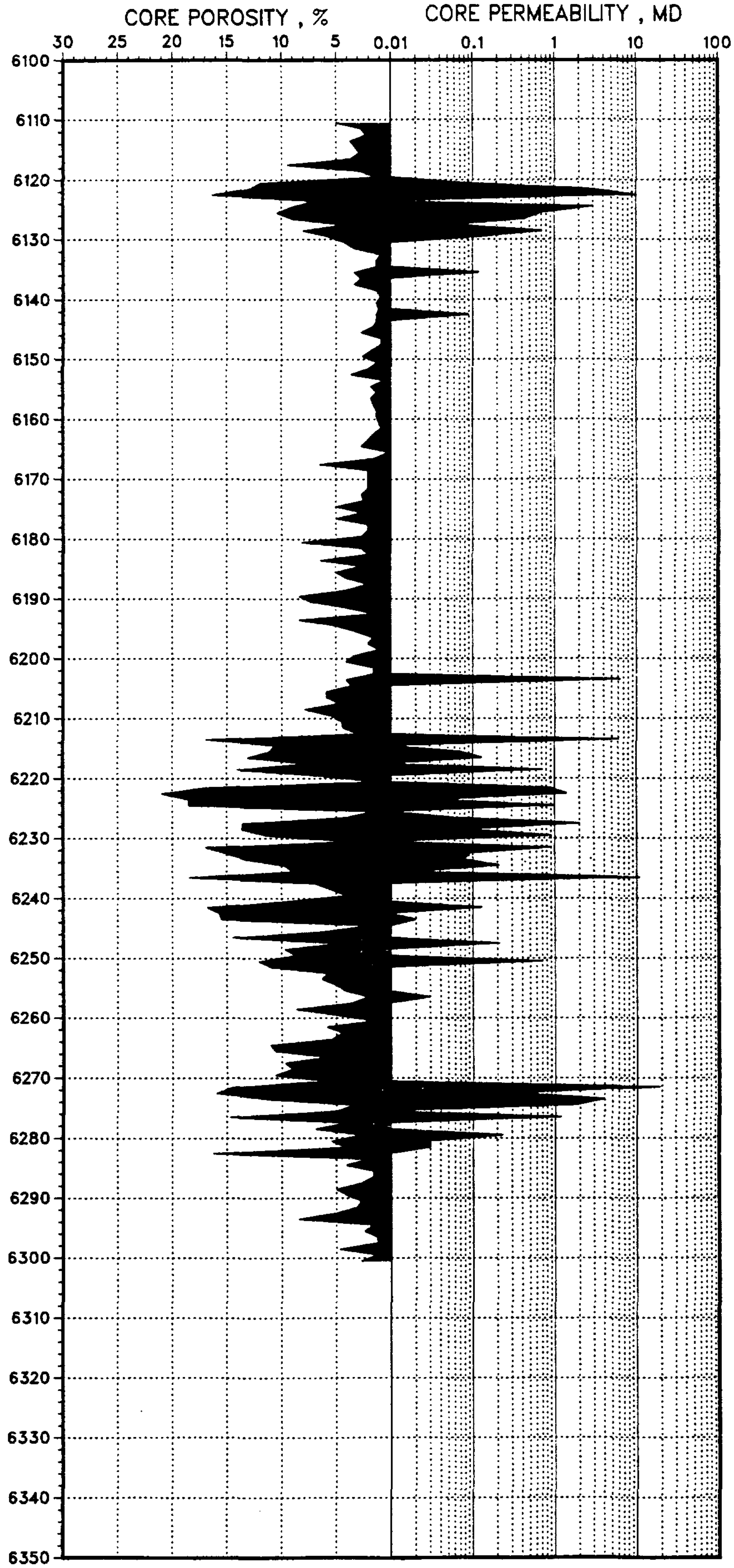


FIGURE 14

SHELL TAYLOR–GLENN NO. 10
SEC. 3, T21S, R37E
LEA CO., NM
DRINKARD FORMATION

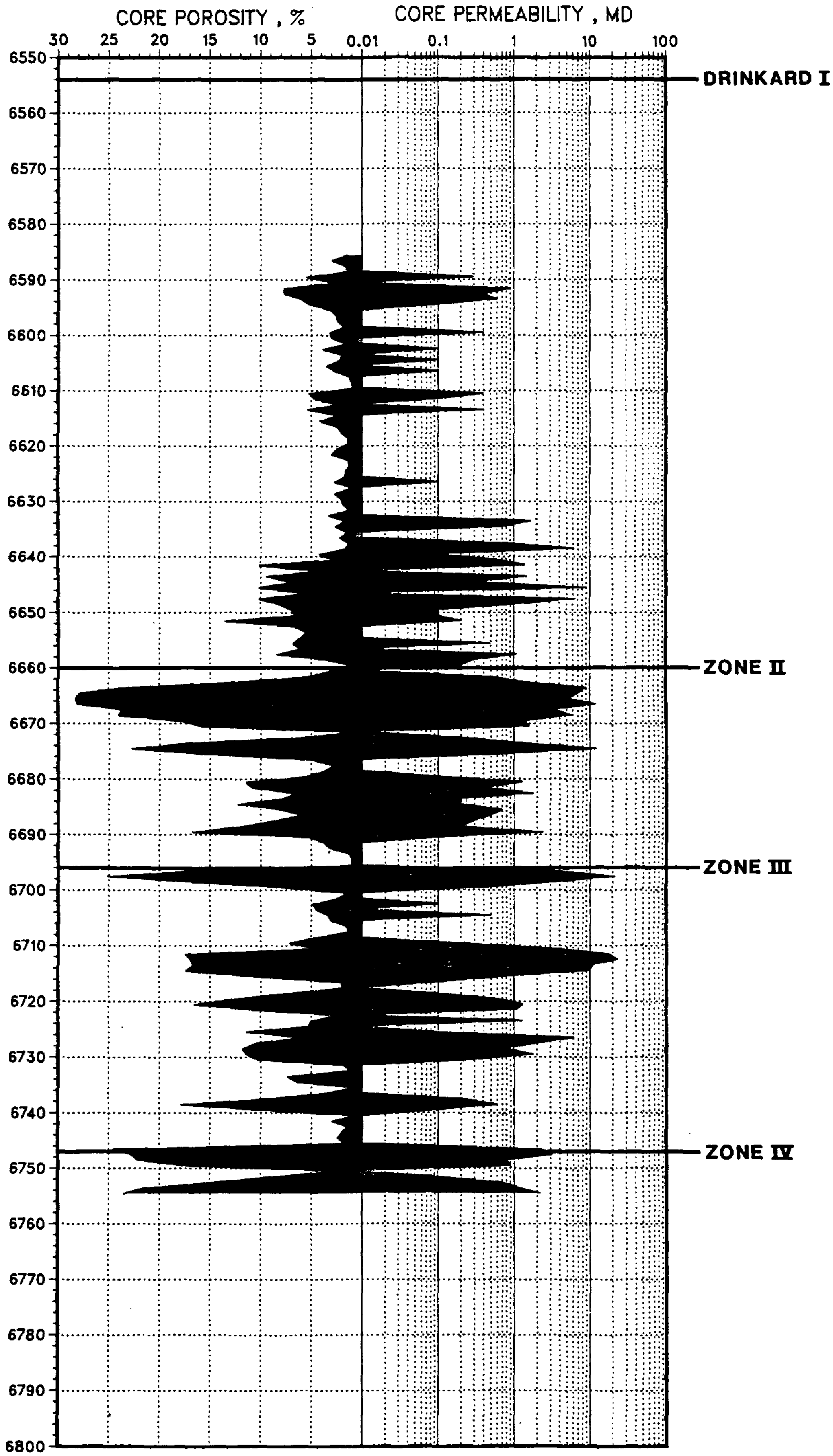


FIGURE 15

RESERVOIR SCHEMATIC

PROPOSED BLINEBRY DRINKARD UNIT

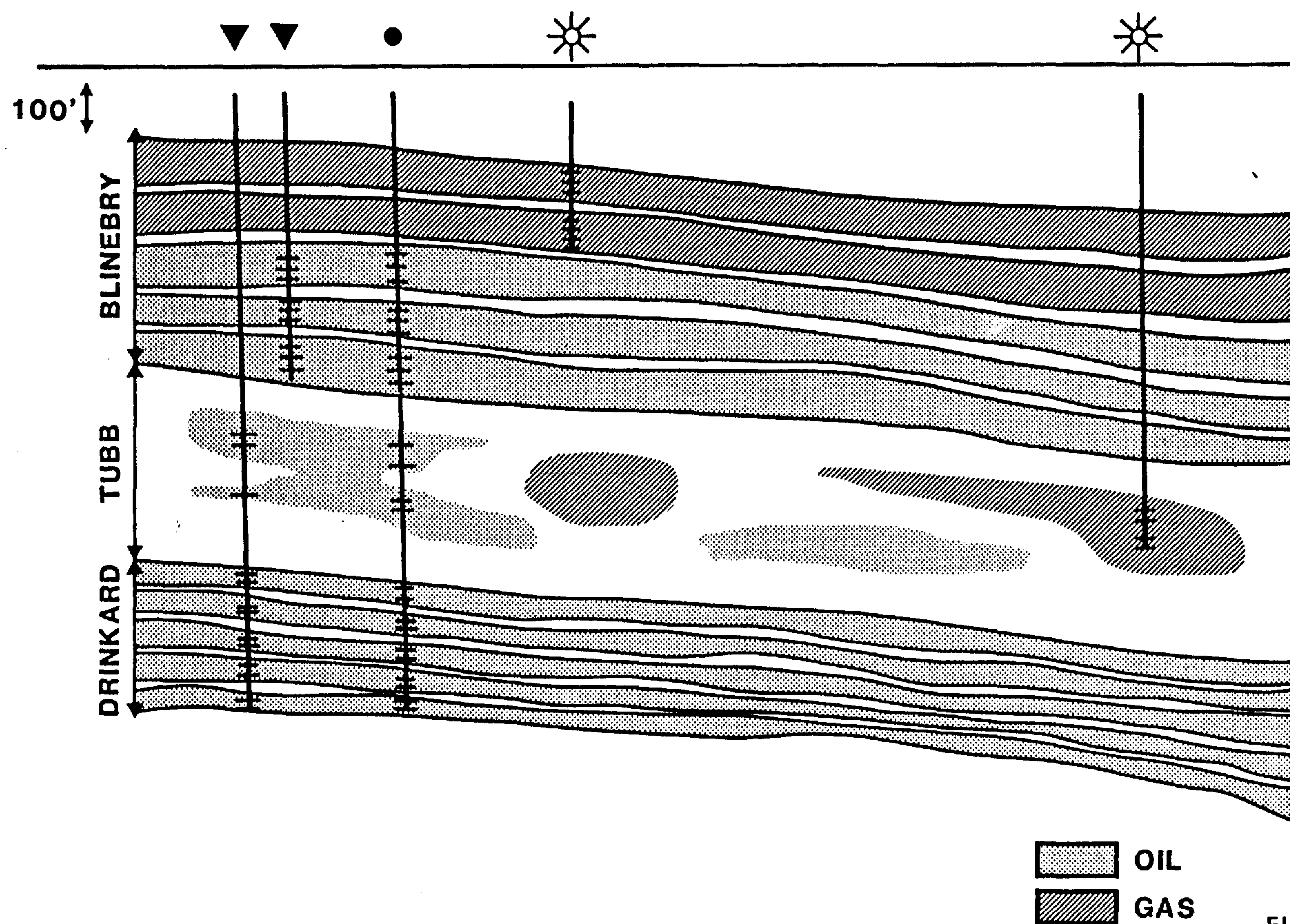
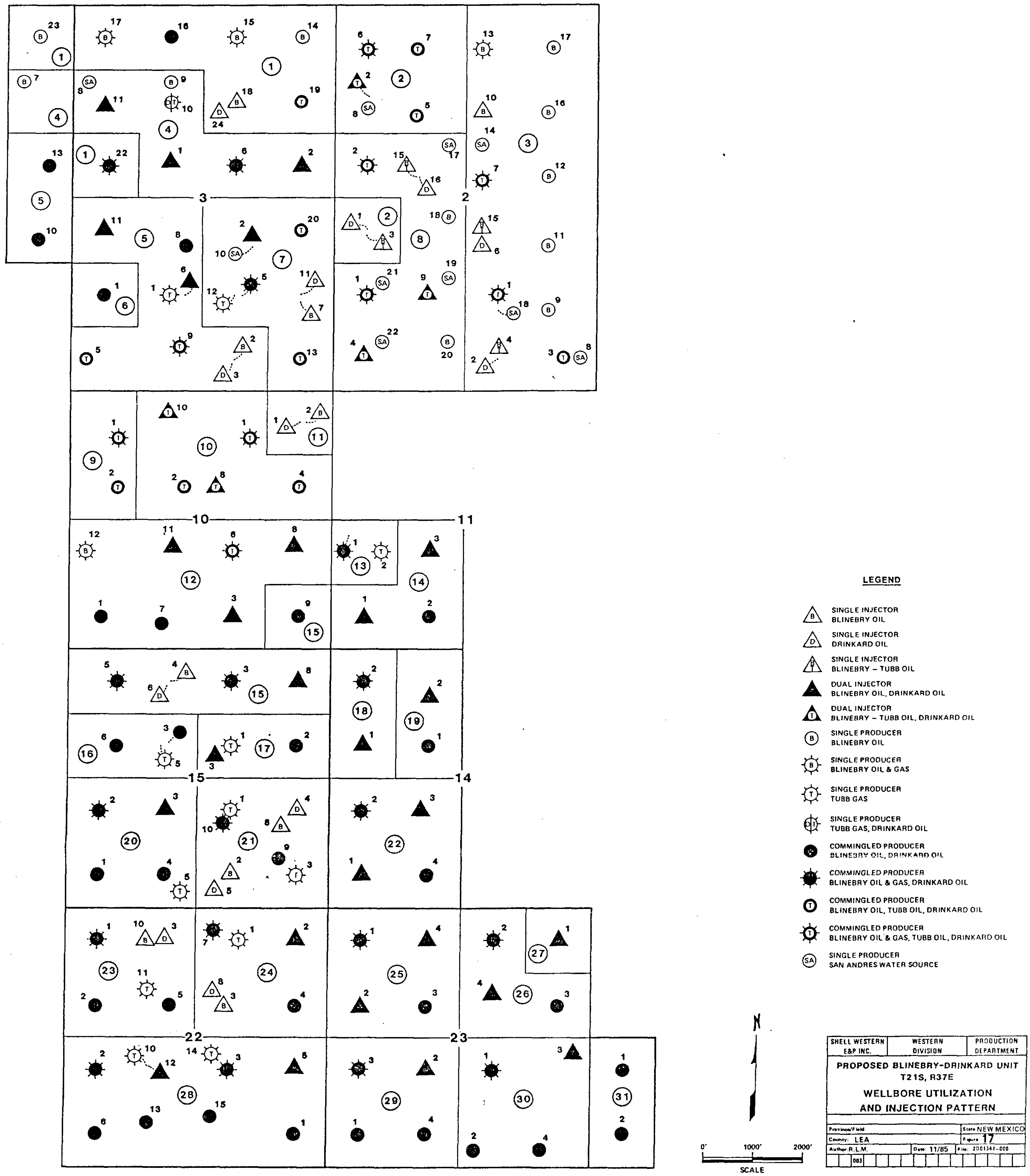


FIGURE 16

2VMC001535


LEGEND
SINGLE INJECTOR BLINEBRY OIL
SINGLE INJECTOR DRINKARD OIL
SINGLE INJECTOR BLINEBRY – TUBB OIL
DUAL INJECTOR BLINEBRY OIL, DRINKARD OIL
DUAL INJECTOR BLINEBRY – TUBB OIL, DRINKARD OIL
SINGLE PRODUCER BLINEBRY OIL
SINGLE PRODUCER BLINEBRY OIL & GAS
SINGLE PRODUCER TUBB GAS
SINGLE PRODUCER TUBB GAS, DRINKARD OIL
COMMINGLED PRODUCER BLINEBRY OIL, DRINKARD OIL
COMMINGLED PRODUCER BLINEBRY OIL & GAS, DRINKARD OIL
COMMINGLED PRODUCER BLINEBRY OIL, TUBB OIL, DRINKARD OIL
COMMINGLED PRODUCER BLINEBRY OIL & GAS, TUBB OIL, DRINKARD OIL
SINGLE PRODUCER SAN ANDRES WATER SOURCE
N
0' 1000' 2000'
SCALE
SHELL WESTERN E&P INC.
WESTERN DIVISION
PRODUCTION DEPARTMENT
PROPOSED BLINEBRY-DRINKARD UNIT
T21S, R37E
WELLBORE UTILIZATION
AND INJECTION PATTERN
Province/Field:
State NEW MEXICO
County: LEA
Figure 17
Author: R.L.M.
Date: 11/85
File: 2001347-000
003