

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

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS LEA COUNTY, NEW MEXICO — **CASE NOS. 24123**

APPLICATIONS OF GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS LEA COUNTY, NEW MEXICO — **CASE NOS. 23614-23617**

APPLICATION OF GOODNIGHT MIDSTREAM PERMIAN LLC TO AMEND ORDER NO. R-22026/SWD-2403 TO INCREASE THE APPROVED INJECTION RATE IN ITS ANDRE DAWSON SWD #1, LEA COUNTY, NEW MEXICO. — **CASE NO. 23775**

APPLICATIONS OF EMPIRE NEW MEXICO LLC TO REVOKE INJECTION AUTHORITY, LEA COUNTY, NEW MEXICO — **CASE NOS. 24018-24027**

GOODNIGHT MIDSTREAM'S NOTICE OF FILING CROSS EXAMINATION EXHIBITS

Goodnight Midstream Permian, LLC ("Goodnight Midstream"), through undersigned counsel, respectfully provides notice that the following Cross Examination Exhibits 10-23 were admitted into the record in the above-captioned matters.

DATED: May 1, 2025

Respectfully submitted,

HOLLAND & HART LLP

By: */s/ Adam G. Rankin*
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CERTIFICATE OF SERVICE

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Goodnight Cross Exhibit 10

WATERFLOOD PERFORMANCE
AND
CASH FLOW PROJECTIONS

FOR

EUNICE MONUMENT SOUTH UNIT
LEA COUNTY, NEW MEXICO

AS OF

JULY 1, 1987

FOR

ENERGY PRODUCTION CORPORATION

WILLIAM M. COBB & ASSOCIATES, INC.
Petroleum Engineering Consultants

WILLIAM M. COBB & ASSOCIATES, INC.
Petroleum Engineering Consultants

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August 3, 1987

Mr. Joe Vaughan
Energy Production Corporation
613 Glen Lakes Tower
9400 N. Central Expressway
Dallas, TX 75231

Dear Mr. Vaughan:

At the request of Energy Production Corporation, we have estimated the production and economic potential for the Eunice Monument South Unit (EMSU) waterflood located in Lea County, New Mexico. The EMSU waterflood covers approximatly 14,280 acres and is projected to contain 175 production and 175 injection wells when it becomes fully developed in 1988. Production is expected to come primarily from the Grayburg formation, a dolomite zone at a depth of about 3800-4000 feet. Chevron Oil Company is the operator of EMSU and they initiated water injection in late 1986 on 80 acre, 5-spot patterns. Current water injection is about 70,000 barrels per day into about 100 - 110 wells. Fieldwide water injection is expected to increase to about 100,000 barrels per day by the end of 1987 and reach 115,000 - 120,000 barrels per day by late 1988. Current production rate is about 1350 barrels of oil and 10,000 barrels of water per day. Cumulative primary production since 1929 to date is 123,000,000 barrels of oil (123 MMBO). The estimated ultimate primary recovery is 134 MMBO.

An early estimate of the original oil in place (OOIP) was 671 MMBO. This value was based on an assumed primary recovery factor of 20 percent. During the past 18 - 24 months, more than 30 new wells have been drilled. Logs are available on all wells and core data is present on 10 wells. Utilizing this new information, we estimate the OOIP to be 1,029 MMBO. In fact, we can make a technical argument that the OOIP could be as much as 1,255 MMBO but we have used 1,029 MMBO in this study.

A waterflood performance prediction has been made for the entire EMSU. A 20 layer, steady state, five-spot waterflood model was used. Average pattern injection rate is estimated to be about 800 BWPD and the average field injection rate is projected to be slightly less than 100 MBW per day. A fieldwide projection indicates that the initial oil production response should occur in 1988 and that a peak production of about 20,000 - 21,000 BOPD will occur in the early 1990's. Estimated remaining primary and secondary recovery over a 30 year period from 1987 to 2007 is calculated to be 155 MMBO of which 144 MMBO is projected to be waterflood recovery. The estimated secondary to primary oil recovery ratio is predicted to be 1.07.

Cash flow calculations are presented for flat oil price and escalated oil price scenarios. Also, cash flow projections are presented for an operating scenario whereby an infill drilling program is needed over a five year period beginning in 1991 in order to achieve the waterflood projections presented in this report. For the infill drilling case, no consideration is given to the possible additional increase in ultimate oil recovery.

We believe this investigation is the most complete engineering and geological study of EMSU available at this time. However, it is important to recognize that oil and gas production forecasts are not exact. The volumes and prices to be received from this property could be more or less depending on a number of reservoir and operating variables. The projections presented in this report represent only informed professional judgments.

We are pleased to prepare this study for Energy Production Corporation. If we can answer any questions regarding our work, please contact us. Detailed work papers are maintained on file in our office.

Yours very truly,

William M. Cobb

William M. Cobb, P.E.

WMC:cac

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INTRODUCTION

The most commonly used supplementary oil recovery process is waterflooding. Conceptually, water is injected into an oil reservoir and oil is displaced to an adjacent wellbore where it is produced. Waterflooding was first introduced to the petroleum industry more than 75 years ago, however, its significance in the petroleum industry has become more widespread during the last 20 - 25 years. In fact, more than 1000 technical papers and several textbooks[1,2] have been published on various aspects of waterflooding. Currently more than 50 percent of the onshore production in the United States is the result of water injection.

The concept of waterflooding is simple. However, the expected oil recovery from water injection in any reservoir is dependent upon four important variables. They include:

(1) Oil in the floodable part of the reservoir at the start of water injection.

(2) The efficiency with which water displaces oil in the water contacted part of the reservoir.

(3) The area of the reservoir swept by the injected water.

(4) The vertical coverage or vertical sweep efficiency of the water between an injection and production well.

The result obtained by multiplying items three and four is frequently referred to as volumetric sweep efficiency. It represents that portion of floodable rock which is contacted by the injected water. The result obtained by multiplying items two, three, and four is a waterflood recovery factor.

Clearly, the waterflood recovery factor multiplied by the oil in place in the floodable part of the reservoir at the start of water injection yields waterflood recovery. Therefore to forecast and predict waterflood recovery at any time in the life of the waterflood, it is necessary to be able to quantify items two, three, and four at the corresponding time.

Without going through a substantial amount of theoretical detail, it can be stated that the oil in place at the start of a flood (item #1) is dependent on the oil saturation, floodable net pay, and porosity. It is significant to note the oil saturation at the beginning of injection may be significantly less than the oil saturation at the time of field discovery[3]. This decrease in oil saturation is due to (1) primary oil production and (2) shrinkage of the remaining oil in the reservoir. Floodable net pay represents reservoir thickness which contributes to production. In waterflood operations the net pay which contributes to waterflood recovery is always less than net pay which contributes to primary recovery. To be considered as net pay for secondary operations, an interval must meet two criteria. First, the interval must possess sufficient permeability to allow for meaningful injection. Second, the interval must be continuous between the injection and production wells. Several recent waterflood case histories have shown the significance of rock continuity on waterflood behavior[4,5,6].

The displacement efficiency (item #2) is essentially dependent upon (1) the viscosity of the oil and the injected water and (2) the relative permeability to oil and water. The areal sweep efficiency (item #3) is dependent upon (1) the type of injection pattern, (2) mobility ratio, and (3) volume of water injected. The vertical sweep efficiency (item #4) is largely influenced by reservoir layering and the variation in permeability within the layers.

Energy Production Corporation requested that William M. Cobb & Associates, Inc., because of its significant experience in waterflooding, evaluate the waterflood potential of the Eunice Monument South Unit (EMSU) located in Lea County, New Mexico. Based upon practical experience and theoretical concepts, a detailed investigation of the newly initiated EMSU waterflood project operated by Chevron Oil Company has been conducted. The purpose of this report is to describe the study and to present the oil production and cash flow projections which represent the end product of this analysis. This study has been conducted for Mr. Joe Vaughan of Energy Production Corporaton of Dallas, Texas. Any reproduction or use of this report requires the prior written consent of Energy Production Corporation or William M. Cobb & Associates, Inc.

EUNICE MONUMENT SOUTH UNIT

The EMSU waterflood project is located in Lea County, New Mexico. The Unit covers approximately 14,280 acres in Township 20 South, Ranges 36 and 37 East and Township 21 South, Range 36 East. Figure 1 shows the location of the EMSU. The unitized interval covers the lower Penrose, Grayburg, and San Andres Formations. The main interval of interest is the Grayburg. Water injection into several wells commenced in late 1986. Additional wells are currently being converted and it is expected that water injection into all injectors will be achieved during 1988. The flood is being conducted on 80 acre 5-spot patterns. At the start of water injection, the primary production rate was about 1800 stock tank barrels of oil (STBO) per day and 9000 BWPD. Current production is about 1350 STBO and 10,000 BW per day. The decline in oil production rate is the direct result of converting more than 100 production wells to water injection wells. The increase in water production is due to the deepening and testing of a number of producing wells to depths substantially below the accepted water-oil contact.

GEOLOGY

The EMSU is located in the southern portion of the Eunice Monument Field and is situated on a NW-SE trending asymmetrical anticline which lies along the northwestern edge of the Central Basin Platform within the Permian Basin. Within the Unit area, the principal oil producing formations are the Queen-Penrose and Grayburg formations with the Grayburg being the major contributor. The depth of the reservoir is about 3900 feet. Figure 2 is a base map showing the Unit outline and well locations. Figure 3 presents a structure map on top of the Grayburg and a type log from EMSU well #457. The maps are provided as a courtesy of the Unit operator.

The Grayburg is reported by Chevron to be a massive dolomite interval with thin stringers of sand interspersed within it. The sand stringers appear to possess low permeability and porosity and are not expected to contribute to secondary production. The sands should serve as vertical barriers and prevent significant crossflow. A majority of production is expected to come from intercrystalline porosity within the dolomite.

This study did not yield a precise location of fluid contacts. A technical report dated April 1983 prepared by a technical committee of the Unit owners indicated a gas-oil contact to be at approximately -100 feet subsea. (Throughout this report, any reference to a technical committee or technical report is intended to refer to the April, 1983 Technical Committee Report prepared for the Unit owners. The report provided a partial basis for forming the EMSU.) The oil-water contact was estimated by the technical committee to lie between -325 and -400 feet subsea. Since the Unit was created, approximately

33 wells have been drilled throughout the field. Each well has a suite of modern electric and/or porosity logs. In addition, 10 wells have been cored. An analysis of this information indicates that no specific oil-water contact is present. Rather, a long transition zone appears to exist. In several of the recently drilled wells, Chevron has tested oil in commercially sustained rates as low as -500 feet subsea. In this study a gas-oil contact and an oil-water contact of -100 and -400 feet subsea respectively are used. Consequently, a gross floodable interval covering 300 feet is assumed.

PRIMARY PRODUCTION PERFORMANCE - EMSU

The oil pool in which the EMSU exists was discovered in 1929. Following discovery, the field was developed on 40 acre spacing with the majority of the wells being drilled and completed between 1934 and 1937. Peak oil production from approximately 343 Unit wells occurred in May, 1937 at a monthly production rate of 791,800 barrels. This represents a daily production rate of approximately 75 STBO per well.

Records from the State of New Mexico yield the following initial reservoir data:

Initial pressure at -250'ss	= 1450 psi
Reservoir temperature at -250'ss	= 90°F
Solution gas-oil ratio	= 432 SCF/BBL
API oil gravity	= 32°

The April 1983 technical committee report indicated that primary oil production at the time of the report to be approximately 120,000,000 STBO (120 MMSTBO). Based on decline curve analysis, the estimated ultimate primary production was projected to be about 134.3 MMSTBO. (Recovery as of July, 1987 is approximately 123 MMSTBO.)

At the time of the 1983 technical report, the lack of modern log and core data prevented an accurate calculation of reservoir pore volume and original oil in place (OOIP). Significantly, the technical committee assumed an ultimate recovery factor to be 20 percent. Hence an OOIP of 671.5 MMSTBO was calculated. Further, the technical committee assumed an average porosity of eight percent, an average initial water saturation of 30 percent, and an initial oil formation volume factor of 1.2 RB/STB.

OOIP Based On Data Obtained Since 1983

The primary production mechanism is solution gas drive. Very minor gas cap expansion may have been present on the NE side of the Unit and minor water influx may be present on the extreme west side of the field. Due to the lack of pressure data, no material balance projection could be prepared for EMSU. Nevertheless, based upon reservoir engineering experience in New Mexico, it is highly doubtful that the primary recovery factor will be as high as 20 percent. A more reasonable recovery factor will probably be between 10 and 15 percent. Using a 15 percent recovery factor, the OOIP would be about 893 MMSTBO.

During the past two years, 33 new wells have been drilled in EMSU. All of these wells have been logged. Ten wells have been cored. Using a six percent porosity cutoff, net isopachous and porosity-thickness (ϕh) maps have been prepared from log data. These maps are shown in Figures 4 and 5. Planimetering of the ϕh map gives a pore volume of 1,715.1 MMBBL.

A detailed review of the new electric logs suggests the connate water saturation is about 25 percent. This value is slightly less than the 30 percent saturation assumed by the 1983 technical committee. Using an initial formation volume factor of

1.25 RB/STB (as compared to a volume of 1.20 RB/STB assumed by the technical committee), a more reliable estimate of OOIP is obtained using the following expression:

$$OOIP = 7758Ah\phi(1-Swc)/Boi$$

Substituting the new estimates for the various parameters leads to:

$$OOIP = (1{,}715.1 \text{ MMBBL})(1-0.25)/1.25$$

or

$$OOIP = 1{,}029.1 \text{ MMSTBO}$$

Using this value of OOIP along with the estimated ultimate primary recovery of 134.1 MMSBO, the primary recovery factor is calculated to be 13.0 percent which appears to be more reasonable than the 20 percent used by the 1983 technical committee.

Porosity and Connate Water Saturation: It is significant to note that porosity values used in the pore volume calculation are log derived values. It is generally accepted in the petroleum industry that core derived porosity values are more reliable than log values. One of the recently cored EMSU wells also contained a Volan log prepared by Schlumberger. A comparison of the core porosity and log porosity indicated that the log porosity was approximately 1.5 porosity units less than the core porosity. The average log derived porosity at EMSU is estimated to be about 10.5 percent. Hence, it is possible that the pore volume at EMSU could be understated by about 14 percent (1.5/10.5 = 0.143) if the core porosity is assumed to be more accurate.

A water saturation of 25 percent is used in this study. Some publications in the petroleum literature indicate the Grayburg to be a slightly oil wet rock[7]. Routine log analysis in slightly oil wet systems have a tendency to over estimate water saturation. Several San Andres carbonate reservoirs in West Texas and Southeast New Mexico which are similar to Grayburg rock have connate water saturations as low as 15 - 16 percent.[4,8] If EMSU Grayburg water saturation is as low as 20 percent, the OOIP could be increased by 6.67 percent.

Consequently, it is possible to make a technical case that the OOIP at EMSU could be as high as 1,254.7 MMSTBO if porosity is increased by 14 percent and if water saturation is decreased by 6.7 percent. Such a value means the primary recovery factor is only 10.7 percent (134.1 MMSTBO/1,254.7 MMSTBO). In this study it is assumed that the maps presented in Figures 4 and 5 are accurate and that the OOIP is near 1,029.1 MMSTBO.

SECONDARY WATERFLOOD PRODUCTION FORECASTS - EMSU

Technical Committee Projections

Due to the lack of technical data, the EMSU technical committee estimated secondary oil recovery by assuming a number of parameters which were projected to give a minimum secondary recovery. From page seven of the technical committee report, the following statements describe the methodology for estimating waterflood recovery.

> "Assuming an OOIP of 671.5 MMSTBO (134.1 MMSTBO/0.20 = 671.5 MMSTBO) and a current formation volume factor of 1.05, the oil saturation at the start of flood, January 1, 1985 (water injection into EMSU was initiated in November, 1986) is estimated at 50%. Using a conservative estimate of 60% for volumetric sweep efficiency, and a residual oil saturation of 25%, the estimated secondary recovery will be approximately 9.8% of the OOIP or 65.8 MMSTBO.

This gives a secondary recovery to primary recovery ratio of 49%."

These calculations are the basis for the technical committee recommending the installation of the waterflood. Water injection commenced in late 1986. As of July, 1987, approximately 100-110 wells are on injection. The injection pattern is an 80 acre five-spot. Current average water injection rate is approximately 650-700 BWPD and most injection wells take water on a vacuum (zero wellhead injection pressure). The EMSU is expected to ultimately have approximately 175 injection wells and approximately 175 production wells. Chevron indicates that approximately 133 injectors will be active by the end of 1987. The remaining injectors will be located along the EMSU boundary. Since agreements with offset lease operators must be negotiated, the remaining injectors are expected to be placed into service during 1988. After installation of the lease line injectors, Chevron indicates that the Unit injection rates could be in the range of 115 to 120 MBW per day.

William M. Cobb & Associates Secondary Projection

Since the 1983 technical report, approximately 33 new logs and 10 sets of core data have been obtained. With this new information it has been possible to develop a more complete description of the reservoir rock and to more accurately predict waterflood performance for the EMSU. The following paragraphs describe the reservoir rock and fluid properties used in this study. In addition, the mathematical model used to predict waterflood performance on a pattern and fieldwide basis is described.

Reservoir Description: An accurate prediction of injection and production performance for any waterflood operation requires an accurate description of the reservoir including both rock property and fluid property data. After a review of all of the available data including logs, cores, the April 1983 technical committee report, and discussions with the EMSU operator, and several additional unit owners, a revised reservoir description has been prepared.

Net Pay - The gross reservoir interval at EMSU covers 300 feet between the gas-oil contact at -100 feet subsea and the oil-water contact at -400 feet subsea. Within this interval net pay ranges from zero to more than 200' depending on location as presented in the isopachous map in Figure 4. Based upon a number of technical publications pertaining to the waterflooding of carbonate reservoirs, a six percent porosity cutoff is used to estimate pay. All intervals possessing log porosity greater than or equal to six percent is considered pay; all intervals possessing log porosity less than six percent is considered non pay. (If log porosity is underestimating actual porosity by about 1.5 porosity units, it is possible the net pay depicted in Figure 4 is underestimated.)

Pore Volume - For all pay intervals, the average log porosity was determined and ϕh maps are prepared. Results are presented in Figure 5. Integration of these maps results in a calculated pore rolume of 1,715.1 MMBBL.

Oil Saturation - For a field that has experienced significant primary production such as the EMSU, the oil saturation can be substantially less than the oil saturation at the time of field discovery. From material balance concepts, the following equation can be developed which allows for the estimation of oil saturation at the start of the waterflood[3].

$$S_o = (1 - PRF)\left(\frac{B_o}{B_{ob}}\right)(1 - S_{wc})$$

where

PRF = Primary Recovery Factor at
flooding

B_o = Oil formation volume facto
waterflooding

B_{ob} = Oil formation volume facto
pressure

S_{wc} = Connate water saturation

For purposes of estimating oil satu
utilized the following parameters:

PRF = 0.15 (As opposed to a value of approximately 120 MMSTB/671.5 MMSTBO or 0.179 using the technical commi

B_o = 1.1 RB/STB

B_{ob} = 1.25 RB/STB

S_{wc} = 0.25

Substituting into the oil saturatio

$$S_o = (1 - 0.15)(\frac{1.1}{1.25})(1 - 0.25$$

or

S_o = 0.561 or 56.1 percent

IF PRF = 13% ← ULT. PRIM.

$S_g = 1 - .25 - \left[(1-.13)\left(\frac{1.1}{1.25}\right)(1-.25)\right]$

$S_g = (1 - .25 - .574) \times 100$

$= 17.6\%$

IF PRF = $\frac{120}{1029} \times 100 = 11.7\%$ ACTUAL EV AT START OF FLOOD

$S_g = 1 - .25 - \left[(1-.117)\left(\frac{1.1}{1.25}\right)(1-.25)\right]$

$S_g = (1 - .25 - .583) \times 100$

$S_g = 16.7\%$

Furthermore, the free gas saturation within the oil zone is calculated to be:

$$S_g = 1 - S_o - S_{wc}$$

or

$$S_g = 1 - 0.561 - 0.25$$

finally

$$S_g = 0.189 \text{ or } 18.9 \text{ percent.}$$

Gas saturation is important because it dictates the time required to achieve fillup and hence the time to initial waterflood oil production response.

Rock and Fluid Properties - Two important rock and fluid properties are necessary to compute waterflood performance. They include oil and water relative permeability and oil and water viscosity. No laboratory relative permeability data are available at this time for EMSU. However, the technical literature[9] provides mathematical expressions which can be used to estimate appropriate relative permeability values. Figure 6 presents the relative permeability data used in this study. Examination of these curves indicates a connate water saturation of 25 percent and a waterflood residual oil saturation of 30 percent (the technical committee assumed a residual oil saturation of 25 percent)

From PVT correlations[10], it is estimated that the current reservoir oil viscosity is 2.75 cp and the viscosity of the injection water is 0.8 cp.

The fractional flow of water in a waterflood can be described by the well known fractional flow equation[1] listed below.

$$f_w = \frac{1}{1 + \frac{k_{ro}}{k_{rw}} \times \frac{\mu_w}{\mu_o}}$$

where

f_w = Fractional flow of water

k_{rw} = Relative permeability to water

k_{ro} = Relative permeability to Oil

μ_w = Water viscosity

μ_o = Oil viscosity

Combining the relative permeability and viscosity data described above with the fractional flow relationship leads to a graph of f_w versus water saturation for EMSU. This graph is shown in Figure 7. This graph is used to predict waterflood displacement efficiency and to estimate mobility ratio.

Reservoir Stratification - Examination of logs and core data indicates that the EMSU will behave as a heterogeneous stratified system. Core data from 10 wells indicate the Dykstra-Parsons permeability coefficient[1,2], V, for EMSU to be between 0.7 and 0.8. A value of 0.75 is used in this study. Figure 8 presents a Dykstra-Parsons plot for EMSU.

Utilizing a V factor of 0.75, a 20 layer, 80 acre pattern, five spot model has been developed to predict EMSU waterflood performance. Table 1 gives the layer thickness, permeability, porosity, and fluid saturations. Permeabilities are assigned to the various layers within the model so as to preserve the V value of 0.75. Porosity is assigned to each layer based upon a porosity versus permeability graph developed from core analysis. The thickness of the most permeable layers is adjusted so as to provide better definition of the time for initial oil production response and water breakthrough.

Reservoir Rock Continuity - As indicated earlier in this report, to be counted as secondary recovery pay, the reservoir rock porosity must exceed a porosity cutoff. A six percent cutoff is used for EMSU. (One important technical publication[6] indicates that porosity cutoffs as low as four percent have been used in one carbonate reservoir in West Texas.) In addition to exceeding the porosity cutoff, the rock must be continuous between injection and production wells. Both Exxon Company[6] and Shell Oil Company[4] have published case studies of this phenomena and both report that as distance between wells increases, the percent of rock continuity decreases. Figure 9 is a graph of rock continuity as a function of distance between wells for the San Andres Dolomite Reservoir in the Means Field in Andrews County, Texas.

It was beyond the scope of this study to prepare a rock continuity study for EMSU. However, to account for the likely absence of 100 percent continuity this study did account for this geological behavior in a quantitative manner. For those areas where net pay based on the porosity cutoff exceeds 200 feet (net to gross ratio greater than 0.67), rock continuity is assumed to be 90 percent. In these areas where net pay exceeds 100 feet but is less than 200 feet (net to gross ratio ranging from 0.33 to 0.67), rock continuity is assumed to be 70 percent. Finally, when net pay is less than 100 feet, rock continuity is assumed to be 50 percent. It is recognized that those geological factors which affect net pay based upon porosity considerations may not have any appreciable effect on rock continuity. The rock continuity factors are estimates only. The factors serve to approximate discontinuous rock behavior which probably exists at EMSU based on similar observations in other carbonate reservoirs.

Waterflood Model: The steady state waterflood prediction model of Craig, Geffen, and Morse[11] is used to predict waterflood performance at EMSU. The method is described in considerable detail in References 1 and 2. The method is best suited for a developed 5-spot pattern flood without crossflow, characteristics that are present at EMSU. The model considers all of the important factors affecting waterflood behavior in the region of interest including (1) stratification, (2) relative permeability, (3) effects of mobility ratio on areal sweep efficiency, (4) the presence of an initial gas saturation, (5) gas resaturation effects, (6) the effect of water injection on areal sweep efficiency, and (7) variable water injection rates. It is beyond the scope of this report to completely describe the model; however, the model is one of the most widely used techniques in the petroleum industry to forecast waterflood behavior.

Five-Spot Pattern Performance: The waterflood performance behavior of an average EMSU 80 acre five-spot pattern was predicted. The 20 layer system described in Table 1 along with the relative permeability data shown in Figure 6 and the fractional flow graph presented in Figure 7 are used. Projections are made using a water injection rate of 800 BWPD for the average pattern. Performance behavior for the average pattern is used along with superposition and equivalent pore volume concepts to develop performance behavior for the entire

EMSU. The field wide projection is described in more detail in the next section.

A detailed inspection of the predicted performance results of the individual pattern layers is revealing. As expected oil production response from the most permeable layer (layer 1) occurs first and oil production response from the least permeable layer (layer 20) occurs last. Waterflood oil production response from each of the 20 layers begins only after the gas saturation within the layer is replaced by injected water. Stated differently, waterflood production response from a given layer occurs after "gas fillup" of the layer is achieved. Since layer one has the highest permeability, it is expected to respond first. Table 2 gives the length of time to waterflood oil production response from each layer since initial injection began for each of the 20 layers. As can be seen, production from layer one is not expected until the second year of injection. On the otherhand, production response from the five least permeable layers (representing 22.7 percent of the average pattern pore volume) does not occur for at least 20 years.

<u>Field Performance Forecast - EMSU</u>: To determine production performance for <u>each</u> of the 175 five-spot patterns in the EMSU, it is necessary to adjust performance behavior obtained for the average pattern discussed in the preceeding section. Specifically, the performance of the average pattern is adjusted to each of the EMSU patterns by considering four factors. These factors include:

1. The pore volume of the specific pattern in relationship to the pore volume of the average pattern,

2. The net pay within a given pattern and the degree of rock continuity within the pattern,

3. The completeness of the pattern (patterns located within the interior of EMSU are complete 5-spots but most of the patterns along the Unit boundary are partial patterns),

4. The time at which the various patterns are to be placed on injection. In general, it is assumed that the interior patterns will be placed on injection by the end of the third quarter of 1988 and that the boundary line patterns will be placed on injection during the final quarter of 1988. (Since these EMSU production forecasts were prepared, it has been learned that Chevron's field implementation of pattern development is on a more aggressive schedule than that assumed in this study. Chevron plans to complete the interior pattern development by the end of 1987, and expects the boundary patterns to be completed by mid-1988.)

Appropriate adjustments to the <u>average</u> pattern for each of the four factors listed above are made so that a production forecast for each EMSU pattern is obtained. The injection and production forecasts of all 175 patterns are then summed together in order to prepare a field wide projection.

Figures 10 and 11 present graphs of projected oil production rate versus time through the year 2006. As can be seen, initial production response occurs in mid to late 1988. Peak production of about 20,500 BOPD is expected in the early 1990's. Further, this peak level of production is projected to continue until the middle to later 1990's when production declines. Tabulated production volumes on an annual basis are given in the economic section.

Figure 12 presents the anticipated future cummulative oil production versus time beginning as of July 1, 1987. As indicated, cummulative recovery after 30 years is estimated to be approximately 155 MMSTBO. The remaining primary production as of July 1, 1987 is about 11 MMSTBO. Thus, the estimated incremental secondary oil production between July, 1987 and July, 2017 is approximately 144 MMSTBO. This means the projected ratio of secondary oil production to primary oil production, after 30 years, is expected to be about 1.07 (144/134 = 1.07:1.0).

Figure 13 presents a graph of predicted water injection rate versus time. It is noted that after 1989, water injection is projected to be near 100 MBWPD. (Currently Chevron is injecting approximately 65 MBWPD and has indicated that field wide injection rates could exceed 115 - 120 MBWPD in late 1988.) It is also noted that after 30 years, the water cut is projected to be about 90 to 95 percent.

Gas Production: It is anticipated that some casinghead gas production will occur, however, the exact amount is unknown. A gas-oil ratio of 200 SCF/STBO is assumed for this study.

Economic Evaluation: Cash flow projections have been prepared for a working interest of 1.0068 percent and a net revenue interest of 0.8809 percent. As of July 1, 1987, Chevron indicated that capital expenditures for the entire EMSU are expected to be about 8MM$ during the last half of 1987 and approximately 17MM$ during 1988. Furthermore Chevron projects initial operating costs for the Unit to be approximately 11M$ per year for each production and injection well. This study assumes operating cost will begin at 12M$ per well. Based on a total well count of 350 wells (175 injectors and 175 producers), the initial Unit operating costs are calculated to be 4.2MM$ per year.

Flat Price Case - Cash flow projections are presented for the EMSU waterflood utilizing both flat prices and escalated prices. For the flat price case, oil and gas prices and operating costs are held constant over the projected 30 year life. Oil price is $18.00/bbl and gas is $2.00/MCF (Chevron currently receives about $2.10/MCF due to the high BTU content.) Table 3 presents the cash flow projection for the flat price case. Cash flow is after deducting severance tax, ad valorem tax, windfall profit tax, operating costs, and capital costs. The ad valorem tax rate is assumed to be two percent of annual revenue.

Escalated Price Case - The escalated cash flow projection is presented in Table 4. In this case, the following pricing scenario is used:

> Oil - $18.00/BBL to July 1, 1989, then escalated to $20.00/BBL. Price held constant until January 1, 1991, then escalated to $22.00/BBL. Price held constant to January 1, 1992, and then escalated at 5 percent per year. Price is capped at $45.00/BBL which is achieved in the year 2006.
>
> Gas - Initially $2.00/MCF and is increased in proporation to oil price. Maximum gas price is $5.00/MCF which is achieved in the year 2006.
>
> Operating Cost - Costs are held constant at the current level of 12M$ per year per well until 1989 at which time costs are escalated 10 percent per year until costs reach 18M$ per year per well. Subsequent costs are escalated at five percent per year until oil prices are capped in 2006.

Infill Drilling Economics - Due to the probable lack of complete reservoir rock continuity, it is likely that an infill drilling program will be implemented at EMSU. If such a program is implemented, it would be reasonable to expect that an additional 350 wells would be drilled so as to reduce the 80 acre 5-spot patterns to 40 acre 5-spot patterns. Based upon similar infill programs in a number of carbonate reservoirs similar to EMSU, significant increases in ultimate recovery should be expected.[4,5,6,12]

It is beyond the scope of this report to quantify the benefits of infill drilling at EMSU. However, two cash flow projections are presented whereby 100MM$ is spent for infill drilling at the rate of 20MM$ per year beginning in 1991. Significantly, no consideration is given to the oil recovery benefits derived from this program. The production forecast is assumed to be identical to the projections presented in Figures 10 and 11 and Tables 3 and 4.

Table 5 presents cash flow projections for the flat price case with infill drilling but without increased oil production. Table 6 presents cashflow projections for the escalated price case with infill drilling but without increased oil production.

CARBON DIOXIDE (CO_2) TERTIARY POTENTIAL

The carbonate oil reservoirs of West Texas and Southeast New Mexico appear to be attractive candidates for CO_2 injection. EMSU is relatively close to CO_2 supply lines. Currently CO_2 is plentiful in the area and can be purchased on a very competitive basis from one of several sources. It is probable that under favorable economic conditions, EMSU will probably be a recipient of CO_2 injection. It is premature to predict what effect CO_2 could have at EMSU but based on published information in other carbonate reservoirs, additional recoveries of 10 - 15 percent of the OOIP could be expected. This study did not attempt to quantify the CO_2 potential at EMSU and did not give it any economic value.

SUMMARY

The EMSU is the largest waterflood in New Mexico. Chevron Oil Company, as Unit operator, commenced water injection in late 1986. The Unit is currently being developed on 80 acre, 5-spot patterns. Production is primarily from the Grayburg carbonate reservoir at a depth of approximately 3900 feet The OOIP is estimated to be 1029.1 MMBO with ultimate primary production projected to be 134 MMBO. This study suggests that secondary recovery could be expected to recover about 144 MMBO during a 30 year period. Moreover, the Unit appears to have attractive infill drilling and CO_2 flood potential. Cash flow projections under escalated oil prices and operating costs without infill drilling indicate that a 6MM$ purchase price for a one percent working interest possessing a 87.5% net revenue interest should result in a rate of return of about 19 percent and a project payout of about 6.5 years.

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FIGURES

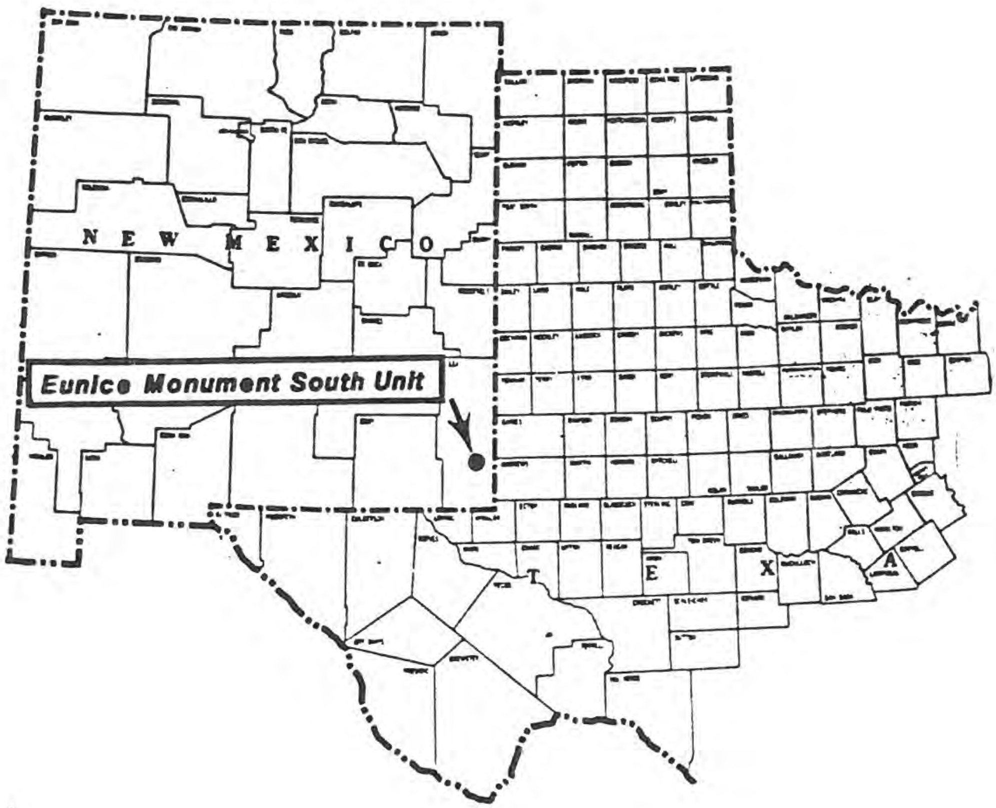


FIGURE 1: EUNICE MONUMENT SOUTH UNIT,
LEA COUNTY, NEW MEXICO

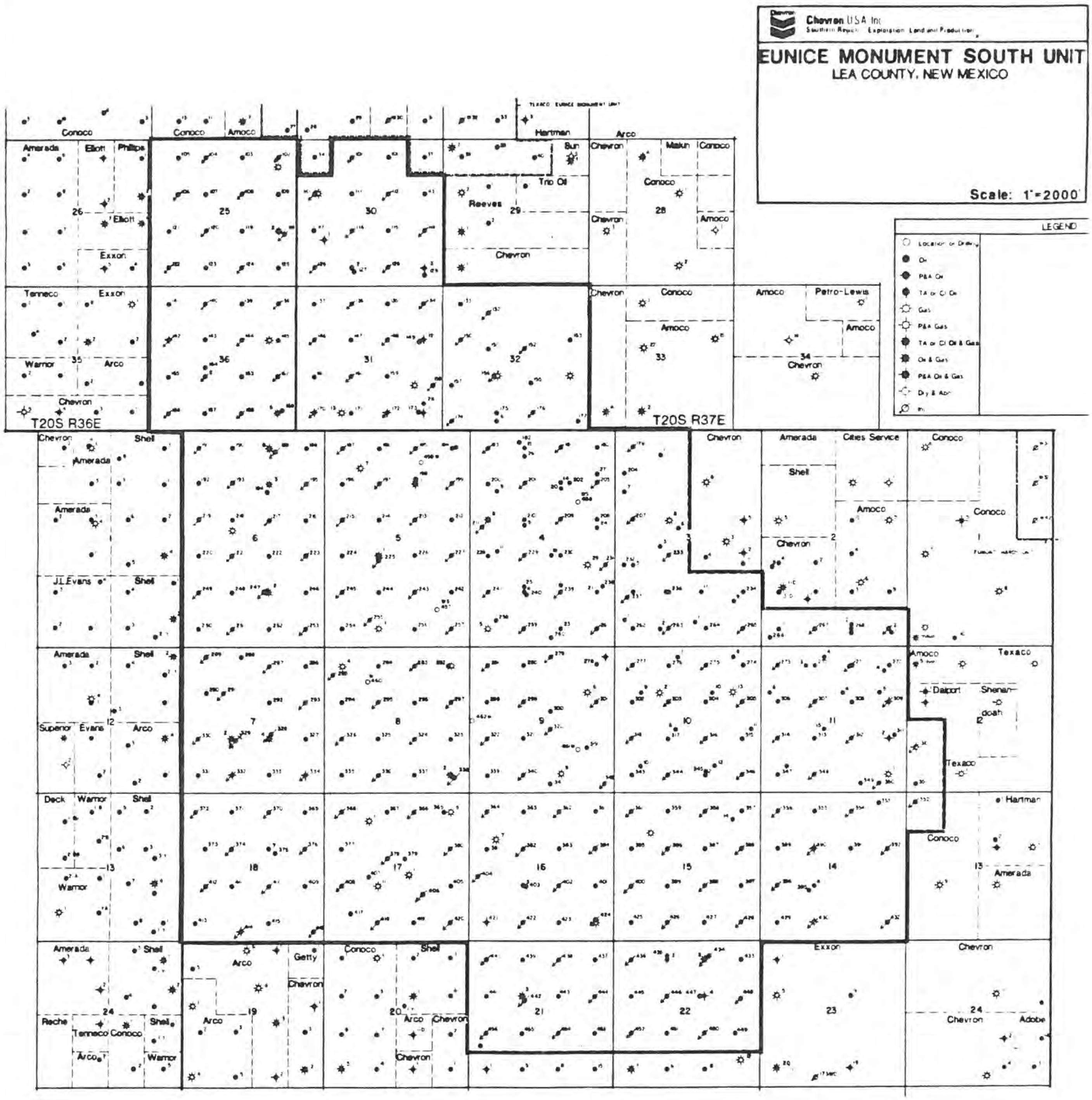
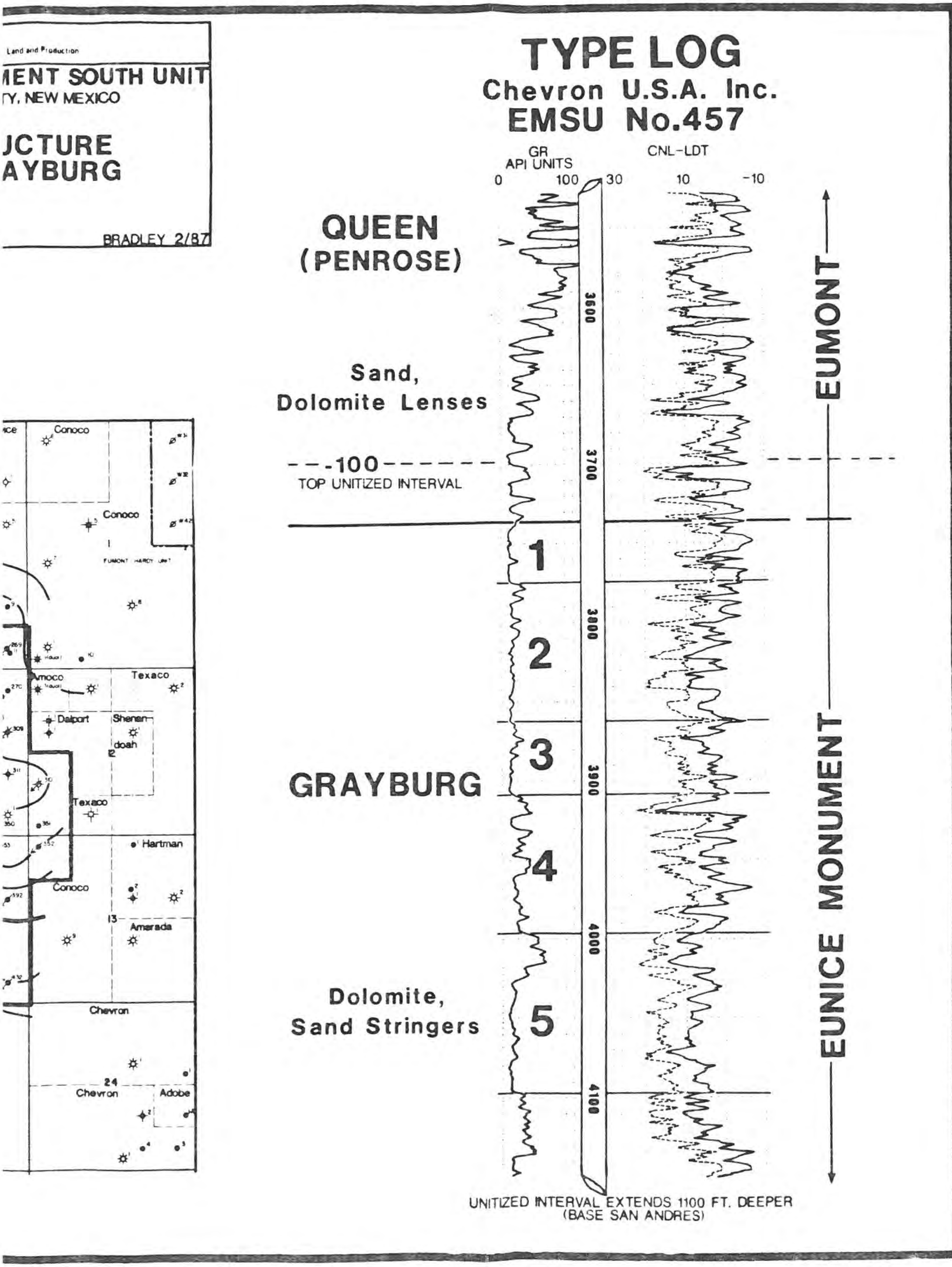


FIGURE 2: BASE MAP SHOWING EMSU OUTLINE AND WELL LOCATIONS

OCD 23614-17 02959



OCD 23614-17 02960

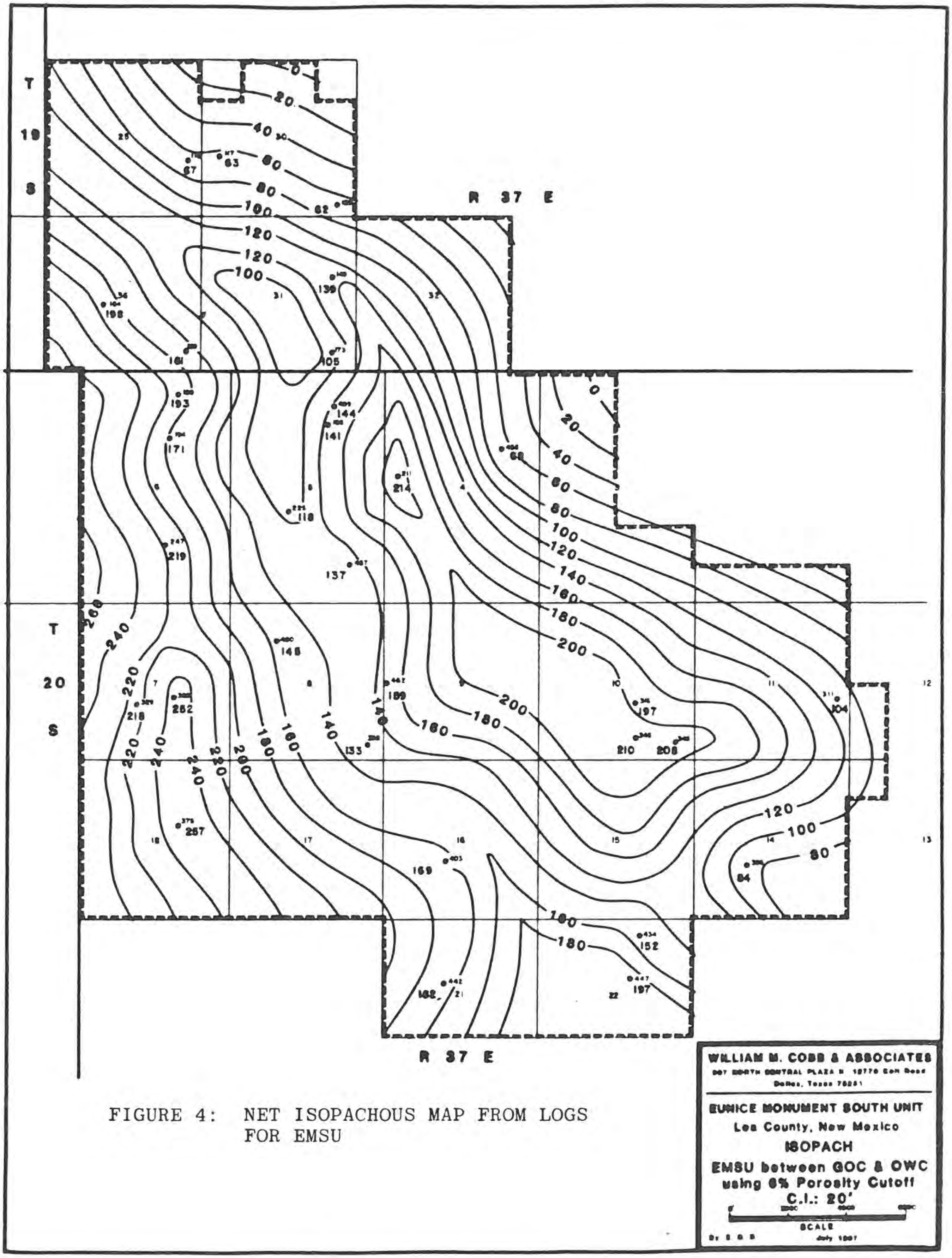


FIGURE 4: NET ISOPACHOUS MAP FROM LOGS
FOR EMSU

OCD 23614-17 02961

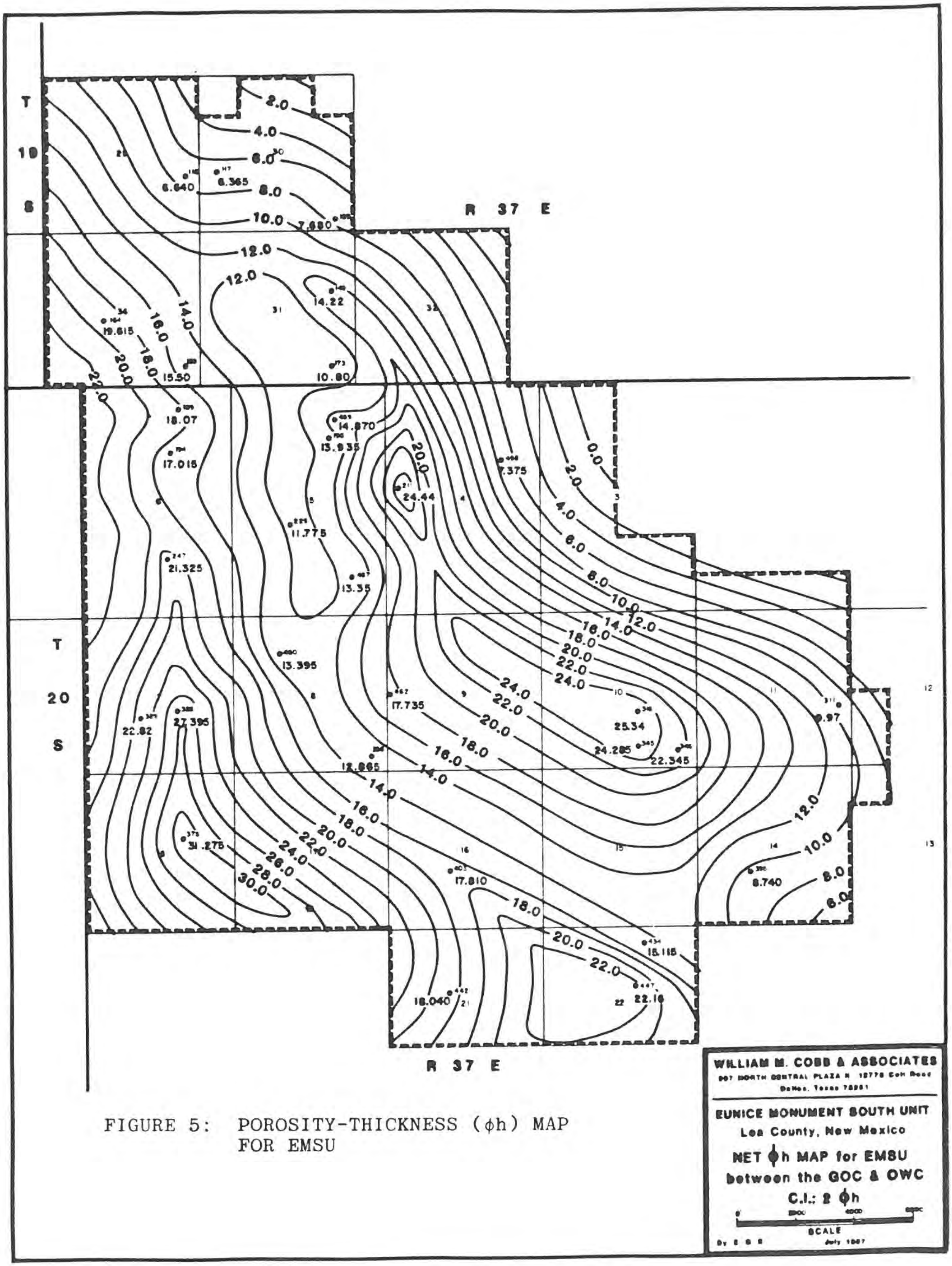


FIGURE 5: POROSITY-THICKNESS (ϕh) MAP
FOR EMSU

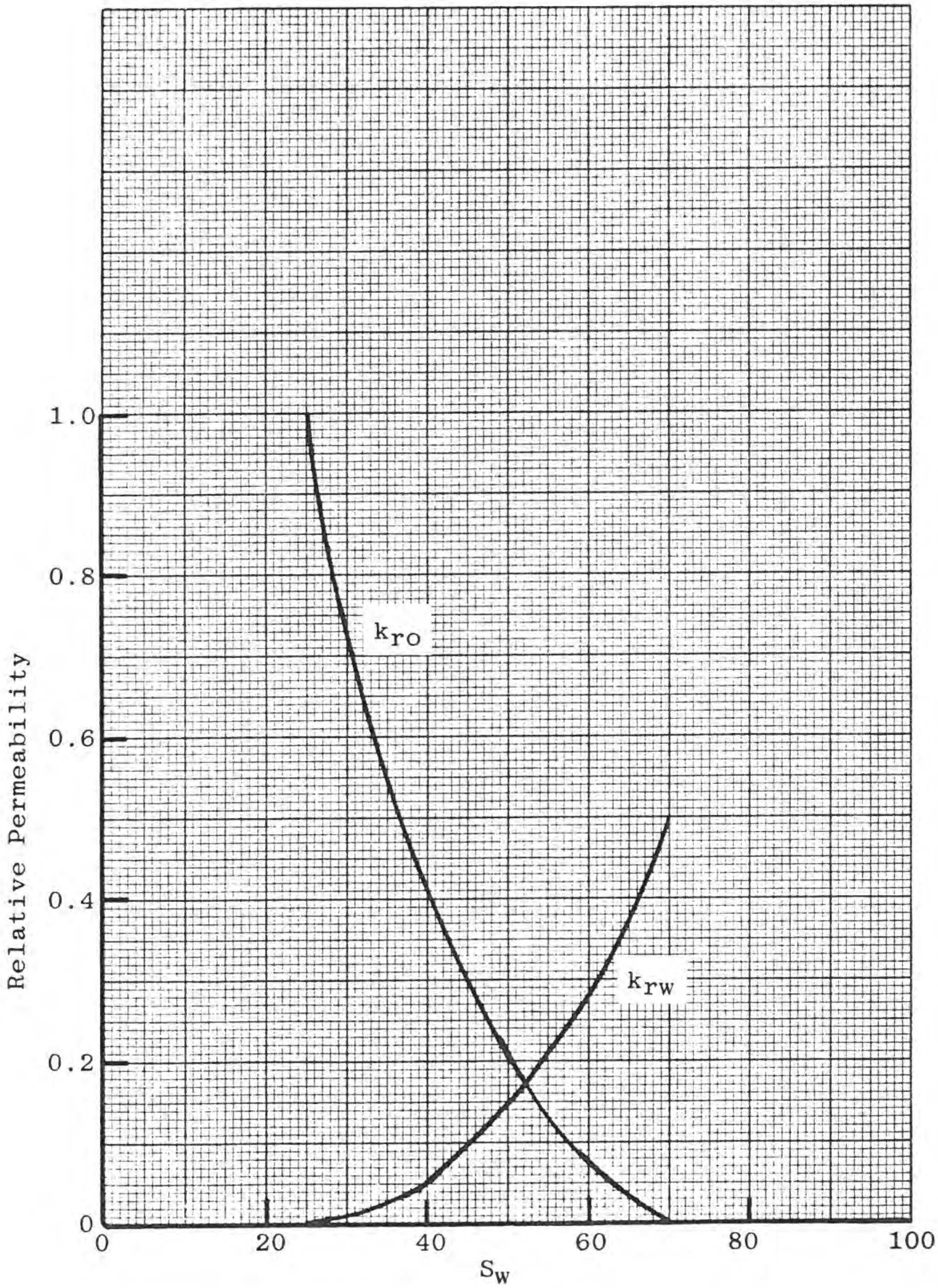


FIGURE 6: OIL-WATER RELATIVE PERMEABILITY USED FOR EMSU WATERFLOOD STUDY

OCD 23614-17 02963

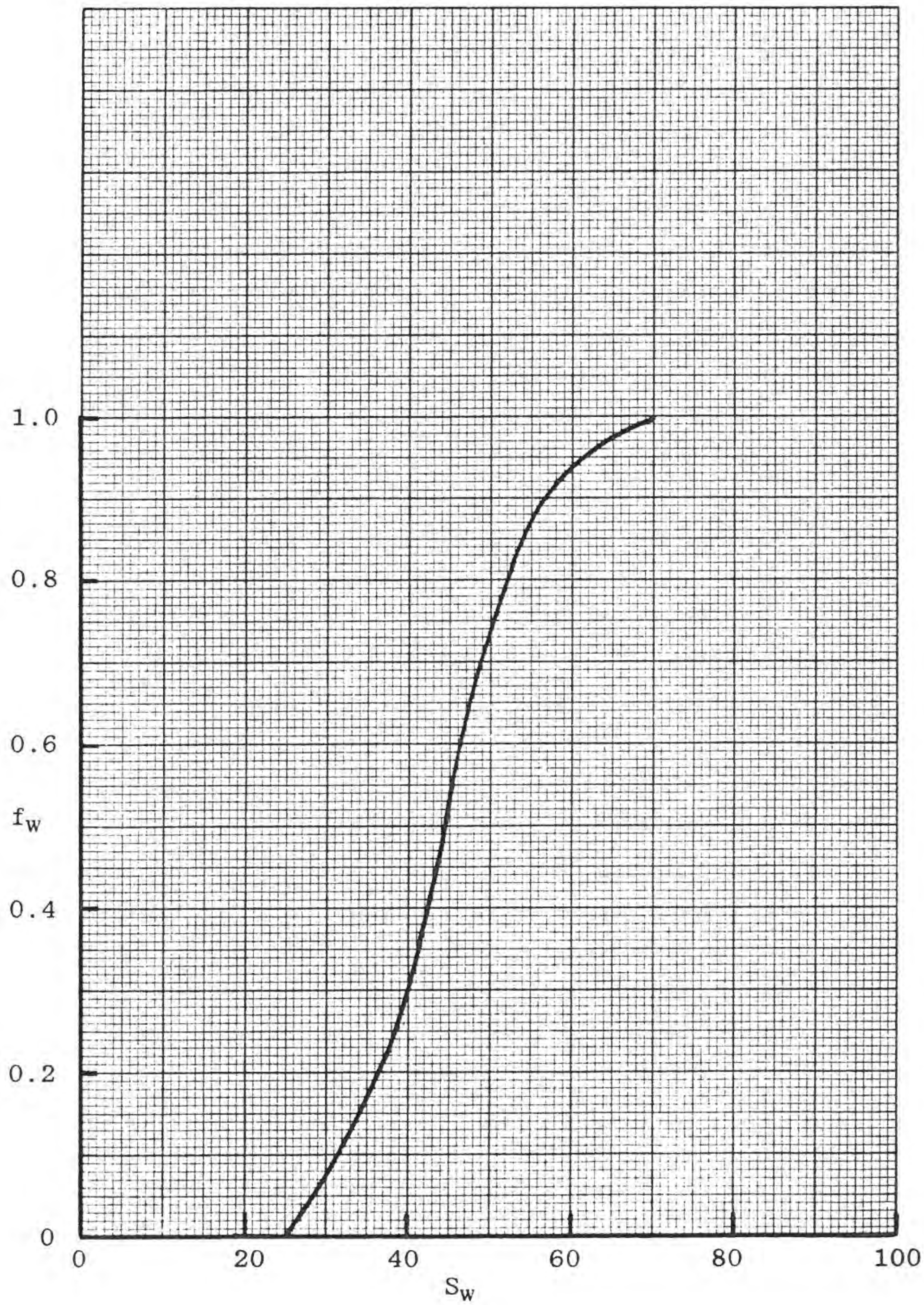


FIGURE 7: FRACTIONAL FLOW OF WATER VERSUS WATER SATURATION USED FOR EMSU

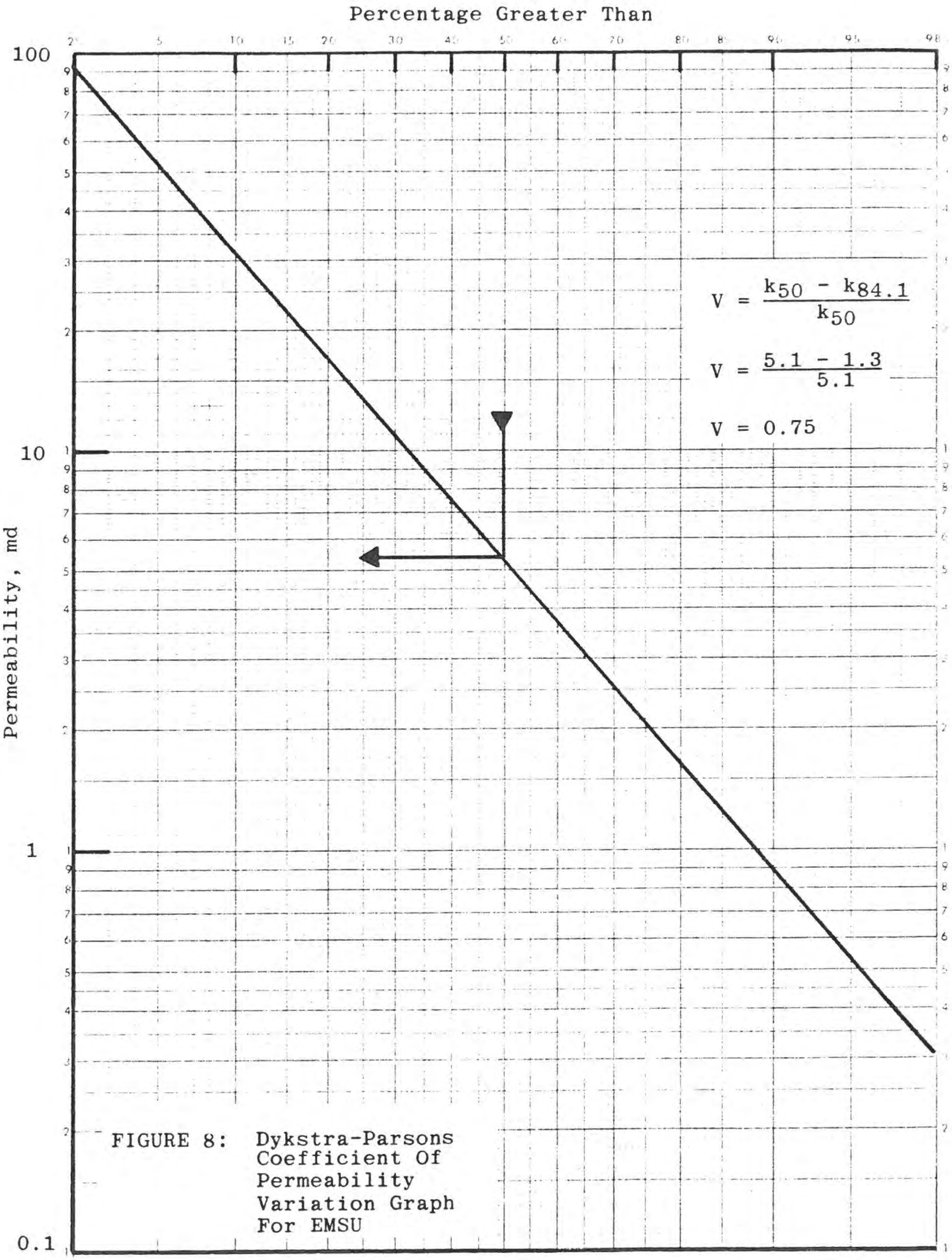


FIGURE 8: Dykstra-Parsons Coefficient Of Permeability Variation Graph For EMSU

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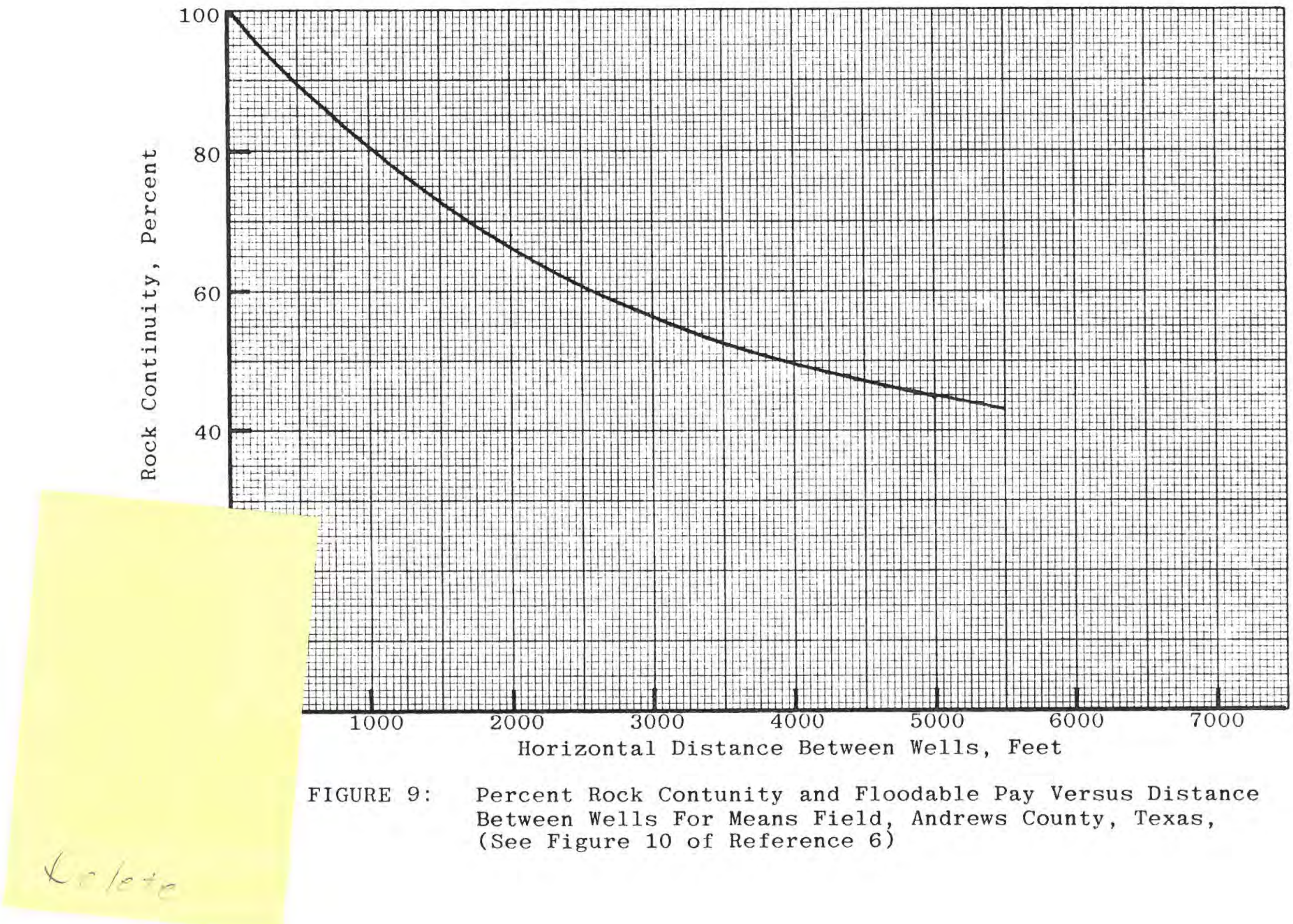

FIGURE 9: Percent Rock Contunity and Floodable Pay Versus Distance Between Wells For Means Field, Andrews County, Texas, (See Figure 10 of Reference 6)

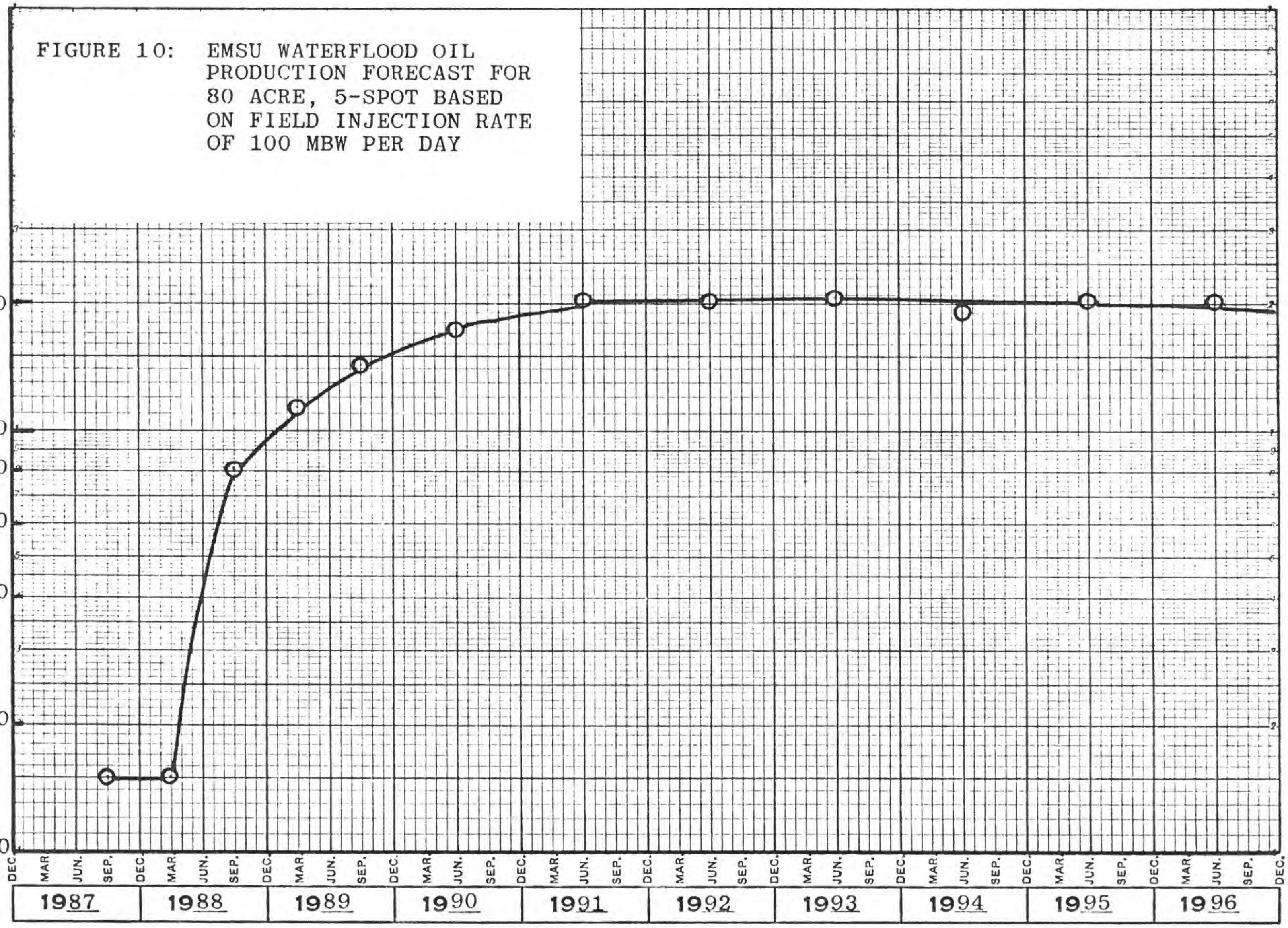
FIGURE 10: EMSU WATERFLOOD OIL PRODUCTION FORECAST FOR 80 ACRE, 5-SPOT BASED ON FIELD INJECTION RATE OF 100 MBW PER DAY
BOPD
20,000
10,000
8,000
6,000
4,000
2,000
1,000
DEC. MAR. JUN. SEP.
1987
1988
1989
1990
1991
1992
1993
1994
1995
1996

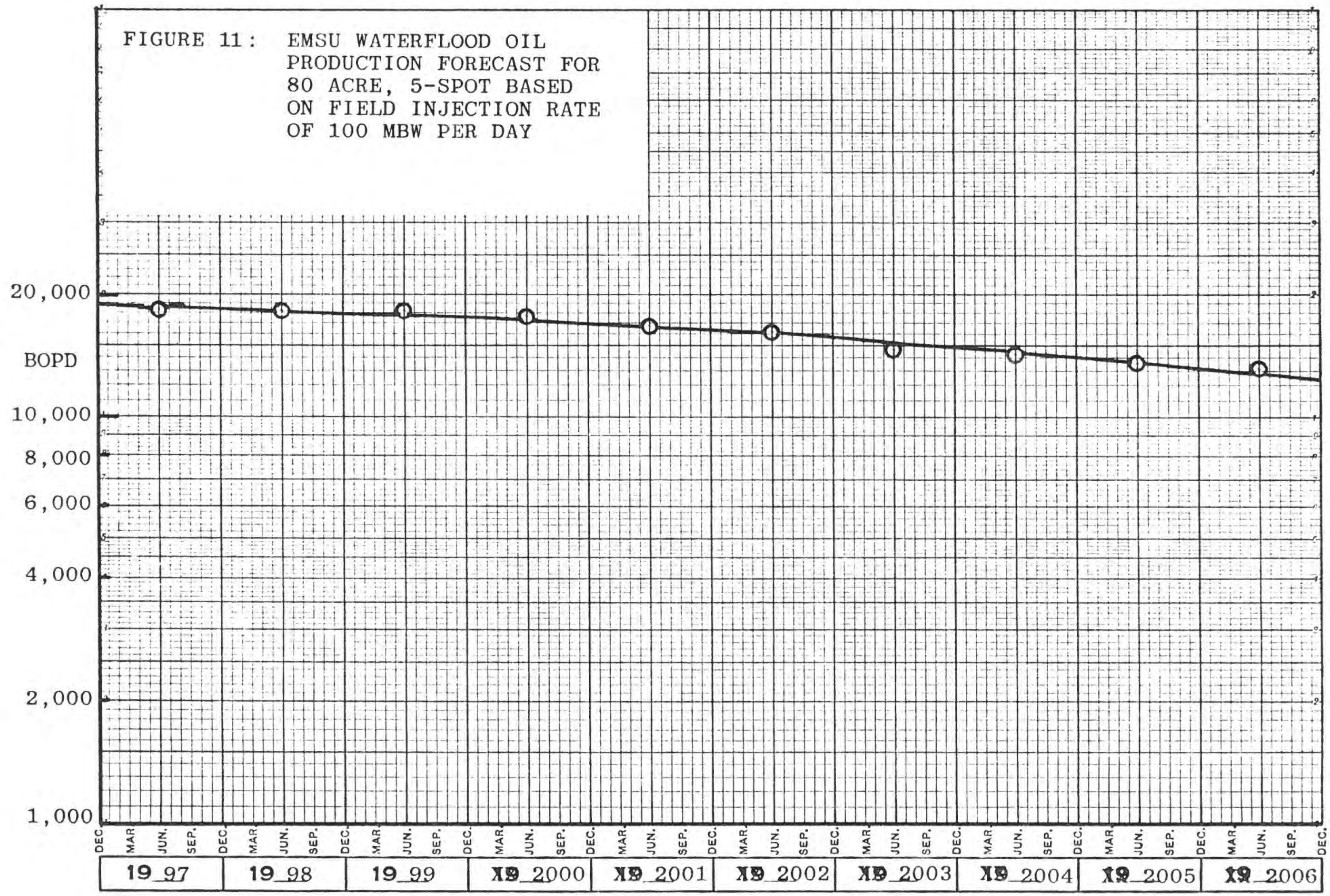

FIGURE 11: EMSU WATERFLOOD OIL PRODUCTION FORECAST FOR 80 ACRE, 5-SPOT BASED ON FIELD INJECTION RATE OF 100 MBW PER DAY

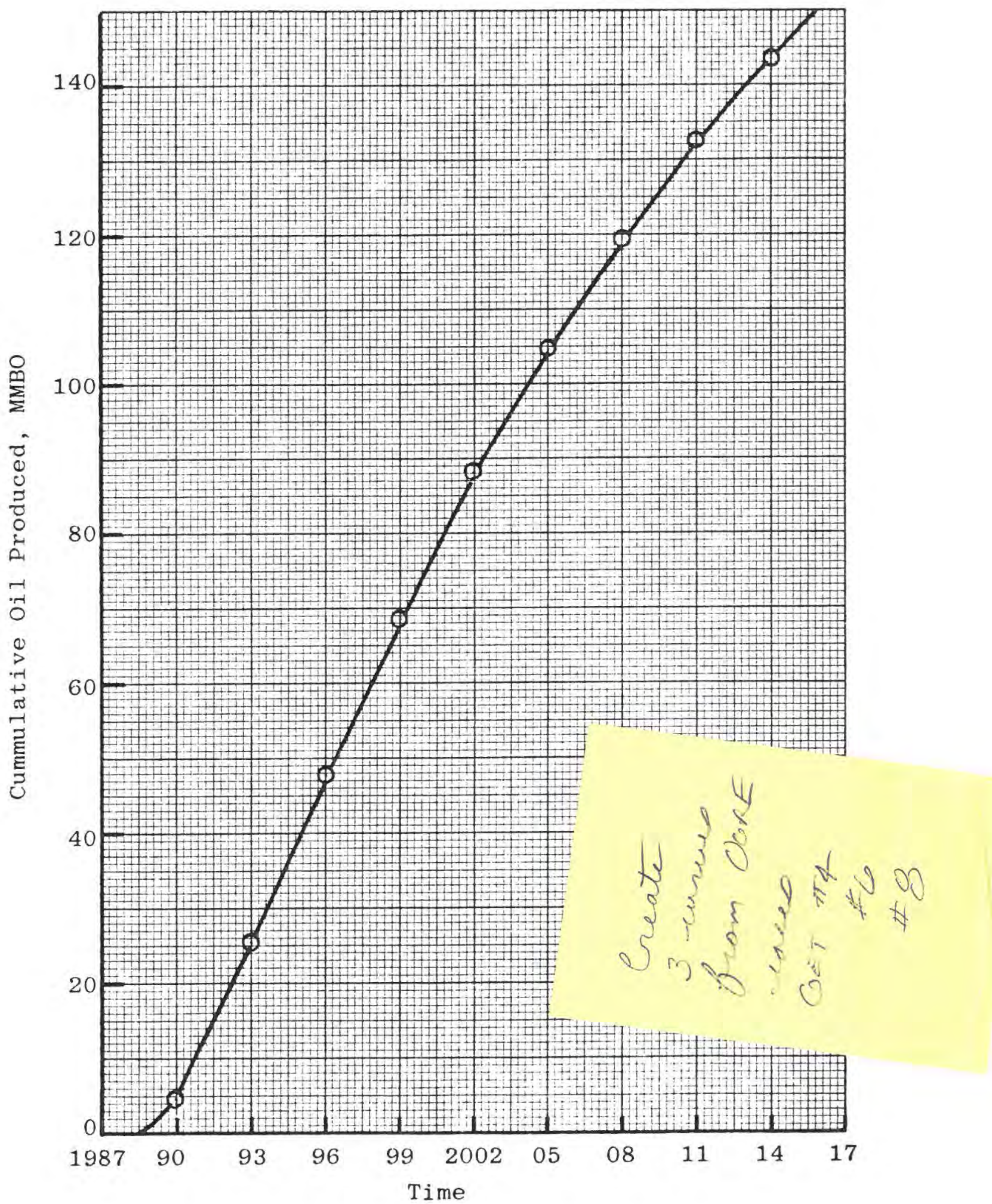

FIGURE 12: EMSU Projected Cummulative Oil Versus Time For A Unit Injection Rate Of Approximately 100 MBW Per Day

Create
3 curves
from Core
cases
Get #4
#6
#8

OCD 23614-17 02969

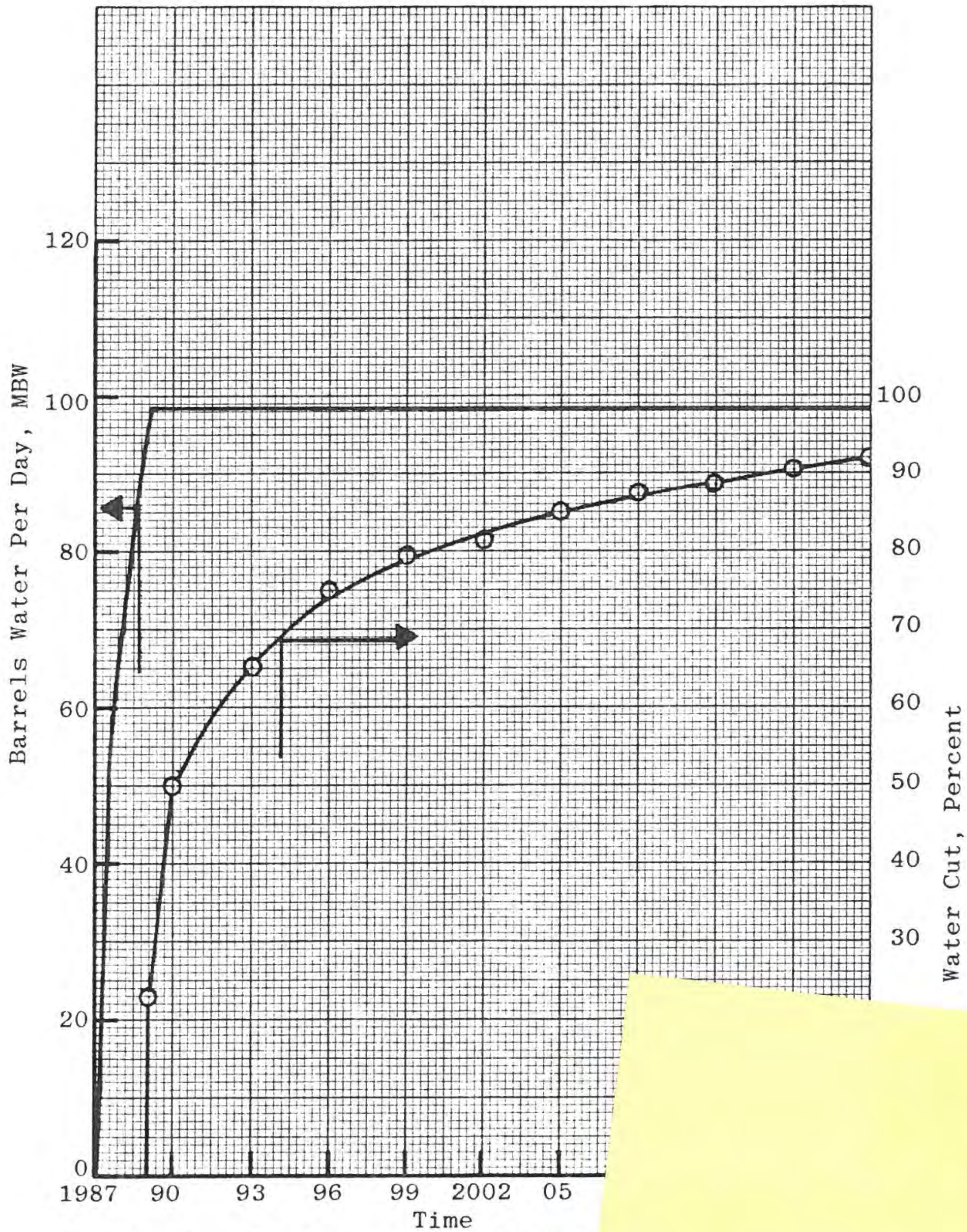

FIGURE 13: PREDICTED DAILY WATER I
WATER CUT FOR EMSU

Delete

OCD 23614-17 02970

TABLES

TABLE 1

80 ACRE 5-SPOT MODEL DESCRIPTION

Layer	Thickness feet	Permeability md	Porosity %	Fluid Saturations S_o	S_{wc}	S_g
1	3.5	70.0	17.5	0.56	0.25	0.19
2	3.5	46.0	16.9	0.56	0.25	0.19
3	3.5	33.0	16.3	0.56	0.25	0.19
4	3.5	23.0	15.7	0.56	0.25	0.19
5	7.0	19.0	15.1	0.56	0.25	0.19
6	7.0	14.2	14.5	0.56	0.25	0.19
7	7.0	11.1	13.9	0.56	0.25	0.19
8	7.0	9.0	13.3	0.56	0.25	0.19
9	7.0	7.4	12.7	0.56	0.25	0.19
10	7.0	6.0	12.1	0.56	0.25	0.19
11	7.0	5.1	11.4	0.56	0.25	0.19
12	7.0	4.3	10.8	0.56	0.25	0.19
13	7.0	3.6	10.2	0.56	0.25	0.19
14	7.0	3.0	9.6	0.56	0.25	0.19
15	7.0	2.5	9.0	0.56	0.25	0.19
16	7.0	2.1	8.4	0.56	0.25	0.19
17	7.0	1.7	7.8	0.56	0.25	0.19
18	7.0	1.4	7.2	0.56	0.25	0.19
19	14.0	1.0	6.6	0.56	0.25	0.19
20	14.0	0.4	6.0	0.56	0.25	0.19

<u>TABLE 2</u>

TIME FOR OIL RESPONSE FOR EACH OF THE 20 LAYERS

Layer	Time, Years
1	1.34
2	1.96
3	2.64
4	3.65
5	4.25
6	5.46
7	6.70
8	7.90
9	9.18
10	10.79
11	11.95
12	13.43
13	15.15
14	17.11
15	19.25
16	21.39
17	23.84
18	27.50
19	35.30
20	78.26

EUNICE MONUMENT S. - CASE II-F
MAX. IW = 800 BWPD/WELL
LEA CO., NEW MEXICO
CHEVRON - OPERATOR

TABLE 3

RESERVES AND ECONOMICS

WILLIAM M. COBB & ASSOC.
PETROLEUM ENGR. CONSULTANTS

AS OF JULY 1, 1987

-END-	---GROSS PRODUCTION---		----NET PRODUCTION----		--PRICES---		--------OPERATIONS, M$--------					10.00 PCT
MO-YR	OIL, MBBL	GAS, MMCF	OIL, MBBL	GAS, MMCF	OIL $/B	GAS $/M	NET OPER REVENUES	SEV+ADV+ WF TAXES	NET OPER EXPENSES	CAPITAL COSTS, M$	CASH FLOW BTAX, M$	CUM. DISC BTAX, M$
12-87	273.600	596.333	2.410	5.253	18.00	2.00	53.886	3.321	21.143	80.544	-51.122	-49.919
6-88	273.600	303.016	2.410	2.669	18.00	2.00	48.718	2.898	21.143	.000	24.677	-26.944
12-88	1477.952	831.739	13.019	7.327	18.00	2.00	248.996	14.497	21.143	171.156	42.200	6.854
6-89	2096.078	599.393	18.464	5.280	18.00	2.00	342.912	19.724	21.143	.000	302.045	262.497
12-89	2583.913	516.782	22.762	4.552	18.00	2.00	418.820	23.996	21.143	.000	373.681	564.053
6-90	3238.727	647.746	28.530	5.706	18.00	2.00	524.952	30.077	21.143	.000	473.732	928.557
12-90	3046.626	609.325	26.838	5.368	18.00	2.00	493.820	28.293	21.143	.000	444.384	1254.568
6-91	3447.520	689.504	30.369	6.074	18.00	2.00	558.790	32.015	21.143	.000	505.632	1608.249
12-91	4040.729	808.146	35.595	7.119	18.00	2.00	654.948	37.524	21.143	.000	596.281	2005.927
6-92	3672.341	734.468	32.350	6.470	18.00	2.00	595.240	34.103	21.143	.000	539.994	2349.306
12-92	3777.080	755.416	33.272	6.654	18.00	2.00	612.204	35.075	21.143	.000	555.986	2686.401
12-93	7645.476	1529.095	67.349	13.470	18.00	2.00	1239.222	70.999	42.286	.000	1125.937	3321.963
12-94	7264.737	1452.947	63.995	12.799	18.00	2.00	1177.508	67.464	42.286	.000	1067.758	3869.892
12-95	7393.551	1478.711	65.130	13.026	18.00	2.00	1198.392	68.660	42.286	.000	1087.446	4377.194
12-96	7354.458	1470.891	64.785	12.957	18.00	2.00	1192.044	68.297	42.286	.000	1081.461	4835.839
12-97	6612.536	1322.507	58.250	11.650	18.00	2.00	1071.800	61.407	42.286	.000	968.107	5209.086
12-98	6623.642	1324.729	58.348	11.670	18.00	2.00	1073.604	61.510	42.286	.000	969.808	5548.998
12-99	6638.821	1327.764	58.481	11.696	18.00	2.00	1076.050	61.651	42.286	.000	972.113	5858.743
12- 0	6551.387	1310.277	57.711	11.542	18.00	2.00	1061.882	60.838	42.286	.000	958.758	6136.461
12- 1	6168.461	1233.693	54.338	10.868	18.00	2.00	999.820	57.282	42.286	.000	900.252	6373.525
12- 2	5862.863	1172.572	51.646	10.329	18.00	2.00	950.286	54.444	42.286	.000	853.556	6577.860
12- 3	5372.944	1074.589	47.330	9.466	18.00	2.00	870.872	49.896	42.286	.000	778.690	6747.326
12- 4	5239.969	1047.994	46.159	9.232	18.00	2.00	849.326	48.660	42.286	.000	758.380	6897.367
12- 5	5024.257	1004.851	44.259	8.852	18.00	2.00	814.366	46.658	42.286	.000	725.422	7027.841
12- 6	4865.376	973.075	42.859	8.572	18.00	2.00	788.606	45.182	42.286	.000	701.138	7142.483
S TOT	116546.644	24815.563	1026.659	218.601	18.00	2.00	18917.064	1084.471	824.577	251.700	16756.316	7142.483
REM.	38882.439	7776.488	342.516	68.503	18.00	2.00	6302.294	361.078	465.146	.000	5476.070	7708.971
TOTAL	155429.083	32592.051	1369.175	287.104	18.00	2.00	25219.358	1445.549	1289.723	251.700	22232.386	7708.971

CUM.	.000	.000
ULT.	155429.083	32592.051

NET OIL REVENUES (M$)	24645.150
NET GAS REVENUES (M$)	574.208
TOTAL REVENUES (M$)	25219.358

BTAX RATE OF RETURN (PCT)	100.00
BTAX PAYOUT YEARS	1.46
BTAX PAYOUT YEARS (DISC)	1.48
BTAX NET INCOME/INVEST	89.33
BTAX NET INCOME/INVEST (DISC)	33.91
INITIAL W.I. FRACTION	.010068
FINAL W.I. FRACTION	.010068
PRODUCTION START DATE	7- 1-87
MONTHS IN FIRST LINE	6.00

PROJECT LIFE (YEARS)	30.500
DISCOUNT RATE (PCT)	10.000
GROSS OIL WELLS	350.000
GROSS GAS WELLS	.000
GROSS WELLS	350.000
INITIAL NET OIL FRACTION	.008809
FINAL NET OIL FRACTION	.008809
INITIAL NET GAS FRACTION	.008809
FINAL NET GAS FRACTION	.008809

---------PRESENT WORTH PROFILE---------

DISC RATE	PW OF NET BTAX, M$	DISC RATE	PW OF NET BTAX, M$
.0	22232.386	30.0	2412.295
2.0	17194.139	35.0	1974.151
5.0	12254.616	40.0	1648.165
8.0	9158.369	45.0	1398.226
10.0	7708.971	50.0	1201.861
12.0	6585.425	60.0	916.145
15.0	5322.371	70.0	721.155
18.0	4402.274	80.0	581.643
20.0	3920.610	90.0	478.134
25.0	3023.946	100.0	399.074

EUNICE MONUMENT S. - CASE II-E
MAX. IW = 800 BWPD/WELL
LEA CO., NEW MEXICO
CHEVRON - OPERATOR

TABLE 4

RESERVES AND ECONOMICS

WILLIAM M. COBB & ASSOC.
PETROLEUM ENGR. CONSULTANTS

AS OF JULY 1, 1987

-END- MO-YR	---GROSS PRODUCTION--- OIL, MBBL	GAS, MMCF	----NET PRODUCTION---- OIL, MBBL	GAS, MMCF	--PRICES--- OIL $/B	GAS $/M	--------OPERATIONS, M$-------- NET OPER REVENUES	SEV+ADV+ WF TAXES	NET OPER EXPENSES	CAPITAL COSTS, M$	CASH FLOW BTAX, M$	10.00 PCT CUM. DISC BTAX, M$
12-87	273.600	596.333	2.410	5.253	18.00	2.00	53.886	3.321	21.143	80.544	-51.122	-49.919
6-88	273.600	303.016	2.410	2.669	18.00	2.00	48.718	2.898	21.143	.000	24.677	-26.944
12-88	1477.952	831.739	13.019	7.327	18.00	2.00	248.996	14.497	21.143	171.156	42.200	6.854
6-89	2096.078	599.393	18.464	5.280	18.00	2.00	342.912	19.724	23.257	.000	299.931	260.708
12-89	2583.913	516.782	22.762	4.552	20.00	2.22	465.356	26.600	23.257	.000	415.499	596.010
6-90	3238.727	647.746	28.530	5.706	20.00	2.22	583.280	33.340	25.583	.000	524.357	999.467
12-90	3046.626	609.325	26.838	5.368	20.00	2.22	548.689	31.363	25.583	.000	491.743	1360.222
6-91	3447.520	689.504	30.369	6.074	22.00	2.44	682.966	38.962	28.141	.000	615.863	1791.008
12-91	4040.729	808.146	35.595	7.119	22.00	2.44	800.492	45.668	28.141	.000	726.683	2275.656
6-92	3672.341	734.468	32.350	6.470	23.10	2.57	763.891	43.539	30.955	.000	689.397	2714.039
12-92	3777.080	755.416	33.272	6.654	23.10	2.57	785.662	44.780	30.955	.000	709.927	3144.469
12-93	7645.476	1529.095	67.349	13.470	24.26	2.70	1669.852	95.093	68.097	.000	1506.662	3994.940
12-94	7264.737	1452.947	63.995	12.799	25.47	2.83	1666.027	94.797	71.506	.000	1499.724	4764.536
12-95	7393.551	1478.711	65.130	13.026	26.74	2.97	1780.353	101.221	75.082	.000	1604.050	5512.837
12-96	7354.458	1470.891	64.785	12.957	28.08	3.12	1859.469	105.639	78.836	.000	1674.994	6223.198
12-97	6612.536	1322.507	58.250	11.650	29.48	3.28	1755.496	99.661	82.778	.000	1573.057	6829.680
12-98	6623.642	1324.729	58.348	11.670	30.96	3.44	1846.373	104.747	86.917	.000	1654.709	7409.645
12-99	6638.821	1327.764	58.481	11.696	32.50	3.61	1943.109	110.164	91.262	.000	1741.683	7964.599
12- 0	6551.387	1310.277	57.711	11.542	34.13	3.79	2013.400	114.077	95.825	.000	1803.498	8487.008
12- 1	6168.461	1233.693	54.338	10.868	35.84	3.98	1990.513	112.712	100.617	.000	1777.184	8954.996
12- 2	5862.863	1172.572	51.646	10.329	37.63	4.18	1986.492	112.421	105.648	.000	1768.423	9378.342
12- 3	5372.944	1074.589	47.330	9.466	39.51	4.39	1911.508	108.120	110.930	.000	1692.458	9746.670
12- 4	5239.969	1047.994	46.159	9.232	41.48	4.61	1957.427	110.660	116.476	.000	1730.291	10088.999
12- 5	5024.257	1004.851	44.259	8.852	43.56	4.84	1970.697	111.356	122.300	.000	1737.041	10401.421
12- 6	4865.376	973.075	42.859	8.572	45.00	5.00	1971.515	111.367	128.415	.000	1731.733	10684.573
S TOT	116546.644	24815.563	1026.659	218.601	30.13	3.27	31647.079	1796.727	1613.990	251.700	27984.662	10684.573
REM.	38882.439	7776.488	342.516	68.503	45.00	5.00	15755.735	890.009	1412.565	.000	13453.161	12077.989
TOTAL	155429.083	32592.051	1369.175	287.104	33.85	3.68	47402.814	2686.736	3026.555	251.700	41437.823	12077.989

CUM.	.000	.000
ULT.	155429.083	32592.051

NET OIL REVENUES (M$)	46346.353
NET GAS REVENUES (M$)	1056.461
TOTAL REVENUES (M$)	47402.814

BTAX RATE OF RETURN (PCT)	100.00
BTAX PAYOUT YEARS	1.46
BTAX PAYOUT YEARS (DISC)	1.48
BTAX NET INCOME/INVEST	165.63
BTAX NET INCOME/INVEST (DISC)	52.56
INITIAL W.I. FRACTION	.010068
FINAL W.I. FRACTION	.010068
PRODUCTION START DATE	7- 1-87
MONTHS IN FIRST LINE	6.00

PROJECT LIFE (YEARS)	30.500
DISCOUNT RATE (PCT)	10.000
GROSS OIL WELLS	350.000
GROSS GAS WELLS	.000
GROSS WELLS	350.000
INITIAL NET OIL FRACTION	.008809
FINAL NET OIL FRACTION	.008809
INITIAL NET GAS FRACTION	.008809
FINAL NET GAS FRACTION	.008809

---------PRESENT WORTH PROFILE---------

DISC RATE	PW OF NET BTAX, M$	DISC RATE	PW OF NET BTAX, M$
.0	41437.823	30.0	3154.157
2.0	30850.624	35.0	2522.617
5.0	20812.930	40.0	2067.609
8.0	14791.189	45.0	1727.855
10.0	12077.989	50.0	1466.754
12.0	10035.920	60.0	1096.444
15.0	7819.199	70.0	850.650
18.0	6268.364	80.0	678.484
20.0	5481.832	90.0	552.861
25.0	4071.176	100.0	458.210

EUNICE MONUMENT S. - CASE II-F
MAX. IW = 800 BWPD/WELL
LEA CO., NEW MEXICO
CHEVRON - OPERATOR

TABLE 5

RESERVES AND ECONOMICS

WILLIAM M. COBB & ASSOC.
PETROLEUM ENGR. CONSULTANTS

AS OF JULY 1, 1987

ASSUMES INFILL DRILLING
WITH NO RESPONSE

-END-	---GROSS PRODUCTION---		----NET PRODUCTION----		--PRICES---		--------OPERATIONS, M$--------					10.00 PCT
MO-YR	OIL, MBBL	GAS, MMCF	OIL, MBBL	GAS, MMCF	OIL $/B	GAS $/M	NET OPER REVENUES	SEV+ADV+ WF TAXES	NET OPER EXPENSES	CAPITAL COSTS, M$	CASH FLOW BTAX, M$	CUM. DISC BTAX, M$
12-87	273.600	596.333	2.410	5.253	18.00	2.00	53.886	3.321	21.143	80.544	-51.122	-49.919
6-88	273.600	303.016	2.410	2.669	18.00	2.00	48.718	2.898	21.143	.000	24.677	-26.944
12-88	1477.952	831.739	13.019	7.327	18.00	2.00	248.996	14.497	21.143	171.156	42.200	6.854
6-89	2096.078	599.393	18.464	5.280	18.00	2.00	342.912	19.724	21.143	.000	302.045	262.497
12-89	2583.913	516.782	22.762	4.552	18.00	2.00	418.820	23.996	21.143	.000	373.681	564.053
6-90	3238.727	647.746	28.530	5.706	18.00	2.00	524.952	30.077	21.143	.000	473.732	928.557
12-90	3046.626	609.325	26.838	5.368	18.00	2.00	493.820	28.293	21.143	.000	444.384	1254.568
6-91	3447.520	689.504	30.369	6.074	18.00	2.00	558.790	32.015	21.143	201.360	304.272	1464.005
12-91	4040.729	808.146	35.595	7.119	18.00	2.00	654.948	37.524	21.143	.000	596.281	1861.683
6-92	3672.341	734.468	32.350	6.470	18.00	2.00	595.240	34.103	21.143	201.360	338.634	2073.931
12-92	3777.080	755.416	33.272	6.654	18.00	2.00	612.204	35.075	21.143	.000	555.986	2411.026
12-93	7645.476	1529.095	67.349	13.470	18.00	2.00	1239.222	70.999	42.286	201.360	924.577	2927.378
12-94	7264.737	1452.947	63.995	12.799	18.00	2.00	1177.508	67.464	42.286	201.360	866.398	3366.934
12-95	7393.551	1478.711	65.130	13.026	18.00	2.00	1198.392	68.660	42.286	201.360	886.086	3775.715
12-96	7354.458	1470.891	64.785	12.957	18.00	2.00	1192.044	68.297	42.286	.000	1081.461	4234.360
12-97	6612.536	1322.507	58.250	11.650	18.00	2.00	1071.800	61.407	42.286	.000	968.107	4607.607
12-98	6623.642	1324.729	58.348	11.670	18.00	2.00	1073.604	61.510	42.286	.000	969.808	4947.519
12-99	6638.821	1327.764	58.481	11.696	18.00	2.00	1076.050	61.651	42.286	.000	972.113	5257.264
12- 0	6551.387	1310.277	57.711	11.542	18.00	2.00	1061.882	60.838	42.286	.000	958.758	5534.982
12- 1	6168.461	1233.693	54.338	10.868	18.00	2.00	999.820	57.282	42.286	.000	900.252	5772.046
12- 2	5862.863	1172.572	51.646	10.329	18.00	2.00	950.286	54.444	42.286	.000	853.556	5976.381
12- 3	5372.944	1074.589	47.330	9.466	18.00	2.00	870.872	49.896	42.286	.000	778.690	6145.847
12- 4	5239.969	1047.994	46.159	9.232	18.00	2.00	849.326	48.660	42.286	.000	758.380	6295.888
12- 5	5024.257	1004.851	44.259	8.852	18.00	2.00	814.366	46.658	42.286	.000	725.422	6426.362
12- 6	4865.376	973.075	42.859	8.572	18.00	2.00	788.606	45.182	42.286	.000	701.138	6541.004
S TOT	116546.644	24815.563	1026.659	218.601	18.00	2.00	18917.064	1084.471	824.577	1258.500	15749.516	6541.004
REM.	38882.439	7776.488	342.516	68.503	18.00	2.00	6302.294	361.078	465.146	.000	5476.070	7107.492
TOTAL	155429.083	32592.051	1369.175	287.104	18.00	2.00	25219.358	1445.549	1289.723	1258.500	21225.586	7107.492

CUM.	.000	.000
ULT.	155429.083	32592.051

NET OIL REVENUES (M$)	24645.150
NET GAS REVENUES (M$)	574.208
TOTAL REVENUES (M$)	25219.358

BTAX RATE OF RETURN (PCT)	100.00
BTAX PAYOUT YEARS	2.83
BTAX PAYOUT YEARS (DISC)	2.55
BTAX NET INCOME/INVEST	17.87
BTAX NET INCOME/INVEST (DISC)	9.50
INITIAL W.I. FRACTION	.010068
FINAL W.I. FRACTION	.010068
PRODUCTION START DATE	7- 1-87
MONTHS IN FIRST LINE	6.00

PROJECT LIFE (YEARS)	30.500
DISCOUNT RATE (PCT)	10.000
GROSS OIL WELLS	350.000
GROSS GAS WELLS	.000
GROSS WELLS	350.000
INITIAL NET OIL FRACTION	.008809
FINAL NET OIL FRACTION	.008809
INITIAL NET GAS FRACTION	.008809
FINAL NET GAS FRACTION	.008809

---------PRESENT WORTH PROFILE---------

DISC RATE	PW OF NET BTAX, M$	DISC RATE	PW OF NET BTAX, M$
.0	21225.586	30.0	2157.779
2.0	16290.879	35.0	1763.052
5.0	11482.939	40.0	1471.459
8.0	8495.113	45.0	1249.058
10.0	7107.492	50.0	1074.963
12.0	6038.653	60.0	822.391
15.0	4846.431	70.0	650.191
18.0	3985.961	80.0	526.804
20.0	3538.858	90.0	434.988
25.0	2713.965	100.0	364.591

OCD 23614-17 02976

EUNICE MONUMENT S. - CASE II-E
MAX. IW = 800 BWPD/WELL
LEA CO., NEW MEXICO
CHEVRON - OPERATOR

TABLE 6

RESERVES AND ECONOMICS

WILLIAM M. COBB & ASSOC.
PETROLEUM ENGR. CONSULTANTS

AS OF JULY 1, 1987

ASSUMES INFILL DRILLING
WITH NO RESPONSE

-END- MO-YR	---GROSS PRODUCTION--- OIL, MBBL	GAS, MMCF	----NET PRODUCTION---- OIL, MBBL	GAS, MMCF	--PRICES--- OIL $/B	GAS $/M	--------OPERATIONS, M$-------- NET OPER REVENUES	SEV+ADV+ WF TAXES	NET OPER EXPENSES	CAPITAL COSTS, M$	CASH FLOW BTAX, M$	10.00 PCT CUM. DISC BTAX, M$
12-87	273.600	596.333	2.410	5.253	18.00	2.00	53.886	3.321	21.143	80.544	-51.122	-49.919
6-88	273.600	303.016	2.410	2.669	18.00	2.00	48.718	2.898	21.143	.000	24.677	-26.944
12-88	1477.952	831.739	13.019	7.327	18.00	2.00	248.996	14.497	21.143	171.156	42.200	6.854
6-89	2096.078	599.393	18.464	5.280	18.00	2.00	342.912	19.724	23.257	.000	299.931	260.708
12-89	2583.913	516.782	22.762	4.552	20.00	2.22	465.356	26.600	23.257	.000	415.499	596.010
6-90	3238.727	647.746	28.530	5.706	20.00	2.22	583.280	33.340	25.583	.000	524.357	999.467
12-90	3046.626	609.325	26.838	5.368	20.00	2.22	548.689	31.363	25.583	.000	491.743	1360.222
6-91	3447.520	689.504	30.369	6.074	22.00	2.44	682.966	38.962	28.141	201.360	414.503	1646.764
12-91	4040.729	808.146	35.595	7.119	22.00	2.44	800.492	45.668	28.141	.000	726.683	2131.412
6-92	3672.341	734.468	32.350	6.470	23.10	2.57	763.891	43.539	30.955	201.360	488.037	2438.664
12-92	3777.080	755.416	33.272	6.654	23.10	2.57	785.662	44.780	30.955	.000	709.927	2869.094
12-93	7645.476	1529.095	67.349	13.470	24.26	2.70	1669.852	95.093	68.097	201.360	1305.302	3600.355
12-94	7264.737	1452.947	63.995	12.799	25.47	2.83	1666.027	94.797	71.506	201.360	1298.364	4261.578
12-95	7393.551	1478.711	65.130	13.026	26.74	2.97	1780.353	101.221	75.082	201.360	1402.690	4911.358
12-96	7354.458	1470.891	64.785	12.957	28.08	3.12	1859.469	105.639	78.836	.000	1674.994	5621.719
12-97	6612.536	1322.507	58.250	11.650	29.48	3.28	1755.496	99.661	82.778	.000	1573.057	6228.201
12-98	6623.642	1324.729	58.348	11.670	30.96	3.44	1846.373	104.747	86.917	.000	1654.709	6808.166
12-99	6638.821	1327.764	58.481	11.696	32.50	3.61	1943.109	110.164	91.262	.000	1741.683	7363.120
12- 0	6551.387	1310.277	57.711	11.542	34.13	3.79	2013.400	114.077	95.825	.000	1803.498	7885.529
12- 1	6168.461	1233.693	54.338	10.868	35.84	3.98	1990.513	112.712	100.617	.000	1777.184	8353.517
12- 2	5862.863	1172.572	51.646	10.329	37.63	4.18	1986.492	112.421	105.648	.000	1768.423	8776.863
12- 3	5372.944	1074.589	47.330	9.466	39.51	4.39	1911.508	108.120	110.930	.000	1692.458	9145.191
12- 4	5239.969	1047.994	46.159	9.232	41.48	4.61	1957.427	110.660	116.476	.000	1730.291	9487.520
12- 5	5024.257	1004.851	44.259	8.852	43.56	4.84	1970.697	111.356	122.300	.000	1737.041	9799.942
12- 6	4865.376	973.075	42.859	8.572	45.00	5.00	1971.515	111.367	128.415	.000	1731.733	10083.094
S TOT	116546.644	24815.563	1026.659	218.601	30.13	3.27	31647.079	1796.727	1613.990	1258.500	26977.862	10083.094
REM.	38882.439	7776.488	342.516	68.503	45.00	5.00	15755.735	890.009	1412.565	.000	13453.161	11476.510
TOTAL	155429.083	32592.051	1369.175	287.104	33.85	3.68	47402.814	2686.736	3026.555	1258.500	40431.023	11476.510

CUM.	.000	.000	
ULT.	155429.083	32592.051	

NET OIL REVENUES (M$)	46346.353		
NET GAS REVENUES (M$)	1056.461		
TOTAL REVENUES (M$)	47402.814		

---------PRESENT WORTH PROFILE---------

DISC RATE	PW OF NET BTAX, M$	DISC RATE	PW OF NET BTAX, M$
.0	40431.023	30.0	2899.641
2.0	29947.364	35.0	2311.518
5.0	20041.253	40.0	1890.903
8.0	14127.933	45.0	1578.687
10.0	11476.510	50.0	1339.856
12.0	9489.148	60.0	1002.690
15.0	7343.259	70.0	779.686
18.0	5852.051	80.0	623.645
20.0	5100.080	90.0	509.715
25.0	3761.195	100.0	423.727

BTAX RATE OF RETURN (PCT)	100.00	PROJECT LIFE (YEARS)	30.500
BTAX PAYOUT YEARS	2.76	DISCOUNT RATE (PCT)	10.000
BTAX PAYOUT YEARS (DISC)	2.51	GROSS OIL WELLS	350.000
BTAX NET INCOME/INVEST	33.13	GROSS GAS WELLS	.000
BTAX NET INCOME/INVEST (DISC)	14.73	GROSS WELLS	350.000
INITIAL W.I. FRACTION	.010068	INITIAL NET OIL FRACTION	.008809
FINAL W.I. FRACTION	.010068	FINAL NET OIL FRACTION	.008809
PRODUCTION START DATE	7- 1-87	INITIAL NET GAS FRACTION	.008809
MONTHS IN FIRST LINE	6.00	FINAL NET GAS FRACTION	.008809

OCD 23614-17 02977

Goodnight Cross Exhibit 11

From:	Nicholas Cestari
To:	Jack Wheeler
Cc:	Royce Lanning
Subject:	FW: Prior Cobb reports - Empire Petroleum
Date:	Friday, December 1, 2023 10:39:07 AM
Attachments:	RRBell4_WholeCoreAnalysis-Digitized.xlsx image001.jpg image002.png image003.jpg image004.png image005.jpg
Sensitivity:	Confidential

Nick Cestari
Senior Geologist

Empire Petroleum Corporation
25025 Interstate 45 North, STE 400
The Woodlands, TX
Mobile: (512)-751-3384
Email: ncestari@empirepetrocorp.com

From: Nicholas Cestari
Sent: Monday, September 25, 2023 4:04 PM
To: Deacon Marek <dmarek@wmcobb.com>; Darrell W. Davis <ddavis@empirepetrocorp.com>; Don Bailey <dbailey@wmcobb.com>
Cc: Robert Williams <rwilliams@wmcobb.com>; Jack Wheeler <jwheeler@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
Sensitivity: Confidential

Deacon,

Apologies there, the handwritten is the correct depth information on the RR Bell #4. I have a digitized version as well that is a little cleaner. The elevation is 3,550' for the RR Bell #4.

I will be leaving town tomorrow through Friday as well so you can coordinate with Darrell on anything further, but that should be all on the core.

Nick Cestari
Senior Geologist

Empire Petroleum Corporation

25025 Interstate 45 North, STE 400
The Woodlands, TX
Mobile: (512)-751-3384
Email: ncestari@empirepetrocorp.com

From: Deacon Marek <dmarek@wmcobb.com>
Sent: Monday, September 25, 2023 1:56 PM
To: Nicholas Cestari <NCestari@empirepetrocorp.com>; Darrell W. Davis <ddavis@empirepetrocorp.com>; Don Bailey <dbailey@wmcobb.com>
Cc: Robert Williams <rwilliams@wmcobb.com>; Jack Wheeler <jwheeler@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
Sensitivity: Confidential

> **Caution:** This is an external email. Please take care when clicking links or opening attachments. When in doubt, contact your IT Department

Nick:

I see that someone has made hand "corrections" to the depths of the core samples. Which depth numbers are correct? Also, what is the elevation of the R. R. Bell #4 well?

Thanks,

Deacon

F. J. "Deacon" Marek, P.E.
Senior VP - Technical Advisor
William M. Cobb & Associates, Inc.
12770 Coit Road, Suite 907
Dallas, TX 75251
(972) 385-0354 office
(972) 672-7479 cell
dmarek@wmcobb.com

From: Nicholas Cestari <NCestari@empirepetrocorp.com>
Sent: Monday, September 25, 2023 1:02 PM
To: Deacon Marek <dmarek@wmcobb.com>; Darrell W. Davis <ddavis@empirepetrocorp.com>; Don Bailey <dbailey@wmcobb.com>
Cc: Robert Williams <rwilliams@wmcobb.com>; Jack Wheeler <jwheeler@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
Sensitivity: Confidential

Apologies, I thought we had sent along the other core RR Bell #4 so here is that data as well.

Nick Cestari
Senior Geologist

Empire Petroleum Corporation
25025 Interstate 45 North, STE 400
The Woodlands, TX
Mobile: (512)-751-3384
Email: ncestari@empirepetrocorp.com

From: Deacon Marek <dmarek@wmcobb.com>
Sent: Monday, September 25, 2023 9:40 AM
To: Darrell W. Davis <ddavis@empirepetrocorp.com>; Don Bailey <dbailey@wmcobb.com>
Cc: Robert Williams <rwilliams@wmcobb.com>; Nicholas Cestari <NCestari@empirepetrocorp.com>; Jack Wheeler <jwheeler@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
Sensitivity: Confidential

Darrell:

This is a list of the core data you have sent me:

Unless you have any more data, I think w have what we need.

Thanks,

Deacon

F. J. "Deacon" Marek, P.E.

Senior VP - Technical Advisor
William M. Cobb & Associates, Inc.
12770 Coit Road, Suite 907
Dallas, TX 75251
(972) 385-0354 office
(972) 672-7479 cell
dmarek@wmcobb.com

From: Darrell W. Davis <ddavis@empirepetrocorp.com>
Sent: Saturday, September 23, 2023 6:28 AM
To: Deacon Marek <dmarek@wmcobb.com>; Don Bailey <dbailey@wmcobb.com>
Cc: Robert Williams <rwilliams@wmcobb.com>; Nicholas Cestari <NCestari@empirepetrocorp.com>; Jack Wheeler <jwheeler@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
Sensitivity: Confidential

Deacon and team,

If there is anything else you need from us, let us know, as our geologist Nick will be out Tuesday thru Friday next week.
As you know the affidavit has to be notarized and we need a copy of the presenter's resume attached to it.

We appreciate your help.

Thanks,

Darrell W. Davis P.E.
Senior Reservoir / Production Engineer

Empire Petroleum Corporation
25025 Interstate 45 North, STE 420
The Woodlands, TX, 77380
Mobile: (832) 525-7575
email: ddavis@empirepetrocorp.com

From: Darrell W. Davis
Sent: Wednesday, September 13, 2023 4:04 PM
To: Deacon Marek <dmarek@wmcobb.com>; Lucy King <lucy@empirepetrocorp.com>; Don Bailey <dbailey@wmcobb.com>
Cc: Jack Wheeler <jack@pieoperating.com>; Robert Williams <rwilliams@wmcobb.com>; William West <william@empirepetrocorp.com>; Nicholas Cestari <NCestari@empirepetrocorp.com>; Anibal Araya <aaraya@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
Sensitivity: Confidential

1:00 PM works fine for our technical staff.

Thanks,
Darrell

From: Deacon Marek <dmarek@wmcobb.com>
Sent: Wednesday, September 13, 2023 3:59 PM
To: Darrell W. Davis <ddavis@empirepetrocorp.com>; Lucy King <lucy@empirepetrocorp.com>; Don Bailey <dbailey@wmcobb.com>
Cc: Jack Wheeler <jack@pieoperating.com>; Robert Williams <rwilliams@wmcobb.com>; William West <william@empirepetrocorp.com>; Nicholas Cestari <NCestari@empirepetrocorp.com>; Anibal Araya <aaraya@empirepetrocorp.com>; Mike Morrisett <mike@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
Sensitivity: Confidential

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How about 1:00pm? We can set up a TEAMS meeting, if you would like.

Deacon

F. J. "Deacon" Marek, P.E.
Senior VP - Technical Advisor
William M. Cobb & Associates, Inc.
12770 Coit Road, Suite 907
Dallas, TX 75251
(972) 385-0354 office
(972) 672-7479 cell
dmarek@wmcobb.com

From: Darrell W. Davis <ddavis@empirepetrocorp.com>
Sent: Wednesday, September 13, 2023 3:56 PM
To: Deacon Marek <dmarek@wmcobb.com>; Lucy King <lucy@empirepetrocorp.com>; Don Bailey <dbailey@wmcobb.com>
Cc: Jack Wheeler <jack@pieoperating.com>; Robert Williams <rwilliams@wmcobb.com>; William West <william@empirepetrocorp.com>; Nicholas Cestari <NCestari@empirepetrocorp.com>; Anibal Araya <aaraya@empirepetrocorp.com>; mike <mike@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
Sensitivity: Confidential

Deacon,

We have a meeting from 10:00 to ~11:30 AM on Thursday but before or after will work.

We can do 9:00 AM or after 11:30 AM.

Thanks,

Darrell W. Davis P.E.
Senior Reservoir / Production Engineer

Empire Petroleum Corporation
25025 Interstate 45 North, STE 420
The Woodlands, TX, 77380
Mobile: (832) 525-7575
email: ddavis@empirepetrocorp.com

From: Deacon Marek <dmarek@wmcobb.com>
Sent: Wednesday, September 13, 2023 1:54 PM
To: Darrell W. Davis <ddavis@empirepetrocorp.com>; Lucy King <lucy@empirepetrocorp.com>; Don Bailey <dbailey@wmcobb.com>
Cc: Jack Wheeler <jack@pieoperating.com>; Robert Williams <rwilliams@wmcobb.com>; William West <william@empirepetrocorp.com>; Nicholas Cestari <NCestari@empirepetrocorp.com>; Anibal Araya <aaraya@empirepetrocorp.com>; Mike Morrisett <mike@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
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Thanks for the response, Darrell. We are tied up today in other meetings. Is there a time tomorrow that works for you?

Best regards,

Deacon

F. J. "Deacon" Marek, P.E.
Senior VP - Technical Advisor
William M. Cobb & Associates, Inc.
12770 Coit Road, Suite 907
Dallas, TX 75251
(972) 385-0354 office
(972) 672-7479 cell
dmarek@wmcobb.com

From: Darrell W. Davis <ddavis@empirepetrocorp.com>
Sent: Wednesday, September 13, 2023 1:40 PM
To: Deacon Marek <dmarek@wmcobb.com>; Lucy King <lucy@empirepetrocorp.com>; Don Bailey <dbailey@wmcobb.com>
Cc: Jack Wheeler <jack@pieoperating.com>; Robert Williams <rwilliams@wmcobb.com>; William West

<william@empirepetrocorp.com>; Nicholas Cestari <NCestari@empirepetrocorp.com>; Anibal Araya <aaraya@empirepetrocorp.com>; mike <mike@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
Sensitivity: Confidential

Deacon,

The SWD wells are injecting in the San Andres which is the ROZ so we need an estimate of the OOIP for the ROZ to show that we want to protect the EOR reserve potential.
We have a 2:00 PM meeting and should be done by 3:30 or 4:00 PM if you need to discuss.

Let me know if you want to meet.

Thanks,
Darrell

From: Deacon Marek <dmarek@wmcobb.com>
Sent: Wednesday, September 13, 2023 1:24 PM
To: Darrell W. Davis <ddavis@empirepetrocorp.com>; Lucy King <lucy@empirepetrocorp.com>; Don Bailey <dbailey@wmcobb.com>
Cc: Jack Wheeler <jack@pieoperating.com>; Robert Williams <rwilliams@wmcobb.com>; William West <william@empirepetrocorp.com>; Nicholas Cestari <NCestari@empirepetrocorp.com>; Anibal Araya <aaraya@empirepetrocorp.com>; Mike Morrisett <mike@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
Sensitivity: Confidential

Darrell:

Do you think we might schedule a TEAMS meeting or conference call to discuss this? We are a bit confused here. The EMSU project is to quantify the ROZ, correct? This would be a separate project from the EMSU injection well issue, which came up in August – having to do with SWD wells in and around the EMSU.

Regarding the November 2 hearing, is that for the EMSU ROZ or the SWD well(s) issue?

Hopefully, a brief call or TEAMS meeting can clear up these questions. We are all available on this end for a meeting tomorrow, Thursday, September 14.

Deacon

F. J. "Deacon" Marek, P.E.
Senior VP - Technical Advisor

William M. Cobb & Associates, Inc.
12770 Coit Road, Suite 907
Dallas, TX 75251
(972) 385-0354 office
(972) 672-7479 cell
dmarek@wmcobb.com

From: Darrell W. Davis <ddavis@empirepetrocorp.com>
Sent: Monday, September 11, 2023 3:22 PM
To: Lucy King <lucy@empirepetrocorp.com>; Deacon Marek <dmarek@wmcobb.com>; Don Bailey <dbailey@wmcobb.com>
Cc: Jack Wheeler <jack@pieoperating.com>; Robert Williams <rwilliams@wmcobb.com>; William West <william@empirepetrocorp.com>; Nicholas Cestari <NCestari@empirepetrocorp.com>; Anibal Araya <aaraya@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
Sensitivity: Confidential

Deacon,

We would like for Cobb & Associates to conduct a study to determine a range of oil-in-place volumes for the San Andres Residual Oil Zone which lies beneath the Empire Petroleum operated Eunice Monument oil field.
We have core and log data which can be used in this evaluation, along with geologic maps of the Grayburg formation.
We are constructing a San Andres top of structure map and can provide information as we obtain it, but will require your assistance in finalizing the map so that P-10, P-50, and P-90 volumes can be determined.
This study and exhibits (affidavit for hearing, write-up, figures, etc.) need to be completed by Oct-23-2023 so that our attorneys can review it before the Nov-2-2023 hearing.

Please confirm that Cobb & Associates can conduct this study and meet our Oct-23 timeline.
We would also like to know an approximate cost for this work and expert witness testimony.

If you would like to have a video meeting to go over what is needed, just let us know.

Thanks,

Darrell W. Davis P.E.
Senior Reservoir / Production Engineer

Empire Petroleum Corporation
25025 Interstate 45 North, STE 420
The Woodlands, TX, 77380
Mobile: (832) 525-7575
email: ddavis@empirepetrocorp.com

OCD 23614-17 02773

From: Lucy King <lucy@empirepetrocorp.com>
Sent: Thursday, August 31, 2023 12:56 PM
To: Deacon Marek <dmarek@wmcobb.com>; Don Bailey <dbailey@wmcobb.com>; Mike Morrisett <mike@empirepetrocorp.com>
Cc: Jack Wheeler <jack@pieoperating.com>; Robert Williams <rwilliams@wmcobb.com>; Darrell W. Davis <ddavis@empirepetrocorp.com>; Anibal Araya <aaraya@empirepetrocorp.com>; William West <william@empirepetrocorp.com>
Subject: RE: Prior Cobb reports - Empire Petroleum
Sensitivity: Confidential

Don –

I don't think Empire has gotten back to you regarding a video meeting. We are evaluating our strategy for opposing the salt water disposal in and offset the Eunice Monument South Units and Arrowhead Grayburg Unit. Currently our hearing is set for 21-Sep-2023 and we have requested a continuance to 07-Dec-2023.

While your input would be invaluable we are uncertain of what to request from you. We know that year-end reserves season is here. We will contact you when we have a better view of what Cobb & Associates can contribute.

Thank you for making yourself and Deacon available last week. We apologize for not getting back to you sooner.

Best regards,

Lucy B. King, P.E.

From: Deacon Marek <dmarek@wmcobb.com>
Sent: Thursday, August 24, 2023 11:15 AM
To: Don Bailey <dbailey@wmcobb.com>; Mike Morrisett <mike@empirepetrocorp.com>
Cc: Jack Wheeler <jack@pieoperating.com>; Lucy King <lucy@empirepetrocorp.com>; Brian Weatherl <brian@empirepetrocorp.com>; Robert Williams <rwilliams@wmcobb.com>
Subject: RE: Prior Cobb reports
Sensitivity: Confidential

Some people who received this message don't often get email from dmarek@wmcobb.com. Learn why this is important

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I am available until about 5:15 today.

Deacon

F. J. "Deacon" Marek, P.E.
Senior VP - Technical Advisor
William M. Cobb & Associates, Inc.
12770 Coit Road, Suite 907
Dallas, TX 75251
(972) 385-0354 office
(972) 672-7479 cell
dmarek@wmcobb.com

From: Don Bailey <dbailey@wmcobb.com>
Sent: Thursday, August 24, 2023 11:12 AM
To: mike <mike@empirepetrocorp.com>
Cc: Jack Wheeler <jack@pieoperating.com>; Lucy King <lucy@empirepetrocorp.com>; Brian Weatherl <brian@empirepetrocorp.com>; Deacon Marek <dmarek@wmcobb.com>; Robert Williams <rwilliams@wmcobb.com>
Subject: RE: Prior Cobb reports
Importance: High
Sensitivity: Confidential

Mike –

1 – We do believe we can help Empire both with the near-term EMSU SWD issues, and the follow-up EMSU waterflood-optimization study.

2 – Were you able to collect data to share with us on the near-term EMSU SWD issues? And, do you have a list of deliverables for the SWD issues?

Thank you,

Don

From: Don Bailey
Sent: Tuesday, August 8, 2023 2:49 PM
To: Mike Morrisett <mike@empirepetrocorp.com>
Cc: Jack Wheeler <jack@pieoperating.com>; Lucy King <lucy@empirepetrocorp.com>; Brian Weatherl <brian@empirepetrocorp.com>; Robert Williams <rwilliams@wmcobb.com>; Deacon Marek <dmarek@wmcobb.com>
Subject: RE: Prior Cobb reports
Importance: High
Sensitivity: Confidential

Mike –

Robert and I have a meeting at 3:00 this afternoon, but are both available for a meeting or call after that meeting.

Would you be available to connect via Microsoft Teams later this afternoon?

Don

Donald L. Bailey, P.G.
Senior Vice President, Geosciences

William M. Cobb & Associates, Inc.
Website: www.wmcobb.com
Office: 972-385-0354
Cell: 214-674-6259

From: Mike Morrisett <mike@empirepetrocorp.com>
Sent: Tuesday, August 8, 2023 1:46 PM
To: Deacon Marek <dmarek@wmcobb.com>; Don Bailey <dbailey@wmcobb.com>; Robert Williams <rwilliams@wmcobb.com>
Cc: Jack Wheeler <jack@pieoperating.com>; Lucy King <lucy@empirepetrocorp.com>; Brian Weatherl <brian@empirepetrocorp.com>
Subject: FW: Prior Cobb reports

Hi Deacon, Don and Robert-
Hope you all are doing well….it's been a while since we connected.
Have a special project would like to discuss with you guys.
We are going to need reservoir, production, geology, expert testimony, etc etc. on something.
Please give me a call on my cell phone when you get a moment.
Deacon, I know you are out of town, but this is a priority for Empire with a short timeline so wanted to send this email now…
Maybe Don or Robert, you guys could give me a call and I can give you a download to talk about getting started.
Thank You,
Mike

Michael R. Morrisett
President & CEO
Empire Petroleum Corporation
2200 S. Utica Place
Suite 150
Tulsa, OK 74114
Mike@EmpirePetroCorp.com
(M)-918-230-6268
(O)- 539-444-8002

NYSE American: EP

From: Thomas Pritchard <tommyp@empirepetrocorp.com>
Sent: Tuesday, December 27, 2022 2:17 PM
To: Michael Morrisett <mike@empirepetrocorp.com>; Mason Matschke <mason@energyevolutionfund.com>
Subject: FW: Prior Cobb reports

From: Thomas Pritchard
Sent: Friday, September 16, 2022 11:12 AM
To: Brian Weatherl <brian@empirepetrocorp.com>
Subject: FW: Prior Cobb reports

From: Deacon Marek <dmarek@wmcobb.com>
Sent: Wednesday, September 14, 2022 2:49 PM
To: Thomas Pritchard <tommyp@empirepetrocorp.com>; Josh Cornell <josh@empirepetrocorp.com>; Eugene Sweeney <eugene@empirepetrocorp.com>; Ernest Padilla <PadillaLawNM@outlook.com>
Cc: Don Bailey <dbailey@wmcobb.com>; Robert Williams <rwilliams@wmcobb.com>
Subject: Prior Cobb reports

Gentlemen:

Attached are PDF copies of our prior reports for the EMSU. I did get permission from the prior client to send this to you.

Best regards,

Deacon

F. J. "Deacon" Marek, P.E.
Senior VP - Technical Advisor
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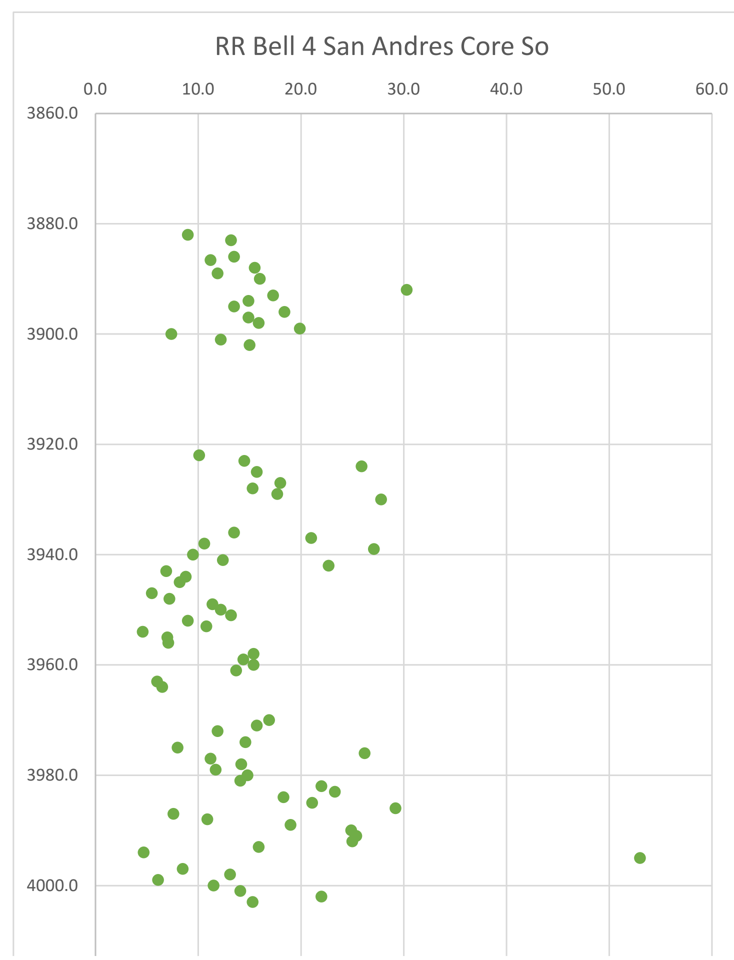
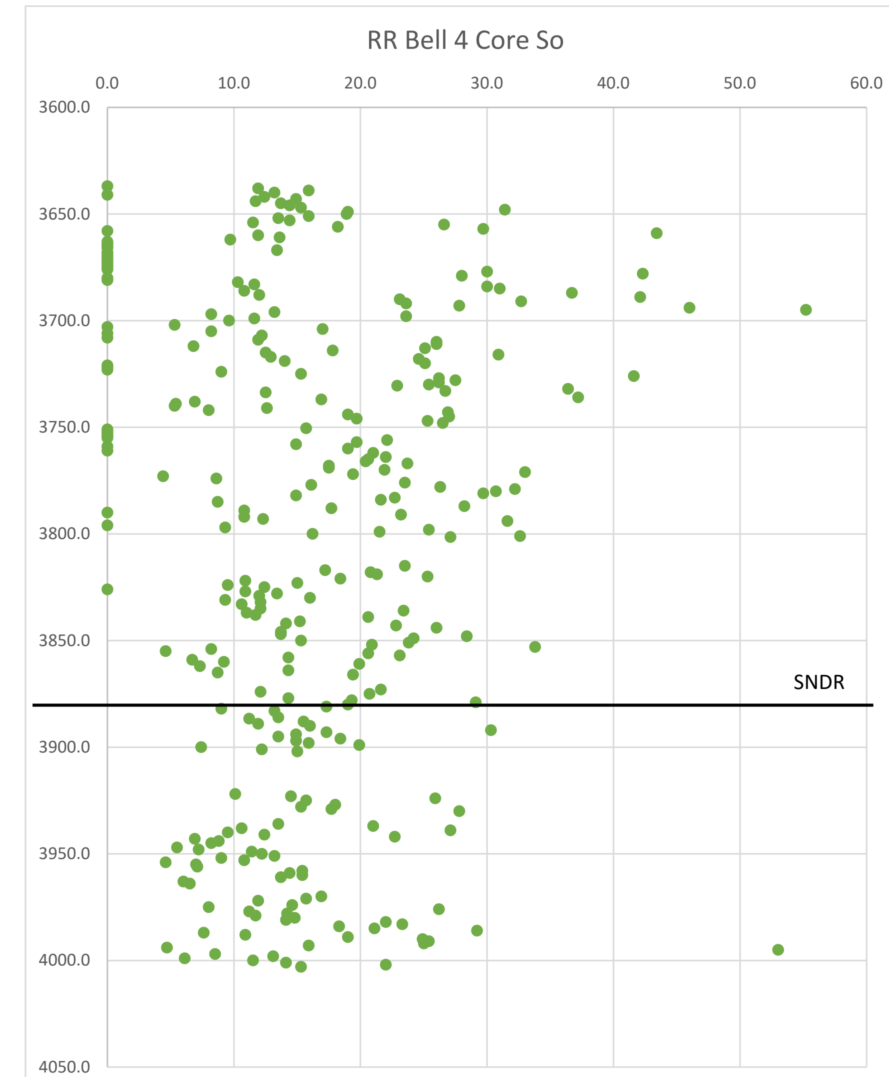
dmarek@wmcobb.com

Depth	Porosity	Perm Max	Perm 90	Sw	So
3637.0	1.5	0.1	0.1	87.5	0.0
3638.0	1.1	0.1	0.1	76.9	11.9
3639.0	1.5	0.1	0.1	74.0	15.9
3640.0	2.2	0.1	0.1	78.4	13.2
3641.0	1.0	0.1	0.1	64.3	0.0
3642.0	1.4	0.1	0.1	75.7	12.4
3643.0	1.8	0.1	0.1	75.7	14.9
3644.0	2.8	0.4	0.1	81.0	11.7
3645.0	2.1	0.1	0.0	79.9	13.7
3646.0	1.8	0.1	0.1	55.0	14.4
3647.0	2.2	0.2	0.0	72.6	15.3
3648.0	2.1	0.1	0.1	62.8	31.4
3649.0	2.5	0.1	0.1	66.0	19.0
3650.0	1.6	0.1	0.1	73.9	18.9
3651.0	1.6	0.1	0.1	74.0	15.9
3652.0	1.2	0.1	0.1	73.6	13.5
3653.0	1.4	0.1	0.1	70.3	14.4
3654.0	1.2	0.1	0.1	77.5	11.5
3655.0	1.0	0.1	0.1	56.4	26.6
3656.0	1.0	0.1	0.1	64.3	18.2
3657.0	1.7	0.2	0.0	56.3	29.7
3658.0	1.8	0.1	0.0	87.5	0.0
3659.0	6.5	0.1	0.0	49.2	43.4
3660.0	1.7	0.1	0.2	76.6	11.9
3661.0	2.1	0.4	0.1	69.1	13.6
3662.0	1.5	0.1	0.1	37.4	9.7
3663.0	1.4	0.1	0.1	83.3	0.0
3664.0	1.7	0.1	0.1	82.8	0.0
3665.0	1.1	0.1	0.1	84.2	0.0
3666.0	2.9	0.1	0.0	47.4	0.0
3667.0	2.2	0.2	0.1	80.3	13.4
3668.0	1.0	0.3	0.1	46.7	0.0
3669.0	1.0	0.1	0.1	50.0	0.0
3670.0	1.4	0.1	0.1	50.0	0.0
3671.0	3.7	0.2	0.1	83.3	0.0
3672.0	1.7	0.1	0.1	40.0	0.0
3673.0	1.8	0.1	0.1	21.4	0.0
3674.0	1.1	0.1	0.1	68.2	0.0
3675.0	0.9	0.1	0.0	60.0	0.0
3676.0	0.6	0.1	0.1	37.5	0.0
3677.0	4.0	0.1	0.1	23.7	30.0
3678.0	2.1	0.1	0.1	33.7	42.3
3679.0	4.0	0.3	0.1	21.4	28.0
3680.0	0.6	0.1	0.0	72.7	0.0
3681.0	2.0	0.1	0.1	91.4	0.0
3682.0	3.1	0.1	0.1	84.8	10.3
3683.0	2.2	0.1	0.1	51.6	11.6
3684.0	4.6	0.7	0.3	20.0	30.0
3685.0	2.9	0.1	0.1	47.4	31.0
3686.0	3.4	0.1	0.1	75.5	10.8
3687.0	7.1	0.3	0.1	42.4	36.7
3688.0	2.9	0.1	0.1	80.4	12.0
3689.0	3.8	0.1	0.1	37.3	42.1
3690.0	2.9	0.1	0.1	38.5	23.1
3691.0	2.3	0.1	0.1	52.7	32.7
3692.0	2.5	0.2	0.1	69.1	23.6
3693.0	5.6	0.1	0.1	44.8	27.8
3694.0	5.9	0.4	0.2	37.6	46.0
3695.0	4.8	0.1	0.1	34.4	55.2
3696.0	3.0	0.1	0.1	67.2	13.2





3697.0	3.2	0.1	0.1	81.4	8.2
3698.0	4.0	0.1	0.1	42.9	23.6
3699.0	4.3	0.1	0.0	76.3	11.6
3700.0	5.8	0.1	0.0	67.8	9.6
3702.0	4.8	0.1	0.1	85.8	5.3
3703.0	1.2	0.1	0.0	72.7	0.0
3704.0	1.5	0.1	0.0	64.9	17.0
3705.0	2.8	0.1	0.1	38.2	8.2
3706.0	2.8	0.1	0.0	64.3	0.0
3707.0	3.9	0.1	0.1	67.5	12.2
3708.0	3.3	0.1	0.1	73.1	0.0
3709.0	3.8	0.1	0.1	73.2	11.9
3710.0	3.0	0.1	0.1	66.8	26.0
3711.0	3.7	0.1	0.1	59.2	26.0
3712.0	4.6	0.3	0.2	55.7	6.8
3713.0	3.0	0.1	0.0	64.5	25.1
3714.0	3.4	0.1	0.1	54.3	17.8
3715.0	2.3	0.1	0.0	74.2	12.5
3716.0	2.1	0.1	0.0	41.5	30.9
3717.0	1.8	0.1	0.0	73.5	12.9
3718.0	4.8	0.1	0.0	37.1	24.6
3719.0	3.0	0.1	0.0	53.4	14.0
3720.0	2.8	0.1	0.0	33.1	25.1
3721.0	1.6	0.1	0.1	72.2	0.0
3722.0	1.2	0.1	0.0	68.0	0.0
3723.0	0.7	0.1	0.0	72.7	0.0
3724.0	2.7	0.9	0.6	53.1	9.0
3725.0	3.1	2.0	2.0	36.6	15.3
3726.0	3.3	0.1	0.1	36.8	41.6
3727.0	7.2	0.4	0.0	24.0	26.2
3728.0	3.5	0.1	0.0	46.2	27.5
3729.0	3.8	0.1	0.0	43.1	26.2
3730.0	6.1	0.1	0.0	31.8	25.4
3730.5	9.6	1.9	0.0	18.4	22.9
3732.0	**6.0**	1.9	0.0	18.2	36.4
3733.0	5.7	2.6	0.5	23.3	26.7
3733.7	2.2	0.1	0.0	74.2	12.5
3736	2.3	0.1	0.0	48.8	37.2
3737	2.3	0.1	0.0	72.4	16.9
3738	2.5	0.1	0.1	82.0	6.9
3739	4.4	0.1	0.0	89.9	5.4
3740	4.3	1.0	0.7	89.2	5.3
3741	2.6	1.3	0.5	55.6	12.6
3742	2.9	0.1	0.0	57.9	8.0
3743	6.2	0.1	0.1	47.4	26.9
3744	7.2	0.1	0.1	40.5	19.0
3745	5.8	2.2	1.1	49.0	27.0
3746	8.5	1.5	0.0	31.0	19.7
3747	8.1	0.7	0.3	22.4	25.3
3748	6.0	0.1	0.1	42.3	26.5
3750.5	6.2	0.1	0.1	33.7	15.7
3751.0	1.6	0.1	0.1	76.5	0.0
3752.0	1.1	0.1	0.0	91.3	0.0
3753.0	0.9	0.1	0.0	71.4	0.0
3754.0	1.3	0.1	0.0	88.5	0.0
3755.0	1.5	0.1	0.0	75.0	0.0
3756.0	3.7	0.1	0.0	32.9	22.1
3757.0	3.2	0.1	0.1	58.7	19.7
3758.0	2.0	0.1	0.1	72.5	14.9
3759.0	1.5	0.1	0.0	72.7	0.0
3760.0	1.7	0.1	0.1	54.0	19.0

3761.0	2.2	0.1	0.1	79.1	0.0
3762.0	5.5	0.3	0.2	25.0	21.0
3764.0	5.8	0.6	0.0	44.5	22.0
3765.0	4.7	0.1	0.0	56.9	20.6
3766.0	7.8	0.1	0.0	32.9	20.4
3767.0	6.8	0.1	0.0	38.2	23.7
3768.0	5.4	0.1	0.1	57.7	17.5
3769.0	6.1	0.1	0.0	63.8	17.5
3770.0	6.0	0.1	0.0	58.7	21.9
3771.0	7.4	0.1	0.1	51.7	33.0
3772.0	7.2	0.1	0.1	71.8	19.4
3773.0	7.0	0.1	0.1	93.6	4.4
3774.0	7.4	0.1	0.1	82.6	8.6
3776.0	10.1	0.6	0.1	33.9	23.5
3777.0	10.1	0.1	0.0	52.2	16.1
3778.0	12.2	0.1	0.0	36.6	26.3
3779.0	8.1	0.1	0.0	33.4	32.2
3780.0	6.0	0.1	0.1	50.2	30.7
3781.0	5.0	0.1	0.0	42.4	29.7
3782.0	5.5	0.4	0.1	74.3	14.9
3783.0	6.9	0.1	0.0	53.8	22.7
3784.0	8.2	0.1	0.1	66.8	21.6
3785.0	8.1	0.3	0.2	76.3	8.7
3787.0	5.2	0.1	0.1	37.9	28.2
3788.0	5.2	0.1	0.0	31.7	17.7
3789.0	2.5	0.1	0.0	82.3	10.8
3790.0	3.1	0.1	0.0	71.4	0.0
3791.0	4.0	0.1	0.0	54.0	23.2
3792.0	4.3	0.1	0.1	83.6	10.8
3793.0	5.0	0.1	0.1	81.8	12.3
3794.0	5.1	0.1	0.0	48.7	31.6
3796.0	7.3	0.1	0.0	87.3	0.0
3797.0	5.3	0.1	0.0	84.9	9.3
3798.0	6.3	0.1	0.0	55.0	25.4
3799.0	5.8	0.1	0.0	66.1	21.5
3800.0	3.4	0.1	0.0	69.5	16.2
3801.0	4.2	0.1	0.0	56.4	32.6
3801.5	5.3	0.1	0.0	36.4	27.1
3815.0	9.9	0.1	0.1	29.8	23.5
3817.0	8.8	0.1	0.1	28.2	17.2
3818.0	11.3	0.6	0.5	40.3	20.8
3819.0	12.0	0.3	0.2	31.1	21.3
3820.0	14.1	1.4	0.3	40.1	25.3
3821.0	10.0	0.6	0.4	41.5	18.4
3822.0	6.3	0.1	0.1	66.5	10.9
3823.0	5.1	0.1	0.0	30.7	15.0
3824.0	4.9	0.1	0.0	22.6	9.5
3825.0	5.5	0.1	0.0	35.5	12.4
3826.0	4.1	0.1	0.0	58.5	0.0
3827.0	6.1	0.1	0.1	53.1	10.9
3828.0	6.4	0.1	0.1	65.3	13.4
3829.0	7.2	2.1	1.1	38.9	12.0
3830.0	6.9	0.1	0.0	30.0	16.0
3831.0	5.3	0.1	0.0	84.8	9.3
3832.0	7.4	0.1	0.0	60.4	12.1
3833.0	8.4	0.1	0.1	42.3	10.6
3835.0	9.8	0.1	0.1	31.6	12.1
3836.0	9.9	0.1	0.0	31.8	23.4
3837.0	5.4	0.1	0.0	62.4	11.0
3838.0	8.6	0.1	0.0	35.3	11.7
3839.0	10.9	4.7	4.5	26.1	20.6

3841.0	5.7	0.1	0.0	46.7	15.2
3842.0	10.7	0.3	0.0	29.8	14.1
3843.0	8.4	0.1	0.0	25.7	22.8
3844.0	8.8	0.2	0.1	30.5	26.0
3846.0	10.9	2.4	2.0	27.1	13.7
3847.0	7.6	0.7	0.0	41.6	13.7
3848.0	11.1	0.4	0.0	27.0	28.4
3849.0	8.4	0.1	0.0	22.7	24.2
3850.0	4.7	0.1	0.0	50.6	15.3
3851.0	8.9	0.1	0.0	33.9	23.8
3852.0	9.1	0.1	0.0	39.9	20.9
3853.0	13.6	1.5	0.0	23.2	33.8
3854.0	9.0	0.1	0.0	82.5	8.2
3855.0	10.8	0.1	0.0	87.8	4.6
3856.0	10.0	0.1	0.0	32.9	20.6
3857.0	12.7	0.6	0.2	27.9	23.1
3858.0	11.7	0.4	0.3	38.3	14.3
3859.0	6.9	0.1	0.0	62.7	6.7
3860.0	7.1	0.2	0.0	52.4	9.2
3861.0	6.5	0.2	0.0	50.8	19.9
3862.0	5.3	0.1	0.0	46.4	7.3
3864.0	9.4	0.1	0.0	54.4	14.3
3865.0	8.0	0.1	0.0	73.0	8.7
3866.0	9.8	0.1	0.0	44.2	19.4
3873.0	8.8	0.1	0.0	42.4	21.6
3874.0	7.8	0.1	0.0	69.3	12.1
3875.0	5.4	0.1	0.0	31.7	20.7
3877.0	5.7	0.1	0.0	29.3	14.3
3878.0	4.3	0.1	0.0	22.9	19.3
3879.0	3.7	0.1	0.0	24.2	29.1
3880.0	2.6	0.1	0.1	39.0	19.0
3881.0	2.5	0.1	0.1	76.2	17.3
3882.0	3.8	30.1	0.1	85.3	9.0
3883.0	4.0	0.1	0.1	73.4	13.2
3886.0	6.9	0.1	0.0	40.7	13.5
3886.6	5.1	0.5	0.0	46.5	11.2
3888.0	7.0	0.1	0.0	49.9	15.5
3889.0	5.8	4.3	0.0	56.8	11.9
3890.0	4.1	0.1	0.0	58.8	16.0
3892.0	3.3	0.1	0.0	38.0	30.3
3893.0	4.0	0.1	0.0	37.0	17.3
3894.0	2.4	0.1	0.0	53.6	14.9
3895.0	4.1	0.1	0.0	50.9	13.5
3896.0	2.5	0.1	0.0	42.8	18.4
3897.0	1.8	0.1	0.0	56.7	14.9
3898.0	2.7	0.1	0.0	47.1	15.9
3899.0	3.5	0.1	0.0	50.6	19.9
3900.0	6.0	0.1	0.0	89.8	7.4
3901.0	3.1	0.1	0.0	56.8	12.2
3902.0	4.2	0.1	0.0	64.2	15.0
3922.0	7.2	0.1	0.0	74.4	10.1
3923.0	7.2	0.1	0.0	70.4	14.5
3924.0	3.7	0.1	0.0	62.6	25.9
3925.0	4.0	2.8	2.3	56.9	15.7
3927.0	5.6	0.1	0.0	35.4	18.0
3928.0	3.8	0.1	0.0	51.9	15.3
3929.0	4.6	0.1	0.0	42.3	17.7
3930.0	2.9	0.1	0.0	52.3	27.8
3936.0	3.3	0.9	0.5	56.0	13.5
3937.0	3.4	0.1	0.0	57.0	21.0
3938.0	4.2	8.1	0.0	40.3	10.6

3939.0	4.4	0.1	0.0	31.6	27.1
3940.0	4.0	0.1	0.0	62.3	9.5
3941.0	6.7	1.1	0.0	58.4	12.4
3942.0	3.9	3.6	0.0	50.5	22.7
3943.0	5.4	0.1	0.0	40.9	6.9
3944.0	6.8	0.1	0.0	30.0	8.8
3945.0	11.6	2.9	2.1	50.7	8.2
3947.0	10.6	0.1	0.0	53.7	5.5
3948.0	10.0	2.3	1.1	59.2	7.2
3949.0	10.0	26.9	21.1	35.7	11.4
3950.0	4.0	0.1	0.0	38.5	12.2
3951.0	4.5	3.9	0.0	30.8	13.2
3952.0	6.3	0.8	0.0	20.9	9.0
3953.0	11.4	2.3	0.0	53.3	10.8
3954.0	7.9	1.2	0.0	44.7	4.6
3955.0	12.7	68.4	66.0	47.1	7.0
3956.0	10.6	0.1	0.1	62.1	7.1
3958.0	8.2	50.4	0.0	41.0	15.4
3959.0	9.5	0.1	0.0	53.9	14.4
3960.0	10.8	1.1	0.0	45.7	15.4
3961.0	8.2	0.1	0.0	39.4	13.7
3963.0	9.5	0.1	0.0	46.6	6.0
3964.0	4.4	1.2	0.0	62.4	6.5
3970.0	7.8	0.1	0.0	28.2	16.9
3971.0	13.5	2.5	0.0	36.0	15.7
3972.0	5.5	7.8	7.7	41.5	11.9
3974.0	5.2	0.1	0.1	60.0	14.6
3975.0	4.8	0.5	0.5	57.6	8.0
3976.0	6.7	0.4	0.1	55.8	26.2
3977.0	10.6	1.3	0.1	45.3	11.2
3978.0	11.8	3.2	1.5	41.0	14.2
3979.0	13.7	5.9	0.9	32.6	11.7
3980.0	10.9	0.2	0.1	43.9	14.8
3981.0	9.2	0.2	0.1	52.3	14.1
3982.0	7.3	1.2	0.9	49.1	22.0
3983.0	6.6	15.3	0.3	56.0	23.3
3984.0	4.6	0.4	0.1	74.0	18.3
3985.0	7.3	0.8	0.2	41.3	21.1
3986.0	4.5	0.1	0.0	61.3	29.2
3987.0	7.7	0.1	0.1	84.4	7.6
3988.0	8.0	0.4	0.1	76.7	10.9
3989.0	9.0	78.1	0.0	42.4	19.0
3990.0	8.1	0.1	0.0	33.9	24.9
3991.0	10.6	38.5	8.6	26.2	25.4
3992.0	12.7	2.9	0.3	34.6	25.0
3993.0	5.9	0.1	0.1	64.2	15.9
3994.0	6.3	7.8	1.1	81.6	4.7
3995.0	5.4	0.1	0.0	61.3	53.0
3997.0	3.3	2.6	2.3	41.3	8.5
3998.0	6.5	0.3	0.3	31.2	13.1
3999.0	7.3	3.1	0.1	73.0	6.1
4000.0	7.5	3.2	0.6	73.1	11.5
4001.0	7.9	2.7	1.4	48.8	14.1
4002.0	12.5	0.3	0.1	30.6	22.0
4003.0	10.4	0.1	0.1	38.3	15.3

Goodnight Cross Exhibit 12

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

APPLICATIONS OF GOODNIGHT MIDSTREAM PERMIAN, LLC FOR APPROVAL OF SALTWATER DISPOSAL WELLS LEA COUNTY, NEW MEXICO

CASE NOS. 23614
23615
23616
23617

SELF-AFFIRMED STATEMENT OF FRANK J. MAREK

1. My name is Frank J. Marek. I am a registered professional engineer in Texas, and currently Senior Vice President of William M. Cobb & Associates, in Dallas Texas. I obtained a Bachelor's Degree in Petroleum Engineering in 1977 from Texas A&M University. I have held leadership positions in industry organizations including the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers. A copy of my resume is attached as Exhibit D-1. I have not previously testified before the New Mexico Oil Conservation Division.

2. I have been involved with numerous carbonate waterfloods in the Permian Basin since the early 1980's. I also have significant experience with CO2 tertiary oil recovery projects in the area. This includes projects in Lea and Eddy Counties, New Mexico. I have specific experience with the Eunice Monument South Unit ("EMSU") through a study my firm prepared in August 1987. The study evaluated the waterflood potential of the EMSU based on 80 acre well spacing, which was current at the time. I was also involved in an April 1988 follow up study that investigated the potential for infill drilling to 40 acre spacing and waterflooding on 80 acre 5-spot patterns.

3. I have been asked to evaluate the impact of saltwater disposal ("SWD") operations within the San Andres interval at the EMSU, located in Lea County, New Mexico. The EMSU is a secondary oil recovery project (waterflood) formed in 1984. The unitized interval at EMSU is defined as follows:

> "The unitized interval shall include the formations from a lower limit defined by the base of the San Andres formation to an upper limit defined by the top of the Grayburg formation or at -100 foot subsea datum, whichever is higher."

This captures the <u>entire</u> Grayburg and San Andres interval.

Exhibit D

4. Exhibits D-2 through D-4 present cross sections showing well logs for the Goodnight Ryno SWD #1 well, EMSU #679, EMSU #660, and the R. R. Bell #4 well. The NuTech processed log for the Ryno SWD #1 well shows oil saturation throughout the entire San Andres interval, top to base. Current perforations are shown on all of the well logs. Clearly, water is being disposed of (injected into) the unitized San Andres interval. Although water injection into the Ryno SWD #1 well is structurally deeper than producing perforations in nearby wells, water is being injected into a documented residual oil zone ("ROZ"). The high-water disposal rates will cause higher pressures in the ROZ, and higher potential for hydraulic fracturing and vertical communication, all of which will impair Empire's ability to produce hydrocarbons from the ROZ.

5. Based on my many years of experience and the above analysis, it is my opinion that Goodnight's proposed injection of produced water into the unitized interval will detrimentally impact Empire's ability to recover hydrocarbons from the ROZ and therefore result in waste of oil and gas. As a result, such water disposal should not be allowed at the EMSU.

6. I understand that this Self-Affirmed Statement will be used as written testimony in this case. I affirm that my testimony above is true and correct and is made under penalty of perjury under the laws of the State of New Mexico. My testimony is made as of the date identified next to my signature below.

WILLIAM M. COBB & ASSOCIATES, INC.
Texas Registered Engineering Firm F-84

STATE OF TEXAS
FRANK J. MAREK
52939
REGISTERED
PROFESSIONAL ENGINEER

Frank J. Marek, P.E.
Senior Vice President

Date: 10/16/2023

EXHIBIT D-1
Frank J. "Deacon" Marek

EDUCATION: B.S., Petroleum Engineering
Texas A&M University, May 1977

WORK EXPERIENCE:

1985 - Present
William M. Cobb & Associates, Inc.
Technical Advisor / Senior Vice President

- Specializes in oil, gas, and CO_2 reserve evaluation and economic analysis, waterflood and CO_2 EOR feasibility and performance analysis, and reservoir simulation studies
- Conduct in-house workshops to assist clients in evaluating waterflood potential
- Considerable experience in providing reserve and economic evaluations of offshore oil and gas properties located in the Gulf of Mexico, including deep water projects

1982 - 1985
Cornell Oil Company
Reservoir Engineering Manager

- Responsible for surveillance and reservoir management of a 5,000 BOPD West Texas waterflood and a smaller Oklahoma waterflood
- Developed economic analysis of an anticipated CO_2 project for the West Texas property which included CO_2 supply alternatives, CO_2 transportation, field production performance, and infill drilling
- Responsible for reservoir engineering and economic evaluation of exploration prospects
- Developed annual internal reserve reports and supervised preparation of external, third-party, company reserve reports

1981 - 1982
Buttes Resources Company
Rocky Mountain District Engineer

- Responsible for all operations in Montana, Wyoming, and Colorado, including management and surveillance of certain waterflood and polymer flood projects

- Designed and recommended development and exploration wells, well completions, and well workovers

1977 - 1981
Hughes & Hughes Oil & Gas
Petroleum Engineer

- Prepared company's annual reserve report

- Evaluated drilling prospects

- Designed and analyzed pressure transient well tests

- Developed internal petroleum economics computer model

- Responsible for the design and implementation of development and exploration drill wells, new well completions, and workovers

TECHNICAL AND PROFESSIONAL SOCIETIES:

- Society of Petroleum Engineers - International (SPEI)
  - Management & Information Awards Committee 2003; Chairman, 2004
  - Economic and Evaluation Award Committee, 2002
  - Admissions Committee, 1994-1995
- Society of Petroleum Engineers – Dallas Section (SPE)
  - Chairman, 2004-2005
  - Hydrocarbon Economics & Evaluation Symposium

        - General Chairman, 1999
        - Arrangements Chairman, 1997
        - Arrangements Committee, 1995
        - Program Committee, 1989

    - Dallas Section Membership Chairman, 1993-1994
    - Dallas Section Arrangements Chairman, 1991-1993
    - Dallas Section Continuing Education Chairman, 1990-1991
    - Dallas Section Secretary, 1989-1990

- Society of Petroleum Evaluation Engineers (SPEE), Dallas Chapter
    - Chairman 1993-1994
    - Membership Chairman, 1994-1995
    - Secretary and Treasurer, Dallas Chapter, 1991-1993

HONORS AND AWARDS:

- SPE Regional Service Award, 2007
- SPE Dallas Section Outstanding Engineer Award, 2005
- SPE Dallas Section Service Award, 1994

REGISTRATION:

- Registered Professional Engineer, State of Texas

PUBLICATIONS:

- Cobb, W.M., and Marek, F.J.: "Determination of Volumetric Sweep Efficiency in Mature Waterfloods Using Production Data." Presented at SPE Annual Technical Conference and Exhibition, San Antonio, Texas, October 5-8, 1997 SPE 38902.

- Cobb, W.M., and Marek, F.J.: "Net Pay Determination for Primary and Waterflood Depletion Mechanisms." Presentation at 1998 SPE Annual Technical Conference and Exhibition, New Orleans, Louisiana, September 27-30, 1998 SPE 48952.

TECHNICAL PRESENTATIONS:

- "Waterflood – A Tried and True Technique for Secondary Oil Recovery" presented to:
  NAPAC Conference, Dallas, TX, May 2012
  Austin Bar Association Oil, Gas and Mineral Section, Austin, TX, October 2012

- "Waterflood Evaluation….In A Hurry" presented to:
  SPEE Midland Chapter, Midland, TX., January 6, 2009.
  Dallas Wildcatter's Luncheon Meeting, Dallas, TX., May 29, 2008.
  The SPE East Texas Section, Tyler, TX., November, 2005.
  The SPE North Texas Section in Wichita Falls, TX., April 2005.

- "Tertiary Oil Recovery Processes" presented to:
  NAPAC Convention, Dallas, TX., May 2001.

- "Due Diligence In Petroleum Property Evaluation" presented to:
  Desk and Derrick Society, Dallas, TX. September 2000.
  NAPAC Convention, Dallas, TX., May 2000.

COMMUNITY INVOLVEMENT

- Director and Secretary for Retina Foundation of the Southwest (RFSW), 2009 to 2018. The RFSW is an Eye Research Institute in Dallas, focusing on finding treatment and cures for debilitating diseases of the eye.

03/13

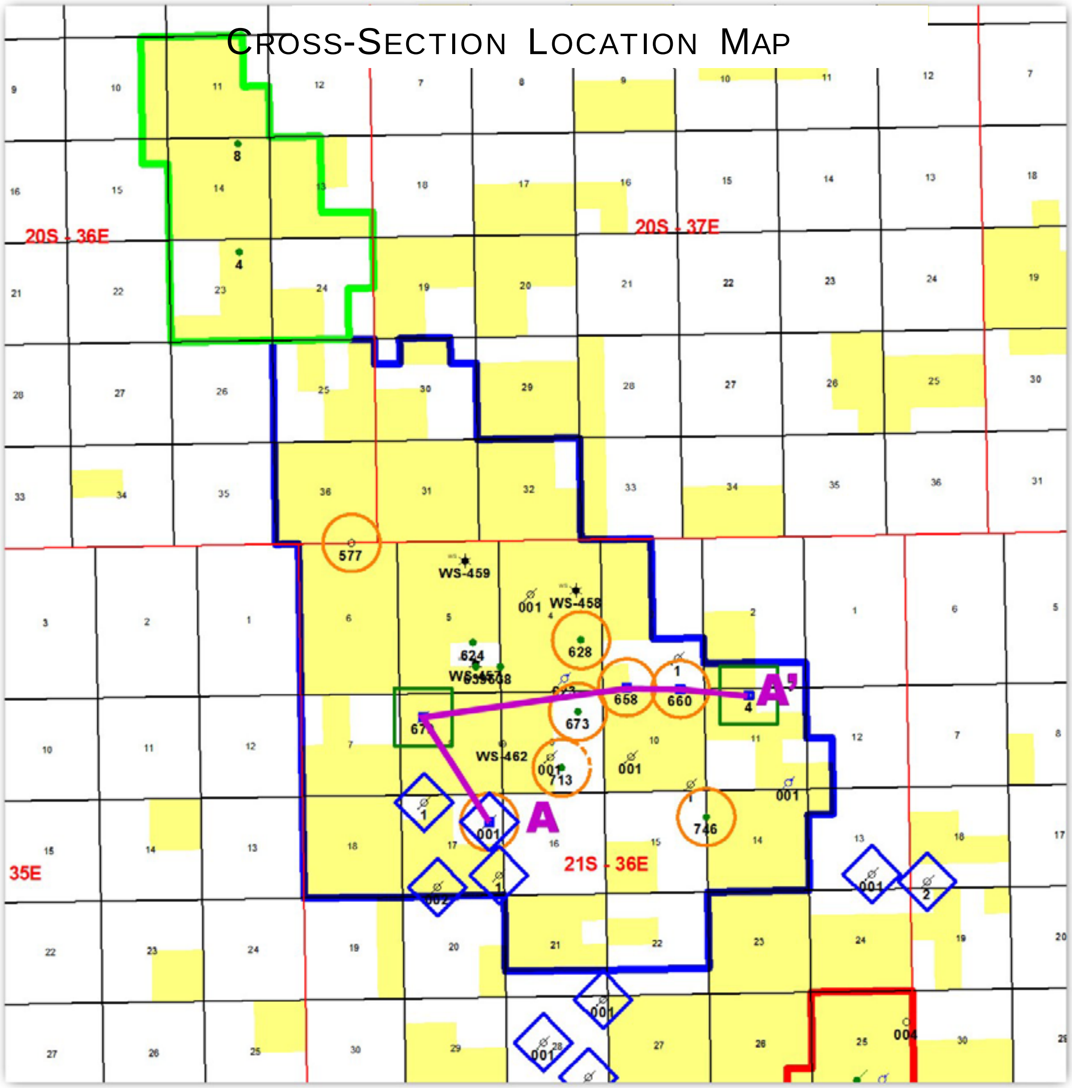

CROSS-SECTION LOCATION MAP
20S - 36E
20S - 37E
21S - 36E
35E
A
A'
577
WS-459
WS-458
628
658
660
673
WS-462
713
746
001

EXHIBIT D-2

EXHIBIT D-3

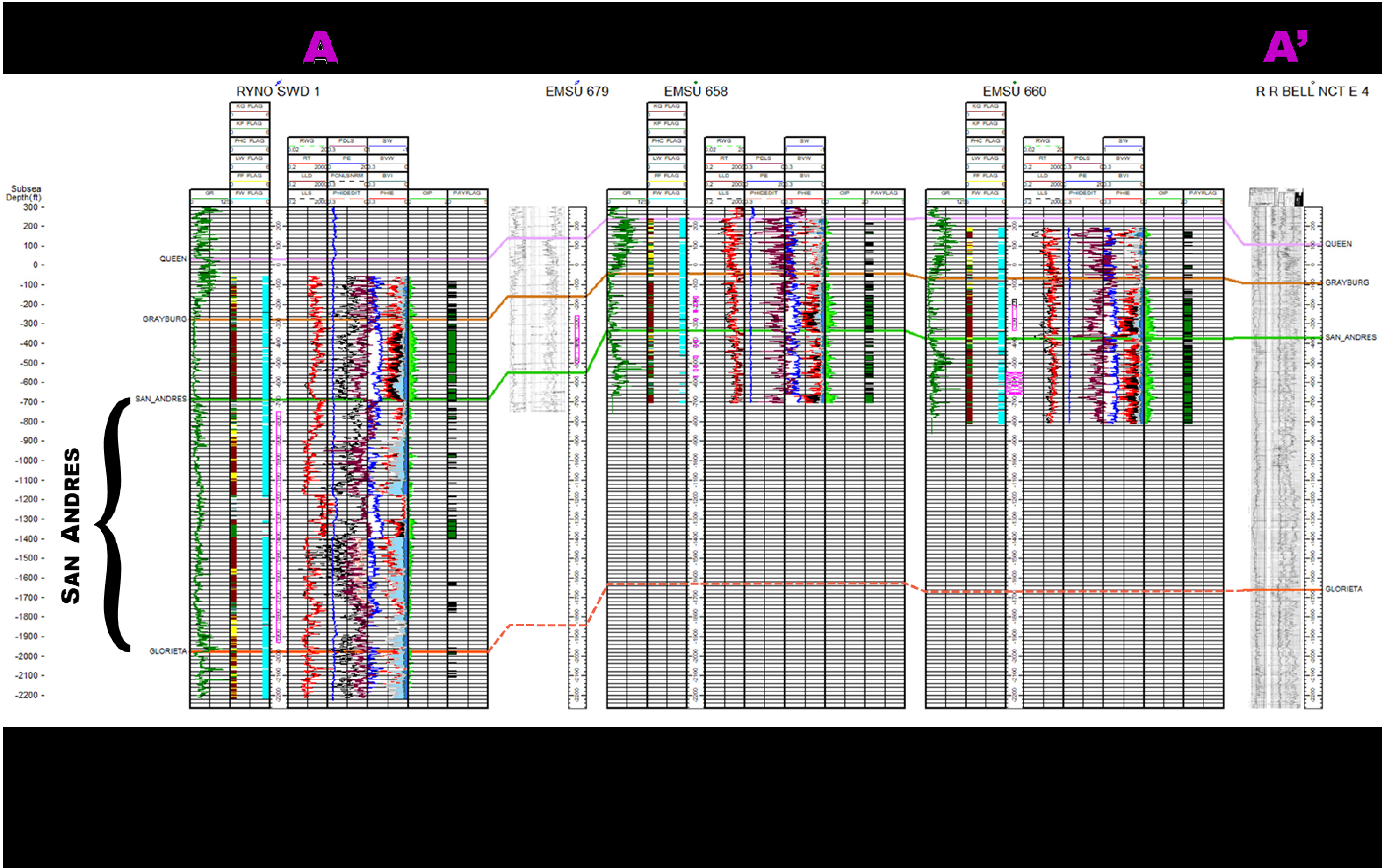
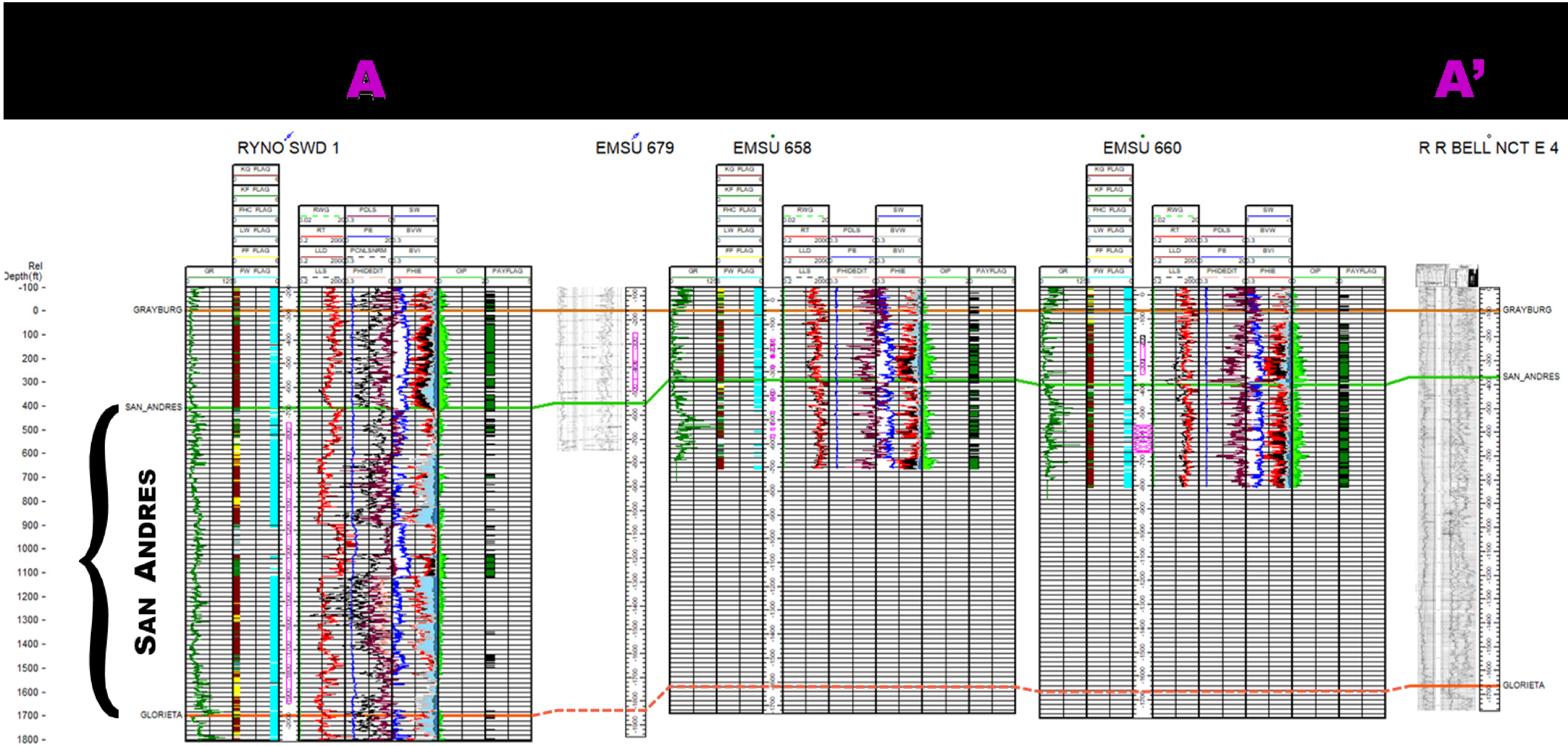

A
A'
RYNO SWD 1
EMSU 679
EMSU 658
EMSU 660
R R BELL NCT E 4
Subsea Depth(ft)
300
200
100
0
-100
-200
-300
-400
-500
-600
-700
-800
-900
-1000
-1100
-1200
-1300
-1400
-1500
-1600
-1700
-1800
-1900
-2000
-2100
-2200
QUEEN
GRAYBURG
SAN_ANDRES
GLORIETA
SAN ANDRES
GR
KG FLAG
KP FLAG
PHC FLAG
LW FLAG
PP FLAG
PW FLAG
RWG
RT
LLD
LLS
PDLS
PE
PHIDEDIT
SW
BVW
BVI
PHIE
OIP
PAYFLAG

EXHIBIT D-4


A
A'
RYNO SWD 1
EMSU 679
EMSU 658
EMSU 660
R R BELL NCT E 4
Rel Depth(ft)
-100
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
1600
1700
1800
GRAYBURG
SAN_ANDRES
GLORIETA
SAN ANDRES
KG FLAG
KF FLAG
FHC FLAG
LW FLAG
FF FLAG
FW FLAG
GR
RWG
RT
LLD
LLS
PDLS
PE
PCNLSNRM
PHIDEDIT
SW
BVW
BVI
PHIE
OIP
PAYFLAG

Goodnight Cross Exhibit 13

XTO ENERGY
An ExxonMobil Subsidiary

Executive Summary - Eunice Assets

Lea County, New Mexico

November 2020

CONFIDENTIAL

XTO ENERGY

XTO Eunice Opportunity Overview

XTO Energy Inc. ("XTO") is offering for sale a large operated package with assets that include certain oil and gas properties, infrastructure, offices, and personnel located in southeastern Lea County , New Mexico.

ASSET HIGHLIGHTS

Proven Resource & Cash Flow

- Three legacy operated waterflood units (Eunice Monument South Unit A and B, Arrowhead Grayburg Unit)
- An additional ~270 operated lease wells with ~90% working interest
- All leasehold is held by production

Low-Risk Development Potential

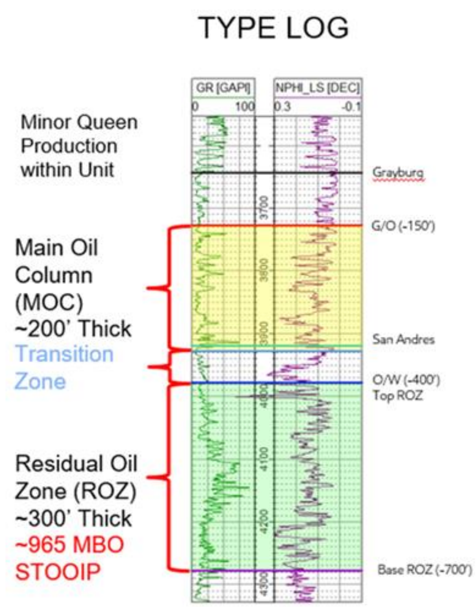
- Numerous workover repair opportunities
- Optimization of waterfloods through conformance work
- Opportunities to reduce operating costs

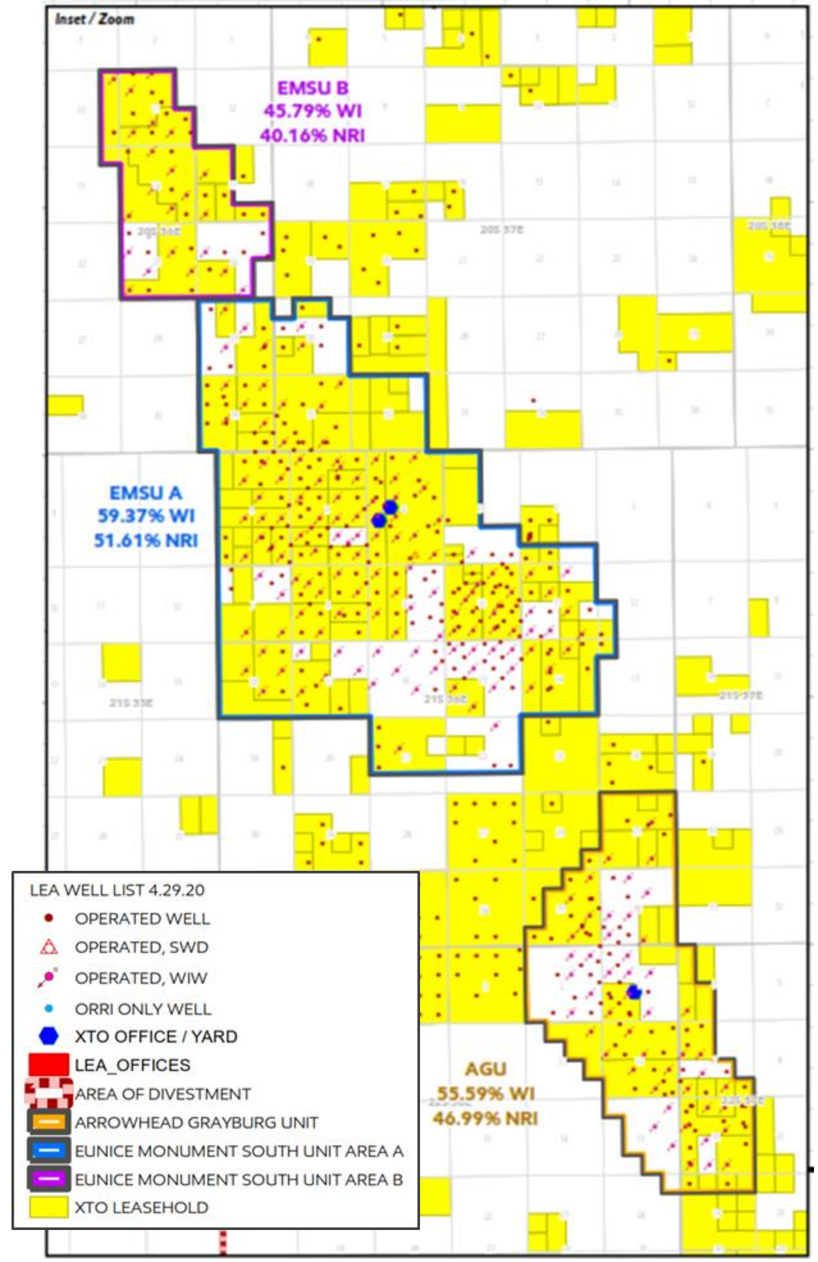
Attractive Upside Opportunities

- Infill drilling locations at 20 acre spacing
- Potential CO2 flooding in the Residual Oil Zone Recent in three units

XTO Eunice Opportunity Snapshot

Acres (Approx.)	GROSS	47k
	NET	40k
PDP Well Count (Approx.)	OP	688
	NON-OP	0
	ROY	14
2019 Net Production	OP	1566 OEBD (23% Gas)
	NON-OP	NONE
	ROY	8 OEBD (90% Gas)





CONFIDENTIAL

Process Details & Contact Information

- Responses of interest should be directed to XOM-UOG-EUNICE@exxonmobil.com
- Following receipt of executed Confidentiality Agreement, interested parties will be given access to the Virtual Data Room (VDR)
- Questions should be directed to **Jim Laumbach**
- Evaluation materials will include:
  - ARIES database
  - Historical financial data / Lease Operating Statements
  - Well, lease, and key contract schedules
  - Well logs and Wellbore Sketches
  - Lease and well map
- Key Process Dates
  - Virtual Data Room opens November 5th
  - Bids due on December 1st
  - PSA signing on or before December 22nd
  - Estimated closing in 1Q 2021

November 2020						
S	M	T	W	T	F	S
1	2	3	4	**5**	6	7
8	9	10	11	12	13	14
15	16	17	18	19	20	21
22	23	24	25	26	27	28
29	30					

December 2020						
S	M	T	W	T	F	S
		1	2	3	4	5
6	7	8	9	10	11	12
13	14	15	16	17	18	19
20	21	**22**	23	24	25	26
27	28	29	30	31		

VDR OPENS   BIDS DUE   PSA SIGNED

CONTACT INFORMATION

Jim Laumbach
Sr. Engineering Advisor
832-625-2936
James_Laumbach@xtoenergy.com

Disclaimer

By reviewing this presentation, you acknowledge and agree that XTO makes no express or implied representation or warranty as to, and expressly disclaims any and all liability for, the quality, accuracy and completeness of the information, data or other materials set forth in this presentation, in the data room established by XTO in connection with this opportunity, or otherwise provided to you by XTO or its representatives (the "Information"). You further acknowledge and agree the Information is being furnished to you for discussion purposes only, and that you will rely solely on your own independent investigations, evaluations, and analyses of the Information in satisfying yourself as to the quality, accuracy and completeness of the Information, and you will proceed with this opportunity, if at all, by submitting a bid, entering into definitive agreements or consummating a transaction with XTO solely on the bases of such investigations, evaluations, and analyses.

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Goodnight Cross Exhibit 14

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

DATE OF REPORT (DATE OF EARLIEST EVENT REPORTED):

MAY 14, 2021

EMPIRE PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	**001-16653**	**73-1238709**
(State or Other Jurisdiction of Incorporation)	(Commission File Number)	(I.R.S. Employer Identification No.)

2200 S. Utica Place, Suite 150, Tulsa Oklahoma 74114
(Address of Principal Executive Offices) (Zip Code)

Registrant's telephone number, including area code: **(539) 444-8002**

(Former name or former address, if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions:

☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)

☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)

☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))

☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
None	**EMPR**	**None**

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (§230.405 of this chapter) or Rule 12b-2 of the Securities Exchange Act of 1934 (§240.12b-2 of this chapter).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 2.01 Completion of Acquisition or Disposition of Assets.

Empire New Mexico LLC, a Delaware limited liability company and wholly owned subsidiary of Empire Petroleum Corporation ("Empire New Mexico"), entered into a purchase and sale agreement dated as of March 12, 2021 (the "Purchase Agreement"), with XTO Holdings, LLC, a subsidiary of ExxonMobil ("Seller"), pursuant to which, among other things, Empire New Mexico agreed to acquire certain oil and gas properties from Seller in New Mexico comprising of 702 gross wells and approximately 47,200 gross acres (40,580 net acres) in Lea County. The oil and gas assets produce from the Eunice Monument field. Under the Purchase Agreement, (a) the purchase price is $17,800,000 (subject to customary adjustments), (b) Empire New Mexico wired a deposit of $1,780,000 to Seller on March 12, 2021 using cash on hand, (c) the effective date of the transactions is January 1, 2021, and (d) the scheduled closing date was April 26, 2021. Empire New Mexico and Seller agreed to extend the closing date to May 14, 2021. The Purchase Agreement also contains various representations and warranties, covenants, indemnities, limitations of liability and other terms and conditions that are customary for transactions similar to the transactions contemplated by the Purchase Agreement. The foregoing description of the Purchase Agreement is only a summary, does not purport to be complete and is subject to, and qualified in its entirety by reference to, the Purchase Agreement, a copy of which is filed as Exhibit 2.1 attached hereto.

On May 14, 2021, the transactions contemplated under the Purchase Agreement were closed. Empire New Mexico paid an adjusted purchase price of approximately $16,089,000 in connection with such closing.

Item 9.01 Financial Statements and Exhibits.

(d) **Exhibits.**

2.1 Purchase and Sale Agreement dated as of March 12, 2021, by and between Empire New Mexico LLC and XTO Holdings, LLC

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, hereunto duly authorized.

EMPIRE PETROLEUM CORPORATION

Date: May 17, 2021	By:	/s/ Michael R. Morrisett Michael R. Morrisett President

EXHIBIT 2.1

PURCHASE AND SALE AGREEMENT BETWEEN

XTO HOLDINGS, LLC

AND

EMPIRE NEW MEXICO LLC

DATED: MARCH 12, 2021

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EXHIBITS

SCHEDULES

PURCHASE AND SALE AGREEMENT

This Purchase and Sale Agreement (this "**Agreement**") is made as of March 12, 2021, by and between XTO Holdings LLC, a limited liability company, with an address of 22777 Springwoods Village Parkway, Spring, Texas 77389 ("**Seller**"), and Empire New Mexico LLC, a limited liability company, with an address of 2200 South Utica Place, Suite 150, Tulsa, Oklahoma 74114 ("**Purchaser**"). Seller and Purchaser are sometimes referred to in this Agreement collectively as the "**Parties**" and individually as a "**Party**."

WITNESSETH

WHEREAS, Seller desires to sell to Purchaser the Assets (as defined below) and Purchaser is willing to purchase the Assets from Seller, upon the terms and conditions set forth in this Agreement:

NOW THEREFORE, in consideration of the mutual promises of the Parties contained in this Agreement, and other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties agree as follows:

ARTICLE I
DEFINITIONS

Section 1.1 **Certain Defined Terms**. Capitalized terms used in this Agreement shall have the meanings given such terms as set forth in Appendix A attached to this Agreement.

ARTICLE II
PURCHASE AND SALE

Section 2.1 **Agreement to Purchase and Sell**. At the Closing, and subject to the terms and conditions of this Agreement, Purchaser agrees to purchase the Assets from Seller, and Seller agrees to sell, transfer and assign the Assets to Purchaser, effective as of the Effective Time.

Section 2.2 **The Assets**. The term "**Assets**" shall mean all of Seller's right, title and interest in and to the following, less and except for the Excluded Assets:

(a) the oil and gas leases described in Exhibit A-1 to the extent and only to the extent that such leases cover the lands and/or the depths described in Exhibit A-1, and all rights incident thereto and derived therefrom, including overriding royalty interests, net profits interests, and other revenue interests therein, to the extent and only to the extent relating to such lands and/or depths described in Exhibit A-1 (the "**Leases**").

(b) the wells described in Exhibit B and all other wells (including all disposal or injection wells) located on any of the Leases or on any other lease or lands with which any Lease has been unitized, whether such wells are producing, shut-in or abandoned (the "**Wells**");

(c) all rights and interests in, under or derived from all unitization or pooling agreements in effect with respect to any of the Leases or Wells and the units created thereby (the "**Units**");

(d) all Rights-of-Way that are used primarily in connection with the ownership or operation of any of the Leases, Wells, Units or other Assets, including the Rights-of-Way set forth in Exhibit A-2;

(e) the offices and office leases described in Exhibit A-3 and all improvements, furniture and fixtures and related tangible personal property used primarily in connection with the offices covered thereby (the "**Assigned Office**");

(f) a royalty free oil and gas lease in the form attached as Exhibit C (the "**Royalty Free Lease**") for each of the mineral interests described in Exhibit A-4 (the "**Mineral Interests**");

(g) all equipment, machinery, fixtures and other personal and mixed property, operational and nonoperational, known or unknown, located on any of the Leases, Wells, Units or other Assets, that are primarily used or held for use in connection with the ownership, operation or development of the Leases, Well, Units or other Assets, including the inventory set forth on Schedule 3.2(f), and pipelines, gathering systems, well equipment, casing, tubing, pumps, motors, fixtures, machinery, compression equipment, flow lines, processing and separation facilities, structures, materials and other items primarily used in the ownership, operation or development of the Leases, Well, Units or other Assets;[1]

(h) to the extent that they may be assigned, all Permits that are primarily used in connection with the ownership or operation of the other Assets;

(i) to the extent they may be assigned, the Existing Contracts;

(j) all Hydrocarbons attributable to the Leases, Wells and/or Units to the extent such Hydrocarbons were produced from and after the Effective Time and all Imbalances relating to the Assets;

(k) the Transferred Vehicles; and

(l) to the extent transferable, the Records.

Section 2.3 **Excluded Assets**. The following are specifically excluded from the Assets and are reserved by Seller (collectively, "**Excluded Assets**"):

(a) all of Seller's corporate minute books, financial records and other business records that relate to Seller's business generally (including the ownership and operation of the Assets);

(b) all accounts, trade credits, accounts receivable, and all other proceeds, income or revenues attributable to the Assets with respect to any period of time prior to the Effective Time;

(c) all claims and causes of action, manufacturer's and contractor's warranties and other rights of Seller arising under or with respect to any Existing Contracts that are attributable to periods of time prior to the Effective Time (including claims for adjustments or refunds), except to the extent any of the foregoing relates to any of the Assumed Obligations;

(d) all rights and interests of Seller (i) under any policy or agreement of insurance, (ii) under any bond or (iii) to any insurance or condemnation proceeds or awards arising;

(e) all Hydrocarbons produced and sold from the Assets with respect to all periods prior to the Effective Time;

(f) any claim, right or interest of Seller in or to any refunds or loss carry forwards, together with any interest due thereon or penalty rebate arising therefrom, with respect to (i) any and all taxes based on net income imposed on Seller or any of its Affiliates, (ii) any Property Taxes allocable to Seller pursuant to Section 13.1 or (iii) any Property Taxes attributable to the Excluded Assets;

(g) all personal computers and associated peripherals and all radio and telephone equipment except and unless located on any of the Wells or facilities to be assigned;

(h) all documents and instruments of Seller that may be protected by an attorney-client or other privilege;

(i) all data that cannot be disclosed to Purchaser as a result of confidentiality arrangements under agreements with third parties (provided that Seller has used its commercially reasonable efforts to cause such confidentiality restrictions to be waived);

(j) all audit rights arising under any of the Existing Contracts or otherwise with respect to any period prior to the Effective Time or to any of the Excluded Assets, except with respect to any Imbalances;

(k) all geophysical and other seismic and related technical data and information relating to the Assets;

(l) documents prepared or received by Seller or its Affiliates with respect to (i) lists of prospective purchasers for such transactions compiled by Seller or its Affiliates or their respective representatives, (ii) offers submitted by other prospective purchasers of the Assets, (iii) analyses by Seller or its Affiliates or any of their respective representatives of any offers submitted by any prospective purchaser, (iv) correspondence between or among Seller or its Affiliates or any of their respective representatives, on the one hand, and any prospective purchaser other than Purchaser, on the other hand, and (v) correspondence among Seller or its Affiliates or any of their respective representatives with respect to any other offers, the prospective purchasers, or the transactions contemplated by this Agreement;

(m) any offices, office leases, and any personal property located in or on such offices or office leases, except the Assigned Office;

(n) concurrent rights to use all Rights-of-Way but only to the extent Seller or any of its Affiliates currently uses such Rights-of-Way in connection with its use, ownership or operation of assets other than the Assets;

(o) all vehicles, other than the Transferred Vehicles;

(p) all fee mineral interests associated with the Assets (but subject to the grant of the Royalty Free Lease);

(q) any royalty only wells and associated leases other than those listed on Schedule 3.2(q);

(r) any master service agreements, blanket agreements or similar contracts; and (s) the Overriding Royalty.

Section 2.4 **Effective Time; Property Expenses and Revenues**. Subject to the terms hereof, ownership and possession of the Assets shall be transferred from Seller to Purchaser at the Closing but effective as of the Effective Time. Except to the extent accounted for in the adjustments to the Purchase Price made under Section 3.2 or Section 3.3 and without duplication of any such amounts: (a) Seller shall remain entitled to all of the rights of ownership (including the right to all production, proceeds of production and other proceeds) and shall remain responsible for all Property Expenses (in each case) attributable to the Assets for the period of time prior to the Effective Time; and (b) from and after the occurrence of Closing, Purchaser shall be entitled to all of the rights of ownership (including the right to all production, proceeds of production and other proceeds) and shall be responsible for all Property Expenses (in each case) attributable to the Assets for the period of time from and after the Effective Time.

ARTICLE III

PURCHASE PRICE

Section 3.1 **Purchase Price**. The purchase price for the Assets shall be SEVENTEEN MILLION EIGHT HUNDRED THOUSAND DOLLARS ($17,800,000.00) (the "**Purchase Price**"). The Purchase Price shall be allocated among the Assets as set forth in Exhibit D (the "**Allocated Values**").

Section 3.2 **Upward Adjustments to the Purchase Price**. The Purchase Price shall be adjusted upward by the following (without duplication):

(a) the amount of all Property Expenses and other costs paid by Seller that are attributable to the Assets on and after the Effective Time including royalties, rentals and similar charges and expenses and capital costs billed under applicable operating agreements and all prepaid expenses, but excluding costs paid by Seller to cure and/or Remediate, as applicable, any Title Defects, Environmental Defects or Casualty Losses, or to obtain any Required Consents or waiver of any Preferential Rights;

(b) an amount equal to the value of all Hydrocarbons attributable to the Assets in pipelines or in tanks (including inventory) above the pipeline sales connection as of the Effective

Time, such value to be based upon the contract price in effect as of the Effective Time (or if no such contract is in effect, the market value in the area as of the Effective Time), less applicable taxes and gravity adjustments;

(c) the amount of any Property Taxes prorated to Purchaser under Section 13.1, but paid or payable by Seller;

(d) an amount equal to the value of all Title Benefits in accordance with Section 4.7 below;

(e) an amount equal to the fair market value of the Transferred Vehicles required to be bought out by Seller plus any transfer costs for such Transferred Vehicles (provided that in the event any Transferred Vehicle leases can be transferred to Purchaser, then the adjustment shall only be the amount of transfer costs for such lease transfer, if any); and

(f) any other upward adjustment agreed upon by Seller and Purchaser.

Section 3.3 **Downward Adjustments to the Purchase Price**. The Purchase Price shall be adjusted downward by the following (without duplication):

(a) the amount of all proceeds and revenues received by Seller, if any, from and after the Effective Time up to the Closing that are attributable to the Assets from and after the Effective Time (net of any royalties and any production, severance, sales or other similar taxes not reimbursed to Seller by the purchaser of production);

(b) an amount equal to the Allocated Value of each of the Assets that have been excluded from the transactions contemplated by this Agreement pursuant to Section 4.4(a), Section 4.8(b), Section 4.8(c), Section 4.11(a) or Section 4.13(b)(ii);

(c) subject to Section 4.6, if Seller makes the election under Section 4.4(c) with respect to any Title Defect, the Title Defect Amount with respect to such Title Defect;

(d) subject to Section 4.12, if Seller makes the election under Section 4.11(c) with respect to any Environmental Defect, the Remediation Amount with respect to such Environmental Defect;

(e) if Seller makes the election under Section 4.13(b)(iii) with respect to any Casualty Loss, the reduction in value of any Asset that is attributable to such Casualty Loss;

(f) an amount equal to the net amount of suspended funds Seller elects to transfer to Purchaser in accordance with Section 12.2;

(g) the amount of all Property Taxes prorated to Seller in accordance with Section 13.1, but paid or payable by Purchaser; and

(h) any other downward adjustment agreed upon by Seller and Purchaser.

Section 3.4 **Payment of the Purchase Price**. Purchaser shall pay the Purchase Price, as adjusted pursuant to Sections 3.2 and 3.3 above (the "**Adjusted Purchase Price**"), as follows:

(a) on the date this Agreement is executed by the Parties, Purchaser shall pay to Seller, by wire transfer of immediately available funds to an account designated by Seller, the Deposit, which Deposit shall not bear interest. If the Closing occurs, the Deposit (without interest) shall be credited towards the Purchase Price. If Closing does not occur, the Deposit will be subject to the provisions of Article XV.

(b) Purchaser shall pay to Seller at Closing, the Adjusted Purchase Price as determined in accordance with Section 10.2, and subject to final adjustment pursuant to Section 12.1, less the Deposit. All such payments shall be by bank wire transfer of immediately available funds to an account designated by Seller in the Preliminary Settlement Statement.

ARTICLE IV
TITLE AND ENVIRONMENTAL MATTERS
AND CASUALTY LOSSES

Section 4.1 **Title Examination**. Subject to the indemnity provisions of Section 7.4 and subject to obtaining any consents or waivers from third parties that are required pursuant to the terms of the Leases, Right-of-Way and/or Existing Contracts (including any restrictions therein related to access during hunting seasons), including any third party operators of the Assets, as soon as is reasonably practicable after the execution of this Agreement, during Seller's normal business hours and without unreasonable disruption of Seller's normal and usual operations, Seller shall make available to Purchaser at Seller's offices all title data in Seller's or its Affiliates' possession relating to the Assets, including title opinions, abstracts of title, title status reports, division order files, and curative matters, the Existing Contracts, and records relating to the payment of rentals, royalties, shut-in gas royalties, and other payments due under any Lease or Existing Contract provided, however, that those items referenced above in this Section 4.1 that are subject to a valid legal privilege or to unwaived disclosure restrictions shall be excluded. Purchaser shall be permitted, at its expense, to make copies of any of such title data. Purchaser shall be entitled to perform or cause to be performed, at Purchaser's expense, such additional title examination as Purchaser deems necessary or appropriate.

Section 4.2 **Seller's Title**.

(a) General Disclaimer of Title Warranties and Representations. Without limiting Purchaser's remedies for Title Defects set forth in this Article IV, Seller makes no warranty or representation, express, implied, statutory or otherwise, with respect to title to any of the Assets and, Purchaser acknowledges and agrees that Purchaser's sole remedy for any defect of title, including any Title Defect, with respect to any of the Assets (i) before Closing, shall be as set forth in Section 4.4 and (ii) after Closing, shall be pursuant to the special warranty of title to the Wells contained in Section 4.2(b), subject to the provisions of Section 4.2(c), and Purchaser waives all other remedies.

(b) Special Warranty of Title. Upon Closing, subject to Section 4.2(c), Seller hereby warrants and agrees to defend Defensible Title to the Wells by, through or under Seller but not otherwise, subject, however, to the Permitted Encumbrances. Such special warranty of title to the Wells shall be subject to the further limitations and provisions of Section 4.2(c).

(c) Recovery on Special Warranty.

(i) Purchaser's Assertion of Title Warranty Breaches. Purchaser shall furnish Seller a Title Defect Notice meeting the requirements of Section 4.3 setting forth any matters which Purchaser intends to assert as a breach of the special warranty of title to the Wells contained in Section 4.2(b). Seller shall have a reasonable opportunity, but not the obligation, to cure any Title Defect asserted by Purchaser pursuant to this Section 4.2(c). Purchaser agrees to reasonably cooperate with any attempt by Seller to cure any such breach of the special warranty of title.

(ii) Limitations on Special Warranty. For purposes of the special warranty of title to the Wells contained in Section 4.2(b), the value of the Assets set forth in Exhibit D shall be deemed to be the Allocated Value thereof, as adjusted pursuant to this Agreement. Recovery on the special warranty of title to the Wells contained in Section 4.2(b) shall be limited to an amount (without any interest accruing thereon) equal to the reduction in the Purchase Price to which Purchaser would have been entitled had Purchaser asserted the Title Defect giving rise to such breach of the special warranty of title, as a Title Defect prior to Closing pursuant to Section 4.3, in each case taking into account the Individual Title Defect Threshold and the Aggregate Title Defect Deductible.

(iii) Purchaser shall not be entitled to protection under Seller's special warranty of title to the Wells in Section 4.2(b), with respect to (A) any matter of which Purchaser or any of its Affiliates had knowledge prior to the Defect Notice Date, or (B) any matter reported to Seller after the one year anniversary of the Closing Date.

Section 4.3 **Notice of Title Defects**. Purchaser shall notify Seller in writing of any Title Defect (each a "**Title Defect Notice**") on or before April 6, 2021 (the "**Defect Notice Date**"). For all purposes of this Agreement and notwithstanding anything herein to the contrary (except for the special warranty of title to the Wells contained in Section 4.2(b)), Purchaser shall be deemed to have waived, and Seller shall have no liability for, any Title Defect that Purchaser fails to assert as a Title Defect by a Title Defect Notice received by Seller on or before the Defect Notice Date. To be effective, each Title Defect Notice shall include (a) a detailed description of the alleged Title Defect, (b) the Well affected by such Title Defect (each a " **Title Defect Property**"), (c) the Allocated Value of such Title Defect Property, (d) supporting documents reasonably necessary for Seller to verify the existence of the alleged Title Defect, and (e) the amount by which Purchaser reasonably believes the Allocated Value of such Title Defect Property is reduced by the alleged Title Defect. Seller shall have the right, but not the obligation, to elect to attempt to cure any Title Defect set forth in a Title Defect Notice by written notice to Purchaser prior to Closing and, if Seller so elects, then Seller shall have sixty (60) days following Closing in which to cure, at Seller's cost, the Title Defect. No adjustment to the Purchase Price will be made at Closing for any Title Defect that Seller elects to attempt to cure pursuant to this Section 4.3 and the affected Well shall be assigned to Purchaser. If any such uncured Title Defect remains uncured at the end of such 60 day period, then (except as provided in Section 4.4 (a)) an adjustment to the Purchase Price in an amount equal to the applicable Title Defect Amount will be made as part of the Final Settlement Statement. To give Seller an opportunity to commence reviewing and curing Title Defects, Purchaser shall use its reasonable efforts to give Seller weekly written notice of all Title Defects discovered by Purchaser (together with any Title Benefits discovered by Purchaser).

Section 4.4 **Remedies for Title Defects**. Subject to Seller's continuing right to dispute the existence of a Title Defect and/or the Title Defect Amount asserted with respect thereto and subject to the Individual Title Defect Threshold and the Aggregate Title Defect Deductible, with respect to any Title Defect that (i) Seller does not elect to attempt to cure or (ii) Seller elects to attempt to cure and Seller fails to cure such Title Defect within sixty (60) days after Closing:

(a) if such Title Defect is not of a nature that would prevent Purchaser from receiving the full Net Revenue Interest share of proceeds of production for a particular Well as such interest is set forth on Exhibit B, Seller shall have the right, but not the obligation, to elect to indemnify Purchaser against all Losses resulting from such Title Defect pursuant to an indemnity agreement in form mutually agreeable to the Parties, in which event the Purchase Price shall not be reduced and the affected Title Defect Property shall be transferred to (or after Closing, retained by) Purchaser notwithstanding and subject to such Title Defect;

(b) at or prior to Closing, Seller shall have the right, but not the obligation, to elect to exclude the affected Title Defect Property from the transactions contemplated hereby, in which event such Title Defect Property and all Assets directly relating thereto (but only to the extent relating thereto) shall be excluded from the transactions contemplated hereby and the Purchase Price shall be reduced by the Allocated Value of such Title Defect Property and related Assets; or

(c) if both Section 4.4(a) and Section 4.4(b) above are not applicable, the affected Title Defect Property shall be transferred to (or if after Closing, retained by) Purchaser notwithstanding and subject to the Title Defect and the Purchase Price shall be reduced by the Title Defect Amount of such Title Defect Property as determined in accordance with Section 4.5 below.

Except for Purchaser's (i) rights under the special warranty of title to the Wells contained in Section 4.2(b) and (ii) rights to terminate this Agreement pursuant to Section 15.1(d), the provisions set forth in this Section 4.4 shall be the sole and exclusive right and remedy of Purchaser with respect to any Title Defect or any other title matter with respect to any Asset and Purchaser hereby waives all other rights and remedies.

Section 4.5 **Title Defect Amounts**. The amount by which the Allocated Value of an affected Title Defect Property is reduced as a result of the existence of a Title Defect shall be the "**Title Defect Amount**" and shall be determined in accordance with the following:

(a) if the Title Defect results in complete failure of title to a Title Defect Property with the effect that Seller has no ownership interest in that Title Defect Property to which an individual Allocated Value is assigned, then the Purchase Price shall be decreased by the Allocated Value for that Title Defect Property;

(b) if the Title Defect is a decrease in Net Revenue Interest from the Net Revenue Interest set forth in Exhibit B for a Title Defect Property, then the Title Defect Amount shall be equal to the product of the Allocated Value of that Title Defect Property multiplied by a fraction, the numerator of which is the amount of Net Revenue Interest set forth in Exhibit B for that Title Defect Property less the actual amount of the Net Revenue Interest for such Title Defect Property and the denominator of which is the Net Revenue Interest set forth in Exhibit B for that Title Defect Property;

(c) if the Title Defect is a lien, encumbrance or other charge on the Assets that is undisputed and liquidated in amount, then the Title Defect Amount shall be the amount necessary to be paid to remove the Title Defect (but never more than the Allocated Value of the affected Title Defect Property);

(d) if Purchaser and Seller agree on the Title Defect Amount, then that amount shall be the Title Defect Amount;

(e) if the Title Defect represents an obligation, Encumbrance upon or other defect in title to the Title Defect Property of a type not described above, then the Title Defect Amount shall be determined by taking into account the Allocated Value of the Title Defect Property, the portion of the Title Defect Property affected by the Title Defect, the legal effect of the Title Defect, the potential economic effect of the Title Defect over the life of the Title Defect Property, the values placed upon the Title Defect by Purchaser and Seller and such other reasonable factors as are necessary to make a proper evaluation; provided, however, that if such Title Defect is reasonably capable of being cured, then the Title Defect Amount shall not be greater than the reasonable cost and expense of curing such Title Defect;

(f) the Title Defect Amount with respect to a Title Defect Property shall be determined without duplication of any costs or losses included in another Title Defect Amount hereunder;

(g) if a Title Defect does not affect a Title Defect Property throughout the entire remaining productive life of such Title Defect Property, such fact shall be taken into account in determining the Title Defect Amount; and

(h) notwithstanding anything to the contrary herein, the aggregate Title Defect Amounts attributable to the effects of all Title Defects upon any single Title Defect Property shall not exceed the Allocated Value of such Title Defect Property.

Section 4.6 **Title Limitations**. Notwithstanding anything to the contrary, (a) in no event shall there be any adjustments to the Purchase Price or other remedies provided by Seller for any individual Title Defect for which the Title Defect Amount does not exceed ONE HUNDRED THOUSAND DOLLARS ($100,000.00) (the "**Individual Title Defect Threshold**"); and (b) in no event shall there be any adjustments to the Purchase Price or other remedies provided by Seller for any Title Defect that exceeds the Individual Title Defect Threshold unless the sum of the Title Defect Amounts of all such Title Defects that exceed the Individual Title Defect Threshold (excluding any Title Defects cured by Seller) exceeds five percent (5%) of the Purchase Price(the "**Aggregate Title Defect Deductible**"), after which point Purchaser shall be entitled to adjustments to the Purchase Price or other remedies only with respect to such Title Defects in excess of such Aggregate Title Defect Deductible (after reducing the value of each such Title Defect by the Individual Title Defect Threshold). For the avoidance of doubt, if Seller elects to exclude a Title Defect Property affected by a Title Defect from the transactions contemplated hereby pursuant to the remedy set forth in Section 4.4(b) or indemnify Purchaser with respect to any Title Defect pursuant to the remedy set forth in Section 4.4 (a), then, after such election, the Title Defect Amount and related Purchase Price adjustment relating to such excluded Assets or such Assets for which Seller has provided an indemnity to Purchaser will not be counted towards the Aggregate Title Defect Deductible or for purposes of Section 8.4 and Section 9.4.

Section 4.7 **Title Benefits**. If Seller determines that the ownership of any Well entitles Seller to a larger net revenue interest or a smaller working interest (without a corresponding decrease in the net revenue interest) than that set forth on Exhibit B (a "**Title Benefit**"), then Seller shall notify Purchaser of such increase in writing on or before the Defect Notice Date, describing in such notice with reasonable detail each alleged increase so discovered and a reasonable estimate of the value attributable to the applicable Title Benefit. Purchaser shall also promptly furnish Seller with written notice of any Title Benefit that is discovered prior to the Defect Notice Date by any of Purchaser's or any of its Affiliate's employees, title attorneys, landmen or other title examiners while conducting Purchaser's due diligence with respect to the Assets. The amount of any such Title Benefit (each, a "**Title Benefit Amount**") shall be determined in the same manner as provided in Section 4.5 with respect to Title Defects.

Section 4.8 **Preferential Purchase Rights and Consents to Assign**.

(a) Seller, within fifteen (15) days following the date of execution of this Agreement, shall send to each holder of (i) a preferential purchase right pertaining to any of the Assets (a "**Preferential Right**") and (ii) a right to consent to assignment pertaining to the Assets and the transactions contemplated hereby, a notice seeking a waiver of such Preferential Right or such holder's consent to the transactions contemplated hereby, as applicable, in accordance with the contractual provisions applicable to such right. In no event shall Seller be required to incur any liability or pay any money in order to be in to obtain any such waiver or consent. Purchaser shall cooperate with Seller in seeking to obtain such waivers of Preferential Rights and consents to assignment and will provide any additional collateral or security to meet reasonable financial requirements demanded by counterparties in order to obtain waivers of Preferential Rights and consents from such counterparties.

(b) If, prior to Closing, any holder of a Preferential Right notifies Seller that it intends to consummate the purchase of the Assets to which its Preferential Right applies or the time for exercising a Preferential Right has not expired and such Preferential Right has not been exercised or waived, then those Assets subject to such Preferential Right shall be excluded from the Assets to be conveyed to Purchaser under this Agreement (together with all Assets directly relating thereto but only to the extent relating thereto), and the Purchase Price shall be reduced by the Allocated Values of all such excluded Assets and in such event, Seller shall be entitled to all proceeds paid by any Person exercising such Preferential Right. If such holder of such Preferential Right thereafter fails to consummate the purchase of the Assets subject to such Preferential Right in accordance with the terms thereof, the time for exercising such Preferential Right has expired and such Preferential Right has not been exercised, or the Preferential Right has been waived, (i)

Seller shall so notify Purchaser, (ii) Purchaser shall purchase, on or before ten (10) Business Days following receipt of such notice, such Assets that were so excluded from the Assets to be assigned to Purchaser at Closing, for a price equal to the amount by which the Purchase Price was reduced at Closing with respect to such excluded Assets and on the same other terms of this Agreement, including the adjustments in accordance with Section 3.2 and Section 3.3, and (iii) Seller shall assign to Purchaser such Assets so excluded at Closing pursuant to an instrument in substantially the same form as the Assignment.

(c) If Seller fails to obtain a Required Consent prior to Closing, then, in each case, the Asset affected by such un-obtained Required Consent (together with all Assets directly relating thereto but only to the extent relating thereto) shall be excluded from the Assets to be assigned to Purchaser at Closing, and the Purchase Price shall be reduced by the Allocated Value of such Assets so excluded. In the event that any such Required Consent (with respect to Assets excluded pursuant to this Section 4.8(c)) that was not obtained prior to the Closing Date is obtained within ninety (90) days following the Closing Date, then, within ten (10) Business Days after such Required Consent is obtained, (i) Seller shall so notify Purchaser, (ii) Purchaser shall purchase, on or before ten (10) Business Days following receipt of such notice, such Assets that were so excluded from the Assets to be assigned to Purchaser at Closing, for a price equal to the amount by which the Purchase Price was reduced at Closing with respect to such excluded Assets and on the same other terms of this Agreement, including the adjustments in accordance with Section 3.2 and Section 3.3, and (iii) Seller shall assign to Purchaser the Assets so excluded at Closing pursuant to an instrument in substantially the same form as the Assignment. If, prior to Closing, Seller fails to obtain a consent to assign and such consent to assign is not a Required Consent, then the Assets subject to such un-obtained consent shall be assigned by Seller to Purchaser at Closing as part of the Assets and Purchaser shall have no claim against Seller, Purchaser hereby releases and indemnifies the Seller Parties from any Losses relating to the failure to obtain such consent, and Purchaser shall be solely responsible for any and all Losses arising from the failure to obtain such consent.

Section 4.9 **Environmental Assessment**.

(a) Prior to the Defect Notice Date, and upon reasonable prior notice to Seller (and notice and consent of the operator(s) of any of the Assets not operated by Seller or its Affiliates), and subject to the other provisions of this Section 4.9 and the indemnity provisions of Section 7.4 below, Purchaser shall have the right to enter upon the Assets, inspect the same and conduct such tests, examinations, investigations, and studies as may be necessary or appropriate to determine the environmental condition of the Assets (" **Purchaser's Environmental Assessment**"). Any such entry onto the Assets is subject to all third-party restrictions, if any, and to Seller's safety, health and environmental policies and procedures, including drug, alcohol and firearms restrictions, and shall be at Purchaser's sole risk and expense. Purchaser shall coordinate its access rights, environmental property assessments and physical inspections of the Assets with Seller and all third party operators, as applicable, to minimize any inconvenience to or interruption of the conduct of business by Seller or any such third party operator.

(b) Notwithstanding anything herein to the contrary, for anything other than a Phase I environmental property assessment, Purchaser must obtain Seller's prior written consent (which consent may be withheld in Seller's sole discretion) and any third party operator's consent as to the scope of any proposed environmental assessment, including testing protocols.

(c) In conducting any assessment or inspection of the Assets, Purchaser shall not operate any equipment or (except with the prior written consent of Seller, which consent may be withheld in Seller's sole discretion, and any third party operator's consent) conduct any testing or sampling of soil, groundwater or other materials (including any testing or sampling for hazardous substances or NORM).

(d) Seller or Seller's designee shall have the right to be present during any stage of any inspection or assessment by Purchaser on the Assets.

(e) During all periods prior to Closing that Purchaser or any of its representatives (including Purchaser's environmental consulting or engineering firm) are on the Assets, Purchaser shall maintain, at its sole cost and expense, and with insurers reasonably satisfactory to Seller, policies of insurance of the types and in the amounts reasonably requested by Seller. Coverage under all insurance required to be carried by Purchaser hereunder will be primary insurance. Upon request by Seller, Purchaser shall provide evidence of such insurance to Seller prior to entering the Assets.

(f) Within five (5) days of the Purchaser's receipt (if performed by a third party) or completion thereof (if performed by Purchaser), Purchaser shall deliver to seller copies of all final reports, results, data and analyses of Purchaser's Environmental Assessment. Seller shall have no confidentiality obligation with regard to such information so provided and Seller shall not be deemed (by Seller's receipt of said documents or otherwise) to have made any representation or warranty, express, implied or statutory, as to the condition of the Assets or to the accuracy of said documents or the information contained therein.

(g) Upon completion of Purchaser's due diligence, Purchaser shall at its sole cost and expense and without any cost or expense to Seller or its Affiliates, (i) repair all damage done to the Assets (including the real property and other assets associated therewith) in connection with Purchaser's due diligence investigation, (ii) restore the Assets (including the real property and other assets associated therewith) to at least the approximate same condition than they were prior to commencement of Purchaser's due diligence investigation, and (iii) remove all equipment, tools or other property brought onto the Assets in connection with such due diligence investigation. Any disturbance to the Assets (including the real property and other assets associated therewith) resulting from the due diligence investigation conducted by or on behalf of Purchaser will be promptly corrected by Purchaser.

Section 4.10 **Environmental Defect Notice**. If Purchaser determines, as a result of Purchaser's Environmental Assessment or otherwise that there exists an Environmental Defect, Purchaser shall notify Seller thereof in writing as soon as practicable after Purchaser has knowledge thereof, but in any event prior to the Defect Notice Date (each an " **Environmental Defect Notice**"). For all purposes of this Agreement and notwithstanding anything herein to the contrary, Purchaser shall be deemed to have waived, and Seller shall have no liability for, any Environmental Defect that Purchaser fails to assert as an Environmental Defect by an Environmental Defect Notice received by Seller on or before the Defect Notice Date. To be effective, each Environmental Defect Notice shall include: (a) a detailed description of the alleged Environmental Defect, (b) the Well or other Asset affected by such Environmental Defect (each an "**Environmental Defect Property**"), (c) the Allocated Value of such Environmental Defect Property, (d) supporting documents reasonably necessary for Seller to verify the existence of the asserted Environmental Defect, (e) the specific Environmental Law that is applicable to the Environmental Defect and the violation of such Environmental Law and (f) Purchaser's good faith estimate of the Remediation Amount. Purchaser's calculation of the Remediation Amount included in the Environmental Defect Notice for any alleged Environmental Defect must describe in reasonable detail the Remediation proposed for such Environmental Defect and identify all assumptions used by Purchaser in calculating the Remediation Amount with respect thereto, including the standards that Purchaser asserts must be met to comply with Environmental Laws. Seller shall have the right but not the obligation to attempt to Remediate any Environmental Defect Property and, if Seller so elects, then Seller shall have sixty (60) days following Closing in which to Remediate, at Seller's cost, the Environmental Defect. No adjustment to the Purchase Price will be made at Closing for any Environmental Defect that Seller elects to attempt to cure pursuant to this Section 4.10 and the affected Environmental Defect Property shall be assigned to Purchaser. If such Environmental Defect Property has not been remediated at the end of such sixty (60) day period, then (except as provided in Section 4.11(a)) an adjustment to the Purchase Price in an amount equal to the applicable Remediation Amount will be made as part of the Final Settlement Statement.

Section 4.11 **Remedies for Environmental Defects**. Subject to Seller's continuing right to dispute the existence of an Environmental Defect and/or the Remediation Amount asserted with respect thereto and subject to the Individual Environmental Defect Threshold and the Aggregate Environmental Defect Deductible, with respect to any Environmental Defect asserted by Purchaser that (i) Seller does not elect to attempt to Remediate or (ii) Seller elects to attempt to Remediate and fails to Remediate within sixty (60) days after Closing:

(a) Seller shall have the right, but not the obligation, to elect to indemnify Purchaser against all Losses resulting from such Environmental Defect pursuant to an indemnity agreement in a form mutually agreeable to the Parties, in which event the Purchase Price shall not be reduced and the affected Environmental Defect Property shall be transferred to (or if after Closing, retained by) Purchaser notwithstanding and subject to such Environmental Defect;

(b) at or prior to the Closing, Seller shall have the right, but not the obligation, to elect to exclude the Asset subject to the Environmental Defect from the transactions contemplated hereby, in which event such Asset and all Assets directly relating thereto (but only to the extent relating thereto) shall be excluded from the transactions contemplated hereby and the Purchase Price shall be reduced by the Allocated Value of such Asset and related Assets; or

(c) if both Section 4.11(a) and Section 4.11(b) above are not applicable, the affected Environmental Defect Property shall be transferred to (or if after Closing, retained by) Purchaser notwithstanding and subject to the Environmental Defect, and the Purchase Price shall be reduced by an amount equal to the Remediation Amount for the affected Environmental Defect Property.

Except for Purchaser's rights to terminate this Agreement pursuant to Section 15.1(d), the provisions set forth in this Section 4.11 shall be the exclusive right and remedy of Purchaser with respect to any Environmental Defect or the environmental condition of any Asset and Purchaser hereby waives all other rights and remedies.

Section 4.12 **Environmental Limitations**. Notwithstanding anything to the contrary, (a) in no event shall there be any adjustments to the Purchase Price or other remedies provided by Seller for any individual Environmental Defect for which the Remediation Amount does not exceed ONE HUNDRED THOUSAND DOLLARS ($100,000.00) (the "**Individual Environmental Defect Threshold**"); and (b) in no event shall there be any adjustments to the Purchase Price or other remedies provided by Seller for any Environmental Defect that exceeds the Individual Environmental Defect Threshold unless the sum of all Remediation Amounts of all Environmental Defects that exceed the Individual Environmental Defect Threshold (excluding any Environmental Defects remediated by Seller) exceeds five percent (5%) of the Purchase Price (the "**Aggregate Environmental Defect Deductible**"), after which point Purchaser shall be entitled to adjustments to the Purchase Price or other remedies only with respect to such Environmental Defects in excess of such Aggregate Environmental Defect Deductible (after reducing the value of each such Environmental Defect by the Individual Environmental Defect Threshold). For the avoidance of doubt, if Seller elects to exclude an Asset affected by an Environmental Defect from the transactions contemplated hereby pursuant to the remedy set forth in Section 4.11(b) or indemnify Purchaser with respect to any Environmental Defect pursuant to the remedy set forth in Section 4.11(a), then, after such election, the Remediation Amount for such Environmental Defect and related Purchase Price adjustment relating to such excluded Assets or such Assets for which Seller has provided an indemnity to Purchaser will not be counted towards the Aggregate Environmental Defect Deductible or for purposes of Section 8.4 and Section 9.4.

Section 4.13 **Casualty Loss**.

(a) Notwithstanding anything herein to the contrary from and after the Effective Time, subject to the remaining provisions of this Section 4.13, if Closing occurs, Purchaser shall assume all risk of loss with respect to production of Hydrocarbons through normal depletion (including watering out of any Well, collapsed casing or sand infiltration of any Well) and the depreciation of all Wells and/or personal property due to ordinary wear and tear, in each case, with respect to the Assets.

(b) If, after the date of the execution of this Agreement but prior to the Closing Date, any portion of the Assets is destroyed or taken in connection with a Casualty Loss and the loss in value of such Assets as a result of such Casualty Loss (net to Seller's interest in the Assets), in the aggregate, exceeds five percent (5%) of the Purchase Price, then, subject to Section 15.1(d), Purchaser shall nevertheless be required to close and Seller shall elect by written notice to Purchaser prior to Closing: (i) with Purchaser's consent, to cause the Assets adversely affected by any such Casualty Loss to be repaired or restored to at least their condition prior to such Casualty Loss, at Seller's sole cost and expense, as promptly as reasonably practicable (which repair or restoration may extend after Closing), (ii) to exclude the Assets adversely affected by such Casualty Loss and any Asset related thereto (to the extent so related) and reduce the Purchase Price by the Allocated Value of such excluded Assets or (iii) to assign the Assets adversely affected by such Casualty Loss and reduce the Purchase Price by the loss in value of such Assets as a result of such Casualty Loss. In each case, Seller shall retain all right, title and interest (if any) in insurance claims, unpaid awards and other rights (in each case) against third parties arising out of such Casualty Loss with respect to the Assets, except to the extent the Parties otherwise agree in writing.

(c) If, after the date of the execution of this Agreement but prior to the Closing Date, any Casualty Loss occurs, and the loss in value of the Assets as a result of such Casualty Loss (net to Seller's interest in the Assets), in the aggregate, is equal to or less than five percent (5%) of the Purchase Price, then, subject to Section 15.1(d), Purchaser shall nevertheless be required to close and Seller, at Closing, shall pay to Purchaser all sums received by Seller from unaffiliated third parties by reason of such Casualty Losses insofar as with respect to the Assets and Seller shall assign, transfer and set over to Purchaser or subrogate Purchaser to all of Seller's right, title and interest (if any) in unpaid awards and other rights (in each case) against unaffiliated third parties (excluding, for the avoidance of doubt, any Losses against any member of the Seller Parties) arising out of such Casualty Losses insofar as with respect to the Assets (provided, however, that Seller shall reserve and retain all rights, title, interests and claims against such third parties for the recovery of Seller's costs and expenses incurred prior to Closing in pursuing or asserting any such insurance claims or other rights against such third parties with respect to any such Casualty Loss).

(d) Notwithstanding the foregoing, if the Casualty Loss consists of any taking under condemnation or eminent domain, the Purchase Price shall be reduced by the Allocated Value of such Assets so taken.

ARTICLE V
REPRESENTATIONS AND WARRANTIES OF SELLER

Seller represents and warrants to Purchaser as follows:

Section 5.1 **Organization, Existence and Qualification**. Seller is an entity duly formed and validly existing under the Laws of the State of Delaware and in good standing under the laws of the State of Delaware. Seller has all requisite power and authority to own and operate the Assets and to carry on its business with respect thereto as currently conducted. Seller is duly licensed or qualified to do business as a limited liability company in all jurisdictions in which the Assets are located, except where the failure to be so qualified would not reasonably be expected to have a Material Adverse Effect.

Section 5.2 **Authority, Approval and Enforceability**. Seller has the power and authority to enter into and perform this Agreement and all Transaction Documents to be delivered at Closing by Seller and the transactions contemplated hereby and thereby. The execution, delivery and performance by Seller of this Agreement have been, and the Transaction Documents to which Seller is a party will be at Closing, duly and validly authorized and approved by all necessary limited liability company action on the part of Seller. This Agreement is, and the Transaction Documents to which Seller is a party when executed and delivered by Seller will be, the valid and binding obligation of Seller and enforceable against Seller in accordance with their respective terms, subject to the effects of bankruptcy, insolvency, reorganization, moratorium and similar Laws, as well as to principles of equity (regardless of whether such enforceability is considered in a proceeding in equity or at Law).

Section 5.3 **No Conflicts**. Assuming the receipt of all applicable consents and approvals in connection with the transactions contemplated hereby and the waiver of, or compliance with, all Preferential Rights applicable to the transactions contemplated hereby, the execution, delivery and performance of this Agreement, and the Transaction Documents to be delivered by Seller at Closing, by Seller, and the consummation by Seller of the transactions contemplated hereby and thereby, will not (a) violate any provision of the organizational documents of Seller, (b) violate, or result in the creation of any Encumbrance under, any material agreement or instrument to which Seller is a party or by which Seller or any of the Assets are bound, (c) violate any judgment, order, ruling, or decree applicable to Seller as a party in interest, or (d) violate any Law applicable to Seller relating to the Assets, except in the case of subsection (b), (c) or (d) where such violation would not reasonably be expected to have a Material Adverse Effect.

Section 5.4 **Asset Taxes**. To Seller's Knowledge, except as set forth on Schedule 5.4, (a) all tax returns relating to or prepared in connection with material Asset Taxes that are required to be filed by Seller have been timely filed and all such tax returns are correct and complete in all material respects and (b) all material Asset Taxes that are or have become due have been timely paid in full, and Seller is not delinquent in the payment of any such Taxes, or, in either case, such Taxes are currently being contested in good faith by Seller.

Section 5.5 **Bankruptcy**. There are no bankruptcy or receivership proceedings pending, being contemplated by or, to Seller's Knowledge, threatened in writing against Seller.

Section 5.6 **Foreign Person**. Seller is not a "foreign person" within the meaning of Section 1445 of the Code.

Section 5.7 **Brokers**. Neither Seller nor any of its Affiliates has incurred any obligation or liability for brokers' or finders' fees relating to the transactions contemplated hereby for which Purchaser or any of its Affiliates will be liable or have any responsibility.

Section 5.8 **Preferential Rights**. To Seller's Knowledge, except as set forth in Schedule 5.8, there are no Preferential Rights that are applicable to the transfer of the Assets by Seller to Purchaser.

Section 5.9 **Litigation**. To Seller's Knowledge, except as set forth in Schedule 5.9or as would not reasonably be expected to have a Material Adverse Effect, as of the date of the execution of this Agreement, there is no suit, action or litigation by or before any governmental authority, and no arbitration proceedings, (in each case) pending and served on Seller, or, to Seller's Knowledge, threatened in writing, against Seller (in each case) with respect to the Assets.

Section 5.10 **Current Commitments**. To Seller's Knowledge, Schedule 5.10 sets forth, as of the date of the execution of this Agreement, all authorities for expenditures ("**AFEs**") that (a) relate to drilling or reworking a Well, or (b) are in excess of ONE HUNDRED THOUSAND DOLLARS ($100,000.00), net to Seller's interest in the Assets.

Section 5.11 **Suspense Funds**. Except as set forth in Schedule 5.11, as of the date set forth on such Schedules, neither Seller nor its Affiliates holds (in escrow or otherwise) any Suspense Funds that Seller shall transfer to Purchaser.

Section 5.12 **Payment of Royalties**. To Seller's Knowledge, Seller has in all material respects properly and timely paid, or caused to be paid, all royalties, overriding royalties, net profits interests, production payments and other similar burdens measured by or payable out of production of Hydrocarbons due with respect the Assets.

Section 5.13 **Imbalance Volumes**. To Seller's Knowledge, except as disclosed on Schedule 5.13, there are no material Imbalances associated with the Assets.

Section 5.14 **Material Contracts.**

(a) To Seller's Knowledge, Schedule 5.14 sets forth all Existing Contracts of the type described below as of the date of the execution of this Agreement (the Existing Contracts contained on such Schedule, collectively, the "**Material Contracts**"):

(i) any Existing Contract that can reasonably be expected to result in aggregate payments of more than TWO HUNDRED FIFTY THOUSAND DOLLARS ($250,000.00) (net to Seller's interest) during the current or any subsequent fiscal year (based solely on the terms thereof and current volumes, without regard to any expected increase in volumes or revenues);

(ii) any Existing Contract that can reasonably be expected to result in aggregate revenues of more than TWO HUNDRED FIFTY THOUSAND DOLLARS ($250,000.00) (net to Seller's interest) during the current or any subsequent fiscal year (based solely on the terms thereof and current volumes, without regard to any expected increase in volumes or revenues);

(iii) any Existing Contract that is a Hydrocarbon purchase and sale, transportation, processing or similar Existing Contract and that is not terminable without penalty upon ninety (90) days or less notice;

(iv) any Existing Contract that is an indenture, mortgage, loan, credit or sale-leaseback or similar Existing Contract;

(v) any Existing Contract between any Seller and any Affiliate of any Seller that will not be terminated prior to Closing; and

(vi) any Existing Contract that (A) contains or constitutes an existing area of mutual interest agreement or (B) includes non-competition restrictions or other similar restrictions on doing business.

To Seller's Knowledge, except as set forth in Schedule 5.14, and except for such matters that, individually or in the aggregate, would not reasonably be expected to have a Material Adverse Effect, there exists no default under any Material Contract by Seller or by any other Person that is a party to such Material Contract.

Section 5.15 **Compliance with Laws**. To Seller's Knowledge, the Assets have been owned and operated by Seller in compliance with all applicable Laws, excluding Environmental Laws, except where such failures to be in compliance, individually or in the aggregate, would not reasonably be expected to have a Material Adverse Effect. Notwithstanding the foregoing, to the extent that Seller has made any representations or warranties in this Article V in connection with matters relating to any Assets not operated by Seller, each and every such representation and warranty shall be deemed to be qualified by the phrase "To Seller's Knowledge" to the extent such individual representations or warranties does not already contain such qualification.

ARTICLE VI
REPRESENTATIONS AND WARRANTIES OF PURCHASER

Purchaser represents and warrants to Seller as follows:

Section 6.1 **Organization, Existence and Qualification**. Purchaser is an entity duly formed and validly existing under the Laws of the State of Delaware and in good standing under the laws of the State of Delaware. Purchaser has all requisite power and authority to own and operate its property (including interests in the Assets following Closing) and to carry on its business with respect thereto. Purchaser is duly licensed or qualified to do business as a limited liability company in all jurisdictions in which the Assets are located, except where the failure to be so qualified would not reasonably be expected to have a material adverse effect on Purchaser's ability to consummate the transactions contemplated by this Agreement and perform its obligations hereunder.

Section 6.2 **Authority, Approval and Enforceability**. Purchaser has the power and authority to enter into and perform this Agreement and all Transaction Documents to be delivered at Closing by Purchaser and the transactions contemplated hereby and thereby. The execution, delivery and performance by Purchaser of this Agreement have been, and the Transaction Documents to which Purchaser is a party will be at Closing, duly and validly authorized and approved by all necessary limited liability company action on the part of Purchaser. This Agreement is, and the Transaction Documents to which Purchaser is a party when executed and delivered by Purchaser will be, the valid and binding obligation of Purchaser and enforceable against Purchaser in accordance with their respective terms, subject to the effects of bankruptcy, insolvency, reorganization, moratorium and similar Laws, as well as to principles of equity (regardless of whether such enforceability is considered in a proceeding in equity or at Law).

Section 6.3 **No Conflicts**. The execution, delivery and performance of this Agreement, and the Transaction Documents to be delivered by Purchaser at Closing, by Purchaser, and the consummation by Purchaser of the transactions contemplated hereby and thereby, will not violate any provision of the organizational documents of Purchaser, (b) violate or result in the creation of any Encumbrance under any material agreement or instrument to which Purchaser is a party or by which its assets are subject (c) violate any judgment, order, ruling, or decree applicable to Purchaser as a party in interest, or (d) violate any Law applicable to Purchaser, except in the case of subsection (b), (c) or (d) where such violation would not reasonably be expected to have a material adverse effect on Purchaser's ability to consummate the transactions contemplated by this Agreement and perform its obligations hereunder.

Section 6.4 **Bankruptcy**. There are no bankruptcy or receivership proceedings pending, being contemplated by or, to Purchaser's knowledge, threatened in writing against Purchaser.

Section 6.5 **Brokers**. Neither Purchaser nor any of its Affiliates has incurred any obligation or liability for brokers' or finders' fees relating to the transactions contemplated hereby for which Seller or any of its Affiliates will be liable or have any responsibility.

Section 6.6 **Consents**. There are no requirements for consents or approvals from third parties in connection with the consummation by Purchaser of the transactions contemplated by this Agreement.

Section 6.7 **No Distribution**. Purchaser is acquiring the Assets for its own account and not with the intent to make a distribution in violation of the Securities Act of 1933, as amended (and the rules and regulations pertaining thereto), or in violation of any other applicable securities Laws.

Section 6.8 **Knowledge and Experience**. Purchaser is sophisticated in the evaluation, purchase, ownership and operation of oil and gas properties and related facilities. In making its decision to enter into this Agreement and to consummate the transactions contemplated hereby, Purchaser has solely relied (a) on the representations and warranties of Seller set forth in Article V and (b) on its own independent investigation and evaluation of the Assets and the advice of its own legal, Tax, economic, environmental, engineering, geological and geophysical advisors and not on any comments, statements, projections or other material made or given by any representative, consultant or advisor of Seller. Purchaser hereby acknowledges that, other than the representations and warranties made by Seller in Article V and the special warranty of title with respect to the Wells, neither Seller nor any representatives, consultants or advisors of Seller or its Affiliates will make or have made any representation or warranty, express or implied, at Law or in equity, with respect to the Assets. Purchaser is able to bear the risks of the acquisition of the Assets, and assumption of the obligations, in accordance with and as set forth in this Agreement, and understands the risks of, and other considerations relating to, a purchase of the Assets.

Section 6.9 **Regulatory**. No later than five (5) days prior to the Scheduled Closing Date, Purchaser shall be qualified to own and assume operatorship of oil, gas and mineral leases in all jurisdictions where the Assets are located, and the consummation of the transactions contemplated by this Agreement will not cause Purchaser to be disqualified as such an owner or operator. To the extent required by any applicable Laws, Purchaser shall, as of the Scheduled Closing Date, (a) hold all lease bonds and any other surety or similar bonds as may be required by, and in accordance with, all applicable Laws governing the ownership and operation of the Assets and (b) have filed any and all required reports necessary for such ownership and operation with all governmental authorities having jurisdiction over such ownership and operation.

Section 6.10 **Funds**. Purchaser has, and at the Closing will have such funds as are necessary for the payment of the Purchase Price and the consummation by Purchaser of the transactions contemplated hereby, including the performance of all of Purchaser's obligations hereunder.

ARTICLE VII
PRE-CLOSING COVENANTS OF THE PARTIES

Section 7.1 **Operations**.

(a) Except (w) as set forth in Schedule 7.1, (x) for the operations covered by the AFEs described in Schedule 5.10, (y) as required in the event of an emergency to protect life, property or the environment, and (z) as expressly contemplated by this Agreement or as expressly consented to in writing by Purchaser (which consent shall not be unreasonably delayed, withheld or conditioned), Seller shall, during the Interim Period:

(i) operate or, in the case of those Assets not operated by Seller or its Affiliates, use its commercially reasonable efforts to cause to be operated, the Assets in the usual, regular and ordinary manner consistent with past practice, subject to (A) Seller's right to comply with the terms of the Leases, Existing Contracts, applicable Laws and requirements of governmental authorities and (B) interruptions resulting from force majeure, mechanical breakdown and planned maintenance; and

(ii) maintain, or cause to be maintained, the books of account and Records relating to the Assets in the usual, regular and ordinary manner and in accordance with the past practices of Seller.

(b) Except (w) as set forth in Schedule 7.1, (x) for the operations covered by the AFEs described in Schedule 5.10, (y) as required in the event of an emergency to protect life, property or the environment, and (z) as expressly contemplated by this Agreement or as expressly consented to in writing by Purchaser (which consent shall not be unreasonably delayed, withheld or conditioned), Seller shall not, during the Interim Period:

(i) terminate (unless the term thereof expires pursuant to the provisions existing therein), materially amend, extend or surrender any rights under any Lease or Right-of-Way; provided that Seller shall be permitted to amend any Lease to increase its pooling authority;

(ii) subject to Section 7.1(d), propose or approve any individual AFE or similar request under any Existing Contract (other than those expressly required under the terms of any Existing Contract or by any order of a governmental authority) that would reasonably be estimated to require expenditures by Seller (net to its interest) in excess of ONE HUNDRED THOUSAND DOLLARS ($100,000.00).

(iii) transfer, sell, mortgage, pledge or dispose of any material portion of the Assets other than the (A) sale and/or disposal of Hydrocarbons in the ordinary course of business and (B) sales of equipment that is no longer necessary in the operation of the Assets or for which replacement equipment has been obtained; or

(iv) commit to do any of the foregoing.

(c) Purchaser acknowledges Seller owns undivided interests in certain of the properties comprising the Assets that it is not the operator thereof, and Purchaser agrees that the acts or omissions of the other Working Interest owners (including the operators) who are not Seller or any Affiliates of Seller shall not constitute a breach by Seller of the provisions of this Section 7.1, nor shall any action required by a vote of Working Interest owners constitute such a breach so long as Seller has voted its interest in a manner that complies with the provisions of this Section 7.1.

(d) With respect to any AFE or similar request received by Seller that is estimated to cost in excess of ONE HUNDRED THOUSAND DOLLARS ($100,000.00), Seller shall forward such AFE to Purchaser as soon as is reasonably practicable and thereafter the Parties shall consult with each other regarding whether or not Seller should elect to participate in such operation. Purchaser agrees that it will (i) timely respond to any written request for consent pursuant to this Section 7.1(d), and (ii) consent to any written request for approval of any AFE or similar request that Purchaser reasonably considers to be economically viable. In the event the Parties are unable to agree within ten (10) days (unless a shorter time, not to be less than 48 hours, is reasonably required by the circumstances and the applicable joint operating agreement and such shorter time is specified in Seller's request for consent) of Purchaser's receipt of any consent request as to whether or not Seller should elect to participate in such operation, Seller's decision shall control and such operation shall be deemed to have been consented to by Purchaser.

Section 7.2 **Governmental Bonds**. Purchaser acknowledges that none of the bonds, letters of credit and guarantees, if any, posted by Seller or its Affiliates with governmental authorities and relating to the Assets are transferable to Purchaser. On or before the Closing Date, Purchaser shall obtain replacements for all such bonds, letters of credit and guarantees to the extent such replacements are necessary for Purchaser's ownership and/or operation of the Assets. At Closing, Purchaser shall cause the cancellation of the bonds, letters of credit and guarantees posted by Seller of its Affiliates with respect to the Assets.

Section 7.3 **Amendment of Schedules**. Purchaser agrees that, with respect to the representations and warranties of Seller contained in this Agreement, Seller shall have the continuing right until the Closing to add, supplement or amend the Schedules to its representations and warranties with respect to any matter hereafter arising or discovered which, if existing or known at the date of the execution of this Agreement or thereafter, would have been required to be set forth or described in such Schedules. For purposes of determining whether the conditions set forth in Article VIII have been fulfilled, the Schedules to Seller's representations and warranties contained in this Agreement shall be deemed to include only that information contained therein on the date of the execution of this Agreement and shall be deemed to exclude all information contained in any addition, supplement or amendment thereto; provided, however, that if the Closing shall occur, then all matters disclosed pursuant to any such addition, supplement or amendment at or prior to the Closing shall be waived and Purchaser shall not be entitled to make a claim with respect thereto pursuant to the terms of this Agreement or otherwise.

Section 7.4 **Indemnity Regarding Access**. Purchaser hereby defends, indemnifies and holds harmless each of the operators of the Assets and the Seller Group from and against any and all Losses arising out of, resulting from or relating to, any field visit, environmental property assessment, or other due diligence activity conducted by Purchaser or any Purchaser's Affiliates or their respect representatives (including any environmental consultant or landman) with respect to the Assets, **EVEN IF SUCH LOSSES ARISE OUT OF OR RESULT FROM, SOLELY OR IN PART, THE SOLE, ACTIVE, PASSIVE, CONCURRENT OR COMPARATIVE NEGLIGENCE, STRICT LIABILITY OR OTHER FAULT OR VIOLATION OF LAW OF OR BY A MEMBER OF THE SELLER GROUP PARTIES, EXCEPTING ONLY IN THE CASE OF THIS SECTION 7.4 LOSSES ACTUALLY RESULTING ON THE ACCOUNT OF THE GROSS NEGLIGENCE OR WILLFUL MISCONDUCT OF A MEMBER OF**

THE SELLER GROUP. For the avoidance of doubt, this indemnity shall survive any termination of this Agreement, if applicable, and the Closing.

Section 7.5 **Financial Security**.

(a) As a condition of Closing, Purchaser will deliver to Seller at Closing an irrevocable performance bond in the amount of FIVE MILLION DOLLARS ($5,000,000.00) in favor of Seller (the "**Performance Bond**") as evidence of Purchaser's financial security to guarantee Purchaser's obligations provided in Section 11.1(b). The Performance Bond shall be in a form substantially similar to the form attached as Exhibit I, issued by a financial institution acceptable to Seller, as Surety, being one with an A.M. Best Financial Strength Rating of "A" and an A.M. Best's Financial Size Category of XII.

(b) Upon occurrence of any of the following, Seller may draw on the Performance Bond, in whole or in part, without prior notice to Purchaser: (i) Seller is required in any manner to perform any Plugging and Abandonment Obligations, whether pursuant to an order or directive issued by a governmental body or regulatory agency or otherwise; (ii) Purchaser is in default of any Plugging and Abandonment Obligation and Seller has opted to therefore perform any or all such obligations of Purchaser (provided however that nothing herein shall be construed as imposing an obligation upon Seller to so perform); or (iii) Purchaser commences proceedings or has proceedings commenced against it (which proceedings are not stayed within twenty-one (21) days of service thereof on Purchaser) in the nature of bankruptcy resulting from the insolvency or its liquidation or for the appointment of a receiver, administrator, trustee in bankruptcy or liquidator or its undertakings or assets. Provided, however, that a reorganization bankruptcy such as a Chapter 11 shall not be an event of default if Purchaser does not reject the Plugging and Abandonment Obligation, the Performance Bond remains in place and Purchaser is not in default of any Plugging and Abandonment Obligations.

(c) Seller shall release the Performance Bond in favor of Seller on or before the date that is one hundred and twenty (120) days from the date of receipt of evidence reasonably satisfactory to it that Purchaser has performed all obligations to abandon, restore and Remediate the Assets contemplated by Section 11.1(b). For purposes of this Section 7.5 and Section 11.1(b), evidence that a Plugging and Abandonment Obligation has been performed shall include written documentation as may be provided by any governmental authority under applicable law to reflect completion of a Plugging and Abandonment Obligation (including, without limitation, forms and documentation related to plugging and abandonment activities, decommissioning activities, site clearance activities and pipeline abandonment or removal activities and completion of remediation activities). Until such time as all of the Plugging and Abandonment Obligations with respect to the Assets have been performed, Seller reserves access rights to the Assets for the limited purpose of performing, documenting and/or verifying the Plugging and Abandonment Obligations, as needed.

(d) The provisions of this Section 7.5 are (i) binding on all successors and assigns of Purchaser with respect to any of the Assets and (ii) covenants running with the Assets. For the avoidance of doubt, in the event Purchaser sells, assigns or otherwise transfers less than all of the Wells to a transferee, the transferee shall be required to obtain a Performance Bond as set forth herein with respect to such transferee shall apply as to the Assets so sold, assigned or otherwise transferred, but shall not relieve Purchaser's obligation to maintain the Performance Bond as to any Assets it retains.

ARTICLE VIII
PURCHASER'S CONDITIONS TO CLOSING

The obligations of Purchaser to consummate the transactions provided for herein are subject, at the option of Purchaser, to the fulfillment by Seller or waiver by Purchaser, on or prior to Closing of each of the following conditions:

Section 8.1 **Representations**. Each of the representations and warranties of Seller set forth in Article V shall be true and correct in all respects on and as of the Closing Date, with the same force and without giving effect to any qualifiers as to materiality, including Material Adverse Effect, as though such representations and warranties had been made or given on and as of the Closing Date (other than representations and warranties that refer to a specified date, which need only be true and correct on and as of such specified date), except for those breaches, if any, of such representations and warranties that in the aggregate would not have a Material Adverse Effect.

Section 8.2 **Performance**. Seller shall have performed or complied in all material respects with all obligations, agreements, and covenants contained in this Agreement as to which performance or compliance by Seller is required prior to or at the Closing Date.

Section 8.3 **No Legal Proceedings**. No suit, action, or other proceeding by any unaffiliated third party shall be pending by or before any governmental authority seeking to restrain, prohibit, enjoin, or declare illegal, or seeking substantial damages in connection with, the transactions contemplated by this Agreement.

Section 8.4 **Title Defects, Environmental Defects and Casualty Loss**. Without giving effect to the Aggregate Title Defect Deductible or the Aggregate Environmental Defect Deductible, the sum of (a) the Title Defect Amounts of all uncured Title Defects exceeding the Individual Title Defect Threshold, plus (b) all Remediation Amounts for uncured Environmental Defects exceeding the Individual Environmental Defect Threshold, plus (c) the amount of loss in value of the Assets resulting from all Casualty Losses, as determined in accordance with Section 4.13, minus the aggregate Title Benefit Amounts of all Title Benefits as determined pursuant to Section 4.7, shall be less than twenty-five percent (25%) of the Purchase Price.

Section 8.5 **Closing Certificate**. Seller shall have executed and delivered to Purchaser an officer's certificate, dated as of the Closing Date and substantially in the form of Exhibit F, certifying that the conditions set forth in Section 8.1 and Section 8.2 have been fulfilled and, if applicable, any exceptions to such conditions that have been waived by Purchaser.

Section 8.6 **Closing Deliverables**. Seller shall have delivered (or be ready, willing and able to deliver at Closing) to Purchaser the documents required to be delivered by Seller at Closing.

ARTICLE IX
SELLER'S CONDITIONS TO CLOSING

The obligations of Seller to consummate the transactions provided for herein are subject, at the option of Seller, to the fulfillment by Purchaser or waiver by Seller on or prior to Closing of each of the following conditions:

Section 9.1 **Representations**. Each of the representations and warranties of Purchaser set forth in Article VI shall be true and correct in all material respects on and as of the Closing Date, with the same force and effect as though such representations and warranties had been made or given on and as of the Closing Date (other than representations and warranties that refer to a specified date, which need only be true and correct on and as of such specified date).

Section 9.2 **Performance**. Purchaser shall have performed or complied in all material respects with all obligations, agreements, and covenants contained in this Agreement as to which performance or compliance by Purchaser is required prior to or at the Closing Date.

Section 9.3 **No Legal Proceedings**. No suit, action, or other proceeding by any unaffiliated third party shall be pending by or before any governmental authority seeking to restrain, prohibit, or declare illegal, or seeking substantial damages in connection with, the transactions contemplated by this Agreement.

Section 9.4 **Title Defects, Environmental Defects and Casualty Losses**. Without giving effect to the Aggregate Title Defect Deductible or the Aggregate Environmental Defect Deductible, the sum of (a) the Title Defect Amounts of all uncured Title Defects exceeding the Individual Title Defect Threshold, plus (b) all Remediation Amounts for uncured Environmental Defects exceeding the Individual Environmental Defect Threshold, plus (c) the amount of loss in value of the Assets resulting from all Casualty Losses, as determined in accordance with Section 4.13, minus the aggregate Title Benefit Amounts of all Title Benefits as determined pursuant to Section 4.7, shall be less than twenty-five percent (25%) of the Purchase Price.

Section 9.5 **Closing Certificate**. Purchaser shall have executed and delivered to Seller an officer's certificate, dated as of the Closing Date and substantially in the form of Exhibit G, certifying that the conditions set forth in Section 9.1 and Section 9.2 have been fulfilled and, if applicable, any exceptions to such conditions that have been waived by Seller.

Section 9.6 **Closing Deliverables**. Purchaser shall have delivered (or be ready, willing and able to deliver at Closing) to Seller the documents and other items required to be delivered by Purchaser at Closing.

ARTICLE X

CLOSING

Section 10.1 **Time and Place of Closing**. The consummation of the transactions contemplated by this Agreement (the " **Closing**") shall be held on April 26, 2021 (the "**Scheduled Closing Date**"), at Seller's offices at 22777 Springwoods Village Parkway, Spring, Texas 77389; provided that if all of the conditions to that Closing are not satisfied as of the Scheduled Closing Date, then Closing shall be held three (3) Business Days after all such conditions have been satisfied or waived, or such other date as the Parties may mutually agree in writing, but in no event later than May 11, 2021 (the "**Longstop Date**").

Section 10.2 **Calculation of Adjusted Purchase Price**. Not less than five (5) Business Days prior to the Closing, Seller shall prepare and submit to Purchaser for review a draft settlement statement (the "**Preliminary Settlement Statement**") that shall set forth (a) the Adjusted Purchase Price, reflecting each adjustment made in accordance with this Agreement as of the date of preparation of such Preliminary Settlement Statement and the itemized calculation (recognizing that Seller may elect to use reasonable good faith estimates in the Preliminary Settlement Statement) and (b) the designation of Seller's accounts for the wire transfers of funds at Closing. Within two (2) Business Days of receipt of the Preliminary Settlement Statement, Purchaser will deliver to Seller a written report containing all changes with the explanation therefor that Purchaser proposes to be made to the Preliminary Settlement Statement. The Preliminary Settlement Statement, as agreed upon by the Parties, will be used to adjust the Purchase Price at Closing; provided that if the Parties do not agree upon an adjustment set forth in the Preliminary Settlement Statement, then the amount of such adjustment used to adjust the Purchase Price at Closing shall be that amount set forth in the draft Preliminary Settlement Statement delivered by Seller to Purchaser pursuant to this Section 10.2. Final adjustments to the Purchase Price shall be made pursuant to Section 12.1 below.

Section 10.3 **Failure to Close**. If the conditions to Closing have been satisfied or waived on or before the Longstop Date, and either Party fails to close, the Party failing to close shall be deemed to have breached the obligations it has undertaken hereunder to perform at Closing, and shall be subject to the provisions of Article XV below.

Section 10.4 **Closing Obligations**. At the Closing:

(a) Seller and Purchaser shall execute, acknowledge and deliver the Assignment and Royalty Free Lease in sufficient duplicate originals to allow recording in all appropriate counties;

(b) Seller and Purchaser shall execute and deliver assignments, on appropriate forms, of state, federal, tribal and other Leases of governmental authorities included in the Assets in sufficient counterparts to facilitate filing with the applicable governmental authorities;

(c) Seller and Purchaser shall acknowledge the Preliminary Settlement Statement;

(d) Seller shall deliver to Purchaser a non-foreign entity affidavit in the form of Exhibit H;

(e) Seller, if and as applicable, shall deliver all appropriate or required forms, applications, notices, permit transfers, declarations, to be filed with the appropriate governmental authorities having jurisdiction with respect to the transfer of operatorship to Purchaser of the Assets that are operated by Seller immediately prior to the Closing;

(f) Seller and Purchaser shall execute, acknowledge and deliver transfer orders or letters in lieu thereof in customary form prepared by Seller directing all purchasers of production to make payment to Purchaser of proceeds attributable to production from the Assets from and after Closing;

(g) Purchaser shall make the payment described in Section 3.4(b);

(h) Purchaser shall furnish evidence that all requirements to own and/or operate the Assets, including bonds and permits, from any governmental authority having jurisdiction, or as required by any Existing Contract, have been satisfied;

(i) pursuant to Section 7.5, Purchaser will execute and deliver the Performance Bond; and

(j) Seller and Purchaser shall execute such other instruments and take sucho ther actions as may be necessary to carry out their respective obligations under this Agreement.

ARTICLE XI
POST-CLOSING OBLIGATIONS

Section 11.1 **Assumed Obligations**. Without limiting Purchaser's rights to indemnity under Section 11.3 (if applicable), if the Closing occurs, from and after Closing, Purchaser hereby assumes and agrees to fulfill, perform, pay and discharge all obligations and Losses, known or unknown, with respect to the Assets or the ownership, use or operation thereof, regardless of whether such obligations or Losses arose prior to, on or after the Effective Time, including obligations and Losses relating to the following (all of such obligations and Losses, the " **Assumed Obligations**"):

(a) the payment of owners of Working Interests, royalties, overriding royalties and other interests all revenues attributable thereto, including the Suspense Funds transferred to Purchaser in accordance with Section 12.2;

(b) fully performing all plugging, decommissioning and abandonment obligations related to the Assets (the "**Plugging and Abandonment Obligations**"), regardless of whether such obligations are attributable to the ownership or operation of the Assets prior to, on, or after the Effective Time, in a good and workmanlike manner and in compliance with all Laws, including:

(i) the necessary and proper plugging, replugging, and abandonment of all wells on the Assets, whether plugged and abandoned prior to, on, or after the Effective Time;

(ii) the necessary and proper removal, abandonment, decommissioning, and disposal of all structures, pipelines, facilities, equipment, abandoned property, and junk located on or comprising part of the Assets;

(iii) the necessary and proper capping and burying of all flow lines and pipelines associated with the Assets and located on or comprising part of the Assets; and

(iv) the necessary and proper restoration of the property, both surface and subsurface, as may be required by Laws or contract;

(c) furnishing make-up gas according to the terms of applicable Existing Contracts, and to satisfy all other Imbalances, if any;

(d) the environmental and physical condition of the Assets, whether such condition existed prior to, on or after the Effective Time, including Environmental Defects, if any, with respect to the Assets, whether or not asserted by Purchaser in accordance with this Agreement, including the clean-up, restoration and remediation of the Assets in accordance with applicable Law, including all Environmental Laws;

(e) obligations or Losses under or imposed on the lessee, owner, or operator under the Leases, the Existing Contracts and applicable Laws; and

(f) storing, handling, transporting and disposing of or discharging all materials, substances and wastes from the Assets (including produced water, drilling fluids, NORM, and other wastes), whether present prior to, on or after the Effective Time, in accordance with applicable Laws and contracts.

Section 11.2 **Purchaser's Indemnity**. Effective upon Closing, **REGARDLESS OF FAULT**, Purchaser shall protect, defend, indemnify and hold harmless the Seller Group from and against any and all Losses arising out of, attributable to, based upon or related to:

(a) any breach of any representation or warranty made by Purchaser in Article VI of this Agreement, in the certificate delivered by Purchaser pursuant to Section 9.6, or any covenant or agreement of Purchaser contained in this Agreement; or

(b) any of the Assumed Obligations.

Section 11.3 **Seller's Indemnity**. Effective upon Closing, **REGARDLESS OF FAULT**, Seller shall protect, defend, indemnify and hold harmless the Purchaser Group from and against any and all Losses arising out of, attributable to, based upon or related to:

(a) any breach of any representation or warranty made by Seller in Article V of this Agreement, in the certificate delivered by Seller pursuant to Section 8.6; or any covenant or agreement of Seller contained in this Agreement;

(b) the Excluded Assets;

(c) Seller's failure to pay or properly account for any royalties, other burdens on production or revenues owed to working interest owners to the extent relating to the production of Hydrocarbons from the Assets prior to the Effective Time, other than Imbalances;

(d) any personal injury or death attributable to Seller's or its Affiliates' operation of the Assets prior to the Effective Time, to the extent a claim relating thereto is asserted by third parties not Affiliated with Purchaser and for which Purchaser's indemnity in Section 7.4 does not apply;

(e) the litigation and/or administrative proceedings set forth on Schedule 11.3(e);

(f) royalty, overriding royalty, working interests and other burdens on production of Hydrocarbons from the Assets held in suspense by Seller or its Affiliates as of Closing for which an adjustment to the Purchase Price is not made pursuant to this Agreement; or

(g) matters related to taxes accruing prior to the Effective Time and more fully set forth in Article XIII.

Section 11.4 **Regardless of Fault**. The phrase "**REGARDLESS OF FAULT**" means **WITHOUT REGARD TO THE CAUSE OR CAUSES OF ANY CLAIM, INCLUDING WHETHER OR NOT A CLAIM IS CAUSED IN WHOLE OR IN PART BY**:

(a) THE NEGLIGENCE (WHETHER SOLE, JOINT, CONCURRENT, COMPARATIVE, CONTRIBUTORY, ACTIVE, PASSIVE, GROSS OR OTHERWISE) WILLFUL MISCONDUCT, STRICT LIABILITY, OR OTHER FAULT OF ANY OF THE INDEMNIFIED PARTIES; AND/OR

(b) A PRE-EXISTING DEFECT, WHETHER PATENT OR LATENT, WITH RESPECT TO THE PROPERTY OF ANY OF THE PARTIES, THEIR AFFILIATES OR THEIR RESPECTIVE REPRESENTATIVES; AND/OR THE UNSEAWORTHINESS OF ANY VESSEL OR UNAIRWORTHINESS OF ANY AIRCRAFT OR MECHANICAL FAILURE OF ANY VEHICLE OF A PARTY, ITS AFFILIATES OR ANY OF THEIR RESPECTIVE REPRESENTATIVES, WHETHER CHARTERED, LEASED, OWNED, OR FURNISHED OR PROVIDED BY ANY OF THE PARTIES, THEIR AFFILIATES OR ANY OF THEIR RESPECTIVE REPRESENTATIVES.

Section 11.5 **Limitation on Liability**.

(a) Seller shall not have any liability for any indemnification under Section 11.3(a) for any individual Loss unless the amount of such Loss exceeds ONE MILLION DOLLARS ($1,000,000.00) and (ii) until and unless the aggregate amount of all such Losses for which Claim Notices are delivered by Purchaser exceeds THREE MILLION FIVE HUNDRED THOUSAND DOLLARS ($3,500,000.00) (the "**Indemnity Deductible**") and then only to the extent such Losses exceed the Indemnity Deductible.

(b) Notwithstanding anything to the contrary contained in this Agreement, Seller shall not be required to indemnify the Purchaser Group (i) under Section 11.3(a) for aggregate Losses in excess of twenty-five percent (25%) of the Purchase Price, and (ii) otherwise under the terms of this Agreement for aggregate Losses in excess of one hundred percent (100%) of the Adjusted Purchase Price.

Section 11.6 **Exclusive Remedy.** Notwithstanding anything to the contrary contained in this Agreement, except with respect to any breach by Purchaser of its obligations to maintain the Performance Bond from and after Closing (in which event, Seller shall have all remedies at law or in equity on account of such breach), from and after the Closing, Section 4.8(c), Section 7.4, Section 11.2, Section 11.3, Section 11.12 and Section 12.2 contain the Parties' exclusive remedy against each other with respect to the transactions contemplated hereby and the sale of the Assets, including breaches of the representations, warranties, covenants and agreements of the Parties contained in this Agreement or in any document delivered pursuant to this Agreement.

Section 11.7 **Indemnification Procedures**. All claims for indemnification under Section 4.8(c), Section 7.4, Section 11.2, Section 11.3, Section 11.12 and Section 12.2 shall be asserted and resolved as follows:

(a) For purposes of this Article XI, Section 4.8(c), Section 7.4 and Section 12.2, the term "**Indemnifying Party**" when used in connection with particular Losses shall mean the Party or Parties having an obligation to indemnify another Party or Parties with respect to such Losses pursuant to such sections, and the term "**Indemnified Party**" when used in connection with particular Losses shall mean the Party or Parties having the right to be indemnified with respect to such Losses by another Party or Parties pursuant to such sections.

(b) To make claim for indemnification under this Article XI, Section 4.8(c), Section 7.4 or Section 12.2, an Indemnified Party shall notify the Indemnifying Party of its claim under this Section 11.7, including the specific details of and specific basis under this Agreement for its claim (the "**Claim Notice**"). In the event that the claim for indemnification is based upon a claim by an unaffiliated third party against the Indemnified Party (a " **Third Party Claim**"), the Indemnified Party shall provide its Claim Notice promptly after the Indemnified Party has actual knowledge of the Third Party Claim and shall enclose a copy of all papers (if any) served with respect to the Third Party Claim; provided that the failure of any Indemnified Party to give notice of a Third Party Claim as provided in this Section 11.7 shall not relieve the Indemnifying Party of its indemnification obligations under this Agreement, except to the extent (and then only to the extent) such failure materially prejudices the Indemnifying Party's ability to defend against the Claim. In the event that the claim for indemnification is based upon an inaccuracy or breach of a representation, warranty, covenant or agreement, the Claim Notice shall specify the representation, warranty, covenant or agreement that was inaccurate or breached.

(c) In the case of a claim for indemnification based upon a Third Party Claim, the Indemnifying Party shall have thirty (30) days from its receipt of the Claim Notice to notify the Indemnified Party whether it admits or denies its liability to defend the Indemnified Party against such Third Party Claim at the sole cost and expense of the Indemnifying Party. The Indemnified Party is authorized, prior to and during such thirty (30) day period, to file any motion, answer or other pleading that it shall deem necessary or appropriate to protect its interests or those of the Indemnifying Party and that is not prejudicial to the Indemnifying Party.

(d) If the Indemnifying Party admits its liability, it shall have the right and obligation to diligently defend, at its sole cost and expense, the Third Party Claim. The Indemnifying Party shall have full control of such defense and proceedings, including any compromise or settlement thereof unless the compromise or settlement includes the payment of any amount by (because of the Indemnity Deductible or otherwise), the performance of any obligation by or the limitation of any right or benefit of, the Indemnified Party, in which event such settlement or compromise shall not be effective without the consent of the Indemnified Party, which shall not be unreasonably withheld or delayed. If requested by the Indemnifying Party, the

Indemnified Party agrees to cooperate in contesting any Third Party Claim which the Indemnifying Party elects to contest. The Indemnified Party may participate in, but not control, at its own expense, any defense or settlement of any Third Party Claim controlled by the Indemnifying Party pursuant to this Section 11.7. An Indemnifying Party shall not, without the written consent of the Indemnified Party, (i) settle any Third Party Claim or consent to the entry of any judgment with respect thereto which does not include an unconditional written release of the Indemnified Party from all liability in respect of such Third Party Claim or (ii) settle any Third Party Claim or consent to the entry of any judgment with respect thereto in any manner that may materially and adversely affect the Indemnified Party (other than as a result of money damages covered by the indemnity).

(e) If the Indemnifying Party does not admit its liability (which it will be deemed to have so done if it fails to timely respond) or admits its liability but fails to diligently prosecute or settle the Third Party Claim, then the Indemnified Party shall have the right to defend against the Third Party Claim at the sole cost and expense of the Indemnifying Party, with counsel of the Indemnified Party's choosing, subject to the right of the Indemnifying Party to admit its liability and assume the defense of the Claim at any time prior to settlement or final determination thereof. If the Indemnifying Party has not yet admitted its liability for a Third Party Claim, the Indemnified Party shall send written notice to the Indemnifying Party of any proposed settlement and the Indemnifying Party shall have the option for ten (10) days following receipt of such notice to (i) admit in writing its liability for the Third Party Claim and (ii) if liability is so admitted, reject, in its reasonable judgment, the proposed settlement.

(f) In the case of a claim for indemnification not based upon a Third Party Claim, the Indemnifying Party shall have thirty (30) days from its receipt of the Claim Notice to(i) cure the Losses complained of, (ii) admit its liability for such Loss or (iii) dispute the claim for such Losses. If the Indemnifying Party does not notify the Indemnified Party within such thirty (30) day period that it has cured the Losses or that it disputes the claim for such Losses, then the Indemnifying Party shall be deemed to be disputing the claim for such Losses.

Section 11.8 **Survival**.

(a) The (i) representations and warranties of Seller in Article V and in the certificate delivered at Closing by Seller pursuant to Section 8.6, and (ii) the covenants and agreements of Seller contained herein to be performed prior to Closing shall, in each case, survive the Closing for a period of twelve (12) months after the Closing Date. The representations, warranties, covenants and agreements of Purchaser contained herein shall survive without time limit.

(b) Subject to Section 11.8(a) and except as set forth in Section 11.8(c), the remainder of this Agreement shall survive the Closing without time limit. Representations, warranties, covenants and agreements shall be of no further force and effect after the date of their expiration; provided that there shall be no termination of any bona fide claim asserted pursuant to this Agreement with respect to such a representation, warranty, covenant or agreement prior to its expiration date.

(c) The indemnities in Section 11.2(a) and Section 11.3(a) shall terminate as of the termination date of each respective representation, warranty, covenant or agreement that is subject to indemnification, except, in each case, as to matters for which a specific written claim for indemnity has been delivered to the Indemnifying Party on or before such termination date. The indemnities in Section 11.3(c), Section 11.3(d), Section 11.3(e), Section 11.3(f) and Section 11.3(g) shall survive the Closing for a period of twelve (12) months after the Closing Date. The indemnities in Section 11.2(b) and Section 11.3(b) shall survive the Closing without time limit.

Section 11.9 **Waiver of Right to Rescission**. Seller and Purchaser acknowledge that, following the Closing, the payment of money, as limited by the terms of this Agreement, shall be adequate compensation for breach of any representation, warranty, covenant or agreement contained herein or for any other claim arising in connection with or with respect to the transactions contemplated by this Agreement. As the payment of money shall be adequate compensation, following the Closing, Purchaser and Seller waive any right to rescind this Agreement or any of the transactions contemplated hereby.

Section 11.10 **Non-Compensatory Damages**. No Indemnified Parties shall be entitled to recover from an Indemnifying Party or its Affiliates any indirect, special, incidental, consequential, punitive, exemplary, remote or speculative damages or damages for lost profits of any kind arising under or in connection with this Agreement or the transactions contemplated hereby, except to the extent any such Party suffers such damages to a Third Party, which damages (including costs of defense and reasonable attorneys' fees incurred in connection with defending against such damages) shall not be excluded by this provision as to recovery hereunder.

Section 11.11 **Insurance**. The amount of any Losses for which any of the Purchaser Group or Seller Group is entitled to indemnification under this Agreement or in connection with or with respect to the transactions contemplated by this Agreement shall be reduced by any corresponding insurance proceeds actually received by any such indemnified Party under any insurance arrangements.

Section 11.12 **ExxonMobil Insurance**. Seller and Purchaser acknowledge that ExxonMobil Corporation maintains a worldwide program of property and liability insurance coverage for itself and its affiliates, including Seller. This program has been designed to achieve a co-coordinated risk management package for the entire ExxonMobil corporate group and includes self-insurance. All of the insurance policies through which the worldwide program of coverage is presently or has previously been provided by or to ExxonMobil, its predecessors or Affiliates are herein referred to collectively as the "**ExxonMobil Policies**." It is understood and agreed by Purchaser that from and after the Closing (a) no insurance coverage shall be provided to Purchaser under the ExxonMobil Policies, and (b) no claims regarding any matter whatsoever, whether or not arising from events occurring prior to the Closing, shall be made by Purchaser or its Affiliates against or with respect to any of the ExxonMobil Policies regardless of their date of issuance. Purchaser hereby indemnifies and defends the Seller Group against, and holds them harmless from, any claim made after Closing against any of the ExxonMobil Policies by Purchaser or its Affiliates or any Person claiming to be subrogated to Purchaser's or its Affiliates' rights, including all costs and expenses (including attorneys' fees) related thereto. Such indemnity shall cover any claim by an insurer for reinsurance, retrospective premium payments or prospective premium increases attributable to any such claim.

Section 11.13 **Access to Seller's Financial and Accounting Information**. Within two (2) years of Closing, and at Purchaser's expense, Seller shall grant to a mutually agreed accounting firm access to Seller's financial and accounting information directly relating to the Assets as needed for the preparation of certain financial statements that may be required of Purchaser pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC") including SEC Regulation S-X and Rule 3-05. Such access shall be limited to information for the calendar years 2019 and 2020, and first quarter of 2021, that exists in Seller's offices, as may reasonably be required to prepare audited financial statements reflecting gross revenues and direct lease operating expenses related to the Assets. Purchaser shall provide at least sixty (60) Business Days prior notice to Seller before the accounting firm shall commence such review. Such review will only be carried out one time. Furthermore, unless otherwise agreed by Seller, the accounting firm shall not disclose information to Purchaser that is proprietary to Seller or its Affiliates, including gas and liquids sales prices.

ARTICLE XII

CERTAIN ADDITIONAL AGREEMENTS

Section 12.1 **Post-Closing Settlement Statement**.

(a) As soon as reasonably practicable after the Closing Date, but in no event longer than one hundred twenty (120) days after the Closing Date (the "**Final Settlement Date**"), Seller shall prepare, in accordance with this Agreement, and deliver to Purchaser, a final statement (the "**Final Settlement Statement**") setting forth each adjustment to the Purchase Price in accordance with Section 3.2 and Section 3.3. The Final Settlement Statement also will include any adjustments necessary because Seller chose to attempt to cure a Title Defect under Section 4.3 of this Agreement. As soon as reasonably practicable, but in any event within thirty (30) days after receipt of the Final Settlement Statement, Purchaser shall return to Seller a written report containing any proposed changes to the Final Settlement Statement and an explanation of any such changes and the reasons therefor (the "**Dispute Notice**"). Purchaser's failure to deliver to Seller a Dispute Notice detailing proposed changes to the Final Settlement Statement by such date shall be deemed to be an acceptance by Purchaser of the Final Settlement Statement delivered by Seller, and Seller's determinations with respect to all such adjustments in the Final Settlement Statement that are not addressed in the Dispute Notice shall prevail. The Parties shall undertake to agree on the Adjusted Purchase Price no later than one hundred eighty (180) days after the Closing Date (the "**Target Settlement Date**"). If the final Purchase Price set forth in the Final Settlement Statement is mutually agreed upon by Seller and Purchaser prior to the Target Settlement Date or is deemed agreed pursuant to the foregoing (or determined by the Accounting Arbitrator pursuant to Section 12.1(b)), the Final Settlement Statement and such final Adjusted Purchase Price (the "**Final Price**"), shall be final and binding on the Parties. Any difference in the Adjusted Purchase Price as paid at Closing pursuant to the Preliminary Settlement Statement and the Final Price shall be paid by the owing Party on or before the date that is ten (10) days following agreement or deemed agreement (or determination by the Accounting Arbitrator, as applicable) (such date, the "**Final Payment Date**") to the owed Party. All amounts paid or transferred pursuant to this Section 12.1(a) shall be delivered in United States currency by wire transfer of immediately available funds to the account specified in writing by the relevant Party.

(b) If Seller and Purchaser cannot reach agreement on the Final Price by the Target Settlement Date, either Party may refer the remaining issues in dispute to the Agreed Accounting Firm. If such issues in dispute are submitted to the Agreed Accounting Firm for resolution, Seller and Purchaser will each enter into a customary engagement letter with the Agreed Accounting Firm at the time the issues in dispute are submitted to the Agreed Accounting Firm. Within ten (10) days of the appointment of the Agreed Accounting Firm, each of Seller and Purchaser shall present the Agreed Accounting Firm with its position on the issues in dispute with respect to the Final Price, and all other supporting information that it deems relevant, with a copy to the other Party. The Agreed Accounting Firm shall also be provided with a copy of this Agreement by Seller. Within forty five (45) days after receipt of such materials, the Agreed Accounting Firm shall make its determination by selecting the position of either Seller or Purchaser for each of the issues presented to the Agreed Accounting Firm, which determination shall be final and binding upon all Parties and, absent manifest error, without right of appeal. In making its determination, the Agreed Accounting Firm shall be bound by the standards and rules set forth in Article IV (if applicable) and this Section 12.1 with regard to valuations. The Agreed Accounting Firm may not award damages, interest or penalties to either Party with respect to any matter. Seller and Purchaser shall each bear its own legal fees and other costs of presenting its case. Each Party shall bear one-half of the costs and expenses of the Agreed Accounting Firm.

Section 12.2 **Suspended Funds**. Seller will provide Schedule 5.11, a listing showing all estimated net proceeds from production attributable to the Assets which are held in suspense by Seller as of the Closing Date (the "**Suspense Funds**") because of lack of identity or address of owners, title defects, change of ownership, netting, over/under distributions or similar reasons. As soon as reasonably practicable after the Closing, but in no event longer than ninety (90) days after the Closing Date, Seller shall provide Purchaser an updated Schedule 5.11, and shall credit Purchaser an amount equal to the Suspense Funds in the Final Settlement Statement. Purchaser shall be responsible for proper distribution of all the Suspense Funds to the Persons lawfully entitled to them, and effective upon Closing, Purchaser hereby protects, defends, indemnifies and holds Seller harmless against any and all Losses associated with claims against the Suspense Funds.

Section 12.3 **Receipts and Credits**. Subject to the following sentence, after the Parties' agreement (or deemed agreement) upon the Final Settlement Statement, then, to the extent not accounted for in the Final Settlement Statement, if (i) any Party receives monies belonging to the other, including proceeds of production, then such amount shall, within five (5) Business Days after the end of the month in which such amounts were received, be paid over to the proper Party,
(ii) any Party pays monies for Property Expenses which are the obligation of the other Party hereto, then such other Party shall, within five (5) Business Days after the end of the month in which the applicable invoice and proof of payment of such invoice were received, reimburse the Party which paid such Property Expenses, (iii) a Party receives an invoice of an expense or obligation which is owed by the other Party, such Party receiving the invoice shall promptly forward such invoice to the Party obligated to pay the same, and (iv) an invoice or other evidence of an obligation is received by a Party, which is partially an obligation of both Seller and Purchaser, then the Parties shall consult with each other, and each shall promptly pay its portion of such obligation to the obligee. Notwithstanding anything herein to the contrary, (a) from and after the first anniversary of the Closing Date, Seller shall have no liabilities or obligations with respect to pre-Effective Time Property Expenses, and (b) the provisions of this Section 12.3 shall not be subject to the provisions of Sections 11.5 and 11.7. Each of Seller and Purchaser shall be permitted to offset any Property Expenses owed by such Party to the other Party pursuant to this Section 12.3 against amounts owing by the second Party to the first Party pursuant to this Section 12.3, but not otherwise.

Section 12.4 **Records; Retention**.

(a) Within sixty (60) days after Closing, Seller will deliver to Purchaser, at Purchaser's cost and request, copies of files, records, and data relating to the Assets (the "**Records**") including title records (including abstracts of title, title opinions, title reports, and title curative documents), the Existing Contracts, correspondence and all related matters in the possession of Seller (but excluding corporate, financial, tax, and general accounting records, any document subject to the attorney-client or other privilege, and any document, data, or other information where disclosure is restricted by agreement with a third party). Purchaser must advise Seller before Closing which such files, records and data it wants copied.

(b) Purchaser, for a period of seven (7) years following the Closing, will (a) retain the Records, (b) provide Seller, its Affiliates and its and their officers, employees and representatives with access to the Records (to the extent that Seller has not retained the original or a copy) during normal business hours for review and copying at Seller's expense, and (c) provide Seller, its Affiliates and its and their officers, employees and representatives with access, during normal business hours, to materials received or produced after the Closing relating to any indemnity claim made under Section 11.3 for review and copying at Seller's expense.

Section 12.5 **Recording**. As soon as practicable after Closing, Purchaser, at its sole cost, shall record the Assignment in the appropriate counties and provide Seller with copies of the recorded Assignment.

Section 12.6 **Filing for Approvals**.

(a) Purchaser, at its sole cost, shall no later than thirty (30) days after Closing:

(i) file for approval with any governmental authorities having jurisdiction (including state, federal, tribal, and local) the transfer documents required to effectuate the transfer of the Assets;

(ii) execute, acknowledge (if necessary), and exchange, as applicable, any applications necessary to transfer to Purchaser any transferable Permits to which the Assets are subject, and which Seller has agreed to transfer under this Agreement;

(iii) file all appropriate forms, declarations, and bonds (or other authorized forms of security) with all applicable governmental authorities and third parties relative to Purchaser's assumption of operations or the transfer of the Assets; and

(iv) prepare and execute appropriate change of operator notices and third-party ballots required under applicable operating agreements.

(b) After Closing, the Parties further agree to take all other actions required of it by governmental authorities having jurisdiction to obtain all requisite regulatory approval with respect to this transaction, and to use their commercially reasonable efforts to obtain unconditional approval by such authorities of any transfer documents requiring governmental approval in order for Purchaser to be recognized as owner of the Assets. Each Party agrees to provide the other Party with approved copies of the documents contemplated by this Section 12.6, as soon as they are available.

Section 12.7 **Further Cooperation**. After Closing, Seller and Purchaser agree to take such further actions and to execute, acknowledge and deliver all such further documents that are reasonably necessary or useful in carrying out the purposes of this Agreement or of any document delivered pursuant to this Agreement.

Section 12.8 **CO_2 Purchase Obligation**.

(a) From and after the Closing until the fiftieth (50^{th}) anniversary thereof, in the event Purchaser (or its Affiliates) elects to conduct carbon dioxide flooding involving the Leases or Wells, in each such instance, Purchaser shall provide Seller with sixty (60) days' advance notice of any such tertiary recovery project. In such event, Seller (or its Affiliates) shall have the right (but not the obligation) to offer, at then current market rates, such quantity of carbon dioxide to Purchaser as Seller may determine, and, subject to clause (b) below, Purchaser shall be required to purchase such carbon dioxide offered by Seller. If, following the Closing, Purchaser assigns its interest in a Lease or the Wells to a third party, the assignment must require that the assignee assume the assigning party's obligations with respect to this Section 12.8.

(b) If Purchaser receives a bona fide offer from a third party to purchase the same quantity of carbon dioxide as offered by Seller, but for a lower price, Purchaser shall notify Seller of the price and term of such transaction and Seller shall, within 30 days of receipt of the notice, notify Purchaser whether it elects to match such price and term. If Seller elects to match, Purchaser shall be obligated to purchase such quantity of carbon dioxide from Seller. If Seller elects not to match or fails to give notice of its intention within the 30-day period, Purchaser shall be free to purchase such quantity of carbon dioxide from the third party at a price not more than stated in the notice and for not longer than such term as stated in the notice (and for avoidance of doubt, the terms of this clause (b) shall again apply to any potential renewal following expiration of such term).

ARTICLE XIII

TAXES

Section 13.1 **Apportionment of Ad Valorem and Property Taxes**. All Property Taxes with respect to the tax period in which the Effective Time occurs shall be apportioned as of the Effective Time between Seller and Purchaser. The Parties will make final settlement of all Property Taxes by estimating the Property Taxes to be due for the tax period in which the Effective Time occurs based on the Property Taxes assessed and paid for the immediately prior tax period. Such settlement of taxes shall be part of the Final Settlement Statement between the Parties. If Property Taxes have not been paid before Closing, Purchaser shall pay the Property Taxes and shall be credited for Seller's portion of the Property Taxes under Section 3.3(g). If Property Taxes have been paid before Closing, Seller shall be credited for Purchaser's portion of the Property Taxes under Section 3.2(c). Purchaser shall be responsible for all subsequent Property Taxes and interest that are applied to the Assets for the periods or portions thereof after the Effective Time.

Section 13.2 **Sales Taxes**. The Purchase Price is exclusive of any sales taxes or other similar taxes in connection with the sale of the Assets. If any sales or other similar taxes are assessed, Purchaser shall be solely responsible for the payment of such taxes. Purchaser shall be responsible for any applicable conveyance, transfer and recording fees, and real estate transfer stamps or taxes imposed on the transfer of the Assets pursuant to this Agreement. If Seller is required to pay any such taxes, then Purchaser will reimburse Seller for such amounts.

Section 13.3 **Severance and Production Taxes**. Seller shall bear and pay all Severance Taxes, to the extent attributable to production from the Assets before the Effective Time. Purchaser shall bear and pay all such Severance Taxes on production from the Assets on and after the Effective Time. Seller shall withhold and pay on behalf of Purchaser all such Severance Taxes on production from the Assets between the Effective Time and the Closing Date, if the Closing Date follows the Effective Time, and the amount of any such payment shall be reimbursed to Seller as a Closing adjustment to the Purchase Price pursuant to Section 12.1. If either Party pays Severance taxes owed by the other under this Agreement, upon receipt of evidence of payment the nonpaying Party will reimburse the paying Party promptly for its proportionate share of such taxes.

Section 13.4 **Cooperation**. Each Party shall provide the other Party with reasonable information which may be required by the other Party for the purpose of preparing tax returns and responding to any audit by any taxing jurisdiction. Each Party shall cooperate with all reasonable requests of the other Party made in connection with contesting the imposition of taxes. Notwithstanding anything to the contrary in this Agreement, neither Party shall be required at any time to disclose to the other Party any tax returns or other confidential tax information.

Section 13.5 **Like-Kind Exchange**. Each Party consents to the other Party's assignment of its rights and obligations under this Agreement to its affiliate or its Qualified Intermediary (as that term is defined in Section 1.1031(k)-l(g)(4)(v) of the Treasury Regulations) and/or to its Qualified Exchange Accommodation Titleholder (as that term is defined in Rev. Proc. 2007-37 issued effective September 15, 2000) in connection with the effectuation of a Like-Kind Exchange Transaction. However, Seller and Purchaser acknowledge and agree that any assignment of this Agreement to its affiliate or a Qualified Intermediary or Qualified Exchange Accommodation Titleholder does not release either Party from any of its respective liabilities and obligations to the other Party under this Agreement. If requested by the other Party, each Party agrees to cooperate with the other Party (to the extent reasonable) to attempt to structure the transaction as a Like-Kind Exchange Transaction. If a Like-Kind Exchange Transaction occurs, the Parties recognize that IRS Form 8824, Like-Kind Exchanges, will be required to be filed, and each Party consents to the filing of such Form and will fully cooperate, to the extent necessary, with the other Party in filing such form.

Section 13.6 **IRS Form 8594**. If the Parties mutually agree that a filing of IRS Form 8594 is required, then the Parties will confer and cooperate in the preparation and filing of their respective forms to reflect consistent reporting of the agreed upon allocation of the value of the Assets.

ARTICLE XIV
DISCLAIMERS AND WAIVERS

Section 14.1 **Condition of the Assets. PURCHASER ACKNOWLEDGES AND AGREES THAT, SUBJECT TO THE PROVISIONS OF ARTICLE IV AND PURCHASER'S RIGHTS UPON A BREACH BY SELLER OF ANY OF ITS REPRESENTATIONS OR WARRANTIES CONTAINED IN ARTICLE V, PURCHASER SHALL ACQUIRE THE ASSETS (INCLUDING ASSETS FOR WHICH A DEFECT NOTICE IS GIVEN UNDER ARTICLE IV) IN AN "AS IS, WHERE IS" CONDITION AND SHALL ASSUME ALL RISKS THAT THE ASSETS MAY CONTAIN WASTE MATERIALS (WHETHER TOXIC, HAZARDOUS, EXTREMELY HAZARDOUS OR OTHERWISE) OR OTHER ADVERSE PHYSICAL CONDITIONS, INCLUDING THE PRESENCE OF UNKNOWN ABANDONED WELLS, PUMPS, PITS, PIPELINES OR OTHER WASTE OR SPILL SITES WHICH MAY NOT HAVE BEEN REVEALED BY PURCHASER'S ENVIRONMENTAL ASSESSMENT. UPON THE OCCURRENCE OF CLOSING, BUT SUBJECT TO PURCHASER'S RIGHTS UPON A BREACH BY SELLER OF ANY OF ITS REPRESENTATIONS OR WARRANTIES CONTAINED IN ARTICLE V, IF APPLICABLE, ALL RESPONSIBILITY AND LIABILITY RELATED TO SUCH**

CONDITIONS, WHETHER KNOWN OR UNKNOWN, FIXED OR CONTINGENT, SHALL BE TRANSFERRED FROM SELLER TO PURCHASER WITHOUT RECOURSE AGAINST SELLER. WITHOUT LIMITING THE FOREGOING BUT SUBJECT TO PURCHASER'S RIGHTS UPON A BREACH BY SELLER OF ANY OF ITS REPRESENTATIONS OR WARRANTIES CONTAINED IN ARTICLE V, IF APPLICABLE, EFFECTIVE AS OF CLOSING, PURCHASER WAIVES ITS RIGHT TO RECOVER FROM SELLER AND FOREVER RELEASES AND DISCHARGES THE SELLER GROUP FROM ANY AND ALL LOSSES, WHETHER DIRECT OR INDIRECT, KNOWN OR UNKNOWN, FORESEEN OR UNFORESEEN, THAT MAY ARISE OR MAY HAVE ARISEN PRIOR TO, ON OR AFTER THE EFFECTIVE TIME ON ACCOUNT OF OR IN ANY WAY CONNECTED WITH THE ENVIRONMENTAL OROTHER PHYSICAL CONDITION OF THE ASSETS OR ANY VIOLATION BY SELLER, PURCHASER OR ANY OTHER PARTY OF ANY APPLICABLE LEASE, CONTRACT OR OTHER INSTRUMENT (BUT ONLY TO THE EXTENT SUCH RELATES TO THE ENVIRONMENTAL OR PHYSICAL CONDITION OF THE PROPERTY) OR OF ANY APPLICABLE EXISTING OR FUTURE ENVIRONMENTAL LAW, REGULATION, ORDER OR OTHER DIRECTIVE OF ANY GOVERNMENTAL AUTHORITY, HAVING JURISDICTION APPLICABLE THERETO, INCLUDING WITHOUT LIMITATION, ALL ENVIRONMENTAL LAWS. PURCHASER IS AWARE THAT THE ASSETS HAVE BEEN USED FOR EXPLORATION, DEVELOPMENT AND PRODUCTION OF OIL AND GAS AND THAT THERE MAY BE PETROLEUM, PRODUCED WATER, WASTES OR OTHER MATERIALS LOCATED ON OR UNDER THE LANDS COVERED BY THE LEASES (OR LANDS POOLED OR ASSOCIATED THEREWITH). EQUIPMENT AND SITES INCLUDED IN THE ASSETS MAY CONTAIN ASBESTOS, HAZARDOUS SUBSTANCES OR NORM. NORM MAY AFFIX OR ATTACH ITSELF TO THE INSIDE OF WELLS, MATERIALS AND EQUIPMENT AS SCALE, OR IN OTHER FORMS. THE WELLS, MATERIALS AND EQUIPMENT LOCATED ON THE LEASES OR LANDS POOLED OR ASSOCIATED THEREWITH MAY CONTAIN NORM AND OTHER WASTES OR HAZARDOUS SUBSTANCES, AND NORM-CONTAINING MATERIAL AND OTHER WASTES MAY HAVE BEEN BURIED, COME IN CONTACT WITH THE SOIL, OR OTHERWISE BEEN DISPOSED OF ON OR UNDER THE LANDS COVERED BY THE LEASES OR LANDS POOLED OR ASSOCIATED THEREWITH. SPECIAL PROCEDURES MAY BE REQUIRED FOR THE REMEDIATION, REMOVAL, TRANSPORTATION OR DISPOSAL OF WASTES, ASBESTOS, HAZARDOUS SUBSTANCES AND NORM FROM THE ASSETS.

Section 14.2 **Other Disclaimers by Seller. EXCEPT AS OTHERWISE SPECIFICALLY PROVIDED FOR IN ARTICLE V OF THIS AGREEMENT, PURCHASER ACKNOWLEDGES AND AGREES THAT SELLER EXPRESSLY DISCLAIMS AND NEGATES ANY REPRESENTATION OR WARRANTY, EXPRESS, STATUTORY OR IMPLIED, AS TO (A) TITLE TO ANY OF THE ASSETS, (B) THE CONTENTS, CHARACTER OR NATURE OF ANY REPORT OF ANY PETROLEUM ENGINEERING CONSULTANT, OR ANY ENGINEERING, GEOLOGICAL OR SEISMIC DATA OR INTERPRETATION, RELATING TO THE ASSETS, (C) THE QUANTITY, QUALITY OR RECOVERABILITY OF HYDROCARBONS IN OR FROM THE ASSETS, (D) ANY ESTIMATES OF THE VALUE OF THE ASSETS OR FUTURE REVENUES GENERATED BY THE ASSETS, (E) THE ABILITY TO PRODUCE HYDROCARBONS FROM THE ASSETS, (F) THE MAINTENANCE, REPAIR, CONDITION, QUALITY, SUITABILITY, DESIGN OR MARKETABILITY OF THE**

ASSETS, (G) THE CONTENT, CHARACTER OR NATURE OF ANY INFORMATION MEMORANDUM, REPORTS, BROCHURES, CHARTS OR STATEMENTS PREPARED BY SELLER OR THIRD PARTIES WITH RESPECT TO THE ASSETS, (H) ANY OTHER MATERIALS OR INFORMATION THAT MAY HAVE BEEN MADE AVAILABLE TO PURCHASER OR ITS AFFILIATES, OR ITS OR THEIR EMPLOYEES, AGENTS, CONSULTANTS, REPRESENTATIVES OR ADVISORS IN CONNECTION WITH THE TRANSACTIONS CONTEMPLATED BY THIS AGREEMENT OR ANY DISCUSSION OR PRESENTATION RELATING THERETO AND (I) ANY IMPLIED OR EXPRESS WARRANTY OF FREEDOM FROM PATENT OR TRADEMARK INFRINGEMENT. EXCEPT AS AND TO THE LIMITED EXTENT EXPRESSLY REPRESENTED OTHERWISE IN ARTICLE V OF THIS AGREEMENT, SELLER FURTHER DISCLAIMS ANY REPRESENTATION OR WARRANTY, EXPRESS, STATUTORY OR IMPLIED, OF MERCHANTABILITY, FREEDOM FROM LATENT VICES OR DEFECTS, FITNESS FOR A PARTICULAR PURPOSE OR CONFORMITY TO MODELS OR SAMPLES OF MATERIALS OF ANY OF THE ASSETS, RIGHTS OF A PURCHASER UNDER APPROPRIATE STATUTES TO CLAIM DIMINUTION OF CONSIDERATION OR RETURN OF THE PURCHASE PRICE, OR RIGHTS OF A PURCHASER UNDER DECEPTIVE TRADE PRACTICE STATUTES, CONSUMER PROTECTION STATUTES OR OTHER SIMILAR STATUTES, IT BEING EXPRESSLY UNDERSTOOD AND AGREED BY THE PARTIES THAT PURCHASER SHALL BE DEEMED TO BE OBTAINING THE ASSETS IN THEIR PRESENT STATUS, CONDITION AND STATE OF REPAIR, "AS IS" AND "WHERE IS" WITH ALL FAULTS OR DEFECTS (KNOWN OR UNKNOWN, LATENT, DISCOVERABLE OR UNDISCOVERABLE), AND THAT PURCHASER HAS MADE OR CAUSED TO BE MADE SUCH INSPECTIONS AS PURCHASER DEEMS APPROPRIATE.

ARTICLE XV

TERMINATION

Section 15.1 **Right of Termination**. This Agreement and the transactions contemplated herein may be terminated at any time prior to the Closing:

(a) by the mutual written agreement of the Parties;

(b) by delivery of written notice from Purchaser to Seller if any of the conditions set forth in Article VIII (other than the conditions set forth in Section 8.3, Section 8.4 and Section 8.5) have not been satisfied by Seller (or waived by Purchaser) by the Longstop Date;

(c) by delivery of written notice from Seller to Purchaser if any of the conditions set forth in Article IX (other than the conditions set forth in Section 9.3, Section 9.4 and Section 9.5) have not been satisfied by Seller (or waived by Purchaser) by the Longstop Date;

(d) by either Party delivering written notice to the other Party if any of the conditions set forth in Section 8.3, Section 8.4, Section 8.5, Section 9.3, Section 9.4 or Section 9.5 are not satisfied or waived by the applicable Party on or before the Longstop Date; and

(e) by either Party at any time during which (i) the conditions set forth in Articles VIII and IX (other than those conditions that by their terms are to be satisfied at Closing) have been satisfied or waived in accordance with this Agreement, (ii) such Party has indicated in writing to the other Party that it is ready, willing and able to consummate the Closing, and (iii) the other Party shall have failed to consummate the Closing by the close of business on the third (3rd) Business Day following the other Party's receipt of such written notification;

Provided however, that no Party shall have the right to terminate this Agreement pursuant to clause (b), (c), (d) or (e) above if such Party is at such time in material breach of any provision of this Agreement.

Section 15.2 **Effect of Termination**. If this Agreement is terminated pursuant to any provision of Section 15.1, then, except as provided in this Section 15.2 (and except for the provisions of Section 4.2(a), Section 7.4, Section 11.11, Section 11.12, Article XIV, this Article XV, and Article XVII), this Agreement shall forthwith become void and of no further force or effect and the Parties shall have no liability or obligation hereunder.

(a) If Seller has the right to terminate this Agreement pursuant to Section 15.1(c) because of a Willful Breach by Purchaser of this Agreement, or Section 15.1(e) above, Seller shall be entitled to (1) terminate this Agreement pursuant to Section 15.1 and retain the Deposit as liquidated damages, and not as a penalty, for such termination, free and clear of any claims thereon by Purchaser, or (2) seek the specific performance of Purchaser hereunder. The Parties agree that, should Seller elect the option under subpart (1) above, the foregoing described liquidated damages are reasonable considering all of the circumstances existing as of the date of the execution of this Agreement and constitute the Parties' good faith estimate of the actual damages reasonably expected to result from such termination of this Agreement by Seller.

(b) If Purchaser has the right to terminate this Agreement pursuant to Section 15.1(b) because of a Willful Breach by Seller of this Agreement, or Section 15.1(e) above, Purchaser shall be entitled to (1) terminate this Agreement pursuant to Section 15.1 and receive the Deposit from Seller, and (2) seek to recover damages from Seller up to but not exceeding the amount of the Deposit. If Purchaser is entitled to the return of the Deposit pursuant to this Section 15.2(b), Seller shall return the Deposit to Purchaser within five (5) Business Days of the date this Agreement is terminated.

(c) If this Agreement is terminated for any reason other than as set forth in Section 15.2(a) or Section 15.2(b), then the Parties shall have no liability or obligation hereunder as a result of such termination, and Seller shall, within five (5) Business Days of the date this Agreement is terminated, return the Deposit to Purchaser free and clear of any claims thereon by Seller.

(d) Subject to the foregoing, upon the termination of this Agreement neither Party shall have any other liability or obligation hereunder and following any termination of this Agreement, Seller shall be free to all the rights and benefits associated with the ownership of the Assets, including the right to sell the Assets at Seller's discretion, without any claim by Purchaser with respect thereto.

Section 15.3 **Return of Documentation and Confidentiality**. Upon any termination of this Agreement, Purchaser shall return to Seller all title, engineering, geological and geophysical data, environmental assessments and/or reports, maps, documents and other information furnished by Seller to Purchaser or prepared by or on behalf of Purchaser in connection with its due diligence investigation of the Assets and an officer of Purchaser shall certify same to Seller in writing.

ARTICLE XVI
EMPLOYEES

Section 16.1 **Employees**. Within five (5) days of the execution of this Agreement, Seller shall provide to Purchaser a list (the "**Employee List**") of all in scope employees of Seller directly engaged in the operation of the Assets (collectively, the "**Employees**"). The Employee List shall include for each Employee the current job title, work location, email, service date or hire date (if different) and leave status (excluding nature and expected duration of leave). Seller shall update the Employee List as necessary at any time prior to ten (10) days before the Closing to reflect any and all employment changes. Purchaser shall extend offers of employment to each of the Employees, conditioned on consummation of the Closing, no later than [ten (10) days within execution of this agreement]. Purchaser shall provide Seller with an update on job acceptances and declines at least five (5) Business Days before Closing. Seller will inform the Employees that their employment with Seller will terminate upon Closing, whether or not they accept the offer of employment from Purchaser.

Section 16.2 **Retirement Eligible Subject Employees**. Notwithstanding any language in this Agreement to the contrary, the Employees listed in Part B of the Employee List are within three years of retirement eligibility under Seller's benefit plans ("**Near Retirement Eligible Employees**"). Purchaser shall make an offer of employment to all Near Retirement Eligible Employees, which offer will include initial salary or wages that will be comparable to such Employee's salary or wages immediately prior to the Closing. For any Near Retirement Eligible Employees who accept an employment offer from Purchaser, Purchaser shall maintain the employment (other than for prohibited conduct as determined under Purchaser's written personnel policies, a voluntary resignation, or death) of any such Near Retirement Eligible Employees at least until each such Near Retirement Eligible Employee meets the eligibility requirements of Seller's benefit plans (at least 55 years old with at least 15 years of service with Seller and its affiliates and Purchaser and its affiliates).

Section 16.3 **Subject Employees Hired by Purchaser**. In connection with an Employee who accepts Purchaser's offer of employment, Purchaser covenants that the initial salary or wages of any such Employee will be comparable to such Employees' the salary or wages immediately prior to the Closing Date, subject to the terms and conditions pertaining to Near Retirement Eligible Employees set forth in Section 16.2. Purchaser will not reduce the salary or wages during the six (6) month period after such Employee commences employment with Purchaser. Purchaser agrees to recognize and grant credit for service with Seller for benefit programs (other than accruals under a defined benefit retirement plan), including vacation accrual under Purchaser's vacation program. In addition, if the Purchaser separates any Employee during the twelve-month period after the Closing Date (other than for prohibited conduct as determined under Purchaser's written personnel policies, a voluntary resignation, or death), they will provide the Employee with a severance payment equal to or greater than the Seller's severance program would have provided the Employee.

Section 16.4 **No Solicitation**. For any Employee that elects not to accept the employment offer from Purchaser, then Purchaser (or any of its affiliates), for a period of six (6) months after the Closing Date, shall not employ or make an offer of employment to any such Employee.

Section 16.5 **No Guaranteed Employment**. No provision of this Article XVI shall be construed as a guarantee of continued employment of any Employee and this Agreement shall not be construed so as to prohibit the Purchaser or any of its Affiliates from having the right to terminate the employment of any Employee, provided, that any such termination is effected in accordance with applicable Law.

Section 16.6 **No Third Party Beneficiaries**. The provisions of this Article XVI are for the sole benefit of the Parties hereto and nothing herein, express or implied, is intended or shall be construed to confer upon or give to any Person (including any Employee), other than the Parties to this Agreement and their respective successors and permitted assigns, any legal or equitable or other rights (including any third-party beneficiary rights) or remedies under or by reason of any provision of this Article XVI. Nothing contained herein, express or implied: (a) shall be construed to establish, amend or modify any benefit plan, program, agreement or arrangement (including any benefit plan of the Purchaser); (b) shall alter or limit the Purchaser's ability to amend, modify or terminate any benefit plan, program, agreement or arrangement (including any benefit plan of the Purchaser) subject to compliance with this Article XVI; or (c) is intended to confer upon any Employee any right to employment or continued employment for any period of time by reason of this Agreement, or any right to a particular term or condition of employment.

ARTICLE XVII
MISCELLANEOUS

Section 17.1 **Entire Agreement**. This Agreement, including all Schedules and Exhibits attached hereto, constitutes the entire agreement between the Parties as to the subject matter of this Agreement and supersedes all prior agreements, understandings, negotiations and discussions of the Parties, whether oral or written. No supplement, amendment, alteration, modification or waiver of this Agreement shall be binding unless executed in writing by the Parties.

Section 17.2 **References and Rules of Construction**. All references in this Agreement to Exhibits, Schedules, Articles, Appendices, Sections and other subdivisions refer to the corresponding Exhibits, Schedules, Articles, Appendices, Sections and other subdivisions of or to this Agreement unless expressly provided otherwise. Titles appearing at the beginning of any such subdivisions are for convenience only and shall be disregarded in construing the language hereof. The words "this Agreement," "herein," "hereby," "hereunder" and "hereof," and words of similar import, refer to this Agreement as a whole and not to any particular subdivision unless expressly so limited. Pronouns in masculine, feminine, and neuter genders shall be construed to include any other gender, and words in the singular form shall be construed to include the plural and vice versa, unless the context otherwise requires. Derivatives and other forms of the terms defined in this Agreement shall have meanings consistent with the definitions herein provided. The term "including" (or "included") shall be deemed to be followed by the phrase "but not limited to." Unless otherwise expressly provided herein, any reference herein to a "day" shall refer to a calendar day. All references to "$" or "dollars" shall be deemed references to United States dollars. The words "shall" and "will" are used interchangeably throughout this Agreement and shall accordingly be given the same meaning, regardless of which word is used.

Section 17.3 **Assignment**. This Agreement may not be assigned by Purchaser without the prior written consent of Seller. In the event that Seller consents to any such assignment, such assignment shall not relieve Purchaser of any of its obligations and responsibilities hereunder. Any assignment or other transfer by Purchaser or its successors and assigns of any of the Assets shall not relieve Purchaser or its successors or assigns of any of their obligations (including indemnity obligations) hereunder, as to the Assets so assigned or transferred.

Section 17.4 **Waiver**. No waiver of any of the provisions of this Agreement shall be deemed or shall constitute a waiver of any other provisions of this Agreement (whether or not similar), nor shall such waiver constitute a continuing waiver unless otherwise expressly provided.

Section 17.5 **Conflict of Law Jurisdiction, Venue**. THIS AGREEMENT AND THE LEGAL RELATIONS AMONG SELLER AND PURCHASER SHALL BE GOVERNED AND CONSTRUED IN ACCORDANCE WITH THE LAWS OF THE STATE OF TEXAS, EXCLUDING ANY CONFLICTS OF LAW RULE OR PRINCIPLE THAT WOULD REQUIRE THE APPLICATION OF ANY OTHER LAW. EACH OF SELLER AND PURCHASER CONSENT TO THE EXERCISE OF JURISDICTION IN PERSONAM BY THE COURTS OF THE STATE OF TEXAS FOR ANY ACTION ARISING OUT OF THIS AGREEMENT, THE OTHER TRANSACTION DOCUMENTS OR THE TRANSACTIONS CONTEMPLATED HEREBY. ALL ACTIONS OR PROCEEDINGS WITH RESPECT TO, ARISING DIRECTLY OR INDIRECTLY IN CONNECTION WITH, OUT OF, RELATED TO OR FROM THIS AGREEMENT OR THE OTHER TRANSACTION DOCUMENTS SHALL BE EXCLUSIVELY LITIGATED IN COURTS HAVING SITES IN HOUSTON, HARRIS COUNTY, TEXAS.

Section 17.6 **Notices**. All notices and communications required or permitted to be given hereunder shall be in writing and shall be delivered personally, by email (provided that confirmation of receipt of such email is requested and received, which confirmation shall be provided reasonably promptly following receipt) or sent by bonded overnight courier, or mailed by U.S. Express Mail or by certified or registered United States Mail with all postage fully prepaid, addressed to Seller or Purchaser, as appropriate, at the address for such Person shown below or at such other address as Seller or Purchaser shall have theretofore designated by written notice delivered to the other Parties:

If to Seller:

XTO Energy Inc.
22777 Springwoods Village Parkway, Loc. 115
Spring, Texas 77389
Attention: Land Acquisition and Divestment Manager

With a copy to (which shall not constitute notice to Seller):

XTO Energy Inc.
22777 Springwoods Village Parkway, Loc. 119
Spring, Texas 77389
Attention: UOG Unconventional Divestment Manager

If to Purchaser:

Empire New Mexico LLC

2200 South Utica Place, Suite 150
Tulsa, Oklahoma 74114 Attention: Thomas W. Pritchard
Email: tommyp@empirepetrocorp.com

With a copy to (which shall not constitute notice to Purchaser):

Conner & Winters, LLP 4100 First Place
Tower 15 East Fifth Street Tulsa, Oklahoma
74103 Attention: J. Ryan Sacra
Email: rsacra@cwlaw.com

Any notice given in accordance herewith shall be deemed to have been given been given as of the date of receipt by the intended Party.

Section 17.7 **Timing.** Timing is of the essence for performance of the Parties' respective obligations hereunder; provided that if the date specified in this Agreement for giving any notice or taking any action under this Agreement is not a Business Day (or if the period during which any notice is required to be given or any action taken expires on a date which is not a Business Day), then the date for giving such notice or taking such action (or the expiration date of such period during which notice is required to be given or action taken) shall be the next day which is a Business Day.

Section 17.8 **Confidentiality**. Any information concerning the Assets (including any information discovered as a result of Purchaser's Environmental Assessment) or any aspect of the transactions contemplated by this Agreement shall be subject to the terms of the Confidentiality Agreement. This obligation shall terminate on the earlier to occur of (a) the Closing, or (b) such time as the information and data in question becomes generally available to the oil and gas industry other than through the breach these obligations by Purchaser or its officers, employees or representatives.

Section 17.9 **Publicity**. The Parties shall consult with each other before they or their Affiliates issue any press release, make any other public statement or schedule any press conference or conference call with investors or analysts with respect to this Agreement or the transactions contemplated by this Agreement. Further, neither Seller nor Purchaser shall issue any press release, make any other public statement or schedule any press conference or conference call concerning this Agreement and the transactions contemplated hereby without the prior written consent of the other Party, except as required to be issued by a Party pursuant to applicable Law including the applicable rules or regulations of any governmental authority or stock exchange.

Section 17.10 **Use of Seller's Names**. Purchaser agrees that, as soon as practicable after the Closing, but in no event longer than sixty (60) days after Closing, it will remove or cause to be removed the names and marks used by Seller and all variations and derivatives thereof and logos relating thereto from the Assets and Purchaser will not make any use whatsoever of such names, marks and logos.

Section 17.11 **Severability**. If any term or other provision of this Agreement is invalid, illegal or incapable of being enforced by any rule of law or public policy, all other conditions and provisions of this Agreement shall nevertheless remain in full force and effect so long as the economic or legal substance of the contemplated transactions is not affected in any material adverse manner to either Party. Upon such determination that any term or other provision is invalid, illegal or incapable of being enforced, the Parties shall negotiate in good faith to modify this Agreement so as to effect the original intent of the Parties as closely as possible in an acceptable manner to the end that the contemplated transactions are fulfilled to the extent possible.

Section 17.12 **Parties in Interest**. The terms and provisions of this Agreement shall be binding upon and inure to the benefit of the Parties and their respective successors and permitted assigns. Notwithstanding anything contained in this Agreement to the contrary, nothing in this Agreement, expressed or implied, is intended to confer on any Person other than Seller and Purchaser and their respective successors and permitted assigns, or the Parties' respective related Indemnified Parties hereunder, any rights, remedies, obligations or liabilities under or by reason of this Agreement, provided that only a Party and its respective successors and permitted assigns will have the right to enforce the provisions of this Agreement on its own behalf or on behalf of any of its related Indemnified Parties.

Section 17.13 **Conspicuousness**. **PURCHASER ACKNOWLEDGES THAT THE PROVISIONS OF THIS AGREEMENT THAT ARE PRINTED IN THE SAME MANNER AS THIS SECTION ARE CONSPICUOUS.**

Section 17.14 **Execution in Counterparts**. This Agreement may be executed in counterparts, and each such counterpart shall be deemed to be an original instrument, but all such counterparts together shall constitute for all purposes one agreement. Facsimiles or other electronic copies (e.g., PDFs) of executed counterparts shall be deemed to be original instruments.

[*Signature Page Follows*]

IN WITNESS WHEREOF, Purchaser and Seller have executed and delivered this Agreement effective as of the Effective Time.

SELLER:

XTO HOLDINGS, LLC

By: /s/ Phyllis Hinze
Name: Phyllis Hinze
Title: Agent and Attorney-In-Fact

PURCHASER:

EMPIRE NEW MEXICO LLC

By: /s/ Thomas W Pritchard
Name: Thomas W Pritchard
Title: Chief Executive Officer

Appendix A
Defined Terms

Capitalized terms used in this Agreement have the following meanings:

"**Adjusted Purchase Price**" has the meaning set forth in Section 3.4.

"**AFE**" has the meaning set forth in Section 5.10.

"**Affiliate**" means with respect to any Person, a Person that, directly or indirectly, through one or more entities, controls, is controlled by or is under common control with the Person specified. For the purpose of the immediately preceding sentence, the term "**control**" and its syntactical variants mean the power, direct or indirect, to direct or cause the direction of the management of such Person, whether through the ownership of voting securities, by contract, agency or otherwise.

"**Aggregate Environmental Defect Deductible**" has the meaning set forth in Section 4.12.

"**Aggregate Title Defect Deductible**" has the meaning set forth in Section 4.16.

"**Agreed Accounting Firm**" means KPMG, or if KPMG does not agree to serve as the Agreed Accounting Firm, then such other nationally-recognized independent accounting firm as mutually agreed to by Purchaser and Seller; provided that if the Parties cannot so agree within fourteen (14) days following the notification by KPMG that it does not agree to serve as the Agreed Accounting Firm, then either Party can request that the Houston, Texas office of the American Arbitration Association appoint such Agreed Accounting Firm.

"**Agreement**" has the meaning set forth in the Preamble.

"**Allocated Value**" has the meaning set forth in Section 3.1.

"**Asset Taxes**" means all Property Taxes and all Severance Taxes.

"**Assets**" has the meaning set forth in Section 2.2.

"**Assigned Office**" has the meaning set forth in Section 2.2(e).

"**Assignment**" shall mean the Assignment and Bill of Sale from Seller to Purchaser pertaining to the Assets and substantially in the form of Exhibit E.

"**Assumed Obligations**" has the meaning set forth in Section 11.1.

"**Business Day**" means a day (other than a Saturday or Sunday) on which commercial banks in Texas are generally open for business.

"**Casualty Loss**" means an event where any of the Assets are (a) taken in condemnation or under the right of eminent domain, or (b) damaged or destroyed by fire or other casualty or act of God.

"**Claim Notice**" has the meaning set forth in Section 11.7.

"**Closing**" has the meaning set forth in Section 10.1.

"**Closing Date**" means the date upon which Closing occurs (or should occur assuming the conditions to Closing have been satisfied or waived by the applicable Party).

"**Confidentiality Agreement**" means the Confidentiality Agreement, dated as of November 5, 2020, between Seller and Empire Petroleum Corp, a Delaware corporation.

"**Customary Post-Closing Consents**" means those consents and approvals from governmental authorities for the assignment of the Assets to Purchaser that are customarily obtained after such assignment of properties similar to the Assets.

"**Defect Notice Date**" has the meaning set forth in Section 4.3.

"**Defensible Title**" shall mean such title of Seller to the Wells that, as of the Effective Time and immediately prior to the Closing and subject to Permitted Encumbrances:

(a) with respect to the Well, entitles Seller to receive during the entirety of the productive life of such Well not less than the Net Revenue Interest for such Well as set forth in Exhibit B, except for (i) decreases in connection with those operations in which Seller or its successors or assigns may from and after the date of the execution of this Agreement be a non- consenting co-owner, (ii) decreases resulting from the establishment or amendment from and after the date of the execution of this Agreement of pools or units, (iii) decreases required to allow other Working Interest owners to make up past underproduction or pipelines to make up past under deliveries, and (iv) as otherwise expressly set forth in Exhibit B;

(b) with respect to the Well, obligates Seller to bear during the entirety of the productive life of such Well not more than the Working Interest for such Well as set forth in Exhibit B, except (i) increases resulting from contribution requirements with respect to defaulting co- owners under applicable operating agreements, (ii) increases to the extent that they are accompanied by a proportionate increase in Seller's Net Revenue Interest in such Well, (iii) increases resulting from the establishment or amendment from and after the date of the execution of this Agreement of pools or units, and (iv) as otherwise expressly set forth in Exhibit B; and

(c) is free and clear of all Encumbrances.

"**Deposit**" means an amount equal to ten percent (10%) of the Purchase Price.

"**Dispute Notice**" has the meaning set forth in Section 12.1(a).

"**Effective Time**" means 12:00:01 a.m. (Houston time) on January 1, 2021.

"**Employee List**" has the meaning set forth in Section 16.1.

"**Employees**" has the meaning set forth in Section 16.1.

"**Encumbrance**" means any lien, security interest, pledge, charge, defect or similar encumbrance.

"**Environmental Defect**" means a condition with respect to the air, land, soil, surface, subsurface strata, surface water, ground water or sediments that (a) constitutes a violation of Environmental Laws in effect as of the Effective Time in the jurisdiction to which the affected Assets are subject, or (b) constitutes a physical condition that requires, if known, or will require, once sufficiently discovered, reporting to a governmental authority, investigation, monitoring, removal, cleanup, remediation, restoration or correction under Environmental Laws. For the avoidance of doubt, (i) the fact that a Well is no longer capable of producing sufficient quantities of oil or gas to continue to be classified as a "producing well" or that such a Well should be temporarily abandoned or permanently plugged and abandoned shall not, in each case, form the basis of an Environmental Defect, (ii) the fact that a pipe is temporarily not in use shall not form the basis of an Environmental Defect, and (iii) except with respect to equipment (A) that causes or has caused any environmental pollution, contamination or degradation where Remediation is presently required (or if known or confirmed, would be presently required) under Environmental Laws or (B) the use or condition of which is a violation of Environmental Law in effect as of the Effective Time, the physical condition of any surface or subsurface production equipment, including water or oil tanks, separators or other ancillary equipment, shall not form the basis of an Environmental Defect.

"**Environmental Defect Notice**" has the meaning set forth in Section 4.10.

"**Environmental Defect Property**" has the meaning set forth in Section 4.10.

"**Environmental Law**" means any Laws pertaining to safety, health or conservation or protection of the environment, wildlife, or natural resources in effect in any and all jurisdictions in which the Assets are located, including the Clean Air Act, as amended, the Federal Water Pollution Control Act, as amended, the Safe Drinking Water Act, as amended, the Comprehensive Environmental Response, Compensation and Liability Act, as amended (" **CERCLA**"), the Superfund Amendments and Reauthorization Act of 1986, as amended, the Resource Conservation and Recovery Act, as amended ("**RCRA**"), the Hazardous and Solid Waste Amendments Act of 1984, as amended, the Toxic Substances Control Act, as amended, the Occupational Safety and Health Act, as amended, and any applicable state, tribal, or local counterparts, but shall not include any applicable Law associated with plugging and abandonment of any well. The terms "hazardous substance", "release", and "threatened release" shall have the meanings specified in CERCLA; provided, however, that to the extent the Laws of the state in which the Assets are located are applicable and have established a meaning for "hazardous substance", "release", "threatened release", "solid waste", "hazardous waste", and "disposal" that is broader than that specified in CERCLA or RCRA, such broader meaning shall apply with respect to the matters covered by such Laws.

"**Excluded Assets**" has the meaning set forth in Section 2.3.

"**Existing Contracts**" means, except for any Excluded Asset, all contracts, agreements and instruments by which any of the Leases, Wells or other Assets are bound, or to which any of the Leases, Wells or other Assets are subject (but in each case only to the extent applicable to such

Leases, Wells or other Assets and not to other properties of Seller or its Affiliates not included in the Assets), including operating agreements, unitization, pooling and communitization agreements, declarations and orders, joint venture agreements, farmin and farmout agreements, water rights agreements, exploration agreements, area of mutual interest agreements, participation agreements, exchange agreements, transportation or gathering agreements, agreements for the sale and purchase of Hydrocarbons and processing agreements; provided, that "Existing Contracts" shall exclude (a) any master service agreements, blanket agreements and similar contracts and
(ii) all of the instruments constituting the Leases, Rights-of-Way or creating or assigning any real property interest.

"**ExxonMobil Policies**" has the meaning set forth in Section 11.11.

"**Final Payment Date**" has the meaning set forth in Section 12.1(a).

"**Final Price**" has the meaning set forth in Section 12.1(a).

"**Final Settlement Date**" has the meaning set forth in Section 12.1(a).

"**Final Settlement Statement**" has the meaning set forth in Section 12.1(a).

"**GAAP**" means generally accepted accounting principles in the United States, consistently applied.

"**Hydrocarbons**" means all oil and gas and all other hydrocarbons produced or processed in association therewith.

"**Indemnity Deductible**" has the meaning set forth in Section 11.5(a).

"**Individual Environmental Defect Threshold**" has the meaning set forth in Section 4.12.

"**Individual Title Defect Threshold**" has the meaning set forth in Section 4.6.

"**Imbalance**" means any Pipeline Imbalance or Well Imbalance.

"**Indemnified Party**" has the meaning set forth in Section 11.8.

"**Indemnifying Party**" has the meaning set forth in Section 11.8.

"**Interim Period**" means the period from and after the execution of this Agreement up until the Closing.

"**Knowledge**" means with respect to Seller, the actual knowledge (upon reasonable investigation) of the Persons set forth on Schedule 1.1.

"**Law**" means any applicable law, statute, regulation, ordinance, order, code, ruling, writ, injunction, decree or other act of or by any governmental authority (including any administrative, executive, judicial, legislative, regulatory or taxing authority).

"**Leases**" has the meaning set forth in Section 2.2(a).

"**Like-Kind Exchange Transaction**" means a like-kind exchange, in whole or in part, as provided in Section 1031 of the Internal Revenue Code and the Treasury Regulations thereto, and if applicable, Rev. Proc. 2000-37, 2000-2 C.B. 308 (Sept. 18, 2000), as amended by Rev. Proc. 2004-51, 2004-33 I.R.B. 294 (Jul. 20, 2004).

"**Longstop Date**" has the meaning set forth in Section 10.1.

"**Losses**" means any and all claims, causes of action, proceedings, hearings, payments, charges, judgments, injunctions, orders, decrees, assessments, liabilities, losses, damages, penalties, fines, obligations, deficiencies, debts or costs and expenses, including any attorneys' fees, legal or other expenses incurred in connection therewith and including liabilities, costs, losses and damages for personal injury or death or property damage or environmental damage or Remediation.

"**Material Adverse Effect**" means with respect to Seller, any event, result, occurrence, condition or circumstance that, individually or in the aggregate (whether foreseeable or not and whether covered by insurance or not), results in a material adverse effect on the (a) ownership or operation of the Assets, taken as a whole and as currently operated as of the date of the execution of this Agreement, or (b) ability of any Seller to consummate the transactions contemplated by this Agreement and perform its obligations hereunder; provided, however, that a Material Adverse Effect shall not include any material adverse effects resulting from: (i) entering into this Agreement or the announcement of the transactions contemplated by this Agreement; (ii) changes in general market, economic, financial or political conditions (including changes in commodity prices (including Hydrocarbons), fuel supply or transportation markets, interest or rates) in the area in which the Assets are located, the United States or worldwide; (iii) conditions (or changes in such conditions) generally affecting the oil and gas and/or gathering, processing or transportation industry whether as a whole or specifically in any area or areas where the Assets are located; (iv) acts of God, including storms or meteorological events; (v) orders, actions or failures to act of governmental authorities; (vi) civil unrest or similar disorder, the outbreak of hostilities, terrorist acts or war; (vii) any actions taken or omitted to be taken (A) by or at the written request or with the prior written consent of Purchaser or (B) as expressly permitted or prescribed hereunder; (viii) matters that are cured or no longer exist by the earlier of the Closing and the termination of this Agreement; (ix) any Casualty Loss; (x) a change in Laws or in GAAP interpretation from and after the date of the execution of this Agreement; (xi) reclassification or recalculation of reserves in the ordinary course of business; and (xii) natural declines in well performance.

"**Material Contracts**" has the meaning set forth in Section 5.14.

"**Near Retirement Eligible Employees**" has the meaning set forth in Section 16.2.

"**Net Revenue Interest**" means with respect to any Well, the interest in and to all Hydrocarbons produced, saved and sold from or allocated to such Well, after giving effect to all royalties, overriding royalties, production payments, carried interests, net profits interests, reversionary interests and other burdens upon, measured by or payable out of production therefrom.

"**NORM**" means naturally occurring radioactive material.

"**Overriding Royalty**" means an overriding royalty interest for the benefit of Seller equal to four percent (4%) (not proportionally reduced) net revenue interest in the Leases and contractual interests in any individual field in which such Leases and contractual interests are located insofar and only insofar as such interests pertain to the time period after which Purchaser conducts any carbon dioxide tertiary recovery efforts commencing after the Effective Time in such field.

"**Parties**" and "**Party**" has the meaning set forth in the Preamble.

"**Performance Bond**" has the meaning set forth in Section 7.5.

"**Permit**" means all permits, licenses, authorizations, registrations, consents or approvals (in each case) granted or issued by any governmental authority.

"**Permitted Encumbrances**" means with respect to any Asset, any of the following:

(a) the terms and conditions of all Leases and all lessor's royalties, non-participating royalties, overriding royalties, reversionary interests and similar burdens upon, measured by or payable out of production if the net cumulative effect of such Leases and burdens does not operate to reduce the Net Revenue Interest of Seller in any Well below the Net Revenue Interest as set forth in Exhibit B for such Well and does not operate to increase the Working Interest of Seller in such Well above the Working Interest for such Well as set forth in Exhibit B for such Well (unless the Net Revenue Interest for such Well is greater than the Net Revenue Interest for such Well as set forth in Exhibit B in the same proportion as any increase in such Working Interest);

(b) Preferential Rights and consents (including Required Consents) to assignment and similar transfer restrictions or requirements;

(c) liens for taxes or assessments not yet delinquent or, if delinquent, that are being contested in good faith in the normal course of business;

(d) materialman's, mechanic's, repairman's, employee's, contractor's, operator's, and other similar liens or charges arising in the ordinary course of business (i) if they have not been filed pursuant to Law, or (ii) if filed, they have not yet become due and payable;

(e) liens or Encumbrances in the form of a judgment secured by a supersedeas bond or other security approved by the court issuing the order;

(f) the loss of lease acreage between the Effective Time and Closing because the lease term expires;

(g) Customary Post-Closing Consents and any required notices to, or filings with, governmental authorities in connection with the consummation of the transactions contemplated by this Agreement;

(h) rights of reassignment arising upon final intention to abandon or release the Assets, or any of them;

(i) the Rights-of-Way and, to the extent that they do not materially interfere with the operation of the Assets (as currently operated), all other easements, rights-of-way, servitudes, Permits, surface leases and other rights relating to surface operations. facilities, pipelines, transmission lines, transportation lines, distribution lines and other like purposes;

(j) all other liens, charges, encumbrances, contracts, agreements, instruments, obligations, defects and irregularities affecting the Assets which individually or in the aggregate are not such as to materially interfere with the operation of any of the Assets (as currently operated), do not reduce the Net Revenue Interest of Seller in any Well below the Net Revenue Interest set forth on Exhibit B for such Well, and do not increase the Working Interest of Seller in such Well above the Working Interest set forth in Exhibit B) for such Well (unless the Net Revenue Interest for such Well is greater than the Net Revenue Interest for such Well as set forth in Exhibit B in the same proportion as any increase in such Working Interest);

(k) all rights reserved to or vested in any governmental authority to control or regulate any of the Assets in any manner, and all applicable Permits and Laws;

(l) rights of a common owner of any interest in Rights-of-Way or Permits held by Seller and such common owner as tenants in common or through common ownership;

(m) liens created under Leases or Rights-of-Way included in the Assets and/or operating agreements or production sales contracts or by operation of Law in respect of obligations that are not yet due or delinquent or, if delinquent, which are being contested in good faith by appropriate procedures by or on behalf of Seller;

(n) any Encumbrance affecting the Assets that is discharged by Seller at or prior to Closing;

(o) any Title Defects that Purchaser may have expressly waived in writing or which are deemed to have been waived under Section 4.4, or that do not meet the Individual Title Defect Deductible or Aggregate Title Defect Deductible as set forth in Section 4.6;

(p) the terms and conditions of the Existing Contracts to the extent that they do not, individually or in the aggregate, (i) reduce the Net Revenue Interest of Seller in any Well below the Net Revenue Interest as set forth in Exhibit B for such Well, (ii) increase the Working Interest of Seller in such Well above the Working Interest for such Well as set forth in Exhibit B for such Well (unless the Net Revenue Interest for such Well is greater than the Net Revenue Interest for such Well as set forth in Exhibit B in the same proportion as any increase in such Working Interest) or (iii) impair in any material respect the prudent or current ownership and/or operation of any of the Assets by Seller (or by Purchaser as Seller's successor-in-interest from and after Closing);

(q) the terms and conditions of this Agreement;

(r) all Imbalances;

(s) the litigation, suits and proceedings set forth in Schedule 5.9 to the extent that such litigation, suits or proceedings do not, individually or in the aggregate, to (i) reduce the Net Revenue Interest of Seller in any Well below the Net Revenue Interest as set forth in Exhibit B for such Well, (ii) increase the Working Interest of Seller in such Well above the Working Interest for such Well as set forth in Exhibit B for such Well (unless the Net Revenue Interest for such Well is greater than the Net Revenue Interest for such Well as set forth in Exhibit B in the same proportion as any increase in such Working Interest) or (iii) impair in any material respect the prudent or current ownership and/or operation of any of the Assets by Seller (or by Purchaser as Seller's successor-in-interest from and after Closing); and

(t) any matter that would not constitute a Title Defect under the terms of this Agreement.

"**Person**" means an individual, corporation, partnership, association, trust, limited liability company or any other entity or organization, including government or political subdivisions or an agency, unit or instrumentality thereof.

"**Pipeline Imbalance**" means any marketing imbalance between the quantity of Hydrocarbons attributable to the Assets required to be delivered by any Seller under any contract or Law relating to the purchase and sale, gathering, transportation, storage, processing or marketing of such Hydrocarbons and the quantity of Hydrocarbons attributable to the Assets actually delivered by Seller pursuant to the relevant contract or at Law, together with any appurtenant rights and obligations concerning production balancing at the delivery point into the relevant sale, gathering, transportation, storage or processing facility.

"**Plugging and Abandonment Obligations**" has the meaning set forth in Section 11.1(b).

"**Preferential Rights**" has the meaning set forth in Section 4.8.

"**Preliminary Settlement Statement**" has the meaning set forth in Section 10.2.

"**Property Expenses**" means all operating expenses (including Property Taxes and all insurance premiums or any other costs of insurance attributable to Seller's and/or its Affiliates' insurance and to coverage periods from and after the Effective Time but excluding in all cases, all costs and expenses of bonds, letters of credit or other surety instruments) and all capital expenditures (in each case) incurred in the ownership and operation of the Assets in the ordinary course of business and, where applicable, in accordance with the relevant operating or unit agreement, if any, and overhead costs charged to the Assets under the relevant operating agreement or unit agreement, if any, or otherwise allocable to the Assets, but excluding all Losses attributable to (i) personal injury or death, property damage or violation of any Law, (ii) Plugging and Abandonment Obligations, (iii) the Remediation of any environmental condition under applicable Environmental Laws, (iv) obligations with respect to Imbalances, or (v) obligations to pay Working Interest owners, royalties, overriding royalties or other interest owners revenues or proceeds attributable to sales of Hydrocarbons relating to the Assets, including those held in suspense.

"**Property Taxes**" means all ad valorem taxes, real property taxes, personal property taxes, and similar obligations relating to the Assets.

"**Purchase Price**" has the meaning set forth in Section 3.1.

"**Purchaser**" has the meaning set forth in the Preamble.

"**Purchaser Group**" means Purchaser and its Affiliates and each of their respective officers, directors, employees, agents and representatives.

"**Purchaser's Environmental Assessment**" has the meaning set forth in Section 4.9.

"**Records**" has the meaning set forth in Section 12.4(a).

"**Remediation**" means with respect to an environmental condition or Environmental Defect, the response required or allowed under Environmental Laws that completely addresses (for current and future use in the same manner as being currently used) the identified environmental condition or Environmental Defect at the lowest cost (considered as a whole) as compared to any other response that is required or allowed under Environmental Laws. "Remediation" may consist of or include taking no action, leaving the condition unaddressed, periodic monitoring, the use of institutional controls or the recording of notices in lieu of remediation, in each case, if such response is allowed under Environmental Laws and completely addresses and resolves (for current and future use in the same manner as being currently used) the identified environmental condition or Environmental Defect.

"**Remediation Amount**" means with respect to an environmental condition or Environmental Defect, the present value as of the Closing Date of the cost (net to Seller's interest) of the Remediation of such condition or defect; provided, however, that "Remediation Amount" shall not include (a) the costs of Purchaser's and/or its Affiliate's employees, or, if Seller is conducting the Remediation, Purchaser's project manager(s) or attorneys, (b) expenses for matters that are ordinary costs of doing business regardless of the presence of an Environmental Condition (e.g., those costs that would ordinarily be incurred in the day-to-day operations of the Assets or in connection with Permit renewal/amendment activities), (c) overhead costs of Purchaser and/or its Affiliates, (d) costs and expenses that would not have been required under Environmental Laws as they exist on the Closing Date or, if prior to the Closing Date, the date on which the Remediation action is being undertaken, or (e) any costs or expenses relating to the assessment, remediation, removal, abatement, transportation and disposal of any asbestos, asbestos-containing materials or NORM unless required to address a violation of Environmental Law. Notwithstanding anything to the contrary in this Agreement, the aggregate Remediation Amounts attributable to the effects of all Environmental Defects upon any Environmental Defect Property shall not exceed the Allocated Value of such Environmental Defect Property.

"**Required Consent**" means any consent or approval where the failure to obtain such consent or approval would cause (or give the lessor or grantor the right to cause) (a) the assignment of the Assets affected thereby to Purchaser to be void or voidable, or (b) the termination of or the right to terminate a Lease, Existing Contract or Right-of-Way under the express terms thereof.

"**Rights-of-Way**" means, except for any Excluded Asset, all permits, licenses, servitudes, easements, fee surface, surface leases and rights-of-way primarily used or held for use in connection with the ownership or operation of the Assets, other than Permits.

"**Royalty-Free Lease**" means a royalty-free oil and gas lease in the form attached as Exhibit C.

"**Scheduled Closing Date**" has the meaning set forth in Section 10.1.

"**Seller**" has the meaning set forth in the Preamble.

"**Seller Group**" means Seller and its Affiliates and each of their respective directors, officers, employees, agents and representatives.

"**Severance Taxes**" means all severance, production or other taxes measured by hydrocarbon production from the Assets, or the receipt of proceeds therefrom.

"**Suspense Funds**" has the meaning set forth in Section 12.2.

"**Target Settlement Date"** has the meaning set forth in Section 12.1(a).

"**Title Benefit**" has the meaning set forth in Section 4.7.

"**Title Benefit Amount**" has the meaning set forth in Section 4.7.

"**Title Defect**" means any Encumbrance, defect or other matter that causes Seller not to have Defensible Title; provided that the following shall not be considered Title Defects:

(a) defects arising out of lack of corporate or other entity authorization or defects consisting of the failure to recite marital status in a document or omissions of successions of heirship or estate proceedings, (in each case) unless Purchaser provides affirmative evidence that such that such corporate or other entity action was not authorized and has resulted, or such failure or omission (in either case) has resulted, in another Person's superior claim of title to the relevant Asset;

(b) defects based on a gap in Seller's chain of title in the applicable county records, unless such gap is affirmatively shown to exist in such records by an abstract of title, title opinion or landman's title chain or run sheet which documents shall be included in a Title Defect Notice and has resulted in another Person's superior claim of title to the relevant Asset;

(c) defects based upon the failure to record any federal, state or tribal Lease or Right- of-Way included in the Assets, or any assignments of interests in such Leases or Rights-of-Way included in the Assets, in the applicable county records, unless such failure has resulted in another Person's superior claim of title to the relevant Asset;

(d) defects arising from any prior oil and gas lease relating to the lands covered by the Leases or Units not being surrendered of record, unless Purchaser provides affirmative evidence that such prior oil and gas lease is still in effect and has resulted in another Person's actual and superior claim of title to the relevant Lease or Well;

(e) defects that affect only which Person has the right to receive payments of royalties or other burdens on production and that do not affect the validity of the underlying Lease;

(f) defects based solely on: (i) lack of information in Seller's files, (ii) references to an unrecorded document to which neither Seller nor any Affiliate of Seller is a party and which document is dated earlier than January 1, 1960; or (iii) any tax assessment, tax payment or similar records or the absence of such activities or records;

(g) any Encumbrance or loss of title resulting from Seller's conduct of business in compliance with this Agreement;

(h) defects as a consequence of cessation of production, insufficient production or failure to conduct operations during any period after the completion of a well capable of production in paying quantities on any of the Leases held by production, or lands pooled or unitized therewith, except to the extent a claims is pending with respect thereto or the cessation of production is affirmatively shown to have occurred within the past five years and it will give rise to a right of the lessor or other third party to terminate the underlying Lease, which documentation shall be provided by Purchaser to Seller in a Title Defect Notice;

(i) Encumbrances created under deeds of trust, mortgages and similar instruments by the lessor under a Lease covering the lessor's interests in the land covered thereby that would customarily be accepted in taking or purchasing such Leases and for which a reasonably prudent lessee would not customarily seek a subordination of such Encumbrance to the oil and gas leasehold estate prior to conducting drilling activities on the Lease;

(j) all defects or irregularities that have been cured or remedied by applicable statutes of limitation or statutes of prescription;

(k) all defects or irregularities resulting from lack of survey unless such survey is required by applicable Law;

(l) all defects or irregularities resulting from the failure to record releases of liens, production payments or mortgages that have expired on their own terms or the enforcement of which are barred by applicable statute of limitations;

(m) Encumbrances created under deeds of trust, mortgages and similar instruments by the grantor under a Right-of-Way that would customarily be accepted by a reasonably prudent oil and gas operator or reasonably prudent pipeline owner in taking or purchasing such Rights-of-Way;

(n) defects arising as a result of actions taken by Purchaser or Purchaser's failure to consent to any action pursuant to Section 7.1 below; and

(o) defects arising as a result of a change in applicable Law after the Effective Time.

In addition, evidence that Seller is receiving its full share of proceeds from a purchaser or third party operator attributable to its net revenue interest for any Well listed on Exhibit B shall create a presumption that no Title Defect exists.

"**Third Party Claim**" has the meaning set forth in Section 11.8.

"**Title Defect Amount**" has the meaning set forth in Section 4.5.

"**Title Defect Notice**" has the meaning set forth in Section 4.3.

"**Title Defect Property**" has the meaning set forth in Section 4.3.

"**Transaction Documents**" means those documents executed and delivered pursuant to or in connection with this Agreement.

"**Transferred Vehicles**" shall mean (i) those certain vehicles (or vehicle leases, to the extent permitted to be transferred by the applicable vehicle leasing company) that are directly associated with the transferred Employees and (ii) any other vehicles that Seller and Purchaser mutually agree shall be transferred from Seller to Purchaser.

"**Units**" has the meaning set forth in Section 2.2(c).

"**Wells**" has the meaning set forth in Section 2.2(b).

"**Well Imbalance**" means any imbalance at the wellhead between the amount of Hydrocarbons produced from a Well and allocable to the interests of Seller therein and the shares of production from the relevant Well to which Seller is entitled, together with any appurtenant rights and obligations concerning future in kind and/or cash balancing at the wellhead.

"**Willful Breach**" means with respect to any Party, such Party knowingly and intentionally breaches in any material respect (by refusing to perform or taking an action prohibited) any material covenant applicable to such Party.

"**Working Interest**" means with respect to any Well, the interest in and to such Well that is burdened with the obligation to bear and pay costs and expenses of maintenance, development and operations on or in connection with such Well, but without regard to the effect of any royalties, overriding royalties, production payments, net profits interests and other similar burdens upon, measured by or payable out of production therefrom.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Goodnight Cross Exhibit 15

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2023

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from _____________ to _____________

Commission File Number 001-16653

EMPIRE PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

DELAWARE
(State or Other Jurisdiction of Incorporation or Organization)

73-1238709
(I.R.S. Employer Identification No.)

2200 S. Utica Place, Suite 150, Tulsa, OK 74114
(Address of Principal Executive Offices) (Zip Code)

Registrant's telephone number, including area code: **(539) 444-8002**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock $.001 par value	**EP**	**NYSE American**

Securities registered pursuant to 12(g) of the Act: None
(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☐ Yes ☑ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☑ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☑ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☑ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☑ Smaller reporting company ☑ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☑ No

The aggregate market value of the voting and non-voting common equity held by non-affiliates, computed by reference to the closing sales price of such common equity as of the last business day of the registrant's most recently completed second fiscal quarter, was $112,628,653.

The number of shares of the registrant's common stock, $0.001 par value, outstanding as of March 25, 2024 was 25,623,674.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement relating to the registrant's 2024 annual meeting of stockholders have been incorporated by reference into Part III of this Annual Report on Form 10-K.

EMPIRE PETROLEUM CORPORATION
FORM 10-K
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FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report on Form 10-K constitute "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future by us or on our behalf. Such statements are generally identifiable by the terminology used such as "anticipate," "believe," "continue," "could," "estimate," "expect," "forecasted," "intend," "may," "might," "plan," "potential," "predict," "project," "should," "would" or other similar words, although not all forward-looking statements contain such identifying words.

By their very nature, forward-looking statements require management to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Factors that could cause actual results to differ materially from the results discussed in such forward-looking statements include, but are not limited to, those discussed in Item 1A ("Risk Factors") and elsewhere in this Form 10-K and in other documents that we file with or furnish to the Securities and Exchange Commission (the "SEC"), and the following:

- changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids;
- our ability to replace reserves and efficiently develop current reserves;
- uncertainties inherent in estimating oil and gas reserves;
- management's ability to execute our business plan;
- delays and other difficulties related to producing oil, natural gas and natural gas liquids;
- delays and other difficulties related to regulatory and governmental approvals and restrictions;
- availability of sufficient capital to execute management's business plan, including future cash flows from operations, available borrowing capacity under revolving credit facilities, from our two largest stockholders and otherwise;
- management's ability to make acquisitions on economically acceptable terms and management's ability to integrate acquisitions;
- weather and environmental conditions;
- unforeseen engineering, mechanical or technological difficulties in working over wells;
- costs of operations and operating hazards;
- competition from other natural resource companies;
- unanticipated reductions in the borrowing base under the revolving credit facility we are party to;
- the availability of sufficient pipeline and other transportation facilities and equipment to carry our production to market and the impact of these facilities on our realized prices;
- our ability to retain key members of senior management and key technical and financial employees;
- the identification of and severity of adverse events and governmental responses to these or other environmental events;
- future ESG compliance developments and increased attention to such matters which could adversely affect our ability to raise equity and debt capital;
- the effect of our derivative activities;
- impacts of public health crises, pandemics and epidemics, such as the coronavirus pandemic ("COVID-19");
- A cyber incident involving our information systems and related infrastructure, or that of our business partners;
- the effects of governmental and environmental regulation; and
- general economic conditions.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Form 10-K. Other than as required by applicable securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations, or otherwise. Readers should not place undue reliance on these forward-looking statements. All forward-looking statements speak only as of the date of this report or, if earlier, as of the date they were made.

GLOSSARY OF CERTAIN OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and within this report.

Bbl – One barrel or 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.

Boe – Barrel of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent. The ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas differs significantly from the price for a barrel of oil. A barrel of NGLs also differs significantly in price from a barrel of oil.

CG&A – Cawley, Gillespie & Associates, Inc.

DD&A – Depreciation, depletion and amortization.

ESG – Environmental, Social and Governance.

Field – An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

LOE – Lease Operating Expense, a current period expense incurred to operate a well.

MBbls – One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe – One thousand barrels of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

MMBoe – One million barrels of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.

Mcf – One thousand cubic feet.

MMcf – One million cubic feet.

Net acres or **net wells** – The sum of the fractional working interests owned in gross acres or gross wells.

NYSE American – NYSE American Stock Exchange.

NGLs – Natural gas liquids measured in barrels. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which have different uses and different pricing characteristics.

Net revenue interest or **NRI** –The total revenue interest controlled by an entity in a specific oil or gas production unit, including a well, lease, or drilling unit.

Operator – An oil and gas joint venture participant that manages the joint venture, pays venture costs, and bills the venture's non-operators for their share of venture costs. The operator is also responsible to market all oil, gas, and NGL production, except for those non-operators who take their production in-kind.

OTCQB – The over-the-counter (OTC) market exchange for the middle tier of three marketplaces for trading OTC stocks.

Overriding Royalty Interest or **ORRI** – A royalty interest that is created out of the operating or working interest. Unlike a royalty interest, an overriding royalty interest terminates with the operating interest from which it was created or carved out of.

Plugging and abandonment or **P&A** – Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another stratum or to the surface.

Proved developed producing reserves or **PDP** – Reserves that can be expected to be recovered from existing wells and completions with existing equipment and operating methods.

PV-10 – The present value, discounted at 10% per annum, of future net revenues (estimated future gross revenues less estimated future costs of production, development, and asset retirement costs) associated with reserves and is not necessarily the same as market value. PV-10 does not include estimated future income taxes. Unless otherwise noted, PV-10 is calculated using the pricing scheme required by the SEC. PV-10 of proved reserves is calculated the same as the standardized measure of discounted future net cash flows, except that the standardized measure of discounted future net cash flows includes future estimated income taxes discounted at 10% per annum.

Royalty Interest or **RI** – The mineral owner's share of production, free of costs, but subject to severance taxes unless the lessor is a government.

SEC – United States Securities and Exchange Commission.

Standardized Measure – The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue.

Undeveloped acreage – Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Working interest or **WI** – The ownership interest, generally defined in a Joint Operating Agreement ("JOA"), that gives the owner the right to drill, produce and/or conduct operating activities on the property and share in the sale of production, subject to all royalties, overriding royalties and other burdens and obligates the owner of the interest to share in all costs of exploration, development operations and all risks in connection therewith.

Workover – Operations on a producing or injection well to restore or increase production.

PART I

ITEM 1. BUSINESS.

In this Form 10-K, references to "Empire", the "Company", "we", "our", and "us" refer to Empire Petroleum Corporation and its wholly-owned subsidiaries, unless context indicates otherwise.

On March 8, 2022, our common stock began trading on the NYSE American under the symbol "EP" and CUSIP 292034303. Prior to trading on the NYSE American, our common stock was accessible on the OTCQB.

Overview

Empire Petroleum Corporation is an independent energy company that engages in unlocking value in developed assets. Empire operates the following wholly-owned subsidiaries in its areas of operations:

- Empire New Mexico LLC ("Empire New Mexico")
  - Empire New Mexico LLC d/b/a Green Tree New Mexico
  - Empire EMSU LLC
  - Empire EMSU-B LLC
  - Empire AGU LLC
  - Empire NM Assets LLC
- Empire Rockies Region
  - Empire North Dakota LLC ("Empire North Dakota")
  - Empire ND Acquisition LLC ("Empire NDA")
- Empire Texas ("Empire Texas"), consisting of the following entities:
  - Empire Texas LLC
  - Empire Texas Operating LLC
  - Empire Texas GP LLC
  - Pardus Oil & Gas Operating, LP (owned 1% by Empire Texas GP LLC and 99% by Empire Texas LLC)
- Empire Louisiana LLC ("Empire Louisiana")

Empire was incorporated in the state of Delaware in 1985. The consolidated financial statements of Empire Petroleum Corporation and subsidiaries include the accounts of the Company and its wholly-owned subsidiaries.

Our mission is to increase shareholder value by building oil and natural gas reserves in strategic plays in the United States. To accomplish its mission, we plan on executing the following business strategies:

- Cost-effectively optimize well production
- Reduce unit operating costs and improve margins
- Target proved developed producing acquisitions in predictable fields that have historically had low production decline and long lives
- Focus on high-quality assets that add scale and provide synergies to our existing portfolio and core areas of operation

We operate as a single segment as each of our operating areas have similar economic characteristics and each meet the criteria for aggregation as defined by accounting standards related to disclosures about segments of an enterprise.

Available Information

Our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as well as proxy statements and other information we file with, or furnish to, the SEC are available free of charge on our website at www.empirepetroleumcorp.com. We make these documents available as soon as reasonably practicable after we electronically file them with, or furnish them to, the SEC. The information contained on our website, or available by hyperlink from our website, is not incorporated into this Form 10-K or other documents we file with, or furnish to, the SEC. We intend to use our website as a means of disclosing material non-public information and for complying with our disclosure obligations under Regulation FD. Such disclosures will be included on our website in the "Investor Relations" sections. Accordingly, investors should monitor such portions of our website, in addition to following our press releases, SEC filings and public conference calls and webcasts.

In addition, we use social media to communicate with our investors and the public about our company, our businesses and our results of operations. The information we post on social media could be deemed to be material information. Therefore, we encourage investors, the media and others interested in our company to review the information we post on the social media channels listed in the "Investor Relations" section of our website.

Properties

We are an independent operator in four geographic areas in the United States. As operator, we manage and influence production on operated properties. We use a combination of experienced field personnel and third-party service providers to execute our mission. Our producing properties have reasonably predictable production profiles and cash flows, subject to commodity price and cost fluctuations.

As is common in the industry in which we operate, we selectively participate in drilling and developmental activities in non-operated properties. Decisions to participate in non-operated properties are made after technical and economic analysis of the projects which also considers the operating expertise and historical track record of the operators.

Empire New Mexico

Empire New Mexico was formed when we purchased producing assets from XTO in May 2021. These assets are located in Lea County, New Mexico and include approximately 670 gross (483 net) producing and injection wells on a contiguous and consolidated acreage position consisting of 48,000 gross (41,000 net). We also have 14 RI wells with an average ORRI of 11%. Empire New Mexico's assets primarily produce oil with natural gas and NGLs accompanying oil production. Empire New Mexico's properties are in the following formations:

- Grayburg/San Andres (primary source of production)
- Queen-Seven Rivers-Yates
- Devonian
- Abo
- Blineberry
- Tubb
- Drinkard

We have begun technical work for uplift opportunities in New Mexico.

Empire North Dakota

Empire North Dakota includes approximately 138 gross (108 net) producing or injection wells on 24,000 gross (18,000 net) acres in North Dakota and western Montana. We also have smaller nonoperating interests in 70 gross (less than 1 net) vertical wells. These properties primarily produce oil with some related gas production. Assets are located in the following formations:

- Madison (primary source of production)
- Bakken
- Duperow
- Red River
- Ratcliffe/Mission Canyon

The existing producing properties have experienced near-flat production rates over the last five years. We have been able to capitalize on operational improvements to allow more immediate recovery of reserves.

In the fourth quarter of 2023, the Company commenced a program to further develop its Starbuck Field located in North Dakota (the "Starbuck Drilling Program"). Empire expects 2024 to be a year of progress as it continues to advance the Starbuck Drilling Program.

The Starbuck Drilling Program's first well came online in December 2023 and a total of five wells in the Upper Charles formation have been placed on production as of the filing date of this report. The Company is currently optimizing completions while increasing the core production through its enhanced oil recovery ("EOR") program.

The Company currently has one rig in the Starbuck Field. As the Starbuck Field is strategically designed for EOR production, the Company anticipates EOR development to begin in the second quarter of 2024 with the goal of providing a meaningful increase in production beginning as soon as the second half of 2024 and going forward.

Empire has also logged five vertical pilot wells to help identify additional pay and extend existing reservoirs, which has confirmed three additional primary zones of interest and two secondary zones of interest. In addition, the Company has drilled a vertical appraisal well in the Starbuck Field to core two new target zones for development. The two new primary target zones of development have been successfully cored and the cores are under analysis. The data will then be added to the development plan while the vertical well will be placed on production in the first quarter of 2024.

Empire Texas

Empire Texas includes approximately 121 gross (106 net) producing wells on approximately 43,000 gross (30,000 net) acres as well as 77 miles of gathering lines and pipelines with related facilities and equipment. Empire Texas owns concentrated acreage and stacked pay in the historically prolific East Texas Basin. Assets are concentrated in the Fort Trinidad Field in Houston and Madison Counties with high working interest and historical production from eight separate formations. We have begun technical work for uplift opportunities in Texas.

Empire Louisiana

Empire Louisiana includes 12 gross (10 net) producing wells and three saltwater disposal wells in the Miocene, Frio, Cockfield, and Wilcox formations. Empire Louisiana's assets primarily produce oil.

Production and Operating Data

The following table sets forth a summary of our production and operating data for the years ended December 31, 2023 and 2022. Because of normal production declines, increased or decreased production due to future acquisitions, divestitures, and development, fluctuations in commodity prices and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Year Ended December 31, 2023	Year Ended December 31, 2022
Production and operating data:		
Net sales volumes:		
Oil (Bbl)	487,869	482,818
Natural gas (Mcf)	854,274	875,647
Natural gas liquids (Bbl)	136,013	160,809
Total (Boe)	766,261	789,568
Average price per unit:		
Oil (a)	$ 75.19	$ 93.16
Natural gas	$ 2.02	$ 5.18
Natural gas liquids	$ 12.21	$ 22.76
Total (Boe)	$ 52.29	$ 67.34
Operating costs and expenses per Boe:		
Lease operating expense (excluding workovers)	$ 21.70	$ 19.92
Workovers	$ 15.66	$ 9.95
Total Lease operating expense	$ 37.36	$ 29.87
Production and ad valorem taxes	$ 3.97	$ 4.99
Depreciation, depletion, amortization and accretion	$ 6.33	$ 4.19
General & administrative (excluding stock-based compensation)	$ 15.71	$ 12.18
Stock-based compensation	$ 4.10	$ 3.44

(a) Excludes the effect of net cash receipts from (payments on) derivatives.

At December 31, 2023 and 2022, we had approximately 1,000 gross (710 net) producing and injection wells.

We have no firm delivery commitments for oil or natural gas.

Oil and Natural Gas Reserves

Our primary mission is to optimize existing producing properties; as such, there are no reserves estimated for undeveloped properties, though we own acreage that can be drilled in the future and are also a non-operator WI owner on acreage subject to future drilling activities. The following table represents our oil and natural gas reserves at December 31, 2023 and 2022.

	Oil (Mbbl)	Natural Gas (MMcf)	NGL (Mbbl)	MBoe
Proved developed at December 31, 2023	6,924	6,104	1,171	9,112
Proved developed at December 31, 2022	8,826	12,936	2,262	13,244

Net proved reserves were calculated using an unweighted arithmetic average of the first-day-of-the-month price within the 12-month period for the year. All prices and costs associated with operating wells were held constant in accordance with SEC guidelines. Prices of $75.45 per barrel of oil, $1.51 per Mcf and $9.82 per barrel of NGL were utilized at December 31, 2023. Prices of $91.14 per barrel and $4.23 per Mcf and $36.29 per barrel of NGL were utilized at December 31, 2022.

Reserve Estimation Process

Reserve estimation is a subjective process as the underground accumulations of crude oil and natural gas cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. The quantities of oil and natural gas that are ultimately recovered, production and operating costs, and future oil and natural gas prices may differ from those assumed in these estimates. Our internal professionals work closely with our external engineers to ensure the integrity, accuracy, and timeliness of data that is furnished to them for their reserve estimation process.

We engage an independent petroleum engineering firm, CG&A, to prepare our annual reserve estimates and rely on CG&A's expertise to ensure that reserve estimates are prepared in accordance with SEC guidelines.

The technical person primarily responsible for the preparation of the reserve report is Zane Meekins, Executive Vice President. Mr. Meekins has been with CG&A since 1989 and graduated from Texas A&M University in 1987 with a bachelor's degree in Petroleum Engineering. He is a registered professional engineer in Texas and has more than 30 years of experience in the estimation and evaluation of oil and natural gas reserves. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

Brian Weatherl, Vice President of Engineering for the Company, is responsible for our reservoir engineering, and is a qualified reserve estimator and is responsible for overseeing CG&A during the preparation of the annual reserve estimates. His professional qualifications meet or exceed the qualifications of reserve estimators set forth in the "Standards Pertaining to Estimation and Auditing of Oil and Natural Gas Reserve Information" promulgated by the Society of Petroleum Engineers. His qualifications include a Bachelor of Science degree in Petroleum Engineering from the University of Tulsa in 1984 and he is a member of the Society of Petroleum Engineers. Mr. Weatherl has been estimating and evaluating reserves for over 35 years.

The primary inputs to the reserve estimation process are technical information, financial data, ownership interest and production data. The relevant field and reservoir technical information, which is updated at least annually, is assessed for validity when CG&A has technical meetings with our personnel. Current revenue and expense information is obtained from accounting records, which are subject to external quarterly reviews, annual audits, and internal controls over financial reporting. All current financial data such as commodity prices, lease operating expenses, production taxes and field level commodity price differentials are updated in the reserve database and then analyzed to ensure that they have been entered accurately and that all updates are complete. Our ownership in mineral interests and well production data are subject to internal controls and are incorporated into the reserve database as well as verified internally by our personnel to ensure accuracy and completeness. Once the reserve database has been updated with current information, and the relevant technical support material has been assembled, CG&A meets with technical personnel to review field performance and future development plans in order to verify the validity of estimates. Following these reviews, the reserve database is furnished to CG&A so that it can prepare its independent reserve estimate and final report. The reserve estimates prepared by CG&A are reviewed and compared to internal estimates by Mr. Weatherl. Material reserve estimation differences are reviewed between CG&A and our technical personnel and additional data is provided to address any variances. If the supporting documentation does not justify additional changes, CG&A reserves are accepted. In the event that additional data supports a reserve estimation adjustment, CG&A will analyze the additional data and may make changes it solely deems necessary. Additional data is usually comprised of updated production information on new wells. Once the review is completed and all material differences are reconciled the reserve report is finalized and our reserve database is updated with the final estimates provided by CG&A.

Marketing Arrangements

We market our oil and natural gas in accordance with standard energy industry practices. This marketing effort endeavors to obtain the combined highest netback and most secure market available at that time.

We sell oil production at the lease locations to third-party purchasers via truck transport or pipeline. We do not transport, refine or process the oil we produce. We sell our produced oil under contracts using market-based pricing, which is adjusted for differentials based upon oil quality.

We sell our natural gas and natural gas liquids under purchase contracts using market-based pricing, which is primarily sold at the lease location.

Principal Customers

We sell our oil, natural gas, and NGL production to marketers which is transported by truck or pipeline to storage facilities arranged by the marketers. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted.

For 2023, 70% of revenues from oil, natural gas, and NGL sales were to three customers. For 2022, 68% of revenues from oil, natural gas, and NGL sales were to four customers. While the loss of these purchasers may result in a temporary interruption in sales of, or a lower price for, our production, we believe that the loss of these purchasers would not have a material adverse effect on our operations, as there are alternative purchasers in our producing regions.

Competition

The oil and natural gas industry in the areas in which we operate is highly competitive. We encounter strong competition from numerous parties, ranging generally from small independent producers to major integrated companies. We primarily encounter significant competition in acquiring properties. At higher commodity prices, we also face competition in contracting for oil field services, rigs, pressure pumping and workover equipment and securing trained personnel. Many of these competitors have financial, technical and personnel resources substantially larger than ours. As a result, our competitors may be able to pay more for desirable properties, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

In addition to competition for drilling, pressure pumping and workover equipment, we are also affected by the availability of related equipment and materials. The oil and natural gas industry periodically experiences shortages of drilling and workover rigs, equipment, pipe, materials and personnel, which can delay workover and exploration activities and cause significant price increases. We are unable to predict the timing or duration of any such shortages.

Seasonality of Business

Weather conditions often affect the demand for, and prices of, natural gas and can also delay oil and natural gas production. Demand for natural gas is traditionally higher in the winter, resulting in higher natural gas prices during the first and fourth quarters. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results realized on an annual basis.

Markets and Price Volatility

The market price of oil and natural gas is volatile, subject to speculative movement and depends upon numerous factors beyond our control, including expectations regarding inflation, global and regional demand, political and economic conditions and production costs. Future profitability, if any, will depend substantially upon the prevailing prices for oil and natural gas. If the market price for oil and natural gas remains depressed in the future, it could have a material adverse effect on our ability to raise additional capital necessary to finance operations. Lower oil and natural gas prices may also reduce the amount of oil and natural gas, if any, that can be produced economically from our properties. We anticipate that the prices of oil and natural gas will fluctuate in the near future.

Regulation

The oil and natural gas industry is subject to extensive federal, state and local laws and regulations governing the production, transportation and sale of hydrocarbons as well as the taxation of income resulting therefrom. Legislation affecting the oil and natural gas industry is constantly changing. Numerous federal and state departments and agencies have issued rules and regulations applicable to the oil and natural gas industry. In general, these rules and regulations regulate, among other things, the extent to which acreage may be acquired or relinquished; spacing of wells; measures required for preventing waste of oil and natural gas resources; and, in some cases, rates of production. The heavy and increasing regulatory burdens on the oil and natural gas industry increase our cost of doing business and, consequently, affect profitability.

Our oil and natural gas operations are also subject to numerous federal, state and local laws and regulations relating to environmental protection. These laws govern, among other things, the amounts and types of substances and materials that may be released into the environment, the issuance of permits in connection with exploration, drilling and production activities, the reclamation and abandonment of wells and facility sites and the remediation of contaminated sites. These laws and regulations may impose substantial liabilities if we fail to comply or if any contamination results from our operations.

Employees

At December 31, 2023, we had 50 full-time employees, not including contract personnel and outsourced service providers. Our team is broadly experienced in oil and natural gas operations and follows a strategy of outsourcing most accounting, human resources, and other non-core functions.

Office Locations

Our corporate headquarters are at 2200 South Utica Place, Suite 150, Tulsa, Oklahoma, with field offices in North Dakota, Texas, and New Mexico.

ITEM 1A. RISK FACTORS.

Our operations are subject to various risks and uncertainties in the ordinary course of business. The following summarizes significant risks and uncertainties that may adversely affect our operations or financial position. Risks and uncertainties discussed below are not a comprehensive listing of those faced by us. Additional risks not presently known or that are deemed immaterial may also affect us. Readers should carefully consider the risk factors included below and other information included and incorporated by reference into this Annual Report on Form 10-K.

Reserves

The Standardized Measure and PV-10 of estimated reserves may not be accurate estimates of the current fair value of estimated proved oil and natural gas reserves.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. PV-10, a non-GAAP (Generally Accepted Accounting Principles) financial measure, is a similar reporting convention that we have disclosed in this report. Both measures require the use of operating and development costs prevailing as of the date of computation. Consequently, they will not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may they reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included in this report of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the 10 percent discount factor, which is required by the rules and regulations of the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Therefore, Standardized Measure and PV-10 included in this report should not be construed as accurate estimates of the current market value of our proved reserves.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. Estimates of proved reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate. Petroleum engineering is a subjective process of estimating accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations by governmental agencies;
- the quality, quantity and interpretation of available relevant data;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs, severance and ad valorem taxes, development costs and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on the average previous twelve months first-of-month prices preceding the date of the estimate and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;
- levels of future capital spending;
- increases or decreases in the supply of or demand for oil, natural gas, and NGLs; and
- changes in governmental regulations or taxation.

Accordingly, estimates included in this report of future net cash flows may be materially different from the future net cash flows that are ultimately received. Therefore, the estimates of discounted future net cash flows in this report should not be construed as accurate estimates of the current market value of our proved reserves.

Unless reserves are replaced, production and estimated reserves will decline, which may adversely affect our financial condition, results of operations and/or cash flows.

Producing oil and natural gas reservoirs are generally characterized by declining production rates that may vary depending upon reservoir characteristics and other factors. Estimates of the decline rate of an oil or natural gas well are inherently imprecise and may be less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Estimated future oil and natural gas reserves and production and, therefore, cash flows and results of operations are highly dependent upon our success in efficiently developing and exploiting current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, cash flows and the value of reserves may decrease, adversely affecting our business, financial condition and results of operations.

Financing

We have indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse business developments.

Our total indebtedness at December 31, 2023 was $5.7 million. At December 31, 2023, commitments from a financial institution under a Revolving Credit Facility (the "Credit Facility") with Empire North Dakota and Empire NDA were approximately $10.0 million, of which approximately $5.5 million was unused and approximately $4.5 million was outstanding. In addition, we had approximately $1.1 million outstanding under a joint development agreement with a related party as of December 31, 2023 (See Note 4 of Notes to Consolidated Financial Statements). Management continues to review existing indebtedness, and may seek to repay, refinance, repurchase, redeem, exchange or otherwise terminate existing indebtedness. If we do seek to refinance existing indebtedness, there can be no guarantee that we would be able to execute the refinancing on favorable terms or at all.

As a result of indebtedness, we use a portion of our cash flow to pay interest, which reduces the amount available to fund operations and other business activities and could limit flexibility in planning for or reacting to changes in the business and the industry in which we operate. Indebtedness under the Credit Facility is at a variable interest rate, and so a rise in interest rates will generate greater interest expense.

We may incur substantially more debt in the future. The Credit Facility contains restrictions on the incurrence of additional indebtedness.

Increases in the level of indebtedness could have adverse effects on our financial condition and results of operations, including:

- imposing additional cash requirements on us in order to support interest payments, which reduces the amount we have available to fund our operations and other business activities;
- increasing the risk that we may default on our debt obligations;
- increasing our vulnerability to adverse changes in general economic and industry conditions, economic downturns and adverse developments in our business;
- limiting our ability to sell assets, engage in strategic transactions or obtain additional financing for working capital, capital expenditures, general corporate and other purposes;
- limiting our flexibility in planning for or reacting to changes in our business and the industry in which we operate; and
- increasing our exposure to a rise in interest rates, which will generate greater interest expense.

Our ability to meet our debt obligations and reduce our level of indebtedness depends on future performance, which is affected by general economic conditions and financial, business and other factors, many of which are outside of the scope of management's control.

Our business requires substantial capital expenditures. Management may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in oil and natural gas reserves.

The oil and natural gas industry is capital intensive. Management makes and expects to continue to make substantial capital expenditures for the acquisition and development of reserves. We intend to finance future capital expenditures through cash flow from operations, incurring additional indebtedness, or capital raises. However, cash flow from operations and access to capital are subject to a number of variables, including:

- the volume of oil, natural gas, and NGLs we are able to produce from existing wells;
- ability to transport oil and natural gas to market;
- the prices at which commodities are sold;
- the costs of producing oil and natural gas;
- global and domestic demand for oil and natural gas;
- global credit and securities markets;
- the ability and willingness of lenders and investors to provide capital and the cost of the capital;
- ability to acquire, locate and produce new reserves;
- the impact of potential changes in our credit ratings; and
- proved reserves.

We may not generate expected cash flows and obtain the capital necessary to sustain our operations at current or anticipated levels. A decline in cash flow from operations or our financing needs may require management to revise our capital program or alter or increase capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under the Credit Facility or the issuance of additional debt securities will require that a greater portion of cash flow from operations be used for the payment of interest and principal on debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, management may curtail activities or be forced to sell some assets on an untimely or unfavorable basis.

The loss or unavailability of capital provided by our two largest stockholders could have a material adverse effect on our business.

Our two largest stockholders, Energy Evolution Master Fund, Ltd. and Phil Mulacek, have been a significant source of capital for our acquisitions of oil and natural gas properties and the development of our oil and natural gas reserves. We have been dependent on this capital to fund our growth plans, including our current drilling programs. The loss of this capital could have a material adverse effect on our business, especially our growth plans.

If we are unable to comply with the covenants in our agreements governing our indebtedness, including the Credit Facility, there could be a default under the terms of such agreements, which could result in an acceleration of payment of funds that we have borrowed.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which management is unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional equity on terms that we may not find attractive if it may be done at all. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest, if any, on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the agreements governing our indebtedness, including the Credit Facility, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;
- the lenders could elect to terminate their commitments thereunder and cease making further loans; and
- we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may need to obtain waivers under the Credit Facility to avoid being in default. If we breach our covenants and cannot obtain a waiver from the required lender, we would be in default and the lender could exercise its rights, as described above, and we could be forced into bankruptcy or liquidation.

A negative shift in stakeholder sentiment towards the oil and natural gas industry and increased attention to ESG matters and conservation matters could adversely affect our ability to raise equity and debt capital.

Much of the investor community has developed negative sentiment towards investing in our industry over the past few years. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. Some investors, including certain public and private fund management firms, pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and natural gas sector based on environmental, social and governance considerations. Certain other stakeholders have pressured private equity firms and commercial and investment banks to stop funding oil and gas projects. Such developments have resulted and could continue to result in downward pressure on the stock prices of oil and natural gas companies, including ours. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results.

Increasing attention to climate change, societal expectations on companies to address climate change, investor and societal expectations regarding voluntary ESG disclosures, and consumer demand for alternative forms of energy may result in increased costs, reduced demand for our products, reduced profits, increased investigations and litigation, and negative impacts on our stock price and access to capital markets. Increasing attention to climate change and environmental conservation, for example, may result in demand shifts for oil and natural gas products and additional governmental investigations and private litigation against us or our operators. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Moreover, while we may create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures are based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Currently, there are no universal standards for such scores or ratings, but the importance of sustainability evaluations is becoming more broadly accepted by investors and stockholders. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with energy-related assets could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our access to and costs of capital. Also, institutional lenders may decide not to provide funding for fossil fuel energy companies based on climate change related concerns, which could affect our access to capital for potential growth projects.

General Operations

The oil and natural gas industry is highly competitive, and our size may put us at a disadvantage in competing for resources.

The oil and natural gas industry is highly competitive where our properties and operations are concentrated. We compete with major integrated and larger independent oil and natural gas companies in seeking to acquire desirable oil and natural gas properties and leases and for the equipment and services required to develop and operate properties. Many of our competitors have financial and other resources that are substantially greater than ours, which makes acquisitions of acreage or producing properties at economic prices difficult. Significant competition also exists in attracting and retaining technical personnel, including geologists, geophysicists, engineers, landmen and other specialists, as well as financial and administrative personnel. Hence, we may be at a competitive disadvantage to companies with larger financial resources than ours.

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas, which could be negatively affected by concerns about public health crises, pandemics and epidemics, such as the COVID-19 pandemic;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including trade or other economic sanctions, armed conflict in Ukraine and the Middle East, the price cap on Russian oil and embargoes, in or affecting other oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions, including extreme climatic events;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. Lower prices also negatively impact the value of our proved reserves. Volatility in the price of oil could force us (as well as other operators) to re-evaluate our current capital expenditure budget and make changes accordingly that we believe are in the best interest of us and our stockholders. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our producing properties and proved reserves are concentrated in New Mexico, North Dakota, Montana, Texas, and Louisiana, making us vulnerable to risks associated with operating in limited major geographic areas.

Our producing properties are geographically concentrated in New Mexico, North Dakota, Montana, Texas, and Louisiana. At December 31, 2023, all of our total estimated proved reserves were attributable to properties located in these areas. As a result of this concentration, we are exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by governmental regulation, processing or transportation capacity constraints, market limitations, severe weather events, water shortages or other drought related conditions or interruption of the processing or transportation of oil or natural gas.

This concentration of assets exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

Our insurance policies may not adequately protect us against certain unforeseen risks.

In accordance with customary industry practice, we maintain insurance against some, but not all, of the risks described in this report. There can be no assurance that any insurance will be adequate to cover our losses or liabilities. We cannot predict the continued availability of insurance, or its availability at premium levels that justify its purchase.

We are subject to various environmental risks, and governmental regulation relating to environmental matters.

We are subject to a variety of federal, state and local governmental laws and regulations related to the storage, use, discharge and disposal of toxic, volatile or otherwise hazardous materials. These regulations subject us to increased operating costs and potential liability associated with the use and disposal of hazardous materials. Although these laws and regulations have not had a material adverse effect on our financial condition or results of operations, there can be no assurance that we will not be required to make material expenditures in the future. Moreover, we anticipate that such laws and regulations will become increasingly stringent in the future, which could lead to material costs for environmental compliance and remediation by us. Any failure by us to obtain required permits for, control the use of, or adequately restrict the discharge of hazardous substances under present or future regulations could subject us to substantial liability or could cause our operations to be suspended. Such liability or suspension of operations could have a material adverse effect on our business, financial condition and results of operations.

Our activities are subject to extensive governmental regulation. Oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic or political conditions. From time to time, regulatory agencies have imposed price controls and limitations on production in order to conserve supplies of oil and natural gas. In addition, the production, handling, storage, transportation and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. To date, expenditures related to complying with these laws and for remediation of existing environmental contamination have not been significant in relation to our operations. There can be no assurance that the trend of more expansive and stricter environmental legislation and regulations will not continue.

If forecasted prices for oil, natural gas and NGL decrease, we may be required to take significant future write-downs of the financial carrying values of our properties in the future.

Accounting rules require that we periodically review the carrying value of our proved and unproved properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to significantly write-down the financial carrying value of our oil and natural gas properties, which constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are recorded.

A write-down could occur when oil and natural gas prices are low or if we have substantial downward adjustments to our estimated proved oil and natural gas reserves, or if operating costs or development costs increase over prior estimates.

The capitalized costs of our oil and natural gas properties, on a field-by-field basis, may exceed the estimated future net cash flows of that field. If so, we would record impairment charges to reduce the capitalized costs of such field to our estimate of the field's fair market value. Unproved properties are evaluated at the lower of cost or fair market value. These types of charges will reduce our earnings and stockholders' equity and could adversely affect our stock price.

We periodically assess our properties for impairment based on future estimates of proved and non-proved reserves, oil and natural gas prices, production rates and operating, development and reclamation costs based on operating budget forecasts. Once incurred, an impairment charge cannot be reversed at a later date even if price increases of oil and/or natural gas occur and in the event of increases in the quantity of our estimated proved reserves.

If oil, natural gas and NGL prices fall below current levels for an extended period of time and all other factors remain equal, we may incur impairment charges in the future. Such charges could have a material adverse effect on our results of operations for the periods in which they are recorded.

Properties we acquire may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain and include properties with which we do not have a long operational history. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of a property. We may be required to assume the risk of the physical condition of properties in addition to the risk that they may not perform in accordance with our expectations. If properties we acquire do not produce as projected or have liabilities we were unable to identify, we could experience a decline in our reserves and production, which could adversely affect our business, financial condition and results of operations.

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions we or other operators may take when drilling, completing, or operating wells that we or they own.

Many of our properties are in reservoirs that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore (and potentially away from existing wellbores). As a result, the drilling and production of these potential locations by us or other operators could cause depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities, including water disposal activities, conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

Acquisitions involve a number of risks, including the risk that we will discover unanticipated liabilities or other problems associated with the acquired business or property.

In assessing potential acquisitions, we consider information available in the public domain and information provided by the seller. In the event publicly available data is limited, then, by necessity, we may rely to a large extent on information that may only be available from the seller, particularly with respect to drilling and completion costs and practices, geological, geophysical and petrophysical data, detailed production data on existing wells, and other technical and cost data not available in the public domain. Accordingly, the review and evaluation of businesses or properties to be acquired may not uncover all existing or relevant data, obligations or actual or contingent liabilities that could adversely impact any business or property to be acquired and, hence, could adversely affect us as a result of the acquisition. These issues may be material and could include, among other things, unexpected environmental liabilities, title defects, unpaid royalties, taxes or other liabilities.

The success of any acquisition that we complete will depend on a variety of factors, including our ability to accurately assess the reserves associated with the acquired properties, assumptions related to future oil and natural gas prices and operating costs, potential environmental and other liabilities and other factors. These assessments are often inexact and subjective. As a result, we may not recover the purchase price of a property from the sale of production from the property or recognize an acceptable return from such sales or operations.

Our ability to achieve the benefits that we expect from an acquisition will also depend on our ability to efficiently integrate the acquired operations. Management may be required to dedicate significant time and effort to the integration process, which could divert its attention from other business opportunities and concerns. The challenges involved in the integration process may include retaining key employees and maintaining employee morale, addressing differences in business cultures, processes and systems and developing internal expertise regarding acquired properties.

Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which we may conduct oil, natural gas and NGL exploration and production activities, and reduce demand for the oil, natural gas and NGL we produce.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the Clean Air Act, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, impose new standards reducing methane emissions from oil and gas operations through limitations on venting and flaring and the implementation of enhanced emission leak detection and repair requirements, and together with the United States Department of Transportation, implement GHG emissions limits on vehicles manufactured for operation in the United States. The federal regulation of methane emissions from oil and natural gas facilities has been subject to considerable attention in recent years. In December 2023, the EPA finalized new and updated rules for both new and existing sources. The final rules make existing regulations more stringent, expand the scope of source types covered by the rules and require states to develop plans to reduce methane and volatile organic compound emissions from existing sources. These new rules will likely be subject to legal challenges. As a result, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and natural gas industry remain a significant possibility.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates elected to public office. President Biden has issued several executive orders focused on addressing climate change, including items that may impact costs to produce, or demand for, oil and gas. There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies may elect in the future to shift some or all of their investments into other sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. For example, at COP26, the Glasgow Financial Alliance for Net Zero ("GFANZ") announced that over 450 firms in the financial sector across 45 countries committed to net zero goals. The various sub-alliances of GFANZ generally require participants to set short-term, sector-specific targets to transition their financing, investing, and/or underwriting activities to net zero emissions by 2050. There is also a risk that financial institutions will be pressured or required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. President Biden signed an executive order calling for the development of a "climate finance plan" and, separately, the Federal Reserve has joined the Network for Greening the Financial System ("NGFS"), a consortium of financial regulators focused on addressing climate-related risks in the financial sector. In November 2021, the Federal Reserve issued a statement in support of the efforts of the NGFS to identify key issues and potential solutions for the climate-related challenges most relevant to central banks and supervisory authorities. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

Additionally, in March 2024, the SEC issued a final rule that requires a public company to disclose, among other things, material climate-related risks, activities to mitigate or adapt to such risks, information about the company’s board of directors' oversight of climate-related risks and management’s role in managing material climate-related risks, and information on any climate-related targets or goals that are material to the company’s business, results of operations, or financial condition. The final rule also requires, on a phased-in basis, disclosure of Scope 1 and/or Scope 2 GHG emissions by certain larger public companies, which currently would not apply to Empire given its size, when those emissions are material and the filing of an attestation report covering the required disclosure of such company’s Scope 1 and/or Scope 2 emissions. The new rule is already subject to legal challenges. Although the ultimate impact of the new rule on our business is uncertain given such legal challenges, compliance with the new rule, if upheld, may result in additional legal, accounting and financial compliance costs.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas. Additionally, political, litigation and financial risks may result in us restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

As a final note, climate change could have an effect on the severity of weather (including hurricanes, droughts and floods), sea levels, water availability and quality, and meteorological patterns. If such effects were to occur, our development and production operations have the potential to be adversely affected.

Potential adverse effects could include damages to our facilities from powerful winds, extreme temperatures, or rising waters in low-lying areas, disruption of our production activities either because of climate related damages to our facilities or in our costs of operation potentially arising from such climatic effects, less efficient or non- routine operating practices necessitated by climate effects or increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. Additionally, changing meteorological conditions, particularly temperature, may result in changes to the amount, timing, or location of demand for energy or the products we produce. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

The marketability of our production is dependent upon gathering systems, transportation facilities and processing facilities that we do not own or control. If these facilities or systems are unavailable, our oil and natural gas production can be interrupted and our revenues reduced.

The marketability of our oil and natural gas production is dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems, transportation and processing facilities owned by third parties. In general, we will not control these facilities, and our access to them may be limited or denied due to circumstances beyond our control. A significant disruption in the availability of these facilities could adversely impact our ability to deliver to market the hydrocarbons we produce and thereby cause a significant interruption in our operations. In some cases, our ability to deliver to market our hydrocarbons is dependent upon coordination among third parties that own transportation and processing facilities we use, and any inability or unwillingness of those parties to coordinate efficiently could also interrupt our operations. The lack of availability or the lack of capacity on these systems and facilities could result in the curtailment of production or the delay or discontinuance of drilling plans. These are risks for which we generally will not maintain insurance.

We operate or participate in oil and natural gas leases with third parties who may not be able to fulfill their commitments to our projects.

In some cases, we operate but own less than 100% of the working interest in the oil and natural gas leases on which we conduct operations, and other parties own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas and NGL prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

Because we cannot control activities on properties we do not operate, we cannot directly control the timing of exploitation. If we are unable to fund required capital expenditures with respect to non-operated properties, our interests in those properties may be reduced or forfeited.

Our ability to exercise influence over operations and costs for the properties we do not operate is limited. Our dependence on the operators and other working interest owners for these projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital with respect to acquisition, exploration and development activities. The success and timing of development, exploitation and exploration activities on properties operated by others depend upon a number of factors that may be outside our control, including but not limited to the timing and amount of capital expenditures; the operator's expertise and financial resources; the approval of other participants in drilling wells; and the selection of technology.

Where we are not the majority owner or operator of a particular oil and natural gas project, we may have no control over the timing or amount of capital expenditures associated with the project. If we are not willing or able to fund required capital expenditures relating to a project when required by the majority owner(s) or operator, our interests in the project may be reduced or forfeited. Also, we could be responsible for plugging and abandonment costs, as well as other liabilities in excess of our proportionate interest in the property.

We could be adversely affected by increased costs of service providers utilized by us.

In accordance with customary industry practice, we have relied and will rely on independent third-party service providers to provide most of the services necessary to operate. The industry has experienced significant price fluctuations for these services during the last year and this trend is expected to continue into the future. These cost uncertainties could, in the future, significantly increase our production costs.

Our ability to use our existing net operating loss carryforwards or other tax attributes could be further limited.

In the event that an entity has an "ownership change" (as defined in Section 382 of the Internal Revenue Code of 1986, as amended (the "Code")), an entity's federal net operating loss carryforwards ("NOLs") generated prior to an ownership change would be subject to annual limitations, which could defer or eliminate our ability to utilize these tax losses against future taxable income. Generally, an "ownership change" occurs if one or more stockholders, each of whom owns 5% or more in value of a corporation's stock, increase their aggregate percentage ownership by more than 50% over the lowest percentage of stock owned by those stockholders at any time during the preceding three-year period. A full Section 382 analysis was prepared in 2023 and it was determined that our NOLs were subject to limitations under Section 382.

At December 31, 2023, we had approximately $24.3 million of federal NOLs generated in prior years that could offset against future taxable income, however, $4.7 million of the NOLs were limited as of December 31, 2023 due to ownership changes. NOLs created prior to 2018 have a 20-year expiration period and NOLs arising after 2017 have an indefinite life. Additionally, utilization of any NOL depends on many factors, including our ability to generate future taxable income, which cannot be assured. At December 31, 2023, we had a tax valuation allowance recorded on the NOLs.

In the event that we were to undergo any further "ownership change", our NOLs generated prior to an ownership change would be subject to further annual limitations, which could defer or eliminate our ability to utilize these tax losses against future taxable income. Depending on participation in our Rights Offering announced in March 2024, it is likely that an ownership change will occur which could further limit the utilization of the NOLs.

Legislation

Climate change legislation, regulations restricting emissions of "greenhouse gases" (GHG's) or legal or other action taken by public or private entities related to climate change could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

The threat of climate change continues to attract considerable attention in the United States and around the world. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG disclosure obligations and regulations that directly limit GHG emissions from certain sources. Moreover, President Biden highlighted addressing climate change as a priority of his administration, issued several executive orders related to climate change and recommitted the United States to long-term international goals to reduce emissions, and continues to require the incorporation of climate change considerations into executive agency decision-making. In recent years, Congress has considered legislation to reduce emissions of GHGs, including methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas. For example, the Inflation Reduction Act of 2022, which appropriates significant federal funding for renewable energy initiatives and, for the first time, imposes a fee on GHG emissions from certain facilities, was signed into law in August 2022. The emissions fee and funding provisions of the law could increase operating costs within the oil and natural gas industry and accelerate the transition away from fossil fuels, which could in turn adversely affect our business and results of operations.

At the international level, the United Nations ("UN") -sponsored "Paris Agreement" requires member states to submit non-binding, individually-determined reduction goals known as Nationally Determined Contributions every five years after 2020. President Biden has recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States' emissions by 50 to 52% below 2005 levels by 2030. Various U.S. states and local governments have also publicly committed to furthering the goals of the Paris Agreement. Additionally, at the UN Climate Change Conference of Parties ("COP26"), held in November 2021, the United States and the European Union jointly announced the launch of a Global Methane Pledge, an initiative committing to a collective goal of reducing global methane emissions by at least 30% from 2020 levels by 2030, including "all feasible reductions" in the energy sector. COP26 concluded with the finalization of the Glasgow Climate Pact, which stated long-term global goals (including those in the Paris Agreement) to limit the increase in the global average temperature and emphasized reductions in GHG emissions. These goals were reaffirmed at the November 2022 Conference of Parties ("COP27"). At COP27, the United States also announced, in conjunction with the European Union and other partner countries, that it would develop standards for monitoring and reporting methane emissions to help create a market for low methane-intensity natural gas. Moreover, various state and local governments have also publicly committed to furthering the goals of the Paris Agreement. In December 2023, the 28th session of Conference Parties was held where parties signed on to an agreement to transition away from fossil fuels and increase renewable energy capacity so as to achieve net zero by 2050, although no timeline for doing so is set. The full impact of these actions, and any legislation or regulation promulgated to fulfill the United States' commitments thereunder, is uncertain at this time, and it is unclear what additional initiatives may be adopted or implemented that may have adverse effects upon our operations.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Reduced demand for the oil and natural gas that we produce could also have the effect of lowering the value of our reserves. It should also be noted that some scientists have concluded that increasing concentrations of GHGs in the earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits or investigations brought by public and private entities against oil and natural gas companies in connection with their GHG emissions. Should we be targeted by any such litigation or investigations, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the causation of or contribution to the asserted damage, or to other mitigating factors. The ultimate impact of GHG emissions-related agreements, legislation and measures on our company’s financial performance is highly uncertain because we are unable to predict with certainty, for a multitude of individual jurisdictions, the outcome of political decision-making processes and the variables and tradeoffs that inevitably occur in connection with such processes.

Any change to government regulation or administrative practices may have a negative impact on our ability to operate and our profitability.

Oil and natural gas operations are subject to substantial regulation under federal, state and local laws relating to the exploration for, and the development, upgrading, marketing, pricing, taxation, and transportation of, oil and natural gas and related products and other associated matters. Amendments to current laws and regulations governing operations and activities of oil and natural gas exploration and development operations could have a material adverse impact on our business. In addition, there can be no assurance that income tax laws, royalty regulations and government programs related to our oil and natural gas properties and the oil and natural gas industry generally will not be changed in a manner which may adversely affect our progress or cause delays.

Permits, leases, licenses, and approvals are required from a variety of regulatory authorities at various stages of exploration and development. There can be no assurance that the various government permits, leases, licenses and approvals sought will be granted in respect of our activities or, if granted, will not be cancelled or will be renewed upon expiration. There is no assurance that such permits, leases, licenses, and approvals will not contain terms and provisions which may adversely affect our exploration and development activities.

Other

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. We are dependent on digital technologies including information systems and related infrastructure, to process and record financial and operating data, communicate with our employees, business partners, and stockholders, analyze 3-D seismic and drilling information, estimate quantities of oil and natural gas reserves as well as other activities related to our business.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems for the purposes of misappropriating assets or sensitive information, corrupting data, causing operational disruption, or result in denial-of-service on websites.

Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period of time. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, data, facilities and infrastructure may result in increased capital and operating costs. Costs for insurance may also increase as a result of security threats, and some insurance coverage may become more difficult to obtain, if available at all. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations.

The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

We depend greatly on the efforts of our executive officers and other key employees to manage our operations. The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

We have had material weaknesses in our internal control over financial reporting in prior fiscal years. Failure to maintain effective internal control over financial reporting could adversely affect our ability to report our financial condition and results of operations accurately and on a timely basis. As a result, our business, operating results and liquidity could be harmed.

As disclosed in our prior annual reports on Form 10-K, we identified a material weakness in internal controls over financial reporting as of December 31, 2022 and 2021. We believe that this material weakness has been successfully remediated.

Our failure to maintain effective internal control over financial reporting could adversely affect our ability to report our financial results on a timely and accurate basis, which could result in a loss of investor confidence in our financial reports or have a material adverse effect on our ability to operate our business or access sources of liquidity. Furthermore, because of the inherent limitations of any system of internal control over financial reporting, including the possibility of human error, the circumvention or overriding of controls and fraud, even effective internal controls may not prevent or detect all misstatements.

We do not expect to declare or pay any dividends in the foreseeable future.

We have not declared or paid any dividends on our common stock. We currently intend to retain future earnings to fund the development and growth of our business, to repay indebtedness and for general corporate purposes, and therefore, do not anticipate paying any cash dividends on our common stock in the foreseeable future.

The price of our common stock may fluctuate significantly, which could negatively affect us and holders of our common stock.

Our common stock trades on the NYSE American. The trading price of our common stock may fluctuate significantly in response to a number of factors, many of which are beyond our control. Adverse events including changes in production volumes, worldwide demand and prices for crude oil and natural gas, regulatory developments, and changes in any securities analysts' estimates of our financial performance could negatively impact the market price of our common stock. General market conditions, including the level of, and fluctuations in, the trading prices of stocks generally could also have a similar negative impact. The stock markets regularly experience price and volume volatility that affects many companies' stock prices without regard to the operating performance of those companies. Volatility of this type may affect the trading price of our common stock.

Provisions of our certificate of incorporation and bylaws and Delaware law may inhibit a takeover, which could limit the price investors might be willing to pay in the future for our common stock.

Provisions in our certificate of incorporation and bylaws may have the effect of delaying or preventing an acquisition of us or a merger in which we are not the surviving company and may otherwise prevent or slow changes in our board of directors and management. In addition, because we are incorporated in Delaware, we are governed by the provisions of Section 203 of the General Corporation Law of the State of Delaware, which provides certain restrictions on business combinations involving interested parties. These provisions could discourage an acquisition of us or other change in control transactions and thereby negatively affect the price that investors might be willing to pay in the future for our common stock.

Holders of our outstanding Series A Voting Preferred Stock have effective control of our board of directors.

We have six shares of Series A Voting Preferred Stock currently issued and outstanding. The Series A Voting Preferred Stock was issued in connection with the strategic investment in us by Energy Evolution Master Fund, Ltd. For so long as the Series A Voting Preferred Stock is outstanding, our board of directors will consist of six directors. Three of the directors are designated as the Series A Directors and the three other directors (each, a "common director") are elected by the holders of common stock and/or any preferred stock (other than the Series A Voting Preferred Stock) granted the right to vote on the common directors. Any Series A Director may be removed with or without cause but only by the affirmative vote of the holders of a majority of the Series A Voting Preferred Stock voting separately and as a single class. The holders of the Series A Voting Preferred Stock have the exclusive right, voting separately and as a single class, to vote on the election, removal and/or replacement of the Series A Directors. Holders of common stock or other preferred stock have no right to vote on the Series A Directors. In addition, in the case of any tie vote or deadlock of the board of directors, our current Chairman of the Board, a Series A Director, has the deciding, tiebreaking vote. Accordingly, the holder(s) of our Series A Voting Preferred Stock have effective control of our board of directors for so long as the voting rights of the Series A Voting Preferred Stock remain in effect.

Our bylaws provide that the Court of Chancery of the State of Delaware (or if the Court of Chancery does not have jurisdiction, the federal district court for the District of Delaware) will be the exclusive forum for certain legal actions between us and our stockholders. These provisions could increase costs to bring a claim, discourage claims or limit the ability of our stockholders to bring a claim in a judicial forum viewed by the stockholders as more favorable for disputes with us or our directors, officers or employees.

Our bylaws provide that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware (or if the Court of Chancery does not have jurisdiction, the federal district court for the District of Delaware) will be the sole and exclusive forum for (a) any derivative action or proceeding brought on our behalf, (b) any action asserting a claim of breach of a fiduciary duty owed by any director, officer, stockholder, employee or agent to us or our stockholders, (c) any action asserting a claim arising pursuant to any provision of the General Corporation Law of the State of Delaware, our certificate of incorporation or our bylaws, or (d) any action asserting a claim governed by the internal affairs doctrine, in each case subject to the court having personal jurisdiction over the defendants. This exclusive forum provision is intended to apply to claims arising under Delaware state law and is not intended to apply to claims arising under the Securities Act of 1933, as amended, or the Securities Exchange Act of 1934, as amended. The choice of forum provisions may increase costs to bring a claim, discourage claims or limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers or employees, which may discourage such lawsuits against us or our directors, officers and employees. Alternatively, if a court were to find the choice of forum provision contained in our bylaws to be inapplicable or unenforceable in an action, we may incur additional costs associated with resolving such action in other jurisdictions.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 1C. CYBERSECURITY.

The Company, with the assistance of a third party, has policies, standards, processes and practices for assessing, identifying, and managing material risks from cybersecurity threats. We engage third party personnel resources to implement and maintain security measures to meet regulatory requirements, and we intend to add internal personnel and further investments to maintain the security of our data and cybersecurity infrastructure. There can be no guarantee that our policies and procedures will be properly followed in every instance or that those policies and procedures will be effective. Our risk factors, which can found be found in Item 1A. "Risk Factors," include further detail about the material cybersecurity risks we face. There can be no assurance that there will not be incidents in the future or that they will not materially affect us, including our business strategy, results of operations, or financial condition.

Risk Management and Strategy Overview

Currently, we rely on our third party for much of our cybersecurity efforts. Internally, we are working towards formally employing and documenting a risk-based approach to cybersecurity which aligns with corporate strategy, risk management and governance, and adaptable information technology ("IT") infrastructure. Our cybersecurity program will consist of policies, procedures, systems, controls and technology designed to help prevent, identify, detect and mitigate cybersecurity risk and will be based on a cybersecurity framework, such as the National Institute of Standards and Technology ("NIST") Cybersecurity framework.

To protect our IT systems and information from cybersecurity risks, we, through our third-party provider, use various security tools that help prevent, identify, escalate, investigate, resolve, and recover from identified cybersecurity vulnerabilities and incidents in a timely manner. These include the utilization of a third-party security operations center connected to a network operation center to identify, investigate, and resolve any cybersecurity threats and incidents.

We assess, at least annually, the technological risks to our key IT systems and information. We have implemented controls to identify and manage cybersecurity risks associated with all third-party service providers. These include, but are not limited to, an understanding of access controls, a records and information management policy, change control procedures, risk and control registry, attestation report reviews, and configuration standards.

Employee awareness of cybersecurity risks and threats is also an important part of an effective control environment. We periodically communicate to employees about this cybersecurity awareness. In 2024, we plan to require each of our employees to complete annual information security training, in addition to other training requirements. This should lead to an educated, informed, and prepared workforce, with an awareness of potential cybersecurity threats, how they may occur, and how to report and escalate such matters.

Our cybersecurity strategy focuses on implementing effective and efficient controls, technologies, and other processes to assess, identify, and manage material cybersecurity risks to our IT systems and information. As a part of this process, we have engaged an independent third-party specialist to review our cybersecurity environment, including formal reviews and assessments, and we have requested specific, actionable recommendations for improvement and implementation.

While we have not, as of the date of this Annual Report on Form 10-K, experienced a cybersecurity incident that has materially impacted our business or operations, there can be no guarantee that we will not experience such a threat or incident in the future. A material cybersecurity threat or incident could adversely impact our operations, our sales or financial and administrative functions, or result in the compromise of personal or other confidential information of our employees, customers, or suppliers. For this reason, we maintain cybersecurity liability insurance to provide additional support, expertise, and resources to help ensure the integrity of our cybersecurity processes and to provide a level of financial protection in the event of cybersecurity incident related costs and losses.

Governance

Our Audit Committee has oversight of our cybersecurity risk processes, as part of its overall oversight of our risk management program. Our CFO is informed about and facilitates prevention, detection, mitigation, and remediation efforts through regular communication and reporting from the third party provider. In addition, we have an escalation process in place to inform our Chief Executive Officer and other members of our senior management and, if necessary, the Audit Committee and Board of Directors, of important issues or events.

ITEM 2. PROPERTIES.

Information regarding our properties is included in Item 1 above and in our consolidated financial statements, which is incorporated herein by reference.

ITEM 3. LEGAL PROCEEDINGS.

In the ordinary course of business, we may be involved in litigation and claims arising from operations. As of December 31, 2023, and through the filing date of this Annual Report on Form 10-K, management does not believe the ultimate resolution of any such actions or potential actions of which management is currently aware will have a material effect on our consolidated financial position or results of operations.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Market Information

Our common stock is traded on the NYSE American under the symbol "EP".

Stockholders

At March 28, 2024, there were approximately 1,250 stockholders of record of our common stock.

Dividends

We have never paid cash dividends on our common stock. We intend to retain future earnings for use in our business and, therefore, do not anticipate paying cash dividends on our common stock in the foreseeable future. Future payment of dividends will depend upon, but not be limited to, our financial condition, funds available for operations, the amount of anticipated capital and other expenditures, future business prospects and any restrictions imposed by present or future financing arrangements.

Issuer Repurchase of Equity Securities

No private or open market repurchases of common stock were made by us during the fourth quarter of 2023.

Unregistered Sales of Equity Securities

No such sales that have not been previously reported on a Quarterly Report on Form 10-Q or a Current Report on Form 8-K.

ITEM 6. RESERVED.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following discussion should be read together with the consolidated financial statements and notes to consolidated financial statements, which are included in this Annual Report on Form 10-K in Item 8, Financial Statements and Supplementary Data, and the information set forth in Part I, Item 1A – Risk Factors.

Overview

Our primary business is the optimization and development of oil and gas interests. In 2022 we had net income from operations but have incurred losses from operations in 2023 and in years prior to 2022. There is no assurance that we will be profitable or obtain funds necessary to finance our future operations.

We seek to increase shareholder value by growing reserves, production, revenues, and cash flow from operating activities by executing our mission to use highly-skilled personnel to thoughtfully and expertly spend capital to realize reserves on producing properties as well as further develop fields.

Management places emphasis on operating cash flow in managing our business, as operating cash flow considers the cash expenses incurred during the period and excludes non-cash expenditures not related directly to our operations.

Production and Operating Data

The following table sets forth a summary of our production and operating data for the years ended December 31, 2023 and 2022.

		Year Ended December 31, 2023		Year Ended December 31, 2022
Production and operating data:				
Net sales volumes:				
Oil (Bbl)		487,869		482,818
Natural gas (Mcf)		854,274		875,647
Natural gas liquids (Bbl)		136,013		160,809
Total (Boe)		766,261		789,568
Average price per unit:				
Oil (a)	$	75.19	$	93.16
Natural gas	$	2.02	$	5.18
Natural gas liquids	$	12.21	$	22.76
Total (Boe)	$	52.29	$	67.34
Operating costs and expenses per Boe:				
Lease operating expense (excluding workovers)	$	21.70	$	19.92
Workovers	$	15.66	$	9.95
Total Lease operating expense	$	37.36	$	29.87
Production and ad valorem taxes	$	3.97	$	4.99
Depreciation, depletion, amortization and accretion	$	6.33	$	4.19
General & administrative (excluding stock-based compensation)	$	15.71	$	12.18
Stock-based compensation	$	4.10	$	3.44

(a) Excludes the effect of net cash receipts from (payments on) derivatives.

Business Strategy

Our business strategy is to obtain long-term growth in reserves and cash flow on a cost-effective basis. Management regularly evaluates potential acquisitions of properties that would enhance current core areas of operation.

Results of Operations

The following table reflects our summary operating information. Because of normal production declines, increased or decreased drilling activity and the effects of acquisitions, the historical information presented below should not be interpreted as indicative of future results.

	Years Ended December 31, 2023	Years Ended December 31, 2022	$ Variance	Variance %
Oil revenues	$ 36,684,494	$ 44,978,554	(8,294,060)	-18%
Natural gas revenues	1,726,754	4,534,370	(2,807,616)	-62%
NGL revenues	1,660,256	3,659,451	(1,999,195)	-55%
Total product revenues	40,071,504	53,172,375		
Lease operating expense	28,625,481	23,584,039	5,041,442	21%
Production and ad valorem taxes	3,044,411	3,943,466	(899,055)	-23%
Depreciation, depletion, amortization and accretion	4,852,555	3,307,097	1,545,458	47%
Impairment	—	936,620	(936,620)	-100%
General and administrative expense (excluding stock-based compensation)	12,034,184	9,614,948	2,419,236	25%
Stock-based compensation	3,144,751	2,716,541	428,210	16%
Cash-based interest expense	650,637	473,205	177,432	37%
Non-cash interest expense	349,790	36,335	313,455	NM
Operating Income (Loss)	(11,625,091)	8,784,163	(20,409,254)	NM
Net Income (Loss)	(12,469,605)	7,084,130	(19,553,735)	NM

NM: A percentage calculation is not meaningful due to change in signs, a zero-value denominator or a percentage change greater than 200.

Revenues

Revenues for 2023 decreased compared to the prior year primarily due to lower realized oil, natural gas and NGL prices and lower NGL volumes, partially offset by higher oil volumes in North Dakota.

Realized oil prices for 2023, were approximately $75.19 per barrel, while realized prices for the prior year were approximately $93.16 per barrel, a decrease in price of approximately 19%. Oil volumes were higher by approximately 5,000 barrels primarily due to increased production in North Dakota partially offset by lower production in New Mexico.

Realized natural gas prices for 2023, were approximately $2.02 per Mcf, while realized prices for the prior year were approximately $5.18 per Mcf, a decrease in price of approximately 61%.

Realized NGL prices for 2023, were approximately $12.21 per barrel, while realized prices for the prior year were approximately $22.76 per barrel, a decrease in price of approximately 46%. NGL sales volumes were lower in 2023 compared to 2022 primarily due to lower volumes in New Mexico.

Lease Operating Expense and Production Taxes

Lease operating expense was higher in 2023 primarily due to higher workover activities. Lease operating expense includes approximately $12.0 million of workover expense for 2023 as compared to approximately $7.9 million for 2022. Workover expense in New Mexico increased due in part to a higher level of compliance-related activities. In addition, workover expense in North Dakota was higher for 2023 as the Company continued to work over wells in the state to enhance production alongside capital recompletions and sidetrack drilling started in 2022.

Production taxes were lower for 2023 compared to 2022 as a result of the lower product revenues discussed above.

Depreciation, Depletion, Amortization and Accretion and Impairment

The higher DD&A in 2023 as compared to 2022 primarily related to a higher depletable basis from capital expenditures in 2023. Accretion expense was higher in 2023 as the overall obligation increases over time.

We assess our oil and gas properties for impairment when circumstances indicate the carrying value may be greater than its estimated future net cash flows. In 2022, estimated future cash flows from our properties in Louisiana were less than the net book value. As a result, we recorded a $936,000 impairment expense.

General and Administrative Expense (excluding stock-based compensation)

General and Administrative Expense (excluding stock-based compensation) increased primarily due to higher employee expenses related to increased headcount in 2023 compared to 2022 and $505,000 related to severance expense for two executives in 2023 (See Note 14 of Notes to Consolidated Financial Statements). Board compensation expense, exclusive of stock-based compensation, was approximately $588,000 in 2023 as compared to $388,000 in 2022. In addition, 2023 expenses were higher due to legal costs related to potential financing transactions and compliance work related to our New Mexico operations. In 2022, we recognized expenses totaling approximately $1,269,000 in conjunction with resolution of a Texas sales tax audit for prior periods for which the initial assessment was received in April 2022. This total includes consulting fees and an accrual for $528,000 for the final settlement which was paid in 2023.

Stock-based Compensation

We utilize stock-based compensation to compensate members of management and retain talented personnel. Our stock-based compensation increased in 2023 due to a higher number of awards in 2023. We anticipate stock-based compensation to continue to be utilized in 2024 and beyond to attract and retain talented personnel and compensate our board members and consultants.

Interest Expense

Cash-based interest expense increased as higher interest rates were partially offset by a lower outstanding balance under our Credit Facility. We have minimal interest-bearing vehicle and equipment notes payable.

Non-cash interest expense is primarily attributable to the related party note payable as described in Note 7 of Notes to Consolidated Financial Statements. In addition, 2023 includes interest from $10,000,000 of bridge loans from related parties that were subsequently converted to equity (See Note 15 of Notes to Consolidated Financial Statements).

Income taxes

We have generated net operating losses since inception, which would normally reflect a tax benefit in the consolidated statement of operations and a deferred asset on the consolidated balance sheet. However, because of the current uncertainty as to our ability to achieve sustained profitability and the potential limitation of NOL carryforwards, a valuation reserve has been established that offsets the amount of any tax benefit available for each period presented in the consolidated statements of operations.

For 2023, we had a loss before income taxes for which the tax benefit was offset by a change in valuation allowance. For 2022, we had income before income taxes which resulted in a tax provision that was offset by a change in the valuation allowance due to the anticipated use of the NOL carryforward and intangible drilling costs. For 2023 and 2022, our effective tax rates were 1% and 3%, respectively.

Liquidity

As noted below, our working capital is negative as of December 31, 2023 and is primarily a result of a higher level of payables related to capital spending in North Dakota. In addition, the Company was not in compliance with the current ratio covenant under its Credit Facility as of December 31, 2023; however, the Company obtained a compliance waiver from the lender for December 31, 2023. As of December 31, 2023, we had approximately $8 million in cash on hand and approximately $5.5 million available on the Credit Facility. For additional information regarding the Credit Facility, see Note 7 of Notes to Consolidated Financial Statements. The Company will require additional funds to satisfy these payables related to the capital spending program which are greater than estimated cash flows from operations over the next 12 months. Management has initiated plans to raise the necessary funds including the commencement of a rights offering expected to raise up to approximately $20.66 million (see Note 18 of Notes to Consolidated Financial Statements). Phil Mulacek and Energy Evolution Master Funds, Ltd, both related parties of the Company and largest shareholders collectively owning 46% of the common shares outstanding, have indicated that they intend to participate in the rights offering and fully subscribe to the shares of Common Stock corresponding to their subscription rights and intend to exercise their over-subscription rights. See Note 1 - Liquidity and Going Concern of Notes to Consolidated Financial Statements for further discussion of management's plans.

We expect to incur costs related to drilling activities in core areas. It is expected that management will use a combination of cash on hand and cash flows from operations as well as seeking additional debt or equity funding to fund these ongoing activities.

Working Capital

Working capital (presented below) was $(6.3) million as of December 31, 2023 compared to $5.1 million as of December 31, 2022, representing a change of approximately $(11.4) million. This change was primarily driven by payables related to the Starbuck Drilling Program.

	As of December 31,	
	2023	2022
Current Assets	$ 18,744,904	$ 22,734,973
Current Liabilities	$ 25,049,572	$ 17,620,660
Working Capital	$ (6,304,668)	$ 5,114,313

Cash Flows

	Year Ended December 31,		
Cash flows provided by (used in):	2023	2022	Variance
Operating activities	$ (9,887,500)	$ 18,055,783	$ (27,943,283)
Investing activities	(14,767,339)	(11,413,487)	(3,353,852)
Financing activities	20,502,905	1,690,275	18,812,630

Cash Flows from Operating Activities

Cash flows from operating activities in 2023 was impacted by lower commodity prices and higher operating expenses compared to 2022, partially offset by higher oil volumes. Cash flow from operating activities in 2022 benefited from higher commodity prices and higher natural gas and NGL volumes.

Cash Flows from Investing Activities

Cash flows from investing activities in 2023 includes approximately $25 million of additions to oil and gas properties primarily due to the development of our operations in North Dakota, partially offset by approximately $9.9 million for a change in accounts payable related to capital expenditures. In 2022, we had approximately $11.4 million of additions to oil and gas properties primarily, partially offset by approximately $1.2 million for a change in accounts payable related to capital expenditures. In 2022, we began recompletions and other capitalizable efforts in multiple states as we sought to bring production online from existing wells and bring on new production from sidetrack drilling in North Dakota which led to an increase in additions to oil and natural gas properties in 2022. We also participated in the drilling of four non-operated wells through Empire Rockies Region in 2022 spending approximately $600,000.

In 2022, we were able to negotiate for the release of the sinking fund requirement. Approximately $2.8 million and $2 million of the sinking fund balance was returned to us in 2023 and 2022, respectively.

In addition, 2023 includes $2 million related to the acquisition of additional interest in our New Mexico oil and gas properties compared to $2.7 million of acquisitions in 2022.

Cash Flows from Financing Activities

In 2023, we received $10 million from related parties in the form of bridge loans which were subsequently converted to our common shares (See Note 15 of Notes to Consolidated Financial Statements).

In 2023, we entered into a new revolving line of credit with Equity Bank (See Note 7 of Notes to Consolidated Financial Statements) and used approximately $4.5 million to retire the outstanding balance of our previous revolving line of credit with CrossFirst Bank. Principal payments made on our revolving line of credit with CrossFirst Bank were approximately $1.5 million and $1.2 million in 2023 and 2022, respectively.

In 2023, we received approximately $12.5 million from stock issuances and warrant exercises. In 2022, we received approximately $3.4 million in cash from warrant exercises.

Capital Resources

Capital Expenditures

For 2023, additions to oil and natural gas properties totaled $27 million including $2.1 million related to acquisitions. The $25 million not related to acquisitions primarily reflects development of our North Dakota operations. We anticipate capital expenditures in 2024 that will be funded with cash on hand, cash flows from operations, debt, and/or equity issuances.

Related Party Transactions

In 2023, we received $10 million in bridge loan funds from Phil Mulacek and Energy Evolution Master Fund, Ltd., related parties, which were subsequently converted to our common shares. In addition, we sold shares to both parties and received $5 million in proceeds from each party. Both transactions are described further in Note 15 of Notes to Consolidated Financial Statements. These transactions were related party transactions for accounting purposes.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Estimates

The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosures of contingent assets and liabilities. Because estimates and assumptions require significant judgment, future actual results could differ from those estimates and could have a significant impact on our results of operations, financial position and cash flows. We re-evaluate our estimates and assumptions at least on a quarterly basis. In our management's opinion, the more significant reporting areas impacted by management's judgments and estimates are as follows:

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

We use the successful efforts method of accounting for oil and natural gas operations. Under this method, costs to acquire oil and natural gas properties, drill successful exploratory wells, drill and equip development wells, and install production facilities are capitalized. Estimated proved oil and natural gas reserves, management's outlook on commodity prices and projected future cash flows of oil and natural gas reserves are a significant part of our financial calculations. Following are examples of how these estimates affect financial results:

- an increase (decrease) in estimated proved oil, natural gas and NGL reserves can reduce (increase) our unit-of-production depletion and amortization rates; and
- changes in the oil, natural gas and NGL reserves and the projected future cash flows from our properties can impact our periodic impairment analyses.

Proved oil and natural gas reserves are the estimated quantities of oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the Financial Accounting Standards Board ("FASB"). The accuracy of reserve estimates is a function of:

- The quality and quantity of available data;
- The interpretation of that data;
- The accuracy of various mandated economic assumptions; and
- The judgments of the persons preparing the estimates.

Proved reserves information included in this report is based on estimates prepared by independent petroleum engineers, Cawley Gillespie &Associates. The independent petroleum engineers evaluated 100% of our estimated proved producing reserve quantities and their related future net cash flows as of December 31, 2023. Estimates prepared by others may be higher or lower than these estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. Management may make revisions to reserve estimates throughout the year as additional information becomes available. Such changes could trigger an impairment of our oil and natural gas properties and have an impact on our depletion expense prospectively. For example, a change of 10 percent in our total proved reserves could change our annual depletion and amortization expense by $350,000. The actual impact would depend on the specific areas impacted.

Impairment of Oil and Gas Properties

We assess our proved properties for impairment using estimates of future undiscounted cash flows. This assessment requires significant judgment and assumptions including commodity price outlooks, estimates of reserve quantities, expected lease operating costs and capital costs. An impairment expense could result if oil and gas prices decline in the future as it may not be economic to develop some of these unproved properties. We performed an assessment as of December 31, 2023 and did not identify any impairments.

Asset Retirement Obligation

Asset retirement obligations ("AROs") consist primarily of estimated future costs associated with the plugging and abandonment of oil and natural gas wells, removal of equipment and facilities from leased acreage, and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

Stock-Based Compensation

We recognize stock-based compensation expense associated with restricted stock units and options. We account for forfeitures of equity-based incentive awards as they occur. Stock-based compensation expense related to time-based restricted stock units is based on the price of our common stock on the grant date. Stock-based compensation related to options is the fair value of the option recognized over the vesting period. The fair value of an option is determined using the Black-Scholes option valuation with the following assumption inputs: dividend yield, expected annual volatility, risk free interest rate and an expected life.

Income Taxes and Uncertain Tax Positions

Our tax provision is based upon the tax laws and rates in effect in the applicable jurisdiction in which operations are conducted and income is earned. As part of the process of preparing the consolidated financial statements, management is required to estimate the income tax provision. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, amortization and certain accrued liabilities for tax and accounting purposes.

Deferred tax expense or benefit represents the change in the balance of deferred tax assets or liabilities. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. At December 31, 2023 and 2022, a valuation allowance for deferred tax assets was recorded.

Management applies the accounting standards related to uncertainty in income taxes. This accounting guidance clarifies the accounting for uncertainties in income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the consolidated financial statements. It requires that we recognize in the consolidated financial statements the financial effects of a tax position, if that position is more likely than not of being sustained upon examination, including resolution of any appeals or litigation processes, based upon the technical merits of the position. It also provides guidance on measurement, classification, interest, penalties and disclosure. We have no uncertain tax positions at either December 31, 2023 or December 31, 2022.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide this information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The financial statements of the Company are set forth at the end of this Form 10-K.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, the Company carried out an evaluation under the supervision and participation of the Company's Principal Executive Officer and Principal Financial Officer, along with our management, of the effectiveness of the design and operation of the Company's disclosure controls and procedures as defined in Exchange Act Rule 13a-15(e). Based on this evaluation, the Company's Principal Executive Officer and Principal Financial Officer concluded that the disclosure controls and procedures were effective, as of the end of the period covered by this report, in ensuring the information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to management, including the Company's Chief Executive Officer (principal executive officer) and Chief Financial Officer (principal financial officer), to allow timely decisions regarding required disclosure.

Remediation of Material Weakness in Internal Control over Financial Reporting

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting such that there is a possibility that a material misstatement in our financial statements will not be prevented or detected on a timely basis. In 2021, a material weakness in internal control application was discovered related to the internal controls over financial reporting, including disclosures around complex and non-routine transactions. At December 31, 2022 and 2021, management believed the Company's lack of sufficient accounting personnel with appropriate accounting expertise to appropriately apply GAAP for complex and non-routine transactions and prepare associated financial statement disclosures amounted to a material weakness in its internal control over financial reporting.

As of December 31, 2023, management has evaluated the material weakness described above and believes that its design and implementation of internal control over financial reporting to remediate the aforementioned material weakness and enhance the Company's internal control environment has been achieved through the strengthening of its accounting resources which to date has included the hiring of a Chief Accounting Officer in October 2021. In the first quarter of 2022, the Chief Accounting Officer engaged an outside company to undertake an internal controls review. This review concluded in the third quarter of 2022. Controls that would strengthen the Company's internal control structure that were identified during the course of the review were implemented in 2023. The Company has continued to use the services of the outside company to assist in its assessment of internal controls. Additionally, in December 2022, we had a change in the Chief Accounting Officer although the former Chief Accounting Officer continued to assist the Company on a part-time basis in the first half of 2023. In addition to continuing to enhance and refine control design, management added additional resources and focused efforts during 2023 to test the operational effectiveness of the controls that were established. In May 2023, we hired an additional accounting resource who serves as Controller.

Based on the foregoing remediation activities and testing of controls, management concluded that the material weakness has been fully remediated.

Inherent Limitations on Effectiveness of Controls

The Company's disclosure controls and procedures and internal control over financial reporting are designed to provide reasonable assurance of achieving their desired objectives. Management recognizes that a control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of their inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect all errors or misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Under the supervision and with the participation of the Company's management, including its Principal Executive Officer and Principal Financial Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework established by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) as set forth in Internal Control - Integrated Framework. Based on our evaluation under that framework, our management concluded that our internal control over financial reporting is effective as of December 31, 2023.

Changes in Internal Control over Financial Reporting

While we continue to implement design enhancements to our internal control procedures, we believe that, other than the changes described above regarding the ongoing remediation efforts, there were no changes to our internal control over financial reporting which were identified in connection with the evaluation required by Rules 13a-15(d) or 15d-15(d) under the Exchange Act during the fourth quarter of 2023 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Attestation Report of Registered Public Accounting Firm

This report does not contain an attestation report of our independent registered public accounting firm related to internal control over financial reporting because the rules for smaller reporting companies provide an exemption from the attestation requirement.

ITEM 9B. OTHER INFORMATION.

The Company was not informed by any of its directors or Section 16 officers of the adoption or termination of a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as those terms are defined in Item 408 of Regulation S-K, during the fourth quarter of 2023.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS.

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information called for by this Item 10 is incorporated herein by reference to our definitive Proxy Statement for 2024 annual meeting of stockholders ("2024 Proxy Statement") to be filed with the SEC no later than 120 days following the fiscal year ended December 31, 2023.

ITEM 11. EXECUTIVE COMPENSATION.

The information called for by this Item 11 is incorporated herein by reference to our 2024 Proxy Statement to be filed with the SEC no later than 120 days following the fiscal year ended December 31, 2023.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information called for by this Item 12 is incorporated herein by reference to our 2024 Proxy Statement to be filed with the SEC no later than 120 days following the fiscal year ended December 31, 2023.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE.

The information called for by this Item 13 is incorporated herein by reference to our 2024 Proxy Statement to be filed with the SEC no later than 120 days following the fiscal year ended December 31, 2023.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

The information called for by this Item 14 is incorporated herein by reference to our 2024 Proxy Statement to be filed with the SEC no later than 120 days following the fiscal year ended December 31, 2023.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

(a) (1) Financial Statements

The financial statements under this item are included in Item 8 of Part II of this Annual Report on Form 10-K.

(2) Schedules

NONE

(3) Exhibits

Exhibit No.	Description
2.1	Purchase and Sale Agreement dated as of March 12, 2021, by and between Empire New Mexico LLC and XTO Holdings, LLC (incorporated herein by reference to Exhibit 2.1 to the Company's Form 8-K dated May 14, 2021, which was filed on May 17, 2021).
3.1	Amended and Restated Certificate of Incorporation of Empire Petroleum Corporation (incorporated herein by reference to Exhibit 3.1 to the Company's Form 8-K dated March 4, 2022, which was filed on March 9, 2022).
3.2	Certificate of Designation of Series A Voting Preferred Stock of Empire Petroleum Corporation (incorporated herein by reference to Exhibit 3.2 to the Company's Form 8-K dated March 4, 2022, which was filed on March 9, 2022).
3.3	Amended and Restated Bylaws of Empire Petroleum Corporation (incorporated herein by reference to Exhibit 3.3 to the Company's Form 8-K dated March 4, 2022, which was filed on March 9, 2022).
4.1	Description of the Common Stock of Empire Petroleum Corporation (incorporated herein by reference to Exhibit 4.1 to the Company's Form 10-K for the fiscal year ended December 31, 2021, which was filed on March 31, 2022).
4.2	Senior Secured Convertible Note due December 31, 2021 (incorporated herein by reference to Exhibit 4.1 to the Company's Form 8-K dated May 14, 2021, which was filed on May 20, 2021).
4.3	Common Share Warrant Certificate No. Energy Evolution-1 dated May 14, 2021 (incorporated herein by reference to Exhibit 4.2 to the Company's Form 8-K dated May 14, 2021, which was filed on May 20, 2021).
10.1*	Empire Petroleum Corporation 2019 Stock Option Plan (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated April 3, 2019, which was filed on April 9, 2019).
10.2*	Form of Non-Qualified Stock Option Award Agreement (incorporated herein by reference to Exhibit 10.2 to the Company's Form 8-K dated April 3, 2019, which was filed on April 9, 2019).
10.3	Senior Revolver Loan Agreement dated as of September 20, 2018 by and between Empire Louisiana, LLC and CrossFirst Bank (incorporated herein by reference to Exhibit 10.1 of the Company's Form 8-K dated September 20, 2018 filed on September 25, 2018).
10.4	First Amendment to Senior Revolver Loan Agreement, dated as of March 27, 2019, by and between Empire Louisiana LLC, Empire North Dakota LLC and CrossFirst Bank (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated March 27, 2019, which was filed on April 2, 2019).
10.5	Loan Agreement dated as of August 6, 2020, by and between Empire Texas LLC and Petroleum Independent & Exploration LLC (incorporated herein by reference to Exhibit 10.6 to the Company's Form 8-K dated August 6, 2020, which was filed on August 11, 2020).
10.6	Second Amendment to Senior Revolver Loan Agreement, dated as of June 30, 2020, by and between Empire Louisiana LLC, Empire North Dakota LLC and CrossFirst Bank (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated September 30, 2020, which was filed on October 6, 2020).

10.7	Third Amendment to Senior Revolver Loan Agreement, dated as of December 31, 2020, by and between Empire Louisiana LLC, Empire North Dakota LLC and CrossFirst Bank (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated March 10, 2021, which was filed on March 15, 2021).
10.8	Form of Securities Purchase Agreement entered into by and between Empire Petroleum Corporation and investors (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated March 30, 2021, which was filed on April 1, 2021).
10.9	Form of Common Share Warrant Certificate issued by Empire Petroleum Corporation (incorporated herein by reference to Exhibit 10.2 to the Company's Form 8-K dated March 30, 2021, which was filed on April 1, 2021).
10.10	Fourth Amendment to Senior Revolver Loan Agreement, dated as of July 7, 2021, by and between Empire Louisiana LLC, Empire North Dakota LLC, and CrossFirst Bank (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated July 30, 2021, which was filed on August 4, 2021).
10.11*	Employment Agreement dated as of August 18, 2021, by and between Empire Petroleum Corporation and Thomas W. Pritchard (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated August 18, 2021, which was filed on August 24, 2021).
10.12*	Employment Agreement dated as of August 18, 2021, by and between Empire Petroleum Corporation and Michael R. Morrisett (incorporated herein by reference to Exhibit 10.2 to the Company's Form 8-K dated August 18, 2021, which was filed on August 24, 2021).
10.13	Loan Modification Agreement dated as of September 29, 2021, by and among Empire New Mexico LLC d/b/a Green Tree New Mexico, Empire Petroleum Corporation and Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated September 29, 2021, which was filed on October 5, 2021).
10.14	Pledge and Security Agreement dated as of September 29, 2021, made by Empire Petroleum Corporation in favor of Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10.2 to the Company's Form 8-K dated September 29, 2021, which was filed on October 5, 2021).
10.15	Common Share Warrant Certificate dated as of September 30, 2021 issued by Empire Petroleum Corporation in favor of Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10.3 to the Company's Form 8-K dated September 29, 2021, which was filed on October 5, 2021).
10.16*	Empire Petroleum Corporation 2021 Stock and Incentive Compensation Plan (incorporated herein by reference to the Company's Information Statement on Schedule 14C filed August 31, 2021).
10.17	Conversion Notice and Note Amendment dated as December 30, 2021 (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated December 30, 2021, which was filed on January 6, 2022).
10.18*	Form of Non-Qualified Stock Option Award Agreement (incorporated herein by reference to Exhibit 10.24 to the Company's Form 10-K for the fiscal year ended December 31, 2021, which was filed on March 31, 2022).
10.19*	Form of Restricted Stock Units Award Agreement (Non-Employee Directors) (incorporated herein by reference to Exhibit 10.25 to the Company's Form 10-K for the fiscal year ended December 31, 2021, which was filed on March 31, 2022).
10.20*	Form of Restricted Stock Units Award Agreement (Executive Officers) (incorporated herein by reference to Exhibit 10.26 to the Company's Form 10-K for the fiscal year ended December 31, 2021, which was filed on March 31, 2022).
10.21*	Empire Petroleum Corporation 2022 Stock and Incentive Compensation Plan (incorporated herein by reference to Annex A to the Company's Proxy Statement on Schedule 14A filed on July 27, 2022).
10.22*	Employment Agreement dated as of September 13, 2022, by and between Empire Petroleum Corporation and Eugene J. Sweeney (incorporated herein by reference to Exhibit 10 to the Company's Form 8-K dated September 13, 2022, which was filed on September 19, 2022).
10.23*	Empire Petroleum Corporation 2023 Stock and Incentive Compensation Plan (incorporated herein by reference to Annex A to the Company's Proxy Statement on Schedule 14A filed on May 1, 2023).
10.24	Shared Services Agreement, dated as of August 1, 2023, by and between PIE Operating, LLC and Empire Petroleum Corporation (incorporated herein by reference to Exhibit 10.8 to the Company's Form 10-Q for the quarter ended September 30, 2023, which was filed on November 13, 2023).

10.25	Empire North Dakota LLC Promissory Note Due October 31, 2023 in the original aggregate principal amount of $5.0 million in favor of Phil Mulacek (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated September 19, 2023, which was filed on September 25, 2023).
10.26	Empire North Dakota LLC Promissory Note Due October 31, 2023 in the original aggregate principal amount of $5.0 million in favor of Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10.2 to the Company's Form 8-K dated September 19, 2023, which was filed on September 25, 2023).
10.27	Commercial Guaranty Agreement, dated as of September 19, 2023, issued by Empire Petroleum Corporation in favor of Phil Mulacek (incorporated herein by reference to Exhibit 10.3 to the Company's Form 8-K dated September 19, 2023, which was filed on September 25, 2023).
10.28	Commercial Guaranty Agreement, dated as of September 19, 2023, issued by Empire Petroleum Corporation in favor of Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10.4 to the Company's Form 8-K dated September 19, 2023, which was filed on September 25, 2023).
10.29	Letter Agreement amending Senior Revolver Loan Agreement, dated as of September 19, 2023, by and among Empire Louisiana LLC and Empire North Dakota LLC, as borrowers, Empire Petroleum Corporation, as guarantor, and CrossFirst Bank, as lender (incorporated herein by reference to Exhibit 10.5 to the Company's Form 8-K dated September 19, 2023, which was filed on September 25, 2023).
10.30	Subordination Agreement, dated as of September 19, 2023, by and among Phil Mulacek, Energy Evolution Master Fund, Ltd. and Empire North Dakota LLC in favor of CrossFirst Bank (incorporated herein by reference to Exhibit 10.6 to the Company's Form 8-K dated September 19, 2023, which was filed on September 25, 2023).
10.31	Letter Amendment amending the Empire North Dakota LLC Promissory Notes Due October 31, 2023, dated as of October 31, 2023, by and among Phil Mulacek and Energy Evolution Master Fund, Ltd., as investors, Empire North Dakota LLC, as borrower, and Empire Petroleum Corporation, as guarantor (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated October 31, 2023, which was filed on November 1, 2023).
10.32	Empire North Dakota LLC Amended and Restated Promissory Note Due December 31, 2024 in the original aggregate principal amount of $5.0 million in favor of Phil Mulacek (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated November 9, 2023, which was filed on November 13, 2023).
10.33	Empire North Dakota LLC Amended and Restated Promissory Note Due December 31, 2024 in the original aggregate principal amount of $5.0 million in favor of Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10.2 to the Company's Form 8-K dated November 9, 2023, which was filed on November 13, 2023).
10.34	Securities Purchase Agreement, dated as of November 29, 2023, by and between Phil Mulacek and Empire Petroleum Corporation (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated November 29, 2023, which was filed on November 29, 2023).
10.35	Letter Amendment to Securities Purchase Agreement, dated as of December 1, 2023, by and between Phil Mulacek and Empire Petroleum Corporation (incorporated herein by reference to Exhibit 10 to the Company's Form 8-K dated December 1, 2023, which was filed on December 1, 2023).
10.36	Securities Purchase Agreement, dated as of November 29, 2023, by and between Energy Evolution Master Fund, Ltd. and Empire Petroleum Corporation (incorporated herein by reference to Exhibit 10.2 to the Company's Form 8-K dated November 29, 2023, which was filed on November 29, 2023).
10.37	Revolver Loan Agreement, dated as of December 29, 2023, by and between Empire North Dakota LLC and Empire ND Acquisition LLC, as borrowers, and Equity Bank, as lender (incorporated herein by reference to Exhibit 10 to the Company's Form 8-K dated December 29, 2023, which was filed on January 5, 2024).
10.38	Empire Petroleum Corporation Promissory Note Due February 15, 2026 in the aggregate principal amount of $5.0 million in favor of Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10 to the Company's Form 8-K dated February 16, 2024, which was filed on February 21, 2024).
21	Subsidiaries of Empire Petroleum Corporation (submitted herewith).

23.1	Consent of Grant Thornton LLP (submitted herewith).
23.2	Consent of Cawley, Gillespie & Associates, Inc. (submitted herewith).
31.1	Rule 13a – 14(a)/15d – 14(a) Certification of Michael R. Morrisett, Chief Executive Officer (submitted herewith).
31.2	Rule 13a – 14(a)/15d – 14(a) Certification of Stephen L. Faulkner, Jr., Chief Financial Officer (submitted herewith).
32.1	Section 1350 Certification of Michael R. Morrisett, Chief Executive Officer (submitted herewith).
32.2	Section 1350 Certification of Stephen L. Faulkner, Jr., Chief Financial Officer (submitted herewith).
97*	Empire Petroleum Corporation Policy for the Recovery of Erroneously Awarded Compensation (submitted herewith).
99.1	Cawley, Gillespie & Associates, Inc. Summary Report (submitted herewith).
101	Financial Statements for Inline XBRL format (submitted herewith).
104	Cover Page Interactive Data File (embedded within Inline XBRL document).

*Indicates a management contract or compensatory plan or arrangement identified under the requirements of Item 15 of Form 10-K.

ITEM 16. FORM 10-K SUMMARY.

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Empire Petroleum Corporation

Date: March 28, 2024

By: /s/ Michael R. Morrisett
Name: Michael R. Morrisett
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Michael R. Morrisett MICHAEL R. MORRISETT	Director, President and Chief Executive Officer (Principal Executive Officer)	March 28, 2024
/s/ Stephen L. Faulkner, Jr. STEPHEN L. FAULKNER, JR.	Chief Financial Officer and Chief Accounting Officer (Principal Financial Officer and Principal Accounting Officer)	March 28, 2024
/s/ Phil E. Mulacek PHIL E. MULACEK	Director and Chairman of the Board	March 28, 2024
/s/ Andrew L. Lewis ANDREW L. LEWIS	Director	March 28, 2024
/s/ Mason H. Matschke MASON H. MATSCHKE	Director	March 28, 2024
/s/ Benjamin J. Marchive II BENJAMIN J. MARCHIVE II	Director	March 28, 2024
/s/ J. Kevin Vann J. KEVIN VANN	Director	March 28, 2024

EMPIRE PETROLEUM CORPORATION

CONSOLIDATED FINANCIAL STATEMENTS

CONTENTS

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
Empire Petroleum Corporation

Opinion on the financial statements

We have audited the accompanying consolidated balance sheets of Empire Petroleum Corporation (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2023 and 2022, the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the two years in the period ended December 31, 2023, and the related notes (collectively referred to as the "financial statements"). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2023 and 2022, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2023, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion

These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matters

Critical audit matters are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. We determined there are no critical audit matters.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2022.

Tulsa, Oklahoma
March 28, 2024

EMPIRE PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

	As of December 31,	
	2023	**2022**
ASSETS		
Current Assets:		
Cash	$ 7,792,508	$ 11,944,442
Accounts Receivable	8,354,636	7,780,239
Derivative Instruments	406,806	121,584
Inventory	1,433,454	1,840,274
Prepaids	757,500	1,048,434
Total Current Assets	18,744,904	22,734,973
Property and Equipment:		
Oil and Natural Gas Properties, Successful Efforts	93,509,803	63,986,339
Less: Accumulated Depreciation, Depletion and Impairment	(22,996,805)	(20,116,696)
Total Oil and Gas Properties, Net	70,512,998	43,869,643
Other Property and Equipment, Net	1,883,211	1,441,529
Total Property and Equipment, Net	72,396,209	45,311,172
Sinking Fund	—	2,779,000
Other Noncurrent Assets	1,474,503	719,930
Total Assets	$ 92,615,616	$ 71,545,075
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts Payable	$ 16,437,219	$ 5,843,366
Accrued Expenses	7,075,302	9,461,010
Current Portion of Lease Liability	432,822	256,975
Current Portion of Note Payable - Related Party (Note 4 and 7)	1,060,004	—
Current Portion of Long-Term Debt	44,225	2,059,309
Total Current Liabilities	25,049,572	17,620,660
Long-Term Debt	4,596,775	4,063,115
Long-Term Note Payable - Related Party (Note 4 and 7)	—	1,076,987
Long Term Lease Liability	544,382	547,692
Asset Retirement Obligations	27,468,427	25,000,740
Total Liabilities	57,659,156	48,309,194
Commitments and Contingencies (Note 16)		
Stockholders' Equity:		
Series A Preferred Stock - $.001 Par Value, 10,000,000 Shares Authorized, 6 and 6 Shares Issued and Outstanding, Respectively	—	—
Common Stock - $.001 Par Value 190,000,000 Shares Authorized, 25,503,530 and 22,093,503 Shares Issued and Outstanding, Respectively	85,025	81,615
Additional Paid-in-Capital	99,490,253	75,303,479
Accumulated Deficit	(64,618,818)	(52,149,213)
Total Stockholders' Equity	34,956,460	23,235,881
Total Liabilities and Stockholders' Equity	$ 92,615,616	$ 71,545,075

See accompanying notes to consolidated financial statements.

EMPIRE PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	Year Ended December 31, 2023	Year Ended December 31, 2022
Revenue:		
Oil Sales	$ 36,684,494	$ 44,978,554
Gas Sales	1,726,754	4,534,370
NGL Sales	1,660,256	3,659,451
Total Product Revenues	40,071,504	53,172,375
Other	70,480	102,429
Gain (Loss) on Derivatives	(65,693)	(387,930)
Total Revenue	40,076,291	52,886,874
Costs and Expenses:		
Lease Operating Expense	28,625,481	23,584,039
Production and Ad Valorem Taxes	3,044,411	3,943,466
Depletion, Depreciation & Amortization	3,096,533	1,949,191
Accretion of Asset Retirement Obligation	1,756,022	1,357,906
Impairment	—	936,620
General and Administrative	15,178,935	12,331,489
Total Cost and Expenses	51,701,382	44,102,711
Operating Income (Loss)	(11,625,091)	8,784,163
Other Income and (Expense):		
Interest Expense	(1,000,427)	(509,540)
Other Income (Expense)	23,721	(981,595)
Income (Loss) Before Taxes	(12,601,797)	7,293,028
Income Tax (Provision) Benefit	132,192	(208,898)
Net Income (Loss)	$ (12,469,605)	$ 7,084,130
Net Income (Loss) per Common Share:		
Basic	$ (0.55)	$ 0.34
Diluted	$ (0.55)	$ 0.30
Weighted Average Number of Common Shares Outstanding:		
Basic	22,718,890	21,003,563
Diluted	22,718,890	23,387,646

See accompanying notes to consolidated financial statements.

EMPIRE PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY
Years Ended December 31, 2023 and 2022

	Common Stock		Preferred Stock				
	Shares	Par Value	Shares	Par Value	Additional Paid-in-Capital	Accumulated Deficit	Total
Balances, December 31, 2021	19,840,648	$ 79,362	—	$ —	$ 68,988,134	$ (59,233,343)	$ 9,834,153
Net Income	—	—	—	—	—	7,084,130	7,084,130
Issuance of Preferred Stock	—	—	6	—	6	—	6
Stock-Based Compensation	299,695	300	—	—	2,716,452	—	2,716,752
Warrants Exercised	1,953,160	1,953	—	—	3,598,887	—	3,600,840
Balances, December 31, 2022	22,093,503	81,615	6	—	75,303,479	(52,149,213)	23,235,881
Net Loss	—	—	—	—	—	(12,469,605)	(12,469,605)
Impact of Former CEO Settlement	—	—	—	—	(2,126,131)	—	(2,126,131)
Stock Issued for Purchase Option (See Note 3)	67,000	67	—	—	600,990	—	601,057
Warrants Exercised	500,000	500	—	—	2,499,500	—	2,500,000
Issuance of Shares for Redemption of Notes	1,263,664	1,264	—	—	10,108,048	—	10,109,312
Issuance of Shares in Private Transaction	1,234,013	1,234	—	—	9,959,962	—	9,961,196
Stock-Based Compensation	345,350	345	—	—	3,144,405	—	3,144,750
Balances, December 31, 2023	25,503,530	85,025	6	—	99,490,253	(64,618,818)	34,956,460

See accompanying notes to consolidated financial statements.

EMPIRE PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31, 2023	Year Ended December 31, 2022
Cash Flows From Operating Activities:		
Net Income (Loss)	$ (12,469,605)	$ 7,084,130
Adjustments to Reconcile Net Income (Loss) to Net Cash Provided By Operating Activities:		
Stock-Based Compensation	3,144,750	2,716,752
Amortization of Right of Use Assets	423,689	263,847
Depreciation, Depletion and Amortization	3,096,533	1,949,191
Accretion of Asset Retirement Obligation	1,756,022	1,357,906
Loss on Derivatives	65,693	387,930
Settlement on or Purchases of Derivative Instruments	(353,695)	(260,266)
Impairment	—	936,620
Loss on XTO Final Settlement	—	1,448,363
PIE-Related Expense (See Note 4)	—	1,399,030
Change in Operating Assets and Liabilities:		
Accounts Receivable	(2,700,528)	(1,812,230)
Inventory, Oil in Tanks	(160,827)	(802,394)
Prepaids, Current	745,648	(369,312)
Accounts Payable	751,355	526,682
Accrued Expenses	(3,082,928)	3,616,826
Other Long Term Assets and Liabilities	(1,103,607)	(387,292)
Net Cash Provided By (Used In) Operating Activities	(9,887,500)	18,055,783
Cash Flows from Investing Activities:		
Acquisition of Oil and Natural Gas Properties	(2,094,419)	(2,702,613)
Capital Expenditures - Oil and Natural Gas Properties [(a)]	(14,546,873)	(10,161,711)
Purchase of Other Fixed Assets	(352,851)	(311,229)
Cash Paid for Right of Use Assets	(552,196)	(268,934)
Sinking Fund Deposit	2,779,000	2,031,000
Net Cash Used In Investing Activities	(14,767,339)	(11,413,487)
Cash Flows from Financing Activities:		
Proceeds from Debt Issued	14,492,484	—
Principal Payments of Debt	(6,450,774)	(1,699,840)
Proceeds from Stock Issuance and Warrant Exercises	12,461,195	3,390,115
Net Cash Provided By Financing Activities	20,502,905	1,690,275
Net Change in Cash	(4,151,934)	8,332,571
Cash - Beginning of Period	11,944,442	3,611,871
Cash - End of Period	$ 7,792,508	$ 11,944,442
Supplemental Cash Flow Information:		
Cash Paid for Interest	$ 650,637	$ 473,205

(a) Incurred capital expenditures were $25,053,107 and $11,206,207 for the respective periods. The differences between incurred and cash capital expenditures is due to changes in related accounts payable.

See accompanying notes to consolidated financial statements.

EMPIRE PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Organization and Basis of Presentation

Empire Petroleum Corporation (the "Company", collectively with its subsidiaries) is an independent energy company operator engaged in optimizing developed production by employing field management methods to maximize reserve recovery while minimizing costs. Empire operates the following wholly-owned subsidiaries in its areas of operations:

- Empire New Mexico LLC ("Empire New Mexico")
  - Empire New Mexico LLC d/b/a Green Tree New Mexico
  - Empire EMSU LLC
  - Empire EMSU-B LLC
  - Empire AGU LLC
  - Empire NM Assets LLC
- Empire Rockies Region
  - Empire North Dakota LLC ("Empire North Dakota")
  - Empire ND Acquisition LLC ("Empire NDA")
- Empire Texas ("Empire Texas"), consisting of the following entities:
  - Empire Texas LLC
  - Empire Texas Operating LLC
  - Empire Texas GP LLC
  - Pardus Oil & Gas Operating, LP (owned 1% by Empire Texas GP LLC and 99% by Empire Texas LLC)
- Empire Louisiana LLC ("Empire Louisiana")

Empire was incorporated in the State of Delaware in 1985. The consolidated financial statements of Empire Petroleum Corporation and subsidiaries include the accounts of the Company and its wholly-owned subsidiaries.

Liquidity and Going Concern

The Company determined that it was not in compliance with the current ratio covenant contained in its revolving line of credit agreement as of December 31, 2023 (see Note 7). Upon discovering this issue, we notified the lender to request a waiver. The noncompliance is due to a higher level of payables related to the capital spending program in North Dakota. On March 27, 2024, the Company obtained a compliance waiver from the lender for December 31, 2023. The Company will require funds to satisfy these payables related to the capital spending program which are greater than estimated cash flows from operations over the next 12 months.

The Company intends and has announced a subscription rights offering ("Rights Offering") to raise additional funds for the payables discussed above as well as the additional capital spending in 2024. In March 2024, the Company commenced a Rights Offering pursuant to which it intends to raise gross proceeds of up to approximately $25.0 million (see Note 18). As a result of a subsequent reduction in the subscription price per share, gross proceeds are now expected to be up to approximately $20.66 million. Phil Mulacek and Energy Evolution Master Fund, Ltd ("Energy Evolution"), both related parties of the Company (see Note 15) and our largest stockholders collectively holding 46% of the common shares outstanding, have indicated that they intend to participate in the Rights Offering and fully subscribe to the shares of Common Stock corresponding to their subscription rights. They have each also indicated that they intend to exercise their over-subscription rights to purchase their pro rata share of the underlying securities related to the Rights Offering that remain unsubscribed at the expiration date of the Rights Offering. The Rights Offering will not close until April 2024. As such, it is likely that the Company would not be in technical compliance with this same covenant as of March 31, 2024; however, in the opinion of the Company this would be cured within the allowable period under the Credit Facility at the close of the Rights Offering.

Management has initiated plans that will allow the Company to remain in compliance with this covenant. The Company as stated above, has indications from existing stockholders for a majority portion of the Rights Offering. Management has considered these plans, including if they are within the control of the Company, in evaluating ASC 205-40, *Presentation of Financial Statements-Going Concern*. Management believes the above actions are sufficient to allow the Company to meet its obligations as they become due for a period of at least 12 months from the issuance of these financial statements. Management believes that the Rights Offering is probable and this has alleviated the substantial doubt regarding the Company's ability to continue as a going concern.

Note 2 – Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts and balances of the Company and have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). All intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Estimated quantities of crude oil, natural gas and natural gas liquids ("NGL") reserves are the most significant of the Company's estimates. All reserve data used in the preparation of the consolidated financial statements, as well as included in *Supplemental Information of Oil and Natural Gas Producing Activities (Unaudited)*, are based on estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGL. There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and NGL reserves. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil, natural gas and NGLs that are ultimately recovered.

Other items subject to estimates and assumptions include, but are not limited to, the carrying amounts of property, plant and equipment, asset retirement obligations, valuation allowances for deferred income tax assets, and valuation of derivative instruments. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions.

Although management believes these estimates are reasonable, actual results may differ from estimates and assumptions of future events and these revisions could be material. Future production may vary materially from estimated oil and natural gas proved reserves. Actual future prices may vary significantly from price assumptions used for determining proved reserves and for financial reporting.

Out of Period Adjustments

In the third quarter of 2022, the Company identified and recorded an out-of-period adjustment related to the Joint Development Agreement discussed in Note 4. The impact of recording this adjustment reduced Utility and Other Deposits and increased Lease Operating Expense by approximately $1.3 million of which $797,000 related to prior periods. The impact of this adjustment was immaterial to the prior period financial statements and thus corrected in the current period.

Accounts Receivable

Accounts receivable include estimated amounts due from crude oil, natural gas, and NGL purchasers and from non-operating working interest owners. Accrued revenue related to product sales from purchasers and operators are due under normal trade terms, generally requiring payment within 60 days of production. For receivables from joint interest owners, the Company generally has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for credit losses account only after all collection attempts have been exhausted. The Company did not have an allowance for credit losses at either December 31, 2023 or 2022. The Company's accounts receivable as of December 31, 2023 and 2022 are as follows:

Schedule of account receivable

	2023	2022
Oil, Gas and NGL Receivables	$ 2,784,745	$ 3,060,341
Joint Interest Billings	5,444,331	2,057,719
Receivable from Former CEO (See Note 14)	—	2,130,614
Other	125,560	531,565
Total Accounts Receivable	$ 8,354,636	$ 7,780,239

Derivative Instruments

The Company enters into hedge agreements to manage its exposure to oil and natural gas price fluctuations. The fair value of derivative contracts is recognized as an asset or liability on the Company's consolidated balance sheets. Realized gain or loss is recognized as a component of revenue when the derivative contracts mature. For contracts which have not matured, an unrealized gain or loss is recorded based on the change in the fair value of the outstanding contracts.

Inventory

Inventory primarily consists of oil in tanks which has not been delivered and is valued at the lower of cost or net realizable value.

Oil and Natural Gas and Other Properties

The Company uses the successful efforts method of accounting for its oil and gas activities. Costs incurred are deferred until exploration and completion results are evaluated. At such time, costs of activities with economically recoverable reserves are capitalized as proven properties, and costs of unsuccessful or uneconomical activities are expensed.

Capitalized drilling costs are reviewed periodically for impairment. Costs related to impaired prospects or unsuccessful exploratory drilling is charged to expense. Management's assessment of the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such leaseholds impact the amount and timing of impairment provisions. An impairment expense could result if oil and gas prices decline in the future as it may not be economical to develop some of these unproved properties.

Lease options are capitalized as unproved property acquisition costs and are reviewed for impairment if indicators exist that the carrying value of the lease option may not be recoverable. If the lease options become impaired, expire or are abandoned, the options will be expensed. If proved reserves are discovered after the options are exercised, these costs will be reclassified as proved property.

Depreciation, depletion and amortization of producing properties is computed on the units-of-production method on a property-by-property basis. The units-of-production method is based primarily on estimates of proved reserve quantities. Due to uncertainties inherent in this estimation process, it is at least reasonably possible that reserve quantities will be revised in the near term. Changes in estimated reserve quantities are applied to depreciation, depletion and amortization computations prospectively.

Other property and equipment is depreciated on the straight-line method.

Segment Reporting

Operating segments are components of an enterprise that engage in activities from which it may earn revenues and incur expenses and for which separate operational financial information is available and is regularly evaluated by management. Based on the Company’s organization and management, it has only one reportable operating segment, which is oil and natural gas exploration and production.

Debt Issuance Costs

Debt issuance fees, which are recorded at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the straight-line method. Unamortized debt issuance costs related to the Company’s credit facility are recorded in other noncurrent assets on the Company’s Consolidated Balance Sheet.

Asset Retirement Obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related oil and natural gas property asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depletion of the asset. Changes in the liability due to passage of time are recognized as an increase in the carrying amount of the liability through accretion expense. Based on certain factors, including commodity prices and costs, the Company may revise its previous estimates of the liability, which would also increase or decrease the related oil and natural gas property asset.

Revenue Recognition

The Company’s revenues are comprised solely of revenues from customers and include the sale of oil, natural gas and NGL. The Company believes that the disaggregation of revenue into these three major product types, as presented in the Consolidated Statements of Operations, appropriately depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors based on its single geographic region, the continental United States. Revenues are recognized at a point in time when production is sold to a purchaser at a determinable price, delivery has occurred, control has transferred and it is probable substantially all of the consideration will be collected. The Company fulfills its performance obligations under its customer contracts through delivery of oil, natural gas and NGL and revenues are recorded on a monthly basis. The Company receives payment from one to three months after delivery. Generally, each unit of product represents a separate performance obligation. The prices received for oil, natural gas and NGL sales under the Company’s contracts are generally derived from stated market prices which are then adjusted to reflect deductions including transportation, fractionation and processing. As a result, revenues from the sale of oil, natural gas and NGL will decrease if market prices decline. The sales of oil, natural gas and NGL, as presented on the Consolidated Statements of Operations, represent the Company’s share of revenues net of royalties and excluding revenue interests owned by others. When selling oil, natural gas and NGL on behalf of royalty or working interest owners, the Company is acting as an agent and thus reports the revenue on a net basis. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded. Variances between the Company's estimated revenue and actual payment are recorded in the month the payment is received. Historically, these differences have been insignificant.

At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are recorded in Accounts Receivable in the Consolidated Balance Sheets. Taxes assessed by governmental authorities on oil, natural gas and NGL sales are presented separately from such revenues in the Consolidated Statements of Operations.

Oil Sales

Oil production is transported from the wellhead to tank batteries or delivery points through flow-lines or gathering systems. Purchasers of the oil take delivery at the tank batteries and transport the oil by truck or at a pipeline delivery point and the Company collects a market price, net of pricing differentials. Revenue is recognized when control transfers to the purchaser at the net price received by the Company.

Natural Gas and NGL Sales

Under the Company's natural gas sales arrangements, the purchaser takes control of wet gas at a delivery point near the wellhead or at the inlet of the purchaser's processing facility. The purchaser gathers and processes the wet gas and remits proceeds to the Company for the resulting natural gas and NGL sales. Based on the nature of these arrangements, the processor is the agent and the purchaser is the Company's customer, thus, the Company recognizes natural gas and NGL sales based on the net amount of proceeds received from the purchaser.

Transaction Price Allocated to Remaining Performance Obligations

Substantially all of the Company's product sales are short-term in nature with a contract term of one year or less. For these contracts, the Company has utilized the practical expedient in ASC 606 which exempts the Company from the requirements to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient in ASC 606 which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior-Period Performance Obligations

The Company records revenue in the month that product is delivered to the purchaser. Settlement statements for certain natural gas and NGL sales, however, may not be received for 30 to 90 days after the date the product is delivered, and as a result the Company is required to estimate the amount of product delivered to the purchaser and the price that will be received for the sale of the product. In these situations, the Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Any identified differences between the Company's revenue estimates and actual revenue received have historically been insignificant. For the years ended December 31, 2023 and 2022, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Stock-Based Compensation

The Company recognizes stock-based compensation expense associated with equity-based incentive awards consisting of stock options and restricted stock units. The Company accounts for forfeitures of equity-based incentive awards as they occur. Stock-based compensation expense related to equity-based awards is generally recognized as vesting occurs. See Note 10 for further discussion.

Income Taxes

The Company accounts for income taxes in accordance with the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to the taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is established if management determines it is more likely than not that some portion of a deferred tax asset will not be realized.

Per Share Amounts

The Company calculates and discloses basic earnings per share ("Basic EPS") and diluted earnings per share ("Diluted EPS"). The computation of basic earnings per share is computed by dividing earnings available to common stockholders by the weighted average number of outstanding common shares during the period.

Diluted EPS gives effect to all dilutive potential common shares outstanding during the period. The computation of Diluted EPS does not assume conversion, exercise or contingent exercise of securities that would have an anti-dilutive effect on losses. As a result, if there is a loss from continuing operations, Diluted EPS is computed in the same manner as Basic EPS.

Fair Value Measurements

The Financial Accounting Standards Board ("FASB") fair value measurement standards define fair value, establish a consistent framework for measuring fair value and establish a fair value hierarchy based on the observability of inputs used to measure fair value.

The three-level fair value hierarchy for disclosure of fair value measurements defined by ASC Topic 820 is as follows:

Level 1 – Unadjusted, quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. An active market is defined as a market where transactions for the financial instrument occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Inputs, other than quoted prices within Level 1, that are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.

Level 3 – Prices or valuations that require unobservable inputs that are both significant to the fair value measurement and unobservable. Valuation under Level 3 generally involves a significant degree of judgment from management.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, valuation models are applied. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instrument's complexity. The Company reflects transfers between the three levels at the beginning of the reporting period in which the availability of observable inputs no longer justifies classification in the original level. There were no transfers between fair value hierarchy levels for the years ended December 31, 2023 and 2022.

Impairment of oil and natural gas properties - The fair value of proved and unproved oil and natural gas properties was measured using valuation techniques that convert the future cash flows to a single discounted amount. Significant inputs to the valuation of proved and unproved oil and natural gas properties include estimates of: (i) recoverable reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted average costs of capital. The Company utilized a combination of the New York Mercantile Exchange ("NYMEX") strip pricing and consensus pricing to value the reserves, then applied various discount rates depending on the classification of reserves and other risk characteristics. For significant acquisitions, management utilized the assistance of a third-party valuation expert to estimate the value of the oil and natural gas properties acquired.

The fair value of asset retirement obligations is included in proved oil and natural gas properties with a corresponding liability. The fair value was determined based on a discounted cash flow model, which included assumptions of the estimated current abandonment costs, discount rate, inflation rate and timing associated with the incurrence of these costs.

The inputs used to value oil and natural gas properties for impairments and asset retirement obligations require significant judgment and estimates made by management and represent Level 3 inputs.

Financial instruments and other- The fair values determined for accounts receivable, accrued expenses and other current liabilities were equivalent to the carrying value due to their short-term nature and generally represent Level 2 fair values.

Derivatives – Derivative financial instruments are carried at fair value and measured on a recurring basis. The Company's commodity price hedges are valued based on discounted future cash flow models that are primarily based on published forward commodity price curves; thus, these inputs are designated as Level 2 within the valuation hierarchy.

The fair values of derivative instruments in asset positions include measures of counterparty nonperformance risk, and the fair values of derivative instruments in liability positions include measures of the Company's nonperformance risk. These measurements were not material to the Consolidated Financial Statements.

The fair value of the amount outstanding on our credit facility is equivalent to the carrying value due to the variable interest rate on such facility.

Related Party Transactions

Transactions between related parties are considered to be related party transactions even though they may not be given accounting recognition. FASB ASC 850, *Related Party Disclosures* ("FASB ASC 850") requires that transactions with related parties that would have influence in decision making shall be disclosed so that users of the financial statements can evaluate their significance. Related party transactions typically occur within the context of the following relationships: affiliates of the entity; entities for which investments in their equity securities is typically accounted for under the equity method by the investing entity; trusts for the benefit of employees; principal owners of the entity and members of their immediate families; management of the entity and members of their immediate families; and other parties that can significantly influence the management or operating policies of the transacting parties and can significantly influence the other to an extent that one or more of the transacting parties might be prevented from fully pursuing its own separate interests.

Recently Issued Accounting Pronouncements

FASB periodically issues new accounting standards in a continuing effort to improve standards of financial accounting and reporting. The Company has reviewed the recently issued pronouncements and concluded that the following new accounting standards are applicable:

In June 2016, the FASB issued Accounting Standards Update ("ASU") 2016-13, *Financial Instruments – Credit Losses*. This ASU, as further amended, affects trade receivables, financial assets and certain other instruments that are not measured through net income. This ASU will replace the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost and is effective for financial statements issued for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. The adoption of this ASU on January 1, 2023 by the Company did not have a material impact on the Company's consolidated financial statements since the Company does not have a history of material credit losses.

In August 2020, the FASB issued ASU 2020-06, *Debt—Debt with Conversion and Other Options (Subtopic 470-20) and Derivatives and Hedging—Contracts in Entity's Own Equity (Subtopic 815-40): Accounting for Convertible Instruments and Contracts in an Entity's Own Equity*. The amendments in this ASU affect entities that issue convertible instruments and/or contracts in an entity's own equity. The amendments in this ASU primarily affect convertible instruments issued with beneficial conversion features or cash conversion features because the accounting models for those specific features are removed. However, all entities that issue convertible instruments are affected by the amendments to the disclosure requirements of this ASU. For contracts in an entity's own equity, the contracts primarily affected are freestanding instruments and embedded features that are accounted for as derivatives under the current guidance because of failure to meet the settlement conditions of the derivatives scope exception related to certain requirements of the settlement assessment. Also affected is the assessment of whether an embedded conversion feature in a convertible instrument qualifies for the derivatives scope exception. Additionally, the amendments in this ASU affect the diluted EPS calculation for instruments that may be settled in cash or shares and for convertible instruments. The amendments in this ASU are effective for public business entities, excluding entities eligible to be smaller reporting companies, for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. For all other entities, the amendments are effective for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years. The Board specified that an entity should adopt the guidance as of the beginning of its annual fiscal year. The Board decided to allow entities to adopt the guidance through either a modified retrospective method of transition or a fully retrospective method of transition. The Company is analyzing the effect that adoption will have but does not currently expect a material impact as a result of adopting these standards.

Note 3 – Property

The capitalized costs of oil and natural gas properties as of December 31, 2023 and 2022 are as follows:

	2023	2022
Proved Properties	$ 75,346,623	$ 52,831,131
Unproved Properties	3,245,431	2,865,556
Work in process	14,917,749	8,289,652
Gross capitalized costs	93,509,803	63,986,339
Depreciation, Depletion, Amortization and Impairment	(22,996,805)	(20,116,696)
Total Oil and Gas Properties, Net	$ 70,512,998	$ 43,869,643

On August 9, 2023, the Company and a subsidiary of Energy Evolution Master Fund, Ltd. ("Energy Evolution"), a related party, collectively acquired additional working interests in certain of the Company's New Mexico properties. The Company paid $2.1 million in cash and acquired 10% of the total acquired working interests in the transaction. The subsidiary of Energy Evolution acquired the other 90% of the acquired working interest ("EEF Interest"). The Company has a one-year option to acquire the EEF Interest for $5 million, subject to adjustments ("Purchase Option"). In exchange for the Purchase Option, the Company issued 67,000 shares of common stock valued at approximately $601,000 and reflected in Other Noncurrent Assets. The Company has the right to extend the initial one-year Purchase Option period for two successive one-year periods by agreeing to issue an additional 42,000 shares of common stock prior to the end of the one-year period then in effect. The Purchase Option may be exercised by the Company at any time during the one-year period then in effect by sending written notice to Energy Evolution prior to the expiration of such one-year period.

The Company assesses its oil and gas properties for impairment when circumstances indicate the carrying value may be greater than its estimated future net cash flows. The Company did not identify any impairments in 2023. In 2022, estimated future cash flows from the Company's properties in Louisiana were less than the net book value. As a result, the Company recorded a $936,000 impairment expense in 2022.

In April 2022, the Company purchased working interests of oil and natural gas properties primarily located in the Landa field in North Dakota and assumed the role of operator. The Company paid approximately $1.4 million for eight producing properties, two properties with behind-pipe reserves, and related lease and well equipment. The Company allocated 80% of the acquisition cost to leasehold costs and the remaining 20% to related lease and well equipment. Non-cash asset retirement obligations were assumed of $233,659. The acquisition was accounted for as an asset acquisition. The Company purchased additional oil and gas properties in 2022 totaling $1.3 million.

Other property and equipment consists of operating lease assets, vehicles, office furniture, and equipment with lives ranging from three to five years. The capitalized costs of other property and equipment as of December 31, 2023 and 2022 are as follows:

		2023		2022
Other property and equipment, at cost	$	2,998,018		1,878,325
Less: accumulated depreciation		(1,114,807)		(436,796)
Oher property and equipment, net	$	1,883,211	$	1,441,529

Note 4 – Joint Development and Shared Services Agreements

On August 6, 2020 the Company, through its wholly owned subsidiary, Empire Texas, entered into a joint development agreement (the "JDA") with Petroleum & Independent Exploration, LLC and related entities ("PIE"), a related party, dated August 1, 2020. Under the terms of the JDA, PIE will perform recompletion or workover on specified mutually agreed upon wells ("Workover Wells") owned by Empire Texas. To fund the work, PIE entered into a term loan agreement with Empire Texas dated August 1, 2020, whereby PIE will loan up to $2,000,000, at an interest rate of 6% per annum, maturing August 7, 2024 unless terminated earlier by PIE. Proceeds of the loan will be used for recompletion or workover of the Workover Wells. As of December 31, 2023 and 2022 approximately $ 1,100,000 was outstanding on this loan and is included in Current Portion of Note Payable – Related Party and Long-Term Note Payable – Related Party on the Consolidated Balance Sheet, respectively. As part of the JDA, Empire Texas will assign to PIE a combined 85% working and revenue interest in the Workover Wells; an assignment was completed in October 2020 for the initial three Workover Wells. Of the assigned interest, 70% working and revenue interest will be used to repay the obligations under the term loan agreement. Once the term loan is repaid, PIE will reassign a 35% working and revenue interest to Empire Texas in each of the Workover Wells and retain a 50% working and revenue interest (See Note 7). To the extent the cash flows from the revenue interest are insufficient to repay the obligations under the term loan, the Company remains required to repay the obligation. In the third quarter of 2022, a $1.4 million long-term asset that had previously been recorded as an offset to the note payable was expensed to workovers within Lease Operating Expense on the Consolidated Statements of Operations.

The Company has also entered into a Shared Services Agreement with PIE effective August 1, 2023 that includes access to administrative, engineering and support services as well as building and insurance services. The agreement provides that the Company will reimburse PIE for the out-of-pocket or actual costs incurred by PIE in providing such services to the Company.

Note 5 – Asset Retirement Obligations

The Company's asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. Market risk premiums associated with asset retirement obligations are estimated to represent a component of the Company's credit-adjusted risk-free rate that is utilized in the calculations of asset retirement obligations.

The Company's asset retirement obligation transactions during the years ended December 31, 2023 and 2022 are summarized in the table below.

	For the Year Ended December 31,	
	2023	2022
Asset retirement obligations, beginning of period	$ 25,000,740	$ 20,640,599
Liabilities assumed in acquisitions	72,000	502,539
Revisions	2,303,938	2,660,653
Liabilities settled	(964,274)	(160,957)
Accretion expense	1,756,023	1,357,906
Asset retirement obligation, end of period	$ 28,168,427	$ 25,000,740
Less current portion included in Accrued Expenses	700,000	—
Asset retirement obligation, long-term	$ 27,468,427	$ 25,000,740

The revisions in 2023 primarily reflect cost revision estimates to wells in New Mexico based on 2023 plugging activity. The revisions in 2022 primarily relate to the identification of nonproducing wells, including injection wells and temporarily abandoned wells in New Mexico.

Note 6 – Commodity Derivative Financial Instruments

The Company uses derivative financial instruments to manage its exposure to commodity price fluctuations. Commodity derivative instruments are used to reduce the effect of volatility of price changes on the oil and natural gas the Company produces and sells. The Company does not enter into derivative financial instruments for speculative or trading purposes. The Company's derivative financial instruments consist of swaps and put options.

The Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its Consolidated Statements of Operations as they occur. These contracts are recognized and recorded at fair value as an asset or liability on the Company's Consolidated Balance Sheets.

The following table summarizes the net realized and unrealized amounts reported in earnings related to the commodity derivative instruments for the years ended December 31, 2023 and 2022:

	For the Year Ended December 31,	
	2023	2022
Gain (loss) on derivatives:		
Oil derivatives	$ (65,693)	$ (387,930)

The following represents the Company's net cash receipts from (payments on) derivatives for the years ended December, 2023 and 2022:

	For the Year Ended December 31,	
	2023	2022
Oil derivatives	$ (353,695)	$ (260,266)

The following table sets forth the Company's outstanding derivative contracts at December 31, 2023:

2024	1st Quarter 2024	2nd Quarter 2024	3rd Quarter 2024	4th Quarter 2024
WTI Fixed-Price Swaps:				
Quarterly volume (MBbls)	38.00	30.00	30.00	30.00
Weighted-average fixed price (Bbl)	$74.01	$72.15	$77.02	$75.57

Note 7 – Debt and Note Payable - Related Party

The following table represents the Company's outstanding debt.

	As of December 31, 2023	As of December 31, 2022
Equity Bank Credit Facility	$ 4,492,484	$ —
CrossFirst Senior Revolver Loan Agreement	—	5,869,500
Note Payable – Related Party	1,060,004	1,076,987
Equipment and vehicle notes, 0.00% to 9.00% interest rates, due in 2025 to 2028 with monthly payments ranging from $900 to $1,400 per month	148,516	252,924
Total Debt	5,701,004	7,199,411
Less: Current Maturities	(44,225)	(2,059,309)
Less: Note Payable – Related Party	(1,060,004)	(1,076,987)
Long-Term Debt	$ 4,596,775	$ 4,063,115

On December 29, 2023, Empire North Dakota and Empire NDA ("Borrowers"), entered into a Revolver Loan Agreement with Equity Bank (the "Credit Facility"). Pursuant to the Credit Facility (a) the initial revolver commitment amount is $10,000,000; (b) the maximum revolver commitment amount is $15,000,000; (c) commencing on January 31, 2024, and occurring on the last day of each calendar month thereafter, the revolver commitment amount is reduced by $150,000; (d) commencing on March 31, 2024, there are scheduled semiannual collateral borrowing base redeterminations each year on March 31 and September 30; (e) the final maturity date is December 29, 2026; (f) outstanding borrowings bear interest at a rate equal to the prime rate of interest plus 1.50%, and in no event lower than 8.50%; (g) a quarterly commitment fee is based on the unused portion of the commitments; and (h) Borrowers have the right to prepay loans under the Credit Facility at any time without a prepayment penalty.

The Credit Facility is guaranteed by the Company. Borrowers entered into a security agreement, pursuant to which the obligations under the Credit Facility are secured by liens on substantially all of the assets of Borrowers. Furthermore, the obligations under the Credit Facility are secured by a continuing, first priority mortgage lien, pledge of and security interest in not less than 80% of Borrowers' producing oil, gas and other leasehold and mineral interests, including without limitation, those situated in the States of North Dakota and Montana.

The Credit Facility requires Borrowers to, commencing as of the fiscal quarter ended December 31, 2023, maintain (a) a current ratio of 1.0 to 1.0 or more and (b) a ratio of funded debt to EBITDAX, calculated quarterly and annually based on a trailing twelve-month basis, of no more than 3.50 to 1.00. At December 31, 2023, the Borrowers were not in compliance with the current ratio, however, a waiver was obtained from the lender. The Company is in compliance with the other covenants as of December 31, 2023.

On July 7, 2021, the Company entered into the Fourth Amendment to its Senior Revolver Loan Agreement with CrossFirst Bank ("CrossFirst") as further amended by Letter Agreements in conjunction with redetermination dates (the "Amended Agreement"). The maximum amount that could be advanced under the Amended Agreement was $20,000,000 and the commitment amount following an August 9, 2023 amendment agreement was $5,180,000. The Amended Agreement was subsequently retired with proceeds from the new Credit Facility discussed above.

On September 19, 2023, each of Phil Mulacek, a member of the Company's Board of Dierctors, and Energy Evolution made a bridge loan to Empire North Dakota in the amount of $5.0 million (collectively, the "Bridge Loans"). These Bridge Loans were subsequently converted to our common shares. Mr. Mulacek and Energy Evolution are each a related party of the Company. See Note 15 for additional information regarding these Bridge Loans and the subsequent conversion to our common shares.

Note Payable - Related Party

In August 2020, concurrent with the JDA with PIE, a related party, the Company entered into a term loan agreement dated August 1, 2020, whereby PIE will loan up to $ 2,000,000, at an interest rate of 6% per annum, maturing August 7, 2024, unless terminated earlier by PIE. The loan proceeds will be used for recompletion or workover of certain designated wells. In addition, the Company assigned 85% working and revenue interest to PIE in the designated wells which will be applied to repayment of the loan. As of December 31, 2023, $1,060,004 has been advanced from the PIE loan.

Note 8 – Leases

As a lessee, the Company leases its corporate office headquarters in Tulsa, Oklahoma and one field office. The leases expire between 2024 and 2028. The corporate office has an option to renew for an additional five-year term. The option to renew the lease is generally not considered reasonably certain to be exercised. Therefore, the period covered by such optional period is not included in the determination of the term of the lease and the lease payments during these periods are similarly excluded from the calculation of right-of-use lease asset and lease liability balances.

The Company also leases vehicles primarily for use by our field operations. These vehicle leases typically have a three-year life.

The Company recognizes right-of use lease expense on a straight-line basis, except for certain variable expenses that are recognized when the variability is resolved, typically during the period in which they are paid. Variable right-of-use lease payments typically include charges for property taxes, insurance, and variable payments related to non-lease components, including common area maintenance.

Right of use lease expense was approximately $424,000 and $267,000 for the years ended December 31, 2023 and 2022, respectively. Cash paid for right of use lease was approximately $404,000 and $268,000 for the same period.

Supplemental balance sheet information related to the right of use leases is as follows:

	As of December 31,			
	2023		2022	
Net operating lease asset (included in Other Property and Equipment)	$	1,077,031	$	776,219
Current portion of lease liability	$	432,822	$	256,975
Long-term lease liability		544,382		547,692
Total right of use lease liabilities	$	977,204	$	804,667

The weighted average remaining term for the Company's right of use leases is 2.28 years. The weighted average discount rate was 8.56% in 2023.

Maturities of lease liabilities as of December 31, 2023 are as follows:

2024	$	498,654
2025		430,631
2026		136,545
2027		12,400
2028		—
Thereafter		—
Total lease payments		1,078,230
Less imputed interest		(101,026)
Total lease obligation	$	977,204

Note 9 – Equity

Pursuant to the Company's Amended and Restated Certificate of Incorporation ("Charter"), effective as of March 4, 2022, the total number of shares of all classes of stock that the Company has the authority to issue is 200,000,000, consisting of 190,000,000 shares of common stock, par value $0.001 per share, and 10,000,000 shares of preferred stock, par value $0.001 per share.

Preferred Stock

Preferred stock may be issued from time to time in one or more series at the direction of the Company's Board of Directors and the directors also have the ability to fix dividend rates and rights, liquidation preferences, voting rights, conversion rights, rights and terms of redemption and other rights, preferences, privileges and restrictions as determined by the Company's Board of Directors, subject to certain limitations set forth in the Charter.

Series A Voting Preferred Stock

On March 8, 2022, the Company formalized the issuance of preferred stock as was required under the terms of the Company's May 2021 financing agreements with Energy Evolution and issued six shares of Series A Voting Preferred Stock. The Series A Voting Preferred Stock was issued in connection with the strategic investment in the Company by Energy Evolution. For so long as the Series

A Voting Preferred Stock is outstanding, the Company's Board of Directors will consist of six directors. Three of the directors are designated as the Series A Directors and the three other directors (each, a "common director") are elected by the holders of common stock and/or any preferred stock (other than the Series A Voting Preferred Stock) granted the right to vote on the common directors. Any Series A Director may be removed with or without cause but only by the affirmative vote of the holders of a majority of the Series A Voting Preferred Stock voting separately and as a single class. The holders of the Series A Voting Preferred Stock have the exclusive right, voting separately and as a single class, to vote on the election, removal and/or replacement of the Series A Directors. Holders of common stock or other preferred stock do not have the right to vote on the Series A Directors. The approval of the holders of the Series A Voting Preferred Stock, voting separately and as a single class, is required to authorize any resolution or other action to issue or modify the number, voting rights or any other rights, privileges, benefits, or characteristics of the Series A Voting Preferred Stock, including without limitation, any action to modify the number, structure and/or composition of the Company's current Board of Directors.

The Series A Voting Preferred Stock is held by Phil Mulacek, Chairman of the Board of Directors of the Company and one of the principals of Energy Evolution, as Energy Evolution's designee (the "Initial Holder"). The Series A Voting Preferred Stock may be transferred only to certain controlled affiliates of the Initial Holder ("Permitted Transferees"), and the voting rights of the Series A Voting Preferred Stock are contingent upon the Initial Holder and Permitted Transferees (collectively, the "Series A Holders") holding together at least 3,000,000 shares of the Company's outstanding common stock.

The Series A Voting Preferred Stock is not entitled to receive any dividends or distributions of cash or other property except in the event of any liquidation, dissolution or winding up of the Company's affairs. In such event, before any amount is paid to the holders of the Company's common stock but after any amount is paid to the holders of the Company's senior securities, the holders of the Series A Voting Preferred Stock will be entitled to receive an amount per share equal to $1.00.

Except as discussed above or as otherwise set forth in the certificate of designation of the Series A Voting Preferred Stock, the holders of the Series A Voting Preferred Stock have no voting rights.

The Series A Voting Preferred Stock is not redeemable at the Company's election or the election of any holder, except the Company may elect to redeem the Series A Voting Preferred Stock for $1.00 per share following satisfaction of its notice and cure requirements in the event that:

- any or all shares of Series A Voting Preferred Stock are held by anyone other than the Initial Holder or a Permitted Transferee; or
- the Series A Holders together hold less than 3,000,000 shares of the Company's outstanding common stock.

The Series A Voting Preferred Stock is not convertible into common stock or any other security.

Common Stock

On August 27, 2021 the Company's Board of Directors approved a one-for-four reverse stock split such that every holder of the Company's common stock would receive one share of common stock for every four shares owned. The reverse stock split was effective as of 6:00 p.m. Eastern Time on March 7, 2022, immediately prior to the Company's listing of its common stock on the NYSE American. All share amounts have retrospectively been stated at post-reverse split amounts and pricing.

The holders of shares of common stock are entitled to one vote per share for all matters on which common stockholders are authorized to vote on. Examples of matters that common stockholders are entitled to vote on include, but are not limited to, election of three of the six directors and other common voting situations afforded to common stockholders.

During February and March 2021, the Company issued to a group of accredited investors 2,248,464 shares of its common stock and warrants to purchase 2,248,464 shares of its common stock for $2.00 per share which expires on December 31, 2022 with that day being accelerated should certain performance criteria be met. Proceeds from the sale were $3,147,850. The value allocated to the warrants was the fair value determined using the Black-Scholes option valuation with the following assumptions: no dividend yield, expected annual volatility of 180%, risk free interest rate of .14% and an expected useful life of 21 months. The fair value of the warrants of $2,350,407 was allocated to Additional Paid-in-Capital. The performance criteria triggering early maturity occurred in April 2022, accelerating the warrant maturity date to July 2022. During the nine months ended September 30, 2022, 1,782,347 shares of common stock were issued as a result of warrant exercises. As of July 10, 2022, all such warrants were fully exercised.

In September and October 2022, a former director of the Company exercised warrants granted in November 2017 to purchase 475,000 shares of common stock for $1.00 per share.

In connection with the purchase of XTO assets, the Company issued a Senior Secured Convertible Note due December 31, 2021, in the aggregate principal amount $16,250,000 (the "Secured Convertible Note") to Energy Evolution, a related party. As partial consideration for the issuance of the Secured Convertible Note, Empire issued to Energy Evolution (i) 375,000 shares of common stock along with (ii) a warrant certificate to purchase up to 750,000 shares of common stock at an exercise price of $4.00 per Warrant Share until May 14, 2022. Under the warrant certificate, the exercise price is subject to customary downward adjustments. The value allocated to the common stock, conversion feature, and warrants was $10,125,177. In September 2021, the Company and Energy Evolution entered into a Loan Modification Agreement (the "Amended Secured Notes"). Under the Amended Secured Notes, among other terms the Company issued a warrant certificate to purchase up to 500,000 shares of common stock at an exercise price of $5.00 per Warrant Share until December 31, 2023. In July 2023, Energy Evolution exercised its remaining warrants for 500,000 shares of common stock for $5.00 per share. The Company received $2.5 million related to this transaction.

See Note 15 for information regarding Bridge Loans issued from two related parties that were subsequently converted to our common shares and additional shares purchased with cash by those same parties.

Note 10 – Stock Based Compensation

On April 3, 2019, the Board of Directors of the Company adopted the Empire Petroleum Corporation 2019 Stock Option Plan (the "2019 Stock Option Plan"). The total number of shares of common stock that may be issued pursuant to stock options under the 2019 Stock Option Plan was 2,500,000. On August 27, 2021, the Board of Directors of the Company adopted the Company's 2021 Stock and Incentive Compensation Plan (the "2021 Incentive Plan") which was subsequently approved by stockholders of the Company. As a result of such approval, no further awards will be made under the 2019 Incentive Plan. The total number of shares of common stock that could be issued pursuant to the 2021 Incentive Plan is 750,000. On August 26, 2022, the stockholders of the Company approved the Company's 2022 Stock and Incentive Compensation Plan (the "2022 Incentive Plan") which reserves 750,000 shares of the Company's common stock for issuance thereunder. As a result of such approval, no further awards will be made under the 2021 Incentive Plan. On June 9, 2023, the stockholders of the Company approved the Company's 2023 Stock and Incentive Compensation Plan (the "2023 Incentive Plan") which reserves 700,000 shares of the Company's common stock for issuance thereunder. As a result of such approval, no further awards will be made under the 2022 Incentive Plan. The 2023 Incentive Plan authorizes the grant of nonqualified stock options, incentive stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units and other stock-based awards (restricted stock awards, restricted stock units, performance shares and performance units are collectively referred to as restricted stock units for purposes of this note). At December 31, 2023, 436,935 shares of our common stock were available for future grants.

Stock-based compensation expense for restricted stock units and stock options is included in General and Administrative expense in the Consolidated Statements of Operations and is recorded with a corresponding increase in Additional Paid-in Capital within the Consolidated Balance Sheets.

Restricted Stock Units

Each RSU represents the contingent right to receive one share of common stock. The holders of outstanding RSUs do not receive dividends or have voting rights prior to vesting and settlement. The Company determines the fair value of granted RSUs based on the market price of the common stock on the date of the grant. Compensation expense for granted RSUs is recognized on a straight-line basis over the vesting and is net of forfeitures, as incurred.

RSUs are generally granted with 12-month, 13-month, or 3 year service periods. Total value assigned to the RSUs granted in 2023 based on grant date price approximated $1,837,000. For the year ended December 31, 2023 and 2022, approximately $2,271,000 and $1,227,000 of compensation expense related to RSUs was recognized. At December 31, 2023, approximately $1,230,000 of unrecognized compensation expense remained and will be recognized on a straight-line basis depending on the service period of each grant.

The following summary reflects nonvested restricted stock unit activity and related information:

	Shares	Weighted Average Fair Value (a)
Outstanding, December 31, 2021	—	$ —
Granted	224,288	15.42
Vested	—	—
Outstanding, December 31, 2022	224,288	$ 15.42
Granted	180,430	10.33
Vested	(145,700)	16.20
Forfeited	(54,201)	14.57
Outstanding, December 31, 2023	204,817	$ 10.61

(a) Shares are valued at the grant-date market price.

		2023
Weighted Average grant date fair value of restricted stock units granted during the year, per share	$	10.33
Total fair value of restricted stock units vested during the year	$	2,286,464

Stock Options

Each stock option award provides the opportunity in the future to purchase Empire common shares at the market price of our common stock on the date the award is granted (the strike price). The options generally become exercisable in equal amounts over a three-year vesting period or over one-year for options awarded to the Board of Directors of the Company. Stock options have no financial statement effect on the date they are granted but rather are reflected over time through recording stock-based compensation expense. The stock-based compensation expense is based on the estimated fair value of the awards expected to vest, and that amount is amortized as compensation expense on a straight-line basis over the respective vesting period and is net of forfeitures, as incurred.

The estimated fair value of an option is calculated using a Black-Scholes option valuation model with the following assumption inputs: dividend yield, expected annual volatility, risk free interest rate and an expected life of the option. The following table summarizes the weighted average fair value and assumptions for 2023 and 2022.

		2023		2022
Weighted average grant-date fair value of stock options	$	4.52	$	4.55
Stock Options Valuation Assumptions:				
Risk-free interest rate		3.9%		1.6%
Dividend yield		0.0%		0.0%
Expected volatility		64.9%		56.0%
Expected option life (in years)		2.88		2.99
Other pricing model inputs:				
Weighted average grant-date market prices of Empire stock (strike price)	$	10.07	$	11.80

For the year ended December 31, 2023 and 2022, approximately $874,000 and $1,458,000 of compensation expense related to stock options was recognized. At December 31, 2023, approximately $1,546,000 of unrecognized compensation expense remained and will be recognized on a straight-line basis depending on the service period of each grant.

The following summary reflects stock option activity and related information:

	Options		Weighted Average Exercise Price
Outstanding, December 31, 2021	2,440,700	$	2.19
Granted	249,000		11.80
Exercised	(310,000)		1.34
Outstanding, December 31, 2022	2,379,700	$	3.31
Granted	533,000		10.07
Exercised	(355,000)		1.35
Forfeited	(492,319)		5.42
Outstanding, December 31, 2023	2,065,381	$	4.89

The following table summarizes information about stock options outstanding as of December 31, 2023:

Range of Exercise Prices	Options Outstanding at 12/31/23	Weighted Average Remaining Contractual Life	Weighted Average Exercise Price	Options Exercisable at 12/31/23	Weighted Average Exercise Price
$1.32 to $12.36	2,065,381	4.94 years	$4.89	1,605,210	$3.09

Note 12 – Income Taxes

The current and deferred income tax provision for the years ended December 31, 2023 and 2022 were comprised of the following:

	2023	2022
Current	$ (132,192)	$ 208,898
Deferred	—	—
Income tax provision	$ (132,192)	$ 208,898

In the event that an entity has an "ownership change" (as defined in Section 382 of the Internal Revenue Code of 1986, as amended ("IRC")), an entity's federal net operating loss carryforwards ("NOLs") generated prior to an ownership change would be subject to annual limitations, which could defer or eliminate the Company's ability to utilize these tax losses against future taxable income. Generally, an "ownership change" occurs if one or more stockholders, each of whom owns 5% or more in value of a corporation's stock, increase their aggregate percentage ownership by more than 50% over the lowest percentage of stock owned by those stockholders at any time during the preceding three-year period. A full Section 382 analysis was prepared in 2023 and it was determined that our NOLs were subject to limitations under IRC Section 382. The Company's ability to use NOLs and other tax attributes to reduce taxable income and income taxes could be materially impacted by a future IRC 382 ownership change. Future transactions involving the Company's stock including those outside of the Company's control could cause an IRC Section 382 ownership change resulting in a limitation on tax attributes currently not limited and a more restrictive limitation on tax attributes currently subject to the previous IRC 382 limitation.

At December 31, 2023, the Company had approximately $24.3 million of federal NOLs generated in prior years available to offset against future taxable income, net of NOLs expected to expire unused due to IRC Section 382 limitations. Of the $24.3 million NOLs, approximately $23 million relate to periods after 2017 and have an indefinite life. Additionally, $ 1.3 million will begin to expire between 2023-2037 if not used. Approximately, $4.7 million of the NOLs were limited as of December 31, 2023 due to previous ownership changes.

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and the tax basis of assets and liabilities. The Company's net tax position as of December 31, 2023 and 2022 is as follows:

	2023	2022
Deferred tax assets:		
Loss carry-forwards	$ 6,269,503	$ 4,789,586
Right of use assets	—	7,341
Stock option grants	2,022,184	1,369,105
Asset retirement obligation	7,433,670	6,616,407
Other	526,873	436,477
Total deferred tax assets	16,252,230	13,218,916
Deferred tax liabilities:		
Oil and Gas Properties	(7,327,620)	(5,552,159)
Other property and equipment	(123,915)	(171,650)
Derivatives	(104,956)	(31,369)
Lease liabilities	(25,133)	—
Other	—	(69,688)
Total deferred tax liabilities	(7,581,624)	(5,824,866)
Net deferred tax asset before valuation allowance	8,670,606	7,394,050
Valuation allowance	(8,670,606)	(7,394,050)
Net deferred taxes	$ —	$ —

Utilization of the Company's loss carryforwards is dependent on realizing taxable income. The Company's recorded valuation allowances of $ 8.7 million and $7.4 million as of December 31, 2023 and 2022, respectively, are due to the uncertainty related to its ability to utilize some of its deferred income tax assets, primarily consisting of net operating loss carryforwards prior to expiration or the limitation under Section 382 as discussed above.

Reconciliations of the tax provision (benefit) computed at the statutory federal rate to the Company's total income tax benefit for the years ended December 31, 2023 and 2022 are as follows:

	2023		2022	
	$	%	$	%
Provision (benefit) at statutory rate	(2,646,378)	21.0%	1,531,536	21.0%
State Taxes (net of federal impact)	(598,191)	4.7%	350,632	4.9%
Nondeductible Expenses	31,037	-0.2%	21,052	0.3%
Return to Accrual	(72,448)	0.6%	(2,135,704)	-29.3%
NOLs Expected to Expire Unused Due to Section 382 Limitation	1,877,230	-14.9%	—	0.0%
Valuation Allowance	1,276,558	-10.1%	441,382	6.1%
Income tax provision (benefit)	(132,192)	1.0%	208,898	2.9%

The Company has evaluated all tax positions for which the statute of limitations remains open and believes that the material positions taken would more likely than not be sustained by examination. Therefore, at December 31, 2023, the Company has not established any reserves for, nor recorded any unrecognized benefits related to uncertain tax positions.

The Company's only taxing jurisdiction is the United States (federal and state). The Company's tax years 2020 to present remain open for federal examination. Additionally, tax years 2003 through 2019 remain subject to examination for the purpose of determining the amount of federal NOL and other carryforwards. The number of years open for state tax audits varies, depending on the state, but is generally from three to five years.

Note 13 – Earnings (Loss) per Share

Diluted Earnings per Share ("EPS") gives effect to all dilutive potential common shares outstanding during the period. The computation of Diluted EPS does not assume conversion, exercise or contingent exercise of securities that would have an anti-dilutive effect on losses. As a result, if there is a loss from continuing operations, Diluted EPS is computed in the same manner as Basic EPS. In addition, approximately 348,000 options were excluded due to the option exercise price exceeding the weighted-average market price of our common shares.

The following table summarizes the calculation of income (loss) per share.

	2023	2022
Net Income (Loss)	$ (12,469,605)	$ 7,084,130
Basic Weighted-Average Shares	22,718,890	21,003,563
Effect of Dilutive Securities:		
Restricted Stock Units and Stock Options [(a)]	—	2,384,083
Diluted Weighted-Average Shares	22,718,890	23,387,646
Income (Loss) per Common Share		
Basic	$ (0.55)	$ 0.34
Diluted	$ (0.55)	$ 0.30

(a) At December 31, 2023 the Company had approximately 1,361,200 RSUs and options that were excluded from the calculation of net income (loss) per share as their inclusion would be antidilutive due to a net loss for the period.

Note 14 – Executive Separations

On March 16, 2023, Thomas W. Pritchard resigned as Chief Executive Officer and a director of the Company to pursue other opportunities. Although not required under Mr. Pritchard's Employment Agreement with the Company, in recognition of Mr. Pritchard's past service to the Company, the Company will pay Mr. Pritchard severance benefits in the amount of approximately $360,000, as set forth in Section 4.2 of his Employment Agreement, in one lump sum payment within 30 days after March 23, 2023, rather than in monthly installments. This was accrued as of March 31, 2023, and payment was made in April 2023. The Company also extended the period under which Mr. Pritchard has the right to exercise his outstanding vested non-qualified stock options from three months after the date of his termination of employment to September 16, 2024. In addition, Mr. Pritchard has surrendered to the Company 340,234 RSUs and options as satisfaction for the $2.1 million receivable that primarily resulted from incorrect withholdings associated with an April 2022 option exercise by Mr. Pritchard. The Company also had a $2.1 million liability recorded at December 31, 2022, related to withholding payables that were remitted in 2023.

On March 17, 2023, the Board of Directors of the Company appointed Michael R. Morrisett to the position of Chief Executive Officer. Mr. Morrisett did not receive any additional compensation for assuming the role of Chief Executive Officer.

In July 2023, the Company's Chief Operating Officer separated from the Company and will receive severance of $145,000 over six months. Additionally, certain vested options were forfeited resulting in the reversal of $576,000 of previously recorded stock-based compensation.

Note 15 – Related Party Transactions

Energy Evolution is a related party of the Company as it beneficially owns approximately 26.6% of the Company's outstanding shares of common stock as of December 31, 2023. Additionally, a board member of Energy Evolution was appointed to the Company's Board of Directors in October 2021. This board member separately beneficially owns approximately 19.3% of the Company's outstanding shares of common stock as of December 31, 2023. This board member also is a majority owner of PIE. In October 2021 another Energy Evolution member was appointed to the Company's Board of Directors.

The Company has a JDA with PIE to perform recompletion or workover on specified mutually agreed upon wells (See Note 4). As of December 31, 2023, the Company has incurred obligations of approximately $1.1 million as a part of the JDA.

On November 29, 2023, the Company entered into a Securities Purchase Agreement with Phil Mulacek, which agreement was amended on December 1, 2023, pursuant to which Mr. Mulacek purchased from the Company (a) 609,013 shares of common stock of the Company for an aggregate purchase price of $5,000,000 (or $8.21 per share) in cash and (b) 631,832 shares of common stock of the Company for an aggregate purchase price of $5,054,658 (or $8.00 per share) which was paid through cancellation and extinguishment of the outstanding principal amount and all accrued interest thereon under that certain Amended and Restated Promissory Note due December 31, 2024, in the original aggregate principal amount of $5,000,000 issued by Empire North Dakota to Mr. Mulacek.

On November 29, 2023, the Company entered into a Securities Purchase Agreement with Energy Evolution pursuant to which Energy Evolution purchased 1,256,832 shares of common stock of the Company for an aggregate purchase price of $10,054,658 (or $8.00 per share), of which $2,000,000 was advanced in cash to the Company on November 22, 2023, $3,000,000 was paid in cash to the Company and $5,054,658 was paid through cancellation and extinguishment of the outstanding principal amount and all accrued interest thereon under that certain Amended and Restated Promissory Note due December 31, 2024, in the original aggregate principal amount of $5,000,000 issued by Empire North Dakota to Energy Evolution.

Accounts receivable on the Consolidated Balance Sheet includes approximately $895,000 receivable from Energy Evolution. Accrued Expenses includes approximately $452,000 of revenue payable to Energy Evolution.

Note 16 – Commitments and Contingencies

From time to time, the Company is subject to various legal proceedings arising in the ordinary course of business, including proceedings for which the Company may not have insurance coverage. While many of these matters involve inherent uncertainty, as of the date hereof, the Company does not currently believe that any such legal proceedings will have a material adverse effect on the Company's business, financial position, results of operations or liquidity.

The Company is subject to extensive federal, state, and local environmental laws and regulations. These laws, among other things, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Management believes no materially significant liabilities of this nature existed as of the balance sheet date.

Note 17 – Concentrations

The Company's producing properties and oil and natural gas reserves are all located in Louisiana, New Mexico, North Dakota, Montana, and Texas. Because of the concentration, the Company is exposed to the impact of regional supply and demand factors, processing or transportation capacity constraints, severe weather events, water shortages, and government regulations specific to the geographic area.

For the year ended December 31, 2023, the Company sold 70% of its oil, natural gas, and NGL to four customers. For the year ended December 31, 2022, the Company sold 68% of its oil and natural gas production to four customers. The loss of these purchasers could result in a temporary interruption in sales or a lower price for production.

The Company's cash balances may at times exceed FDIC insurance limits. The Company maintains cash accounts at reputable financial institutions.

Note 18 – Subsequent Events

Promissory Note

On February 16, 2024, the Company issued a Promissory Note in the aggregate principal amount of $5,000,000 (the "Note") to Energy Evolution. Energy Evolution has advanced the Company $5,000,000 under the Note. The proceeds of the Note will be used by the Company to fund, in part, its ongoing oil and gas drilling program and for working capital purposes.

The Note matures on February 15, 2026 (the "Maturity Date") and accrues interest at the rate of 7% per annum. After the Maturity Date, any principal balance of the Note remaining unpaid accrues interest at the rate of 9% per annum. At the option of Energy Evolution, interest payments will be paid either in cash or in shares of common stock of the Company on each of the following dates (or if any such date is not a business day, the next following business day) (each an "Interest Payment Date"), except upon the occurrence of an Event of Default, in which case interest will accrue and be paid in cash on demand: (i) March 31, 2024; (ii) June 30, 2024; (iii) September 30, 2024; (iv) December 31, 2024; (v) March 31, 2025; (vi) June 30, 2025; (vii) September 30, 2025; (viii) December 31, 2025; and (ix) the Maturity Date. All or any portion of the outstanding principal amount of the Note may be converted into shares of common stock of the Company at a conversion price of $6.25 per share (the "Conversion Price"), at the option of Energy Evolution, at any time and from time to time. If the full principal amount of the Note is drawn and converted into shares of common stock of the Company, 800,000 shares would be issued (without giving effect to any interest that may be converted). Accrued interest on the principal amount converted will be due on the applicable date of conversion in cash or, at the option of Energy Evolution, by issuance of shares of common stock of the Company in the manner set forth in the Note (where the date of conversion is the relevant Interest Payment Date"). The Conversion Price is subject to customary adjustments. The Note may be prepaid at any time or from time to time without the consent of Energy Evolution and without penalty or premium, provided that the Company provides Energy Evolution with at least five business days prior written notice, each principal payment is made in cash and all accrued interest is paid in cash, or at the option of Energy Evolution, by issuance of shares of common stock of the Company in the manner set forth in the Note (where the Interest Payment Date is the date of prepayment).

Rights Offering

In March 2024, the Company announced that it has commenced a subscription rights offering ("Rights Offering") pursuant to which it intends to raise gross proceeds of up to approximately $25.0 million. The Company has distributed at no charge to holders of its common stock, as of the close of business on March 7, 2024 (the record date for the Rights Offering), one subscription right for each share of Common Stock held. Each subscription right initially entitled the holder to purchase 0.161 shares of Common Stock at a subscription price of $6.05 per share per one whole share of Common Stock.On March 28, 2024, the Company announced a reduction in the subscription price to $5.00 which results in gross proceeds to the Company of up to approximately $20.66 million. The subscription rights are non-transferable, and will not be listed for trading on any stock exchange or market. In addition, holders of subscription rights who fully exercise their subscription rights are entitled to over-subscribe for additional shares of Common Stock, subject to proration. The Rights Offering is expected to expire at 5:00 p.m., Eastern Time, on April 10, 2024, subject to extension or earlier termination.

Phil Mulacek and Energy Evolution, both related parties of the Company (see Note 15) and our largest stockholders, have indicated that they intend to participate in the Rights Offering and fully subscribe to the shares of Common Stock corresponding to their subscription rights. They have each also indicated that they intend to fully exercise their over-subscription rights to purchase their pro rata share of the underlying securities related to the Rights Offering that remain unsubscribed at the Expiration Date.

EMPIRE PETROLEUM CORPORATION

Supplemental Information of Oil and Natural Gas Producing Activities (Unaudited)

December 31, 2023 and 2022

The following reserve estimates present the Company's estimate of the proven natural gas and oil reserves and net cash flow of the Company's properties, in accordance with the guidelines established by the Securities and Exchange Commission. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing natural gas and oil properties. Accordingly, the estimates are expected to change as future information becomes available. All the oil and natural gas reserves are located in Louisiana, New Mexico, North Dakota, Montana and Texas.

Costs Incurred Related to Oil and Gas Activities

Costs incurred includes capitalized costs of properties, equipment, and lease facilities for oil and natural gas producing activities.

	Years Ended December 31, 2023	2022
Acquisition	$ 2,094,419	$ 2,702,613
Exploration	—	—
Development	25,053,107	11,206,207
	$ 27,147,526	$ 13,908,820

Reserve Quantity Information

Proved oil and natural gas reserves are those quantities of oil and gas, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditures is required for recompletion. The information below excludes proved undeveloped reserves. Below are the net quantities of net proved developed reserves of the Company's properties:

	Oil (MMBbls)	Gas (MMcf)	NGLs (a)	MBOE
Balance, December 31, 2021	8,448	11,208	87	10,404
Acquisition of Reserves	650	205	61	745
Revisions	(350)	1,834	2,248	2,203
Extensions	561	566	27	682
Production	(483)	(876)	(161)	(790)
Balance, December 31, 2022	8,826	12,937	2,262	13,244
Acquisition of Reserves	36	19	5	44
Revisions	(1,625)	(5,998)	(960)	(3,585)
Extensions	175	—	—	175
Production	(488)	(854)	(136)	(766)
Balance, December 31, 2023	6,924	6,104	1,171	9,112

The 2023 acquisitions primarily relate to additional working interests in certain of the Company's New Mexico properties (See Note 3). The 2022 acquisitions relate to small acquisition in our Rockies and New Mexico regions. The revisions in 2023 are primarily related to decreases in prices.

Standardized Measure of Discounted Future Net Cash Flows Relating to Oil and Natural Gas Reserves

The standardized measure of discounted future net cash flows relating to oil and natural gas reserves and associated changes in standard measure amounts were prepared in accordance with the provision of Financial Accounting Standard Board ASC 932-235-555. Future cash inflows were computed by applying average prices of oil and natural gas for the last 12 months to estimated future production. Future production and development costs were computed by estimating the expenditures to be incurred in developing the oil and natural gas reserves at the end of the year, based on yearend costs and assuming continuation of existing economic conditions. Future net cash flows are discounted at the rate of 10% annually to derive the standardized measure of discounted cash flows. Actual future cash inflows may vary considerably, and the standardized measure does not necessarily represent the fair value of the acquired properties' oil and natural gas reserves. Standard measure amounts are:

	December 31, 2023	December 31, 2022
Future cash inflows	$ 543,067,776	$ 941,172,544
Future production costs	(350,439,800)	(509,154,924)
Future development costs	(42,475,160)	(55,901,780)
Future income tax expense	(25,201,886)	(90,724,632)
Future net cash flows	124,950,930	285,391,208
10% annual discount for estimated timing of cash flows	(41,934,370)	(137,723,795)
Standardized measure	$ 83,016,560	$ 147,667,413

The 12-month average prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate the properties' reserves. The prices for the properties' reserves were as follows:

	2023	2022
Oil (BBl)	$ 75.45	$ 91.14
Natural gas (MMBtu)	$ 1.51	$ 4.23
NGLs (BBl)	$ 9.82	$ 36.29

Changes in the Standardized Measure of Discounted Future Net Cash Flows at 10% per annum are as follows:

	December 31, 2023	December 31, 2022
Beginning of year	$ 147,667,413	$ 93,852,093
Net change in prices and production costs	(71,619,375)	24,651,555
Net change in future development costs	3,314,220	(7,141,431)
Oil & Gas net revenue	(6,256,366)	(21,418,327)
Extensions	4,684,473	11,037,719
Acquisition of reserves	526,848	12,043,912
Revisions of previous quantity estimates	(55,329,684)	46,871,217
Net change in taxes	33,317,731	(32,133,473)
Accretion of discount	19,542,907	10,939,619
Changes in timing and other	7,168,393	8,964,529
End of year	$ 83,016,560	$ 147,667,413

Estimates of economically recoverable natural gas and oil reserves and of future net revenues are based upon a number of variable factors and assumptions, all of which are to some degree subjective and may vary considerably from actual results. Therefore, actual production, revenues, development and operating expenditures may not occur as estimated. The reserve data are estimates only, are subject to many uncertainties, and are based on data gained from production histories and on assumptions as to geologic formations and other matters. Actual quantities of natural gas and oil may differ materially from the amounts estimated.

EMPIRE PETROLEUM CORPORATION
Subsidiaries

Entity	Place of Incorporation/Organization
Empire Louisiana LLC	Delaware
Empire New Mexico LLC	Delaware
Empire EMSU LLC	Delaware
Empire EMSU-B LLC	Delaware
Empire AGU LLC	Delaware
Empire NM Assets LLC	Delaware
Empire North Dakota LLC	Delaware
Empire ND Acquisition LLC	Delaware
Empire Northwest Shelf LLC	Delaware
Empire Texas LLC	Delaware
Empire Texas GP LLC	Texas
Empire Texas Operating LLC	Texas
Pardus Oil & Gas Operating, LP	Texas

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated March 28, 2024, with respect to the consolidated financial statements included in the Annual Report of Empire Petroleum Corporation on Form 10-K for the year ended December 31, 2023. We consent to the incorporation by reference of said report in the Registration Statements of Empire Petroleum Corporation on Forms S-3 (File No. 333-260570 and File No. 333-274327) and on Forms S-8 (File No. 333-261364, File No. 333-267220 and File No. 333-272789).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
March 28, 2024

CONSENT OF CAWLEY, GILLESPIE & ASSOCIATES, INC.

We consent to the incorporation by reference in the registration statements (File Nos. 333-261364, 333-267220 and 333-272789) on Form S-8 and the registration statements (File Nos. 333-260570 and 333-274327) on Form S-3 of Empire Petroleum Corporation (the “Company”) of our report for the Company and the references to our firm and said report, in the context in which they appear, in this Annual Report on Form 10-K of the Company for the year ended December 31, 2023 (this “Form 10-K”), which report is included as an exhibit to this Form 10-K.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

J. Zane Meekins, P.E.
Executive Vice President

Fort Worth, Texas
March 28, 2024

CERTIFICATION

I, Michael R. Morrisett, certify that:

1. I have reviewed this annual report on Form 10-K of Empire Petroleum Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 28, 2024

/s/ Michael R. Morrisett
Michael R. Morrisett
President and Chief Executive Officer

CERTIFICATION

I, Stephen L. Faulkner, Jr., certify that:

1. I have reviewed this annual report on Form 10-K of Empire Petroleum Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

    (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

    (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 28, 2024

/s/ Stephen L. Faulkner, Jr.
Stephen L. Faulkner, Jr.
Chief Financial Officer and
Chief Accounting Officer
(principal financial officer)

**CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002**

In connection with the annual report of Empire Petroleum Corporation (the "Company") on Form 10-K for the year ended December 31, 2023, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael R. Morrisett, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 28, 2024

/s/ Michael R. Morrisett
Michael R. Morrisett
President and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.

EXHIBIT 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Empire Petroleum Corporation (the "Company") on Form 10-K for the year ended December 31, 2023, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Stephen L. Faulkner, Jr., Chief Financial Officer and Chief Accounting Officer (principal financial officer) of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 28, 2024

/s/ Stephen L. Faulkner, Jr.
Stephen L. Faulkner, Jr.
Chief Financial Officer and
Chief Accounting Officer
(principal financial officer)

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.

EMPIRE PETROLEUM CORPORATION

POLICY FOR THE
RECOVERY OF ERRONEOUSLY AWARDED COMPENSATION

1. Overview

In accordance with the applicable rules of the NYSE American LLC Company Guide (the "**NYSE American Rules**"), Section 10D of the Securities Exchange Act of 1934, as amended (the "**Exchange Act**"), and Rule 10D-1 under the Exchange Act ("**Rule 10D-1**"), the Board of Directors (the "**Board**") of Empire Petroleum Corporation (the "**Company**") has adopted this Policy to provide for the recovery of erroneously awarded Incentive-based Compensation from Executive Officers. All capitalized terms used and not otherwise defined herein shall have the meanings set forth in Section 8 below.

2. Recovery of Erroneously Awarded Compensation

(a) In the event of an Accounting Restatement, the Company will reasonably promptly recover the Erroneously Awarded Compensation Received in accordance with NYSE American Rules and Rule 10D-1 as follows:

(i) After an Accounting Restatement, the Compensation Committee of the Board (if composed entirely of independent directors, or in the absence of such a committee, a majority of independent directors serving on the Board) (the "**Committee**") shall determine the amount of any Erroneously Awarded Compensation Received by each Executive Officer and shall promptly notify each Executive Officer with a written notice containing the amount of any Erroneously Awarded Compensation and a demand for repayment or return of such compensation, as applicable.

For Incentive-based Compensation based on (or derived from) the Company's stock price or total shareholder return, where the amount of Erroneously Awarded Compensation is not subject to mathematical recalculation directly from the information in the applicable Accounting Restatement:

(A) The amount to be repaid or returned shall be determined by the Committee based on a reasonable estimate of the effect of the Accounting Restatement on the Company's stock price or total shareholder return upon which the Incentive-based Compensation was Received; and

(B) The Company shall maintain documentation of the determination of such reasonable estimate and provide the relevant documentation as required to the NYSE American.

(ii) The Committee shall have discretion to determine the appropriate means of recovering Erroneously Awarded Compensation based on the particular facts and circumstances, which may include without limitation (A) seeking reimbursement of all or part of any cash or equity-based award, (B) cancelling prior cash or equity-based awards, whether vested or unvested or paid or unpaid, (C) cancelling or offsetting against any planned future cash or equity-based awards, (D) forfeiture of deferred compensation, subject to compliance with Section 409A of the Internal Revenue Code of 1986, as amended (the "**Code**"), and regulations thereunder and (E) any other method authorized by applicable law or contract. Subject to compliance with any applicable law, the Committee may affect recovery under this Policy from any amount otherwise payable to the Executive Officer, including amounts payable to such individual under any otherwise applicable Company plan or program, including base salary, bonuses or commissions and compensation previously deferred by the Executive Officer. Notwithstanding the foregoing, except as set forth in Section 2(b) below, in no event may the Company accept an amount that is less than the amount of Erroneously Awarded Compensation in satisfaction of an Executive Officer's obligations hereunder.

(iii) To the extent that the Executive Officer has already reimbursed the Company for any Erroneously Awarded Compensation Received under any duplicative recovery obligations established by the Company or applicable law, it shall be appropriate for any such reimbursed amount to be credited to the amount of Erroneously Awarded Compensation that is subject to recovery under this Policy.

(iv) To the extent that an Executive Officer fails to repay all Erroneously Awarded Compensation to the Company when due, the Company shall take all actions reasonable and appropriate to recover such Erroneously Awarded Compensation from the applicable Executive Officer. The applicable Executive Officer shall be required to reimburse the Company for any and all expenses reasonably incurred (including legal fees) by the Company in recovering such Erroneously Awarded Compensation in accordance with the immediately preceding sentence.

(b) Notwithstanding anything herein to the contrary, the Company shall not be required to take the actions contemplated by Section 2(a) above if the Committee (which, as specified above, is composed entirely of independent directors or in the absence of such a committee, a majority of the independent directors serving on the Board) determines that recovery would be impracticable and any of the following two conditions are met:

(i) The Committee has determined that the direct expenses paid to a third party to assist in enforcing this Policy would exceed the amount to be recovered. Before making this determination, the Company must make a reasonable attempt to recover the Erroneously Awarded Compensation, documented such attempt(s) and provided such documentation to the NYSE American; or

(ii) Recovery would likely cause an otherwise tax-qualified retirement plan, under which benefits are broadly available to employees of the Company, to fail to meet the requirements of Section 401(a)(13) or Section 411(a) of the Code and regulations thereunder.

3. Disclosure Requirements

The Company shall file all disclosures with respect to this Policy required by applicable U.S. Securities and Exchange Commission (the "**SEC**") filings and rules.

4. Prohibition of Indemnification

The Company shall not be permitted to insure or indemnify any Executive Officer against (a) the loss of any Erroneously Awarded Compensation that is repaid, returned or recovered pursuant to the terms of this Policy or (b) any claims relating to the Company's enforcement of its rights under this Policy, including any payment or reimbursement for the cost of third-party insurance purchased by any Executive Officer to cover any such loss or claims. Further, the Company shall not enter into any agreement that exempts any Incentive-based Compensation that is granted, paid or awarded to an Executive Officer from the application of this Policy .

or that waives the Company's right to recovery of any Erroneously Awarded Compensation, and this Policy shall supersede any such agreement (whether entered into before, on or after the effective date of this Policy).

---

5. Administration and Interpretation

This Policy shall be administered by the Committee, and any determinations made by the Committee shall be final and binding on all affected individuals.

The Committee is authorized to interpret and construe this Policy and to make all determinations necessary, appropriate, or advisable for the administration of this Policy and for the Company's compliance with NYSE American Rules, Section 10D of the Exchange Act, Rule 10D-1 and any other applicable law, regulation, rule or interpretation of the SEC or the NYSE American promulgated or issued in connection therewith.

6. Amendment; Termination

The Board may amend this Policy from time to time in its discretion and shall amend this Policy as it deems necessary. The Board may terminate this Policy at any time. Notwithstanding anything in this Section 6 to the contrary, no amendment or termination of this Policy shall be effective if such amendment or termination would (after taking into account any actions taken by the Company contemporaneously with such amendment or termination) cause the Company to violate any federal securities laws, SEC rule or NYSE American Rule.

7. Other Recovery Rights

This Policy shall be binding and enforceable against all Executive Officers and their beneficiaries, heirs, executors, administrators or other legal representatives. The Committee intends that this Policy will be applied to the fullest extent required by applicable law. If any provision of this Policy or the application of such provision to any Executive Officer shall be adjudicated to be invalid, illegal or unenforceable in any respect, such invalidity, illegality or unenforceability shall not affect any other provisions of this Policy, and the invalid, illegal or unenforceable provisions shall be deemed amended to the minimum extent necessary to render any such provision (or the application of such provision) valid, legal or enforceable. Any employment agreement, equity award agreement, compensatory plan or any other agreement or arrangement with an Executive Officer shall be deemed to include, as a condition to the grant of any benefit thereunder, an agreement by the Executive Officer to abide by the terms of this Policy. Any right of recovery under this Policy is in addition to, and not in lieu of, any other remedies or rights of recovery that may be available to the Company under applicable law, regulation or rule or pursuant to the terms of any policy of the Company or any provision in any employment agreement, equity award agreement, compensatory plan, agreement or other arrangement.

8. Definitions

For purposes of this Policy, the following capitalized terms shall have the meanings set forth below.

(a) "**Accounting Restatement**" means an accounting restatement of the Company's financial statements due to the material noncompliance of the Company with any financial reporting requirement under the securities laws, including any required accounting restatement to correct an error in previously issued financial statements that is material to the previously issued financial statements (a "Big R" restatement), or that would result in a material misstatement if the error were corrected in the current period or left uncorrected in the current period (a "little r" restatement).

(b) "**Clawback Eligible Incentive Compensation**" means all Incentive-based Compensation Received by an Executive Officer (i) on or after October 2, 2023, the effective date of the applicable NYSE American Rules, (ii) after beginning service as an Executive Officer, (iii) who served as an Executive Officer at any time during the applicable performance period relating to any Incentive-based Compensation (whether or not such Executive Officer is serving at the time the Erroneously Awarded Compensation is required to be repaid to the Company), (iv) while the Company has a class of securities listed on a national securities exchange or a national securities association, and (v) during the applicable Clawback Period (as defined below).

(c) "**Clawback Period**" means, with respect to any Accounting Restatement, the three completed fiscal years of the Company immediately preceding the Restatement Date (as defined below), and if the Company changes its fiscal year, any transition period of less than nine months within or immediately following those three completed fiscal years.

(d) "**Erroneously Awarded Compensation**" means, with respect to each Executive Officer in connection with an Accounting Restatement, the amount of Clawback Eligible Incentive Compensation that exceeds the amount of Incentive-based Compensation that otherwise would have been Received had it been determined based on the restated amounts, computed without regard to any taxes paid.

(e) "**Executive Officer**" means each individual who is currently or was previously designated as an "officer" of the Company as defined in Rule 16a-1(f) under the Exchange Act. For the avoidance of doubt, the identification of an executive officer for purposes of this Policy shall include each executive officer who is or was identified pursuant to Item 401(b) of Regulation S-K, as well as the principal financial officer and principal accounting officer (or, if there is no principal accounting officer, the controller).

(f) "**Financial Reporting Measures**" means measures that are determined and presented in accordance with the accounting principles used in preparing the Company's financial statements, and all other measures that are derived wholly or in part from such measures. Stock price and total shareholder return (and any measures that are derived wholly or in part from stock price or total shareholder return) shall, for purposes of this Policy, be considered Financial Reporting Measures. For the avoidance of doubt, a Financial Reporting Measure need not be presented in the Company's financial statements or included in a filing with the SEC.

(g) "**Incentive-based Compensation**" means any compensation that is granted, earned or vested based wholly or in part upon the attainment of a Financial Reporting Measure.

(h) "**NYSE American**" means the NYSE American Stock Exchange.

(i) "**Received**" means, with respect to any Incentive-based Compensation, actual or deemed receipt, and Incentive-based Compensation shall be deemed received in the Company's fiscal period during which the Financial Reporting Measure specified in the Incentive-based Compensation award is attained, even if the payment or grant of the Incentive-based Compensation to the Executive Officer occurs after the end of that period.

(j) "**Restatement Date**" means the earlier to occur of (i) the date the Board, a committee of the Board or the officer or officers of the Company authorized to take such action if Board action is not required, concludes, or reasonably should have concluded, that the Company is required to prepare an Accounting Restatement, or (ii) the date a court, regulator or other legally authorized body directs the Company to prepare an Accounting Restatement, in each case regardless of if or when the restated financial statements are filed.

Effective as of October 2, 2023.

Exhibit A

**ATTESTATION AND ACKNOWLEDGEMENT OF POLICY
FOR THE RECOVERY OF ERRONEOUSLY AWARDED COMPENSATION**

By my signature below, I acknowledge and agree that:

- I have received and read the attached Policy for the Recovery of Erroneously Awarded Compensation (this "**Policy**").
- I hereby agree to abide by all of the terms of this Policy both during and after my employment with the Company, including, without limitation, by promptly repaying or returning any Erroneously Awarded Compensation to the Company as determined in accordance with this Policy.

Signature: ______________________________

Printed Name: ______________________________

Date: ______________________________

CAWLEY, GILLESPIE & ASSOCIATES, INC.
PETROLEUM CONSULTANTS
302 FORT WORTH CLUB BUILDING
306 WEST SEVENTH STREET
FORT WORTH, TEXAS 76102-4987
(817) 336-2461

March 21, 2024

Mr. Michael R. Morrisett
President
Empire Petroleum Corporation
2200 S. Utica Place, Suite 150
Tulsa, OK 74114

Re: Evaluation Summary
Empire Petroleum Corporation Interests
Various States
Proved Developed Reserves
As of December 31, 2023

Dear Mr. Morrisett:

As requested, we are submitting our estimates of proved developed reserves and our forecasts of the resulting economics attributable to the above captioned interests in various states. It is our understanding that the proved developed reserve estimates shown herein constitute 100 percent of all proved developed reserves owned by Empire Petroleum Corporation. This report, completed on March 21, 2024, has been prepared for use in filings with the Securities and Exchange Commission ("SEC") by Empire Petroleum Corporation. In our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Composite reserve estimates and economic forecasts for the proved developed reserves are summarized below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Developed
Net Reserves				
Oil	- Mbbl	6,757.7	165.8	6,923.6
Gas	- MMcf	6,103.5	0.0	6,103.5
NGL	- Mbbl	1,170.6	0.0	1,170.6
Revenue				
Oil	- M$	510,078.1	12,297.1	522,375.2
Gas	- M$	9,202.4	0.0	9,202.4
NGL	- M$	11,490.3	0.0	11,490.3
Severance and Ad Valorem Taxes	- M$	39,970.5	680.2	40,650.7
Operating Expenses	- M$	302,359.6	7,429.6	309,789.1
Investments	- M$	42,040.9	434.2	42,475.2
Operating Income (BFIT)	- M$	146,399.7	3,753.1	150,152.8
Discounted at 10.0%	- M$	94,877.9	2,582.6	97,460.5

The discounted value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

Hydrocarbon pricing of $2.637 per MMBtu of gas (Henry Hub spot) and $78.22 per barrel of oil/condensate (WTI spot) was applied without escalation. In accordance with the SEC guidelines, these prices were determined as an unweighted arithmetic average of the first-day-of-the-month price for the previous 12 months. The oil and gas prices were held constant and were adjusted for gravity, heating value, quality, transportation and marketing. NGL prices were forecasted as fractions of the above oil price. The adjusted volume-weighted average product prices over the life of the properties are $75.45 per barrel of oil, $1.51 per Mcf of gas and $9.82 per barrel of NGL.

Operating expenses were supplied by Empire Petroleum Corporation and reviewed for reasonableness. Severance and ad valorem taxes were scheduled based on historical rates. Neither expenses nor investments were escalated. The cost of plugging and the salvage value of equipment have been considered.

The proved reserves classifications conform to criteria of the SEC. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the SEC Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the effective date except as noted herein. The possible effects of changes in legislation or other Federal or State restrictive actions have not been considered.

The reserves were estimated using a combination of the production performance and analogy methods, in each case as we considered to be appropriate and necessary to establish the conclusions set forth herein. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserve estimates were based on interpretations of factual data furnished by Empire Petroleum Corporation. Ownership interests were supplied by Empire Petroleum Corporation and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. An on-site inspection of these properties has not been made nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered.

Our work-papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

Cawley, Gillespie & Assoc., Inc.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

JZM:ptn

Goodnight Cross Exhibit 16

Memo To File

From: Darrell W Davis

Senior Production & Reservoir Engineer

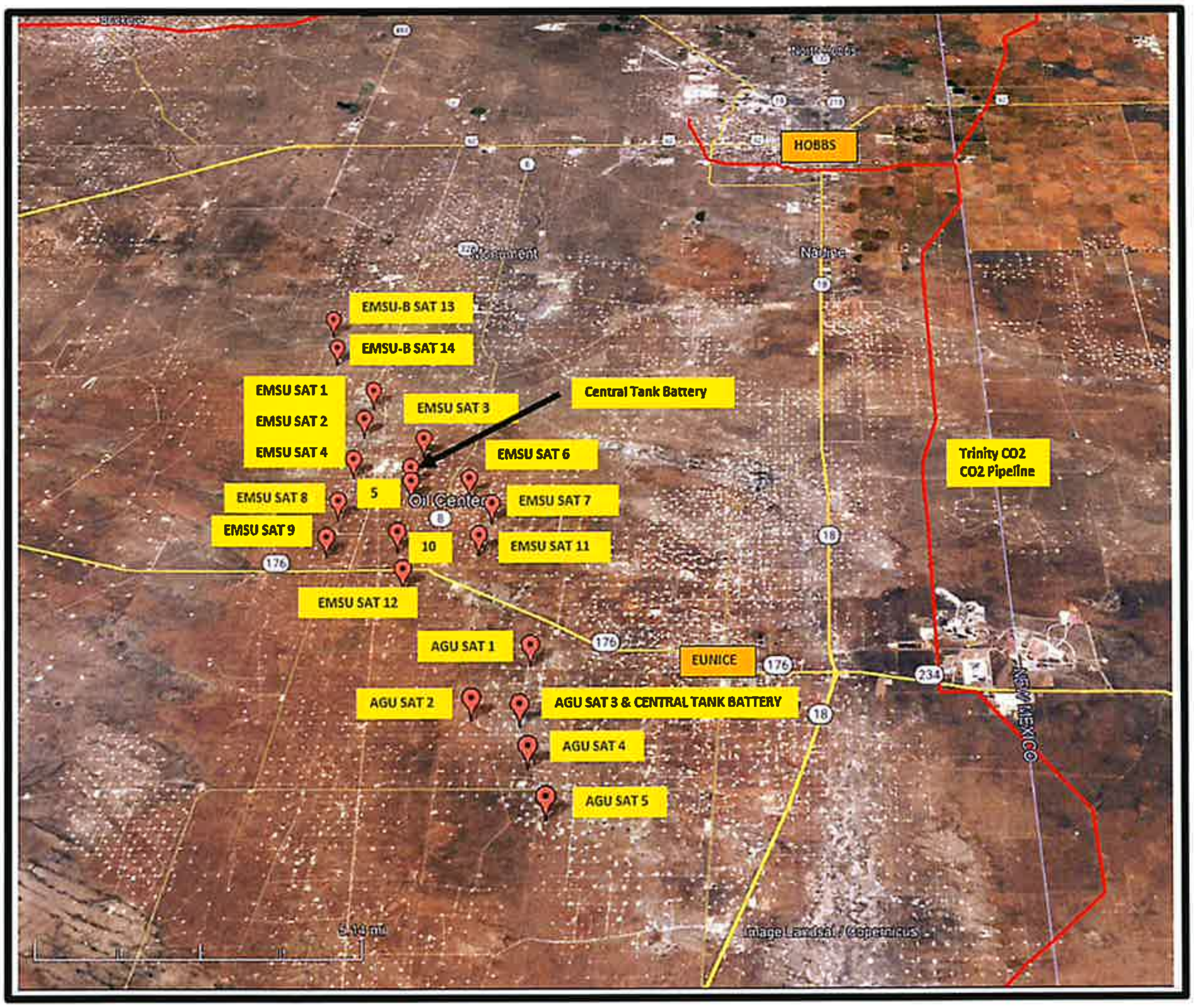
Date: January 15, 2024

Reference: **Eunice Monument & Arrowhead Field CO2 Development Plan**

Lea County, New Mexico

Empire Petroleum Corporation
Eunice Monument & Arrowhead Field CO_2 Development Plan

Figure 1 – Location Map with Production Satellites



Introduction

Injecting CO2 into an oil reservoir has proven to be one of the most effective ways to increase oil recovery from the reservoir. Residual oil is held to the reservoir rock by capillary pressure and interfacial tension, therefore waterflooding will not recover this oil. By injecting CO2 and building reservoir pressure above minimum miscibility pressure, the interfacial tension and capillary pressure will be reduced to zero and the oil is allowed to flow. CO2 swells the oil and reduces its viscosity in addition to removing these binding forces. The injected CO2 displaces the water and oil from the reservoir and reaches the producing well and facilities where it is separated from the oil and water and reinjected back into the reservoir. CO2 has a density less than water so it has a tendency to sweep the upper portions of the reservoir first and results in low vertical sweep efficiency due to gravity override. To improve the vertical sweep efficiency, water is pumped in stages with the CO2 after an initial large slug is injected, in an alternating process called Water-Alternating-Gas or WAG. The WAG cycle improves the vertical sweep efficiency but also reduces the amount of CO2 which is purchased, thus reducing compression requirements at the surface facilities. The total CO2 injected (MCF) divided by the amount of incremental oil recovered (BBLS) is the Gross CO2 Utilization Factor (MCF/BBL). The purchase amount of CO2 injected (MCF) divided by the amount of incremental oil recovered (BBLS) is the Net CO2 Utilization Factor (MCF/BBL). These are Key Performance Indicators (KPI's) for a CO2 flood.

To improve the areal sweep efficiency of a CO2 flood, the field is often developed on smaller spacing so that the CO2 and water injection streamlines will not bypass as much oil. Eunice Monument and Arrowhead fields are developed on 40-acre spacing with the water injector recovering oil from an 80-acre patterns, with the water injector 1320 feet from the surrounding 4 producers. Infill wells were drilled in both fields to reduce the spacing to 20-acres in some areas, and this reduced the spacing between injector and producer to 933 feet. At Eunice Monument South Unit (EMSU) there were 125 new wells drilled from March 1985 to November 2005 to complete the 40-acre infills for the waterflood and to drill some 20-acre infills for improved oil recovery. From March 1998 to September 2005, 20 new wells were drilled at Arrowhead Grayburg Unit (AGU) and only 4 new wells at EMSU-B from January 1991 to September 1993. There will be additional 20-acre infill wells drilled in 2024-2026 to improve oil recovery from these 3 UNITS and to prepare for the CO2 flood. Oil recovery efficiency is based on the following equation:

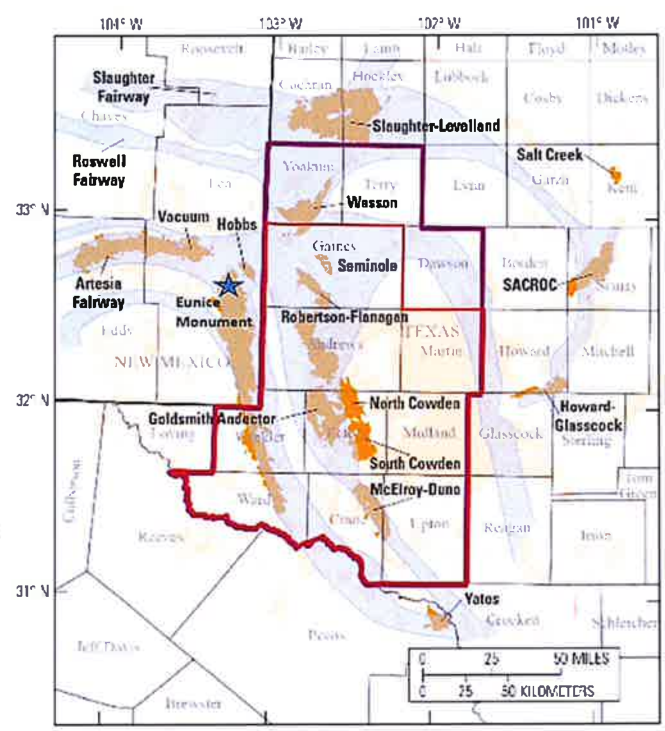
Recovery Efficiency = (Displacement Efficiency) x (Aerial Sweep Efficient) x (Vertical Sweep Efficiency)

The displacement efficiency can be close to 100% if miscible conditions between the oil and CO2 can be developed in the reservoir. If we mix water and oil in a jug and shake it up, the oil rises to the top and the water falls to the bottom for low density oils. (immiscible condition) If however, we mix CO2 and oil at a pressure and temperature where miscibility is achieved, the CO2 and oil becomes one phase and there is no capillary pressure or interfacial tension. (miscible condition) This is why a waterflood leaves large quantities of oil in the reservoir because there is a strong interfacial tension holding the oil to the rock. For Eunice Monument and Arrowhead fields, there is a Residual Oil Zone (ROZ) in the San Andres beneath the Grayburg where mother nature could not strip the oil away from the rock. For the Grayburg interval, there was a large moveable oil volume which the waterflood displaced to the producers, but due to nonuniform areal sweep efficiency and poor vertical sweep efficiency, there still remains a large moveable oil volume and a residual oil volume. Infill drilling and CO2 flooding will recovery this oil, therefore increasing the Oil Recovery Efficiency.

Empire Petroleum Corporation acquired the Eunice Monument and Arrowhead assets from XTO Energy in 2021. Empire saw this as an opportunity to increase oil production from an underperforming asset which has high remaining oil-in-place in the waterflooded Grayburg interval and a residual oil zone (ROZ) in the San Andres interval of the Unitized carbonate reservoir. Water injection in the Eunice Monument South Unit (EMSU), Eunice Monument South Unit "B" (EMSU-B), and Arrowhead Grayburg Unit (AGU) began in Nov-1986, Mar-1991, and Sep-1992 respectively. Chevron obtained unitization on these properties in Feb-1985, Dec-1990, and Jun-1991 respectively.

Empire plans to drill wells during 2024 to increase oil recovery from the Grayburg interval. Conformance work (pattern modification, cement squeeze, gel treatments, etc.) will also be done to reduce water production from high permeability intervals within the Grayburg and to shut off zones which have reached high water saturation. This write-up will discuss activities performed thus far to define the scope of work for the CO2 flood and highlight some of the data gathering activities which will take place during the drilling programs in 2024-2026.

Figure 2 – Eunice Monument in Relation to Other Oil Fields

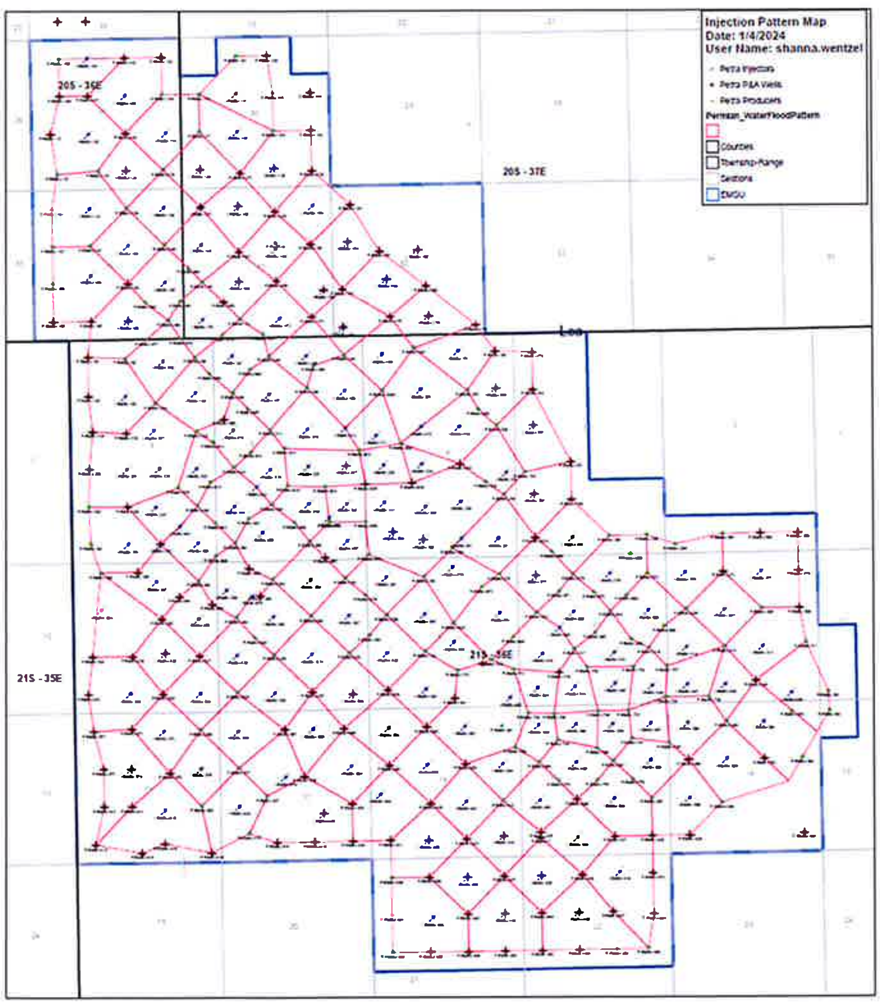


OCD 23614-17 03485

Eunice Monument South Unit (EMSU)

As shown by the cover page, EMSU is located roughly 21 miles southwest of Hobbs in Lea County, New Mexico. This Grayburg and San Andres 14,190 acre unitized interval has been developed using 417 wells thus far. Primary production occurred from the early 1930's to November 1986 when water injection began. Reservoir pressure in the Grayburg had dropped from 1450 psi to 250 psi at the start of the waterflood. From March 1985 to November 2005, 126 new wells were drilled at EMSU to establish the 40-acre spacing for waterflood and to improve oil recovery with some 20-acre infills. In June, 1989 there were 205 producers, 133 water injectors, and 6 water supply wells. San Andres water was produced by these supply wells to pressure up the Grayburg interval. The UNIT currently has 111 producers, 103 water injectors, and 2 water supply wells. Production is 830 BOPD; 67,600 BWPD, and 540 MCFPD with all produced water reinjected.

Figure 3 - Eunice Monument South Unit – Waterflood Patterns



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Information from the February 27, 1990 Working Interest Owner's meeting provided the following information regarding reservoir properties and oil in place for EMSU Grayburg interval. Based on this average data, each 80-acre drainage area would have 3.881 MMBO OOIP or 4.657 MMRB Hydrocarbon Pore Volume (HCPV) which is used in CO_2 oil production forecasting. In addition to the 671.5 million barrels of original oil-in-place in the Grayburg, ExxonMobil (XTO Energy) estimated 912 million barrels of oil in the San Andres ROZ interval down to a subsea depth of -700 feet. Core data taken in the EMSU-679 showed oil down to -750 feet subsea indicating a potentially larger ROZ OOIP. By definition of ROZ, none of this oil has been produced by primary production and waterflood of the Grayburg interval. New wells drilled will provide additional insight into San Andres oil volume.

TABLE 1 – EMSU Reservoir Parameters Based on 1990 Working Interest Owner's Meeting

EMSU RESERVOIR PARAMETERS

UNIT AREA	14190 ACRES
INITIAL RESERVOIR PRESSURE	1450 PSI
RESERVOIR PRESSURE AT START OF WATERFLOOD	250 PSI
SATURATION PRESSURE	1372 PSI
SOLUTION GOR	423 SCF/STB
CURRENT PRODUCING GOR	4007 SCF/STB
RESERVOIR TEMPERATURE	90 DEG F
OIL GRAVITY	32 DEG API
INITIAL FORMATION VOLUME FACTOR	1.20 RB/STB
CURRENT FORMATION VOLUME FACTOR	1.05 RB/STB
AVERAGE NET PAY	134 FT
AVERAGE POROSITY	8.0 %
INITIAL WATER SATURATION	30.0 %
OIL SATURATION AT START OF WATERFLOOD	50.0 %
RESIDUAL OIL SATURATION	25.0 %
VOLUMETRIC SWEEP EFFICIENCY	60 %
ULTIMATE PRIMARY RECOVERY	134.3 MMBO 20 % OOIP
OOIP	671.5 MMBO
ESTIMATED SECONDARY RECOVERY	65.8 MMBO 9.8 % OOIP
SECONDARY TO PRIMARY RATIO	49 %
ESTIMATED RECOVERY DUE TO INFILL DRILLING	5 % OOIP 33 MMBO
ESTIMATED RECOVERY DUE TO CO2 FLOODING	10 % OOIP 67 MMBO

Based on Table 1, Chevron estimated during 1990 that EMSU ultimate recovery with waterflood would be around 200.1 MMBO or 29.8% OOIP (134.3 MMBO primary, 65.8 MMBO waterflood) and that infill drilling could add an additional 33 MMBO, resulting in 230.1 MMBO ultimate recovery. Cumulative oil to date is approximately 123.6 MMBO (18.4% OOIP) therefore the waterflood did not perform as well as predicted. This leaves a large target oil for conformance work, infill drilling, and CO2 flooding.

As highlighted in SPE paper #49201 written in 1998 by Chevron, waterflood patterns suffered from rapid water breakthrough due to high permeability streaks in the lower half of Zones 1 and 2, and also had slow pressure increase due to low injection to withdrawal (production) ratios. In all, the oil production rate decreased in 70% of the wells and total field oil production dropped after the waterflood was implemented. In 1996 Chevron started the EMSU Waterflood Conformance Project to characterize the flood conformance and squeeze off the high permeability streaks which caused cycling of injected water and bypassed oil. The project focus area consisted of 16 contiguous 80-acre producer centered patterns. The EMSU reservoir characterization was a long process that included the creation of conformance cross-sections, mapping of high perm streaks, calculating the percent hydrocarbon pore volume (HCPV) swept for each major zone, and production diagnostics. Unfortunately this information was not conveyed to Empire Petroleum and it is having to be re-created.

Conformance problems were observed over the entire EMSU when evaluated during 1996. It was confirmed during the study that (1) the reservoir contained natural fractures and extensive permeability streaks and (2) large volumes of water were being injected into the secondary gas cap formed when the reservoir pressure dropped from discovery in 1929 to start of the waterflood in 1986. The steps taken to increase oil production and decrease cycling of water between injector and producer were (1) eliminate water injection into the gas cap, including the Penrose interval which overlies the Grayburg and (2) stimulation of under processed zones in both injection and production wells. Injection of water into the gas cap was initially allowed to prevent oil from being pushed into the gas cap and the high water injection rates into the gas cap reduced the time to pressure up the reservoir. Cement squeezes were applied when there was a barrier isolating the thief zone from the rest of the productive interval. Gel treatments were also applied to achieve deep penetration into the matrix and fractures.

This conformance work which occurred from March 1997 to April 1998 is described in this document so that everyone is aware of the challenges which will be faced during the CO2 flood. To prevent CO2 cycling through the high permeability intervals in Zones 1 and 2 of the Grayburg, the CO2 flood will focus on Layers 3, 4, and 5 of the Grayburg and the entire ROZ interval of the San Andres. CO2 flood design will be discussed later in more detail.

Tables 2 thru 5 show the water injection rates and production rates for each well at EMSU. The tables have 109 producers and 97 water injectors, with 3 wells shut-in. The water injection rates provide some insight into what the probable CO2 injection rate for each well will be. The average water injection rate is 506 BWPD which would suggest a CO2 injection rate of around 1000 MCF/day (54 tons per day per well). This is dependent upon the pressure coming off the CO2 pipeline.

TABLE 2 – EMSU Water Injector Rates (Page 1 of 2)

Lease	Well No	Type Well	API	BWPD Injecti
EMSU	108	INJ	30025043300000	39
EMSU	118	INJ	30025295980000	84
EMSU	120	INJ	30025043320000	575
EMSU	134	INJ	30025063060000	14
EMSU	140	INJ	30025044250000	89
EMSU	146	INJ	30025063040000	984
EMSU	148	INJ	30025299460000	110
EMSU	162	INJ	30025044190000	875
EMSU	164	INJ	30025298200000	97
EMSU	170	INJ	30025062970000	95
EMSU	172	INJ	30025299120000	1124
EMSU	181	INJ	30025044790000	24
EMSU	183	INJ	30025044930000	124
EMSU	187	INJ	30025045150000	307
EMSU	189	INJ	30025296140000	295
EMSU	193	INJ	30025045350000	322
EMSU	195	INJ	30025045320000	434
EMSU	197	INJ	30025045110000	493
EMSU	199	INJ	30025045100000	263
EMSU	201	INJ	30025044720000	138
EMSU	210	INJ	30025044690000	178
EMSU	211	INJ	30025296150000	321
EMSU	213	INJ	30025045030000	486
EMSU	215	INJ	30025045080000	363
EMSU	217	INJ	30025299110000	416
EMSU	221	INJ	30025087060000	1514
EMSU	222	INJ	30025045310000	956
EMSU	223	INJ	30025045300000	309
EMSU	226	INJ	30025045010000	543
EMSU	228	INJ	30025044900000	322
EMSU	229	INJ	30025044670000	6
EMSU	231	INJ	30025044640000	176
EMSU	239	INJ	30025044680000	254
EMSU	240	INJ	30025298670000	637
EMSU	241	INJ	30025044890000	322
EMSU	242	INJ	30025045190000	336
EMSU	245	INJ	30025044980000	935
EMSU	247	INJ	30025295750000	455
EMSU	251	INJ	30025045200000	1107
EMSU	253	INJ	30025087020000	798
EMSU	255	INJ	30025200720000	658
EMSU	257	INJ	30025044960000	731
EMSU	261	INJ	30025044710000	259
EMSU	263	INJ	30025044560000	771
EMSU	271	INJ	30025046120000	321
EMSU	273	INJ	30025046090000	464
EMSU	275	INJ	30025045980000	1
EMSU	279	INJ	30025045810000	701
EMSU	281	INJ	30025045770000	954

TABLE 3 – EMSU Water Injector Rates (Page 2 of 2)

Lease	Well No	Type Well	API	BWPD Injecti
EMSU	283	INJ	30025045690000	536
EMSU	285	INJ	30025245630000	933
EMSU	287	INJ	30025299090000	657
EMSU	293	INJ	30025045390000	334
EMSU	297	INJ	30025045680000	794
EMSU	301	INJ	30025045870000	678
EMSU	303	INJ	30025045940000	1205
EMSU	305	INJ	30025045970000	988
EMSU	307	INJ	30025087080000	328
EMSU	314	INJ	30025046050000	566
EMSU	316	INJ	30025298820000	1045
EMSU	318	INJ	30025299010000	84
EMSU	320	INJ	30025045780000	239
EMSU	322	INJ	30025045740000	671
EMSU	326	INJ	30025045590000	99
EMSU	340	INJ	30025045720000	139
EMSU	343	INJ	30025045890000	295
EMSU	344	INJ	30025045920000	526
EMSU	345	INJ	30025298230000	589
EMSU	346	INJ	30025298810000	641
EMSU	347	INJ	30025046060000	276
EMSU	350	INJ	30025046140000	516
EMSU	354	INJ	30025046400000	300
EMSU	356	INJ	30025046290000	742
EMSU	357	INJ	30025046430000	364
EMSU	358	INJ	30025046420000	182
EMSU	359	INJ	30025046510000	853
EMSU	360	INJ	30025046490000	1478
EMSU	362	INJ	30025046620000	352
EMSU	366	INJ	30025046990000	171
EMSU	368	INJ	30025046970000	341
EMSU	370	INJ	30025046840000	852
EMSU	376	INJ	30025046800000	380
EMSU	378	INJ	30025046870000	221
EMSU	382	INJ	30025046630000	217
EMSU	386	INJ	30025046520000	282
EMSU	388	INJ	30025046410000	830
EMSU	396	INJ	30025046330000	109
EMSU	398	INJ	30025046470000	199
EMSU	400	INJ	30025046530000	206
EMSU	404	INJ	30025046880000	270
EMSU	408	INJ	30025046920000	563
EMSU	410	INJ	30025302810000	1910
EMSU	434	INJ	30025296020000	1470
EMSU	442	INJ	30025295840000	1495
EMSU	643	INJ	30025305120000	795
EMSU	679	INJ	30025310090000	266
EMSU	696	INJ	30025341370000	294

TABLE 4 – EMSU Oil Production Rates (Page 1 of 2)

Lease	Well No	Type Well	API	Total Flu	BOPD	BWPD
EMSU	101	PROD	30025302200000	313	7	306
EMSU	115	PROD	30025062950000	28	1	27
EMSU	117	PROD	30025293960000	1120	5	1115
EMSU	122	PROD	30025302770000	101	6	96
EMSU	125	PROD	30025043220000	202	3	199
EMSU	141	PROD	30025044290000	317	7	309
EMSU	142	PROD	30025044280000	329	1	327
EMSU	145	PROD	30025125450000	886	12	875
EMSU	161	PROD	30025063050000	804	6	798
EMSU	169	PROD	30025295830000	186	5	181
EMSU	171	PROD	30025062960000	552	1	550
EMSU	182	PROD	30025298680000	28	2	26
EMSU	184	PROD	30025045130000	275	5	270
EMSU	188	PROD	30025045330000	383	7	376
EMSU	190	PROD	30025045360000	133	3	130
EMSU	196	PROD	30025045140000	816	2	814
EMSU	198	PROD	30025296820000	4	4	0
EMSU	209	PROD	30025044730000	1710	28	1682
EMSU	212	PROD	30025045040000	330	3	326
EMSU	214	PROD	30025045070000	1091	8	1082
EMSU	224	PROD	30025045060000	485	9	476
EMSU	238	PROD	30025044660000	197	10	187
EMSU	244	PROD	30025044970000	363	4	359
EMSU	246	PROD	30025045270000	490	6	485
EMSU	249	PROD	30025045250000	1033	11	1023
EMSU	250	PROD	30025045260000	297	8	289
EMSU	254	PROD	30025045000000	1825	27	1798
EMSU	260	PROD	30025044630000	520	15	505
EMSU	265	PROD	30025044590000	166	4	162
EMSU	266	PROD	30025261010000	105	3	102
EMSU	267	PROD	30025044400000	147	1	146
EMSU	274	PROD	30025046020000	967	12	955
EMSU	276	PROD	30025046030000	1444	3	1441
EMSU	280	PROD	30025045730000	230	3	227
EMSU	282	PROD	30025219020000	476	5	471
EMSU	284	PROD	30025045610000	970	10	960
EMSU	286	PROD	30025045400000	878	5	874
EMSU	289	PROD	30025087070000	250	4	247
EMSU	290	PROD	30025045430000	17	0	16
EMSU	294	PROD	30025045620000	2035	19	2017
EMSU	296	PROD	30025045660000	478	7	471
EMSU	300	PROD	30025045790000	312	3	309
EMSU	306	PROD	30025046040000	644	18	627
EMSU	308	PROD	30025046180000	392	7	384
EMSU	313	PROD	30025046080000	570	11	559
EMSU	315	PROD	30025046000000	1271	7	1264
EMSU	317	PROD	30025045900000	786	6	780
EMSU	319	PROD	30025045840000	744	13	731
EMSU	321	PROD	30025045700000	704	9	694
EMSU	323	PROD	30025045550000	239	5	234
EMSU	325	PROD	30025045560000	1686	22	1664
EMSU	351	PROD	30025046220000	99	3	96
EMSU	352	PROD	30025046250000	114	8	107
EMSU	355	PROD	30025046360000	164	13	151
EMSU	361	PROD	30025046550000	1469	8	1461

TABLE 5 – EMSU Oil Production Rates (Page 2 of 2)

Lease	Well No	Type Well	API	Total Flu	BOPD	BWPD
EMSU	377	PROD	30025046890000	435	5	430
EMSU	385	PROD	30025046500000	1042	18	1025
EMSU	387	PROD	30025046450000	517	11	506
EMSU	395	PROD	30025298210000	19	2	17
EMSU	401	PROD	30025046670000	3114	13	3101
EMSU	407	PROD	30025245880000	193	1	192
EMSU	440	PROD	30025047350000	1810	13	1796
EMSU	449	PROD	30025253510000	68	1	67
EMSU	462	PROD	30025296220000	517	2	514
EMSU	554	PROD	30025348450000	184	8	176
EMSU	560	PROD	30025354610000	535	1	534
EMSU	574	PROD	30025351600000	140	3	137
EMSU	575	PROD	30025348240000	300	2	298
EMSU	576	PROD	30025346400000	140	10	130
EMSU	584	PROD	30025341390000	291	6	284
EMSU	609	PROD	30025314060000	430	7	423
EMSU	610	PROD	30025314070000	343	4	339
EMSU	612	PROD	30025351590000	166	2	164
EMSU	613	PROD	30025351610000	605	5	601
EMSU	614	PROD	30025354530000	517	2	514
EMSU	620	PROD	30025305110000	365	2	362
EMSU	621	PROD	30025331860000	305	2	303
EMSU	624	PROD	30025314080000	877	6	871
EMSU	628	PROD	30025372790000	30	4	26
EMSU	638	PROD	30025314260000	132	4	127
EMSU	639	PROD	30025314090000	487	6	481
EMSU	640	PROD	30025342120000	53	1	53
EMSU	641	PROD	30025331890000	630	2	628
EMSU	642	PROD	30025309580000	1055	11	1044
EMSU	653	PROD	30025342130000	1914	36	1878
EMSU	658	PROD	30025372800000	760	8	753
EMSU	660	PROD	30025373190000	173	4	169
EMSU	669	PROD	30025341380000	384	6	378
EMSU	670	PROD	30025342140000	269	5	263
EMSU	671	PROD	30025354560000	500	2	498
EMSU	673	PROD	30025373200000	10	6	3
EMSU	676	PROD	30025354570000	1269	8	1262
EMSU	688	PROD	30025352050000	1223	8	1216
EMSU	699	PROD	30025342150000	363	3	360
EMSU	707	PROD	30025351640000	130	7	123
EMSU	709	PROD	30025348490000	518	4	514
EMSU	711	PROD	30025348500000	733	1	732
EMSU	713	PROD	30025373210000	146	3	143
EMSU	735	PROD	30025348260000	694	10	684
EMSU	736	PROD	30025348520000	658	7	651
EMSU	737	PROD	30025348530000	518	13	505
EMSU	738	PROD	30025351650000	942	14	928
EMSU	739	PROD	30025354580000	522	4	518
EMSU	746	PROD	30025373560000	334	4	330
EMSU	748	PROD	30025346320000	1140	14	1126
EMSU	749	PROD	30025346410000	849	10	839
EMSU	750	PROD	30025351680000	2174	8	2165
EMSU	774	PROD	30025351660000	880	26	854
EMSU	776	PROD	30025354600000	1610	10	1601

Arrowhead Grayburg Unit (AGU)

AGU consists of 5,922.26 acres of unitized interval in the Grayburg and San Andres formations. For AGU, the top of the UNIT is defined as -150' subsea or the top of the Grayburg, whichever is shallowest, and the base is defined as -1500' subsea. Essentially all oil produced from the unit was produced from the Grayburg. Some tests were made in the San Andres on new wells drilled during the 1998-2006 time period, and although oil rates were higher than what was seen at EMSU, the San Andres is considered a ROZ (residual oil zone) for all three units. Plans are to CO2 flood both the Grayburg and San Andres intervals.

AGU was discovered May 24, 1938 by Continental's State J-2 Well No. 1 and produces from the Grayburg carbonate (predominately dolomite) formation with average porosity of 8% and average net thickness of 85 feet. The field was developed on 40 acre spacing and completions were typically open-hole and included both the Penrose (Queen lowest member) and Grayburg formations. Chevron estimated OOIP of 175. 4 million barrels 34^0 API oil based on initial water saturation of 25% and oil formation volume factor of 1.2 RB/STB. The reservoir had produced 30.8 million barrels as of 12-31-1988 (based on Unitization document) and was expected to recover an additional 5.23 million barrels with depletion drive, resulting in 36.03 million barrels (21% primary oil recovery factor). Reservoir pressure dropped from 1460 psi to 450 psi by 1964 and by the time first water injection occurred in September 1992, reservoir pressure had dropped below 300 psi. At the time the UNIT was proposed in September, 1989, the field was producing 1083 BOPD, 8255 BWPD, and 4223 MCFPD with watercut of 88.4% and GOR of 3899 scf/stb. Initial solution GOR was approximately 432 scf/stb and bubble point pressure 1372 psi based on Eunice Monument South Unit values.

Chevron estimated incremental oil reserves of 15 MMBO for the waterflood. This would have resulted in 51.1 MMBO ultimate recovery or 29.13% OOIP. The waterflood did not perform well due to the low initial reservoir pressure, high initial gas saturation at the start of the waterflood, and high permeability intervals in the Upper Grayburg interval. Cumulative production to date is approximately 36.2 MMBO which is very close to the predicted primary recovery without waterflood. This leaves a large target oil for conformance work, infill drilling, and CO2 flood. The field still produces approximately 190 BOPD; 25,000 BWPD, and 221 MCFPD while injecting the 25,000 BWPD. Watercut is 99.25%.

The cumulative oil map on the next page was used to determine the oil recovery from each well as of 12/31/1988, the date used for the unitization document. (A similar approach was used at EMSU.) Sixty-eight (68) wells did not have cumulative oil volumes in the "IHS" database so this identified 14.9 MMBO which needed to be added. The "IHS" cumulative volume as of 12/31/1988 on 58 wells matched the volumes on the cumulative oil map and therefore no correction was required on those wells. The 19 new producers drilled at the start of the waterflood and thereafter produced a total of 1.362 MMBO, an average of 71,667 barrels per well. The waterflood used 51 five-spot patterns as shown on page 3, with the pattern designation indicating the water injector in the center of the pattern. Cumulative water injection is 457.8 MMBW with incremental oil recovery since 12/31/1988 of 6.4 MMBO based on this analysis.

TABLE 6 – AGU Reservoir Parameters based on Sept-1989 Technical Committee Report

PROPOSED ARROWHEAD GRAYBURG UNIT
PERTINENT RESERVOIR DATA

Pool Discovery Well:	Continental State J-2 No. 1
Discovery Date:	5-24-38
Producing Formation:	Grayburg
Lithology:	Dolomite
Average Porosity:	8%
Average Net Thickness:	85 ft
Swi:	25%
Initial Reservoir Pressure (250 S.S.):	1460 psi
Reservoir Temperature:	90° F
Oil Gravity (API):	34°
Cumulative Oil Recovery (12-31-88):	30.8 MMSTBO
Predicted Ultimate Primary Recovery:	36.1 MMSTBO
OOIP:	175.4 MMSTBO

The predicted ultimate primary recovery in this table is without waterflood or additional infill drilling. Current cumulative oil production is 36.2 MMBO after the waterflood and infill drilling.

Based on this average data, each 80-acre drainage area would have 2.638 MMBO OOIP or 3.165 MMRB Hydrocarbon Pore Volume (HCPV) which is used in CO_2 oil production forecasting to be discussed later.

Figure 4 - Cumulative Oil by Well – December 31, 1988

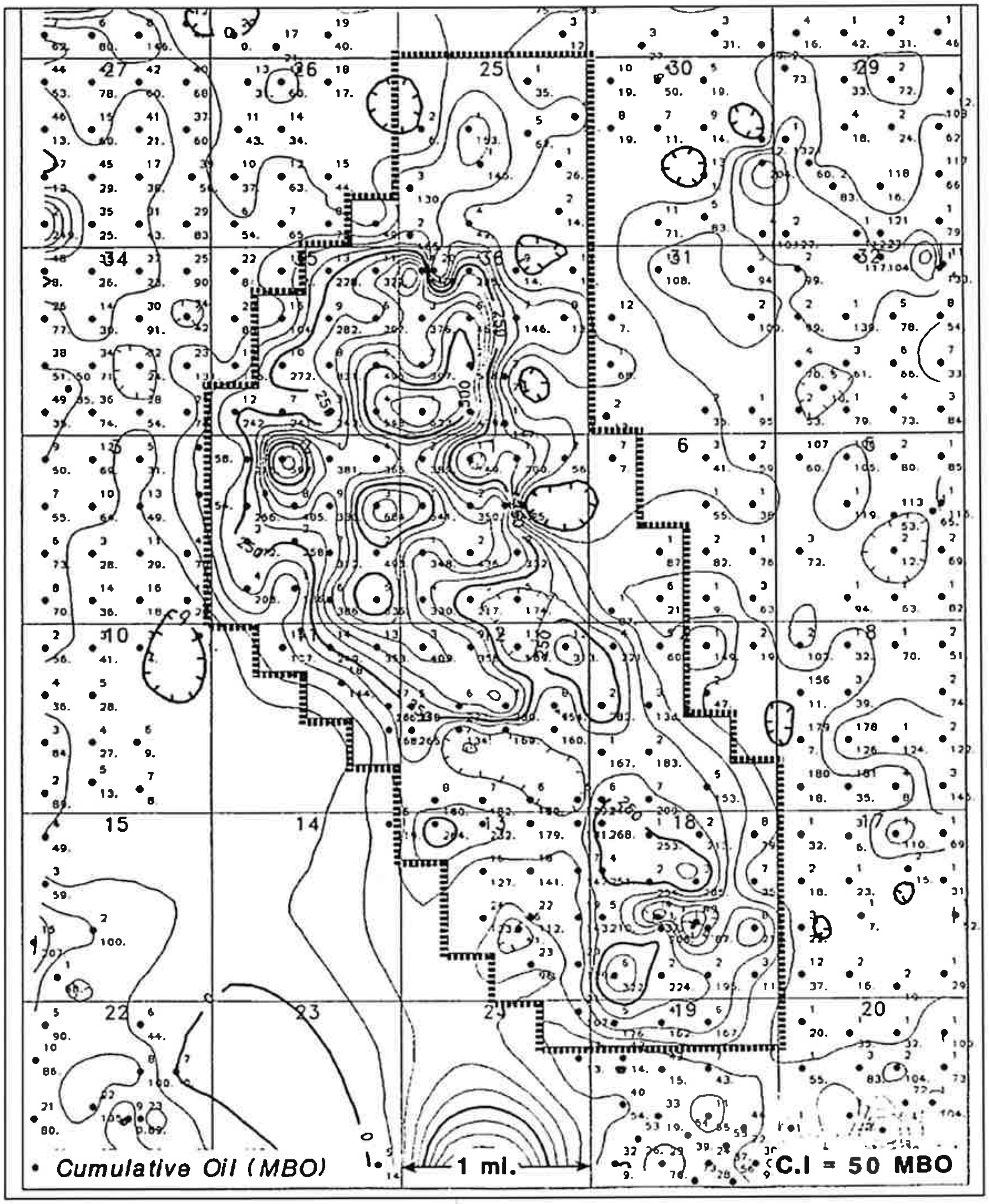

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Table 7 - Arrowhead Grayburg Unit – Production Rates by Well

Lease	Well No	Type Well	API	Total Flu	BOPD	BWPD
AGU	107	PROD	30025216200000	96	2	94
AGU	108	PROD	30025239490000	44	2	42
AGU	120	PROD	30025290930000	113	5	108
AGU	125	PROD	30025314330000	123	4	119
AGU	127	PROD	30025049330000	2421	6	2416
AGU	135	PROD	30025049170000	1830	9	1821
AGU	140	PROD	30025049210000	1981	7	1974
AGU	142	PROD	30025049280000	97	2	95
AGU	149	PROD	30025087330000	1317	14	1303
AGU	157	PROD	30025087400000	1019	8	1011
AGU	166	PROD	30025087240000	113	4	109
AGU	168	PROD	30025087270000	1342	15	1326
AGU	170	PROD	30025314350000	1149	3	1146
AGU	186	PROD	30025317220000	417	3	414
AGU	195	PROD	30025088820000	347	7	340
AGU	197	PROD	30025316310000	665	8	658
AGU	204	PROD	30025264780000	3205	10	3195
AGU	211	PROD	30025315340000	576	10	567
AGU	213	PROD	30025315820000	62	2	60
AGU	215	PROD	30025317510000	228	4	224
AGU	219	PROD	30025316090000	2064	11	2053
AGU	247	PROD	30025103620000	29	6	23
AGU	328	PROD	30025372820000	325	4	321
AGU	335	PROD	30025346360000	182	11	171
AGU	336	PROD	30025342970001	570	7	563
AGU	342	PROD	30025346370000	1006	8	998
AGU	343	PROD	30025348440000	963	7	956
AGU	351	PROD	30025349270000	550	5	545
AGU	390	PROD	30025342990000	586	6	580

Table 8 - Arrowhead Grayburg Unit – Water Injection Rates by Well

Lease	Well No	Type Well	API	BWPD Injecti
AGU	106	INJ	30025233240000	115
AGU	113	INJ	30025315190000	904
AGU	115	INJ	30025239390000	1991
AGU	119	INJ	30025049320000	1972
AGU	124	INJ	30025049160000	739
AGU	128	INJ	30025241050000	557
AGU	132	INJ	30025049290000	602
AGU	133	INJ	30025049390000	328
AGU	134	INJ	30025049200000	997
AGU	139	INJ	30025313050000	1041
AGU	141	INJ	30025049380000	583
AGU	143	INJ	30025049400000	182
AGU	148	INJ	30025313930000	671
AGU	150	INJ	30025087410000	943
AGU	151	INJ	30025087380000	914
AGU	158	INJ	30025087210000	776
AGU	159	INJ	30025087230000	543
AGU	160	INJ	30025242720000	476
AGU	167	INJ	30025087280000	421
AGU	169	INJ	30025087390000	1644
AGU	175	INJ	30025087450000	597
AGU	177	INJ	30025087290000	973
AGU	179	INJ	30025087260000	797
AGU	187	INJ	30025088860000	398
AGU	189	INJ	30025088720000	533
AGU	194	INJ	30025088810000	617
AGU	196	INJ	30025088830000	1985
AGU	198	INJ	30025100920000	820
AGU	199	INJ	30025315600000	368
AGU	201	INJ	30025316750000	63
AGU	203	INJ	30025313790000	2048
AGU	205	INJ	30025266590000	559
AGU	210	INJ	30025263910000	616
AGU	217	INJ	30025315620000	247
AGU	220	INJ	30025314370000	605
AGU	225	INJ	30025314100000	115
AGU	227	INJ	30025312450000	1211
AGU	229	INJ	30025317400000	334
AGU	233	INJ	30025258780000	222
AGU	240	INJ	30025316320000	834
AGU	241	INJ	30025315350000	28
AGU	242	INJ	30025313290000	342
AGU	600	INJ	30025312340000	3808

Table 9 -Cumulative Oil Volumes and Acreage for 51 Patterns at AGU

#	Pattern Designation	Acreage	Cumulative Water Injection	CUM OIL 8/31/2023	CUM OIL 12/31/1988	Incremental Oil BBLS	Incremental % of Primary
	TOTALS	3,945.92	460,545,536	36,190,158	29,826,699	6,363,459	
1	AGU-106	99.80	3,930,424	319,634	242,952	76,682	31.6%
2	AGU-110 P&A	98.07	2,932,017	346,848	324,641	22,207	6.8%
3	AGU-113	78.75	9,217,524	337,579	284,260	53,319	18.8%
4	AGU-115	59.47	1,662,697	118,357	114,469	3,889	3.4%
5	AGU-119	69.66	12,354,000	503,795	415,927	87,868	21.1%
6	AGU-121 P&A	93.29	5,690,848	604,811	558,479	46,332	8.3%
7	AGU-124	80.29	9,386,016	871,366	774,231	97,135	12.5%
8	AGU-126 P&A	80.61	5,736,204	777,944	632,390	145,555	23.0%
9	AGU-128	79.84	7,090,348	295,173	255,167	40,006	15.7%
10	AGU-132	76.70	5,009,630	936,751	826,932	109,819	13.3%
11	AGU-134	77.31	12,668,503	1,216,868	1,003,566	213,302	21.3%
12	AGU-139	82.30	13,852,450	1,064,663	916,455	148,208	16.2%
13	AGU-141	80.07	8,077,883	1,486,450	1,084,432	402,018	37.1%
14	AGU-143	69.35	7,412,703	378,303	342,007	36,296	10.6%
15	AGU-146 P&A	73.27	1,929,685	156,827	153,296	3,532	2.3%
16	AGU-148	79.77	7,854,274	614,081	402,691	211,390	52.5%
17	AGU-150	79.87	13,498,012	1,247,967	837,688	410,279	49.0%
18	AGU-152 P&A	77.07	2,519,648	1,485,191	1,430,096	55,095	3.9%
19	AGU-156	78.25	15,504,519	1,063,953	871,781	192,173	22.0%
20	AGU-158	80.08	10,874,569	1,293,129	960,715	332,415	34.6%
21	AGU-160	79.68	10,429,676	476,118	412,719	63,399	15.4%
22	AGU-167	86.09	7,611,414	909,838	774,262	135,576	17.5%
23	AGU-169	71.80	16,713,886	1,316,411	966,720	349,690	36.2%
24	AGU-171 P&A	78.44	10,770,159	1,030,798	920,138	110,659	12.0%
25	AGU-175	76.12	13,048,808	1,089,168	904,591	184,577	20.4%
26	AGU-177	82.31	15,405,955	969,259	730,710	238,549	32.6%
27	AGU-179	79.86	9,194,996	422,395	380,069	42,326	11.1%
28	AGU-181	81.40	2,741,832	365,982	297,789	68,193	22.9%
29	AGU-185 P&A	84.31	3,368,416	545,241	466,371	78,870	16.9%
30	AGU-187	94.89	7,487,158	733,790	639,634	94,156	14.7%
31	AGU-189	82.20	11,681,631	1,076,604	982,002	94,603	9.6%
32	AGU-194	50.85	8,112,384	897,289	835,602	61,688	7.4%
33	AGU-196	76.64	15,197,838	724,698	584,171	140,527	24.1%
34	AGU-198	78.12	5,227,806	647,557	534,533	113,024	21.1%
35	AGU-201	86.98	5,154,170	380,573	346,000	34,573	10.0%
36	AGU-203	62.59	14,951,626	571,663	312,500	259,163	82.9%
37	AGU-205	84.66	10,431,255	715,586	595,084	120,503	20.2%
38	AGU-210	67.27	8,832,383	634,653	397,762	236,891	59.6%
39	AGU-212	65.67	15,453,567	601,611	433,250	168,361	38.9%
40	AGU-214	73.41	5,537,366	387,005	302,583	84,422	27.9%
41	AGU-218 P&A	66.29	7,462,504	673,171	533,083	140,087	26.3%
42	AGU-220	59.35	8,291,121	515,200	361,846	153,354	42.4%
43	AGU-222 P&A	69.53	2,169,336	756,089	725,355	30,734	4.2%
44	AGU-225	72.53	10,890,436	412,409	403,409	9,000	2.2%
45	AGU-227	78.85	12,075,196	640,247	470,750	169,497	36.0%
46	AGU-229	82.62	9,050,967	623,212	581,419	41,793	7.2%
47	AGU-233	66.35	5,596,450	650,007	478,586	171,421	35.8%
48	AGU-235	82.27	6,871,479	518,717	457,063	61,654	13.5%
49	AGU-240	80.58	10,993,597	741,540	624,970	116,570	18.7%
50	AGU-242	74.04	4,102,761	471,516	446,086	25,430	5.7%
51	AGU-246 P&A	76.39	1,326,000	572,125	495,470	76,655	15.5%

52	AGU-133		4,997,737	Converted to Water Injector April 2001
53	AGU-151		9,340,882	Converted to Water Injector April 2001
54	AGU-159		9,738,704	Converted to Water Injector April 2001
55	AGU-199		2,141,755	Converted to Water Injector March 2008
56	AGU-217		498,457	Converted to Water Injector March 2010
57	AGU-241		443,874	Converted to Water Injector November 2007

Table 10 - Cumulative Oil & Water Injection for Wells at AGU (Page 1 of 4)

#	Converted to INJ	Producer	29,826,699 Cum Oil 12/31/1988	36,190,158 Cum Oil 8/31/2023	6,363,459 Incremental BBLS
1		AGU-101 P&A	35,102	49,970	14,868
2		104	6,000	6,000	-
3		AGU-105 P&A	153,000	153,845	845
4	INJ	AGU-106	66,641	66,641	-
5		AGU-107	58,709	120,100	61,391
6		AGU-108	25,891	46,522	20,631
7	INJ	AGU-110 P&A	145,000	145,000	-
8		AGU-111	130,000	130,000	-
9		112	49,000	49,000	-
10	INJ	AGU-113	165,000	191,713	26,713
11		AGU-114 P&A	49,000	53,614	4,614
12	INJ	AGU-115	83,815	83,815	-
13		AGU-116 P&A	13,737	16,472	2,735
14		117	1,000	1,000	-
15		AGU-118	14,000	14,000	-
16	INJ	AGU-119	315,000	341,410	26,410
17		AGU-120	70,040	171,848	101,808
18	INJ	AGU-121 P&A	328,219	332,378	4,159
19		122	228,000	228,000	-
20		AGU-123 P&A	103,554	113,461	9,907
21	INJ	AGU-124	282,000	287,461	5,461
22		AGU-125	297,000	363,884	66,884
23	INJ	AGU-126 P&A	376,000	432,089	56,089
24		AGU-127	262,000	401,410	139,410
25	INJ	AGU-128	146,000	150,162	4,162
26		129	13,000	13,000	-
27		AGU-131 P&A	78,000	80,974	2,974
28	INJ	AGU-132	516,781	530,638	13,857
29	INJ	AGU-133	396,518	403,784	7,266
30	INJ	AGU-134	493,063	510,717	17,654
31		AGU-135	330,281	525,419	195,138
32		136	271,000	271,000	-
33		137	242,000	242,000	-
34		AGU-138Y	241,000	281,227	40,227
35	INJ	AGU-139	243,000	243,000	-
36		AGU-140	546,786	749,551	202,765
37	INJ	AGU-141	632,169	649,184	17,015
38		AGU-142	478,084	594,183	116,099
39	INJ	AGU-143	146,403	151,520	5,117
40		AGU-144 P&A	-	940	940

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Table 11 - Cumulative Oil & Water Injection for Wells at AGU (Page 2 of 4)

#	Converted to INJ	Producer	29,826,699 Cum Oil 12/31/1988	36,190,158 Cum Oil 8/31/2023	6,363,459 Incremental BBLS
41		145	7000	7000	-
42	INJ	AGU-146 P&A	56,185	58,445	2,260
43		AGU-147 P&A	200,332	203,105	2,773
44	INJ	AGU-148	49,000	49,000	-
45		AGU-149	387,664	674,518	286,854
46	INJ	AGU-150	358,821	393,249	34,428
47	INJ	AGU-151	379,324	393,124	13,800
48	INJ	AGU-152 P&A	595,432	607,638	12,206
49		153	278,000	278,000	-
50		154	256,000	256,000	-
51		AGU-155	405,000	462,976	57,976
52	INJ	AGU-156	328,193	333,107	4,914
53		AGU-157	601,694	826,915	225,221
54	INJ	AGU-158	539,657	555,533	15,876
55	INJ	AGU-159	348,685	362,575	13,890
56	INJ	AGU-160	125,000	161,878	36,878
57		AGU-161 P&A	80,055	80,272	217
58		163	87,000	87,000	-
59		AGU-166	331,312	398,051	66,739
60	INJ	AGU-167	435,857	442,448	6,591
61		AGU-168	346,187	611,818	265,631
62	INJ	AGU-169	493,000	539,783	46,783
63		AGU-170	312,000	450,944	138,944
64	INJ	AGU-171 P&A	258,000	258,000	-
65		AGU-172 P&A	270,805	288,516	17,711
66		AGU-174	186,000	263,774	77,774
67	INJ	AGU-175	381,841	408,038	26,197
68		AGU-176	635,000	957,665	322,665
69	INJ	AGU-177	329,163	341,770	12,607
70		AGU-178	217,000	235,556	18,556
71	INJ	AGU-179	173,132	176,614	3,482
72		AGU-180	-	999	999
73	INJ	181	87,000	87,219	219
74		182	21,000	21,000	-
75		183	59,573	121,950	62,377
76		AGU-184	219,007	328,364	109,357
77	INJ	AGU-185 P&A	312,619	318,147	5,528
78		AGU-186	169,000	215,503	46,503
79	INJ	AGU-187	356,787	364,789	8,002
80		AGU-188 P&A	408,000	429,088	21,088

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Table 12 - Cumulative Oil & Water Injection for Wells at AGU (Page 3 of 4)

#	Converted to INJ	Producer	29,826,699 Cum Oil 12/31/1988	36,190,158 Cum Oil 8/31/2023	6,363,459 Incremental BBLS
81	INJ	AGU-189	353,067	356,265	3,198
82		AGU-190 P&A	249,000	257,182	8,182
83		191	137,000	137,000	-
84		192	144,000	144,000	-
85		AGU-193 P&A	206,369	209,120	2,751
86	INJ	AGU-194	258,000	258,000	-
87		AGU-195	337,388	497,901	160,513
88	INJ	AGU-196	379,074	389,046	9,972
89		AGU-197	154,000	253,724	99,724
90	INJ	AGU-198	282,494	284,536	2,042
91	INJ	AGU-199	138,000	150,141	12,141
92		AGU-200	-	16,424	16,424
93	INJ	201	183,000	183,000	-
94		AGU-202	167,000	216,360	49,360
95	INJ	AGU-203	160,000	160,000	-
96		AGU-204	160,000	375,478	215,478
97	INJ	AGU-205	134,000	137,005	3,005
98		AGU-206 P&A	264,404	294,090	29,686
99		AGU-207 P&A	167,736	167,874	138
100		208	180,000	180,000	-
101		AGU-209 P&A	182,000	207,764	25,764
102	INJ	AGU-210	160,000	164,398	4,398
103		AGU-211	129,000	374,592	245,592
104	INJ	AGU-212	240,000	240,000	-
105		AGU-213	209,000	240,801	31,801
106	INJ	AGU-214	153,000	153,000	-
107		AGU-215	-	46,023	46,023
108		AGU-216 P&A	79,000	140,844	61,844
109	INJ	AGU-217	213,000	217,866	4,866
110	INJ	AGU-218 P&A	253,000	253,000	-
111		AGU-219	268,000	509,930	241,930
112	INJ	AGU-220	181,000	181,000	-
113		AGU-221 P&A	179,383	195,937	16,554
114	INJ	AGU-222 P&A	232,214	235,166	2,952
115		AGU-223	264,129	279,184	15,055
116		224	127,000	127,000	-
117	INJ	AGU-225	141,000	141,000	-
118		AGU-226 P&A	147,000	160,081	13,081
119	INJ	AGU-227	251,000	251,000	-
120		AGU-228 P&A	254,000	300,374	46,374

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Table 13 - Cumulative Oil & Water Injection for Wells at AGU (Page 4 of 4)

#	Converted to INJ	Producer	29,826,699 Cum Oil 12/31/1988	36,190,158 Cum Oil 8/31/2023	6,363,459 Incremental BBLS
121	INJ	AGU-229	285,000	285,000	-
122		230	35,000	35,000	-
123		AGU-231	214,720	235,841	21,121
124		AGU-232 P&A	87,037	89,804	2,767
125	INJ	AGU-233	206,000	300,949	94,949
126		AGU-234	210,000	435,304	225,304
127	INJ	AGU-235	143,000	143,000	-
128		AGU-236 P&A	111,626	114,809	3,183
129		237	123,000	123,000	-
130		238	96,000	96,000	-
131		AGU-239 P&A	119,000	119,932	932
132	INJ	AGU-240	322,000	322,000	-
133	INJ	AGU-241	224,000	226,359	2,359
134	INJ	AGU-242	195,000	195,000	-
135		243	11,000	11,000	-
136		AGU-245	167,000	200,755	33,755
137	INJ	AGU-246 P&A	162,000	162,000	-
138		AGU-247	173,940	292,316	118,376
139		248	107,000	107,000	-
140		AGU-324	-	21,247	21,247
141		AGU-328	-	17,149	17,149
142		AGU-329	-	84,350	84,350
143		AGU-330	-	58,554	58,554
144		AGU-335	-	144,908	144,908
145		AGU-336	-	175,702	175,702
146		AGU-337Y P&A	-	666	666
147		AGU-342	-	146,884	146,884
148		AGU-343	-	64,130	64,130
149		AGU-344	-	68,064	68,064
150		AGU-351	-	41,774	41,774
151		AGU-352	-	63,311	63,311
152		AGU-359	-	66,273	66,273
153		AGU-360	-	22,664	22,664
154		AGU-369	-	48,977	48,977
155		AGU-390	-	160,868	160,868
156		AGU-391	-	52,380	52,380
157		AGU-398	-	48,130	48,130
158		AGU-408	-	75,649	75,649

Pattern analysis was performed to determine the oil recovery in each of the 51 patterns. Water injection began in Sept-1992 in a majority of the wells. The information on the left side of the table indicates AGU-105, 107, 101, and 109 are the four producers west, east, north, and south respectively of the AGU-106 water injector and that AGU-104 is also impacted by its water injection. Six additional water injectors (highlighted in blue) were added during 2001 to 2010 to increase water injection in the areas where the 20-acre infill wells were drilled from 1998 to 2005 and in areas where water injection had to be increased. The water injection wells recovered 14 MMBO prior to water injection and the producers recovered the additional 22.2 MMBO, resulting in 36.2 MMBO oil recovery. For this analysis we assumed that for a fully developed 5-spot pattern, one quarter of the production is produced by four separate patterns.

If we assume 8% porosity, 25% initial water saturation, 85 feet thickness, and 1.2 RB/STB for each pattern with actual pattern acreage (Table 7) used in the calculation of OOIP, we calculate 130 MMBO OOIP. Chevron's more detailed estimate of 175. 4 MMBO included the unaccounted for OOIP contained in the one pattern where AGU-165 would be located if drilled, and volumes in the outlying areas around the patterns. The table below shows that 11 patterns have recovered over 1 million barrels of oil which would be 38% OOIP of a standard 80-acre pattern.

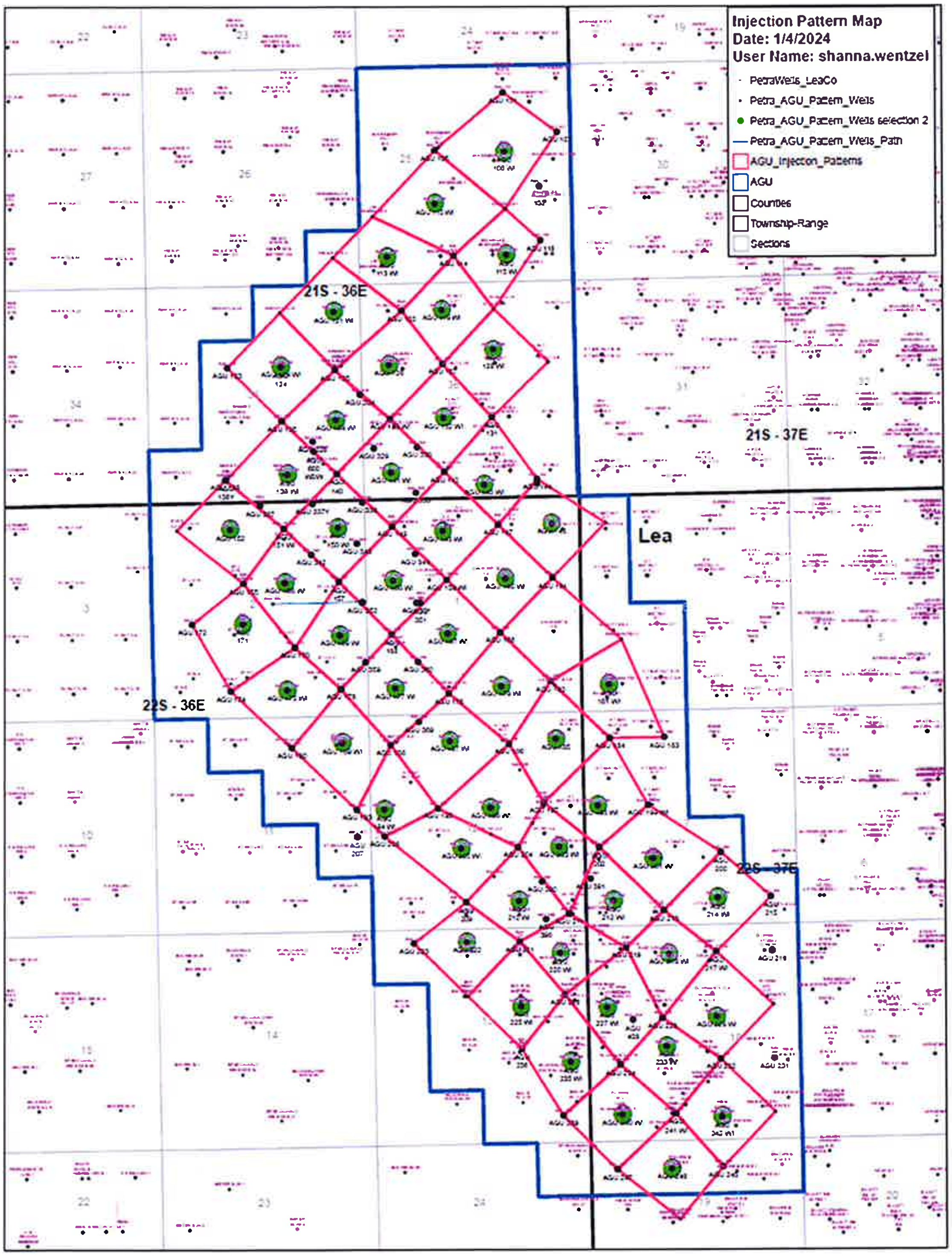
Table 14 - Cumulative Oil Recovery (BBLS) as of 8/31/2023 by Pattern

Wells Impacted by Injection | **Oil Volume Produced By Each Well per Pattern**

#	Injector	Cumulative Water INJ	Start-up	West Prod-1	East Prod-2	North Prod-3	South Prod-4	New1	New2	New3	New4	Injector CUM	West	East	North	South	New1	New2	New3	New4	TOTAL
		457,803,704										14,005,751									36,190,158
1	AGU-106	3,930,424		105	107	101	109	104				66,641	76,923	120,100	49,970		6,000				319,634
2	AGU-110 P&A	2,932,017		111	109	105	114	108				145,000	65,000		76,923	13,404	46,522				346,848
3	AGU-113	9,217,524		112	114	111	120					191,713	24,500	13,404	65,000	42,962					337,579
4	AGU-115	1,662,697		114	116	109	118					83,815	13,404	16,472		4,667					118,357
5	AGU-119	12,154,000		120	118	114	127	117				341,410	42,962	4,667	13,404	100,353	1,000				503,795
6	AGU-121 P&A	5,690,848		122	120	112	125					332,378	114,000	42,962	24,500	90,971					604,811
7	AGU-124	9,386,016		123	125	122	135	136				287,461	113,461	90,971	114,000	175,140	90,333				871,366
8	AGU-126 P&A	5,736,204		125	127	120	133	324				432,089	90,971	100,353	42,962	100,946	10,624				777,944
9	AGU-128	7,090,348		127	129	118	131					150,162	100,353	13,000	4,667	26,991					295,173
10	AGU-132	5,009,630		133	131	127	142	330				530,638	100,946	26,991	100,353	148,546	29,277				936,751
11	AGU-133	4,997,737	Apr-01																		-
12	AGU-134	12,668,503		135	133	125	140	324	329	328	136	510,717	175,140	100,946	90,971	187,388	10,624	42,175	8,575	90,333	1,216,868
13	AGU-139	13,852,450		138Y	140	135	151	328	337Y	336	137	243,000	140,614	187,388	175,140	98,281	8,575	333	90,333	121,000	1,064,663
14	AGU-141	8,077,883		140	142	133	149	329	330	335	336	649,184	187,388	148,546	100,946	168,630	42,175	29,277	72,454	87,851	1,486,450
15	AGU-143	7,412,703		142	144	131	147					151,520	148,546	470	26,991	50,776					378,303
16	AGU-146 P&A	1,929,685		147	145	144	161					58,445	50,776	7,000	470	40,136					156,827
17	AGU-148	7,854,274		149	147	142	159	335	344			49,000	168,630	50,776	148,546	90,644	72,454	34,032			614,081
18	AGU-150	13,498,012		151	149	140	157	337Y	336	341	342	393,249	98,281	168,630	187,388	206,729	333	87,851	32,065	73,442	1,247,967
19	AGU-151	9,340,882	Apr-01																		-
20	AGU-152 P&A	2,519,648		153	151	138Y	155	137	154			607,638	278,000	98,281	140,614	154,325	121,000	85,333			1,485,191
21	AGU-156	15,504,519		155	157	151	170	342	154			333,107	154,325	206,729	98,281	112,736	73,442	85,333			1,063,953
22	AGU-158	10,874,569		157	159	149	168	343	344	351	352	555,533	206,729	90,644	168,630	152,955	32,065	34,032	20,887	31,656	1,293,329
23	AGU-159	9,738,704	Apr-01																		-
24	AGU-160	10,429,676		159	161	147	166					161,878	90,644	40,136	50,776	132,684					476,118
25	AGU-167	7,611,414		168	166	159	178	351	360			442,448	152,955	132,684	90,644	58,889	20,887	11,332			909,838
26	AGU-169	16,713,886		170	168	157	176	359	352			539,783	112,736	152,955	206,729	239,416	33,137	31,656			1,316,411
27	AGU-171 P&A	10,770,159		172	170	155	174	154				258,000	288,516	112,736	154,325	131,887	85,333				1,030,798
28	AGU-175	13,048,808		174	176	170	190	191				408,038	131,887	239,416	112,736	128,591	68,500				1,089,168
29	AGU-177	15,405,955		176	178	168	188	359	360	369		341,770	239,416	58,889	152,955	107,272	33,137	11,332	24,489		969,259
30	AGU-179	9,194,996		178	180	166	186					176,614	58,889	333	132,684	53,876					422,395
31	AGU-181			180	182	164	184	163	183			87,219	333	21,000	-	109,455	87,000	60,975			365,982
32	AGU-185 P&A	3,368,416		186	184	180	197					318,147	53,876	109,455	333	63,431					545,241
33	AGU-187	7,487,158		188	186	178	195	369				364,789	107,272	53,876	58,889	124,475	24,489				733,790
34	AGU-189	11,681,631		190	188	176	193	191	192			356,265	128,591	107,272	239,416	104,560	68,500	72,000			1,076,604
35	AGU-194	8,112,384		193	195	188	206	192	207			258,000	104,560	124,475	107,272	147,045	72,000	83,937			897,289
36	AGU-196	15,197,838		195	197	186	204					389,046	124,475	63,431	53,876	93,870					724,698
37	AGU-198	5,227,806		197	199	184	202	183				284,536	63,431	75,071	109,455	54,090	60,975				647,557
38	AGU-199	2,141,755	Mar-08																		-
39	AGU-201	5,154,170		202	200	190	213					183,000	54,090	8,212	75,071	60,200					380,573
40	AGU-203	14,951,626		204	202	197	211	390	391			160,000	93,870	54,090	63,431	93,648	80,434	26,190			571,663
41	AGU-205	10,431,255		206	204	195	209	207	208			137,005	147,045	93,870	124,475	69,255	83,937	60,000			715,586
42	AGU-210	8,832,383		209	211	204	221	398	390	208		164,398	69,255	93,648	93,870	48,984	24,065	80,434	60,000		634,653
43	AGU-212	15,453,567		211	213	202	219	391				240,000	93,648	60,200	54,090	127,483	26,190				601,611
44	AGU-214	5,537,366		213	215	200	217	216				153,000	60,200	46,023	8,212	72,622	46,948				387,005
45	AGU-217	498,457	Mar-10																		-
46	AGU-218 P&A	7,462,504		219	217	213	228	408	216			253,000	127,483	72,622	60,200	75,094	37,825	46,948			673,171
47	AGU-220	8,291,121		221	219	211	226	398				181,000	48,984	127,483	93,648	40,020	24,065				515,200
48	AGU-222 P&A	2,169,336		223	221	209	224	208				235,166	279,184	48,984	69,255	63,500	60,000				756,089
49	AGU-225	10,890,436		224	226	221	236	237				141,000	63,500	40,020	48,984	57,405	61,500				412,409
50	AGU-227	12,075,196		226	228	219	234	408				251,000	40,020	75,094	127,483	108,826	37,825				640,247
51	AGU-229	9,050,967		228	230	217	232	216	231			285,000	75,094	35,000	72,622	29,935	46,948	78,614			623,212
52	AGU-233	5,596,450		234	232	228	241	231				300,949	108,826	29,935	75,094	56,590	78,614				650,007
53	AGU-235	6,871,479		236	234	226	239	237	238			143,000	57,405	108,826	40,020	59,966	61,500	48,000			518,717
54	AGU-240	10,993,597		239	241	234	247	238				322,000	59,966	56,590	108,826	146,158	48,000				741,540
55	AGU-241	443,874	Nov-07																		-
56	AGU-242	4,102,761		241	243	232	245	231				195,000	56,590	11,000	29,935	100,378	78,614				471,516
57	AGU-246 P&A	1,326,000		247	245	241	248					162,000	146,158	100,378	56,590	107,000					572,125

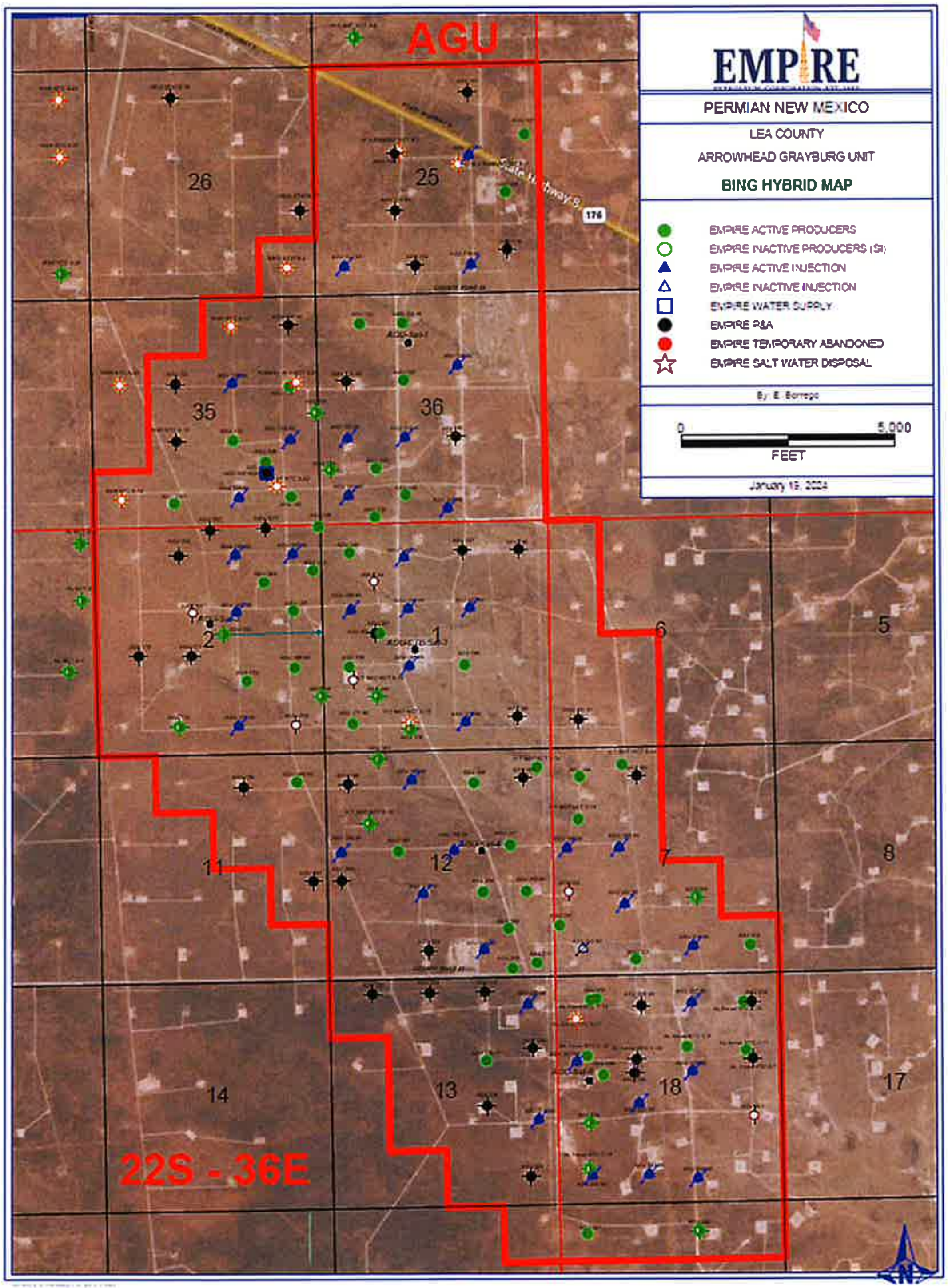
OCD 23614-17 03503

Figure 5 – Arrowhead Grayburg Unit Injection Pattern Map



OCD 23614-17 03504

Figure 6 – AGU Map Showing Well Status



OCD 23614-17 03505

Below is shown the incremental oil recovery for each pattern from 12/31/1988 to 8/31/2023. 6.4 million barrels of incremental oil were produced. Patterns #12, 13, 14, 18, 20, 21, 22, 26, 27, 28, and 34 are the patterns which have recovered over 1 million barrels. Patterns #14, 18, 22, and 26 produced more than 350,000 barrels after 12/31/1988. The 20-acre infills (as shown by the 300 series wells under new wells on the table) helped increase oil recovery in many of these patterns. We will look at the logs on the new wells drilled to see what they looked like and where they were perforated.

Table 15 - Incremental Oil Recovery (BBLS) since 12/31/1988 by Pattern

Wells Impacted by Injection — **Incremental Oil Volume Produced By Each Well per Pattern**

											513,124									6,363,459
#	Injector	Start-up	West Prod-1	East Prod-2	North Prod-3	South Prod-4	New1	New2	New3	New4	Injector CUM	West	East	North	South	New1	New2	New3	New4	TOTAL
1	AGU-106		105	107	101	109	104				-	423	61,391	14,868		-				76,682
2	AGU-110 P&A		111	109	105	114	108				-	-		423	1,154	20,631				22,207
3	AGU-113		112	114	111	120					26,713	-	1,154	-	25,452					53,319
4	AGU-115		114	116	109	118					-	1,154	2,735		-					3,889
5	AGU-119		120	118	114	127	117				26,410	25,452	-	1,154	34,853	-				87,868
6	AGU-121 P&A		122	120	112	125					4,159	-	25,452	-	16,721					46,332
7	AGU-124		123	125	122	135	136				5,461	9,907	16,721	-	65,046	-				97,135
8	AGU-126 P&A		125	127	120	133	324				56,089	16,721	34,853	25,452	1,817	10,624				145,555
9	AGU-128		127	129	118	131					4,162	34,853	-	-	991					40,006
10	AGU-132		133	131	127	142	330				13,857	1,817	991	34,853	29,025	29,277				109,819
11	AGU-133	Apr-01																		-
12	AGU-134		135	133	125	140	324	329	328	136	17,654	65,046	1,817	16,721	50,691	10,624	42,175	8,575	-	213,302
13	AGU-139		138Y	140	135	151	328	337Y	136	137	-	20,114	50,691	65,046	3,450	8,575	333	-	-	148,208
14	AGU-141		140	142	133	149	329	330	335	336	17,015	50,691	29,025	1,817	71,714	42,175	29,277	72,454	87,851	402,018
15	AGU-143		142	144	131	147					5,117	29,025	470	991	693					36,296
16	AGU-146 P&A		147	145	144	161					2,260	693	-	470	109					3,532
17	AGU-148		149	147	142	159	335	344			-	71,714	693	29,025	3,473	72,454	34,032			211,390
18	AGU-150		151	149	140	157	337Y	336	343	342	34,428	3,450	71,714	50,691	56,305	333	87,851	32,065	73,442	410,279
19	AGU-151	Apr-01																		-
20	AGU-152 P&A		153	151	138Y	155	137	154			12,206	-	3,450	20,114	19,325	-	-			55,095
21	AGU-156		155	157	151	170	342	154			4,914	19,325	56,305	3,450	34,736	73,442	-			192,173
22	AGU-158		157	159	149	168	343	344	351	352	15,876	56,305	3,473	71,714	66,408	32,065	34,032	20,887	31,656	332,415
23	AGU-159	Apr-01																		-
24	AGU-160		159	161	147	166					36,878	3,473	109	693	22,246					63,399
25	AGU-167		168	166	159	178	351	360			6,591	66,408	22,246	3,473	4,639	20,887	11,332			135,576
26	AGU-169		170	168	157	176	359	352			46,783	34,736	66,408	56,305	80,666	33,137	31,656			349,690
27	AGU-171 P&A		172	170	155	174	154				-	17,711	34,736	19,325	38,887	-				110,659
28	AGU-175		174	176	170	190	191				26,197	38,887	80,666	34,736	4,091	-				184,577
29	AGU-177		176	178	168	188	359	360	369		12,607	80,666	4,639	66,408	5,272	33,137	11,332	24,489		238,549
30	AGU-179		178	180	166	186					3,482	4,639	333	22,246	11,626					42,326
31	AGU-181		180	182	164	184	163	183			219	333	-	-	36,452	-	31,189			68,193
32	AGU-185 P&A		186	184	180	197					5,528	11,626	36,452	333	24,931					78,870
33	AGU-187		188	186	178	195	369				8,002	5,272	11,626	4,639	40,128	24,489				94,156
34	AGU-189		190	188	176	193	191	192			3,198	4,091	5,272	80,666	1,376	-	-			94,603
35	AGU-194		193	195	188	206	192	207			-	1,376	40,128	5,272	14,843	-	69			61,688
36	AGU-196		195	197	186	204					9,972	40,128	24,931	11,626	53,870					140,527
37	AGU-198		197	199	184	202	183				2,042	24,931	6,071	36,452	12,340	31,189				113,024
38	AGU-199	Mar-08																		-
39	AGU-201		202	200	199	213					-	12,340	8,212	6,071	7,950					34,573
40	AGU-203		204	202	197	211	390	391			-	53,870	12,340	24,931	61,398	80,434	26,190			259,163
41	AGU-205		206	204	195	209	207	208			3,005	14,843	53,870	40,128	8,588	69	-			120,503
42	AGU-210		209	211	204	221	398	390	208		4,398	8,588	61,398	53,870	4,139	24,065	80,434	-		236,891
43	AGU-212		211	213	202	219	391				-	61,398	7,950	12,340	60,483	26,190				168,361
44	AGU-214		213	215	200	217	216				-	7,950	46,023	8,212	1,622	20,615				84,422
45	AGU-217	Mar-10																		-
46	AGU-218 P&A		219	217	213	228	408	216			-	60,483	1,622	7,950	11,594	37,825	20,615			140,087
47	AGU-220		221	219	211	226	398				-	4,139	60,483	61,398	3,270	24,065				153,354
48	AGU-222 P&A		223	221	209	224	208				2,952	15,055	4,139	8,588	-	-				30,734
49	AGU-225		224	226	221	236	237				-	-	3,270	4,139	1,592	-				9,000
50	AGU-227		226	228	219	234	408				-	3,270	11,594	60,483	56,326	37,825				169,497
51	AGU-229		228	230	217	232	216	231			-	11,594	-	1,622	922	20,615	7,040			41,793
52	AGU-233		234	232	228	241	231				94,949	56,326	922	11,594	590	7,040				171,421
53	AGU-235		236	234	226	239	237	238			-	1,592	56,326	3,270	466	-	-			61,654
54	AGU-240		239	241	234	247	238				-	466	590	56,326	59,188	-				116,570
55	AGU-241	Nov-07																		-
56	AGU-242		241	243	232	245	231				-	590	-	922	16,878	7,040				25,430
57	AGU-246 P&A		247	245	241	248					-	59,188	16,878	590	-					76,655

The table below has additional production and water injection data for each AGU well. It also has formations tops provided on the wellbore diagrams by XTO, with Empire tops being very similar. On average Zone 1 of the Grayburg is 39' thick, Zone 2 is 64', Zone 3 is 37', Zone 4 is 47', and Zone 5 is 45' for total of 231' thick. Table 6 shows an average net thickness of 85' therefore the average net-to-gross is approximately 36.8%.

Table 16 – AGU Well Information Including XTO Formation Tops (Page 1 of 2)

Arrowhead Grayburg Unit

#	Well	Type Well	Wellhead Pressure	BWPD Injection	Comments	BOPD	MCFPD	BWPD	Casing	Lift	Current Completion Interval	Queen	Penrose	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	San Andres
1	600	WSW								ESP	4132-5000	3432	3540	3725	3764	3821	3858	3912	
2	106	INJ	609	177					4-1/2"	INJ	Z1, Z2, Z3, Z4, Z5		3497	3672	3705	3762	3793	3835	3878
3	107	PROD				1.8	3	68.9	4-1/2"	ROD	Z1, Z2, Z3, Z4, Z5	3378	3485	3654	3689	3750	3785	3829	3862
4	108	PROD				1.8	4	41.0	5-1/2"	ROD	Z1, Z2, Z3, Z4, Z5	3392	3506	3689	3724	3782	3812	3853	
5	110	P&A																	
6	113	INJ	631	1111					5-1/2"	INJ	Z1, Z2, Z3, Z4	3410	3537	3710	3746	3804	3840	3883	3920
7	115	INJ	583	63					5-1/2"	INJ	Z1, Z2, Z3, Z4, Z5	3380	3491	3673	3712	3764	3795	3837	3870
8	119	INJ	7	930						INJ									
9	120	PROD			Z1 not perforated	4.5	4	114	5-1/2"	ROD	Z3, Z4, Z5	3382	3499	3671	3746	3774	3805	3849	
10	121	SI-INJ			Casing leaks @ 815-819 and 939-943. Last injected in 2019				5-1/2"	SI-INJ	Openhole Z1,Z2,Z3,Z4,Z5	3452	3545	3734	3774	3842	3876	3926	3968
11	124	INJ	626	620					5-1/2"	INJ				3815	3856	3918	3958	4012	4058
12	125	PROD				2.9	3	113	5-1/2"	ROD	Z3, Z4, Z5	3429	3536	3713	3758	3818	3859	3909	3954
13	126	P&A																	
14	127	PROD				5.5	4	2325	5-1/2"	ESP	Openhole			3652	3674	3752	3768	3815	
15	128	INJ	653	557					5-1/2"	INJ	Z2, Z3, Z4, Z5	3356	3437	3648	3690	3758	3803	3837	3887
16	132	INJ	625	613					4-1/2"	INJ				3654	3682	3744	3778	3826	3863
17	133	INJ	552	317					4"	INJ		3367	3468	3648	3688	3752	3786	3825	
18	134	INJ	572	841					4-1/2"	INJ	Z1, Z2, Z3, Z4, Z5			3722	3757	3813	3854	3906	3945
19	135	PROD				8.6	7	1776	5-1/2"	ESP	Penrose & Openhole	3472	3592	3780	3818	3886	3918	3970	4010
20	138Y	PROD			Z1 & Z5 not perforated	3.6	17	137	5-1/2"	ROD	Penrose, Z2, Z3, Z4	3538	3659	3830	3866	3930	3968	4020	4051
21	139	INJ	no reading	1067					5-1/2"	INJ	Z1 squeezed Z2,Z3,Z4,Z5			3752	3790	3849	3886	3938	3986
22	140	PROD				6.4	7	1975	6"	ESP	Z1 & Openhole Z2, Z3, Z4, Z5	3411	3529	3712	3747	3810	3846	3896	3944
23	141	INJ	534	624					5"	INJ	Z1 & Z2 squeezed, Z3	3377	3485	3672	3705	3764	3800	3848	3893
24	142	PROD				11.1	3	540	4-1/2"	ROD	Z3, Z4	3349	3449	3643	3679	3739	3776	3824	3866
25	143	INJ	351	143						INJ	no WBD								
26	146	P&A																	
27	148	INJ	701	681					5-1/2"	INJ	Z1, Z2, Z3, Z4, Z5	3368	3478	3670	3704	3766	3803	3852	3891
28	149	PROD				22.4	6	1258	7"	ESP	Z1	3382	3485	3671	3706	3772	3809	3863	3904
29	150	INJ	514	934					4"	INJ	Z1, Z2, Z3, Z4			3688	3721	3778	3822		
30	151	INJ	394	917					4"	INJ	Openhole Z3, Z4, Z5	3443	3561	3740	3777	3839	3873	3926	3966
31	155	SI-OIL		Waiting on Rig to RTP	Zone of >10% porosity not perf'd at 3865-3889'				5-1/2"	ROD	Penrose, Z1, Z2, Z3, Z4, Z5	3477	3590	3773	3810	3881	3918	3970	4013
32	156	INJ							5-1/2"	INJ	Openhole Z2, Z3, Z4, Z5			3724	3762	3830	3858	3918	
33	157	PROD			Currently on well. Can perf Z1 and acidize on next job	1.5	1	185	5-1/2"	ESP	Z2, Z3, Z4, Z5 Openhole	3387	3503	3690	3729	3794	3830	3884	3928
34	158	INJ	543	778					5-1/2"	INJ	Openhole Z2, Z3, Z4, Z5	3375	3482	3668	3708	3769	3814	3870	3914
35	159	INJ	436	548					3-1/2"	INJ	Z1, Z2, Z3, Z4	3370	3476	3666	3703	3756	3788	3836	
36	160	INJ	377	508					7"	INJ	Z1, Z2, Z3, Z4, Z5	3360	3467	3666	3704	3768	3800	3845	
37	165	SI-INJ			No wellbore diagram, No information on well					SI-INJ									
38	166	PROD				0.5	1	17	5-1/2"	ROD	Penrose & Openhole All Zones	3374	3474	3682	3720	3788	3820	3863	3902
39	167	INJ	3	243					4-1/2"	INJ	Z2, Z3, Z4, Z5	3367	3481	3676	3717	3781	3814	3860	3900
40	168	PROD			Well deepened. Has squeezed casing leaks at 600' and 1000'-1200'.	14.6	5	1288	6"	ROD	Openhole Z2, Z3, Z4, Z5	3378	3495	3683	3720	3799	3829	3877	3921
41	169	INJ	67	1401					4"	INJ	Z1, Z2, Z3			3695	3737	3792	3828		
42	170	PROD			Z1 squeezed	2.6	8	1067	5-1/2"	ROD	Z2, Z3, Z4, Z5	3404	3525	3704	3745	3816	3854	3904	3939
43	171	P&A																	
44	174	SI-OIL		Waiting on Rig to RTP	Perf'd in Penrose & GRBG - drilled through most zones in GRBG - western down-dip edge. Z1 perfs squeezed				5-1/2"	ROD	Penrose, Z2, Z3, Z4, Z5	3522	3638	3835	3875	3946	3981	4032	4069
45	175	INJ	353	505					4"	INJ	Penrose, Z1, Z2, Z3			3747	3791				
46	176	TA							4"		Z1, Z2	3396	3513	3712	3756	3823	3854	3900	3946
47	177	INJ	95	956					4-1/2"	INJ	Z1, Z2, Z3, Z4, Z5								
48	178	SI-OIL		Waiting on Rig to RTP					5-1/2"	SI-PROD	Z4		3496	3691	3748	3800	3838		
49	179	INJ	694	854					5-1/2"	INJ	Openhole Z2, Z3, Z4, Z5	3368	3478	3640					
50	181	INJ							5-1/2"	INJ	Z2, Z3, Z4, Z5			3665	3700	3765	3799	3841	3875
51	184	TA		TA Failed - May P&A	Last produced in Oct-2022. Well TA'd but had leaks.	3	18	198	5-1/2"	ROD	Z1, openhole Z2, Z3, Z4, Z5	3327	3433	3629	3666	3736	3776	3823	3864
52	185	P&A																	
53	186	PROD			Z1 not perforated	2.7	5	402	5-1/2"	ROD	Penrose, Z2, Z3, Z4, Z5	3331	3442	3648	3687	3752	3791	3834	3867
54	187	INJ	686	394					4-1/2"	INJ	Z1, Z2, Z3, Z4		3498	3690	3730	3787	3823	3868	3904
55	189	INJ	17	458					5-1/2"	INJ	Penrose Squeezed, Z1, Z2, Z3			3741	3780	3850	3886	3938	
56	194	INJ	683	657					4"	INJ	Z2, Z3		3567	3752	3795	3856	3890	3939	3979
57	195	PROD			Used Sonic Hammer with 180 barrels brine and acidized with 5500 gallons 20% 90/10 acid	6.4	19	330	5-1/2"	ROD	Openhole 3669'-3904'	3404	3510	3709	3751	3808	3843	3890	3930
58	196	INJ	no reading	2026					5-1/2"	INJ	Openhole Z1,Z2,Z3,Z4,Z5	3354	3471	3664	3704	3767	3806	3850	3897
59	197	PROD				7.3	19	639	5-1/2"		Z2, Z3	3317	3441	3637	3679	3756	3791	3836	3872
60	198	INJ	289	391					4-1/2"	INJ	Z2, Z3, Z4, Z5	3323	3423	3630	3673	3737	3772	3820	3858
61	199	INJ	241	374					5-1/2"	INJ	Z2, Z3, Z4, Z5	3350	3451	3642	3681	3760	3801	3845	3884
62	200	SI-OIL		Waiting on Rig to RTP	Last produced in 2018. Run RST and set CIBP to isolate bottom perfs	0.7	11	61	5-1/2"	ROD	Z1, Z2, Z3, Z4, Z5	3347	3450	3631	3668	3740	3776	3820	3858
63	201	INJ	712	76					5-1/2"	INJ	Z1, Z2, Z3			3644	3682	3752	3790	3836	3875
64	202	TA							5-1/2"		Z2, Z3	3322	3425	3637	3674	3728	3778	3825	3867
65	203	INJ	69	1589					5-1/2"	INJ	Z1, Z2, Z3, Z4	3297	3425	3626	3668	3746	3782	3831	
66	204	PROD			Squeezed off bottom of Z4 and Z5	9.1	10	3103	5-1/2"		Z1, Z2, Z3, Z4	3340	3450	3656	3694	3756	3794	3842	3885

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Table 17 – AGU Well Information Including XTO Formation Tops (Page 2 of 2)

Arrowhead Grayburg Unit

#	Well	Type Well	Wellhead Pressure	BWPD Injection	Comments	BOPD	MCFPD	BWPD	Casing	Lift	Current Completion Interval	Queen	Penrose	Zone 1	Zone 2	Zone 3	Zone 4	Zone 5	San Andres
67	205	INJ	446	646					5-1/2"	INJ	Z2, Z3, Z4, Z5	3362	3480	3680	3717	3780	3816	3866	
68	209	P&A							5-1/2"		Z2, Z3, Z4, Z5	3380	3505	3701	3738	3800	3836	3885	3928
69	210	INJ	442	630					5-1/2"	INJ	Z2, Z3	3346	3461	3663	3700	3766	3801	3844	3902
70	211	PROD				9.1	10	550	5-1/2"	ROD	Penrose, Z1, Z2, Z3	3328	3450	3650	3686	3748	3786	3833	3874
71	212	SI-INJ							3-1/2"	SI-INJ	Z1 only	3305	3423	3623	3664	3704	3735	3774	3858
72	213	PROD				1.8	3	58	5-1/2"		Penrose, Z1, Z2, Z3, Z4, Z5	3328	3438	3648	3682	3746	3786	3828	3868
73	214	INJ	703	240					4-1/2"	INJ	3646'-3830'								
74	215	PROD				3.6	9	218	5-1/2"		Penrose, Z1, Z2, Z3, Z4, Z5	3357	3460	3638	3675	3732	3778	3824	3859
75	216	P&A		Submitting Paperwork					5-1/2"		Penrose, Z1, Z2	3345	3450	3634	3671	3742	3782	3828	3866
76	217	INJ	674	248					5-1/2"	INJ	Z2, Z3	3331	3434	3635	3671	3741	3783	3828	3869
77	218	P&A							5-1/2"		Z1, Z2, Z3	3314	3435	3633	3671	3736	3775	3820	
78	219	PROD				10.0	11	1994	5-1/2"		Penrose, Z1, Z2, Z3, Z4	3333	3454	3654	3688	3751	3789	3833	3874
79	220	INJ	689	639					5-1/2"	INJ	Z1, Z2, Z3, Z5 No Z4 ??	3337	3468	3656	3691	3753	3790	3838	3880
80	222	P&A																	
81	225	INJ	3	81					5-1/2"	INJ	Z2, Z3, Z4, Z5	3375	3498	3692	3724	3786	3822	3867	3906
82	226	P&A																	
83	227	INJ	460	1226					5-1/2"	INJ	Z1, Z2, Z3	3316	3438	3630	3665	3734	3768	3814	3856
84	229	INJ	445	349					5-1/2"	INJ	3667'-3810'								
85	231	TA		Submitting Paperwork	Last produced in 2022	1	1	130	5-1/2"	ROD	3430'-3680'	no tops picked							
86	233	INJ	677	231					5-1/2"	INJ	3602'-3770'								
87	234	SI-OIL		Waiting on Rig to RTP	Last produced at high rate in 2018	8	32	6300	5-1/2"	ESP	Z1, Z2, Z3, Z4, Z5	3318	3435	3625	3665	3724	3767	3817	3853
88	235	SI-INJ							5-1/2"	SI-INJ	Z1,Z2,Z3,Z4,Z5			3652	3687	3754	3792	3841	3879
89	240	INJ	644	1185					5-1/2"	INJ	Z1, Z2, Z3, Z4	3341	3460	3651	3687	3752	3785	3835	3875
90	241	INJ	672	34					5-1/2"	INJ	3690'-3770'								
91	242	INJ	684	477					5-1/2"	INJ	Z1, Z2, Z3, Z4	3328	3438	3632	3665	3726	3760	3810	3850
92	245	SI-OIL		Waiting on Rig to RTP	Penrose & GRBG perfs - OH from 3714-3813' - no log after 3700' - cum'd 180 mbo, Casing leak @ 1600' sqzed	2	18	100	5-1/2"	ROD		Tops not provided							
93	247	PROD			Openhole Z1-Z5	5.5	13	23	5-1/2"		Penrose, Z1, Z2, Z3, Z4, Z5								
94	324	TA		Waiting on Rig to RTP	RAS candidate - cum'd 21 mmbo - porosity is 10-20% throughout open interval. Set CIBP & perf Z1	2	2	741	7"	ROD	Z2, Z3, Z4	3375	3482	3669	3708	3774	3809	3851	
95	328	PROD				3.6	5	293	5-1/2"		Z2, Z3, Z4			3735	3770	3830	3865	3920	4030
96	329	SI-OIL		Waiting on Rig to RTP	Last produced steady in 2018. Z3 only making lots of fluid	3.5	11	2350	7"	ESP	Z3	3383	3481	3675	3712	3768	3808	3854	
97	330	SI-OIL			Currently on well. Everything squeezed off except Z3 and Z4	7	6	900	7"	ESP	Z3, Z4	3364	3469	3648	3686	3744	3786	3834	
98	335	PROD				10.8	5	168	5-1/2"		Z2, Z3, Z4			3658	3691	3753	3789		
99	336	PROD				6.5	4	532	7"		Openhole Z1, Z2, Z3, Z4	3346	3493	3676	3737	3787	3820		3950
100	342	PROD				7.3	9	977	5-1/2"		Z3, Z4, Z5			3701	3739	3806	3839	3892	3964
101	343	PROD			High Perm Zone 3736'-3746'	5.4	4	756	7"		Z2, Z3, Z4	3196	3500	3682	3716	3785	3821	3876	
102	344	TA		Waiting on Rig to TA	Made 200 BW in 2019 Can perf Zone Z1	0	0	200	5-1/2"	ROD	Z2, Z3, Z4		3486	3674	3708	3778	3813	3869	
103	351	PROD			Lufkin 640-365-168	3.8	5	532	7"	ROD	Z3, Z4	3380	3489	3675	3709	3780	3814		
104	352	TA		Waiting on Rig to RTP		No wellbore diagram													
105	359	SI-OIL		Waiting on Rig to RTP	Last produced continuously in 2020. Zone 1 not perforated.	3	5	900	7"	ESP	3752'-3832'	3381		3691	other tops not shown				
106	360	SI-OIL		Waiting on Rig to RTP	Z1 interval not perforated. Last produced in 2018	3	6	1000	5-1/2"	ESP	Z2, Z3, Z4, Z5, Z6			3685	3724	3787	3825	3871	3950
107	369	SI-OIL		Waiting on Rig to RTP	Last produced in 2022.	4	10	2200	7"	ESP	Openhole Z1, Z2, Z3	3389	3512	3700	3749	3802			3931
108	390	PROD				5.5	4	563	7"	ROD	Openhole Z2, Z3, Z4	3327	3434	3617	3667	3714	3750		
109	391	PROD				4.5	10	3064	5-1/2"	ESP	Z2, Z3, Z4	3280		3618					3897
110	392																		
111	398	SI-OIL		Waiting on Rig to TA	Last produced in 2022. Approved to RTP. Z1 never perforated	3	6	300	5-1/2"	ROD	Z2, Z2A, Z3			3660	3696	3760	3797	3845	3926
112	408	PROD				No Test Yet			5-1/2"		Z2, Z3, Z4	3316	3415	3620	3648	3720	3762	3805	3904

Residual Oil Zone (ROZ)

A residual oil zone (ROZ) is an interval of reservoir rock containing immobile oil, with respect to water, at residual oil saturation levels generally less than 40% (Sanguinito et al., 2020). ROZs form due to regional tectonic tilting, leakage from traps, or hydrodynamic activity, which naturally waterflood the oil-bearing intervals, causing remobilization of the moveable oil out of the reservoir by hydrodynamic forces (Melzer, 2006). The Eunice Monument San Andres ROZ can be classified as brownfield, where the ROZ occurs below the producing oil-water contact (OWC) of the Grayburg main pay zone (MPZ). Empire plans to develop this San Andres ROZ interval using the same facilities it will use for developing the Grayburg MPZ.

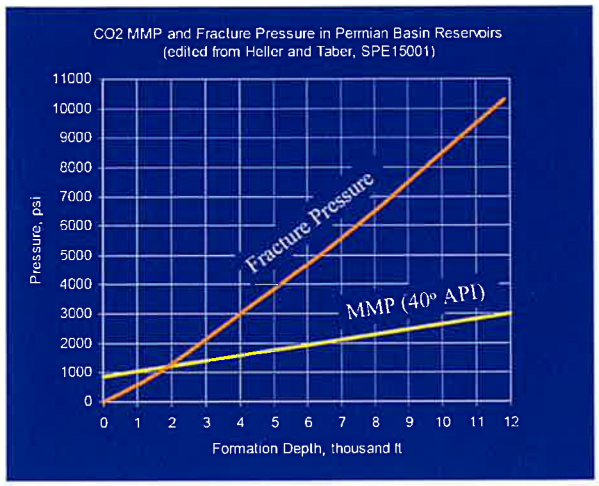
Several detailed studies of selected formations in the Permian Basin of the United States have shown that ROZs can be as common as traditional conventional oil reservoir traps, suggesting significant resources for potential additional hydrocarbon recovery and subsurface CO2 sequestration via CO2-EOR. Core data at EMSU and AGU show that the San Andres ROZ interval could extend to -750' subsea and based on XTO Energy's estimate using -700' subsea as the oil water contact, 912 MMBO oil-in-place target is available for CO2-EOR.

CO2 Flood Design Considerations

For the first 10 years of field operation, CO2 purchases are the single largest operating expense in CO2 EOR floods. Kinder Morgan and others in the Permian Basin typically charge 2% of oil price for CO2 purchase, therefore at $75/BO the CO2 purchase price will be roughly $1.50/MCF. With CO2 being captured from industrial plants and sequestered in oil and saline aquifers, there is an opportunity to purchase the CO2 at a reduced rate and allow the seller to receive 45-Q tax credits for sequestering the CO2. Empire has spoken with CO2 suppliers and will work out the most cost effective means of securing large volumes of CO2. Net CO2 utilization (purchased CO2 volume per barrel of incremental oil recovered) is often around 5 MCF/bbl for WAG CO2 floods. If we assume 50 million barrels incremental oil recovery, we would expect to purchase around 375 billion cubic feet (BCF) of CO2. At $1.50/MCF the CO2 would cost $375 million but the oil at $75/bbl would be worth $3.75 billion.

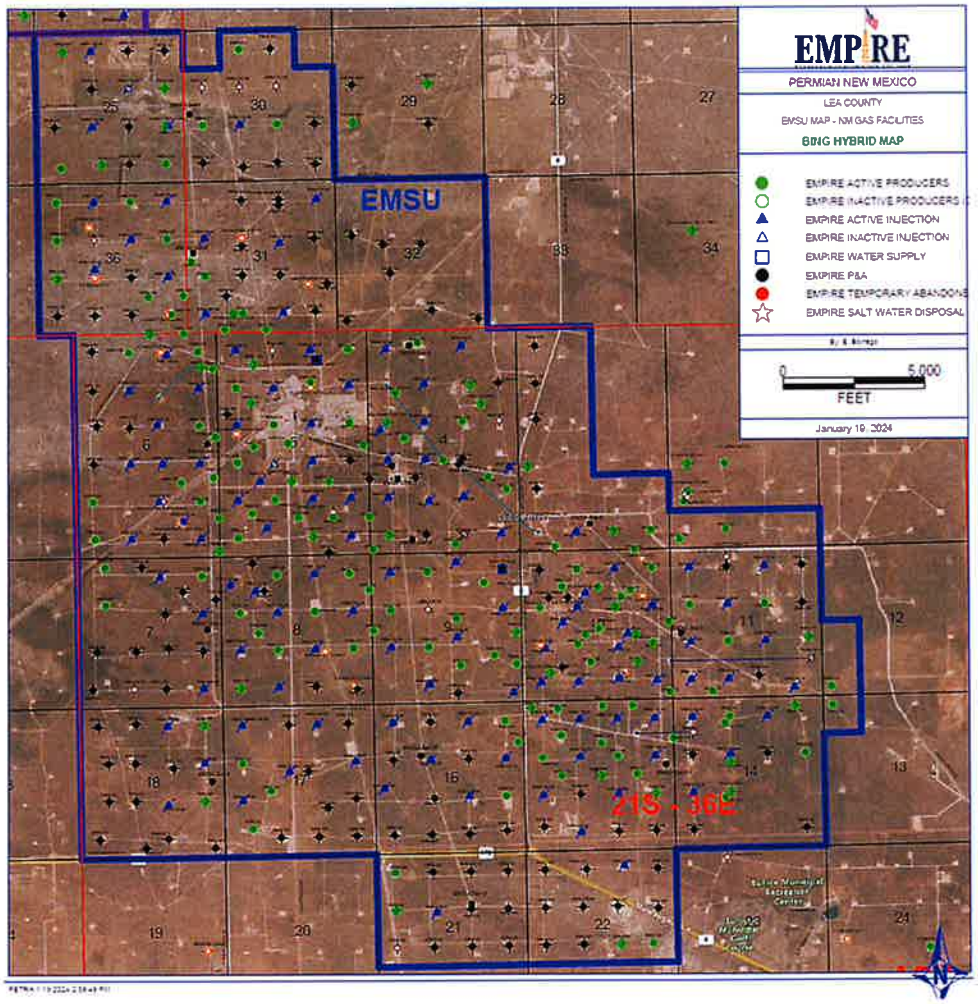
Figure 7 shows a plot of MMP and Fracture pressure for Permian Basin reservoirs with an API Gravity of 40^0 API. It shows at a depth of 4000 feet that the reservoir pressure needs to be around 1600 psi to be miscible. CO2 will be used to pressurize the reservoir to maximize oil recovery.

Figure 7 – CO2 Minimum Miscibility Pressure & Fracture Pressure



For field scale miscible CO2 EOR floods, projected incremental recoveries range from 7 to 23% of the original oil in place (OOIP) and the net (purchased) amount of CO2 required is estimated to be between 2.5 to 11 MCF/STB of incremental recovery with an average value of 6 to 7 MCF/STB. For EMSU and AGU we anticipate an oil recovery of 15% OOIP which will result in 127 MMBO being produced from the Grayburg (OOIP = 847 MMBO) and 137 MMBO from the San Andres ROZ (OOIP = 912 MMBO) if all areas of the reservoir are CO2 flooded. Figure 8 shows the oil producers with green dots, water injectors with blue triangles, and plugged wells with black dots. It is seen that there are many plugged wells in the northern and southern areas of EMSU therefore the central area is the preferred location to start the CO2 flood. The CO2 flood at EMSU will likely start on the western portion of the reservoir in sections 4, 5, 6, 7, 8, and 9 as seen in Figures 9 and 10, due to good reservoir characteristics and high remaining well count of producers and injectors.

Figure 8 – EMSU Map Showing Well Status



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Shown below in Figure 9 is the possible area for Phase 1 CO_2 development of the Grayburg at EMSU. It has twenty 80-acre 5-spot patterns (1600 acres) which would contain approximately 77.6 MMBO OOIP based on average reservoir properties shown in Table 1 on page 5. Assuming 15% OOIP EOR oil recovery during the CO_2 flood, this area will recover 11.64 MMBO. In addition to CO_2 flooding this area, a portion of the San Andres shown on Figure 10 will also be CO_2 flooded using the same facilities as the Grayburg. Sections 4 through 9 are labeled to indicate where the Grayburg patterns are located. Section 4 will be a good location to start the San Andres CO_2 flood because it is structurally high and contains 960 acres of ROZ interval. The yellow area of Figure 10 represents a subsea elevation of -400 feet, indicating gross oil column of 350 feet assuming -750 subsea for the oil-water contact. Assuming 75% net-to-gross, 35% oil saturation, and 10% porosity, the OOIP over this 960 acres will be approximately 57 MMBO. Based on 15% oil recovery, this would equate to 8.55 MMBO EOR oil. Total EOR oil recovery over this Grayburg and San Andres interval would be 20.19 MMBO.

Figure 9 – EMSU Map Showing Possible Phase 1 CO_2 Project Area

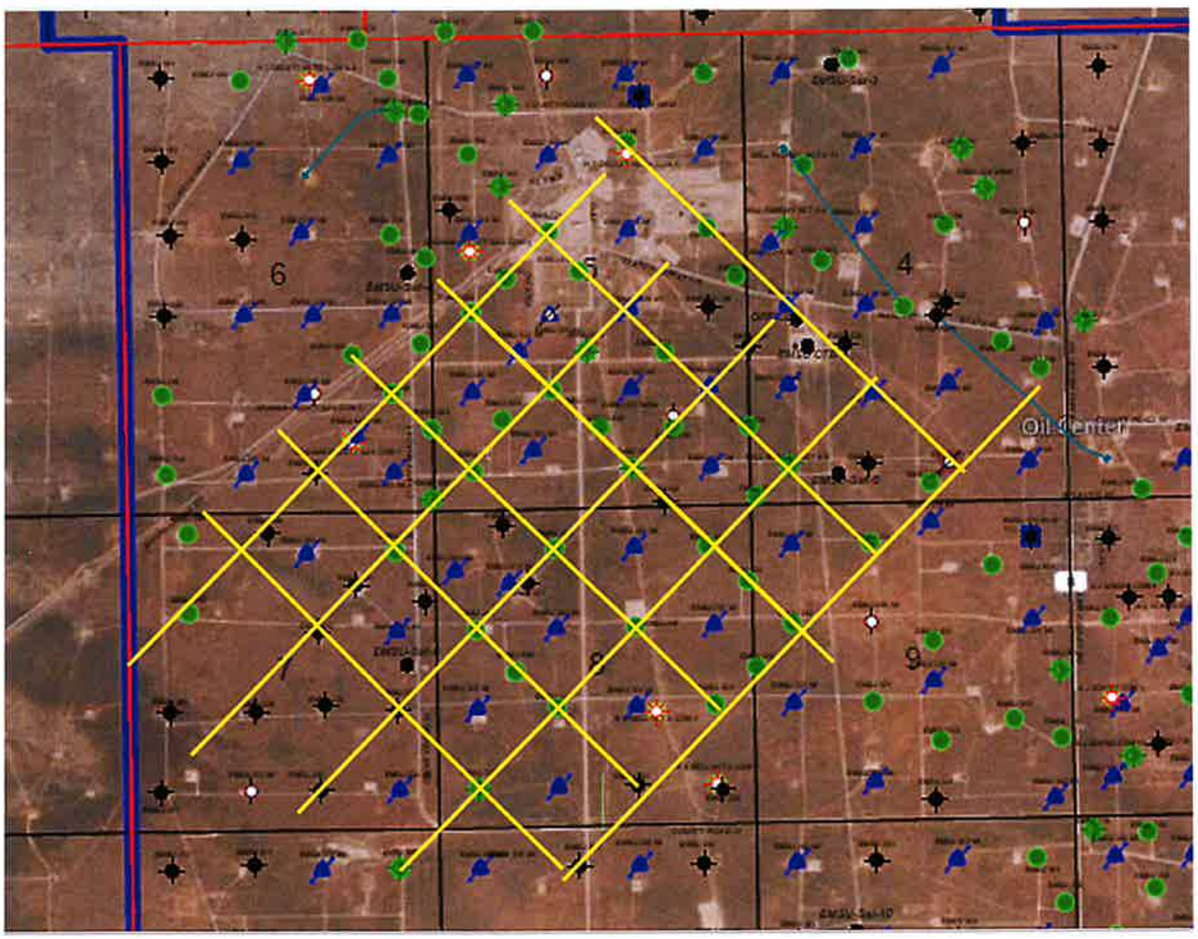
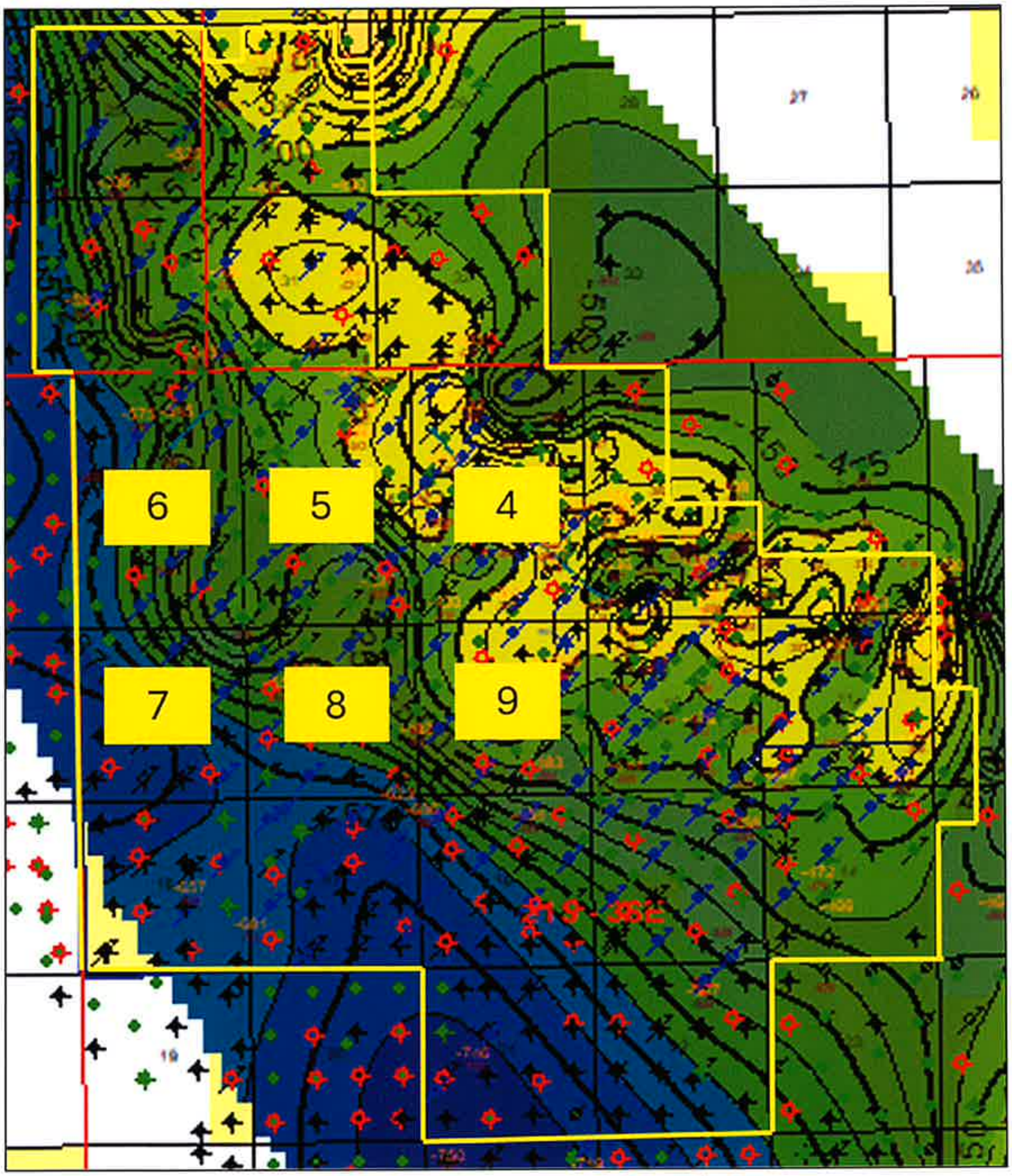


Figure 10 – Top of San Andres Interval with EMSU Unit Outline

(Highlights Sections 4, 5, 6, 7, 8, and 9 where Grayburg Phase 1 CO2 Project May Occur)



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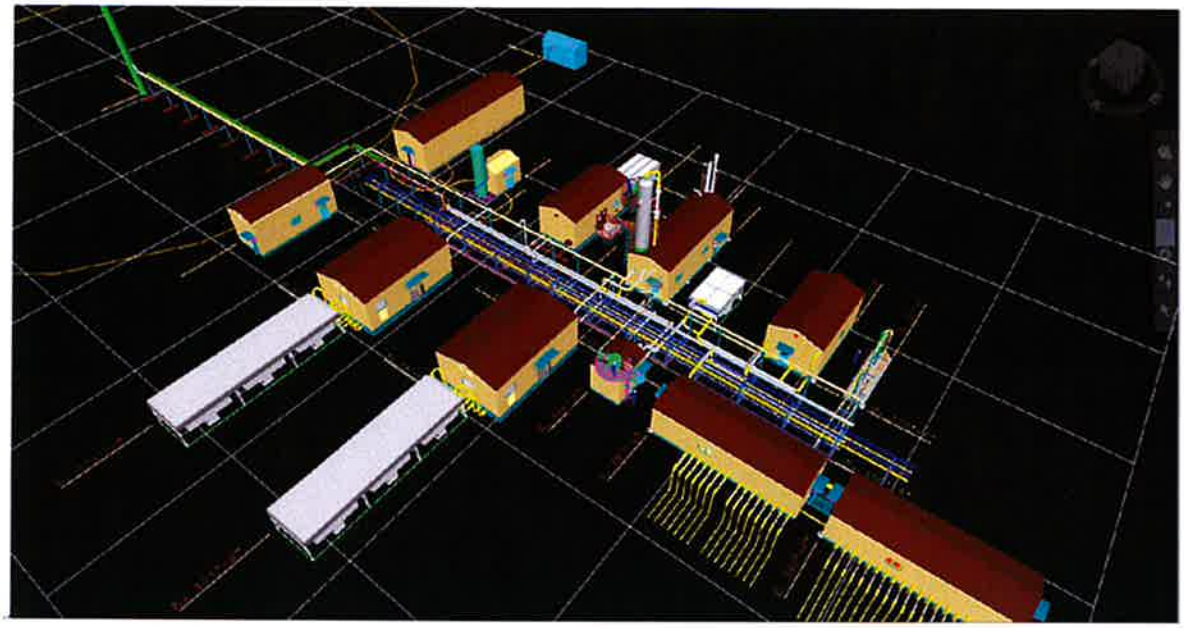
Capital Cost

Phase 1 of the CO_2 project will require that an 8-mile CO_2 pipeline be installed from Trinity Midstream's CO_2 pipeline running north-south east of EMSU at an estimated cost of $20 million. Based on 25 CO_2 injection wells, peak CO_2 injection could be 25 MMCFPD during Phase 1 and CO_2 recycle compression of 20 MMCFPD will be needed. Initial electrical driven compressor with 5 MMCFPD capacity has installed cost of $14.5 million. Gas driven compressors with 16.8 MMCFPD capacity can be installed for $5.5 million based on costs from another project so these will be utilized where possible to meet the CO_2 recycle gas demand. It is estimated that Phase 1 can recover 20 MMBO EOR oil which has a value of $1.5 billion based on $75/bbl so the CO_2 project can support this investment.

TABLE 18 – Phase 1 Capital Cost Estimate

Item	Number of Items	Cost Per Unit ($MM)	Total Cost ($MM)
CO2 Pipeline	8 miles	$2.5/mile	$20.00
Production Well Modifications	40 wells	$0.25/well	$10.00
Injection Well Modifications	25 wells	$0.30/well	$7.50
Drill New Producers and Injectors	10 wells	$1.0/well	$10.00
Injection Well Lines	25 wells	$0.20/well	$5.00
Production Well Lines	40 wells	$0.20/well	$8.00
Plug and Abandon	15 wells	$0.10/well	$1.50
CO2 Compressor and Well Header System	1	$14.50	$14.50
2nd Compressor	1	$5.00	$5.00
Dehydration Unit	1	$3.50	$3.50
Separators, Tanks	1	$10.00	$10.00
Fabrication	1	$10.00	$10.00
Electrical Upgrade	1	$3.50	$3.50
Engineering Survey	1	$0.50	$0.50
Right-of-Ways	1	$2.50	$2.50
Environmental	1	$1.00	$1.00
10% Contingencies			$11.25
Total			$123.75

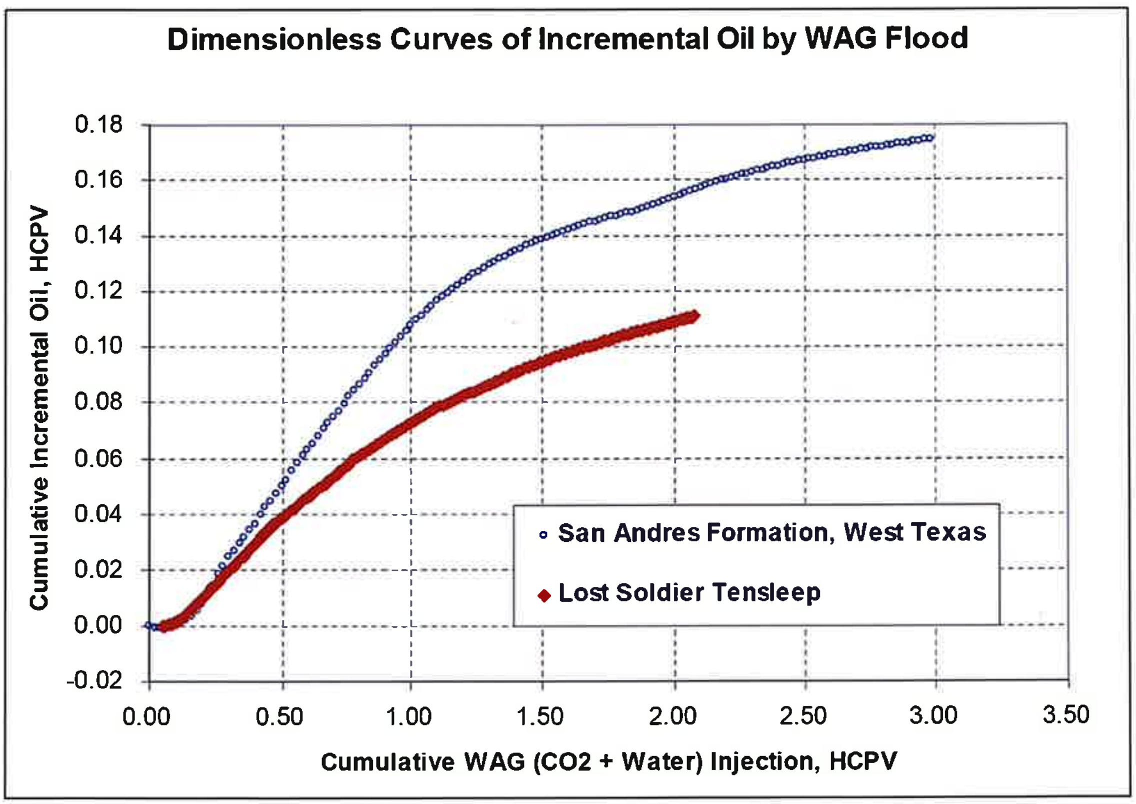
Figure 11 – Example CO2 Recycle Facility Layout



CO2 Oil Production Forecasting

The most common way to forecast oil production for a CO2 project is to use dimensionless curves (% OOIP oil recovered versus HCPV CO2 + water injected) which are developed for a typical pattern. Figure 12 shows a typical San Andres formation CO2 injection response where 3 HCPV's of CO2 and water injected, the pattern has produced 18% OOIP. This curve is included in a presentation entitled "CO2 Demand Estimates for Major Oil Fields in Wyoming Basins" by Shaochang Wo from University of Wyoming. It shows that the San Andres formation recovered more oil with the same amount of CO2 and water injected. Since we are dealing with the San Andres and Grayburg intervals, we use the top curve for our analysis.

Figure 12 – Dimensionless CO2-EOR Oil Recovery Curves



Hydrocarbon Pore Volume (HCPV) is calculated as the OOIP (Original Oil-in-Place) multiplied by the oil formation volume factor, providing the number of Reservoir Barrels the pattern will hold. After we inject 0.5 (or 50%) of a HCPV of CO2 into the pattern, the curve indicates that we will recover approximately 5.5% OOIP. After injecting one full HCPV (100%) we will have recovered approximately 11% OOIP and after 1.5 HCPV's (or 150%) we will have recovered 14% OOIP. If we continue to inject until we have injected 3 HCPV's, we can expect around 18% OOIP. This oil recovery in the incremental oil recovery as a result of CO2 injection and does not include the primary and waterflood oil already being produced.

For EMSU we indicated on page that for an 80-acre pattern we would expect an OOIP of 3.881 MMBO and a HCPV of 4.657 MMRB. The reservoir temperature at EMSU is 90^0 F so the table below indicates that at 1500 psia that it takes 2.29 MCF CO2 to fill up 1 reservoir barrel downhole in the well. So to fill up the entire HCPV of an 80-acre pattern, we have to the following:

80-acre HCPV of CO2 = 4.657 MMRB x 2.29 MCF/RB = 10.66 million MCF CO2 or 10.66 BCF

If we assume that we inject 2000 MCFPD (2 MMCFPD) per pattern, it will take 14.61 years to inject 1 HCPV in the 80-acre pattern. This explains why CO2 floods often take 30-40 years to complete and how important CO2 injection rate per well is a determining factor on process rate. For the San Andres, CO2 injection rate should not be a major issue based on water disposal rates currently being achieved by Goodnight Midstream Permian, LLC., whereas for the Grayburg interval it will be a concern especially if we do not inject into the high permeability layers within zones 1 and 2.

TABLE 19 – Properties of CO2 at 90^0 F and Various Pressures

Temperature	Pressure	Density	Compressibility	Heat Capacity	Heat Ratio	Velocity	Enthalpy	Entropy	Viscosity		Factor	Factor	Factor
F	PSIA	LB CF	FACTOR	BTU LB°F	CP/CV	Ft/Sec	BTU LB	BTU LB°F	cp	PHASE	CF/SCF	res bbl/Mcf	Mcf/res bbl
90	14.696	0.11016	0.99534	0.20501	1.2904	890.99	220.27	0.659	0.015281	V	1.053191	187.631126	
90	100	0.77098	0.9677	0.21456	1.3236	877.02	217.99	0.56949	0.015335	D	0.150479	26.808549	
90	200	1.5978	0.93386	0.22769	1.3702	860.03	215.16	0.53452	0.015425	D	0.072608	12.935534	
90	300	2.4918	0.89822	0.2436	1.4276	842.28	212.14	0.51223	0.015551	D	0.046558	8.294573	
90	400	3.4684	0.86042	0.26342	1.4999	823.61	208.89	0.49487	0.015722	D	0.033449	5.959133	
90	500	4.5494	0.81996	0.28895	1.5939	803.83	205.35	0.47996	0.015953	D	0.025501	4.543131	0.22
90	600	5.7675	0.77615	0.32338	1.7212	782.68	201.43	0.46626	0.016264	D	0.020115	3.583662	0.28
90	700	7.1751	0.72786	0.37291	1.9039	759.75	197.02	0.45299	0.016693	D	0.016169	2.880596	0.35
90	800	8.8656	0.67323	0.45147	2.1911	734.29	191.86	0.43938	0.017304	D	0.013086	2.331342	0.43
90	900	11.036	0.60842	0.59912	2.7194	704.78	185.49	0.42437	0.018243	D	0.010512	1.872809	0.53
90	1000	14.264	0.52303	1.0036	4.1019	666.45	176.54	0.40537	0.019964	D	0.008133	1.448969	0.69
90	1100	28.23	0.29071	29.72	76.332	524.55	145.76	0.34743	0.031977	D	0.00411	0.732150	1.37
90	1200	41.913	0.21361	1.4657	5.8064	889.39	126.09	0.31078	0.052356	D	0.002768	0.493143	2.03
90	1300	44.406	0.21841	1.0531	4.3873	1032.5	122.88	0.30416	0.057399	D	0.002613	0.465438	2.15
90	1400	46.013	0.227	0.89211	3.8143	1134.7	120.88	0.29978	0.060951	D	0.002521	0.449190	2.23
90	1500	47.232	0.23694	0.80189	3.4834	1216.7	119.41	0.29638	0.063826	D	0.002456	0.437602	2.29
90	1600	48.227	0.24752	0.74243	3.2601	1286.5	118.24	0.29355	0.0663	D	0.002406	0.428571	2.33
90	1700	49.075	0.25845	0.69951	3.0959	1348	117.28	0.29112	0.068502	D	0.002364	0.421173	2.37
90	1800	49.816	0.26958	0.66669	2.9683	1403.5	116.47	0.28895	0.070507	D	0.002329	0.414904	2.41
90	1900	50.478	0.28082	0.64059	2.8655	1454.3	115.77	0.287	0.07236	D	0.002298	0.409456	2.44
90	2000	51.077	0.29214	0.61921	2.7804	1501.3	115.15	0.28522	0.074091	D	0.002271	0.404663	2.47

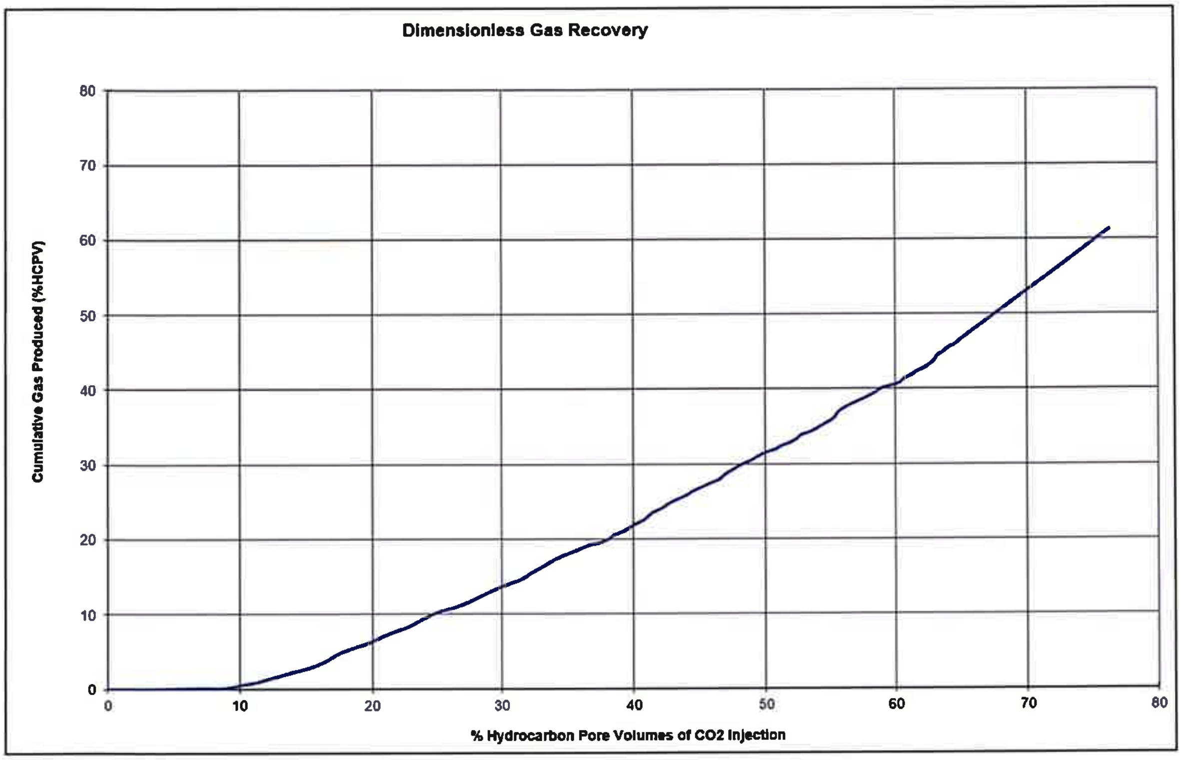
Another observation from this calculation is that we need 10.66 BCF CO2 to completely displace one 80-acre pattern. This CO2 would have to be purchased if not for CO2 being produced back by the producers. For Gulf Coast sandstones 5 to 6 HCPV's of CO2 is injected to recover 17% OOIP. Each well is capable of injecting 5-10 MMCFPD so it usually only takes 5 years to displace 1 HCPV and 25-30 years to complete the project. Depending on CO2 cost, the Operator may choose to not inject water In these high permeability sands and therefore the wells are able to flow at high pressure (>800 psi). After 1 HCPV most of the CO_2 injected is produced back so there is very little CO_2 purchase required. CO_2 net utilization (purchase) on these CO_2 floods is usually 10-15 MCF/BBL and Gross CO_2 utilization (Total CO_2 Injection) can be on the order of 50-100 MCF/BBL with lots of CO_2 recycle.

For West Texas, since the reservoirs are so large and CO_2 is more expensive, water is used to reduce the amount of CO_2 required to perform the CO_2 flood. The Operators often inject 30-40% of 1 HCPV of pure CO_2 and then begin injecting water on a 1 to 1 volume ratio with the CO_2 and then gradually taper off the CO_2 injected. For the 80-acre pattern example for EMSU, if we inject 30% of the HCPV with pure CO_2 at a rate of 2000 MCFPD (2 MMCFPD), it will take 4.38 years to reach the 30% HCPV slug and then we begin injecting water for one or two months followed by CO_2 for the same on one or two month cycles. This process is known as Water-Alternating-Gas (WAG) with a 1:1 WAG cycle. This 1:1 WAG is carried out for an extended period of time and then water may be injected for 2 months followed by CO_2 for 1 month in what is known as 2:1 WAG ratio. By tapering off on the CO_2 injected the Operator can reduce CO_2 purchase and allow the purchased CO_2 to be used for other patterns.

To calculate the amount of CO_2 produced over time, a dimensionless curve of Cumulative Gas Produced (% HCPV) versus HCPV's of CO_2 injected is developed using reservoir simulation or analogs to other CO_2 floods. The size of the pattern and thickness of the zone will impact this curve. Figure 13 is an example of how this curve should look. It can be seen that CO_2 breakthrough doesn't occur until approximately 10% of a HCPV of CO_2 is injected. For the 80-acre EMSU pattern this would mean that we will begin producing CO_2 after 1 BCF CO_2 is injected.

The chart shows that after 60% HCPV CO_2 (6.4 BCF) is injected, we will have produced 40% HCPV (4.27 BCF) back, resulting in 20% HCPV CO_2 (2.13 BCF) purchase. At $1.50/MCF the CO_2 purchase will cost $3.2 million.

Figure 13 – Dimensionless CO2 Production Curve



OCD 23614-17 03519

EMSU is developed on 40-acre spacing with the water injector located in the center of the 80-acre pattern as shown by the simplified drawing in Figure 14. Consideration will be given to converting the 80-acre patterns to 40-acre patterns for faster response during the pilot CO2 flood by drilling additional 20-acre injection wells and converting some producers to injectors and some injectors to producers as shown by Figure 15. A water curtain (row of water injectors) will be established around the 320-acre area to prevent CO2 movement outside the pattern. Four (4) new wells will be drilled, four (4) wells will be converted to producers, and eight (8) wells will be converted to water injectors.

Figure 14 – Simplified Map of 80-acre 5-spot Patterns

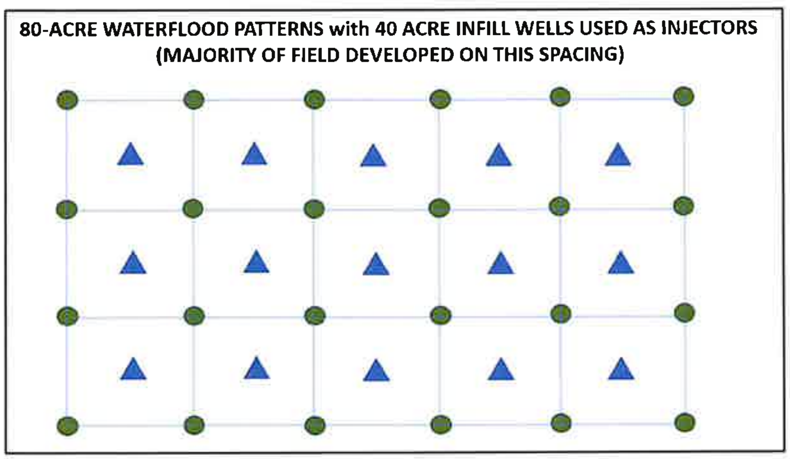
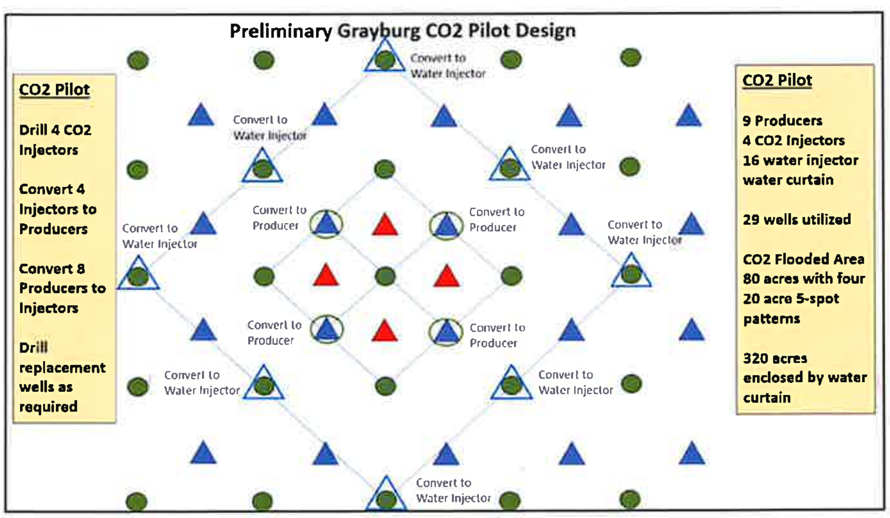


Figure 15 – Method to Convert Pattern to 40-acre 5-spot Patterns for CO2



OCD 23614-17 03520

Conclusions

EMSU, EMSU-B, and AGU waterflood units operated by Empire Petroleum have high remaining oil volumes which can be produced by CO2 injection. A CO2 pipeline within 8 miles of the field can be tied into to provide a reliable source of CO2. Design of the CO2 flood will take into account learnings from the waterflood where two high permeability intervals caused poor vertical sweep, with water bypassing the oil. Preliminary cost estimate of $124 million is required to initiate Phase 1 of the project where 20 MMBO will be recovered from the Grayburg and San Andres intervals.

The performance of Phase 1 will be based upon CO2 response obtained by injecting 25 MMCFPD CO2 into the Grayburg and San Andres patterns, and increasing CO2 injection as CO2 is produced back. This is a preliminary design and it will be refined during 2024-2025 by results of the infill drilling program.

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Goodnight Cross Exhibit 17

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2024

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ______________ to ______________

Commission File Number 001-16653

EMPIRE PETROLEUM CORPORATION

(Exact name of registrant as specified in its charter)

DELAWARE
(State or Other Jurisdiction of Incorporation or Organization)

73-1238709
(I.R.S. Employer Identification No.)

2200 S. Utica Place, Suite 150, Tulsa, OK 74114
(Address of Principal Executive Offices) (Zip Code)

Registrant's telephone number, including area code: **(539) 444-8002**

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Common Stock $0.001 par value	**EP**	**NYSE American**

Securities registered pursuant to 12(g) of the Act: None
(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. ☐ Yes ☑ No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. ☐ Yes ☑ No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. ☑ Yes ☐ No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). ☑ Yes ☐ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large accelerated filer ☐ Accelerated filer ☐ Non-accelerated filer ☑ Smaller reporting company ☑ Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Indicate by check mark whether the registrant has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☐

If securities are registered pursuant to Section 12(b) of the Act, indicate by check mark whether the financial statements of the registrant included in the filing reflect the correction of an error to previously issued financial statements. ☐

Indicate by check mark whether any of those error corrections are restatements that required a recovery analysis of incentive-based compensation received by any of the registrant's executive officers during the relevant recovery period pursuant to §240.10D-1(b). ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). ☐ Yes ☑ No

The aggregate market value of the voting and non-voting common equity held by non-affiliates, computed by reference to the closing sales price of such common equity as of the last business day of the registrant's most recently completed second fiscal quarter, was $72,446,281.

The number of shares of the registrant's common stock, $0.001 par value, outstanding as of March 25, 2025 was 33,700,234.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement relating to the registrant's 2025 annual meeting of stockholders have been incorporated by reference into Part III of this Annual Report on Form 10-K.

EMPIRE PETROLEUM CORPORATION
FORM 10-K
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FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report on Form 10-K constitute "forward-looking statements" within the meaning Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future by us or on our behalf. All statements, other than statements of historical facts, which address activities, events, or developments that Empire expects, believes, or anticipates will or may occur in the future, including future sources of financing and other possible business developments, are forward-looking statements.

By their very nature, forward-looking statements require management to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such forward-looking statements. Factors that could cause actual results to differ materially from the results discussed in such forward-looking statements include, but are not limited to, those discussed in Item 1A ("Risk Factors") and elsewhere in this Form 10-K and in other documents that we file with or furnish to the Securities and Exchange Commission (the "SEC"), and the following:

- changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids;
- our ability to replace reserves and efficiently develop current reserves;
- uncertainties inherent in estimating oil and gas reserves;
- management's ability to execute our business plan;
- delays and other difficulties related to producing oil, natural gas and natural gas liquids;
- delays and other difficulties related to regulatory and governmental approvals and restrictions;
- availability of sufficient capital to execute management's business plan, including future cash flows from operations, available borrowing capacity under revolving credit facilities, from our two largest stockholders and otherwise;
- management's ability to make acquisitions on economically acceptable terms and management's ability to integrate acquisitions;
- weather and environmental conditions;
- unforeseen engineering, mechanical or technological difficulties in working over wells;
- costs of operations and operating hazards;
- competition from other natural resource companies;
- unanticipated reductions in the borrowing base under the revolving credit facility we are party to;
- the availability of sufficient pipeline and other transportation facilities and equipment to carry our production to market and the impact of these facilities on our realized prices;
- our ability to retain key members of senior management and key technical and financial employees;
- the identification of and severity of adverse events and governmental responses to these or other environmental events;
- future Environmental, Social and Governance compliance developments and increased attention to such matters which could adversely affect our ability to raise equity and debt capital;
- the effect of our derivative activities;
- impacts of public health crises, pandemics and epidemics, such as the coronavirus pandemic ("COVID-19");
- A cyber incident involving our information systems and related infrastructure, or that of our business partners;
- the effects of governmental and environmental regulation; and
- general economic conditions including inflation, tariffs and interest rates.

All forward-looking statements are expressly qualified in their entirety by the cautionary statements in this section and elsewhere in this Form 10-K. Other than as required by applicable securities laws, we undertake no duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations, or otherwise. Readers should not place undue reliance on these forward-looking statements. All forward-looking statements speak only as of the date of this report or, if earlier, as of the date they were made.

GLOSSARY OF TERMS

The following are abbreviations and definitions of certain terms used within this Annual Report on Form 10-K.

ASC – Accounting Standards Codification.
ASU – Accounting Standards Update.
Basin – A large natural depression on the earth's surface in which sediments, generally brought by water, accumulate.
Bbl – One barrel or 42 U.S. gallons liquid volume of oil or other liquid hydrocarbons.
Boe – Barrel of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent. The ratio does not assume price equivalency and, given price differentials, the price for a barrel of oil equivalent for natural gas differs significantly from the price for a barrel of oil. A barrel of NGLs also differs significantly in price from a barrel of oil.
CG&A – Cawley, Gillespie & Associates, Inc.
Completion – The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.
DD&A – Depreciation, depletion and amortization.
Development Well – A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.
EPA – United States Environmental Protection Agency.
ESG – Environmental, Social and Governance.
Exploratory Well – A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, a well that is not a development well, a service well, or a stratigraphic test well.
FASB – Financial Accounting Standards Board.
Federal Deposit Insurance Corporation or **FDIC –** An independent agency created by the Congress to maintain stability and public confidence in the nation's financial system. The FDIC insures deposits; examines and supervises financial institutions for safety, soundness, and consumer protection; makes large and complex financial institutions resolvable; and manages receiverships.
Field – An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.
GHG – Greenhouse gas.
LOE – Lease Operating Expense, a current period expense incurred to operate a well.
MBbls – One thousand barrels of crude oil or other liquid hydrocarbons.
MBoe – One thousand barrels of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.
MMBoe – One million barrels of oil equivalent, determined using a ratio of six Mcf of natural gas equal to one barrel of oil equivalent.
Mcf – One thousand cubic feet.
MMcf – One million cubic feet.

National Institute of Standards and Technology or **NIST** – An agency of the United States Department of Commerce whose mission is to promote American innovation and industrial competitiveness.
Net acres or **net wells** – The sum of the fractional working interests owned in gross acres or gross wells.
New York Mercantile Exchange – A commodity futures exchange owned and operated by CME Group of Chicago.
NYSE American – NYSE American Stock Exchange.
NGLs – Natural gas liquids measured in barrels. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which have different uses and different pricing characteristics.
Net revenue interest or **NRI** –The total revenue interest controlled by an entity in a specific oil or gas production unit, including a well, lease, or drilling unit.
New Mexico Oil Conservation Division – The New Mexico Oil Conservation Division regulates oil and gas activity in New Mexico. The Division gathers well production data, permits new wells, enforces the division's rules and the state's oil and gas statutes, makes certain abandoned wells are properly plugged, and ensures the land is responsibly restored.
Operator – An oil and gas joint venture participant that manages the joint venture, pays venture costs, and bills the venture's non-operators for their share of venture costs. The operator is also responsible to market all oil, gas, and NGLs production, except for those non-operators who take their production in-kind.
OTCQB – The over-the-counter ("OTC") market exchange for the middle tier of three marketplaces for trading OTC stocks.
Overriding Royalty Interest or **ORRI** – A royalty interest that is created out of the operating or working interest. Unlike a royalty interest, an overriding royalty interest terminates with the operating interest from which it was created or carved out of.
Plugging and abandonment or **P&A** – Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another stratum or to the surface.

Proved developed producing reserves or **PDP** – Reserves that can be expected to be recovered from existing wells and completions with existing equipment and operating methods.
Proved undeveloped reserves – Reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required.
PV-10 – The present value, discounted at 10% per annum, of future net revenues (estimated future gross revenues less estimated future costs of production, development, and asset retirement costs) associated with reserves and is not necessarily the same as market value. PV-10 does not include estimated future income taxes. Unless otherwise noted, PV-10 is calculated using the pricing scheme required by the SEC. PV-10 of proved reserves is calculated the same as the standardized measure of discounted future net cash flows, except that the standardized measure of discounted future net cash flows includes future estimated income taxes discounted at 10% per annum.
Reasonable Certainty – A high degree of confidence.
Recompletion – The process of re-entering an existing wellbore that is either producing or not producing and completing in new reservoirs in an attempt to establish or increase existing production.
Reservoir – A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.
Royalty Interest or **RI** – The mineral owner's share of production, free of costs, but subject to severance taxes unless the lessor is a government.
SEC – United States Securities and Exchange Commission.
Standardized Measure – The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue.
Undeveloped acreage – Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.
Working interest or **WI** – The ownership interest, generally defined in a Joint Operating Agreement ("JOA"), that gives the owner the right to drill, produce and/or conduct operating activities on the property and share in the sale of production, subject to all royalties, overriding royalties and other burdens and obligates the owner of the interest to share in all costs of exploration, development operations and all risks in connection therewith.
Workover – Operations on a producing or injection well to restore or increase production.
WTI – West Texas Intermediate.
XTO – XTO Holdings, LLC, a subsidiary of ExxonMobil.

Energy equivalent is determined by using the ratio of one barrel of crude oil, condensate or NGLs to six Mcf of natural gas.

PART I

ITEM 1. BUSINESS.

In this Form 10-K, references to "Empire", the "Company", "we", "our", and "us" refer to Empire Petroleum Corporation and its wholly-owned subsidiaries, unless context indicates otherwise.

Overview

Empire Petroleum Corporation is an independent energy company that engages in unlocking value in developed assets. Empire operates the following wholly-owned subsidiaries in its areas of operations:

- Empire New Mexico LLC ("Empire New Mexico"), consisting of the following entities:
    - Empire New Mexico LLC d/b/a Green Tree New Mexico
    - Empire EMSU LLC
    - Empire EMSU-B LLC
    - Empire AGU LLC
    - Empire NM Assets LLC
- Empire North Dakota ("Empire North Dakota"), consisting of the following entities:
    - Empire North Dakota LLC ("Empire North Dakota")

- Empire ND Acquisition LLC ("Empire NDA")
- Empire Texas ("Empire Texas"), consisting of the following entities:
    - Empire Texas LLC
    - Empire Texas Operating LLC
    - Empire Texas GP LLC
    - Pardus Oil & Gas Operating, LP (owned 1% by Empire Texas GP LLC and 99% by Empire Texas LLC)
- Empire Louisiana LLC ("Empire Louisiana")

Empire was incorporated in the state of Delaware in 1985. The consolidated financial statements of Empire Petroleum Corporation and subsidiaries include the accounts of the Company and its wholly-owned subsidiaries.

Our mission is to increase shareholder value by building oil and natural gas reserves in strategic plays in the United States. To accomplish its mission, we plan to execute the following business strategies:

- Cost-effectively optimize well production
- Reduce unit operating costs and improve margins
- Target proved developed producing acquisitions in predictable fields that have historically had low production decline and long lives
- Focus on high-quality assets that add scale and provide synergies to our existing portfolio and core areas of operation

We operate as a single operating segment. For additional information, see Note 18 – Segment Reporting of Notes to Consolidated Financial Statements.

Available Information

Our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Exchange Act, as well as proxy statements and other information we file with, or furnish to, the SEC are available free of charge on our website at www.empirepetroleumcorp.com. We make these documents available as soon as reasonably practicable after we electronically file them with, or furnish them to, the SEC. The information contained on our website, or available by hyperlink from our website, is not incorporated into this Form 10-K or other documents we file with, or furnish to, the SEC. We intend to use our website as a means of disclosing material non-public information and for complying with our disclosure obligations under Regulation Fair Disclosure. Such disclosures will be included on our website in the "Investor Relations" sections. Accordingly, investors should monitor such portions of our website, in addition to following our press releases, SEC filings and public conference calls and webcasts.

In addition, we use social media to communicate with our investors and the public about our company, our businesses and our results of operations. The information we post on social media could be deemed to be material information. Therefore, we encourage investors, the media and others interested in our company to review the information we post on the social media channels listed in the "Investor Relations" section of our website.

Properties

We are an independent operator in four geographic areas in the United States. For our operated properties, we manage and influence production using a combination of experienced field personnel and third-party service providers to execute our mission. Our producing properties have reasonably predictable production profiles and cash flows, subject to commodity price and cost fluctuations.

As is common in the industry in which we operate, we selectively participate in drilling and developmental activities in non-operated properties. Decisions to participate in non-operated properties are made after technical and economic analysis of the projects which also considers the operating expertise and historical track record of the operators.

Empire New Mexico

Empire New Mexico was formed when we purchased producing assets from XTO in May 2021. These assets are located in Lea County, New Mexico, and include approximately 714 gross (529 net) producing and injection wells on a contiguous and consolidated acreage position consisting of 48,000 gross (41,000 net). We also have 15 royalty interest ("RI") wells with an average overriding royalty interest ("ORRI") of 0.6%. Empire New Mexico's assets primarily produce oil with accompanying natural gas and NGLs production. Empire New Mexico's properties are located in Grayburg/San Andres (primary source of production), Queen-Seven Rivers-Yates, Devonian, Abo, Blineberry, Tubb, and Drinkard formations.

Empire North Dakota

Empire North Dakota includes approximately 232 gross (108 net) producing or injection wells on 24,480 gross (18,480 net) acres in North Dakota and western Montana. We also have smaller nonoperating interests in 106 gross (less than 1 net) vertical wells. These properties primarily produce oil with some related gas production. Assets are located in Madison (primary source of production), Bakken, Duperow, Red River, and Ratcliffe/Mission Canyon formations.

The existing producing properties have experienced near-flat production rates over the last five years. We have been able to capitalize on operational improvements to allow a more immediate recovery of reserves.

In the fourth quarter of 2023, the Company commenced a program to further develop its Starbuck Field located in North Dakota (the "Starbuck Drilling Program"). The Starbuck Drilling Program's first well came online in December 2023 and a total of 13 wells in the Upper Charles formation have been placed in production as of the filing date of this report. The Company is currently optimizing completions while increasing the core production through its enhanced oil recovery ("EOR") program.

As the Starbuck Field is strategically designed for EOR production, the Company has experienced an increase in production throughout 2024 which is anticipated to continue into 2025.

Empire has also logged five vertical pilot wells to help identify additional pay and extend existing reservoirs, which has confirmed three additional primary zones of interest and two secondary zones of interest. In addition, the Company has drilled a vertical appraisal well in the Starbuck Field to core two new target zones for development. The two new primary target zones of development have been successfully cored and the cores are under analysis. The data will then be added to a future development plan while the vertical wells have been placed in production during 2024.

Empire Texas

Empire Texas includes approximately 119 gross (106 net) producing wells on approximately 43,000 gross (30,000 net) acres as well as 77 miles of gathering lines and pipelines with related facilities and equipment. Empire Texas owns concentrated acreage and stacked pay in the historically prolific East Texas Basin. Assets are concentrated in the Fort Trinidad Field in Houston and Madison Counties with high working interest and historical production from eight separate formations. We have begun technical work for uplift opportunities in Texas.

In the fourth quarter of 2024, the Company initiated a return-to-production program on four wells primarily focused on facility work on the existing saltwater disposal system.

Empire Louisiana

Empire Louisiana includes 7 gross (5 net) producing wells and three saltwater disposal wells in the Miocene, Frio, Cockfield, and Wilcox formations. Empire Louisiana's assets primarily produce oil.

Production and Operating Data

The following table sets forth a summary of our production and operating data. Because of normal production declines, increased or decreased production due to future acquisitions, divestitures, and development, fluctuations in commodity prices and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	For the Years Ended December 31,	
Production and operating data:	**2024**	**2023**
Net sales volumes:		
Oil (Bbl)	581,159	487,869
Natural gas (Mcf)	916,955	854,274
Natural gas liquids (Bbl)	150,091	136,013
Total (Boe)	884,076	766,261
Average price per unit:		
Oil (1)	$ 71.44	$ 75.19
Natural gas	$ 0.37	$ 2.02
Natural gas liquids	$ 14.21	$ 12.21
Total (Boe)	$ 49.76	$ 52.29
Operating costs and expenses per Boe:		
Lease operating expense (excluding workovers)	$ 24.46	$ 21.70
Workovers	$ 6.71	$ 15.65
Total Lease operating expense	$ 31.16	$ 37.36
Production and ad valorem taxes	$ 4.26	$ 3.97
Depreciation, depletion, amortization and accretion	$ 12.74	$ 6.33
General & administrative (excluding stock-based compensation)	$ 14.23	$ 15.71
Stock-based compensation	$ 2.44	$ 4.10
Total General & administrative	$ 16.67	$ 19.81

(1) Excludes the effect of net cash receipts from (payments on) derivatives.

At December 31, 2024 and 2023, we had approximately 1,072 gross (748 net) producing and injection wells.

We have no firm delivery commitments for oil or natural gas.

Oil and Natural Gas Reserves

Our primary mission is to optimize existing producing properties; as such, there are no reserves estimated for undeveloped properties, though we own acreage that can be drilled in the future and are also a non-operator WI owner on acreage subject to future drilling activities. The following table represents our oil and natural gas reserves:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total MBoe
Proved developed at December 31, 2024	7,001	6,064	1,215	9,227
Proved developed at December 31, 2023	6,924	6,104	1,171	9,112

Net proved reserves were calculated using an unweighted arithmetic average of the first-day-of-the-month price within the 12-month period for the year. All prices and costs associated with operating wells were held constant in accordance with SEC guidelines. Prices of $71.66 per barrel of oil, $0.95 per Mcf and $24.54 per barrel of NGLs were utilized at December 31, 2024. Prices of $75.45 per barrel of oil, $1.51 per Mcf and $9.82 per barrel of NGLs were utilized at December 31, 2023.

Reserve Estimation Process

Reserve estimation is a subjective process as the underground accumulations of crude oil and natural gas cannot be measured in an exact manner, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves depend on several variable factors, including but not limited to historical production from the area compared with production from other producing areas, and assumptions about: reservoir size; the effects of regulations by governmental agencies; future oil and natural gas prices; future operating costs; severance and excise taxes; operational risks; development costs and workover and remedial costs.

Some or all of these assumptions may vary considerably from actual results. For these and other reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any group of properties, classifications of those oil and natural gas reserves based on the risk of recovery, and estimates of the future net cash flows from oil, and natural gas reserves prepared by different engineers or by the same engineers but at different times may vary substantially. Such estimates may be subject to periodic downward or upward adjustments. Actual production, revenues, and expenditures regarding our oil, NGLs, and natural gas reserves will likely vary from estimates, and those variances may be material.

We engage and consult with an independent petroleum engineering firm, CG&A, to prepare our annual reserve estimates and rely on CG&A's expertise to ensure that reserve estimates are prepared in accordance with SEC guidelines. The technical person primarily responsible for the preparation of the reserve report is Zane Meekins, Executive Vice President. Mr. Meekins has been with CG&A since 1989 and graduated from Texas A&M University in 1987 with a bachelor's degree in petroleum engineering. He is a registered professional engineer in Texas and has more than 30 years of experience in the estimation and evaluation of oil and natural gas reserves. He is also a member of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers.

The primary inputs to the reserve estimation process are technical information, financial data, ownership interest and production data. The relevant field and reservoir technical information, which is updated at least annually, is assessed for validity when CG&A has technical meetings with our personnel. Our accounting records, operational data and well information used in the reserve estimation process are subject to internal and external quarterly reviews, annual audits, and internal controls over financial reporting. Our reserves database is updated and maintained by our Senior Reserves Engineer who has the appropriate technical qualifications to maintain and assist in the preparation of reserve estimates. The Senior Reserves Engineer has over 40 years of industry experience, a degree in engineering from Tulane University in 1978, a licensed professional, and holds several memberships in professional petroleum engineer organizations. Once the reserves database has been appropriately updated, Empire will meet with CG&A who will then review the relevant information and validate the estimates. CG&A will work with the Senior Reserves Engineer to resolve any differences in reserve estimates. CG&A will then finalize the reserve report once any differences are resolved and provide a final report to the Company.

Marketing Arrangements

We market our oil and natural gas in accordance with standard energy industry practices. This marketing effort endeavors to obtain the combined highest netback and most secure market available at that time.

We sell oil production at the lease locations to third-party purchasers via truck transport or pipeline. We do not transport, refine or process the oil we produce. We sell our produced oil under contracts using market-based pricing, which is adjusted for differentials based upon oil quality.

We sell our natural gas and NGLs under purchase contracts using market-based pricing, which is primarily sold at the lease location.

Principal Customers

We sell our oil, natural gas, and NGLs production to marketers which is transported by truck or pipeline to storage facilities arranged by the marketers. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted.

For 2024, 78% of revenues from oil, natural gas, and NGLs sales were to four customers. For 2023, 70% of revenues from oil, natural gas, and NGLs sales were to four customers. No other purchaser accounted for more than 10% of our total revenues during the respective periods. While the loss of these purchasers may result in a temporary interruption in sales of, or a lower price for, our production, we believe that the loss of these purchasers would not have a material adverse effect on our operations, as there are alternative purchasers in our producing regions.

Competition

The oil and natural gas industry in the areas in which we operate is highly competitive. We encounter strong competition from numerous parties, ranging generally from small independent producers to major integrated companies. We primarily encounter significant competition in acquiring properties. At higher commodity prices, we also face competition in contracting for oil field services, rigs, pressure pumping and workover equipment, and securing trained personnel. Many of these competitors have financial, technical and personnel resources substantially larger than ours. As a result, our competitors may be able to pay more for desirable properties, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

In addition to competition for drilling, pressure pumping and workover equipment, we are also affected by the availability of related equipment and materials. The oil and natural gas industry periodically experiences shortages of drilling and workover rigs, equipment, pipe, materials, and personnel, which can delay workover and exploration activities and cause significant price increases. We are unable to predict the timing or duration of any such shortages.

Seasonality of Business

Weather conditions often affect the demand for, and prices of, natural gas and can also delay oil and natural gas production. Demand for natural gas is traditionally higher in the winter, resulting in higher natural gas prices during the first and fourth quarters. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results realized on an annual basis.

Markets and Price Volatility

The market price of oil and natural gas is volatile, subject to speculative movement and depends upon numerous factors beyond our control, including expectations regarding inflation, global and regional demand, political and economic conditions and production costs. Future profitability, if any, will depend substantially upon the prevailing prices for oil and natural gas. If the market price for oil and natural gas remains depressed in the future, it could have a material adverse effect on our ability to raise the additional capital necessary to finance operations. Lower oil and natural gas prices may also reduce the amount of oil and natural gas, if any, that can be produced economically from our properties. We anticipate that the prices of oil and natural gas will fluctuate in the near future.

Title to Properties

Our title to properties are subject to royalty, overriding royalty, carried, net profits, working and other similar interests and contractual arrangements customary in the oil and natural gas industry, to liens for current taxes not yet due and to other encumbrances. As is customary in the industry in the case of undeveloped properties, only cursory investigation of record title is made at the time of acquisition. Drilling title opinions are usually prepared before commencement of drilling operations. We believe we have satisfactory title to substantially all of our active properties in accordance with standards generally accepted in the natural gas and oil industry. Nevertheless, we are involved in title disputes from time to time that may result in litigation.

Regulation

The oil and natural gas industry is subject to extensive federal, state and local laws and regulations governing the production, transportation and sale of hydrocarbons as well as the taxation of income resulting therefrom. Legislation affecting the oil and natural gas industry is constantly changing. Numerous federal and state departments and agencies have issued rules and regulations applicable to the oil and natural gas industry. In general, these rules and regulations regulate, among other things, the extent to which acreage may be acquired or relinquished; spacing of wells; measures required for preventing waste of oil and natural gas resources; and, in some cases, rates of production. The heavy and increasing regulatory burdens on the oil and natural gas industry increase our cost of doing business and, consequently, affect profitability.

The Comprehensive Environmental, Response, Compensation, and Liability Act ("CERCLA"), also known as the Superfund law, and comparable state statutes impose strict, joint and several liabilities on owners and operators of sites and on persons who disposed of or arranged for the disposal of "hazardous substances" found at such sites. These persons include the owner or operator of the site where the release occurred, persons who disposed or arranged for the disposal of hazardous substances at the site, and any person who accepted hazardous substances for transportation to the site. CERCLA authorizes the EPA, state environmental agencies, and in some cases third parties, to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for the neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Although CERCLA currently excludes petroleum from its definition of "hazardous substance," state laws affecting our operations may impose clean-up liability relating to petroleum and petroleum related products.

Our oil and natural gas operations are also subject to numerous federal, state and local laws and regulations relating to environmental protection. These laws govern, among other things, the amounts and types of substances and materials that may be released into the environment, the issuance of permits in connection with exploration, drilling and production activities, the reclamation and abandonment of wells and facility sites and the remediation of contaminated sites. These laws and regulations may impose substantial liabilities if we fail to comply or if any contamination results from our operations.

Various state governments and regional organizations comprising state governments have enacted legislation and promulgated rules restricting GHG emissions or promoting the use of renewable energy, and additional such measures are frequently under consideration. Although it is not possible at this time to estimate how potential future requirements addressing GHG emissions would impact operations on the Company properties and revenue, either directly or indirectly, any future federal, state or local laws or implementing regulations that may be adopted to address GHG emissions could require the operators of our properties to incur new or increased costs to obtain permits, operate and maintain equipment and facilities, install new emission controls, acquire allowances to authorize GHG emissions, pay taxes related to GHG emissions or administer a GHG emissions program. Regulation of GHGs could also result in a reduction in demand for and production of oil and natural gas. Additionally, to the extent that unfavorable weather conditions are exacerbated by global climate change or otherwise, the Company properties may be adversely affected to a greater degree than previously experienced.

Our sales of crude oil are affected by the availability, terms, and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission ("FERC"), regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors. Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by pro-rationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Employees

At December 31, 2024, we had 63 full-time employees, not including contract personnel and outsourced service providers. Our team is broadly experienced in oil and natural gas operations and follows a strategy of outsourcing most accounting, human resources, and other non-core functions.

Office Locations

Our corporate headquarters are at 2200 South Utica Place, Suite 150, Tulsa, Oklahoma, with field offices in North Dakota, Texas, and New Mexico.

ITEM 1A. RISK FACTORS.

Our operations are subject to various risks and uncertainties in the ordinary course of business. The following summarizes significant risks and uncertainties that may adversely affect our operations or financial position. Risks and uncertainties discussed below are not a comprehensive listing of those faced by us. Additional risks not presently known or that are deemed immaterial may also affect us. Readers should carefully consider the risk factors included below and other information included and incorporated by reference into this Annual Report on Form 10-K.

Reserves

The Standardized Measure of estimated reserves may not be accurate estimates of the current fair value of estimated proved oil and natural gas reserves.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. This measure requires the use of operating and development costs prevailing as of the date of computation. Consequently, it will not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may they reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included in this report of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the 10 percent discount factor, which is required by the rules and regulations of the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Therefore, the Standardized Measure included in this report should not be construed as an accurate estimate of the current market value of our proved reserves.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities of our proved reserves and future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. Estimates of proved reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate. Petroleum engineering is a subjective process of estimating accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;
- the assumed effects of regulations by governmental agencies;
- the quality, quantity and interpretation of available relevant data;
- assumptions concerning future commodity prices; and
- assumptions concerning future operating costs, severance and ad valorem taxes, development costs and workover costs including remediation.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of oil and natural gas that are ultimately recovered;
- the production and operating costs incurred;
- the amount and timing of future development expenditures; and
- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on the average previous twelve months first-of-month prices preceding the date of the estimate and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;
- levels of future capital spending;
- increases or decreases in the supply of or demand for oil, natural gas, and NGLs; and
- changes in governmental regulations or taxation.

Accordingly, estimates included in this report of future net cash flows may be materially different from the future net cash flows that are ultimately received. Therefore, the estimates of discounted future net cash flows in this report should not be construed as accurate estimates of the current market value of our proved reserves.

Unless reserves are replaced, production and estimated reserves will decline, which may adversely affect our financial condition, results of operations and/or cash flows.

Producing oil and natural gas reservoirs are generally characterized by declining production rates that may vary depending upon reservoir characteristics and other factors. Estimates of the decline rate of an oil or natural gas well are inherently imprecise and may be less precise with respect to new or emerging oil and natural gas formations with limited production histories than for more developed formations with established production histories. Estimated future oil and natural gas reserves and production and, therefore, cash flows and results of operations are highly dependent upon our success in efficiently developing and exploiting current properties and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, cash flows and the value of reserves may decrease, adversely affecting our business, financial condition and results of operations.

New technologies may cause our exploration and development methods to become obsolete, causing an adverse effect on our production.

Our industry is subject to rapid and significant technological advancements, including the introduction of new products and services using new technologies. As competitors use or develop new technologies, we may be at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, our competitors may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may allow them to implement new technologies before we can. We cannot be sure that we can implement technologies timely or at an acceptable cost. One or more technologies we use or that we may implement may become obsolete or may not work as we expected, and we may be hurt financially and operationally as a result.

Financing

We have indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse business developments.

Our total indebtedness at December 31, 2024, was $11.3 million. At December 31, 2024, commitments from a financial institution under a Revolving Credit Facility (the "Credit Facility") with Empire North Dakota and Empire NDA were approximately $19.8 million, of which approximately $8.7 million was unused and approximately $11.1 million was outstanding. Management continues to review existing indebtedness, and may seek to repay, refinance, repurchase, redeem, exchange or otherwise terminate existing indebtedness. If we do seek to refinance existing indebtedness, there can be no guarantee that we would be able to execute the refinancing on favorable terms or at all.

As a result of indebtedness, we use a portion of our cash flow to pay interest, which reduces the amount available to fund operations and other business activities and could limit flexibility in planning for or reacting to changes in the business and the industry in which we operate. Indebtedness under the Credit Facility is at a variable interest rate, and so a rise in interest rates will generate greater interest expense.

We may incur substantially more debt in the future. The Credit Facility contains restrictions on the incurrence of additional indebtedness.

Increases in the level of indebtedness could have adverse effects on our financial condition and results of operations, including:

- imposing additional cash requirements on us in order to support interest payments, which reduces the amount we have available to fund our operations and other business activities;

- increasing the risk that we may default on our debt obligations;

- increasing our vulnerability to adverse changes in general economic and industry conditions, economic downturns and adverse developments in our business;
- limiting our ability to sell assets, engage in strategic transactions or obtain additional financing for working capital, capital expenditures, general corporate and other purposes;
- limiting our flexibility in planning for or reacting to changes in our business and the industry in which we operate; and
- increasing our exposure to a rise in interest rates, which will generate greater interest expense.

Our ability to meet our debt obligations and reduce our level of indebtedness depends on future performance, which is affected by general economic conditions and financial, business and other factors, many of which are outside of the scope of management's control.

Our business requires substantial capital expenditures. Management may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in oil and natural gas reserves.

The oil and natural gas industry is capital intensive. Management makes and expects to continue to make substantial capital expenditures for the acquisition and development of reserves. We intend to finance future capital expenditures through cash flow from operations, incurring additional indebtedness, or capital raises. However, cash flow from operations and access to capital are subject to a number of variables, including:

- the volume of oil, natural gas, and NGLs we are able to produce from existing wells;
- ability to transport oil and natural gas to market;
- the prices at which commodities are sold;
- the costs of producing oil and natural gas;
- global and domestic demand for oil and natural gas;
- global credit and securities markets;
- the ability and willingness of lenders and investors to provide capital and the cost of the capital;
- ability to acquire, locate and produce new reserves;
- the impact of potential changes in our credit ratings; and
- proved reserves.

We may not generate expected cash flows and obtain the capital necessary to sustain our operations at current or anticipated levels. A decline in cash flow from operations or our financing needs may require management to revise our capital program or alter or increase capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under the Credit Facility or the issuance of additional debt securities will require that a greater portion of cash flow from operations be used for the payment of interest and principal on debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, management may curtail activities or be forced to sell some assets on an untimely or unfavorable basis.

The loss or unavailability of capital provided by our two largest stockholders could have a material adverse effect on our business.

Our two largest stockholders, Energy Evolution Master Fund, Ltd. ("Energy Evolution") and Phil Mulacek, have been a significant source of capital for our acquisitions of oil and natural gas properties and the development of our oil and natural gas reserves. We have been dependent on this capital to fund our growth plans, including our current drilling programs. The loss of this capital could have a material adverse effect on our business, especially our growth plans.

If we are unable to comply with the covenants in our agreements governing our indebtedness, including the Credit Facility, there could be a default under the terms of such agreements, which could result in an acceleration of payment of funds that we have borrowed.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which management is unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional equity on terms that we may not find attractive if it may be done at all. If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest, if any, on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the agreements governing our indebtedness, including the Credit Facility, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default:

- the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;
- the lenders could elect to terminate their commitments thereunder and cease making further loans; and
- we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may need to obtain waivers under the Credit Facility, and have done so in the past, to avoid being in default. If we breach our covenants and cannot obtain a waiver from the required lender, we would be in default and the lender could exercise its rights, as described above, and we could be forced into bankruptcy or liquidation.

A negative shift in stakeholder sentiment towards the oil and natural gas industry and increased attention to ESG matters and conservation matters could adversely affect our ability to raise equity and debt capital.

Much of the investor community has developed negative sentiment towards investing in our industry over the past few years. Recent equity returns in the sector versus other industry sectors have led to lower oil and gas representation in certain key equity market indices. Some investors, including certain public and private fund management firms, pension funds, university endowments and family foundations, have stated policies to reduce or eliminate their investments in the oil and natural gas sector based on environmental, social and governance considerations. Certain other stakeholders have pressured private equity firms and commercial and investment banks to stop funding oil and gas projects. Such developments have resulted and could continue to result in downward pressure on the stock prices of oil and natural gas companies, including ours. This may also result in a reduction of available capital funding for potential development projects, further impacting our future financial results.

Increasing attention to climate change, societal expectations on companies to address climate change, investor and societal expectations regarding voluntary ESG disclosures, and consumer demand for alternative forms of energy may result in increased costs, reduced demand for our products, reduced profits, increased investigations and litigation, and negative impacts on our stock price and access to capital markets. Increasing attention to climate change and environmental conservation, for example, may result in demand shifts for oil and natural gas products and additional governmental investigations and private litigation against us or our operators. To the extent that societal pressures or political or other factors are involved, it is possible that such liability could be imposed without regard to our causation of or contribution to the asserted damage, or to other mitigating factors.

Moreover, while we may create and publish voluntary disclosures regarding ESG matters from time to time, many of the statements in those voluntary disclosures are based on hypothetical expectations and assumptions that may or may not be representative of current or actual risks or events or forecasts of expected risks or events, including the costs associated therewith. Such expectations and assumptions are necessarily uncertain and may be prone to error or subject to misinterpretation given the long timelines involved and the lack of an established single approach to identifying, measuring and reporting on many ESG matters.

In addition, organizations that provide information to investors on corporate governance and related matters have developed ratings processes for evaluating companies on their approach to ESG matters. Currently, there are no universal standards for such scores or ratings, but the importance of sustainability evaluations is becoming more broadly accepted by investors and stockholders. Such ratings are used by some investors to inform their investment and voting decisions. Unfavorable ESG ratings and recent activism directed at shifting funding away from companies with energy-related assets could lead to increased negative investor sentiment toward us and our industry and to the diversion of investment to other industries, which could have a negative impact on our access to and costs of capital. Also, institutional lenders may decide not to provide funding for fossil fuel energy companies based on climate change related concerns, which could affect our access to capital for potential growth projects.

General Operations

The oil and natural gas industry is highly competitive, and our size may put us at a disadvantage in competing for resources.

The oil and natural gas industry is highly competitive where our properties and operations are concentrated. We compete with major integrated and larger independent oil and natural gas companies in seeking to acquire desirable oil and natural gas properties and leases and for the equipment and services required to develop and operate properties. Many of our competitors have financial and other resources that are substantially greater than ours, which makes acquisitions of acreage or producing properties at economic prices difficult. Significant competition also exists in attracting and retaining technical personnel, including geologists, geophysicists, engineers, landmen and other specialists, as well as financial and administrative personnel. Hence, we may be at a competitive disadvantage to companies with larger financial resources than ours.

A substantial or extended decline in oil and natural gas prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

- changes in global supply and demand for oil and natural gas, which could be negatively affected by concerns about public health crises, pandemics and epidemics, such as the COVID-19 pandemic;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including trade or other economic sanctions, armed conflict in Ukraine and the Middle East, the price cap on Russian oil and embargoes, in or affecting other oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions, including extreme climatic events;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. Lower prices also negatively impact the value of our proved reserves. Volatility in the price of oil could force us, as well as other operators, to re-evaluate our current capital expenditure budget and make changes accordingly that we believe are in the best interest of us and our stockholders. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our producing properties and proved reserves are concentrated in New Mexico, North Dakota, Montana, Texas, and Louisiana, making us vulnerable to risks associated with operating in limited major geographic areas.

Our producing properties are geographically concentrated in New Mexico, North Dakota, Montana, Texas, and Louisiana. At December 31, 2024, all of our total estimated proved reserves were attributable to properties located in these areas. As a result of this concentration, we are exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by governmental regulation, processing or transportation capacity constraints, market limitations, severe weather events, water shortages or other drought related conditions or interruption of the processing or transportation of oil or natural gas.

This concentration of assets exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

A significant portion of our oil, natural gas, and NGLs sales are concentrated in only a few purchasers, which increases our exposure to substantial sales interruptions.

For the year ended December 31, 2024, the Company sold 78% of its oil, natural gas, and NGLs revenues to four customers. No other customer made up more than 10%. As a result of this concentration, we are exposed to the impact of our sales if one of these customers fails to meet their obligations or ceases its relationship with the Company. The loss in revenues may result in a disruption in the Company's cash flows limiting the ability to meet its obligations or investing in capital projects.

Our insurance policies may not adequately protect us against certain unforeseen risks.

In accordance with customary industry practice, we maintain insurance against some, but not all, of the risks described in this report. There can be no assurance that any insurance will be adequate to cover our losses or liabilities. We cannot predict the continued availability of insurance, or its availability at premium levels that justify its purchase.

Hedging transactions may expose us to risk of financial loss or limit participation in commodity price increases and involve other risks.

While intended to reduce the effects of volatile oil and natural gas prices, derivative contracts designed as hedges expose us to risk of financial loss in some circumstances, including when there is a change in the expected differential between the underlying price in the derivative contract and actual prices received, or when the counterparty to the derivative contract defaults on its contractual obligations. It is also possible that sales volumes fall below the hedged volumes leaving a portion of our position uncovered.

Alternatively, to the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may be prevented from fully realizing the benefits of commodity price increases above the prices established by our derivative contracts. Moreover, many of our contract counterparties have become subject to increasing governmental oversight and regulations in recent years, which could adversely affect the cost and availability of our hedging arrangements.

We are subject to various environmental risks, and governmental regulation relating to environmental matters.

We are subject to a variety of federal, state and local governmental laws and regulations related to the storage, use, discharge and disposal of toxic, volatile or otherwise hazardous materials. These regulations subject us to increased operating costs and potential liability associated with the use and disposal of hazardous materials. Although these laws and regulations have not had a material adverse effect on our financial condition or results of operations, there can be no assurance that we will not be required to make material expenditures in the future. Moreover, we anticipate that such laws and regulations will become increasingly stringent in the future, which could lead to material costs for environmental compliance and remediation by us. Any failure by us to obtain required permits for, control the use of, or adequately restrict the discharge of hazardous substances under present or future regulations could subject us to substantial liability or could cause our operations to be suspended. Such liability or suspension of operations could have a material adverse effect on our business, financial condition and results of operations.

Our activities are subject to extensive governmental regulation. Oil and natural gas operations are subject to various federal, state and local governmental regulations that may be changed from time to time in response to economic or political conditions. From time to time, regulatory agencies have imposed price controls and limitations on production in order to conserve supplies of oil and natural gas. In addition, the production, handling, storage, transportation and disposal of oil and natural gas, by-products thereof and other substances and materials produced or used in connection with oil and natural gas operations are subject to regulation under federal, state and local laws and regulations primarily relating to protection of human health and the environment. To date, expenditures related to complying with these laws and for remediation of existing environmental contamination have not been significant in relation to our operations. There can be no assurance that the trend of more expansive and stricter environmental legislation and regulations will not continue.

If forecasted prices for oil, natural gas, and NGLs decrease, we may be required to take significant future write-downs of the financial carrying values of our properties in the future.

Accounting rules require that we periodically review the carrying value of our proved and unproved properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to significantly write-down the financial carrying value of our oil and natural gas properties, which constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are recorded.

A write-down could occur when oil and natural gas prices are low or if we have substantial downward adjustments to our estimated proved oil and natural gas reserves, or if operating costs or development costs increase over prior estimates.

The capitalized costs of our oil and natural gas properties, on a field-by-field basis, may exceed the estimated future net cash flows of that field. If so, we would record impairment charges to reduce the capitalized costs of such field to our estimate of the field's fair market value. Unproved properties are evaluated at the lower of cost or fair market value. These types of charges will reduce our earnings and stockholders' equity and could adversely affect our stock price.

We periodically assess our properties for impairment based on future estimates of proved and unproved reserves, oil and natural gas prices, production rates and operating, development and reclamation costs based on operating budget forecasts. Once incurred, an impairment charge cannot be reversed at a later date even if price increases of oil and/or natural gas occur and in the event of increases in the quantity of our estimated proved reserves.

If oil, natural gas and NGLs prices fall below current levels for an extended period of time and all other factors remain equal, we may incur impairment charges in the future. Such charges could have a material adverse effect on our results of operations for the periods in which they are recorded.

Properties we acquire may not produce as projected and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain and include properties with which we do not have a long operational history. In connection with the assessments, we perform a review of the subject properties, but such a review will not reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of a property. We may be required to assume the risk of the physical condition of properties in addition to the risk that they may not perform in accordance with our expectations. If properties we acquire do not produce as projected or have liabilities we were unable to identify, we could experience a decline in our reserves and production, which could adversely affect our business, financial condition and results of operations.

Many of our properties are in areas that may have been partially depleted or drained by offset wells and certain of our wells may be adversely affected by actions we or other operators may take when drilling, completing, or operating wells that we or they own.

Many of our properties are in reservoirs that may have already been partially depleted or drained by earlier offset drilling. The owners of leasehold interests adjoining any of our properties could take actions, such as drilling and completing additional wells, which could adversely affect our operations. When a new well is completed and produced, the pressure differential in the vicinity of the well causes the migration of reservoir fluids toward the new wellbore and potentially away from existing wellbores. As a result, the drilling and production of these potential locations by us or other operators could cause depletion of our proved reserves and may inhibit our ability to further develop our proved reserves. In addition, completion operations and other activities, including water disposal activities, conducted on adjacent or nearby wells could cause production from our wells to be shut in for indefinite periods of time, could result in increased lease operating expenses and could adversely affect the production and reserves from our wells after they re-commence production. We have no control over the operations or activities of offsetting operators.

Acquisitions involve a number of risks, including the risk that we will discover unanticipated liabilities or other problems associated with the acquired business or property.

In assessing potential acquisitions, we consider information available in the public domain and information provided by the seller. In the event publicly available data is limited, then, by necessity, we may rely to a large extent on information that may only be available from the seller, particularly with respect to drilling and completion costs and practices, geological, geophysical and petrophysical data, detailed production data on existing wells, and other technical and cost data not available in the public domain. Accordingly, the review and evaluation of businesses or properties to be acquired may not uncover all existing or relevant data, obligations or actual or contingent liabilities that could adversely impact any business or property to be acquired and, hence, could adversely affect us as a result of the acquisition. These issues may be material and could include, among other things, unexpected environmental liabilities, title defects, unpaid royalties, taxes or other liabilities.

The success of any acquisition that we complete will depend on a variety of factors, including our ability to accurately assess the reserves associated with the acquired properties, assumptions related to future oil and natural gas prices and operating costs, potential environmental and other liabilities and other factors. These assessments are often inexact and subjective. As a result, we may not recover the purchase price of a property from the sale of production from the property or recognize an acceptable return from such sales or operations.

Our ability to achieve the benefits that we expect from an acquisition will also depend on our ability to efficiently integrate the acquired operations. Management may be required to dedicate significant time and effort to the integration process, which could divert its attention from other business opportunities and concerns. The challenges involved in the integration process may include retaining key employees and maintaining employee morale, addressing differences in business cultures, processes and systems and developing internal expertise regarding acquired properties.

Our operations are subject to a series of risks arising out of the threat of climate change that could result in increased operating costs, limit the areas in which we may conduct oil, natural gas, and NGLs exploration and production activities, and reduce demand for the oil, natural gas, and NGLs we produce.

In the United States, no comprehensive climate change legislation has been implemented at the federal level. However, following the U.S. Supreme Court finding that GHG emissions constitute a pollutant under the Clean Air Act, the EPA has adopted regulations that, among other things, establish construction and operating permit reviews for GHG emissions from certain large stationary sources, require the monitoring and annual reporting of GHG emissions from certain petroleum and natural gas system sources in the United States, impose new standards reducing methane emissions from oil and gas operations through limitations on venting and flaring and the implementation of enhanced emission leak detection and repair requirements, and together with the United States Department of Transportation, implement GHG emissions limits on vehicles manufactured for operation in the United States. The federal regulation of methane emissions from oil and natural gas facilities has been subject to considerable attention in recent years. In December 2023, the EPA finalized new and updated rules for both new and existing sources. The final rules make existing regulations more stringent, expand the scope of source types covered by the rules and require states to develop plans to reduce methane and volatile organic compound emissions from existing sources. These new rules have been subject to legal challenges. The Trump Administration may seek to revise or repeal these rules. As a result, we cannot predict the scope of any final methane regulatory requirements or the cost to comply with such requirements. However, given the long-term trend toward increasing regulation, future federal GHG regulations of the oil and natural gas industry remain a significant possibility.

Governmental, scientific, and public concern over the threat of climate change arising from GHG emissions has resulted in increasing political risks in the United States, including climate change related pledges made by certain candidates elected to public office. Former President Biden issued several executive orders focused on addressing climate change, including items that may impact costs to produce, or demand for, oil and gas. There are also increasing financial risks for fossil fuel producers as shareholders currently invested in fossil-fuel energy companies may elect in the future to shift some or all of their investments into other sectors. Institutional lenders who provide financing to fossil-fuel energy companies also have become more attentive to sustainable lending practices and some of them may elect not to provide funding for fossil fuel energy companies. There is also a risk that financial institutions will be pressured or required to adopt policies that have the effect of reducing the funding provided to the fossil fuel sector. Former President Biden signed an executive order calling for the development of a "climate finance plan” and, separately, the Federal Reserve has joined the Network for Greening the Financial System ("NGFS”), a consortium of financial regulators focused on addressing climate-related risks in the financial sector. Limitation of investments in and financings for fossil fuel energy companies could result in the restriction, delay or cancellation of drilling programs or development or production activities.

Policy makers have also advocated for expanding existing, or creating new, reporting and disclosure requirements regarding GHG emissions and other climate-related matters. For example, the EPA adopted amendments in May 2024 to its GHG Reporting Program, which, among other things, added well blowouts and other abnormal events as new categories of sources for GHG emissions reporting. In addition, the SEC finalized rules in March 2024 that require public companies to include extensive climate-related disclosures in their SEC filings, such as new disclosures on (i) material Scope 1 and 2 GHG emissions, including an independent assurance report, which currently would not apply to Empire given its size, and (ii) financial statement information regarding the effects of severe weather events and other natural conditions. In April 2024, the SEC stayed the effectiveness of these rules pending the completion of a judicial review of certain legal challenges. While we are still awaiting resolution of the review of the SEC climate change rules, we are continuing to assess its potential impact and expect heightened disclosure requirements given that reporting frameworks on GHG emissions and other climate-related metrics are still maturing and often require the use of numerous assumptions and judgments.

The adoption and implementation of new or more stringent international, federal or state legislation, regulations or other regulatory initiatives that impose more stringent standards for GHG emissions from the oil and natural gas sector or otherwise restrict the areas in which this sector may produce oil and natural gas or generate GHG emissions could result in increased costs of compliance or costs of consuming, and thereby reduce demand for, oil and natural gas. Additionally, political, litigation and financial risks may result in us restricting or cancelling production activities, incurring liability for infrastructure damages as a result of climatic changes, or having an impaired ability to continue to operate in an economic manner. One or more of these developments could have a material adverse effect on our business, financial condition and results of operations.

In addition to regulatory risk, other market and social initiatives relating to climate change present risks for our business. For example, in an effort to promote a lower-carbon economy, there are various public and private initiatives subsidizing or otherwise encouraging the development and adoption of alternative energy sources and technologies, including by mandating the use of specific fuels or technologies. These initiatives may reduce the competitiveness of carbon-based fuels, such as oil and gas. Moreover, an increasing number of financial institutions, funds and other sources of capital have restricted or eliminated their investment in oil and natural gas activities due to their concern regarding climate change. Such restrictions in capital could decrease the value of our business and make it more difficult to fund our operations. In addition, governmental entities and other plaintiffs have brought, and may continue to bring, claims against us and other oil and gas companies for purported damages caused by the alleged effects of climate change. The increasing attention to climate change may result in further claims or investigations against us, and heightened societal or political pressures may increase the possibility that liability could be imposed on us in such matters without regard to our causation of, or contribution to, the asserted damage or violation, or to other mitigating factors.

As a final note, climate change could have an effect on the severity of weather (including hurricanes, droughts and floods), sea levels, water availability and quality, and meteorological patterns. If such effects were to occur, our development and production operations have the potential to be adversely affected.

Potential adverse effects could include damage to our facilities from powerful winds, extreme temperatures, or rising waters in low-lying areas, disruption of our production activities either because of climate related damages to our facilities or in our costs of operation potentially arising from such climatic effects, less efficient or non- routine operating practices necessitated by climate effects or increased costs for insurance coverage in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. Additionally, changing meteorological conditions, particularly temperature, may result in changes to the amount, timing, or location of demand for energy or the products we produce. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

The marketability of our production is dependent upon gathering systems, transportation facilities and processing facilities that we do not own or control. If these facilities

or systems are unavailable, our oil and natural gas production can be interrupted and our revenues reduced.

The marketability of our oil and natural gas production is dependent upon the availability, proximity and capacity of pipelines, natural gas gathering systems, transportation and processing facilities owned by third parties. In general, we will not control these facilities, and our access to them may be limited or denied due to circumstances beyond our control. A significant disruption in the availability of these facilities could adversely impact our ability to deliver to market the hydrocarbons we produce and thereby cause a significant interruption in our operations. In some cases, our ability to deliver to market our hydrocarbons is dependent upon coordination among third parties that own transportation and processing facilities we use, and any inability or unwillingness of those parties to coordinate efficiently could also interrupt our operations. The lack of availability or the lack of capacity on these systems and facilities could result in the curtailment of production or the delay or discontinuance of drilling plans. These are risks for which we generally will not maintain insurance.

We operate or participate in oil and natural gas leases with third-parties who may not be able to fulfill their commitments to our projects.

In some cases, we operate but own less than 100% of the working interest in the oil and natural gas leases on which we conduct operations, and other parties own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas and NGLs prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

Because we cannot control activities on properties we do not operate, we cannot directly control the timing of exploration. If we are unable to fund required capital expenditures with respect to non-operated properties, our interests in those properties may be reduced or forfeited.

Our ability to exercise influence over operations and costs for the properties we do not operate is limited. Our dependence on the operators and other working interest owners for these projects and our limited ability to influence operations and associated costs could prevent the realization of our targeted returns on capital with respect to acquisition, exploration and development activities. The success and timing of development, exploitation and exploration activities on properties operated by others depend upon a number of factors that may be outside our control, including but not limited to the timing and amount of capital expenditures; the operator's expertise and financial resources; the approval of other participants in drilling wells; and the selection of technology.

Where we are not the majority owner or operator of a particular oil and natural gas project, we may have no control over the timing or amount of capital expenditure associated with the project. If we are not willing or able to fund required capital expenditures relating to a project when required by the majority owner(s) or operator, our interests in the project may be reduced or forfeited. Also, we could be responsible for plugging and abandonment costs, as well as other liabilities in excess of our proportionate interest in the property.

We could be adversely affected by increased costs of service providers utilized by us.

In accordance with customary industry practice, we have relied and will rely on independent third-party service providers to provide most of the services necessary to operate. The industry has experienced significant price fluctuations for these services during the last year and this trend is expected to continue into the future. These cost uncertainties could, in the future, significantly increase our production costs.

Our ability to use our existing net operating loss carryforwards or other tax attributes could be further limited.

In the event that an entity has an "ownership change" (as defined in Section 382 of the Internal Revenue Code of 1986, as amended (the "Code")), an entity's federal net operating loss carryforwards ("NOLs") generated prior to an ownership change would be subject to annual limitations, which could defer or eliminate our ability to utilize these tax losses against future taxable income. Generally, an "ownership change" occurs if one or more stockholders, each of whom owns 5% or more in value of a corporation's stock, increase their aggregate percentage ownership by more than 50% over the lowest percentage of stock owned by those stockholders at any time during the preceding three-year period. A full Section 382 analysis was prepared in 2024, and it was determined that our NOLs were subject to limitations under Section 382.

At December 31, 2024, we had approximately $35.8 million of federal NOLs generated in prior years that could offset against future taxable income, however, $2.4 million of the NOLs were limited as of December 31, 2024 due to ownership changes. NOLs created prior to 2018 have a 20-year expiration period and NOLs arising after 2017 have an indefinite life. Additionally, utilization of any NOL depends on many factors, including our ability to generate future taxable income, which cannot be assured. At December 31, 2024, we had a full tax valuation allowance recorded on the NOLs.

In the event that we were to undergo any further "ownership change", our NOLs generated prior to an ownership change would be subject to further annual limitations, which could defer or eliminate our ability to utilize these tax losses against future taxable income.

Legislation

Climate change legislation, regulations restricting emissions of GHG's or legal or other action taken by public or private entities related to climate change could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

The threat of climate change continues to attract considerable attention in the United States and around the world. Numerous proposals have been made and could continue to be made at the international, national, regional and state levels of government to monitor and limit existing emissions of GHGs as well as to restrict or eliminate such future emissions. These efforts have included consideration of cap-and-trade programs, carbon taxes, GHG disclosure obligations and regulations that directly limit GHG emissions from certain sources. Moreover, Former President Biden highlighted addressing climate change as a priority of his administration, issued several executive orders related to climate change and recommitted the United States to long-term international goals to reduce emissions, and continues to require the incorporation of climate change considerations into executive agency decision-making. In recent years, Congress has considered legislation to reduce emissions of GHGs, including methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of natural gas. For example, the Inflation Reduction Act of 2022, which appropriates significant federal funding for renewable energy initiatives and, for the first time, imposes a fee on GHG emissions from certain facilities, was signed into law in August 2022. The emissions fee and funding provisions of the law could increase operating costs within the oil and natural gas industry and accelerate the transition away from fossil fuels, which could in turn adversely affect our business and results of operations.

At the international level, the United Nations ("UN") sponsored the "Paris Agreement" requires member states to submit non-binding, individually-determined reduction goals known as Nationally Determined Contributions every five years after 2020. Former President Biden recommitted the United States to the Paris Agreement and, in April 2021, announced a goal of reducing the United States' emissions by 50 to 52% below 2005 levels by 2030. Subsequent UN climate conferences have called for additional action to transition away from fossil fuels or otherwise reduce GHG emissions. Various states and local governments have also publicly committed to furthering the goals of the Paris Agreement. In January 2025, the Trump Administration re-withdrew the United States from the Paris Agreement, and the United States' participation in future UN climate related efforts is unclear. The full impact of these actions is uncertain at this time, and it is unclear what additional initiatives may be adopted or implemented that may have adverse effects upon our operations.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Reduced demand for the oil and natural gas that we produce could also have the effect of lowering the value of our reserves. It should also be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. In addition, there have also been efforts in recent years to influence the investment community, including investment advisors and certain sovereign wealth, pension and endowment funds promoting divestment of fossil fuel equities and pressuring lenders to limit funding to companies engaged in the extraction of fossil fuel reserves. Such environmental activism and initiatives aimed at limiting climate change and reducing air pollution could interfere with our business activities, operations and ability to access capital. Finally, increasing attention to the risks of climate change has resulted in an increased possibility of lawsuits or investigations brought by public and private entities against oil and natural gas companies in connection with their GHG emissions. Should we be targeted by any such litigation or investigations, we may incur liability, which, to the extent that societal pressures or political or other factors are involved, could be imposed without regard to the causation of or contribution to the asserted damage, or to other mitigating factors. The ultimate impact of GHG emissions-related agreements, legislation and measures on our company's financial performance is highly uncertain because we are unable to predict with certainty, for a multitude of individual jurisdictions, the outcome of political decision-making processes and the variables and tradeoffs that inevitably occur in connection with such processes.

Any change to government regulation or administrative practices may have a negative impact on our ability to operate and our profitability.

Oil and natural gas operations are subject to substantial regulation under federal, state and local laws relating to the exploration for, and the development, upgrading, marketing, pricing, taxation, and transportation of, oil and natural gas and related products and other associated matters. Amendments to current laws and regulations governing operations and activities of oil and natural gas exploration and development operations could have a material adverse impact on our business. In addition, there can be no assurance that income tax laws, royalty regulations and government programs related to our oil and natural gas properties and the oil and natural gas industry generally will not be changed in a manner which may adversely affect our progress or cause delays.

Permits, leases, licenses, and approvals are required from a variety of regulatory authorities at various stages of exploration and development. There can be no assurance that the various government permits, leases, licenses and approvals sought will be granted in respect of our activities or, if granted, will not be cancelled or will be renewed upon expiration. There is no assurance that such permits, leases, licenses, and approvals will not contain terms and provisions which may adversely affect our exploration and development activities.

Other

A cyber incident could result in information theft, data corruption, operational disruption and/or financial loss.

The oil and natural gas industry has become increasingly dependent on digital technologies to conduct day-to-day operations including certain exploration, development and production activities. We are dependent on digital technologies including information systems and related infrastructure, to process and record financial and operating data, communicate with our employees, business partners, and stockholders, analyze 3-D seismic and drilling information, estimate quantities of oil and natural gas reserves as well as other activities related to our business.

As dependence on digital technologies has increased, cyber incidents, including deliberate attacks or unintentional events, have also increased. A cyber-attack could include gaining unauthorized access to digital systems for the purposes of misappropriating assets or sensitive information, corrupting data, causing operational disruption, or result in denial-of-service on websites.

Our technologies, systems, networks, and those of our business partners may become the target of cyber-attacks or information security breaches that could result in the unauthorized release, gathering, monitoring, misuse, loss or destruction of proprietary and other information, or other disruption of our business operations. In addition, certain cyber incidents, such as surveillance, may remain undetected for an extended period of time. In particular, our implementation of various procedures and controls to monitor and mitigate security threats and to increase security for our information, data, facilities and infrastructure may result in increased capital and operating costs. Costs for insurance may also increase as a result of security threats, and some insurance coverage may become more difficult to obtain, if available at all. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. As cyber threats continue to evolve, we may be required to expend significant additional resources to continue to modify or enhance our protective measures or to investigate and remediate any information security vulnerabilities. A cyber incident involving our information systems and related infrastructure, or that of our business partners, could disrupt our business plans and negatively impact our operations.

The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

We depend greatly on the efforts of our executive officers and other key employees to manage our operations. The loss or unavailability of any of our executive officers or other key employees could have a material adverse effect on our business.

We have had material weaknesses in our internal control over financial reporting in prior fiscal years. Failure to maintain effective internal control over financial reporting could adversely affect our ability to report our financial condition and results of operations accurately and on a timely basis. As a result, our business, operating results and liquidity could be harmed.

As disclosed in our prior annual reports on Form 10-K, we identified a material weakness in internal controls over financial reporting as of December 31, 2022, and 2021. We believe that this material weakness has been successfully remediated.

Our failure to maintain effective internal control over financial reporting could adversely affect our ability to report our financial results on a timely and accurate basis, which could result in a loss of investor confidence in our financial reports or have a material adverse effect on our ability to operate our business or access sources of liquidity. Furthermore, because of the inherent limitations of any system of internal control over financial reporting, including the possibility of human error, the circumvention or overriding of controls and fraud, even effective internal controls may not prevent or detect all misstatements.

We do not expect to declare or pay any dividends in the foreseeable future.

We have not declared or paid any dividends on our common stock. We currently intend to retain future earnings to fund the development and growth of our business, to repay indebtedness and for general corporate purposes, and therefore, do not anticipate paying any cash dividends on our common stock in the foreseeable future.

The price of our common stock may fluctuate significantly, which could negatively affect us and the holders of our common stock.

Our common stock trades on the NYSE American. The trading price of our common stock may fluctuate significantly in response to a number of factors, many of which are beyond our control. Adverse events including changes in production volumes, worldwide demand and prices for crude oil and natural gas, regulatory developments, and changes in any securities analysts' estimates of our financial performance could negatively impact the market price of our common stock. General market conditions, including the level of, and fluctuations in, the trading prices of stocks generally could also have a similar negative impact. The stock markets regularly experience price and volume volatility that affects many companies' stock prices without regard to the operating performance of those companies. Volatility of this type may affect the trading price of our common stock.

Provisions of our certificate of incorporation and bylaws and Delaware law may inhibit a takeover, which could limit the price investors might be willing to pay in the future for our common stock.

Provisions in our certificate of incorporation and bylaws may have the effect of delaying or preventing an acquisition of us or a merger in which we are not the surviving company and may otherwise prevent or slow changes in our board of directors and management. In addition, because we are incorporated in Delaware, we are governed by the provisions of Section 203 of the General Corporation Law of the State of Delaware, which provides certain restrictions on business combinations involving interested parties. These provisions could discourage an acquisition of us or other change in control transactions and thereby negatively affect the price that investors might be willing to pay in the future for our common stock.

Holders of our outstanding Series A Voting Preferred Stock have effective control of our board of directors.

We have six shares of Series A Voting Preferred Stock currently issued and outstanding. The Series A Voting Preferred Stock was issued in connection with the strategic investment in us by Energy Evolution. For so long as the Series A Voting Preferred Stock is outstanding, our board of directors will consist of six directors. Three of the directors are designated as the Series A Directors and the three other directors (each, a "common director") are elected by the holders of common stock and/or any preferred stock (other than the Series A Voting Preferred Stock) granted the right to vote on the common directors. Any Series A Director may be removed with or without cause but only by the affirmative vote of the holders of a majority of the Series A Voting Preferred Stock voting separately and as a single class. The holders of the Series A Voting Preferred Stock have the exclusive right, voting separately and as a single class, to vote on the election, removal and/or replacement of the Series A Directors. Holders of common stock or other preferred stock have no right to vote on the Series A Directors. In addition, in the case of any tie vote or deadlock of the board of directors, our current Chairman of the Board, a Series A Director, has the deciding, tiebreaking vote. Accordingly, the holder(s) of our Series A Voting Preferred Stock have effective control of our board of directors for so long as the voting rights of the Series A Voting Preferred Stock remain in effect.

Our bylaws provide that the Court of Chancery of the State of Delaware (or if the Court of Chancery does not have jurisdiction, the federal district court for the District of Delaware) will be the exclusive forum for certain legal actions between us and our stockholders. These provisions could increase costs to bring a claim, discourage claims or limit the ability of our stockholders to bring a claim in a judicial forum viewed by the stockholders as more favorable for disputes with us or our directors, officers or employees.

Our bylaws provide that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware (or if the Court of Chancery does not have jurisdiction, the federal district court for the District of Delaware) will be the sole and exclusive forum for (a) any derivative action or proceeding brought on our behalf, (b) any action asserting a claim of breach of a fiduciary duty owed by any director, officer, stockholder, employee or agent to us or our stockholders, (c) any action asserting a claim arising pursuant to any provision of the General Corporation Law of the State of Delaware, our certificate of incorporation or our bylaws, or (d) any action asserting a claim governed by the internal affairs doctrine, in each case subject to the court having personal jurisdiction over the defendants. This exclusive forum provision is intended to apply to claims arising under Delaware state law and is not intended to apply to claims arising under the Securities Act or the Exchange Act. The choice of forum provisions may increase costs to bring a claim, discourage claims or limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers or employees, which may discourage such lawsuits against us or our directors, officers and employees. Alternatively, if a court were to find the choice of forum provision contained in our bylaws to be inapplicable or unenforceable in an action, we may incur additional costs associated with resolving such action in other jurisdictions.

The credit risk of our counterparties could adversely affect us.

We enter into a variety of transactions that expose us to counterparty credit risk. For example, we have exposure to financial institutions and insurance companies through our hedging arrangements, our Credit Facility and our insurance policies. Disruptions in the financial markets or otherwise may impact these counterparties and affect their ability to fulfill their existing obligations and their willingness to enter into future transactions with us.

In addition, we are exposed to the risk of financial loss from trade, joint interest billing and other receivables. We sell our oil, gas and NGLs to a variety of purchasers, and, as an operator, we pay expenses and bill our non-operating partners for their respective share of costs. Certain of these counterparties or their successors may experience insolvency, liquidity problems or other issues and may not be able to meet their obligations owed to us, particularly during a depressed or volatile commodity price environment. Any such default may result in us being forced to cover the costs of those obligations and liabilities.

ITEM 1B. UNRESOLVED STAFF COMMENTS.

None.

ITEM 1C. CYBERSECURITY.

The Company continues to implement policies, standards, processes and practices for assessing, identifying, and managing material risks from cybersecurity threats. We employ a variety of tools designed to identify, assess and maintain security measures to meet regulatory requirements, and possess technical personnel to maintain the security of our data and cybersecurity infrastructure. There can be no guarantee that our policies and procedures will be properly followed in every instance or that those policies and procedures will be effective. Our risk factors, which can be found in Item 1A. "Risk Factors," include further detail about the material cybersecurity risks we face. There can be no assurance that there will not be incidents in the future or that they will not materially affect us, including our business strategy, results of operations, or financial condition.

Risk Management and Strategy Overview

We continue the process of designing and implementing a formal risk-based approach to cybersecurity which aligns with corporate strategy, risk management and governance, and adaptable information technology ("IT") infrastructure. Our cybersecurity program consists of policies, procedures, systems, controls and technology designed to help prevent, identify, detect and mitigate cybersecurity risk and will be based on a cybersecurity framework, such as the National Institute of Standards and Technology ("NIST") Cybersecurity framework.

To protect our IT systems and information from cybersecurity risks, we use and continue to implement various security tools that help prevent, identify, escalate, investigate, resolve, and recover from identified cybersecurity vulnerabilities and incidents in a timely manner. These include monitoring and detection programs, network security measures, firewall monitoring devices and multi-factor authentication which are all overseen by our IT Director, who possesses the necessary expertise to implement the appropriate tools and processes to effectively manage cybersecurity risks. With over 30 years of experience in the oil and natural gas industry, our IT Director has 12 years of cybersecurity experience where he has led several teams introducing cybersecurity initiatives and implementing robust frameworks and response plans against cyber threats.

We are actively assessing the technological risks to our key IT systems and information and are implementing controls to identify and manage cybersecurity risks associated with all third-party service providers. These include, but are not limited to, an understanding of access controls, a records and information management policy, change control procedures, risk and control registry, and configuration standards.

Employee awareness of cybersecurity risks and threats is also an important part of an effective control environment. We periodically communicate to employees about this cybersecurity awareness. We are working on an implementation plan to require each of our employees to complete an annual information security training course, in addition to other training requirements. This should lead to an educated, informed, and prepared workforce, with an awareness of potential cybersecurity threats, how they may occur, and how to report and escalate such matters.

Our cybersecurity strategy focuses on implementing effective and efficient controls, technologies, and other processes to assess, identify, and manage material cybersecurity risks to our IT systems and information. As a part of this process, we engaged and worked with an independent third-party specialist to review our cybersecurity environment, which included a formal review and assessment, and determined specific, actionable recommendations for improvement and implementation.

While we have not, as of the date of this Annual Report on Form 10-K, experienced a cybersecurity incident that has materially impacted our business or operations, there can be no guarantee that we will not experience such a threat or incident in the future. A material cybersecurity threat or incident could adversely impact our operations, our sales or financial and administrative functions, or result in the compromise of personal or other confidential information of our employees, customers, or suppliers. For this reason, we maintain cybersecurity liability insurance to provide additional support, expertise, and resources to help ensure the integrity of our cybersecurity processes and to provide a level of financial protection in the event of cybersecurity incident related costs and losses.

Governance

Our Audit Committee has oversight of our cybersecurity risk processes, as part of its overall oversight of our risk management program. Our Chief Executive Officer is informed about and facilitates prevention, detection, mitigation, and remediation efforts through regular communication and reporting from our IT Director. In addition, we have an escalation process in place to inform our Chief Executive Officer and other members of our senior management and, if necessary, the Audit Committee and Board of Directors, of important issues or events.

ITEM 2. PROPERTIES.

Information regarding our properties is included in Item 1 above and in our consolidated financial statements, which is incorporated herein by reference.

ITEM 3. LEGAL PROCEEDINGS.

For information regarding legal proceedings, see Note 15 in our consolidated financial statements.

ITEM 4. MINE SAFETY DISCLOSURES.

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Market Information

Our common stock is traded on the NYSE American under the symbol "EP".

Stockholders

At March 25, 2025, there were approximately 1,350 stockholders of record of our common stock.

Dividends

We have never paid cash dividends on our common stock. We intend to retain future earnings for use in our business and, therefore, do not anticipate paying cash dividends on our common stock in the foreseeable future. Future payment of dividends will depend upon, but not be limited to, our financial condition, funds available for operations, the amount of anticipated capital and other expenditures, future business prospects and any restrictions imposed by present or future financing arrangements.

Issuer Repurchase of Equity Securities

No private or open market repurchases of common stock were made by us during the fourth quarter of 2024.

Unregistered Sales of Equity Securities

No such sales that have not been previously reported on a Quarterly Report on Form 10-Q or a Current Report on Form 8-K.

ITEM 6. RESERVED.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following discussion and analysis presents management's perspective of our business, financial condition and overall performance. This information is intended to provide investors with an understanding of our past performance, current financial condition and outlook for the future and should be read in conjunction with the consolidated financial statements and notes to consolidated financial statements, which are included in this Annual Report on Form 10-K in Item 8, Financial Statements and Supplementary Data, and the information set forth in Part I, Item 1A – Risk Factors.

Overview

Our primary business is the optimization and development of oil and gas interests. We have incurred losses from operations in 2024 and 2023. There is no assurance that we will be profitable or obtain funds necessary to finance our future operations.

We seek to increase shareholder value by growing reserves, production, revenues, and cash flow from operating activities by executing our mission to use highly-skilled personnel to thoughtfully and expertly spend capital to realize reserves on producing properties as well as further develop fields.

Management places emphasis on operating cash flow in managing our business, as operating cash flow considers the cash expenses incurred during the period and excludes non-cash expenditures not related directly to our operations.

Inflation

The effect of inflation on the Company has generally been to increase its cost of operations, general and administrative costs and direct costs associated with oil and natural gas production.

Business Strategy

Our business strategy is to obtain long-term growth in reserves and cash flow on a cost-effective basis. Management regularly evaluates potential acquisitions of properties that would enhance current core areas of operation.

Liquidity and Going Concern

The Company has a revolving line of credit agreement with Equity Bank which requires the Company to maintain compliance with certain financial covenants computed on a quarterly and annual basis. As of December 31, 2024, the Company was in compliance with all required covenants and projected to be in compliance with all debt covenants over the next 12 months. However, the Company was in default of its covenants in the third quarter of 2024 but obtained a waiver on November 12, 2024, to alleviate all prior defaults. The Company carried a negative working capital of approximately $8.9 million as of December 31, 2024, an overall decline of approximately $2.6 million from the previous year. Cash on hand also declined approximately $5.5 million during the same period. The overall decline in working capital and cash is primarily driven by the Starbuck Drilling Program in North Dakota which incurred substantial capital spend. Additionally, the Company initiated a return-to-production program in Texas which incurred additional unforeseen operational costs. The additional production from these projects did not fully offset the costs incurred and contributed to the overall negative financial trend. To meet its obligations, the Company increased its revolver commitment to $20.0 million in November 2024 and had two rights offerings in April and November of 2024 which raised approximately $30.5 million of capital, net of transaction costs, to help fund the capital spend projects. Additionally, as a result of increasing its revolver commitment, the Company had approximately $8.7 million remaining unused commitment as of December 31, 2024, which can be used for future obligations. However, the revolver commitment is reduced monthly by $0.25 million commencing on December 31, 2024 (See Note 7), limiting future access to capital. While these debt and equity transactions provided additional funding towards these projects and other obligations, the Company still carried approximately $8.9 million of negative working capital at period end and future expected operating cash flows do not sufficiently meet the Company's obligations for the next 12 months. Given the negative working capital and insufficient expected operating cash flow there is substantial doubt about the Company's ability to continue as a going concern.

Empire has committed financial support from Phil Mulacek who owns approximately 21.2% of our common stock outstanding as of December 31, 2024, and Energy Evolution, our largest stockholder who owns approximately 31.9% of our common stock outstanding as of December 31, 2024. Both are related parties of the Company (see Note 14). Mr. Mulacek and Energy Evolution are willing and able to provide these additional funds, if required, for Empire to continue to meet its obligations over the next 12 months. These additional funds may be raised through related party warrants, or a related party note payable that may or may not have conversion rights into shares of common stock of Empire.

Management has considered these plans in evaluating FASB ASC 205-40, *Presentation of Financial Statements - Going Concern*. Management believes the above actions are sufficient to allow Empire to meet its obligations as they become due within one year after the date the financial statements are issued. Management believes that its plans, and support from the existing related-party stockholders discussed above, is probable and has alleviated the substantial doubt regarding Empire's ability to continue as a going concern.

Recent Developments

Empire has completed 13 wells in North Dakota related to our Starbuck Drilling Program during the year ended December 31, 2024.

On February 16, 2024, Empire issued a Promissory Note to Energy Evolution, a related party. Energy Evolution advanced Empire $5.0 million. On May 24, 2024, Energy Evolution elected to convert the Note to shares of common stock of Empire and received 800,000 shares under the terms of the Promissory Note. See Note 7 for further details.

In April 2024, the Company completed a subscription rights offering (the "April Rights Offering") which raised gross proceeds of approximately $20.7 million. Each subscription right entitled the holder to purchase 0.161 shares of common stock at a subscription price of $5.00 per share per one whole share of common stock. The subscription rights were non-transferable and not listed for trading on any stock exchange or market.

On April 9, 2024, Empire partially exercised a purchase option originally issued on August 9, 2023, (the "Purchase Option") to acquire additional working interests in certain of Empire's New Mexico properties from Energy Evolution. The additional assets acquired represent approximately 60% of the total assets collectively acquired by Empire and Energy Evolution in the third quarter of 2023 (the "Option Assets"). As consideration, upon closing of the partial exercise of the Purchase Option, Empire issued Energy Evolution 600,000 shares of common stock of Empire based on an agreed upon price of $5.00 per share for an aggregate agreed upon value of $3.0 million which was 60% of the purchase price of $5.0 million under the Purchase Option.

On August 8, 2024, Empire successfully extended the Purchase Option with the issuance of 16,800 shares of common stock to Energy Evolution to obtain the right to acquire the remaining Option Assets for an exercise price of $2.0 million subject to certain adjustments and payable in cash, unless the parties agree that some or all may be paid by issuance of common stock to Energy Evolution. The Purchase Option expires on August 9, 2026.

In November 2024, Empire completed a subscription rights offering (the "November Rights Offering") which raised gross proceeds of $10.0 million. Each subscription right entitled the holder to purchase 0.063 shares of common stock at a subscription price of $5.05 per share per one whole share of common stock. The subscription rights were non-transferable and not listed for trading on any stock exchange or market.

On November 18, 2024, the Company entered into the First Amendment to the Credit Facility (the "First Amendment") to increase the initial maximum revolver commitment to $20.0 million through December 29, 2026. See Note 7 for further details.

Production and Operating Data

The following table sets forth a summary of our production and operating data:

	For the Years Ended December 31,			
	2024		2023	
Production and operating data:				
Net sales volumes:				
Oil (Bbl)		581,159		487,869
Natural gas (Mcf)		916,955		854,274
Natural gas liquids (Bbl)		150,091		136,013
Total (Boe)		884,076		766,261
Average price per unit:				
Oil (1)	$	71.44	$	75.19
Natural gas	$	0.37	$	2.02
Natural gas liquids	$	14.21	$	12.21
Total (Boe)	$	49.76	$	52.29
Operating costs and expenses per Boe:				
Lease operating expense (excluding workovers)	$	24.46	$	21.70
Workovers	$	6.71	$	15.65
Total Lease operating expense	$	31.16	$	37.36
Production and ad valorem taxes	$	4.26	$	3.97
Depreciation, depletion, amortization and accretion	$	12.74	$	6.33
General & administrative (excluding stock-based compensation)	$	14.23	$	15.71
Stock-based compensation	$	2.44	$	4.10
Total General & administrative	$	16.67	$	19.81

(1) Excludes the effect of net cash receipts from (payments on) derivatives.

Results of Operations

The following table reflects our summary of operating information. Because of normal production declines, increased or decreased drilling activity and the effects of acquisitions, the historical information presented below should not be interpreted as indicative of future results.

	For the Years Ended December 31,		Percent
	2024	2023	Change

Oil revenues	$ 41,515,661	$ 36,684,494	13%
Natural gas revenues	343,503	1,726,754	-80%
NGL revenues	2,132,666	1,660,256	28%
Total product revenues	43,991,830	40,071,504	
Lease operating expense	27,545,028	28,625,481	-4%
Production and ad valorem taxes	3,770,078	3,044,411	24%
Depreciation, depletion, amortization and accretion	11,263,010	4,852,555	132%
General and administrative expense (excluding stock-based compensation)	12,581,859	12,034,185	5%
Stock-based compensation	2,155,774	3,144,750	-31%
Cash-based interest expense	894,282	650,637	37%
Non-cash interest expense	620,987	349,790	78%
Operating Loss	(13,665,457)	(11,625,091)	18%
Net Loss	(16,197,989)	(12,469,605)	30%

Revenues

Revenues for 2024 increased compared to prior year primarily due to higher oil volumes in North Dakota due to our Starbuck Drilling Program partially offset by a slight overall decline in commodity prices.

Realized oil prices for 2024 were approximately $71.44 per barrel, while realized prices for the prior year were approximately $75.19 per barrel, a decrease in price of approximately 5%. Oil volumes were higher by approximately 93,000 barrels or 19% primarily due to new wells completed in North Dakota during the third quarter of 2024 as well as the acquisition of additional working interest in New Mexico.

Realized natural gas prices for 2024 were approximately $0.37 per Mcf, while realized prices for the prior year were approximately $2.02 per Mcf, a decrease in price of approximately 82%. This is primarily due to the depressed natural gas prices in the third quarter of 2024 in New Mexico.

Realized NGLs prices for 2024 were approximately $14.21 per barrel, while realized prices for the prior year were approximately $12.21 per barrel, an increase in price of approximately 16%.

Lease Operating Expense and Production Taxes

Lease operating expense was lower in 2024 primarily due to lower workover activities partially offset by higher expenses related to an increase in production. Lease operating expense includes approximately $5.9 million of total workover expense for 2024 as compared to approximately $12.0 million for 2023. The higher workover expense in 2023 was primarily in New Mexico as Empire continued to work over wells in the region to enhance and maintain production.

Production taxes were higher for 2024 compared to 2023 as a result of the higher product revenues discussed above.

Depreciation, Depletion, Amortization, Accretion and Impairment

The higher DD&A in 2024 as compared to 2023 is due in part to the increase in production, the acquisition of additional working interest in New Mexico as well as the impact of the capitalized costs associated with the new drilling activity as part of our Starbuck Drilling Program in North Dakota. Accretion also increased slightly from prior period due to the new drilling activity.

We assess our oil and gas properties for impairment when circumstances indicate the carrying value may be greater than its estimated future net cash flows. There was no impairment recorded during the years ended December 31, 2024 and 2023.

General and Administrative Expense (excluding stock-based compensation)

General and Administrative Expense (excluding stock-based compensation) increased primarily due to an increase in salaries and benefits associated with an increase in employee headcount.

Stock-based Compensation

We utilize stock-based compensation to compensate members of management and retain talented personnel. Our stock-based compensation decreased in 2024 due to a lower number of awards in 2024. We anticipate stock-based compensation to continue to be utilized in 2025 and beyond to attract and retain talented personnel and compensate our board members and consultants.

Interest Expense

Cash-based interest expense increased slightly due to a higher outstanding balance under our Credit Facility partially offset by lower interest rates. We have minimal interest-bearing vehicle and equipment notes payable.

Non-cash interest expense is primarily attributable to the conversion to equity of the related party note payable as described in Note 7 of Notes to Consolidated Financial Statements.

Income taxes

We have generated net operating losses since inception, which would normally reflect a tax benefit in the consolidated statement of operations and a deferred asset on the consolidated balance sheet. However, because of the current uncertainty as to our ability to achieve sustained profitability and the potential limitation of NOL carryforwards, a full valuation allowance has been established that offsets the amount of any tax benefit available for each period presented in the consolidated statements of operations.

We had a loss before income taxes for 2024 and 2023, respectively, which the tax benefit was offset by a change in the valuation allowance. For 2024 and 2023, our effective tax rates were 0% and 1%, respectively.

Liquidity

As noted below, our working capital is negative as of December 31, 2024, which is primarily the result of a lower cash balance due to capital spending as part of our Starbuck Drilling Program and return-to-production efforts in Texas. As of December 31, 2024, we had approximately $2.3 million in cash on hand and approximately $8.7 million available under our Credit Facility. Empire will require additional funds to satisfy the payables discussed above which are greater than estimated cash flows from operations over the next 12 months. Phil Mulacek and Energy Evolution, both related parties of Empire and our largest two stockholders, owning 21.2% and 31.9%, respectively, of the common shares outstanding as of December 31, 2024, have indicated that they will, and have the ability to, provide sufficient support to sustain the operating, investing, and financing activities of Empire, as necessary. In addition to the April Rights Offering and November Rights Offering, management continues to seek additional sources of capital via the debt or equity markets to improve liquidity going forward. See Liquidity and Going Concern in Note 1 of Notes to Consolidated Financial Statements for further discussion of management's plans.

Empire expects to continue to incur costs related to drilling activities in core areas as well as future oil and natural gas acquisitions in core areas. During 2024, Empire has incurred approximately $42.2 million of additions to oil and natural gas properties, primarily related to the drilling program in the Starbuck field of North Dakota. It is expected that Empire will use a combination of debt or equity issuances, cash on hand, and cash flows from operations to fund capital programs, ongoing operations, and any potential acquisitions.

Working Capital

Working capital is presented in the table below. The decrease of approximately $2.6 million was primarily driven by a lower cash balance due to increased capital spending related to the Starbuck Drilling Program in North Dakota.

	As of December 31,	
	2024	2023
Current Assets	$ 12,350,945	$ 18,744,904
Current Liabilities	21,270,471	25,049,572
Working Capital	$ (8,919,526)	$ (6,304,668)

Cash Flows

The following table summarizes our statements of cash flows:

	For the Years Ended December 31,		
Cash flows provided by (used in):	2024	2023	Change
Operating activities	$ 6,157,003	$ (9,887,500)	$ 16,044,503
Investing activities	(53,869,461)	(14,767,339)	(39,102,122)
Financing activities	42,171,414	20,502,905	21,668,509

Cash Flows from Operating Activities

The impact of higher oil production and lower workover expenses in 2024 compared to 2023 contributed to the increase in cash flows from operating activities.

Cash Flows from Investing Activities

Cash flows from investing activities in 2024 include approximately $42.2 million of additions to oil and gas properties compared to approximately $25.0 million in 2023 primarily due to the development of our operations as part of our Starbuck Drilling Program in North Dakota.

In 2023, we received approximately $2.8 million due to the release of a negotiated sinking fund requirement and acquired additional interest in our New Mexico oil and gas properties for approximately $2.0 million.

Cash Flows from Financing Activities

Cash flow from financing activities in 2024 include proceeds from the April Rights Offering and the November Rights Offering of approximately $30.5 million, net of transaction costs (see Note 9). In addition, cash flows from financing activities in 2024 include $5.0 million from a promissory note issued by the Company to a related party and approximately $6.7 million borrowed on the Credit Facility (see Note 7).

In 2024, we received approximately $0.6 million from stock issuances and warrant exercises. In 2023, we received approximately $12.5 million from stock issuances and warrant exercises.

Capital Resources

General

Empire's primary sources of short-term liquidity are cash and cash equivalents, net cash provided by operating activities, and issuance of debt or equity securities. Empire's short- and long-term liquidity requirements consist primarily of capital expenditures, acquisitions of oil and natural gas properties, payments of contractual obligations, and working capital obligations. Funding for these requirements may be provided by any combination of Empire's sources of liquidity. Although Empire expects that its sources of funding will be adequate to fund its liquidity requirements, no assurance can be given that such funding sources will be adequate to meet Empire's future needs.

Capital Expenditures

For 2024, Empire incurred approximately $42.2 million of additions to oil and natural gas properties which primarily reflects continued drilling and completions activity related to our Starbuck Drilling Program in North Dakota. For 2023, additions to oil and natural gas properties totaled $27.0 million including $2.1 million related to acquisitions. The approximate

$25.0 million not related to acquisitions primarily reflects development of our North Dakota operations.

Related Party Transactions

At times the Company may enter into transactions with related parties. These transactions primarily occur with our two largest shareholders, Phil Mulacek and Energy Evolution, and are approved by the board of directors. See Note 14 for further discussion on related party activity during the year.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States ("US GAAP") requires management to use judgment to make estimates and assumptions that affect certain amounts reported in the consolidated financial statements. As additional information becomes available, these estimates and assumptions are subject to change and thus impact amounts reported in the future. Because estimates and assumptions require significant judgment, future actual results could differ from those estimates and could have a significant impact on our results of operations, financial position and cash flows. We re-evaluate our estimates and assumptions at least on a quarterly basis and periodically update the estimates used in the preparation of the financial statements based on management's latest assessment of the current and projected business and general economic environment. There have been no significant changes to Empire's critical accounting estimates during the year ended December 31, 2024. In our management's opinion, the more significant reporting areas impacted by management's judgments and estimates are as follows:

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

We use the successful efforts method of accounting for oil and natural gas operations. Under this method, costs to acquire oil and natural gas properties, drill successful exploratory wells, drill and equip development wells, and install production facilities are capitalized. Estimated proved oil and natural gas reserves, management's outlook on commodity prices and projected future cash flows of oil and natural gas reserves are a significant part of our financial calculations. The following are examples of how these estimates affect financial results:

- an increase (decrease) in estimated proved oil, natural gas and NGLs reserves can reduce (increase) our unit-of-production depletion and amortization rates; and
- changes in the oil, natural gas and NGLs reserves and the projected future cash flows from our properties can impact our periodic impairment analysis.

Proved oil and natural gas reserves are the estimated quantities of oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. Reserve quantities and future cash flows included in this report are prepared in accordance with guidelines established by the SEC and the FASB. The accuracy of reserve estimates is a function of:

- The quality and quantity of available data;
- The interpretation of that data;
- The accuracy of various mandated economic assumptions; and
- The judgments of the persons preparing the estimates.

Proved reserves information included in this report is based on estimates prepared by independent petroleum engineers, CG&A. The independent petroleum engineers evaluated 100% of our estimated proved producing reserve quantities and their related future net cash flows as of December 31, 2024. Estimates prepared by others may be higher or lower than these estimates. Because these estimates depend on many assumptions, all of which may differ substantially from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. Management may make revisions to reserve estimates throughout the year as additional information becomes available. Such changes could trigger an impairment of our oil and natural gas properties and have an impact on our depletion expense prospectively. For example, a change of 10 percent in our total proved reserves could change our annual depletion expense by approximately $0.9 million. The actual impact would depend on the specific areas impacted.

Impairment of Oil and Gas Properties

We assess our proved properties for impairment using estimates of future undiscounted cash flows. This assessment requires significant judgment and assumptions including commodity price outlooks, estimates of reserve quantities, expected lease operating costs and capital costs. An impairment expense could result if oil and gas prices decline in the future as it may not be economic to develop some of these unproved properties. We performed an assessment as of December 31, 2024 and 2023, and did not identify any impairments, respectively.

Asset Retirement Obligation

Asset retirement obligations ("ARO") consist primarily of estimated future costs associated with the plugging and abandonment of oil and natural gas wells, removal of equipment and facilities from leased acreage, and land restoration in accordance with applicable local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement cost capitalized as part of the carrying cost of the oil and natural gas asset. The recognition of an ARO requires that management make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements; the credit-adjusted risk-free rate to be used; inflation rates; and future advances in technology. In periods subsequent to the initial measurement of the ARO, we must recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

Stock-Based Compensation

We recognize stock-based compensation expense associated with restricted stock units and options. We account for forfeitures of equity-based incentive awards as they occur. Stock-based compensation expense related to time-based restricted stock units is based on the price of our common stock on the grant date. Stock-based compensation related to options is the fair value of the option recognized over the vesting period. The fair value of an option is determined using the Black-Scholes option valuation with the following assumption inputs: dividend yield, expected annual volatility, risk free interest rate and an expected life.

Income Taxes and Uncertain Tax Positions

Our tax provision is based upon the tax laws and rates in effect in the applicable jurisdiction in which operations are conducted and income is earned. As part of the process of preparing the consolidated financial statements, management is required to estimate the income tax provision. This process involves estimating the actual current tax exposure together with assessing temporary differences resulting from differing treatment of items, such as depreciation, amortization and certain accrued liabilities for tax and accounting purposes.

Deferred tax expense or benefit represents the change in the balance of deferred tax assets or liabilities. Valuation allowances are established to reduce deferred tax assets when it is more likely than not that some portion or all of the deferred tax assets will not be realized. At December 31, 2024 and 2023, a full valuation allowance for deferred tax assets was recorded.

Management applies the accounting standards related to uncertainty in income taxes. This accounting guidance clarifies the accounting for uncertainties in income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the consolidated financial statements. It requires that we recognize in the consolidated financial statements the financial effects of a tax position, if that position is more likely than not of being sustained upon examination, including resolution of any appeals or litigation processes, based upon the technical merits of the position. It also provides guidance on measurement, classification, interest, penalties and disclosure. We had no uncertain tax positions at December 31, 2024, or December 31, 2023.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK.

We are a smaller reporting company as defined by Rule 12b-2 of the Exchange Act and are not required to provide this information.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

The financial statements of the Company are set forth at the end of this Form 10-K.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE.

None.

ITEM 9A. CONTROLS AND PROCEDURES.

Evaluation of Disclosure Controls and Procedures

As of the end of the period covered by this report, the Company carried out an evaluation under the supervision and participation of the Company's Principal Executive Officer/Principal Financial Officer, along with our management, of the effectiveness of the design and operation of the Company's disclosure controls and procedures as defined in Exchange Act Rule 13a-15(e). Based on this evaluation, the Company's Principal Executive Officer/Principal Financial Officer concluded that the disclosure controls and procedures were effective, as of the end of the period covered by this report, in ensuring the information required to be disclosed by the Company in the reports it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to management, including the Company's Chief Executive Officer (Principal Executive Officer/Principal Financial Officer), to allow timely decisions regarding required disclosure.

Inherent Limitations on Effectiveness of Controls

The Company's disclosure controls and procedures and internal control over financial reporting are designed to provide reasonable assurance of achieving their desired objectives. Management recognizes that a control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of their inherent limitations, disclosure controls and procedures and internal control over financial reporting may not prevent or detect all errors or misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as defined in Exchange Act Rule 13a-15(f). The Company's internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Under the supervision and with the participation of the Company's management, including its Principal Executive Officer/Principal Financial Officer, the Company conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework established by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") as set forth in Internal Control - Integrated Framework. Based on our evaluation under that framework, our management concluded that our internal control over financial reporting is effective as of December 31, 2024.

Changes in Internal Control over Financial Reporting

While we continue to implement design enhancements to our internal control procedures, we believe that, there were no changes to our internal control over financial reporting which were identified in connection with the evaluation required by Rules 13a-15(d) or 15d-15(d) under the Exchange Act during the fourth quarter of 2024 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Attestation Report of Registered Public Accounting Firm

This report does not contain an attestation report of our independent registered public accounting firm related to internal control over financial reporting because the rules for smaller reporting companies provide an exemption from the attestation requirement.

ITEM 9B. OTHER INFORMATION.

The Company was not informed by any of its directors or Section 16 officers of the adoption or termination of a "Rule 10b5-1 trading arrangement" or "non-Rule 10b5-1 trading arrangement," as those terms are defined in Item 408 of Regulation S-K, during the fourth quarter of 2024.

ITEM 9C. DISCLOSURE REGARDING FOREIGN JURISDICTIONS THAT PREVENT INSPECTIONS.

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE.

The information called for by this Item 10 is incorporated herein by reference to our definitive Proxy Statement for 2025 annual meeting of stockholders ("2025 Proxy Statement") to be filed with the SEC no later than 120 days following the fiscal year ended December 31, 2024.

ITEM 11. EXECUTIVE COMPENSATION.

The information called for by this Item 11 is incorporated herein by reference to our 2025 Proxy Statement to be filed with the SEC no later than 120 days following the fiscal year ended December 31, 2024.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS.

The information called for by this Item 12 is incorporated herein by reference to our 2025 Proxy Statement to be filed with the SEC no later than 120 days following the fiscal year ended December 31, 2024.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE.

The information called for by this Item 13 is incorporated herein by reference to our 2025 Proxy Statement to be filed with the SEC no later than 120 days following the fiscal year ended December 31, 2024.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES.

The information called for by this Item 14 is incorporated herein by reference to our 2025 Proxy Statement to be filed with the SEC no later than 120 days following the fiscal year ended December 31, 2024.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES.

(a) (1) Financial Statements

The financial statements under this item are included in Item 8 of Part II of this Annual Report on Form 10-K.

(2) Schedules

NONE

(3) Exhibits

Exhibit No.	Description
2.1	Purchase and Sale Agreement dated as of March 12, 2021, by and between Empire New Mexico LLC and XTO Holdings, LLC (incorporated herein by reference to Exhibit 2.1 to the Company's Form 8-K dated May 14, 2021, which was filed on May 17, 2021).
3.1	Amended and Restated Certificate of Incorporation of Empire Petroleum Corporation (incorporated herein by reference to Exhibit 3.1 to the Company's Form 8-K dated March 4, 2022, which was filed on March 9, 2022).

3.2	Certificate of Designation of Series A Voting Preferred Stock of Empire Petroleum Corporation (incorporated herein by reference to Exhibit 3.2 to the Company's Form 8-K dated March 4, 2022, which was filed on March 9, 2022).
3.3	Amended and Restated Bylaws of Empire Petroleum Corporation (incorporated herein by reference to Exhibit 3.3 to the Company's Form 8-K dated March 4, 2022, which was filed on March 9, 2022).
4.1	Description of the Common Stock of Empire Petroleum Corporation (incorporated herein by reference to Exhibit 4.1 to the Company's Form 10-K for the fiscal year ended December 31, 2021, which was filed on March 31, 2022).
4.2	Common Share Warrant Certificate No. Energy Evolution-2 dated May 31, 2024 (incorporated herein by reference to Exhibit 4 to the Company's Form 8-K dated May 24, 2024, which was filed on May 31, 2024).
10.1*	Empire Petroleum Corporation 2019 Stock Option Plan (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated April 3, 2019, which was filed on April 9, 2019).
10.2*	Form of Non-Qualified Stock Option Award Agreement (incorporated herein by reference to Exhibit 10.2 to the Company's Form 8-K dated April 3, 2019, which was filed on April 9, 2019).
10.3	Loan Agreement dated as of August 6, 2020, by and between Empire Texas LLC and Petroleum Independent & Exploration LLC (incorporated herein by reference to Exhibit 10.6 to the Company's Form 8-K dated August 6, 2020, which was filed on August 11, 2020).
10.4*	Employment Agreement dated as of August 18, 2021, by and between Empire Petroleum Corporation and Michael R. Morrisett (incorporated herein by reference to Exhibit 10.2 to the Company's Form 8-K dated August 18, 2021, which was filed on August 24, 2021).
10.5	Loan Modification Agreement dated as of September 29, 2021, by and among Empire New Mexico LLC d/b/a Green Tree New Mexico, Empire Petroleum Corporation and Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated September 29, 2021, which was filed on October 5, 2021).
10.6	Common Share Warrant Certificate dated as of September 30, 2021 issued by Empire Petroleum Corporation in favor of Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10.3 to the Company's Form 8-K dated September 29, 2021, which was filed on October 5, 2021).
10.7*	Empire Petroleum Corporation 2021 Stock and Incentive Compensation Plan (incorporated herein by reference to the Company's Information Statement on Schedule 14C filed August 31, 2021).

10.8*	Form of Non-Qualified Stock Option Award Agreement (incorporated herein by reference to Exhibit 10.24 to the Company's Form 10-K for the fiscal year ended December 31, 2021, which was filed on March 31, 2022).
10.9*	Form of Restricted Stock Units Award Agreement (Non-Employee Directors) (incorporated herein by reference to Exhibit 10.25 to the Company's Form 10-K for the fiscal year ended December 31, 2021, which was filed on March 31, 2022).
10.10*	Form of Restricted Stock Units Award Agreement (Executive Officers) (incorporated herein by reference to Exhibit 10.26 to the Company's Form 10-K for the fiscal year ended December 31, 2021, which was filed on March 31, 2022).
10.11*	Empire Petroleum Corporation 2022 Stock and Incentive Compensation Plan (incorporated herein by reference to Annex A to the Company's Proxy Statement on Schedule 14A filed on July 27, 2022).
10.12*	Empire Petroleum Corporation 2023 Stock and Incentive Compensation Plan (incorporated herein by reference to Annex A to the Company's Proxy Statement on Schedule 14A filed on May 1, 2023).
10.13	Shared Services Agreement, dated as of August 1, 2023, by and between PIE Operating, LLC and Empire Petroleum Corporation (incorporated herein by reference to Exhibit 10.8 to the Company's Form 10-Q for the quarter ended September 30, 2023, which was filed on November 13, 2023).
10.14	Empire North Dakota LLC Promissory Note Due October 31, 2023 in the original aggregate principal amount of $5.0 million in favor of Phil Mulacek (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated September 19, 2023, which was filed on September 25, 2023).
10.15	Empire North Dakota LLC Promissory Note Due October 31, 2023 in the original aggregate principal amount of $5.0 million in favor of Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10.2 to the Company's Form 8-K dated September 19, 2023, which was filed on September 25, 2023).
10.16	Commercial Guaranty Agreement, dated as of September 19, 2023, issued by Empire Petroleum Corporation in favor of Phil Mulacek (incorporated herein by reference to Exhibit 10.3 to the Company's Form 8-K dated September 19, 2023, which was filed on September 25, 2023).
10.17	Commercial Guaranty Agreement, dated as of September 19, 2023, issued by Empire Petroleum Corporation in favor of Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10.4 to the Company's Form 8-K dated September 19, 2023, which was filed on September 25, 2023).
10.18	Letter Agreement amending Senior Revolver Loan Agreement, dated as of September 19, 2023, by and among Empire Louisiana LLC and Empire North Dakota LLC, as borrowers, Empire Petroleum Corporation, as guarantor, and CrossFirst Bank, as lender (incorporated herein by reference to Exhibit 10.5 to the Company's Form 8-K dated September 19, 2023, which was filed on September 25, 2023).
10.19	Subordination Agreement, dated as of September 19, 2023, by and among Phil Mulacek, Energy Evolution Master Fund, Ltd. and Empire North Dakota LLC in favor of CrossFirst Bank (incorporated herein by reference to Exhibit 10.6 to the Company's Form 8-K dated September 19, 2023, which was filed on September 25, 2023).
10.20	Letter Amendment amending the Empire North Dakota LLC Promissory Notes Due October 31, 2023, dated as of October 31, 2023, by and among Phil Mulacek and Energy Evolution Master Fund, Ltd., as investors, Empire North Dakota LLC, as borrower, and Empire Petroleum Corporation, as guarantor (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated October 31, 2023, which was filed on November 1, 2023).

10.21	Empire North Dakota LLC Amended and Restated Promissory Note Due December 31, 2024 in the original aggregate principal amount of $5.0 million in favor of Phil Mulacek (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated November 9, 2023, which was filed on November 13, 2023).
10.22	Empire North Dakota LLC Amended and Restated Promissory Note Due December 31, 2024 in the original aggregate principal amount of $5.0 million in favor of Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10.2 to the Company's Form 8-K dated November 9, 2023, which was filed on November 13, 2023).

10.23	Securities Purchase Agreement, dated as of November 29, 2023, by and between Phil Mulacek and Empire Petroleum Corporation (incorporated herein by reference to Exhibit 10.1 to the Company's Form 8-K dated November 29, 2023, which was filed on November 29, 2023).
10.24	Letter Amendment to Securities Purchase Agreement, dated as of December 1, 2023, by and between Phil Mulacek and Empire Petroleum Corporation (incorporated herein by reference to Exhibit 10 to the Company's Form 8-K dated December 1, 2023, which was filed on December 1, 2023).
10.25	Securities Purchase Agreement, dated as of November 29, 2023, by and between Energy Evolution Master Fund, Ltd. and Empire Petroleum Corporation (incorporated herein by reference to Exhibit 10.2 to the Company's Form 8-K dated November 29, 2023, which was filed on November 29, 2023).
10.26	Revolver Loan Agreement, dated as of December 29, 2023, by and between Empire North Dakota LLC and Empire ND Acquisition LLC, as borrowers, and Equity Bank, as lender (incorporated herein by reference to Exhibit 10 to the Company's Form 8-K dated December 29, 2023, which was filed on January 5, 2024).
10.27	Empire Petroleum Corporation Promissory Note Due February 15, 2026 in the aggregate principal amount of $5.0 million in favor of Energy Evolution Master Fund, Ltd. (incorporated herein by reference to Exhibit 10 to the Company's Form 8-K dated February 16, 2024, which was filed on February 21, 2024).
10.28*	Empire Petroleum Corporation 2024 Stock and Incentive Compensation Plan (incorporated herein by reference to Annex A to the Company's Proxy Statement on Schedule 14A, filed on April 29, 2024).
10.29	Note Repayment and Loan Termination Agreement dated as of July 31, 2024, by and among Petroleum Independent & Exploration, LLC, Empire Texas LLC and Empire Petroleum Corporation (incorporated herein by reference to Exhibit 10 to the Company's Form 8-K dated July 31, 2024, which was filed on August 6, 2024).
10.30	First Amendment to Revolver Loan Agreement dated as of November 18, 2024, by and between Empire North Dakota LLC and Empire ND Acquisition LLC, as borrowers, and Equity Bank, as lender (incorporated herein by reference to Exhibit 10 to the Company's Form 8-K dated November 18, 2024, which was filed on November 22, 2024).
19	Empire Petroleum Corporation Insider Trading Policy (submitted herewith).
21	Subsidiaries of Empire Petroleum Corporation (submitted herewith).
23.1	Consent of Grant Thornton LLP (submitted herewith).
23.2	Consent of Cawley, Gillespie & Associates, Inc. (submitted herewith).
31.1	Rule 13a – 14(a)/15d – 14(a) Certification of Michael R. Morrisett, Chief Executive Officer (submitted herewith).
31.2	Rule 13a – 14(a)/15d – 14(a) Certification of Michael R. Morrisett, Principal Financial Officer (submitted herewith).
32.1	Section 1350 Certification of Michael R. Morrisett, Chief Executive Officer (submitted herewith).
32.2	Section 1350 Certification of Michael R. Morrisett, Principal Financial Officer (submitted herewith).
97*	Empire Petroleum Corporation Policy for the Recovery of Erroneously Awarded Compensation (incorporated herein by reference to Exhibit 97 to the Company's Form 10-K for the fiscal year ended December 31, 2023, which was filed on March 28, 2024).
99.1	Cawley, Gillespie & Associates, Inc. Summary Report (submitted herewith).
101	Financial Statements for Inline XBRL format (submitted herewith).
104	Cover Page Interactive Data File (embedded within Inline XBRL document).

*Indicates a management contract or compensatory plan or arrangement identified under the requirements of Item 15 of Form 10-K.

ITEM 16. FORM 10-K SUMMARY.

None.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

Empire Petroleum Corporation

Date: March 27, 2025

By:/s/ Michael R. Morrisett

Name: Michael R. Morrisett
Title: President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Michael R. Morrisett MICHAEL R. MORRISETT	Director, President and Chief Executive Officer (Principal Executive Officer and Principal Financial Officer)	March 27, 2025
/s/ Matthew E. Watson MATTHEW E. WATSON	Chief Accounting Officer (Principal Accounting Officer)	March 27, 2025
/s/ Phil E. Mulacek PHIL E. MULACEK	Director and Chairman of the Board	March 27, 2025
/s/ Andrew L. Lewis ANDREW L. LEWIS	Director	March 27, 2025
/s/ Mason H. Matschke MASON H. MATSCHKE	Director	March 27, 2025
/s/ Benjamin J. Marchive II BENJAMIN J. MARCHIVE II	Director	March 27, 2025
/s/ J. Kevin Vann J. KEVIN VANN	Director	March 27, 2025

EMPIRE PETROLEUM CORPORATION

CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders
Empire Petroleum Corporation

Opinion on the financial statements
We have audited the accompanying consolidated balance sheets of Empire Petroleum Corporation (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2024 and 2023, the related consolidated statements of operations, changes in stockholders' equity, and cash flows for each of the two years in the period ended December 31, 2024, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2024, in conformity with accounting principles generally accepted in the United States of America.

Basis for opinion
These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company's consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) ("PCAOB") and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audits we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion.

Our audits included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical audit matters
Critical audit matters are matters arising from the current period audit of the financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the financial statements and (2) involved our especially challenging, subjective, or complex judgments. We determined that there are no critical audit matters.

/s/ GRANT THORNTON LLP

We have served as the Company's auditor since 2022.

Tulsa, Oklahoma
March 27, 2025

EMPIRE PETROLEUM CORPORATION
CONSOLIDATED BALANCE SHEETS

	As of December 31, 2024	As of December 31, 2023
ASSETS		
Current Assets:		
Cash	$ 2,251,464	$ 7,792,508
Accounts Receivable	8,154,433	8,354,636
Derivative Instruments	—	406,806
Inventory	1,304,699	1,433,454
Prepaids	640,349	757,500
Total Current Assets	12,350,945	18,744,904
Property and Equipment:		
Oil and Natural Gas Properties, Successful Efforts	140,675,399	93,509,803
Less: Accumulated Depreciation, Depletion and Impairment	(31,974,184)	(22,996,805)

Total Oil and Gas Properties, Net	108,701,215	70,512,998
Other Property and Equipment, Net	1,391,113	1,883,211
Total Property and Equipment, Net	110,092,328	72,396,209
Other Noncurrent Assets	1,425,198	1,474,503
Total Assets	$ 123,868,471	$ 92,615,616
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current Liabilities:		
Accounts Payable	$ 10,452,237	$ 16,437,219
Accrued Expenses	10,347,990	7,075,302
Current Portion of Lease Liability	400,692	432,822
Current Portion of Note Payable - Related Party (Note 7)	—	1,060,004
Current Portion of Long-Term Debt	69,552	44,225
Total Current Liabilities	21,270,471	25,049,572
Long-Term Debt	11,266,127	4,596,775
Long Term Lease Liability	143,689	544,382
Asset Retirement Obligations	28,423,000	27,468,427
Total Liabilities	61,103,287	57,659,156
Commitments and Contingencies (Note 15)		
Stockholders' Equity:		
Series A Preferred Stock - $0.001 Par Value, 10,000,000 Shares Authorized, 6 and 6 Shares Issued and Outstanding, Respectively	—	—
Common Stock - $0.001 Par Value 190,000,000 Shares Authorized, 33,667,132 and 25,503,530 Shares Issued and Outstanding, Respectively	93,188	85,025
Additional Paid-in-Capital	143,488,803	99,490,253
Accumulated Deficit	(80,816,807)	(64,618,818)
Total Stockholders' Equity	62,765,184	34,956,460
Total Liabilities and Stockholders' Equity	$ 123,868,471	$ 92,615,616

The accompanying notes are an integral part of these consolidated financial statements.

EMPIRE PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the Years Ended December 31,	
	2024	**2023**
Revenue:		
Oil Sales	$ 41,515,661	$ 36,684,494
Gas Sales	343,503	1,726,754
NGL Sales	2,132,666	1,660,256
Total Product Revenues	43,991,830	40,071,504
Other	47,348	70,480
Loss on Derivatives	(388,886)	(65,693)
Total Revenue	43,650,292	40,076,291
Costs and Expenses:		
Lease Operating Expense	27,545,028	28,625,481
Production and Ad Valorem Taxes	3,770,078	3,044,411
Depletion, Depreciation & Amortization	9,256,254	3,096,533
Accretion of Asset Retirement Obligation	2,006,756	1,756,022
General and Administrative:		
General and Administrative	12,581,859	12,034,185
Stock-Based Compensation	2,155,774	3,144,750
Total General and Administrative	14,737,633	15,178,935
Total Cost and Expenses	57,315,749	51,701,382
Operating Loss	(13,665,457)	(11,625,091)
Other Income and (Expense):		
Interest Expense	(1,515,269)	(1,000,427)
Other Income (Expense)	(1,017,263)	23,721
Loss Before Taxes	(16,197,989)	(12,601,797)
Income Tax Benefit	—	132,192

	2024	2023
Net Loss	$ (16,197,989)	$ (12,469,605)
Net Loss per Common Share:		
Basic	$ (0.54)	$ (0.55)
Diluted	$ (0.54)	$ (0.55)
Weighted Average Number of Common Shares Outstanding:		
Basic	30,064,856	22,718,890
Diluted	30,064,856	22,718,890

The accompanying notes are an integral part of these consolidated financial statements.

EMPIRE PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS' EQUITY

	Common Stock		Preferred Stock				
	Shares	Par Value	Shares	Par Value	Additional Paid-in-Capital	Accumulated Deficit	Total
Balances as of December 31, 2022	22,093,503	$ 81,615	6	$ —	$ 75,303,479	$ (52,149,213)	$ 23,235,881
Net Loss	—	—	—	—	—	(12,469,605)	(12,469,605)
Impact of Former CEO Settlement	—	—	—	—	(2,126,131)	—	(2,126,131)
Stock Issued for Purchase Option (Note 3)	67,000	67	—	—	600,990	—	601,057
Warrants Exercised	500,000	500	—	—	2,499,500	—	2,500,000
Issuance of Shares for Redemption of Notes	1,263,664	1,264	—	—	10,108,048	—	10,109,312
Issuance of Shares in Private Transaction	1,234,013	1,234	—	—	9,959,962	—	9,961,196
Stock-Based Compensation	345,350	345	—	—	3,144,405	—	3,144,750
Balances as of December 31, 2023	25,503,530	$ 85,025	6	$ —	$ 99,490,253	$ (64,618,818)	$ 34,956,460
Net Loss	—	—	—	—	—	(16,197,989)	(16,197,989)
Rights Offerings (Note 9)	6,112,430	6,112	—	—	30,478,376	—	30,484,488
Partial Conversion of Option to Purchase (Note 3)	616,800	617	—	—	3,231,655	—	3,232,272
Warrants Exercised	128,800	129	—	—	949,642	—	949,771
Conversion of Related-Party Note (Note 7)	1,005,427	1,005	—	—	7,246,605	—	7,247,610
Stock-Based Compensation	300,145	300	—	—	2,092,272	—	2,092,572
Balances as of December 31, 2024	33,667,132	$ 93,188	6	$ —	$ 143,488,803	$ (80,816,807)	$ 62,765,184

The accompanying notes are an integral part of these consolidated financial statements.

EMPIRE PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the Years Ended December 31,	
	2024	2023
Cash Flows From Operating Activities:		
Net Loss	$ (16,197,989)	$ (12,469,605)
Adjustments to Reconcile Net Loss to Net Cash Provided By (Used In) Operating Activities:		
Stock-Based Compensation	2,155,774	3,144,750
Amortization of Right of Use Assets	540,401	423,689
Depreciation, Depletion and Amortization	9,256,254	3,096,533
Accretion of Asset Retirement Obligation	2,006,756	1,756,022

Loss on Commodity Derivatives	388,886	65,695
Settlement on or Purchases of Derivative Instruments	18,200	(353,695)
Loss on Financial Derivatives (See Note 7)	998,000	—
Amortization of Debt Discount on Convertible Notes	500,382	—
Loss on Extinguishment of Debt	10,094	—
Change in Operating Assets and Liabilities:		
Accounts Receivable	(357,473)	(2,700,528)
Inventory, Oil in Tanks	128,755	(160,827)
Prepaids, Current	607,925	745,648
Accounts Payable	5,019,857	751,355
Accrued Expenses	2,144,204	(3,082,928)
Other Long Term Assets and Liabilities	(1,063,023)	(1,103,607)
Net Cash Provided By (Used In) Operating Activities	6,157,003	(9,887,500)
Cash Flows From Investing Activities:		
Acquisition of Oil and Natural Gas Properties	—	(2,094,419)
Capital Expenditures - Oil and Natural Gas Properties (1)	(53,219,169)	(14,546,873)
Purchase of Other Fixed Assets	(151,638)	(352,851)
Cash Paid for Right of Use Assets	(498,654)	(552,196)
Sinking Fund Deposit	—	2,779,000
Net Cash Used In Investing Activities	(53,869,461)	(14,767,339)
Cash Flows From Financing Activities:		
Borrowings on Credit Facility	6,650,000	14,492,484
Proceeds from Promissory Note - Related Party (Note 7)	5,000,000	—
Proceeds from Rights Offerings, net of transaction costs (Note 9)	30,484,488	—
Principal Payments of Debt	(591,975)	(6,450,774)
Proceeds from Stock Issuance and Warrant Exercises	628,901	12,461,195
Net Cash Provided By Financing Activities	42,171,414	20,502,905
Net Change in Cash	(5,541,044)	(4,151,934)
Cash - Beginning of Period	7,792,508	11,944,442
Cash - End of Period	$ 2,251,464	$ 7,792,508
Supplemental Cash Flow Information:		
Cash Paid for Interest	$ 894,282	$ 650,637

(1) Incurred capital expenditures were $42,214,332 and $25,053,107 for the respective periods. The differences between incurred and cash capital expenditures is due to changes in related accounts payable.

The accompanying notes are an integral part of these consolidated financial statements.

EMPIRE PETROLEUM CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Note 1 - Organization and Basis of Presentation

Empire Petroleum Corporation (the "Company", collectively with its subsidiaries) is an independent energy company operator engaged in optimizing developed production by employing field management methods to maximize reserve recovery while minimizing costs. Empire operates the following wholly-owned subsidiaries in its areas of operations:

- Empire New Mexico LLC ("Empire New Mexico"), consisting of the following entities:
  - Empire New Mexico LLC d/b/a Green Tree New Mexico
  - Empire EMSU LLC
  - Empire EMSU-B LLC
  - Empire AGU LLC
  - Empire NM Assets LLC
- Empire North Dakota ("Empire North Dakota"), consisting of the following entities:
  - Empire North Dakota LLC ("Empire North Dakota")
  - Empire ND Acquisition LLC ("Empire NDA")
- Empire Texas ("Empire Texas"), consisting of the following entities:
  - Empire Texas LLC
  - Empire Texas Operating LLC
  - Empire Texas GP LLC
  - Pardus Oil & Gas Operating, LP (owned 1% by Empire Texas GP LLC and 99% by Empire Texas LLC)
- Empire Louisiana LLC ("Empire Louisiana")

Empire was incorporated in the State of Delaware in 1985. The consolidated financial statements of Empire Petroleum Corporation and subsidiaries include the accounts of the Company and its wholly-owned subsidiaries. The terms "Company," "we," "us," "our," and similar terms refer to Empire Petroleum Corporation and its subsidiaries.

Liquidity and Going Concern

The Company has a revolving line of credit agreement with Equity Bank which requires the Company to maintain compliance with certain financial covenants computed on a quarterly and annual basis. As of December 31, 2024, the Company was in compliance with all required covenants and projected to be in compliance with all debt covenants over the next 12 months. However, the Company was in default of its covenants in the third quarter of 2024 but obtained a waiver on November 12, 2024, to alleviate all prior defaults. The Company carried a negative working capital of approximately $8.9 million as of December 31, 2024, an overall decline of approximately $2.6 million from the previous year. Cash on hand also declined approximately $5.5 million during the same period. The overall decline in working capital and cash is primarily driven by the Starbuck Drilling Program in North Dakota which incurred substantial capital spend. Additionally, the Company initiated a return-to-production program in Texas which incurred additional unforeseen operational costs. The additional production from these projects did not fully offset the costs incurred and contributed to the overall negative financial trend. To meet its obligations, the Company increased its revolver commitment to $20.0 million in November 2024 and had two rights offerings in April and November of 2024 which raised approximately $30.5 million of capital, net of transaction costs, to help fund the capital spend projects. Additionally, as a result of increasing its revolver commitment, the Company had approximately $8.7 million remaining unused commitment as of December 31, 2024, which can be used for future obligations. However, the revolver commitment is reduced monthly by $0.25 million commencing on December 31, 2024 (See Note 7), limiting future access to capital. While these debt and equity transactions provided additional funding towards these projects and other obligations, the Company still carried approximately $8.9 million of negative working capital at period end and future expected operating cash flows do not sufficiently meet the Company's obligations for the next 12 months. Given the negative working capital and insufficient expected operating cash flow there is substantial doubt about the Company's ability to continue as a going concern.

Empire has committed financial support from Phil Mulacek who owns approximately 21.2% of our common stock outstanding as of December 31, 2024, and Energy Evolution, our largest stockholder who owns approximately 31.9% of our common stock outstanding as of December 31, 2024. Both are related parties of the Company (see Note 14). Mr. Mulacek and Energy Evolution are willing and able to provide these additional funds, if required, for Empire to continue to meet its obligations over the next 12 months. These additional funds may be raised through related party warrants or a related party note payable that may or may not have conversion rights into shares of common stock of Empire.

Management has considered these plans in evaluating FASB ASC 205-40, *Presentation of Financial Statements - Going Concern*. Management believes the above actions are sufficient to allow Empire to meet its obligations as they become due within one year after the date the financial statements are issued. Management believes that its plans, and support from the existing related-party stockholders discussed above, is probable and has alleviated the substantial doubt regarding Empire's ability to continue as a going concern.

Note 2 – Summary of Significant Accounting Policies

Principles of Consolidation

The consolidated financial statements include the accounts and balances of the Company and have been prepared in accordance with US GAAP. All intercompany accounts and transactions have been eliminated in consolidation.

Use of Estimates

The preparation of financial statements in conformity with US GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. Actual results could differ from those estimates.

Estimated quantities of crude oil, natural gas and NGLs reserves are the most significant of the Company's estimates. All reserve data used in the preparation of the consolidated financial statements, including depletion estimates, and information included in Note 19 - Supplemental Information of Oil and Natural Gas Producing Activities (Unaudited), are based on estimates. Reservoir engineering is a subjective process of estimating underground accumulations of crude oil, natural gas and NGLs. There are numerous uncertainties inherent in estimating quantities of proved crude oil, natural gas and NGLs reserves. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, reserve estimates may be different from the quantities of crude oil, natural gas and NGLs that are ultimately recovered.

Other items subject to estimates and assumptions include, but are not limited to, the carrying amounts of property, plant and equipment, asset retirement obligations, valuation allowances for deferred income tax assets, and valuation of derivative instruments. Management evaluates estimates and assumptions on an ongoing basis using historical experience and other factors, including the current economic and commodity price environment. The volatility of commodity prices results in increased uncertainty inherent in such estimates and assumptions.

Although management believes these estimates are reasonable, actual results may differ from estimates and assumptions of future events and these revisions could be material. Future production may vary materially from estimated oil and natural gas proved reserves. Actual future prices may vary significantly from price assumptions used for determining proved reserves and for financial reporting.

Out of Period Adjustments

In the third quarter of 2022, the Company identified and recorded an out-of-period adjustment related to the joint development agreement ("JDA") discussed in Note 7. In 2023, the impact of recording this adjustment reduced other noncurrent assets and increased lease operating expense by approximately $1.3 million of which $0.8 million related to prior to 2023. The impact of the adjustment was immaterial to the prior period financial statements and thus corrected in 2023. No adjustments were made in 2024.

Accounts Receivable

Accounts receivable include estimated amounts due from crude oil, natural gas, and NGLs purchasers and from non-operating working interest owners. Accrued revenue related to product sales from purchasers and operators are due under normal trade terms, generally requiring payment within 60 days of production. For receivables from joint interest owners, the Company generally has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings.

Receivables are stated at amounts due, net of an allowance for credit losses, if necessary and are considered past due if full payment is not received by the contractual due date. The Company estimates uncollectible amounts based on the length of time that the accounts receivable has been outstanding, historical collection experience and current and future economic and market conditions, if failure to collect is expected to occur. Past due accounts are generally written off against the allowance for credit losses account only after all collection attempts have been exhausted. The Company did not have an allowance for credit losses at either December 31, 2024 or 2023.

The Company's accounts receivable are as follows:

	As of December 31,	
	2024	2023
Oil, Gas and NGLs receivables	$ 2,627,885	$ 2,784,745
Joint interest billings	5,071,508	4,549,331
Joint interest billings - related party	394,311	895,000
Other	60,729	125,560
Total Accounts receivable	$ 8,154,433	$ 8,354,636

Concentrations of Credit Risk

Empire's accounts receivable are primarily receivables from oil and natural gas purchasers and joint interest owners. The oil and natural gas purchasers consist primarily of independent marketers, major oil and natural gas companies and gas pipeline companies. Historically, the Company has not experienced any significant losses from uncollectible accounts from its oil and natural gas purchasers. The Company operates a substantial portion of its oil and natural gas properties. As the operator of a property we make full payments for costs associated with the property and seek reimbursement from the other working interest owners in the property for their share of those costs. Joint operating agreements govern the operations of an oil or natural gas well and, in most instances, provide for the offsetting of amounts payable or receivable between the Company and its joint interest owners. Our joint interest partners consist primarily of independent oil and natural gas producers. If the oil and natural gas exploration and production industry in general were adversely affected, the ability of the joint interest partners to reimburse Empire could be adversely affected.

Convertible Debt and Derivative Instruments

During the year ended December 31, 2024, Empire added the following significant accounting policy and estimate relating to convertible debt and derivative liability.

In connection with Empire's issuance of a promissory note in the first quarter of 2024, Empire bifurcated the embedded conversion option and recorded the embedded conversion option as a long-term derivative liability in Empire's consolidated balance sheets in accordance with FASB ASC 815, *Derivatives and Hedging*. The convertible debt and the derivative liability associated with the promissory note were presented on the consolidated balance sheets as the long-term note payable – related party and long-term derivative instruments. The convertible debt was carried at amortized cost. The derivative liability was remeasured at each reporting period using a binomial lattice model with changes in fair value recorded in the consolidated statements of operations in other income (expense). The conversion option related to the promissory note was exercised in the second quarter of 2024. See Note 7 for further details.

The Company enters into hedge agreements to manage its exposure to oil and natural gas price fluctuations. The fair value of derivative contracts is recognized as an asset or liability on the Company's consolidated balance sheets. Realized gain or loss is recognized as a component of revenue when the derivative contracts mature. For contracts which have not matured, an unrealized gain or loss is recorded based on the change in the fair value of the outstanding contracts.

Inventory

Inventory primarily consists of oil in tanks which has not been delivered and is valued at the lower of cost or net realizable value.

Leases

The Company's right-of-use operating lease assets and lease liabilities are primarily for leased vehicles for field operations and office spaces. Some of these lease agreements include variable payments for non-lease components such as common area maintenance.

Oil and Natural Gas and Other Properties

The Company uses the successful efforts method of accounting for its oil and gas activities. Costs incurred are deferred until exploration and completion results are evaluated. At such time, costs of activities with economically recoverable reserves are capitalized as proven properties, and costs of unsuccessful or uneconomical activities are expensed.

Capitalized drilling costs are reviewed periodically for impairment. Costs related to impaired prospects or unsuccessful exploratory drilling are charged to expense. Management's assessment of the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such leaseholds impact the amount and timing of impairment provisions. An impairment expense could result if oil and gas prices decline in the future as it may not be economical to develop some of these unproved properties.

Lease options are capitalized as unproved property acquisition costs and are reviewed for impairment if indicators exist that the carrying value of the lease option may not be recoverable. If the lease options become impaired, expire or are abandoned, the options will be expensed. If proved reserves are discovered after the options are exercised, these costs will be reclassified as proved property.

Depletion and amortization of producing properties is computed on the units-of-production method on a property-by-property basis. The units-of-production method is based primarily on estimates of proved reserve quantities. Due to uncertainties inherent in this estimation process, it is at least reasonably possible that reserve quantities will be revised in the near term. Changes in estimated reserve quantities are applied to depletion and amortization computations prospectively.

Other property and equipment is depreciated on the straight-line method.

Segment Reporting

The Company operates as one operating segment and one reportable segment which is engaged in the exploration, development, and production of oil, gas, and NGLs in New Mexico, North Dakota, Montana, Texas, and Louisiana, from which all of its revenues are derived and expenses incurred. All financial results are reviewed by the Chief Executive Officer ("CEO"), the Company's Chief Operating Decision Maker ("CODM"), on a consolidated basis to evaluate performance of the Company. The single segment constitutes all of the consolidated entity and the accompanying consolidated financial statements and the notes to the accompanying consolidated financial statements are representative of such amounts. Refer to Note 18 for further discussion.

Debt Issuance Costs

Debt issuance fees, which are recorded at cost, net of amortization, are amortized over the life of the respective debt agreements utilizing the straight-line method. We had approximately $0.2 million and $0.1 million of unamortized debt issuance costs as of year-end December 31, 2024 and 2023, respectively. Unamortized debt issuance costs related to the Company's credit facility are recorded in other noncurrent assets on the Company's consolidated balance sheets.

Asset Retirement Obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related oil and natural gas property asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depletion of the asset. Changes in the liability due to passage of time are recognized as an increase in the carrying amount of the liability through accretion expense. Based on certain factors, including commodity prices and costs, the Company may revise its previous estimates of the liability, which would also increase or decrease the related oil and natural gas property asset.

Revenue Recognition

The Company's revenues are comprised solely of revenues from customers and include the sale of oil, natural gas and NGLs. The Company believes that the disaggregation of revenue into these three major product types, as presented in the consolidated statements of operations, appropriately depicts how the nature, amount, timing and uncertainty of revenue and cash flows are affected by economic factors based on its single geographic region, the continental United States. Revenues are recognized at a point in time when production is sold to a purchaser at a determinable price, delivery has occurred, control has transferred and it is probable substantially all of the consideration will be collected. The Company fulfills its performance obligations under its customer contracts through delivery of oil, natural gas and NGLs and revenues are recorded on a monthly basis. The Company receives payment from one to three months after delivery. Generally, each unit of product represents a separate performance obligation. The prices received for oil, natural gas and NGLs sales under the Company's contracts are generally derived from stated market prices which are then adjusted to reflect deductions including transportation, fractionation and processing. As a result, revenues from the sale of oil, natural gas and NGLs will decrease if market prices decline. The sales of oil, natural gas and NGLs, as presented on the consolidated statements of operations, represent the Company's share of revenues net of royalties and excluding revenue interests owned by others. When selling oil, natural gas and NGLs on behalf of royalty or working interest owners, the Company is acting as an agent and thus reports the revenue on a net basis. To the extent actual volumes and prices of oil and natural gas sales are unavailable for a given reporting period because of timing or information not received from third parties, the expected sales volumes and prices for those properties are estimated and recorded. Variances between the Company's estimated revenue and actual payment are recorded in the month the payment is received. Historically, these differences have been insignificant.

At the end of each month when the performance obligation is satisfied, the variable consideration can be reasonably estimated and amounts due from customers are recorded in accounts receivable on the consolidated balance sheets. Taxes assessed by governmental authorities on oil, natural gas and NGLs sales are presented separately from such revenues in the consolidated statements of operations.

Oil Sales

Oil production is transported from the wellhead to tank batteries or delivery points through flow-lines or gathering systems. Purchasers of the oil take delivery at the tank batteries and transport the oil by truck or at a pipeline delivery point and the Company collects a market price, net of pricing differentials. Revenue is recognized when control transfers to the purchaser at the net price received by the Company.

Natural Gas and NGLs Sales

Under the Company's natural gas sales arrangements, the purchaser takes control of wet gas at a delivery point near the wellhead or at the inlet of the purchaser's processing facility. The purchaser gathers and processes the wet gas and remits proceeds to the Company for the resulting natural gas and NGLs sales. Based on the nature of these arrangements, the purchaser is the Company's processor, thus, the Company recognizes natural gas and NGLs sales based on the net amount of proceeds received from the purchaser.

Transaction Price Allocated to Remaining Performance Obligations

Substantially all of the Company's product sales are short-term in nature with a contract term of one year or less. For these contracts, the Company has utilized the practical expedient in ASU 2024, *Revenue from Contracts with Customers* ("Topic 606") which exempts the Company from the requirements to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of a contract that has an original expected duration of one year or less.

For the Company's product sales that have a contract term greater than one year, the Company has utilized the practical expedient in Topic 606 which states the Company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under these contracts, each unit of product generally represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required.

Prior-Period Performance Obligations

The Company records revenue in the month that product is delivered to the purchaser. Settlement statements for certain natural gas and NGLs sales, however, may not be received for 30 to 90 days after the date the product is delivered, and as a result the Company is required to estimate the amount of product delivered to the purchaser and the price that will be received for the sale of the product. In these situations, the Company records the differences between its estimates and the actual amounts received for product sales in the month that payment is received from the purchaser. Any identified differences between the Company's revenue estimates and actual revenue received have historically been insignificant. For the years ended December 31, 2024 and 2023, revenue recognized in the reporting period related to performance obligations satisfied in prior reporting periods was not material.

Stock-Based Compensation

The Company recognizes stock-based compensation expense associated with equity-based incentive awards consisting of stock options and restricted stock units. The Company accounts for forfeitures of equity-based incentive awards as they occur. Stock-based compensation expense related to equity-based awards is generally recognized as vesting occurs. See Note 10 for further discussion.

Income Taxes

The Company accounts for income taxes in accordance with the asset and liability method of accounting for income taxes. Under the asset and liability method, deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carry forwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to the taxable income in the years in which those temporary differences are expected to be recovered or settled. A valuation allowance is established if management determines it is more likely than not that some portion of a deferred tax asset will not be realized. Interest and penalties, if any, related to accrued liabilities for potential tax assessments are included in income tax benefit (expense) on the consolidated statements of operations.

Per Share Amounts

The Company calculates and discloses basic earnings per share ("Basic EPS") and diluted earnings per share ("Diluted EPS"). The computation of basic earnings per share is computed by dividing earnings available to common stockholders by the weighted average number of outstanding common shares during the period.

Diluted EPS gives effect to all dilutive potential common shares outstanding during the period. The computation of Diluted EPS does not assume conversion, exercise or contingent exercise of securities that would have an anti-dilutive effect on losses. As a result, if there is a loss from continuing operations, Diluted EPS is computed in the same manner as Basic EPS.

Fair Value Measurements

The FASB ASC 820, *Fair Value Measurement* ("Topic 820") standards define fair value, establish a consistent framework for measuring fair value and establish a fair value hierarchy based on the observability of inputs used to measure fair value.

The three-level fair value hierarchy for disclosure of fair value measurements defined by Topic 820 is as follows:

Level 1 – Unadjusted, quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. An active market is defined as a market where transactions for the financial instrument occur with sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Inputs, other than quoted prices within Level 1, that are either directly or indirectly observable for the asset or liability through correlation with market data at the measurement date and for the duration of the instrument's anticipated life.

Level 3 – Prices or valuations that require unobservable inputs that are both significant to the fair value measurement and unobservable. Valuation under Level 3 generally involves a significant degree of judgment from management.

A financial instrument's level within the fair value hierarchy is based on the lowest level of any input that is significant to the fair value measurement. Where available, fair value is based on observable market prices or parameters or derived from such prices or parameters. Where observable prices or inputs are not available, valuation models are applied. These valuation techniques involve some level of management estimation and judgment, the degree of which is dependent on the price transparency for the instruments or market and the instrument's complexity. The Company reflects transfers between the three levels at the beginning of the reporting period in which the availability of observable inputs no longer justifies classification in the original level. There were no transfers between fair value hierarchy levels for the years ended December 31, 2024 and 2023. See Note 17.

Related Party Transactions

Transactions between related parties are considered to be related party transactions even though they may not be given accounting recognition. FASB ASC 850, *Related Party Disclosures* ("Topic 850") requires that transactions with related parties that would have influence in decision making shall be disclosed so that users of the financial statements can evaluate their significance. Related party transactions typically occur within the context of the following relationships: affiliates of the entity; entities for which investments in their equity securities is typically accounted for under the equity method by the investing entity; trusts for the benefit of employees; principal owners of the entity and members of their immediate families; management of the entity and members of their immediate families; and other parties that can significantly influence the management or operating policies of the transacting parties and can significantly influence the other to an extent that one or more of the transacting parties might be prevented from fully pursuing its own separate interests.

Recently Issued Accounting Pronouncements

The FASB periodically issues new accounting standards in a continuing effort to improve standards of financial accounting and reporting. The Company has reviewed the recently issued pronouncements and concluded that the following new accounting standards are applicable:

In June 2016, the FASB issued ASU 2016-13, *Financial Instruments – Credit Losses*. This ASU, as further amended, affects trade receivables, financial assets and certain other instruments that are not measured through net income. This ASU will replace the currently required incurred loss approach with an expected loss model for instruments measured at amortized cost and is effective for financial statements issued for fiscal years beginning after December 15, 2022, including interim periods within those fiscal years. The adoption of this ASU on January 1, 2023, by the Company did not have a material impact on the Company's consolidated financial statements as the Company does not have a history of credit losses.

In August 2020, the FASB issued ASU 2020-06, *Debt—Debt with Conversion and Other Options* ("Subtopic 470-20") and *Derivatives and Hedging—Contracts in Entity's Own Equity: Accounting for Convertible Instruments and Contracts in an Entity's Own Equity* ("Subtopic 815-40"). The amendments in this ASU affect entities that issue convertible instruments and/or contracts in an entity's own equity. The amendments in this ASU primarily affect convertible instruments issued with beneficial conversion features or cash conversion features because the accounting models for those specific features are removed. However, all entities that issue convertible instruments are affected by the amendments to the disclosure requirements of this ASU. For contracts in an entity's own equity, the contracts primarily affected are freestanding instruments and embedded features that are accounted for as derivatives under the current guidance because of failure to meet the settlement conditions of the derivatives scope exception related to certain requirements of the settlement assessment. Also affected is the assessment of whether an embedded conversion feature in a convertible instrument qualifies for the derivatives scope exception. Additionally, the amendments in this ASU affect the diluted EPS calculation for instruments that may be settled in cash or shares and for convertible instruments. The amendments in this ASU are effective for public business entities, excluding entities eligible to be smaller reporting companies, for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. For all other entities, the amendments are effective for fiscal years beginning after December 15, 2023, including interim periods within those fiscal years. The Board specified that an entity should adopt the guidance as of the beginning of its annual fiscal year. The Company adopted this standard on January 1, 2024 through a modified retrospective method of transition and determined it did not impact the prior period financials. The adoption also did not have a material impact on our current period consolidated financial statements.

In November 2023, FASB issued ASU 2023-07, *Segment Reporting* ("Topic 280"). This update requires that a public entity, including entities with a single reportable segment, disclose significant segment expenses that are regularly provided to the chief operating decision maker, as well as other segment items that are included in the calculation of segment profit or loss. A public entity will also be required to disclose all annual disclosures about a reportable segment's profit or loss currently required by Topic 280 in interim periods. Although a public entity is permitted to disclose multiple measures of a segment's profit or loss, at least one of the reported segment profit or loss measures should be consistent with the measurement principles used in measuring the corresponding amounts of the public entity's consolidated financial statements. Further, a public entity must disclose the title and position of the CODM as well as how the CODM uses the reported measure(s) of segment profit or loss in assessing segment performance and deciding how to allocate resources. The amendments in this update are effective for fiscal years beginning after December 15, 2023, and interim periods within fiscal years beginning after December 15, 2024. See Note 18.

In December 2023, FASB, issued ASU 2023-09, *Income Taxes: Improvements to Income Tax Disclosures* ("Topic 740"). The guidance in Topic 740 improves the transparency of income tax disclosures by greater disaggregation of information in the rate reconciliation and income taxes paid disaggregated by jurisdiction. The standard is effective for public companies for fiscal years beginning after December 15, 2024 with early adoption permitted and should be applied prospectively. The Company is currently evaluating the impact of this standard on its consolidated financial statements and related disclosures.

In November 2024, the FASB issued ASU 2024-03, *Income Statement – Reporting Comprehensive Income – Expense Disaggregation Disclosures* ("Subtopic 220-40"), which expands disclosures around a public entity's costs and expenses of specific items (i.e., employee compensation, DD&A), requires the inclusion of amounts that are required to be disclosed under US GAAP in the same disclosure as other disaggregation requirements, requires qualitative descriptions of amounts remaining in expense captions that are not separately disaggregated quantitatively, and requires disclosure of total selling expenses, and in annual periods, the definition of selling expenses. The amendment does not change or remove existing disclosure requirements. The amendment is effective for fiscal years beginning after December 15, 2026, and interim periods within fiscal years beginning after December 15, 2027. Early adoption is permitted, and the amendment can be adopted prospectively or retrospectively to any or all periods presented in the financial statements. Empire is currently assessing the impact of adopting this standard which is expected to only affect financial statement disclosures.

Note 3 – Property

Empire follows the successful efforts method of accounting for its oil and natural gas activities. Under this method, costs to acquire oil and natural gas properties and costs incurred to drill and equip development and exploratory wells are deferred until exploration and completion results are evaluated. Exploration drilling costs are expensed if recoverable reserves are not found. Upon sale or retirement of oil and natural gas properties, the costs and related accumulated depletion and amortization are eliminated from the accounts and the resulting gain or loss is recognized.

Costs incurred to maintain wells and related equipment and lease and well operating costs are charged to expense as incurred.

Depletion is calculated on a unit-of-production basis at the field level based on total proved developed reserves.

Proved oil and natural gas properties are reviewed for impairment at least annually, or as indicators of impairment arise. There have been no indicators of impairment during the years ended December 31, 2024 and 2023.

The aggregate capitalized costs of oil and natural gas properties are as follows:

	As of December 31,	
	2024	2023
Proved properties	$ 134,239,227	$ 75,346,623
Unproved properties	3,857,862	3,245,431
Work in process	2,578,310	14,917,749
Gross capitalized costs	140,675,399	93,509,803
Accumulated depletion, amortization and impairment	(31,974,184)	(22,996,805)
Total Oil and gas properties, net	$ 108,701,215	$ 70,512,998

Depletion amortization expense related to oil and gas properties for the years ended December 31, 2024 and 2023, was approximately $9.0 million and $2.8 million, respectively.

Empire has completed 13 wells in North Dakota related to our Starbuck Drilling Program during the year ended December 31, 2024.

On August 9, 2023, the Company and a subsidiary of Energy Evolution, a related party, collectively acquired additional working interests in certain of the Company's New Mexico properties. The Company paid $2.1 million in cash and acquired 10% of the total acquired working interests in the transaction. The subsidiary of Energy Evolution acquired the other 90% of the acquired working interest ("EEF Interest"). The Company has a one-year option to acquire the EEF Interest for $5.0 million, subject to adjustments ("Purchase Option"). In exchange for the Purchase Option, the Company issued 67,000 shares of common stock valued at approximately $0.6 million and reflected in other noncurrent assets. The Company has the right to extend the initial one-year Purchase Option period for two successive one-year periods by agreeing to issue an additional 42,000 shares of common stock prior to the end of the one-year period then in effect. The Purchase Option may be exercised by the Company at any time during the one-year period then in effect by sending a written notice to Energy Evolution prior to the expiration of such one-year period.

On April 9, 2024, Empire partially exercised the Purchase Option to acquire additional working interests in certain of Empire New Mexico's properties from Energy Evolution, a related party. The additional assets acquired represent approximately 60% of the total assets collectively acquired by Empire and Energy Evolution in the third quarter of 2023 (the "Option Assets"). As consideration, upon closing of the partial exercise of the Purchase Option, Empire issued Energy Evolution 600,000 shares of common stock of Empire based on an agreed upon price of $5.00 per share for an aggregate agreed upon value of $3.0 million which was 60% of the purchase price of $5.0 million under the Purchase Option. Pursuant to the remaining unexercised portion of the Purchase Option, Empire had the right to extend the initial one-year Purchase Option period for two successive one-year periods by agreeing to issue additional shares of common stock prior to the end of the one-year period then in effect.

On August 8, 2024, Empire successfully extended the Purchase Option with the issuance of 16,800 shares of common stock to Energy Evolution, and as such, Empire has the right to acquire the remaining Option Assets for an exercise price of $2.0 million, subject to certain adjustments and payable in cash, unless the parties agree that some or all may be paid by issuance of common stock to Energy Evolution. The Purchase Option expires on August 9, 2026.

Other property and equipment consists of operating lease assets, vehicles, office furniture, and equipment with lives ranging from three to five years. The capitalized costs of other property and equipment are as follows:

	As of December 31,	
	2024	2023
Other property and equipment, at cost	$ 3,303,829	$ 2,998,018
Less: accumulated depreciation	(1,912,716)	(1,114,807)
Other property and equipment, net	$ 1,391,113	$ 1,883,211

Depreciation expense related to other property and equipment for the years ended December 31, 2024 and 2023, was approximately $0.3 million and $0.2 million, respectively.

Note 4 - Asset Retirement Obligations

The Company's asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws.

Market risk premiums associated with asset retirement obligations are estimated to represent a component of the Company's credit-adjusted risk-free rate that is utilized in the calculations of asset retirement obligations.

The Company's asset retirement obligation activities are summarized in the following table:

	For the Years Ended December 31,			
		2024		2023
Asset retirement obligations, beginning of period	$	28,168,427	$	25,000,740
Liabilities incurred from drilling activity and assumed in acquisitions		876,955		72,000
Revisions		—		2,303,938
Liabilities settled		(864,137)		(964,274)
Accretion expense		2,006,755		1,756,023
Asset retirement obligation, end of period	$	30,188,000	$	28,168,427
Less: current portion included in Accrued expenses		1,765,000		700,000
Asset retirement obligation, long-term	$	28,423,000	$	27,468,427

The liabilities incurred from drilling activity in 2024 primarily relate to the completion of new wells as part of Empire's North Dakota Starbuck Drilling Program. The liabilities assumed in acquisitions in 2024 relate to additional working interest acquired in New Mexico.

Note 5 – Commodity Derivative Financial Instruments

The Company has used derivative financial instruments to manage its exposure to commodity price fluctuations in the past. Commodity derivative instruments have been used to reduce the effect of volatility of price changes on the oil and natural gas the Company produces and sells. The Company does not enter into derivative financial instruments for speculative or trading purposes. The Company's derivative financial instrument activity has consisted of swaps and put options.

The Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its consolidated statements of operations as they occur. These contracts are recognized and recorded at fair value as an asset or liability on the Company's consolidated balance sheets. Cash receipts or payments upon settlement of swaps and put options are reflected in the operating activities section of its consolidated statements of cash flows.

The following table summarizes the net realized and unrealized amounts reported in earnings related to the oil derivative instruments:

	For the Years Ended December 31,			
		2024		2023
Gain (loss) on derivatives, realized	$	18,200	$	(353,695)
Gain (loss) on derivatives, unrealized		(407,086)		288,002
Loss on derivatives, net	$	(388,886)	$	(65,693)

The following table represents the Company's net cash receipts from (payments on) derivatives:

	For the Years Ended December 31,			
		2024		2023
Cash receipts from (payments on) on oil derivatives, net	$	18,200	$	(353,695)

The Company did not have any open commodity derivative positions as of December 31, 2024.

Note 6 – Accrued Expenses

The following table represents the Company's accrued expenses:

	As of December 31,			
		2024		2023
Accrued and suspended third-party revenue	$	5,986,597	$	4,049,984
Accrued salaries and payroll taxes		1,091,125		1,059,295
Accrued production taxes		836,784		829,226
Asset retirement obligation - current		1,765,000		700,000
Other		668,484		436,797
Total Accrued Expenses	$	10,347,990	$	7,075,302

Note 7 – Debt Including Debt with Related Parties

The following table represents the Company's outstanding debt:

	As of December 31,	
	2024	2023
Equity Bank Credit Facility	$ 11,088,647	$ 4,492,484
Note Payable – Related Party	—	1,060,004
Equipment and vehicle notes, 0.00% to 9.59% interest rates, due in 2025 to 2029 with monthly payments ranging from $900 to $1,400 per month (1)	247,032	148,516
Total Debt	11,335,679	5,701,004
Less: Current Maturities	(69,552)	(44,225)
Less: Note Payable – Related Party	—	(1,060,004)
Long-Term Debt	$ 11,266,127	$ 4,596,775

(1)Weighted-average interest rate of 8.32%

On July 7, 2021, the Company entered into the Fourth Amendment to its Senior Revolver Loan Agreement with CrossFirst Bank ("CrossFirst") as further amended by Letter Agreements in conjunction with redetermination dates (the "Amended Agreement"). The maximum amount that could be advanced under the Amended Agreement was $ 20.0 million and the commitment amount following an August 9, 2023, amendment agreement was approximately $5.2 million. The Amended Agreement was subsequently retired with proceeds from the new revolver loan agreement discussed below.

On December 29, 2023, Empire North Dakota and Empire NDA ("Borrowers"), entered into a revolver loan agreement with Equity Bank (the "Credit Facility"). Pursuant to the Credit Facility (a) the initial revolver commitment amount is $10.0 million; (b) the maximum revolver commitment amount is $15.0 million; (c) commencing on January 31, 2024, and occurring on the last day of each calendar month thereafter, the revolver commitment amount is reduced by $150,000; (d) commencing on March 31, 2024, there are scheduled semiannual collateral borrowing base redeterminations each year on March 31 and September 30; (e) the final maturity date is December 29, 2026; (f) outstanding borrowings bear interest at a rate equal to the prime rate of interest plus 1.50%, and in no event lower than 8.50%; (g) a quarterly commitment fee is based on the unused portion of the commitments; and (h) Borrowers have the right to prepay loans under the Credit Facility at any time without a prepayment penalty.

The Credit Facility is guaranteed by the Company. Borrowers entered into a security agreement, pursuant to which the obligations under the Credit Facility are secured by liens on substantially all of the assets of Borrowers. Furthermore, the obligations under the Credit Facility are secured by a continuing, first priority mortgage lien, pledge of and security interest in not less than 80% of Borrowers' producing oil, gas and other leasehold and mineral interests, including without limitation, those situated in the States of North Dakota and Montana.

The Credit Facility requires Borrowers to, commencing as of the fiscal quarter ended December 31, 2023, maintain (a) a current ratio of 1.0 to 1.0 or more and (b) a ratio of funded debt to EBITDAX (as defined in the Credit Facility), calculated quarterly and annually based on a trailing twelve-month basis, of no more than 3.50 to 1.00. At December 31, 2024, the Borrowers were in compliance with all required covenants under the Credit Facility.

On November 18, 2024, the Company entered into the First Amendment. Pursuant to the First Amendment (a) the maximum revolver commitment amount is $20.0 million; and (b) commencing on December 31, 2024, and occurring on the last day of each calendar month thereafter, the revolver commitment amount is reduced by $250,000.

On September 19, 2023, each of Phil Mulacek, a member of the Company's Board of Directors, and Energy Evolution made a bridge loan to Empire North Dakota in the amount of $5.0 million (collectively, the "Bridge Loans"). These Bridge Loans were subsequently converted to our common shares through entering into subsequent Securities Purchase Agreements. Mr. Mulacek and Energy Evolution are each a related party of the Company. See Note 14 for additional information regarding the Securities Purchase Agreements and the subsequent conversion to our common shares.

Promissory Note - Related Party

On February 16, 2024, Empire issued a promissory note in the aggregate principal amount of $5.0 million (the "Note") to Energy Evolution. Energy Evolution advanced Empire $5.0 million under the Note. The proceeds of the Note were used by Empire to fund, in part, its ongoing oil and gas drilling program and for working capital purposes.

The Note matures on February 15, 2026, (the "Maturity Date") and accrues interest at the rate of 7% per annum. After the Maturity Date, any principal balance of the Note remaining unpaid accrues interest at the rate of 9% per annum. At the option of Energy Evolution, interest payments will be paid either in cash or in shares of common stock of Empire on each of the following dates (or if any such date is not a business day, the next following business day) (each an "Interest Payment Date"), except upon the occurrence of an Event of Default, in which case interest will accrue and be paid in cash on demand: (i) March 31, 2024; (ii) June 30, 2024; (iii) September 30, 2024; (iv) December 31, 2024; (v) March 31, 2025; (vi) June 30, 2025; (vii) September 30, 2025; (viii) December 31, 2025; and (ix) the Maturity Date. All or any portion of the outstanding principal amount of the Note may be converted into shares of common stock of Empire at a conversion price of $6.25 per share (the "Conversion Price"), at the option of Energy Evolution, at any time and from time to time. If the full principal amount of the Note is drawn and converted into shares of common stock of Empire, 800,000 shares would be issued (without giving effect to any interest that may be converted). Accrued interest on the principal amount converted will be due on the applicable date of conversion in cash or, at the option of Energy Evolution, by issuance of shares of common stock of Empire in the manner set forth in the Note (where the date of conversion is the relevant Interest Payment Date). The Conversion Price is subject to customary adjustments. The Note may be prepaid at any time or from time to time without the consent of Energy Evolution and without penalty or premium, provided that Empire provides Energy Evolution with at least five business days prior written notice, each principal payment is made in cash and all accrued interest is paid in cash, or at the option of Energy Evolution, the accrued interest may be paid by issuance of shares of common stock of Empire in the manner set forth in the Note (where the Interest Payment Date is the date of prepayment).

Empire determined that an embedded conversion feature included in the Note required bifurcation from the host contract that is recognized as a separate derivative liability carried at fair value. The estimated fair value of the derivative liability, which represents a Level 3 valuation, was approximately $1.3 million as of March 31, 2024, and was determined using a binomial lattice model using certain assumptions and inputs discussed in Note 17. Accordingly, Empire recognized a gain on the fair value adjustment of the derivative liability in the amount of approximately $0.7 million in other income (expense) in the consolidated statements of operations for the year ended December 31, 2024. The conversion option was exercised by Energy Evolution on May 24, 2024, in exchange for 800,000 shares of common stock of the Company under the terms of the Note and the fair value of the derivative was revalued as of that date resulting in a loss of $1.7 million in 2024. All of the other embedded features of the Note were clearly and closely related to the debt host and did not require bifurcation as a derivative liability.

Note Payable - Related Party

In August 2020, Empire, through its wholly-owned subsidiary, Empire Texas, entered into a JDA with Petroleum & Independent Exploration, LLC and related entities ("PIE"), a related party (see Note 14), dated August 1, 2020. Under the terms of the JDA, PIE performed recompletion or workover on specified mutually agreed upon wells owned by Empire Texas. Concurrent with the JDA with PIE, Empire entered into a term loan agreement dated August 1, 2020, whereby PIE will loan up to $2.0 million, at an interest rate of 6% per annum, maturing August 6, 2024, unless terminated earlier by PIE. The loan proceeds were used for recompletion or workover of certain designated wells. In addition, Empire assigned 85% working and revenue interest to PIE in the designated wells which will be applied to repayment of the loan.

On July 31, 2024, PIE, Empire Texas, and Empire entered into a note repayment and loan termination agreement providing for the payment in full of the remaining outstanding amount of the approximate $1.1 million PIE loan and extending the loan maturity date to December 31, 2024, unless terminated earlier by PIE. As payment in full, Empire issued PIE 205,427 shares of common stock of Empire following the approval of a supplemental listing application by the NYSE American stock exchange in the third quarter of 2024.

Note 8 - Leases

As a lessee, the Company leases its corporate office headquarters in Tulsa, Oklahoma, and one field office. The leases expire between 2025 and 2027. The corporate office has an option to renew for an additional five-year term. The option to renew the lease is generally not considered reasonably certain to be exercised. Therefore, the period covered by such optional period is not included in the determination of the term of the lease and the lease payments during these periods are similarly excluded from the calculation of right-of-use lease asset and lease liability balances.

The Company also leases vehicles primarily used in our field operations. These vehicle leases typically have a three-year life.

The Company recognizes right-of-use lease expense on a straight-line basis, except for certain variable expenses that are recognized when the variability is resolved, typically during the period in which they are paid. Variable right-of-use lease payments typically include charges for property taxes, insurance, and variable payments related to non-lease components, including common area maintenance.

Right-of-use lease expense was approximately $0.5 million and $0.4 million for the years ended December 31, 2024 and 2023, respectively. Cash paid for right-of-use lease was approximately $0.5 million and $0.4 million for the same period.

Supplemental balance sheet information related to the right of use leases is as follows:

	As of December 31,			
	2024		2023	
Net operating lease asset (included in Other property and equipment)	$	603,611	$	1,077,031
Current portion of lease liability	$	400,692	$	432,822
Long-term lease liability		143,689		544,382
Total right-of-use lease liabilities	$	544,381	$	977,204

The weighted average remaining term for the Company's right of use leases is 1.4 years. The weighted average discount rate is 8.26% in 2024.

Maturities of lease liabilities as of December 31, 2024, are as follows:

2025	$	430,631
2026		136,545
2027		12,400
2028		—
2029		—
Thereafter		—
Total lease payments		579,576
Less: imputed interest		(35,195)
Total lease obligation	$	544,381

Note 9 – Equity

Pursuant to the Company's Amended and Restated Certificate of Incorporation ("Charter"), effective as of March 4, 2022, the total number of shares of all classes of stock that the Company has the authority to issue is 200,000,000, consisting of 190,000,000 shares of common stock, par value $0.001 per share, and 10,000,000 shares of preferred stock, par value $0.001 per share.

Preferred Stock

Preferred stock may be issued from time to time in one or more series at the direction of the Company's Board of Directors and the directors also have the ability to fix dividend rates and rights, liquidation preferences, voting rights, conversion rights, rights and terms of redemption and other rights, preferences, privileges and restrictions as determined by the Company's Board of Directors, subject to certain limitations set forth in the Charter.

Series A Voting Preferred Stock

On March 8, 2022, the Company formalized the issuance of preferred stock as was required under the terms of the Company's May 2021 financing agreements with Energy Evolution and issued six shares of Series A Voting Preferred Stock. The Series A Voting Preferred Stock was issued in connection with the strategic investment in the Company by Energy Evolution. For so long as the Series A Voting Preferred Stock is outstanding, the Company's Board of Directors will consist of six directors. Three of the directors are designated as the Series A Directors and the three other directors (each, a "common director") are elected by the holders of common stock and/or any preferred stock (other than the Series A Voting Preferred Stock) granted the right to vote on the common directors. Any Series A Director may be removed with or without cause but only by the affirmative vote of the holders of a majority of the Series A Voting Preferred Stock voting separately and as a single class. The holders of the Series A Voting Preferred Stock have the exclusive right, voting separately and as a single class, to vote on the election, removal and/or replacement of the Series A Directors. Holders of common stock or other preferred stock do not have the right to vote on the Series A Directors. The approval of the holders of the Series A Voting Preferred Stock, voting separately and as a single class, is required to authorize any resolution or other action to issue or modify the number, voting rights or any other rights, privileges, benefits, or characteristics of the Series A Voting Preferred Stock, including without limitation, any action to modify the number, structure and/or composition of the Company's current Board of Directors.

The Series A Voting Preferred Stock is held by Phil Mulacek, Chairman of the Board of Directors of the Company and one of the principals of Energy Evolution, as Energy Evolution's designee (the "Initial Holder"). The Series A Voting Preferred Stock may be transferred only to certain controlled affiliates of the Initial Holder ("Permitted Transferees"), and the voting rights of the Series A Voting Preferred Stock are contingent upon the Initial Holder and Permitted Transferees (collectively, the "Series A Holders") holding together at least 3,000,000 shares of the Company's outstanding common stock.

The Series A Voting Preferred Stock is not entitled to receive any dividends or distributions of cash or other property except in the event of any liquidation, dissolution or winding up of the Company's affairs. In such event, before any amount is paid to the holders of the Company's common stock but after any amount is paid to the holders of the Company's senior securities, the holders of the Series A Voting Preferred Stock will be entitled to receive an amount per share equal to $1.00.

Except as discussed above or as otherwise set forth in the certificate of designation of the Series A Voting Preferred Stock, the holders of the Series A Voting Preferred Stock have no voting rights.

The Series A Voting Preferred Stock is not redeemable at the Company's election or the election of any holder, except the Company may elect to redeem the Series A Voting Preferred Stock for $1.00 per share following satisfaction of its notice and cure requirements in the event that:

- any or all shares of Series A Voting Preferred Stock are held by anyone other than the Initial Holder or a Permitted Transferee; or
- the Series A Holders together hold less than 3,000,000 shares of the Company's outstanding common stock.

The Series A Voting Preferred Stock is not convertible into common stock or any other security.

Common Stock

On August 27, 2021, the Company's Board of Directors approved a one-for-four reverse stock split such that every holder of the Company's common stock would receive one share of common stock for every four shares owned. The reverse stock split was effective as of 6:00 p.m. Eastern Time on March 7, 2022, immediately prior to the Company's listing of its common stock on the NYSE American. All share amounts have retrospectively been stated at post-reverse split amounts and pricing.

The holders of shares of common stock are entitled to one vote per share for all matters on which common stockholders are authorized to vote on. Examples of matters that common stockholders are entitled to vote on include, but are not limited to, the election of three of the six directors and other common voting situations afforded to common stockholders.

In July 2023, Energy Evolution exercised its remaining warrants under a Loan Modification Agreement between the Company and Energy Evolution entered into in September 2021 for 500,000 shares of common stock for $5.00 per share. The Company received $2.5 million related to this transaction.

In April 2024, Empire completed a subscription rights offering (the "April Rights Offering") which raised gross proceeds of $20.7 million. Empire distributed at no charge to holders of its common stock, as of the close of business on March 7, 2024 (the record date for the April Rights Offering), one subscription right for each share of common stock held. Each subscription right entitled the holder to purchase 0.161 shares of common stock at a subscription price of $5.00 per share per one whole share of common stock. The subscription rights were non-transferable and not listed for trading on any stock exchange or market.

On May 31, 2024, Empire issued Energy Evolution a warrant certificate granting them the right to purchase 128,800 shares of common stock of Empire at $5.00 per share. On June 28, 2024, Energy Evolution exercised the warrants and received 128,800 shares in exchange for approximately $0.6 million.

In November 2024, Empire completed a subscription rights offering (the "November Rights Offering") which raised gross proceeds of $10.0 million. Empire distributed at no charge to holders of its common stock, as of the close of business on September 30, 2024 (the record date for the November Rights Offering), one subscription right for each share of common stock held. Each subscription right entitled the holder to purchase 0.063 shares of common stock at a subscription price of $5.05 per share per one whole share of common stock. The subscription rights were non-transferable and not listed for trading on any stock exchange or market.

See Note 14 for information regarding other transactions where shares of common stock of the Company were issued.

Note 10 – Stock Based Compensation

Empire recognizes stock-based compensation expense associated with granted stock options and restricted stock units ("RSUs"). Empire accounts for forfeitures of equity-based incentive awards as they occur. Stock-based compensation expense related to time-based restricted stock units is based on the price of the common stock on the grant date and recognized as vesting occurs. For options, the fair value is determined using the Black-Scholes option valuation assumptions on dividend yield, expected annual volatility, risk-free interest rate and an expected useful life. Stock-based compensation expense for restricted stock units and stock options is included in general and administrative expense in the consolidated statements of operations and is recorded with a corresponding increase in additional paid-in capital within the consolidated balance sheets.

On April 3, 2019, the Board of Directors of the Company adopted the Empire Petroleum Corporation 2019 Stock Option Plan (the "2019 Stock Option Plan"). The total number of shares of common stock that may be issued pursuant to stock options under the 2019 Stock Option Plan was 2,500,000. On August 27, 2021, the Board of Directors of the Company adopted the Company's 2021 Stock and Incentive Compensation Plan (the "2021 Incentive Plan") which was subsequently approved by stockholders of the Company. As a result of such approval, no further awards will be made under the 2019 Incentive Plan. The total number of shares of common stock that could be issued pursuant to the 2021 Incentive Plan is 750,000. On August 26, 2022, the stockholders of the Company approved the Company's 2022 Stock and Incentive Compensation Plan (the "2022 Incentive Plan") which reserves 750,000 shares of the Company's common stock for issuance thereunder. As a result of such approval, no further awards will be made under the 2021 Incentive Plan. On June 9, 2023, the stockholders of the Company approved the Company's 2023 Stock and Incentive Compensation Plan (the "2023 Incentive Plan") which reserves 700,000 shares of the Company's common stock for issuance thereunder. As a result of such approval, no further awards will be made under the 2022 Incentive Plan. On June 14, 2024, the Board of Directors adopted the Company's 2024 Stock and Incentive Compensation Plan (the "2024 Incentive Plan") which reserves 700,000 shares of the Company's common stock for issuance thereunder. As a result of such approval no further awards will be made under the 2023 Incentive Plan. The 2024 Incentive Plan authorizes the grant of non-qualified stock options, stock appreciation rights, restricted stock, restricted stock units, performance shares, performance units, cash-based awards and other stock-based awards (restricted stock awards, restricted stock units, performance shares and performance units are collectively referred to as restricted stock units for purposes of this Note). At December 31, 2024, 528,165 shares of our common stock were available for future grants.

Restricted Stock Units

Each RSU represents the contingent right to receive one share of common stock. The holders of outstanding RSUs do not receive dividends or have voting rights prior to vesting and settlement. The Company determines the fair value of granted RSUs based on the market price of the common stock on the date of the grant. Compensation expense for granted RSUs is recognized on a straight-line basis over the vesting and is net of forfeitures, as incurred.

RSUs are generally granted with 12-month, 13-month, or 3-year service periods. Total value assigned to the RSUs granted in 2024 based on grant date price approximated $0.6 million. For the years ended December 31, 2024 and 2023, approximately $0.9 million and $2.3 million of compensation expense related to RSUs was recognized. At December 31, 2024, approximately $0.7 million of unrecognized compensation expense remained and will be recognized on a straight-line basis depending on the service period of each grant.

The following summary reflects nonvested restricted stock unit activity and related information:

	Shares		Weighted-Average Fair Value (1)
Outstanding, December 31, 2022	224,288	$	15.42
Granted	180,430		10.33
Vested	(145,700)		16.20
Forfeited	(54,201)		14.57
Outstanding, December 31, 2023	204,817	$	10.61
Granted	106,260		5.29
Vested	(162,034)		9.79
Forfeited	(22,500)		11.05
Outstanding, December 31, 2024	126,543	$	7.11

(1) Shares are valued at the grant-date market price.

		2024
Weighted-Average grant date fair value of restricted stock units granted during the year, per share	$	5.29
Total fair value of restricted stock units vested during the year	$	1,586,313

Stock Options

Each stock option award provides the opportunity in the future to purchase Empire common shares at the market price of our common stock on the date the award is granted (the strike price). The options generally become exercisable in equal amounts over a three-year vesting period or over one-year for options awarded to the Board of Directors of the Company; however, certain options become exercisable only if certain performance criteria are met. Stock options have no financial statement effect on the date they are granted but rather are reflected over time through recording stock-based compensation expense. The stock-based compensation expense is based on the estimated fair value of the awards expected to vest, and that amount is amortized as compensation expense on a straight-line basis over the respective vesting period and is net of forfeitures, as incurred.

The estimated fair value of an option is calculated using a Black-Scholes option valuation model with the following assumption inputs: dividend yield, expected annual volatility, risk free interest rate and an expected life of the option. The following table summarizes the weighted-average fair value and assumptions:

		2024		2023
Weighted-average grant-date fair value of stock options	$	3.25	$	4.52
Stock Options Valuation Assumptions:				
Risk-free interest rate		4.5%		3.9%
Dividend yield		0.0%		0.0%
Expected volatility		73.9%		64.9%
Expected option life (in years)		5.00		2.88
Other pricing model inputs:				
Weighted average grant-date market prices of Empire stock (strike price)	$	5.12	$	10.07

For the years ended December 31, 2024 and 2023, approximately $1.1 million and $0.9 million of compensation expense related to stock options was recognized. At December 31, 2024, approximately $1.0 million of unrecognized compensation expense remained and will be recognized on a straight-line basis depending on the service period of each grant.

The following summary reflects stock option activity and related information:

	Options		Weighted-Average Exercise Price
Outstanding, December 31, 2022	2,379,700	$	3.31
Granted	533,000		10.07
Exercised	(355,000)		1.35
Forfeited	(492,319)		5.42

Outstanding, December 31, 2023	2,065,381	$	4.89
Granted	149,335		5.12
Exercised	(193,866)		1.35
Forfeited	(135,000)		12.17
Outstanding, December 31, 2024	1,885,850	$	4.75

The following table summarizes information about stock options as of December 31, 2024:

Range of Exercise Price	$1.32 to $12.36
Weighted-Average Remaining Contractual Life	4.17 years
Options Outstanding	1,885,850
Options Exercisable	1,489,928
Options Outstanding Aggregate Intrinsic Value	$5,376,036
Options Exercisable Aggregate Intrinsic Value	$5,453,136
Weighted-Average Outstanding Price	$4.75
Weighted-Average Exercise Price	$3.94

Note 11 – Income Taxes

The following table represents the current and deferred income tax provisions:

	For the Years Ended December 31,			
	2024		2023	
Current	$	—	$	(132,192)
Deferred		—		—
Income tax provision	$	—	$	(132,192)

In the event that an entity has an "ownership change" (as defined in Section 382 of the Internal Revenue Code of 1986, as amended ("IRC"), an entity's federal net operating loss carryforwards ("NOLs") generated prior to an ownership change would be subject to annual limitations, which could defer or eliminate the Company's ability to utilize these tax losses against future taxable income. Generally, an "ownership change" occurs if one or more stockholders, each of whom owns 5% or more in value of a corporation's stock, increase their aggregate percentage ownership by more than 50% over the lowest percentage of stock owned by those stockholders at any time during the preceding three-year period. A full Section 382 analysis was prepared in 2024 and it was determined that our NOLs were subject to limitations under IRC Section 382. The Company's ability to use NOLs and other tax attributes to reduce taxable income and income taxes could be materially impacted by a future IRC 382 ownership change. Future transactions involving the Company's stock including those outside of the Company's control could cause an IRC Section 382 ownership change resulting in a limitation on tax attributes currently not limited and a more restrictive limitation on tax attributes currently subject to the previous IRC 382 limitation.

At December 31, 2024, the Company had approximately $35.8 million of federal NOLs generated in prior years available to offset against future taxable income, net of NOLs expected to expire unused due to IRC Section 382 limitations. Of the $35.8 million NOLs, approximately $35.4 million relate to periods after 2017 and have an indefinite life. Additionally, approximately $0.5 million will begin to expire between 2024-2037 if not used. Approximately $2.4 million of the NOLs were limited as of December 31, 2024, due to previous ownership changes.

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and the tax basis of assets and liabilities. The Company's net tax position is as follows:

	As of December 31,			
	2024		2023	
Deferred tax assets:				
Loss carry-forwards	$	9,248,840	$	6,269,503
Stock option grants		2,527,263		2,022,184
Asset retirement obligation		7,954,720		7,433,670
Other		784,505		526,873
Total deferred tax assets		20,515,328		16,252,230
Deferred tax liabilities:				
Oil and gas properties		(7,863,169)		(7,327,620)
Other property and equipment		(62,125)		(123,915)
Financial Derivatives		—		(104,956)
Lease liabilities		(15,281)		(25,133)
Total deferred tax liabilities		(7,940,575)		(7,581,624)
Net deferred tax asset before valuation allowance		12,574,753		8,670,606
Valuation allowance		(12,574,753)		(8,670,606)
Net deferred taxes	$	—	$	—

Utilization of the Company's loss carryforwards is dependent on realizing taxable income. The Company's recorded valuation allowances of approximately $ 12.6 million and $8.7 million as of December 31, 2024 and 2023, respectively, are due to the uncertainty related to its ability to utilize some of its deferred income tax assets, primarily consisting of net operating loss carryforwards prior to expiration or the limitation under Section 382 as discussed above.

For 2024 and 2023, our effective tax rates were 0% and 1%, respectively. Other than the full year of 2022, Empire has generated net operating losses since inception, which would normally reflect a tax benefit in the consolidated statements of operations and a deferred asset on the consolidated balance sheets. However, because of the current uncertainty as to Empire's ability to achieve sustained profitability, a full valuation reserve has been established that offsets the amount of any tax benefit available for each period presented in the consolidated statements of operations.

The following table presents a reconciliation of its income tax (benefit) provision and effective income tax rate to the U.S. statutory income tax rate:

	For the Years Ended December 31,					
	2024			2023		
(Benefit) provision at statutory rate	$	(3,401,578)	21.0%	$	(2,646,378)	21.0%
State Taxes (net of federal impact)		(733,390)	4.5%		(598,191)	4.7%
Nondeductible Expenses		(119,525)	0.7%		31,037	-0.2%
Return to Accrual		35,686	-0.2%		(72,448)	0.6%
Derivative Liability, Promissory Note Conversion		314,660	-1.9%		—	0.0%
NOLs Expected to Expire Unused Due to Section 382 Limitation		—	0.0%		1,877,230	-14.9%
Valuation Allowance		3,904,147	-24.1%		1,276,558	-10.1%
Income tax (benefit) provision	$	—	0.0%	$	(132,192)	1.0%

The Company has evaluated all tax positions for which the statute of limitations remains open and believes that the material positions taken would more likely than not be sustained by examination. Therefore, at December 31, 2024, the Company has not established any reserves for, nor recorded any unrecognized benefits related to uncertain tax positions.

The Company's only taxing jurisdiction is the United States. The Company's tax years 2021 to present remain open for federal examination. Additionally, tax years 2004 through 2020 remain subject to examination for the purpose of determining the amount of federal NOL and other carryforwards. The number of years open for state tax audits varies, depending on the state, but is generally from three to five years.

Note 12 – Loss per Share

Diluted EPS gives effect to all dilutive potential common shares outstanding during the period. The computation of Diluted EPS does not assume conversion, exercise or contingent exercise of securities that would have an anti-dilutive effect on losses. As a result, if there is a loss from continuing operations, Diluted EPS is computed in the same manner as Basic EPS. In addition, approximately 647,000 options were excluded in the current period Diluted EPS computation due to the option exercise price exceeding the weighted-average market price of our common shares.

The following table summarizes the calculation of loss per share:

	For the Years Ended December 31,			
	2024		2023	
Net Loss	$	(16,197,989)	$	(12,469,605)
Basic Weighted-Average Shares		30,064,856		22,718,890
Effect of Dilutive Securities:				
Restricted Stock Units and Stock Options (1)		—		—
Diluted Weighted-Average Shares	$	30,064,856	$	22,718,890
Loss per Common Share				
Basic	$	(0.54)	$	(0.55)
Diluted	$	(0.54)	$	(0.55)

(1) At December 31, 2024 and 2023, respectively, the Company had approximately 981,314 and 1,361,200 RSUs and options that were excluded from the calculation of net loss per share as their inclusion would be antidilutive due to a net loss for the period.

Note 13 – Executive Management

On March 16, 2023, Thomas W. Pritchard resigned as Chief Executive Officer and a director of the Company to pursue other opportunities. Although not required under Mr. Pritchard's Employment Agreement with the Company, in recognition of Mr. Pritchard's past service to the Company, the Company will pay Mr. Pritchard severance benefits in the amount of approximately $0.4 million, as set forth in Section 4.2 of his Employment Agreement, in one lump sum payment within 30 days after March 23, 2023, rather than in monthly installments. This was accrued as of March 31, 2023, and payment was made in April 2023. The Company also extended the period under which Mr. Pritchard has the right to exercise his outstanding vested non-qualified stock options from three months after the date of his termination of employment to September 16, 2024. In addition, Mr. Pritchard has surrendered to the Company 340,234 RSUs and options as satisfaction for the $2.1 million receivable that primarily resulted from incorrect withholdings associated with an April 2022 option exercise by Mr. Pritchard. The Company also had a $2.1 million liability recorded at December 31, 2022, related to withholding payables that were remitted in 2023.

On March 17, 2023, the Board of Directors of the Company appointed Michael R. Morrisett to the position of Chief Executive Officer. Mr. Morrisett did not receive any additional compensation for assuming the role of Chief Executive Officer.

In July 2023, the Company's Chief Operating Officer separated from the Company and received a severance of approximately $0.1 million over six months. Additionally, certain vested options were forfeited resulting in the reversal of $0.6 million of previously recorded stock-based compensation.

Note 14 – Related Party Transactions

Energy Evolution is a related party of the Company as it beneficially owns approximately 31.9% of the Company's outstanding shares of common stock as of December 31, 2024. In October 2021, a member of Energy Evolution and a board member of Energy Evolution were appointed to the Company's Board of Directors. The board member of Energy Evolution separately beneficially owns approximately 21.2% of the Company's outstanding shares of common stock as of December 31, 2024 and is also a majority owner of PIE.

In July 2023, Energy Evolution exercised its warrants for 500,000 shares of common stock of the Company for $5.00 per share. See Note 9 for additional information.

On November 29, 2023, the Company converted its Bridge Loan (see Note 7) with Phil Mulacek into common shares through a Securities Purchase Agreement which was amended on December 1, 2023, pursuant to which Mr. Mulacek purchased from the Company (a) 609,013 shares of common stock of the Company for an aggregate purchase price of $5.0 million (or $8.21 per share) in cash and (b) 631,832 shares of common stock of the Company for an aggregate purchase price of $5.1 million (or $8.00 per share) which was paid through cancellation and extinguishment of the outstanding principal amount and all accrued interest thereon under that certain amended and restated promissory note due December 31, 2024, in the original aggregate principal amount of $5.0 million issued by Empire North Dakota to Mr. Mulacek.

On November 29, 2023, the Company converted its Bridge Loan (see Note 7) with Energy Evolution into common shares through a Securities Purchase Agreement, pursuant to which Energy Evolution purchased 1,256,832 shares of common stock of the Company for an aggregate purchase price of $10.1 million (or $8.00 per share), of which $2.0 million was advanced in cash to the Company on November 22, 2023, $3.0 million was paid in cash to the Company and $5.1 million was paid through cancellation and extinguishment of the outstanding principal amount and all accrued interest thereon under that certain amended and restated promissory note due December 31, 2024, in the original aggregate principal amount of $5.0 million issued by Empire North Dakota to Energy Evolution.

On February 16, 2024, Empire issued the Note to Energy Evolution. Energy Evolution advanced Empire $5.0 million under the Note in the first quarter of 2024. On May 24, 2024, Energy Evolution elected to convert the Note to shares of common stock of Empire and received 800,000 shares under the terms of the Note (see Note 7).

The Company had a JDA with PIE to perform recompletion or workover on specified mutually agreed upon wells (See Note 7). In the third quarter of 2024, Empire issued PIE 205,427 shares of common stock of Empire as payment in full for this outstanding note balance of $1.1 million (see Note 7).

In connection with the JDA, the Company also entered into a shared services agreement with PIE effective August 1, 2023, that includes access to administrative, engineering and support services as well as building and insurance services. The agreement provides that the Company will reimburse PIE for the out-of-pocket or actual costs incurred by PIE in providing such services to the Company.

Empire elected to partially exercise a purchase option in the second quarter of 2024 and acquired 60% of certain New Mexico interests from Energy Evolution. See Note 3 for additional information.

On June 28, 2024, Energy Evolution exercised its warrants of Empire and received 128,800 shares in exchange for approximately $0.6 million. See Note 9 for additional information.

Accounts receivable on the consolidated balance sheet include approximately $0.4 million and $0.9 million receivable as of December 31, 2024 and 2023, respectively, from Energy Evolution. Accrued expenses on the consolidated balance sheet include approximately $0.1 million and $0.5 million of revenue payable as of December 31, 2024 and 2023, respectively, to Energy Evolution.

Note 15 – Commitments and Contingencies

From time to time, the Company is subject to various legal proceedings arising in the ordinary course of business, including proceedings for which the Company may not have insurance coverage. While many of these matters involve inherent uncertainty, as of the date hereof, the Company does not currently believe that any such legal proceedings will have a material adverse effect on the Company's business, financial position, results of operations or liquidity.

The Company is subject to extensive federal, state, and local environmental laws and regulations. These laws, among other things, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Management believes no materially significant liabilities of this nature existed as of the balance sheet date.

Agreed Compliance Order

In January 2024, the Company deposited $1.0 million into an escrow account in accordance with an Agreed Compliance Order ("ACO") with the New Mexico Oil Conservation Division for compliance work on certain inactive wells in New Mexico. Under the terms of the ACO, the escrow funds will be returned to the Company at a rate of $0.01 million for each well as the compliance work is completed. As of June 30, 2024, all work had been completed, and the Company expects to receive the remaining outstanding escrow amount of $0.2 million in 2025.

New Mexico Trespass

In December 2023, the Company initiated a legal action in the Fifth Judicial District Court, Lea County, New Mexico, against a saltwater company for trespassing within one of the New Mexico water flood units. This suit is currently being pursued by Empire; however, the ultimate outcome of the litigation cannot be determined at this time, and no amount has been recognized due to the uncertainty of any conclusions that may arise as a result of such action.

Note 16 – Concentrations

The Company's producing properties and oil and natural gas reserves are all located in Louisiana, New Mexico, North Dakota, Montana, and Texas. Because of the concentration, the Company is exposed to the impact of regional supply and demand factors, processing or transportation capacity constraints, severe weather events, water shortages, and government regulations specific to the geographic area.

For the year ended December 31, 2024, the Company sold 78% of its oil, natural gas, and NGLs to four customers. For the year ended December 31, 2023, the Company sold 70% of its oil and natural gas production to four customers. No other purchaser accounted for more than 10% of our total revenues during the respective periods. The loss of these purchasers could result in a temporary interruption in sales or a lower price for production.

The Company's cash balances may at times exceed Federal Deposit Insurance Corporation ("FDIC") insurance limits. The Company maintains cash accounts at reputable financial institutions.

Note 17 – Fair Value Measurements

The following table provides the carrying value and fair value measurement information for certain financial assets and liabilities. The carrying values of cash, accounts receivable, inventory, accounts payable, accrued expenses, lease liabilities, and equipment and vehicle notes included in the accompanying consolidated balance sheets approximated fair value at December 31, 2024 and December 31, 2023, as applicable, and generally represent Level 2 fair values due to their short-term nature. Therefore, such financial assets and liabilities are not presented in the following table:

			Fair Value Measurements Using:		
	Carrying Amount	Total Fair Value	Level 1 Inputs	Level 2 Inputs	Level 3 Inputs
December 31, 2024 assets (liabilities)					
Derivative instruments	$ —	$ —	$ —	$ —	$ —
Debt - Credit Facility	(11,088,647)	(11,088,647)	—	(11,088,647)	—
Debt - Promissory Note, Related Party	—	—	—	—	—
December 31, 2023 assets (liabilities)					
Derivative instruments	406,806	406,806	—	406,806	—
Debt - Credit Facility	(4,492,484)	(4,492,484)	—	(4,492,484)	—
Debt - Promissory Note, Related Party	(1,060,004)	(1,055,790)	—	(1,055,790)	—

The following methods and assumptions were used to estimate the fair values in the table above and other fair value measurements.

Level 2

Derivatives – Derivative financial instruments are carried at fair value and measured on a recurring basis. The Company's commodity price hedges are valued based on discounted future cash flow models that are primarily based on published forward commodity price curves.

The fair values of derivative instruments in asset positions include measures of counterparty nonperformance risk, and the fair values of derivative instruments in liability positions include measures of the Company's nonperformance risk. These measurements were not material to the consolidated financial statements.

Debt – The fair value of our Credit Facility variable rate debt approximates the carrying value as the underlying prime rate changes based on prevailing market rates. The fair value of the promissory note prior to when the conversion was triggered was determined using a discounted cash flow model. See below for discussion on the fair value determination of the promissory note once conversion occurred.

Level 3

Impairment of oil and natural gas properties – The fair value of proved and unproved oil and natural gas properties was measured using valuation techniques that convert the future cash flows to a single discounted amount. Significant inputs to the valuation of proved and unproved oil and natural gas properties include estimates of: (i) recoverable reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices; and (v) a market-based weighted-average costs of capital. The Company utilized a combination of the New York Mercantile Exchange strip pricing and consensus pricing to value the reserves, then applied various discount rates depending on the classification of reserves and other risk characteristics. For significant acquisitions, management utilized the assistance of a third-party valuation expert to estimate the value of the oil and natural gas properties acquired.

Asset Retirement Obligation – The fair value of AROs is included in proved oil and natural gas properties with a corresponding liability. The fair value was determined based on a discounted cash flow model, which included assumptions of the estimated current abandonment costs, discount rate, inflation rate and timing associated with the incurrence of these costs.

The inputs used to value oil and natural gas properties for impairments and asset retirement obligations require significant judgment and estimates made by management and represent Level 3 inputs.

Empire applies the provisions of fair value measurement on a non-recurring basis to its non-financial assets and liabilities, including oil and gas properties and asset retirement obligations. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments if events or changes in certain circumstances indicate that adjustments may be necessary. No triggering events that require assessment of such items were observed during the years ended December 31, 2024 and 2023.

Assets and Liabilities Measured at Fair Value on a Recurring Basis – In the determination of the fair value of the promissory note including the embedded conversion feature, Empire uses a binomial lattice valuation model to value Level 3 derivative liabilities at inception and on subsequent valuation dates. This model incorporates transaction details such as Empire's stock price, contractual terms of the promissory note, and unobservable inputs classified as Level 3 including risk-free rate and expected volatility. Due to the subjective nature of these inputs, the fair value measurement could differ materially under alternative assumptions. As of the conversion option exercise date of May 24, 2024, these unobservable inputs were 5.0% and 46.9%, respectively.

Note 18 – Segment Reporting

The Company's operations are managed and reported to its CEO, the Company's CODM, on a consolidated basis. The CEO uses consolidated net loss in assessing performance of capital spend projects to allocate the appropriate resources to drive efficiencies and develop growth strategies. Under the organizational and reporting structure, the Company has one operating segment and one reportable segment.

The CODM is provided with the following significant segment expenses within lease operating expense on the consolidated statements of operations:

	For the Years Ended December 31,	
	2024	2023
Production costs	$ 21,625,784	$ 16,631,618
Workover activity	4,768,286	10,161,285
Plugging and abandonment activity	1,150,958	1,832,578
Lease operating expense	$ 27,545,028	$ 28,625,481

Other segment items within consolidated net loss are all separately disclosed on the consolidated statements of operations. Segment asset information is not presented to and used by the CODM to allocate resources, assess performance or make strategic decisions.

Note 19 – Supplemental Information of Oil and Natural Gas Producing Activities (Unaudited)

The following reserve estimates present the Company's estimate of the proven natural gas and oil reserves and net cash flow of the Company's properties, in accordance with the guidelines established by the Securities and Exchange Commission. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing natural gas and oil properties. Accordingly, the estimates are expected to change as future information becomes available. All the oil and natural gas reserves are located in Louisiana, New Mexico, North Dakota, Montana and Texas.

Costs Incurred Related to Oil and Gas Activities

Costs incurred include capitalized costs of properties, equipment, and lease facilities for oil and natural gas producing activities.

	For the Years Ended December 31,	
	2024	2023
Acquisition	$ 4,074,310	$ 2,094,419
Exploration	—	—
Development	42,214,332	25,053,107
Total costs incurred	$ 46,288,642	$ 27,147,526

Reserve Quantity Information

Proved oil and natural gas reserves are those quantities of oil and gas, which by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. Proved developed reserves are proved reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well. Proved undeveloped reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. The information below excludes proved undeveloped reserves. Below are the net quantities of net proved developed reserves of the Company's properties:

	Oil (MBbls)	Gas (MMcf)	NGLs (MBbls)	MBoe
Balance, December 31, 2022	8,826	12,937	2,262	13,244
Acquisition of Reserves	36	19	5	44
Revisions	(1,625)	(5,998)	(960)	(3,585)
Extensions	175	—	—	175
Production	(488)	(854)	(136)	(766)
Balance, December 31, 2023	6,924	6,104	1,171	9,112
Acquisition of Reserves	198	240	35	274
Revisions	(90)	637	159	175
Extensions	550	—	—	550
Production	(581)	(917)	(150)	(884)
Balance, December 31, 2024	7,001	6,064	1,215	9,227

The acquisition of reserves for 2024 and 2023 primarily relate to additional working interests in certain of the Company's New Mexico properties (See Note 3) during the respective periods. The revisions for the respective periods primarily relate to changes in pricing and the extensions relate to increased volumes from our Starbuck Drilling Program.

Standardized Measure of Discounted Future Net Cash Flows Relating to Oil and Natural Gas Reserves

The standardized measure of discounted future net cash flows relating to oil and natural gas reserves and associated changes in standard measure amounts were prepared in accordance with the provision of FASB ASC 932-235-555, *Extracting Activities – Oil and Gas* ("Topic 932"). Future cash inflows were computed by applying average prices of oil and natural gas for the last 12 months to estimated future production. Future production and development costs were computed by estimating the expenditures to be incurred in developing the oil and natural gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. Future net cash flows are discounted at the rate of 10% annually to derive the standardized measure of discounted cash flows. Actual future cash inflows may vary considerably, and the standardized measure does not necessarily represent the fair value of the acquired properties' oil and natural gas reserves. Standard measure amounts are:

	As of December 31,	
	2024	2023
Future cash inflows	$ 537,303,424	$ 543,067,776
Future production costs	(324,214,760)	(350,439,800)
Future development costs	(38,681,208)	(42,475,160)
Future income tax expense	(18,019,644)	(25,201,886)
Future net cash flows	156,387,812	124,950,930
10% annual discount for estimated timing of cash flows	(58,022,633)	(41,934,370)
Standardized measure	$ 98,365,179	$ 83,016,560

The 12-month average prices were adjusted to reflect applicable transportation and quality differentials on a well-by-well basis to arrive at realized sales prices used to estimate the properties' reserves. The prices for the properties' reserves were as follows:

	2024		2023	
Oil (BBl)	$	71.66	$	75.45
Natural gas (MMBtu)	$	0.95	$	1.51
NGLs (BBl)	$	24.54	$	9.82

Changes in the Standardized Measure of Discounted Future Net Cash Flows at 10% per annum are as follows:

	As of December 31,			
	2024		2023	
Beginning of year	$	83,016,560	$	147,667,413
Net change in prices and production costs		(5,842,745)		(71,619,375)
Net change in future development costs		220,549		3,314,220
Oil & Gas net revenue		(9,381,470)		(6,256,366)
Extensions		11,255,319		4,684,473
Acquisition of reserves		1,890,863		526,848
Revisions of previous quantity estimates		6,675,903		(55,329,684)
Net change in taxes		4,274,178		33,317,731
Accretion of discount		9,746,049		19,542,907
Changes in timing and other		(3,490,026)		7,168,393
End of year	$	98,365,179	$	83,016,560

Estimates of economically recoverable natural gas and oil reserves and of future net revenues are based upon a number of variable factors and assumptions, all of which are to some degree subjective and may vary considerably from actual results. Therefore, actual production, revenues, development and operating expenditures may not occur as estimated. The reserve data are estimates only, are subject to many uncertainties, and are based on data gained from production histories and on assumptions as to geologic formations and other matters. Actual quantities of natural gas and oil may differ materially from the amounts estimated.

EMPIRE PETROLEUM CORPORATION

Insider Trading Policy
Updated April 18, 2024

Background

The Board of Directors of Empire Petroleum Corporation ("Empire") has adopted this Insider Trading Policy relating to the trading of Empire securities as well as the securities of publicly traded companies with whom Empire has a business relationship.

Federal and state securities laws prohibit the purchase or sale of a company's securities by persons who are aware of material information about that company that is not generally known or available to the public. These laws also prohibit persons who are aware of such material nonpublic information from disclosing this information to others who may trade. Companies and their controlling persons are also subject to liability if they fail to take reasonable steps to prevent insider trading by company personnel.

It is important that you understand the breadth of activities that constitute illegal insider trading and the resulting consequences, which can be severe. This policy is applicable to all trading of Empire securities in the public market. Both the Securities and Exchange Commission ("SEC") and the exchange on which Empire's common stock is listed investigate and are very effective at detecting insider trading. The SEC and U.S. Attorneys pursue insider trading violations vigorously. Cases have been successfully prosecuted against trading by employees through foreign accounts, trading by family members, and friends and trading involving only a small number of shares.

This policy is designed to prevent insider trading or allegations of insider trading and protect Empire's reputation for integrity and ethical conduct. It is your obligation to understand and comply with this policy. Should you have any questions regarding this policy, please contact a compliance officer designated by Empire's Board of Directors (each, a "compliance officer").

Penalties for Noncompliance

Civil and Criminal Penalties. Potential penalties for insider trading violations include imprisonment for up to 20 years, criminal fines of up to $5 million and civil fines of disgorgement, or return of profit gained or loss avoided, plus a fine of up to three times the profit gained or loss avoided.

Controlling Person Liability. If Empire fails to take appropriate steps to prevent illegal insider trading, Empire may have "controlling person" liability for a trading violation and be subject to civil penalties of up to the greater of $1 million and three times the profit gained or loss avoided as well as a criminal penalty of up to $25 million. The civil penalties can extend personal liability to Empire's directors, officers, and other supervisory personnel if they fail to take appropriate steps to prevent insider trading.

Empire Sanctions. Failure to comply with this policy may also subject you to sanctions imposed by Empire, including dismissal for cause, whether or not your failure to comply with this policy results in a violation of law.

Scope of Policy

Persons. This policy applies to directors, officers, employees, and consultants of Empire and its subsidiaries and affiliates. The same restrictions that apply to you apply to your family members who reside with you, anyone else who lives in your household, and any family members who do not live in your household but whose transactions in Empire securities are directed by you or are subject to your influence or control (such as parents or children who consult with you before they trade in securities). You are responsible for making sure that the transactions in any security covered by this policy by any such person complies with this policy.

It is also the policy of Empire that Empire will not engage in purchases and sales of Empire securities while aware of material nonpublic information relating to Empire or Empire securities.

Companies. The prohibition on insider trading in this policy is not limited to trading in Empire securities. It includes trading in the securities of other firms with which Empire does business, such as customers or suppliers of Empire, and those with which Empire may be negotiating major transactions, such as an acquisition, investment, or sale. Information that is not material to Empire may nevertheless be material to one of those other firms.

Transactions. The transactions covered by this policy include purchases and sales of stock, derivative securities (such as put and call options and convertible debentures), preferred stock, and debt securities (debentures, bonds, and notes) and gifts of Empire securities. Although this policy generally will not apply to the exercise of a stock option under Empire's equity incentive plans, it will apply to the sale of the underlying stock and the cashless exercise of the option (as this entails selling a portion of the underlying stock to cover the costs of exercise).

Policy Delivery. This policy will be delivered to all directors, officers, and employees at the start of their relationship with Empire. Upon request, a recipient must sign an acknowledgment that he or she has received a copy of the policy and agrees to comply with the policy's terms.

Definition of Material Nonpublic Information

Material Information. Information is material if there is a substantial likelihood that a reasonable investor would consider it important in deciding whether to buy, hold, or sell a security. Any information that could reasonably be expected to affect the price of the security is material. Common examples of material information are: (i) financial performance, especially quarterly and year-end earnings or projections of future earnings or losses or other earnings guidance; (ii) earnings that are inconsistent with the consensus expectations of the investment community; (iii) a material discovery or material change in hydrocarbon reserves and/or production numbers from producing fields; (iv) a pending or proposed merger or entity acquisition; (v) a tender offer on, acquisition of or disposition of significant assets; (vi) a change of Empire's Chief Executive Officer, President, Chief Operations Officer, or members of the Board of Directors; (vii) major events regarding Empire securities, including the declaration of a stock split or the offering of additional securities; (viii) financial liquidity problems; (ix) actual or threatened major litigation, or a material development with respect to such litigation; (x) a significant cybersecurity incident; and (xi) material approvals or denials of requests for regulatory approval from a government agency. This list is not exhaustive; other types of information may also be material. Both positive and negative information can be material. The quantity of variation should also be considered

when determining if information is material. For example, a 10% change (whether up or down) in either the overall production or the cost of overall operations of a company should be considered material while you may determine that smaller changes may not constitute a material change. However, because trading that receives scrutiny will be evaluated after the fact with the benefit of hindsight, questions concerning the materiality of particular information should be resolved in favor of materiality.

Nonpublic Information. Nonpublic information is information that is not generally known or available to the public. One common misconception is that material information loses its "nonpublic" status as soon as a press release is issued disclosing the information. In fact, information is considered to be available to the public only when it has been released broadly to the marketplace (such as by a press release or an SEC filing) and the investing public has had time to absorb the information fully. As a general rule, after nonpublic information is publicly disseminated, one full trading day must elapse before such information loses its status as nonpublic information.

Restrictions on Purchases, Sales and Tipping

Trading on Inside Information. Whether or not you are in a blackout period, you may not trade in the securities of Empire, directly or indirectly (through family members or other persons or entities), if you are aware of material nonpublic information relating to Empire. Similarly, you may not trade in the securities of any other company, directly or indirectly, if you are aware of material nonpublic information about that company which you obtained in the course of your relationship with Empire.

Tipping. You may not pass material nonpublic information on to others or recommend to anyone the purchase or sale of any securities when you are aware of such information. This practice, known as "tipping," also violates the securities laws and can result in the same civil and criminal penalties that apply to insider trading, even though you did not trade and did not gain any benefit from another's trading.

Short Sales. You may not engage in short sales of Empire securities (sales of securities that are not then owned), including a "sale against the box" (a sale with delayed delivery).

Margin Accounts or Pledges. You are required to get written pre-clearance from Empire's Board of Directors before holding Empire securities in a margin account or pledging Empire securities as collateral for a loan where the total amount borrowed against any security of Empire exceeds 10% of the value of the securities utilized to secure the funds borrowed, whether under a margin account or pledge to secure a loan.

Regular Blackout Periods. In addition to the general policy prohibiting trading while in possession of material nonpublic information, all directors and officers and any employees who regularly have access to internal financial information ("Designated Employees"), and all family members of Designated Employees, are also prohibited from purchasing or selling Empire securities during the period beginning fifteen trading days prior to the deadline for Empire to file its Annual Report on Form 10-K or Quarterly Report on Form 10-Q, as applicable, and ending one full trading day after earnings have been released with respect to such quarter or fiscal year (each, a "regular blackout period"). Notwithstanding the foregoing, a compliance officer may

shorten a regular blackout period if (a) Empire issues public guidance and (b) the compliance officer determines that such guidance sufficiently and accurately discloses all material items and issues a notice to all affected personnel of such compliance officer's determination.

Special Blackout Periods. From time to time an event may occur that is known by only a few directors, officers, and key employees. So long as the event remains material and non-public, the persons who are aware of the event, as well as persons covered by the pre-clearance provisions described below, shall not trade in Empire securities (each, a "special blackout period"). The existence of a special blackout period will not be announced, other than to those who are aware of the event giving rise to the special blackout. If, however, a person subject to pre-clearance requests permission to trade in Empire securities during a special blackout period, a compliance officer will inform the requesting person of the existence of a special blackout period, without disclosing the reason for the special blackout. Any person made aware of the existence of a special blackout period shall not disclose the existence of the blackout to any other person.

No Safe Harbor

For those persons who are subject to blackout periods, the existence of such blackouts shall not be considered a safe harbor for trading during other periods, and all officers, directors, other employees, and agents should use good judgment at all times. For example, occasions may arise when individuals covered by this policy become aware prior to the blackout period that earnings for that quarter are likely to exceed, or fall below, market expectations to an extent that is material. In such a case, the general policy against trading on inside information would still prohibit trading even though the time period is not within the blackout period or even if you are not subject to the blackout periods in the normal course of business. If you have any questions about whether you are permitted to trade in Empire securities at any particular time, you should contact a compliance officer.

Pre-Clearance Provisions

To help prevent inadvertent violations of the federal securities laws and to avoid even the appearance of trading on the basis of inside information, the following pre-clearance provisions are applicable to Empire's directors and executive officers. Empire may from time to time determine that these provisions shall also apply to certain other employees and consultants of Empire and its subsidiaries and affiliates who have access to material nonpublic information about Empire. Individuals who are not directors or executive officers but who are subject to the pre-clearance will be so notified.

All persons subject to pre-clearance, together with their family members and other members of their household, shall not engage in any transaction involving Empire securities (including a stock plan transaction such as an option exercise, or a gift, loan, pledge or hedge, contribution to a trust, or any other transfer) without first obtaining pre-clearance of the transaction from a compliance officer. A request for pre-clearance should be submitted to a compliance officer at least two business days in advance of the proposed transaction. A compliance officer is under no obligation to approve a trade submitted for pre-clearance and may determine not to permit the trade. A compliance officer may not trade in Empire securities unless Empire's President or Board has approved the trade in accordance with the procedures set forth in this paragraph.

Exceptions for Approved 10b5-1 Plans

Trades in Empire securities that are executed pursuant to an approved 10b5-1 plan are not subject to the prohibition on trading on the basis of material nonpublic information contained in this policy or to the restrictions relating to pre-clearance procedures and blackout periods. Rule 10b5-1 provides an affirmative defense from insider trading liability under the federal securities laws for trading plans that meet certain requirements. In general, a 10b5-1 plan must be entered into before you are aware of material nonpublic information. Once the plan is adopted, you must not exercise any influence over the amount of securities to be traded, the price at which they are to be traded, or the date of the trade. The plan must either specify (including by formula) the amount, pricing, and timing of transactions in advance or delegate discretion on those matters to an independent third party. Empire requires that all 10b5-1 plans be approved in writing in advance by a compliance officer and meet the requirements of Rule 10b5-1. A 10b5-1 plan may not be adopted during a blackout period.

Post-Termination Transactions

If you are aware of material nonpublic information when you terminate employment or services with Empire or your service on Empire's Board of Directors, you may not trade in Empire securities until that information has become public or is no longer material. If you are serving on Empire's Board of Directors when you terminate employment or service with Empire, you may not, in any case, trade in Empire securities until the expiration of 90 days after your termination. In addition, if you are subject to a blackout period at the time of your exit from Empire, the restrictions on trading in Empire securities will not cease to apply until the expiration of such blackout period. For the avoidance of doubt, once you (a) terminate employment or services with Empire or your service on Empire's Board of Directors, (b) are no longer in possession of material nonpublic information, (c) have waited any applicable waiting periods required by law, rule, regulation, or this Insider Trading Policy, and (d) any blackout period that existed at the time of your exit has terminated, this policy shall no longer apply to you even if you own 10% or more of Empire's stock.

Unauthorized Disclosure

Maintaining the confidentiality of Empire information is essential for competitive, security, and other business reasons, as well as to comply with securities laws. You should treat all information you learn about Empire or its business plans in connection with your employment as confidential and proprietary to Empire. Inadvertent disclosure of confidential or inside information may expose Empire and you to significant risk of investigation and litigation.

The timing and nature of Empire's disclosure of material information to outsiders is subject to legal rules, the breach of which could result in substantial liability to you, Empire, and its management. Accordingly, it is important that responses to inquiries about Empire by the press, investment analysts, or others in the financial community be made on Empire's behalf only through authorized individuals.

Personal Responsibility

You should remember that the ultimate responsibility for adhering to this policy and avoiding improper trading rests with you. If you violate this policy, Empire may take disciplinary action, including dismissal for cause.

Assistance

Your compliance with this policy is of the utmost importance both for you and Empire. If you have any questions about this policy or its application to any proposed transaction, you may obtain additional guidance from Empire's compliance officers. Do not try to resolve uncertainties on your own, as the rules relating to insider trading are often complex, not always intuitive and carry severe consequences.

Receipt and Acknowledgment

I, ____, hereby acknowledge that I have received and read a copy of the Empire Petroleum Corporation's Insider Trading Policy and agree to comply with its terms. I understand that violation of insider trading or tipping laws or regulations may subject me to severe civil and/or criminal penalties, and that violation of the terms of the above-titled policy may subject me to discipline by Empire up to and including termination for cause.

____
Signature

____
(Print Name)

____
Date

EXHIBIT 21

EMPIRE PETROLEUM CORPORATION
Subsidiaries

Entity	Place of Incorporation/Organization
Empire Louisiana LLC	Delaware
Empire New Mexico LLC	Delaware
Empire EMSU LLC	Delaware
Empire EMSU-B LLC	Delaware
Empire AGU LLC	Delaware
Empire NM Assets LLC	Delaware
Empire North Dakota LLC	Delaware
Empire ND Acquisition LLC	Delaware
Empire Northwest Shelf LLC	Delaware
Empire Texas LLC	Delaware
Empire Texas GP LLC	Texas
Empire Texas Operating LLC	Texas
Pardus Oil & Gas Operating, LP	Texas

EXHIBIT 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have issued our report dated March 27, 2025, with respect to the consolidated financial statements included in the Annual Report of Empire Petroleum Corporation on Form 10-K for the year ended December 31, 2024. We consent to the incorporation by reference of said report in the Registration Statements of Empire Petroleum Corporation on Forms S-3 (File No. 333-260570 and File No. 333-274327) and on Forms S-8 (File No. 333-261364, File No. 333-267220, File No. 333-272789 and File No. 333-282100).

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma
March 27, 2025

EXHIBIT 23.2

CONSENT OF CAWLEY, GILLESPIE & ASSOCIATES, INC.

We consent to the incorporation by reference in the registration statements (File Nos. 333-261364, 333-267220, 333-272789 and 333-282100) on Form S-8 and the registration statements (File Nos. 333-260570 and 333-274327) on Form S-3 of Empire Petroleum Corporation (the "Company") of our report for the Company and the references to our firm and said report, in the context in which they appear, in this Annual Report on Form 10-K of the Company for the year ended December 31, 2024 (this "Form 10-K"), which report is included as an exhibit to this Form 10-K.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

J. Zane Meekins, P.E.
Executive Vice President

Fort Worth, Texas
March 27, 2025

CERTIFICATION

I, Michael R. Morrisett, certify that:

1. I have reviewed this annual report on Form 10-K of Empire Petroleum Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 27, 2025

/s/ Michael R. Morrisett
Michael R. Morrisett
President and Chief Executive Officer

CERTIFICATION

I, Michael R. Morrisett, certify that:

1. I have reviewed this annual report on Form 10-K of Empire Petroleum Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   (a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   (b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   (c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   (d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   (a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   (b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

March 27, 2025

/s/ Michael R. Morrisett
Michael R. Morrisett
President and Chief Executive Officer
(Principal Financial Officer)

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Empire Petroleum Corporation (the "Company") on Form 10-K for the year ended December 31, 2024, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Michael R. Morrisett, President and Chief Executive Officer of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 27, 2025

/s/ Michael R. Morrisett
Michael R. Morrisett
President and Chief Executive Officer

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350, AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the annual report of Empire Petroleum Corporation (the “Company”) on Form 10-K for the year ended December 31, 2024, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), I, Michael R. Morrisett, Chief Executive Officer (principal financial officer) of the Company, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

March 27, 2025

/s/ Michael R. Morrisett
Michael R. Morrisett
President and Chief Executive Officer
(Principal Financial Officer)

A signed original of this written statement required by Section 906 has been provided to the Company and will be retained by the Company and furnished to the Securities and Exchange Commission or its staff upon request.

The foregoing certification is being furnished to the Securities and Exchange Commission as an exhibit to the Report and shall not be considered filed as part of the Report.

CAWLEY, GILLESPIE & ASSOCIATES, INC.

PETROLEUM CONSULTANTS

302 FORT WORTH CLUB BUILDING
306 WEST SEVENTH STREET
FORT WORTH, TEXAS 76102-4987
(817) 336-2461

March 25, 2025

Mr. Michael R. Morrisett
President
Empire Petroleum Corporation
2200 S. Utica Place, Suite 150
Tulsa, OK 74114

Re: Evaluation Summary
Empire Petroleum Corporation Interests
Various States
Proved Developed Reserves
As of December 31, 2024

Dear Mr. Morrisett:

As requested, we are submitting our estimates of proved developed reserves and our forecasts of the resulting economics attributable to the above captioned interests in various states. It is our understanding that the proved developed reserve estimates shown herein constitute 100 percent of all proved developed reserves owned by Empire Petroleum Corporation. This report, completed on March 25, 2025, has been prepared for use in filings with the Securities and Exchange Commission ("SEC") by Empire Petroleum Corporation. In our opinion the assumptions, data, methods, and procedures used in the preparation of this report are appropriate for such purpose.

Composite reserve estimates and economic forecasts for the proved developed reserves are summarized below:

		Proved Developed Producing	Proved Developed Non-Producing	Proved Developed
Net Reserves				
Oil	- Mbbl	6,634.2	367.3	7,001.5
Gas	- MMcf	6,063.7	0.0	6,063.7
NGL	- Mbbl	1,215.5	0.0	1,215.5
Revenue				
Oil	- M$	477,100.0	24,603.8	501,703.7
Gas	- M$	5,774.8	0.0	5,774.8
NGL	- M$	29,824.8	0.0	29,824.8
Severance and Ad Valorem Taxes	- M$	46,127.4	1,894.5	48,021.9
Operating Expenses	- M$	270,885.2	5,307.6	276,192.8
Investments	- M$	38,450.4	230.8	38,681.2
Operating Income (BFIT)	- M$	157,236.6	17,170.9	174,407.5
Discounted at 10.0%	- M$	100,221.5	8,313.4	108,534.9

The discounted value shown above should not be construed to represent an estimate of the fair market value by Cawley, Gillespie & Associates, Inc.

Hydrocarbon pricing of $2.130 per MMBtu of gas (Henry Hub spot) and $75.48 per barrel of oil/condensate (WTI spot) was applied without escalation. In accordance with the SEC guidelines, these prices were determined as an unweighted arithmetic average of the first-day-of-the-month price for the previous 12 months. The oil and gas prices were held constant and were adjusted for gravity, heating value, quality, transportation and marketing. NGL prices were forecasted as fractions of the above oil price. The adjusted volume-weighted average product prices over the life of the properties are $71.66 per barrel of oil, $0.95 per Mcf of gas and $24.54 per barrel of NGL.

Operating expenses were supplied by Empire Petroleum Corporation and reviewed for reasonableness. Severance and ad valorem taxes were scheduled based on historical rates. Neither expenses nor investments were escalated. The cost of plugging and the salvage value of equipment have been considered.

The proved reserves classifications conform to criteria of the SEC. The estimates of reserves in this report have been prepared in accordance with the definitions and disclosure guidelines set forth in the SEC Title 17, Code of Federal Regulations, Modernization of Oil and Gas Reporting, Final Rule released January 14, 2009 in the Federal Register (SEC regulations). The reserves and economics are predicated on the regulatory agency classifications, rules, policies, laws, taxes and royalties in effect on the effective date except as noted herein. The possible effects of changes in legislation or other Federal or State restrictive actions have not been considered.

The reserves were estimated using a combination of the production performance and analogy methods, in each case as we considered to be appropriate and necessary to establish the conclusions set forth herein. All reserve estimates represent our best judgment based on data available at the time of preparation and assumptions as to future economic and regulatory conditions. It should be realized that the reserves actually recovered, the revenue derived therefrom and the actual cost incurred could be more or less than the estimated amounts.

The reserve estimates were based on interpretations of factual data furnished by Empire Petroleum Corporation. Ownership interests were supplied by Empire Petroleum Corporation and were accepted as furnished. To some extent, information from public records has been used to check and/or supplement these data. The basic engineering and geological data were utilized subject to third party reservations and qualifications. Nothing has come to our attention, however, that would cause us to believe that we are not justified in relying on such data. An on-site inspection of these properties has not been made nor have the wells been tested by Cawley, Gillespie & Associates, Inc. Possible environmental liability related to the properties has not been investigated nor considered.

Our work-papers and related data are available for inspection and review by authorized parties.

Respectfully submitted,

Cawley, Gillespie & Assoc., Inc.

CAWLEY, GILLESPIE & ASSOCIATES, INC.
Texas Registered Engineering Firm F-693

JZM:ptn

Goodnight Cross Exhibit 18

R. I. 3456

JULY 1939

UNITED STATES
DEPARTMENT OF THE INTERIOR
HAROLD L. ICKES, SECRETARY

BUREAU OF MINES
JOHN W. FINCH, DIRECTOR

REPORT OF INVESTIGATIONS

RESERVOIR CHARACTERISTICS OF THE EUNICE OIL FIELD, LEA COUNTY, N. MEX.

BY

C. C. ANDERSON, H. H. HINSON, AND H. J. SCHROEDER

R.I. 3456,
July 1939.

REPORT OF INVESTIGATIONS

UNITED STATES DEPARTMENT OF THE INTERIOR - BUREAU OF MINES

RESERVOIR CHARACTERISTICS OF THE EUNICE OIL FIELD, LEA COUNTY, N. MEX.[1]

By C. C. Anderson[2], H. H. Hinson[3], and H. J. Schroeder[4]

CONTENTS

ILLUSTRATIONS

1/ The Bureau of Mines will welcome reprinting of this paper provided the following footnote acknowledgment is used: "Reprinted from Bureau of Mines Report of Investigations 3456."
2/ Petroleum engineer, Bureau of Mines, Amarillo, Tex.
3/ Junior petroleum engineer, Bureau of Mines, Amarillo, Tex.
4/ Assistant petroleum engineer, Bureau of Mines, Amarillo, Tex.

INTRODUCTION

The Eunice field is one of a group in southeastern New Mexico producing oil and gas from so-called limestone-type reservoirs in which the productive strata are dolomite or dolomitic limestone. Ordinarily, wells in reservoirs of this type show wide differences in their productive characteristics, indicating erratic variations in porosity and permeability. Often there is a large difference in total footage of actual "pay" penetrated in neighboring wells and the vertical distribution of the "pay" within the productive strata varies. In the Eunice field there are few easily recognizable geologic markers to indicate true structural conditions of the oil-productive section, due to horizontal and vertical gradation in chemical compositions and lithologic characteristics of the strata. Geologic markers are found some distance above the oil-producing zones in this field and consequently they indicate only the general structure. Furthermore, no direct relation has been found between the general structure and the accumulation of oil within the reservoir.

Many problems in well-completion and production practice have been met in the Eunice field because of erratic variations in porosity, permeability, in vertical distribution of "pays," and the apparent departure from ordinarily accepted relations of oil accumulation to structure. A detailed study of the position and characteristics of the oil- and gas-producing zones aids production procedure. The methods employed in studying the Eunice field, discussed in this paper, may be applicable to other limestone-type reservoirs.

ACKNOWLEDGMENTS

This report was prepared under the general supervision of R. A. Cattell, chief engineer, Petroleum and Natural Gas Division, Bureau of Mines, Washington, D. C., and C. W. Seibel, supervising engineer, Bureau of Mines Helium Plant, Amarillo, Tex.

The writers wish to express their appreciation for the hearty cooperation of the oil companies and individuals operating in the Eunice field who so generously furnished field data and other information. Special acknowledgment for helpful assistance is given to C. G. Staley and his staff of the Proration Office, Hobbs, N. Mex. The writers thank D. B. Taliaferro, Jr. of the Bureau's Petroleum Experiment Station at Bartlesville, Okla., for determining the porosities and permeabilities of the core specimens referred to in this report.

Grateful acknowledgment is given to the engineers and geologists of the operating companies in the Eunice field and associates of the writers in the Bureau of Mines for many constructive criticisms and review of this report.

HISTORY OF DEVELOPMENT

The Eunice field is in Lea County, New Mexico, approximately 15 miles southwest of Hobbs and 7 miles northwest of Eunice. (See fig. 1.) Most of the field lies in T. 21 S., R. 36 E.; the rest is in the three adjoining townships to the north and west. (See fig. 2.)

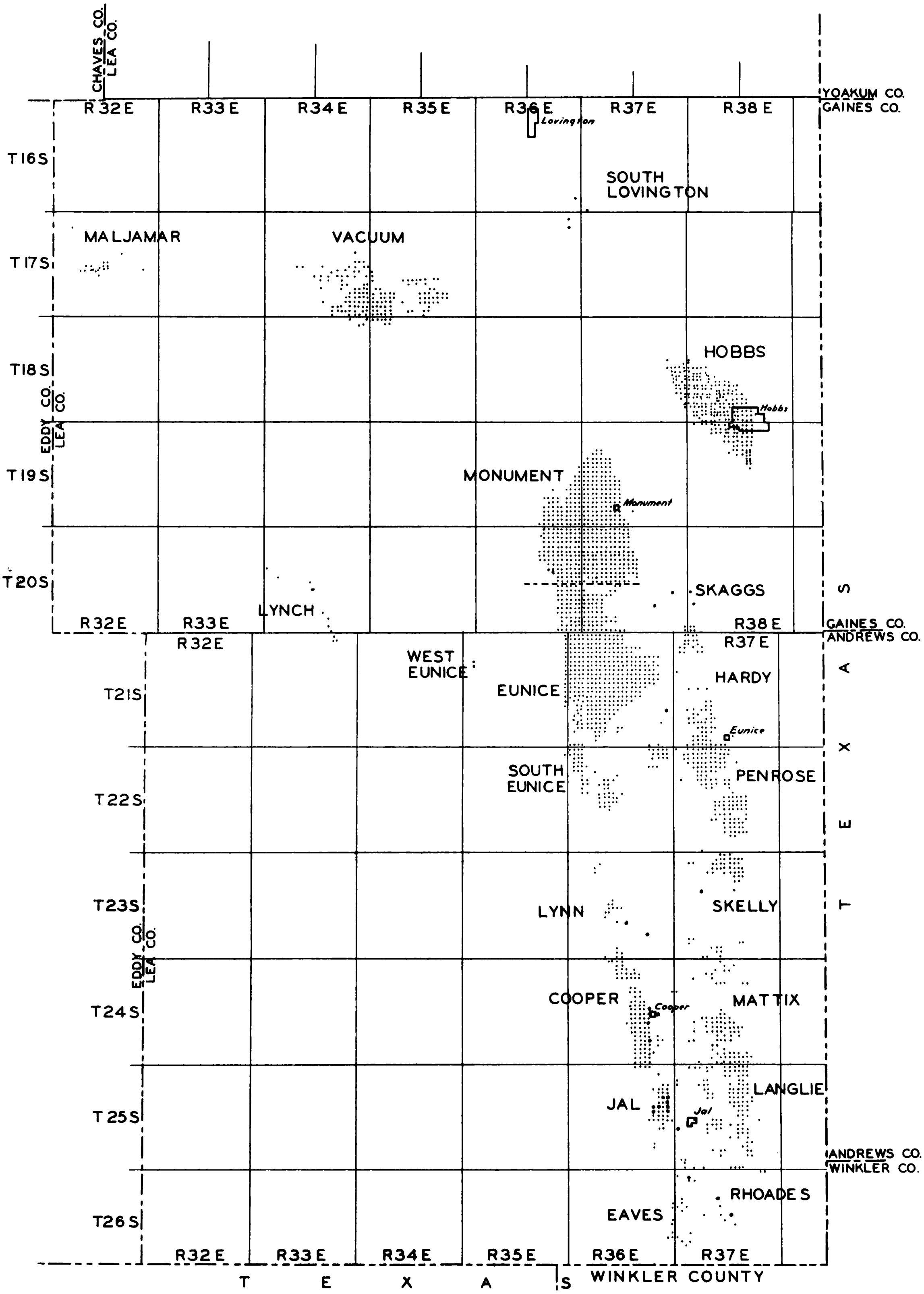


Figure 1.—Oil fields of central and southern Lea County, New Mexico.

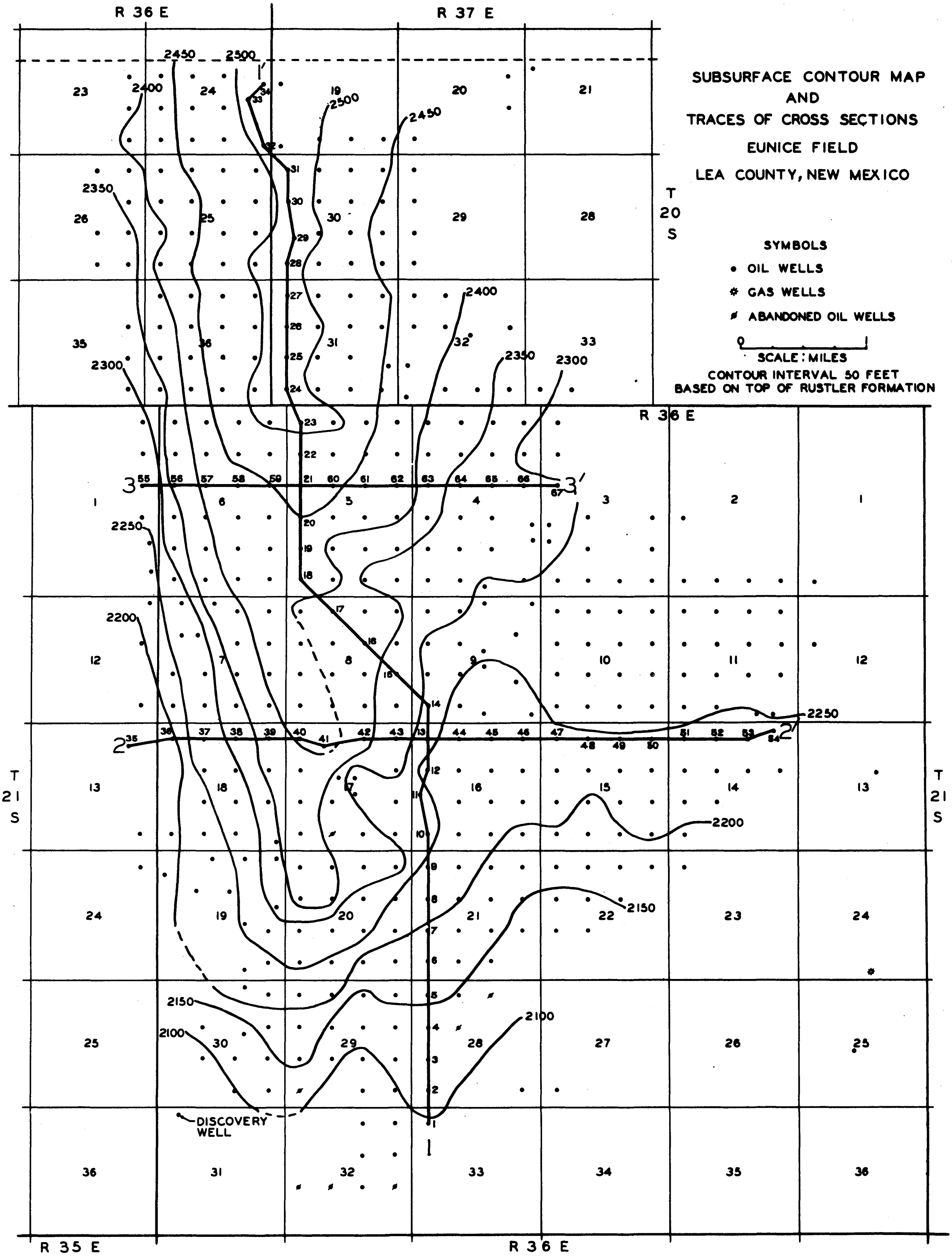

SUBSURFACE CONTOUR MAP
AND
TRACES OF CROSS SECTIONS
EUNICE FIELD
LEA COUNTY, NEW MEXICO
SYMBOLS
OIL WELLS
GAS WELLS
ABANDONED OIL WELLS
SCALE: MILES
CONTOUR INTERVAL 50 FEET
BASED ON TOP OF RUSTLER FORMATION
R 36 E
R 37 E
R 35 E
T 20 S
T 21 S
DISCOVERY WELL

Figure 2.

The discovery well was completed on March 8, 1929, by the Marland Oil Co., now the Continental Oil Co., at a depth of 3,992 feet for an initial production of approximately 250 barrels of oil per day. This well, known as the Lockhart B-31 No. 1, is in sec. 31, T. 21 S., R. 36 E. On August 20, 1929, the Continental Oil Co. completed Meyer A-17 No. 1 well in sec. 17, T. 21 S., R. 36 E., approximately 2-1/2 miles northeast of the discovery well. This well was the second producer in the field and flowed at the rate of 1,260 barrels of oil per day.

Owing to lack of pipe-line transportation facilities, the field was developed very slowly, and by the end of 1933 only 11 producing wells had been drilled. Drilling operations increased during the last half of 1934, and by the end of 1935 there were 113 wells in the field. The most active development occurred in 1936, when 191 wells were completed. During 1937, 131 wells were added, and 39 more were drilled in 1938, making a total of 474 oil wells as of January 1, 1939. Nearly all wells were drilled in the center of 40-acre units, and the field has been developed to a density of one well to each of these units. The 474 well units cover an area of approximately 18,960 acres.

Rotary tools were used extensively in drilling the wells in the Eunice field. The general practice was to set three "strings" of casing, namely, a short surface string, an intermediate string, and a production string. The surface casing was set to shut off and protect the fresh-water sands in the Tertiary formations. The usual practice was to set and cement 1,100 to 1,400 feet of intermediate casing, frequently 7-5/8-inch or 9-5/8-inch in size, to protect the hole from red shales, which have a tendency to cave. In some wells the intermediate string of casing was set and cemented at a depth of about 2,500 feet to protect potash-bearing salt strata as well as to exclude caving shales from the hole. The production string was usually 5-1/2 or 7 inches in diameter, depending upon the size of the intermediate string. This casing was set and cemented in the productive zone at a depth of about 3,775 feet. In 430 wells the average elevation of the casing seat of the production string was 174 feet below sea level and the average penetration below the casing seat was 128 feet.

The first million barrels of crude oil was produced by March 1934, or about 5 years after discovery. At that time there were only 11 wells in the field. The cumulative production as of January 1, 1939, was 32,187,000 barrels of oil, an average recovery of 1,698 barrels of oil per acre for the 474 well units. The field has been under production curtailment since active development began, and the greatest daily allowed production was had in May 1937, when an average of 31,936 barrels of oil was produced.

GENERAL DESCRIPTION OF STRATA DRILLED IN THE EUNICE FIELD

The Eunice field is covered by a mantle of sand, soil, and an impure, flaggy limestone commonly called caliche, and the major part of the area is overlain with windblown sand, which in places reaches a depth of 30 feet. Underlying these materials is approximately 200 feet of strata consisting principally of sand, buff to pink in color, with thin shale streaks. The uppermost 50 feet is the more calcareous, and near the top there is usually a deposit of caliche. These beds are considered to be Tertiary in age.

Underlying these strata are 700 to 1,100 feet of red shales and sandstones, which correspond to the portion of the columnar section of the Hobbs field described by DeFord and Wahlstrom5/ as belonging to the Dockum group of Triassic age. This section, except for a basal sandstone member approximately 100 feet thick, consists largely of dense red shales. Beneath this are 100 to 200 feet of sandy red beds, which may correlate with the Post-Rustler Red Beds6/ of Permian age.

The next stratigraphic unit, commonly referred to in the Eunice area as the Rustler formation, consists of about 100 feet of white to gray anhydrite, red shale, sand, and dolomite. In some areas in the field, the basal part of the Rustler formation is interfingered or interbedded with the upper part of the underlying salt, which is potash-bearing in part and attains a thickness of 1,000 to 1,500 feet. Below the salt is a bed of anhydrite 100 to 300 feet thick, which sometimes contains salt, red shale, light-colored dolomite, and sand in the upper part. (See figs. 3, 4, and 5 for generalized geologic section from the Rustler formation to the oil- and gas-producing zones along the cross-section lines 1-1', 2-2', and 3-3', respectively, shown in figure 2.)

Directly beneath this anhydrite are 500 to 800 feet of interbedded buff to brown dolomite and anhydrite with varying amounts of sand and bentonitic shale. In these beds, known as the brown lime section, the interbedded anhydrite decreases with depth and usually disappears at the top of the "sandy-lime" section. The anhydrite and brown-lime sections are thinnest in the southern part of the field and thicken in the northward direction.

The sandy-lime section, as the term is used in this report refers to the fine-grained sandy dolomite or dolomitic sandstone 150 to 300 feet thick that lies immediately under the brown lime. Below this sandy lime is a lighter-colored dolomite, which is white, gray, and buff in color and contains varying amounts of sandy material. The "sandy lime" and the underlying light-colored dolomite probably correlate wholly or in part with the "sandy section" of DeFord and Wahlstrom7/ in the Hobbs field. The principal oil-productive zones in the Eunice field usually are present from a few to 200 feet below the top of the light-colored dolomite.

5/ DeFord, Ronald K., and Wahlstrom, Edwin A., Hobbs Field, Lea County, New Mexico: Bull. Am. Assoc. Petrol. Geol., vol. 16, 1932, pp. 58-59.
6/ DeFord, Ronald K., and Wahlstrom, Edwin A., Work cited, p. 59.
7/ DeFord, Ronald K., and Wahlstrom, Edwin A., Work cited, pp. 58 and 68-69.

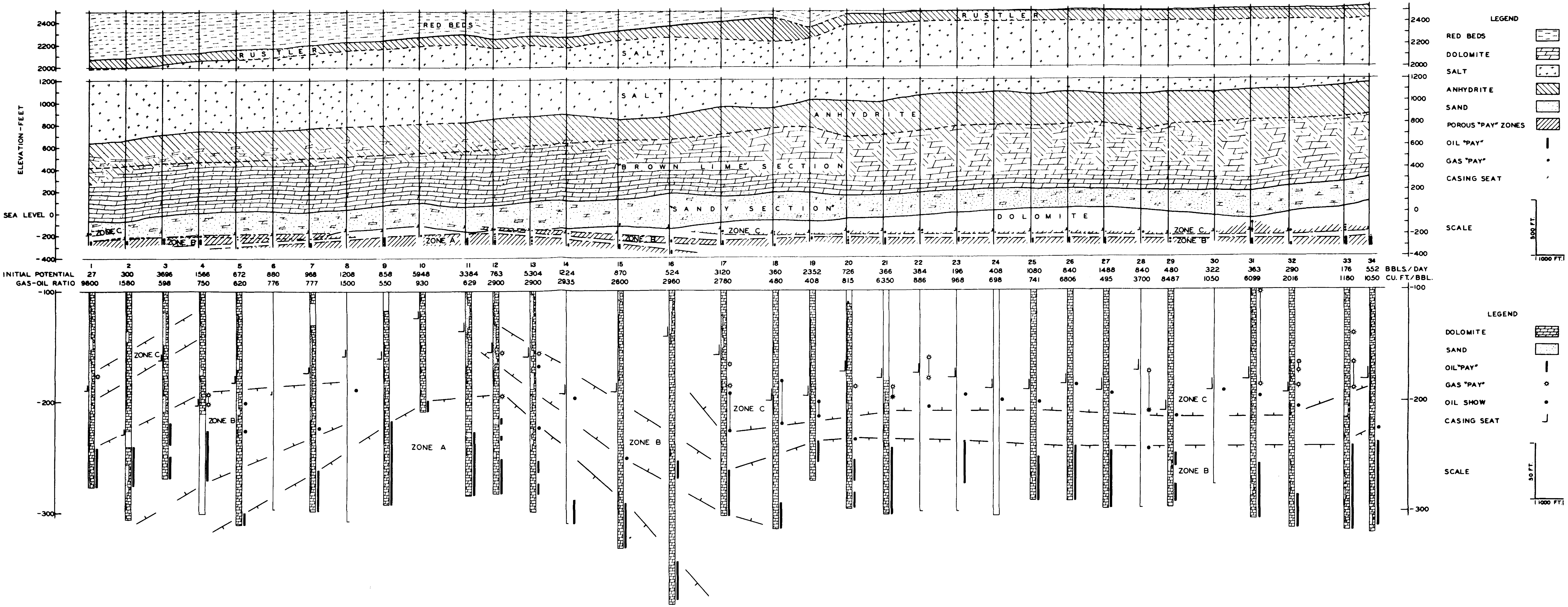


Figure 3.-Cross section 1-1'

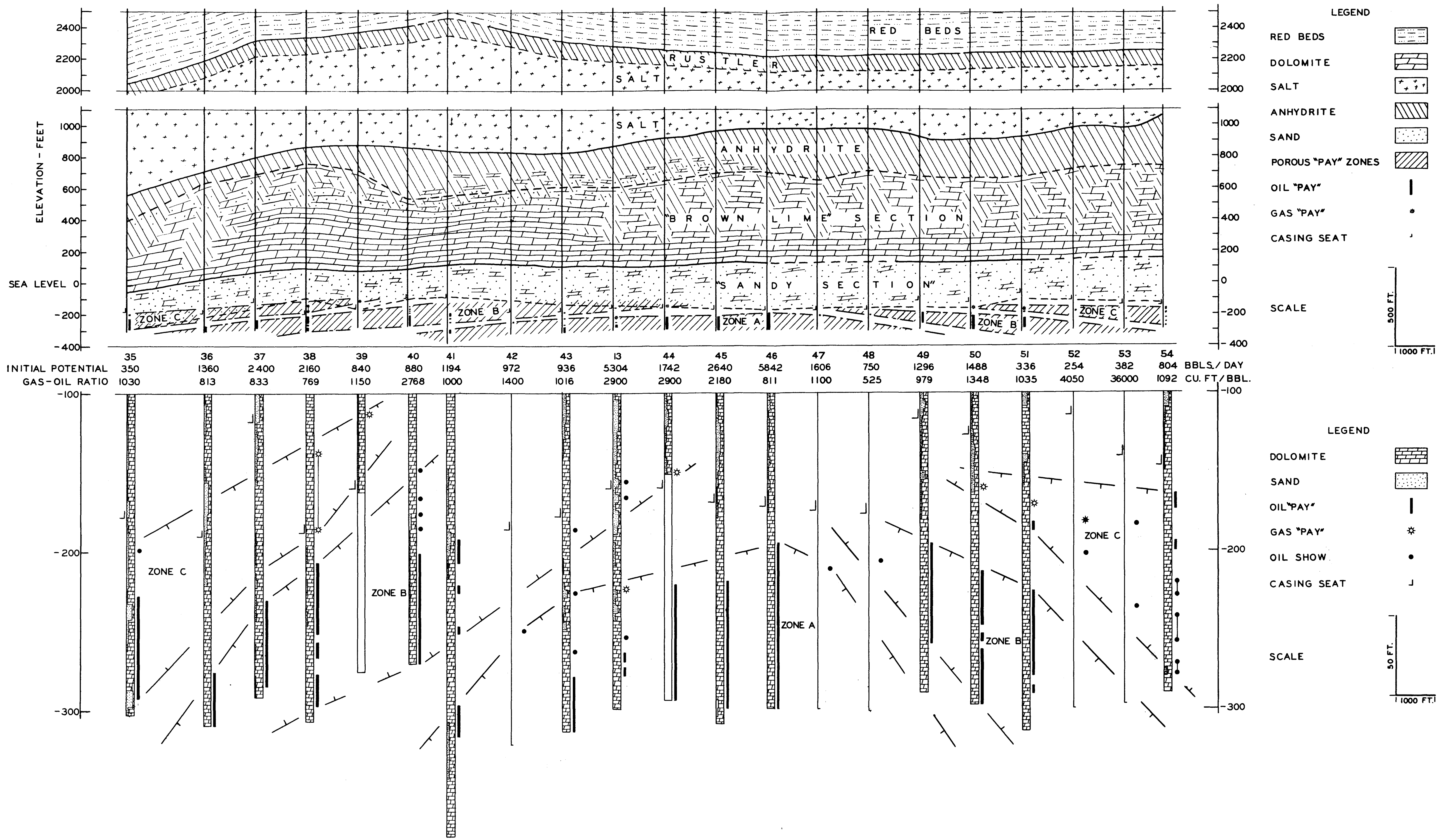


Figure 4.-Cross section 2-2'

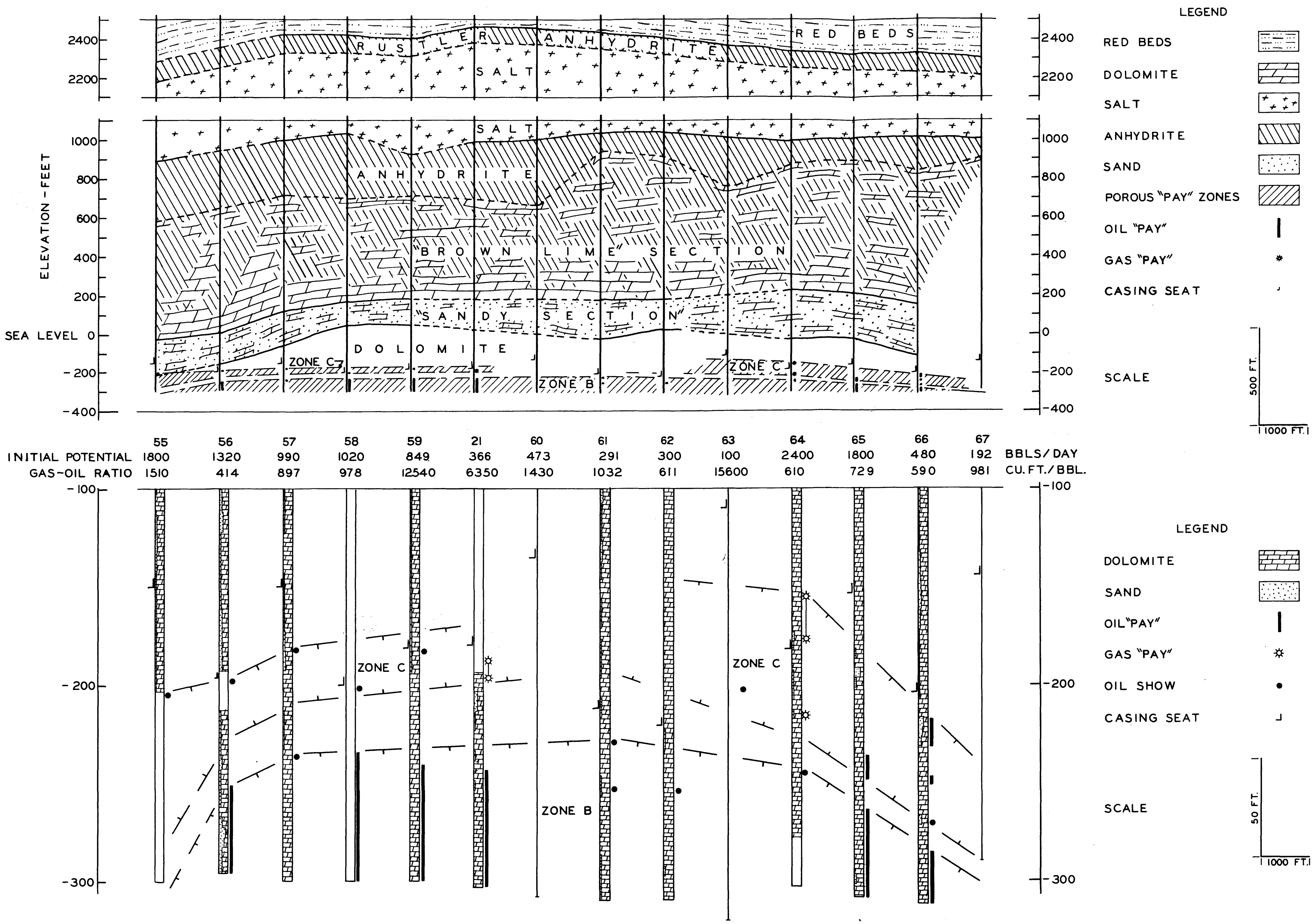


Figure 5.–Cross section 3–3'

GENERAL STRUCTURE

The Eunice field is on the west edge of the Central Basin Platform[8,9] in the Permian Basin of west Texas and southeastern New Mexico. This field is in the northern part of the "structural trend" that includes Hendrick (Winkler County, Texas), Jal, Cooper, Eunice, and Monument oil fields of Lea County, New Mexico. (See fig. 1.)

Based on the configuration of the top of the Rustler formation, which is about 2,500 feet above the oil-producing zones, the structural fold has a relatively steep dip on the west flank and a more gentle slope on the eastern side. (See fig. 2.) The structure rises uniformly from south to north and merges with the Monument anticline. Thus, the Eunice and Monument fields may be considered as one large anticlinal fold, or the Eunice portion may be described as a nose of the Monument structure. The cross sections of the Eunice field, shown on figure 2 and illustrated in figures 3, 4, and 5, which show the strata below the Rustler formation, indicate similar structural conditions. The oil-bearing zones, however, appear to have little relation to the general structure of the overlying beds. In general, the oil-producing section is horizontal, and the oil is found between definite elevations, provided porosity and permeability are developed adequately in the formation between these datum planes.

CROSS SECTIONS OF THE EUNICE RESERVOIR

In a field that produces from a uniform stratum, deposited as a parallel member of a geologic formation, the reservoir often may be defined readily from geologic information. The reservoir of the Eunice field, however, cannot be interpreted so easily because it consists of a series of porous streaks or lenses that, upon casual inspection, are erratic in occurrence and have little or no relation to the attitude of the beds containing them. With enough data, it may be possible to develop an accurate conception of the detailed geologic structure of the reservoir, but, as already mentioned, the oil-producing zones may not coincide with or be directly related to this structure.

In studying the Eunice field, detailed cross sections for each east-west row of wells were constructed from well-completion data and logs that were made from the examinations of cuttings from wells. These cross sections, which have a vertical range of 250 feet (from 100 to 350 feet below sea level), include the known oil-productive zones of the Eunice field. A study of these cross sections suggested the possibility of grouping the various oil and gas "pays" into three major zones, which are separated from each other by dolomitic beds through which there is little or no flow of fluids.

8/ Carpenter, Charles B., and Hill, H. B., Petroleum Engineering Report, Big Spring Field and Other Fields in West Texas and Southeastern New Mexico: Bureau of Mines Rept. Inv. 3316, November 1936, pp. 16-17.

9/ See Regional Structure Map of West Oklahoma, Texas, and New Mexico: Oil and Gas Jour., vol. 37, No. 21, Oct. 6, 1938, p. 21.

To illustrate graphically the findings of this study, three detailed cross sections, 1-1', 2-2', and 3-3' (the traces of which are shown in fig. 2), are presented in figures 3, 4, and 5, respectively. In these illustrations three major porous and permeable zones have been outlined to conform as nearly as possible to the information obtained from the whole group of cross sections. For convenience in discussing reservoir conditions, the three major porous zones that produce oil and gas are designated, from the bottom upward and from the central portion of the field outward, as zones A, B, and C.

A south-north cross section (1-1', fig. 2) through the central part of the field is shown in figure 3. All three of the major porous zones are indicated in this cross section. It will be seen that the top of zone A is approximately 200 feet below sea level in the southern part of the field, where this zone has a productive width of almost 3 miles. Along 1-1', zone B contains gas in its higher parts and is productive of oil across the field except over the central part of zone A. Zone B thins toward the central portion of the field but does not seem to extend completely across the top of zone A. Zone C is above zone B on the north and south ends of the section. In the southern part of the field, where zone C is relatively thin, it produces gas only; in the northern portion it is productive of oil in the lower part and gas in the upper part. From the available data, the writers have been unable to trace zone C across the top of the structure.

A west-east cross section (2-2', fig. 2) across the southern part of the field is shown in figure 4. Zone A, the top of which is 200 feet below sea level, has a productive width of about 2-1/2 miles and has a thickness of 100 feet in places. Zone B overlaps zone A on the east and west sides of the field, but the data are not complete enough to indicate whether this zone is continuous over the top of zone A. Zone B, which contains gas in its higher parts, is more irregular in thickness and porosity than zone A. Zone C, which is present on the east and west edges and overlaps zone B, appears to have more erratic variations in porosity and permeability than the lower zones and probably is absent on the upper part of the structure. To substantiate this thought, it will be noted from figure 4 that wells nos. 40, 41, 45, and 49, drilled near the crest of the structure, where zone C would be penetrated at a high elevation if it were present, do not have large gas-oil ratios,[10] although the casing seats are high.

A study of figure 5, a transverse cross section (3-3', fig. 2), reveals that zones B and C are present but zone A is absent in the northern part of the field. On this cross section, zone B is the principal oil-producing pay and zone C overlaps zone B on the east and west sides. Zone C may not be continuous across this part of the field, because well no. 60 in the central part of the cross section with the producing string set high does not have an

[10] Gas-oil ratios and well potentials as used in this report refer to the original or initial production from wells. Reference to high or excessive initial gas-oil ratios should not be construed to imply that remedial steps have not been taken to operate these wells in accordance with good production practices.

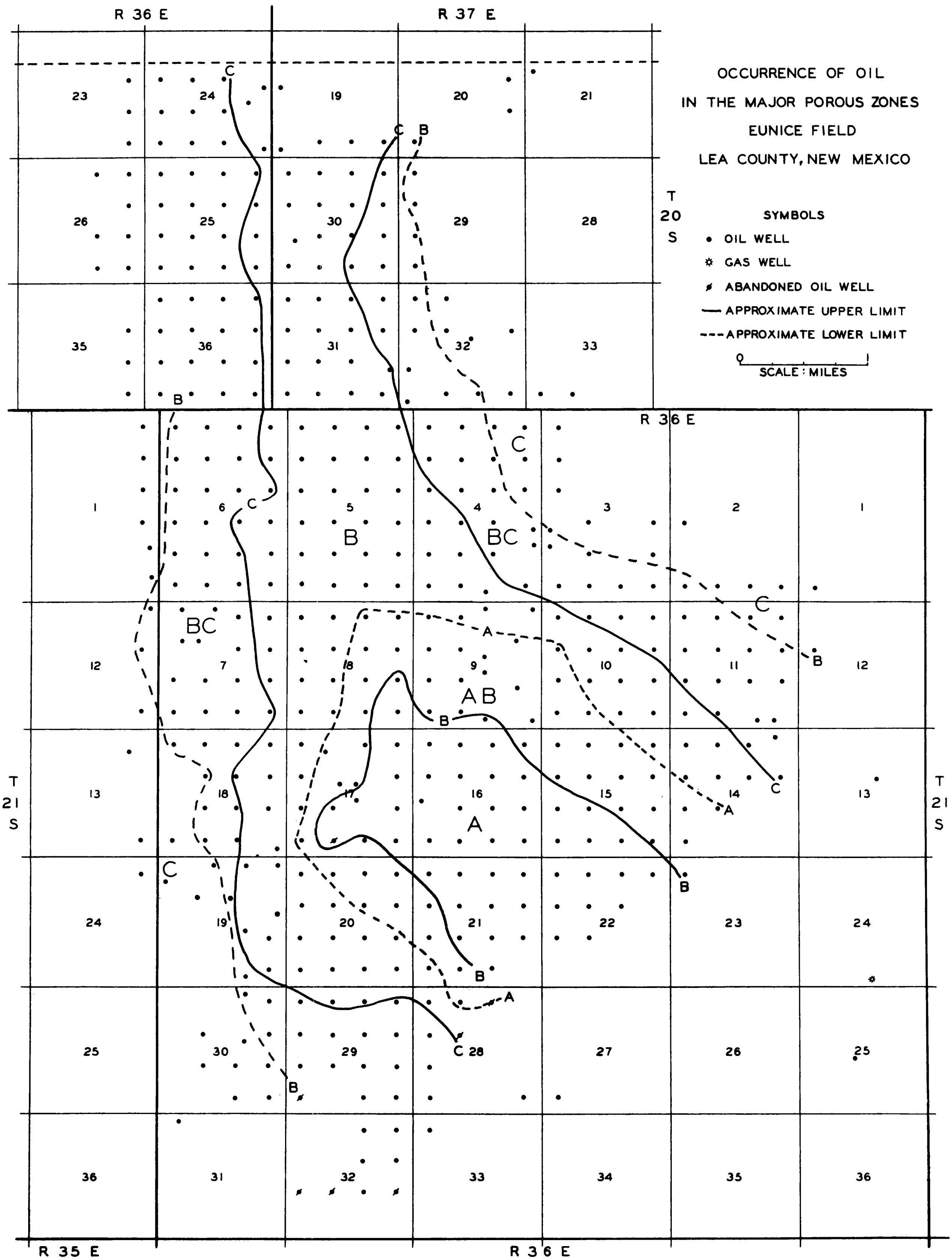

R 36 E
R 37 E
OCCURRENCE OF OIL
IN THE MAJOR POROUS ZONES
EUNICE FIELD
LEA COUNTY, NEW MEXICO
T 20 S
SYMBOLS
OIL WELL
GAS WELL
ABANDONED OIL WELL
APPROXIMATE UPPER LIMIT
APPROXIMATE LOWER LIMIT
SCALE: MILES
R 36 E
T 21 S
T 21 S
R 35 E
R 36 E

Figure 6.

excessive gas-oil ratio. On the other hand, well no. 63, with the casing set high and penetrating the upper part of zone C on the east side of the field, had a high initial gas-oil ratio.

Three partly overlapping zones have been indicated on the cross sections 1-1', 2-2', and 3-3'. In each, the zone consists of a number of small porous pays. The three major zones probably are interconnected, at least to the extent that the reservoir may be assumed to have been in a state of equilibrium prior to drilling, but the channels of communication are not extensive enough to maintain pressure equilibrium among zones under the present production practices. As the permeability between zones is small compared to that within zones, and as the time of producing the field is short compared to that required for accumulation and equilization, the field will react to production according to zonal pattern rather than as a reservoir consisting of continuous and uniformly porous rock.

The relations of the three major porous zones to the detailed geologic structure have not been determined by the writers. If it is assumed that the structure of the upper beds (such as the Rustler formation) is the result of folding, then the attitude of the major porous zones in the oil-producing section may be the result of folding, at least in part. Other factors in addition to folding probably influenced the origin and development of the porous zones and, therefore, they may not lie parallel to the strata that contain them.

AREAL EXTENT OF MAJOR POROUS ZONES

Following the construction of the cross sections of the Eunice field, a map (fig. 6) was prepared to show the areal extent of porous zones A, B, and C. The broken lines on this map indicate the intersection of each zone with a horizontal plane defining the top of the oil-water contact, which is assumed to be at 325 feet below sea level. The solid lines represent the approximate upper limits of oil production from the respective zones. Porous zones continuing inwardly beyond such a solid line are productive of gas. The areas designated by the letters A, B, and C represent the zone or zones from which oil production may be expected.

Apparently these zones are on a structure having an approximate north and south trend. Zone A is productive only in the southeast part of the field. Zone B, overlapping zone A, is productive of oil throughout the central part of the field and dips below the oil-water contact on the edges. Zone C overlaps zone B and is productive of oil only on the edges of the field. Probably zone C overlies zone B in the central and northern parts of the field, but in those areas its pore spaces contain gas only.

COORDINATED STUDY OF WELL PERFORMANCE AND OTHER FIELD DATA

Some of the information disclosed by the cross sections was not adequate to establish the boundaries of the major productive zones. To overcome this difficulty, a coordinated study was made of well performances and other data in relation to the field as a whole. Details concerning this study are discussed in following sections of this paper.

Before equilibrium within a reservoir is disturbed by the drill, the oil in the pore spaces of the structural trap is in equilibrium (for all practical purposes) with water below and gas above. When oil is withdrawn from the reservoir through wells, pressure gradients are set up in the reservoir, and oil, gas, and water move to regions surrounding the wells, where the pressures are lower than elsewhere in the reservoir. As the pressure in the reservoir declines, the gas cap above the oil expands and the water enters the oil-vacated parts of the structure from below. Obviously, the fluids move through the more permeable parts of the reservoir, where they meet with the least resistance to flow. Particularly in limestone-type fields well performance is influenced by the location of the well relative to a porous zone or zones and by the permeability of the zones to flow of fluids through them.

In coordinating the study, it was thought that the position of the porous zones of the Eunice field - a limestone-type reservoir - might be outlined further and many of their producing characteristics determined if enough fundamental engineering data were obtained and analyzed. Well-completion and production data should provide a basis for interpreting reservoir conditions, as such data give information on the position of the reservoir fluids with respect to the wells and the productiveness of these fluids. A study of the oil, gas, and water production of a well also should give an indication of the relation of the well to the porous zones. Accordingly these and other data on "top of oil pay", initial well potentials, gas-oil ratios, and water encroachment were studied to aid in defining the extent of the major porous zones in the Eunice field and to determine some of their physical characteristics.

Study of "Top-Oil-Pay" Data

In the Eunice field, as mentioned previously, the downward dip of one porous zone is covered by the overlap of another. However, in these areas of overlap the productive zones should be found relatively high or low[11]. (See fig. 7.) If the porosity and permeability were more nearly uniform, the productive zones might be recognized more easily. However, considering the erratic variations in porosity and permeability characteristic of the Eunice reservoir, there are 3 possible conditions affecting the determination of the top of the oil-producing zone or zones in the areas of overlap.

If two zones are present and sufficiently permeable, the top of each can be recognized if adequate well data are recorded. If the upper zone is not permeable enough, it may not be recognized in drilling and only the lower zone will be defined. Thus, the recorded elevation of the top of the productive zone will be relatively low. If the upper zone is permeable enough for recognition and the top of the pay in the lower zone is not detected, the reported elevation of the top of the productive zone will be high. From the above it appears that most of the recorded elevations of the top of the productive zone in an area of overlap will be either high or low, but where the porosity and permeability of the zones are very erratic, medial figures may be obtained.

11/ The words "high" and "low" are used in this report to convey impressions of relative positions much as they are used in describing hills and valleys, and not as they are used in describing structural conditions.

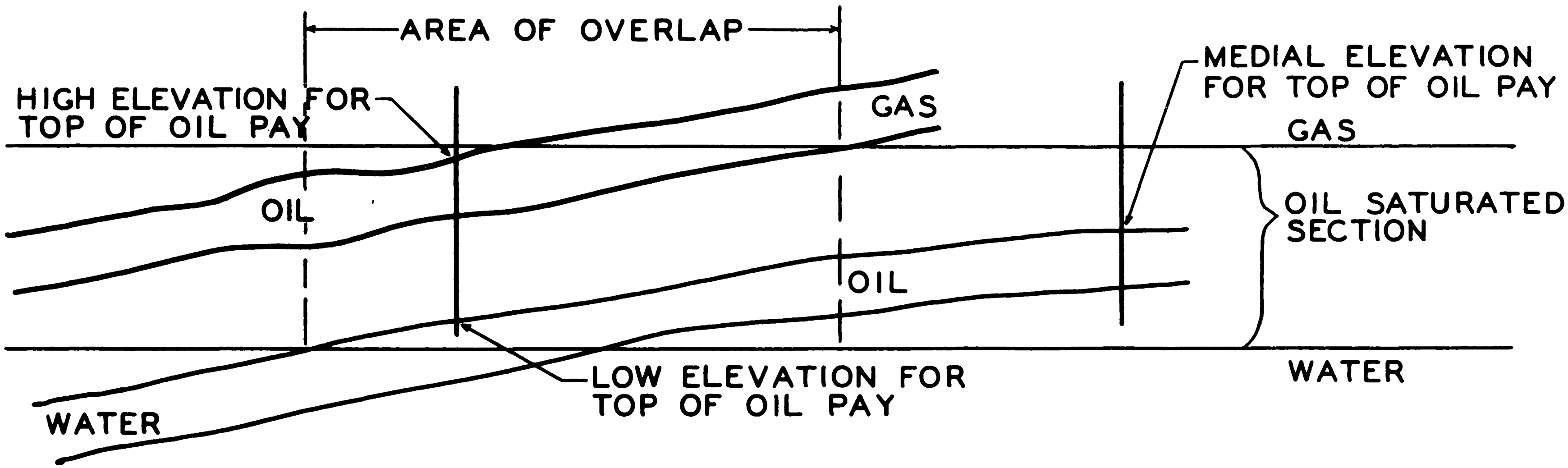


Figure 7.—An idealized section to illustrate overlapping zones.

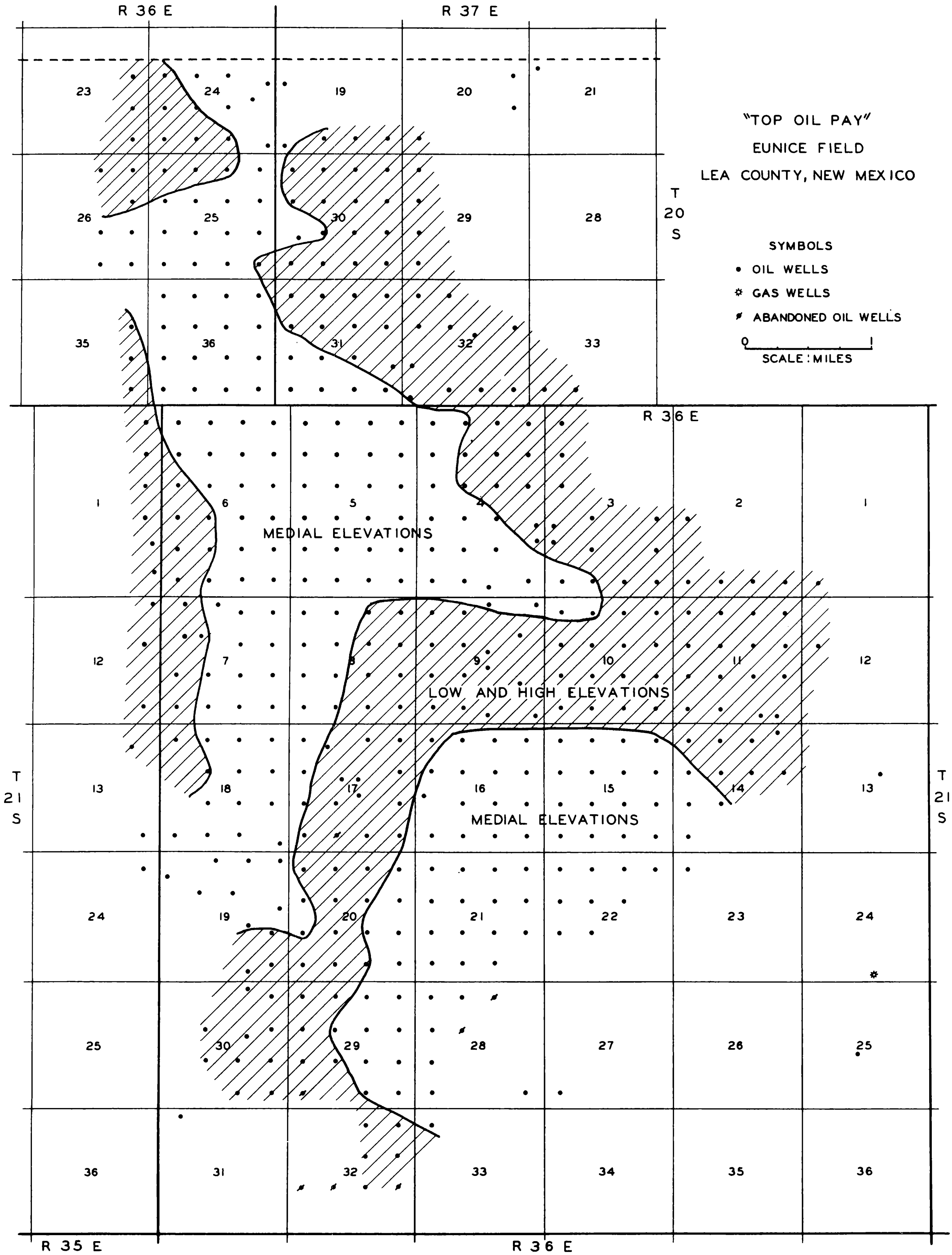

"TOP OIL PAY"
EUNICE FIELD
LEA COUNTY, NEW MEXICO
SYMBOLS
OIL WELLS
GAS WELLS
ABANDONED OIL WELLS
0
1
SCALE : MILES
R 36 E
R 37 E
T 20 S
T 21 S
R 35 E
R 36 E
MEDIAL ELEVATIONS
LOW AND HIGH ELEVATIONS
MEDIAL ELEVATIONS

Figure 8.

Following this method of analysis, the Eunice field was divided into two areas based on the conditions of productive-zone overlap; that is, one area in which the top of oil pay was found either high or low and another in which the elevations of the top of oil pay were more uniform and approached a medial figure between the high and low elevations. Figure 8 is a map of the Eunice field divided into these two areas, and table 1 presents data on top of oil pay for the field. The shaded portion of the map shows the areas where low and high elevations for the top of the oil-productive zones occur, and the unshaded portion outlines the medial elevations.

In the development of the top of oil pay map of the Eunice field, the relationship of the occurrence of high, low, and medial elevations for the top of the oil-productive zones in the various wells were noted, and some of these are discussed. As the average elevation of the highest oil production was approximately 225 feet below sea level, the medial elevations were taken to be between 200 and 250 feet below sea level. The high elevations were taken to be above 200 feet and the low below 250 feet below sea level. By this division of high and low deviations, the total number of wells in which elevations of the top of the pay were medial was found to be approximately equal to the sum of the high and low wells. In other words, for half of the wells the elevations were medial and the number of wells in which high and low figures were recorded each made up one-fourth of the total. It was found that in the unshaded area of figure 8, 164 wells had medial elevations, 55 high, and 13 low. Thus, medial elevations in the unshaded area occur 2.4 times as frequently as high and low elevations combined, indicating that top of oil pay elevations in this area are predominantly medial. In the shaded portion of the map, 75 elevations are high, 84 low, and 72 medial. In this shaded area the combined low and high figures occur 2.2 times as often as the medial ones, which indicates that the low-high figures predominate.

As indicated by figure 8, the low-high areas are on both the east and west sides, in addition to being in the area crossing the south-central part of the field. As it was exceedingly difficult to determine the top of oil pay accurately in many of the wells, errors may have been introduced into the data, and thus the shaded area of figure 8 should not be assumed to define the boundaries of the overlaps definitely.

TABLE 1. - Top of oil pay data, Eunice field

Zone	Wells with high elevations1/	Wells with low elevations2/	Wells with medial elevations3/	Average, High elevations4/	Average, Low elevations4/	Average, Medial elevations4/	Average, All elevations4/
A	6	7	37	191	260	217	220
A-B overlap	17	14	19	182	272	219	222
B	29	11	70	187	274	221	217
West flank B-C overlap ...	19	15	24	186	277	220	223
East flank B-C overlap ...	19	21	15	189	268	228	230
Total B-C overlap	38	36	39	188	272	223	227
West flank C	5	4	17	178	290	214	219
East flank C	4	4	14	176	281	227	228
Total C	9	8	31	177	286	220	223

1/ Above 200 feet below sea level.
2/ Below 250 feet below sea level.
3/ Between 200 and 250 feet below sea level.
4/ Feet below sea level.

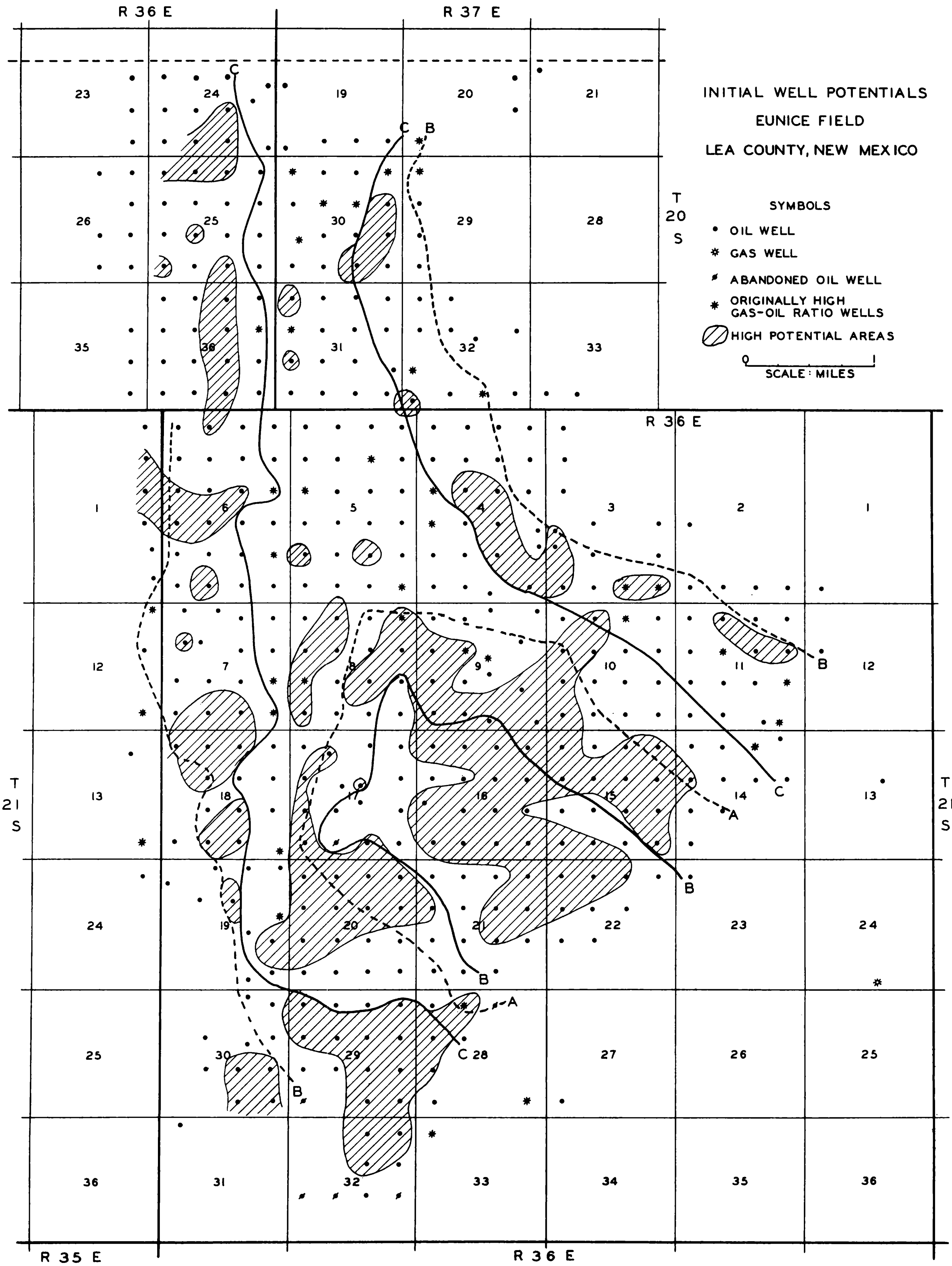

INITIAL WELL POTENTIALS
EUNICE FIELD
LEA COUNTY, NEW MEXICO
SYMBOLS
OIL WELL
GAS WELL
ABANDONED OIL WELL
ORIGINALLY HIGH GAS-OIL RATIO WELLS
HIGH POTENTIAL AREAS
0 1
SCALE: MILES
R 36 E
R 37 E
T 20 S
R 36 E
T 21 S
T 21 S
R 35 E
R 36 E
A
B
C

Figure 9.

Study of Initial Well Potentials

In a field with overlapping productive oil zones it is probable that in the areas of overlap total combined thicknesses of the producing formations will be greater than the maximum thickness of any individual zone, and if the permeability of each zone is uniform throughout, the wells in areas where zones overlap should have relatively large "potentials."12/ The general practice in the Eunice field has been to obtain data on the potential productivity of wells only at the time of their completion. As previously indicated, this field is thought to have more than one major zone porous and permeable enough to be productive of oil and gas, and, therefore, initial potentials of wells in the overlap areas may have been influenced to some extent by the greater productive thickness of pay formations. Time of development, acidization, diameter of well bores, tubing sizes, procedures followed in taking potential tests, and other details were considered by the writers as having an influence on the productivity of the wells in the Eunice field. However, as the present study was to be very general, these factors were considered to be of minor importance.

The following table is a summary by zones of the well-potential study of the Eunice field:

TABLE 2. - Summary of well-potential data by zones

Zone	Number of wells	Total initial well-potential, barrels of oil per day	Average initial well-potential, barrels of oil per well per day
West flank C	23	20,455	889
East flank C	27	8,512	315
Total C	50	28,967	579
West flank B-C overlap	98	107,780	1,100
East flank B-C overlap	54	47,579	881
Total B-C overlap	152	155,359	1,022
B	128	91,138	712
A-B overlap	53	75,329	1,421
A	48	87,502	1,823

On figure 9 the areas of high initial oil potentials in the Eunice field are shaded, those of low potentials are unshaded. The average of the initial potentials was 1,016 barrels of oil per well per day.

12/ Potential, as used in this report, refers to the volume of oil produced by a well during its initial test. Generally, a well in the Eunice field is tested by producing through the tubing, under steady flow, for 4 hours or longer, the duration of the test depending upon the capacity of the well to produce and on storage facilities. The average hourly rate of production during the test period was multiplied by 24 to obtain the average daily initial well potentials used in this report.

Areas in which the potentials were equal to and greater than 1,016 barrels of oil per well per day were inclosed by a heavy line, thus visually separating the field into areas of low and high potentials. Upon defining these areas, it was found that many of them were on the overlaps of the zones. The outlines of the three major porous zones shown in figure 6 have been superimposed on figure 9 to show the relations mentioned.

On the east and west flanks of the field most of the high-potential areas lie on the overlap of zones C and B. In these parts of the field the irregular occurrence of the high-potential areas indicates that the original potentials were influenced by erratic conditions of pay thickness and permeability as well as the overlapping of the pay zones. In the southeast part of the field, a large number of the high potential wells are in the area of overlap of zone B on zone A. The central and northeast portions of zone A show high potentials, which may indicate that this zone has relatively high productivity. Zone B apparently contains a few irregular areas of high potentials, most of which lie in the southern part of the field.

The wells having initial gas-oil ratios greater than 5,000 cubic feet of gas per barrel of oil are shown by a conventional symbol on the potential map (fig. 9). From the areal distribution of these high gas-oil-ratio wells, it appears that most of the gas from the Eunice field was produced from the upper parts of zones B and C. No high gas-oil-ratio wells were found in the area where production is obtained only from zone A.

Study of Water Encroachment

In a field producing from one uniform zone and acted upon by a water drive, the water encroaches uniformly from the edges if production rates are controlled properly. As the Eunice field has more than one major porous zone, the water should move through each zone according to its relative position with respect to the source of water, the permeability and porosity of the formation, and rate of withdrawal of oil and gas. The appearance of water in any area is influenced locally by the total depth of the wells. In an area subject to water encroachment, the deeper wells produce water first if the bottoms of the well bores are in a porous and permeable formation connected to a source of water. The first general sustained appearance of water in an area may indicate the base of the oil-producing zone.

Using data assembled by the New Mexico Proration Office, a water-encroachment map of the Eunice field (fig. 10) was prepared. The shaded portions of this map indicate areas in which the wells are producing some water. The lines within the shaded areas indicate the water encroachment by years from 1934 to 1937. The lines outlining the three major porous zones shown in figure 6 have been superimposed on this water map to show the relation of water encroachment to the major porous zones A, B, and C. The broken lines A and B in figure 10 indicate the approximate outermost limits of the areas in which the porous zones dip below the water level.

Water was produced first in the southwest part of the Eunice field, probably because that part was drilled first. Water is encroaching on the

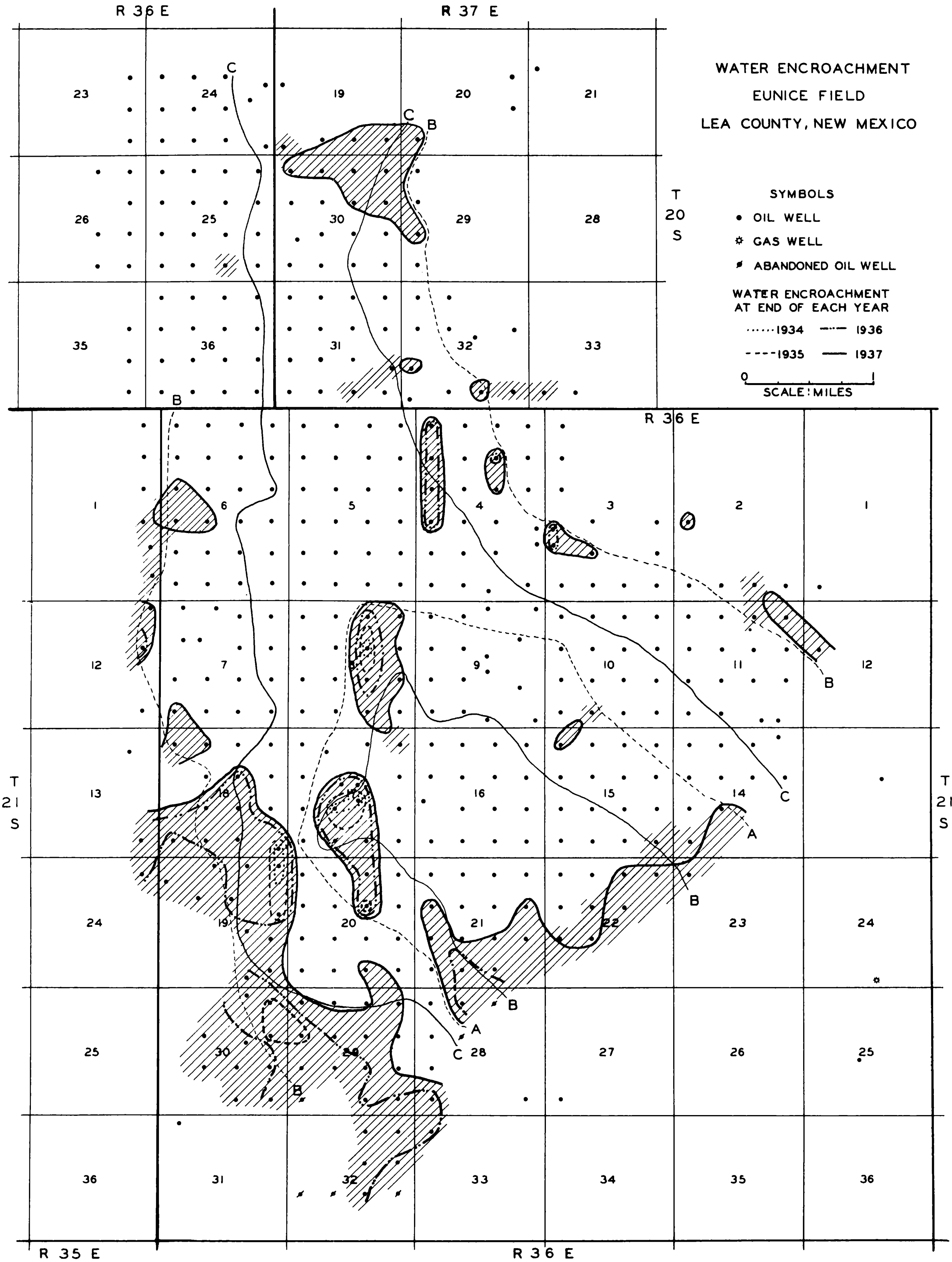
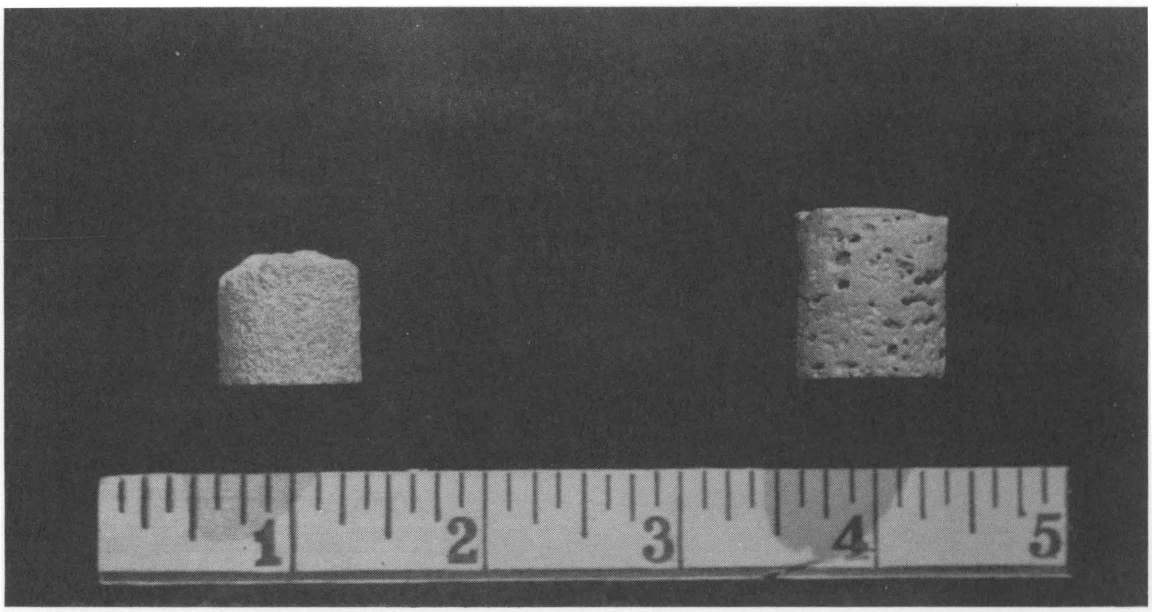
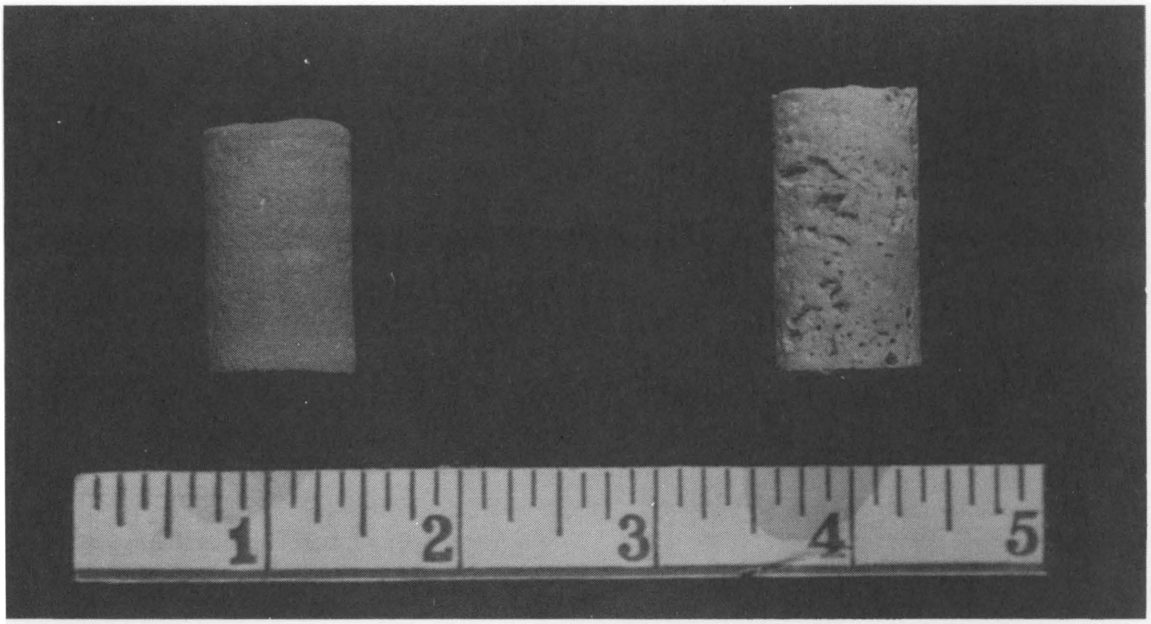

WATER ENCROACHMENT
EUNICE FIELD
LEA COUNTY, NEW MEXICO
SYMBOLS
OIL WELL
GAS WELL
ABANDONED OIL WELL
WATER ENCROACHMENT AT END OF EACH YEAR
1934
1936
1935
1937
0
SCALE: MILES
R 36 E
R 37 E
R 35 E
T 20 S
T 21 S

Figure 10.



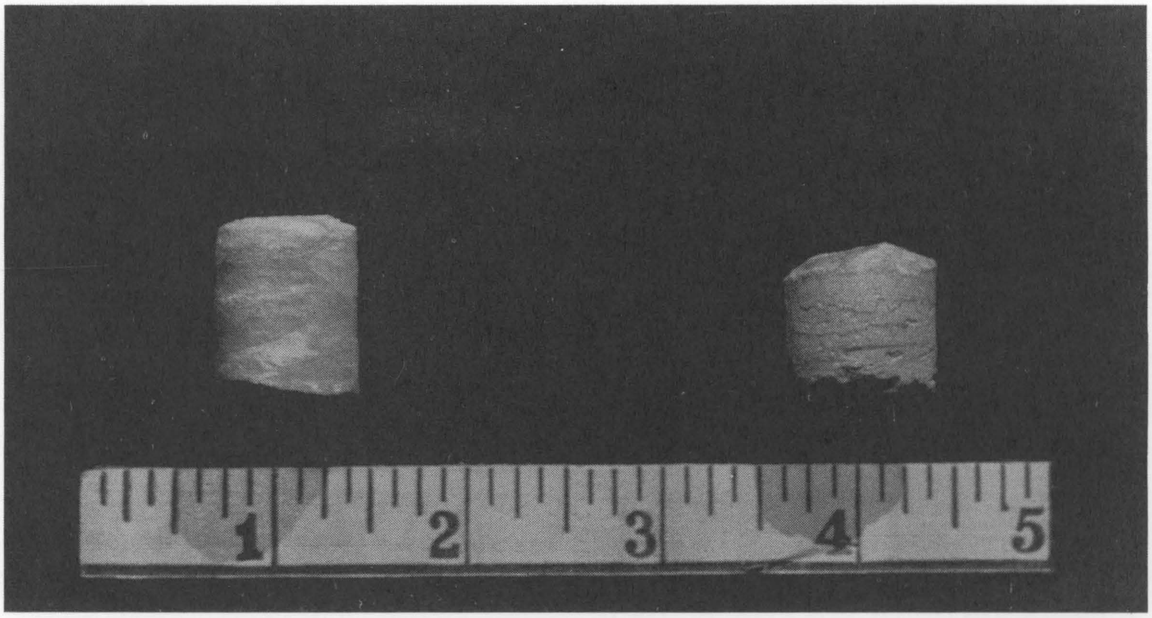
Core 1	Core 2

Figure 11.



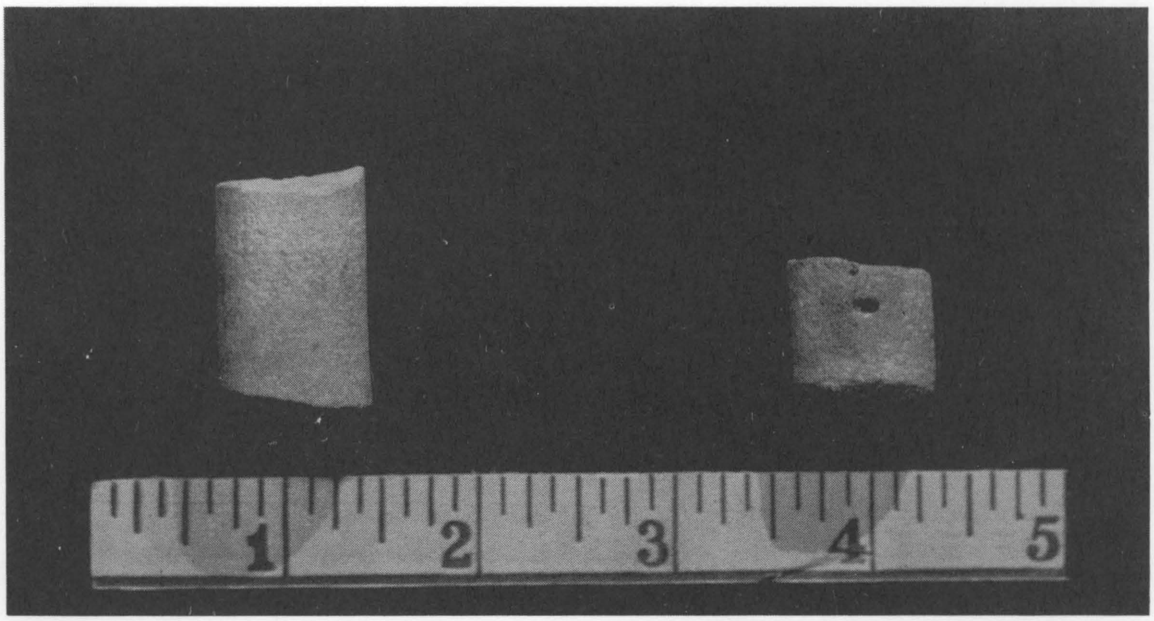
Core 3	Core 4

Figure 12.



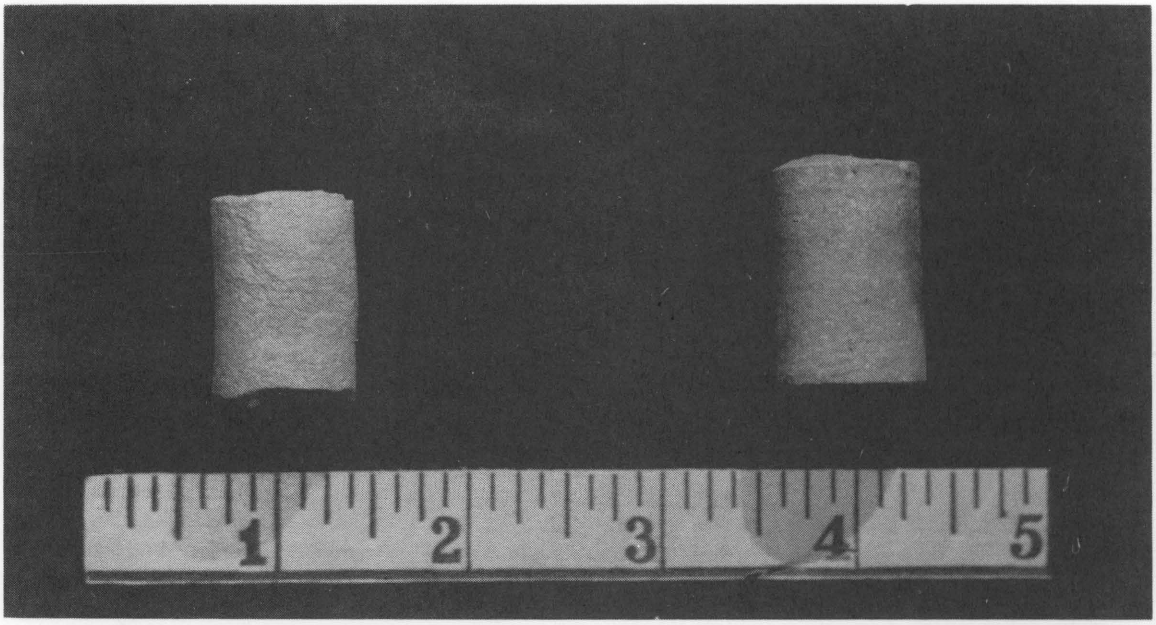
Core 5 Core 6

Figure 13.



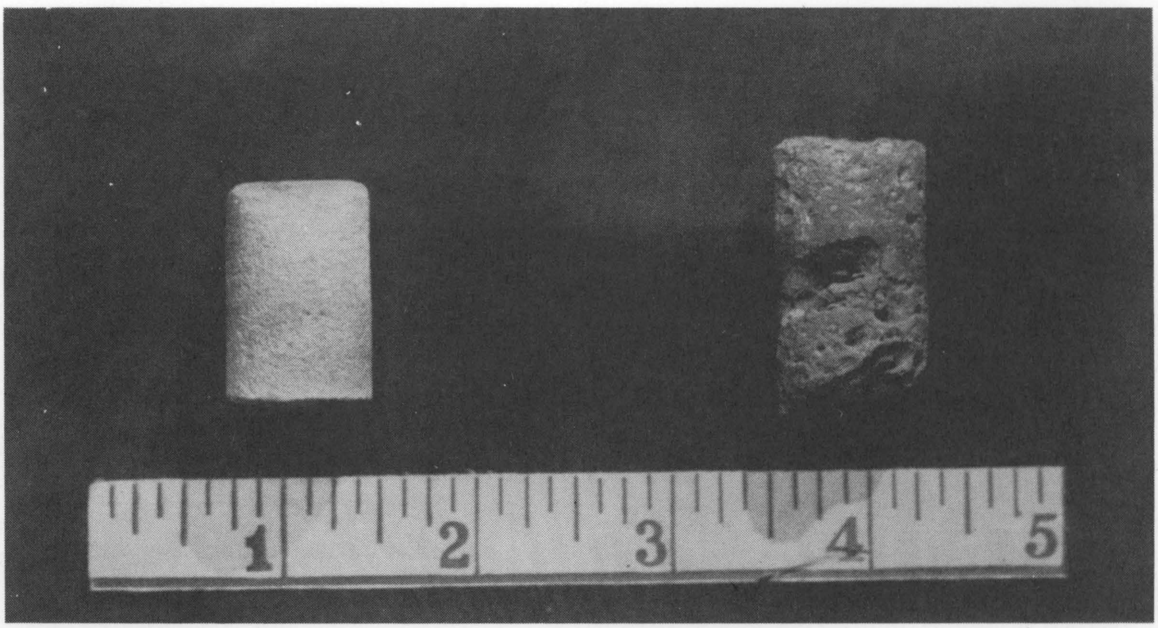
Core 7 Core 8

Figure 14.



Core 9 Core 10

Figure 15.



Core 11 Core 12

Figure 16.

west, southwest, and southeast edges of the field, but the water drive appears to be most active on the southwest.

It will be noted in figure 10 that water is being produced from a large part of the structurally low portion of zone A. Water is encroaching from the southeast and only recently has made its appearance in the northeastern portion of the zone.

On the west water encroachment is active in zone B but is irregular in zone C. The northwest edge of the field shows no water encroachment, probably because it had not been drilled until recently. On the east side of the field, water has encroached irregularly in zones B and C.

POROSITY AND PERMEABILITY DATA

The erratic character of the porosity and permeability of the major productive zones in the Eunice field has been mentioned. To illustrate some of the porosity and permeability characteristics of the reservoir, six photographs showing 12 core specimens, together with porosity and permeability data, are included in this report (figs. 11-13). These specimens were selected as being representative of the various types of porous materials recovered by coring but were not classified as to major porous zones, as these types may be present in each zone. Generally, in coring limestone or dolomite reservoirs the percentages of core recovery are very small in the prolific parts of the pay section and, therefore, the data presented with the photographs probably are representative only of the harder and less prolific oil-producing portions of the reservoir rock.

The specimens shown were three-fourths inch in diameter and were cut approximately perpendicular to the bedding planes from larger cores taken from wells. These specimens were selected primarily for use in porosity determinations, but information as to vertical permeabilities also was obtained.

Core 1 (porosity 19.7 percent, permeability 218 millidarcys) is a porous oolitic dolomite, at least half of the individual pore spaces of which are filled with cementing material. Although the pores are very small, this core is the most permeable of those shown.

Core 2 (porosity 23.6 percent, permeability 0.48 millidarcy) is dark-gray, flaky, sandy, and oolitic dolomite. The original pores were large and much secondary material had been deposited in them. Even though the pores appear large, the vertical permeability is low.

Core 3 (porosity 23.6 percent, permeability 35.9 millidarcys) is an example of fine-grained dolomitic sandstone. Its porosity is as high as that of any core shown.

Core 4 (porosity 10.9 percent, permeability 0.05 millidarcy) is dense white dolomite with local dark streaks, which dip at about 15° from the horizontal. Most of the original pore space is filled with secondary material.

Core 5 (porosity 8.5 percent, permeability 0.07 millidarcy) consists of gray and light buff-colored dolomitic sand with abundant inclusions of very angular dolomite fragments.

Core 6 (porosity 11.6 percent; no permeability test) contains cream-colored sandy dolomite and banded gray dolomitic sandstone. The pores in the sandstone are very small.

Core 7 (porosity 15.3 percent, permeability 5.84 millidarcys) is an example of oolites embedded in a dense flaky and sandy dolomite. The oolites are about four times as large as the grains of sandy dolomite and show hollow interiors when broken.

Core 8 (porosity 20.9 percent, permeability 18.6 millidarcys) consists of fine-grained, flaky, and partly oolitic dolomite with some very fine, irregularly spaced pores.

Core 9 (porosity 15.4 percent, permeability 0.50 millidarcy) is a uniform-gray dolomitic sandstone. Upon casual inspection, this specimen appears to have little porosity, but the test indicated more than 15 percent.

Core 10 (porosity 11.9 percent, permeability 2.97 millidarcys) is a flaky and microscopically sandy dolomite with a trace of open solution-channel porosity.

Core 11 (porosity 11.2 percent, permeability 1.95 millidarcys) is a very fine-grained, flaky, partly oolitic dolomite.

Core 12 (porosity 19.5 percent, permeability 0.95 millidarcy) is a dark-gray flaky and sandy oolitic dolomite with large pores partly filled with secondary material.

SUMMARY

From an analysis of logs that were made from examinations of cuttings from wells and data concerning well completions, initial well potentials, gas-oil ratios, and water encroachment for the Eunice field, three major porous and permeable zones have been outlined as shown in figure 6. These zones must not be confused with lithologic or geologic units, as they may not be directly related to geologic structure.

Attention is called to the special value of each group of information in outlining the major porous zones of the Eunice field and the general agreement between the sets of data. Each zone in the field was defined by determining its approximate upper and lower limit. The upper limits of the zones were determined by the use of cross sections, elevations of the top of oil pay, initial well potentials, and gas-oil ratios. The lower limits were defined by the use of cross sections, elevations of the top of the oil pays, and water-encroachment data.

The lowest productive zone, A, is in the southeastern part of the field and overlapped by the intermediate zone B. Zone A probably does not extend above the gas-oil contact. Wells producing from zone A had the highest initial potentials in the field, and none had excessively high gas-oil ratios. The water encroachment occurring on the west in the lower part of zone A may be due largely to the fact that this part of the field was drilled first.

Of the three major oil-producing zones, B has the largest areal extent, overlapping zone A in the southern part of the field, extending through the central and northern portions, and being overlapped by zone C on the east and west sides. Zone B probably does not extend entirely across the top of zone A but rises above the gas-oil contact in the area of overlap. The top of zone B also may rise above the gas-oil contact in portions of the central and northern parts of the field. Water is encroaching into zone B more rapidly on the western side of the field than on the eastern flank. The average initial potential for wells in this zone is larger than for those in zone C but smaller than for zone A. In the area of productive overlap of zones A and B, the average initial well potential is larger than for zone B and less than for zone A.

As previously mentioned, zone C, overlapping zone B on the east and west edges of the field, probably is not continuous over the high portions of zone B but is productive of gas in the higher parts of the areas of overlap. The group of wells in the overlap area of zone C on zone B have an average initial potential which is larger than for either of these zones. The wells producing wholly from zone C have the smallest average initial potential of any zone or area of overlap in the Eunice field.

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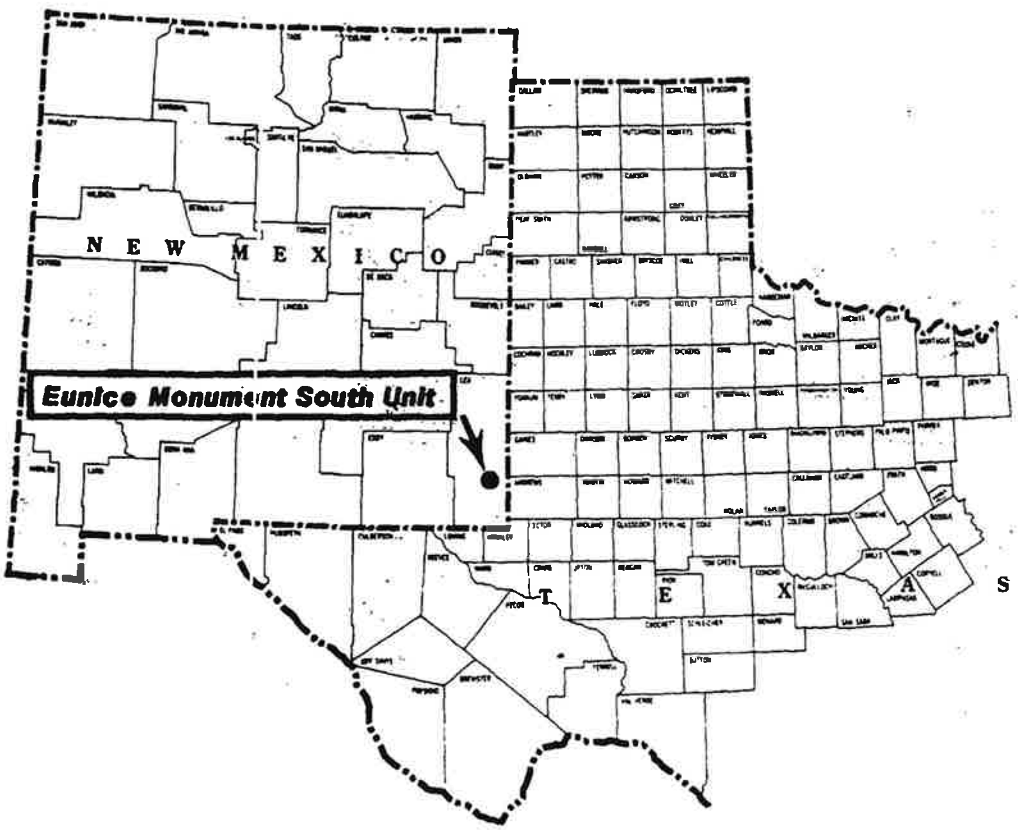
Goodnight Cross Exhibit 19

PROPOSED EUNICE MONUMENT SOUTH UNIT
LEA COUNTY, NEW MEXICO



TECHNICAL COMMITTEE REPORT
APRIL 1983

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INTRODUCTION

This report summarizes a study of the feasibility of unitizing and waterflooding leases in the southern portion of the Eunice Monument oil pool, and fulfills the charges given to the Technical Committee in a meeting of the Working Interest Owners on May 10, 1979. As outlined in Figure 1, the proposed unit will include 14,280 acres which lie in Township 20 South, Ranges 36 and 37 East, and Township 21 South, Range 36 East, in Lea County, New Mexico. This waterflood will unitize all oil production from the lower Penrose, Grayburg, and San Andres formations within the vertical limits described in the Recommendations section of this report.

Twenty-three companies have current or historical operations within the proposed unit area. Table 1 is a summary of the 101 tracts comprising the unit.

TABLE 1

EUNICE MONUMENT SOUTH UNIT
INDEX TO TRACTS AND OPERATORS

TRACT	OPERATOR	LEASE	TRACT	OPERATOR	LEASE
1	Getty	Skelly 'H' State	60	Getty	State 'A'
2	Arco	State 'P'	62	Arco	State 'B'
3	Amoco	Gillully 'A' Federal	63	Gulf	Bell (NCT-A)
4	Amoco	Gillully 'B' Federal	64	Gulf	Bell-Ramsay (NCT-A) Battery 2
5	Gulf	White (NCT-A)	65	Conoco	Meyer 'B-9'
6	Exxon	Fopeano Federal	66	Arco	Adkins
7	Hudson	Phillips	67	Exxon	Adkins
8	Amerada	State 'W'	68	Brady	Adkins
9	Arco	State '193'	69	Exxon	Knox
10	Gulf	Sunshine State	70	Hartman	Rasmussen State
12	Getty	Skelly 'G' State	71	Gulf	Bell (NCT-E)
13	Cities	State 'F'	72	Arco	State 'L' Battery 3
17	Gulf	Bell (NCT-F)	73	Two States	State 'B'
18	Shell	State 'K'	74	Wiser	McQuatters
19	Arco	State 'M'	75	Conoco	State 'D' Battery 2
20	Gulf	Orcutt (NCT-C)	77	Arco	Berryman
21	Exxon	Aggies State	78	Bruno	Marshall
22	Texaco	New Mexico State 'H' (NCT-1)	79	Bruno	Marshall Battery 2
23	Arco	State 'O'	80	Conoco	Meyer 'B-18'
24	Fields	Turner State	81	Conoco	Meyer 'A-1'
25	Getty	State 'AY'	82	Conoco	Lockhart 'A-18'
26	Arco	State '196'	83	Getty	Coleman "A'
27	Shell	State 'J'	84	Arco	Coleman
28	Arco	State 'L' Battery 2	85	Getty	Coleman
31	Wilbanks	State 'G'	86	Shell	Coleman
32	Shell	State 'EE'	87	Conoco	Meyer 'B-17'
33	Shell	State 'F'	88	Getty	Skelly 'B' State
34	Gulf	Orcutt (NCT-A)	89	Getty	State 'AW'
35	Gulf	Bell (NCT-D)	90	Getty	State 'AX'
36	Arco	State 'K'	91	Cities	State 'C'
37	Gulf	Graham State (NCT-E)	92	Getty	State 'D'
38	Gulf	Bell (NCT-B)	93	Getty	State 'E'
39	Gulf	Heasley State	94	Gulf	Bell (NCT-C)
40	Gulf	Orcutt (NCT-B)	95	Gulf	Janda (NCT-C)
42	Arco	State 'H'	96	Conoco	State 'D'
43	Arco	State 'E'	97	Conoco	Lockhart 'B-14'
44	Koch	State 'A'	98	Gulf	Collins
45	Arco	State 'G'	99	Gulf	Leck
46	Arco	State 'C'	102	Gulf	Arnott-Ramsay (NCT-C)
47	Gulf	Bell-Ramsay (NCT-A)	103	Getty	State 'G'
48	Conoco	Meyer 'B-4'	104	Amoco	State 'I'
49	Arco	State 'L'	105	Amoco	State 'J'
50	Me-Tex	Wallace State	106	Arco	State 'L' Battery 4
51	Sun	Akens	107	Gulf	Leonard (NCT-A)
52	Apollo	Akens	113	Rasmussen	State 'G'
53	Arco	Houston	114	Amoco	State 'C' Tract 11
54	Arco	Houston 'MA'	115	Amoco	McQuatters
55	Amerada	Houston	116	Conoco	Lockhart 'B-13'
56	Gulf	Campbell	117	Getty	Mexico State 'V'
57	Gulf	Houston	118	Fields	Turner State Battery 2
59	Conoco	Meyer 'B-8'			

CONCLUSIONS

1. Potential secondary reserves are present in sufficient quantity to justify unitizing properties in the southern portion of the Eunice Monument field to install a waterflood.

2. Secondary recovery factors of 48% and 18% were calculated for an optimum and minimum recovery cases, respectively. The optimum recovery case would produce 63.2 MM barrels of oil over a 30 year flood life, while the minimum recovery case would yield 23.7 MM barrels over the same time period.

3. The proposed unit is an economically attractive project. The optimum case yields a rate of return of 37.2% with a P/I ratio of 17.5, and the minimum case provides a rate of return of 23.4% with a P/I ratio of 5.

4. The proposed unit area contained an estimated OOIP of 671.5 MM STB. This solution gas drive reservoir has produced 119.8 MM barrels of oil to October 1, 1982, with ultimate primary production expected to reach 134.3 MM STB.

5. A total investment of approximately $62.5 MM will be required to install the surface facilities described in this report, drill and equip new wells to complete the waterflood pattern, perform the remedial work, install new pumping equipment, and obtain reservoir information.

RECOMMENDATIONS

1. The area within the southern portion of the Eunice Monument oil pool as outlined in Figure 1 of this report should be unitized.

2. The parameter table included as Table 8 on page 40 should be accepted as the basis for the Working Interest Owners to negotiate an equitable participation formula.

3. The vertical interval to be unitized should be described as follows:

   'The unitized interval shall include the formations from a lower limit defined by the base of the San Andres formation, to an upper limit defined by the top of the Grayburg formation or a -100 foot subsea datum, whichever is higher.'

4. A waterflood project should be initiated in the proposed unit area.

GEOLOGY

The proposed Eunice Monument South Unit, located in the southern portion of the Eunice Monument field, is situated on a NW-SE trending asymetrical anticline which lies along the northwestern edge of the Central Basin Platform. In this part of the field the oil producing formations are the Queen-Penrose and Grayburg, with the Grayburg being the major contributor to production (See Figures 3 and 4).

The Grayburg is a massive dolomite with thin stringers of sand interspersed within it. The majority of production probably comes from intercrystalline porosity within the dolomite. Overlaying the Grayburg is the Queen-Penrose. This section is composed of alternating layers of hard dolomite and sand stringers which are present over the entire anticline. The sands of the Queen-Penrose produce either oil or gas depending on their structural position on the anticline. Relative position and thickness of these formations are depicted on the Typelog shown in Figure 5.

Reports published during the early development of the field indicate that the gas-oil contact was believed to be -150 feet subsea, and the water-oil contact was believed to be -400 feet subsea. Our study of both field production data and individual well completion intervals indicates that the gas-oil contact is at approximately -100 feet subsea, and the oil-water contact is located at approximately -325 feet subsea. These contacts appear to be valid across the entire anticline and across formation boundaries. At this time there is insufficient data available to determine the degree of vertical reservoir communication.

Only 170 of the 344 proposed unit wells have logs, and the majority of these logs are of such poor quality that they are useless for technical interpretation. Most logs are uncompensated radioactivity and neutron logs, vintage 1955, or earlier, which were run in the open hole and through casing. The resulting gamma ray and neutron curves are very erratic due to the open hole conditions encountered by the sonde, and the primitive nature of the equipment. Many wells had been acidized and/or shot in years prior to logging, and this caused erratic and oversized open hole sections. The resulting neutron logs show exaggerated porosity readings up to 100% because the logging tool was probably hanging free in the cavern-like condition. Years of oil production have concentrated radioactive salts along the wellbore and this also distorts the gamma ray logs. The combination of the above cited problems makes it impossible to calculate fluid saturations and reservoir volumes from existing information.

A few modern logs are available in the area from Blinebry wells; however, these wells are concentrated in the northeastern fringe of the field and would not provide sufficient information to allow volumetric calculations for the entire unit.

Core information has been located on 10 wells in the unit area. Of these cores, only two have saturation information, and they are also located in the northeastern edge of the field.

In conclusion, there is not enough reliable technical information available from logs or cores to accurately determine reservoir volumes and fluid saturations for the unit area. The new wells proposed for this unit will allow opportunities to selectively core and log wells to gain the information needed to effectively characterize this reservoir.

HYDROCARBON VOLUMES AND RECOVERIES

Due to a lack of modern log and core data from unit wells, no accurate calculation of reservoir volume or original oil in place (OOIP) can be made. This necessarily means that any estimate of recoverable secondary oil must be made by assuming a number of parameters which can be expected to define a minimum reservoir volume. We assume that this reservoir is typical of other Grayburg - San Andres reservoirs in West Texas and New Mexico, and that a reasonable estimate of ultimate primary recovery is 20% of the OOIP. For the Eunice Monument South Unit, the 134.3 MM barrel primary ultimate, as estimated from individual tract decline curves, would give an OOIP of 671.5 MM Stock Tank Barrels (STB). Based upon this value, the estimated OOIP for the 13,800 developed acres would then be 48,660 STB/acre. The average net pay for the unit is 134 feet, assuming an average porosity of 8%, an initial formation volume factor of 1.2 reservoir barrels per STB, and an initial water saturation of 30%. The calculated average thickness of 134' compares to the estimated thickness of 120-150 feet taken from the few usable logs and cores from unit wells.

Assuming an OOIP of 671.5 MM STB and a current formation volume factor of 1.05, the oil saturation at start of flood, January 1, 1985, is estimated at 50%. Using a conservative estimate of 60% for volumetric sweep efficiency, and a residual oil saturation of 25%, the estimated secondary recovery will be approximately 9.8% of OOIP or 65.8 MM STB. This gives a secondary recovery to primary recovery ratio of 49%.

FIELD DEVELOPMENT

The proposed unit includes virtually all wells which have current or historical production from the southern portion of the Eunice Monument pool, which was formerly designated the Eunice (Penrose, Grayburg, San Andres) pool. The Eunice pool was discovered March 21, 1929, upon completion of the #1 Continental Lockhart 'B-31' in Section 31, Township 21 South, Range 36 East, Lea County. This well is located approximately two miles South of the proposed unit. Records from the State of New Mexico show the following initial reservoir data for the Eunice (Penrose, Grayburg, San Andres) pool:

Initial Reservoir Pressure at 250' S.S.	1450 PSI
Reservoir Temperature at 250' S.S.	90° F
Solution Gas-Oil Ratio	432 FT^3/BBL
Saturation Pressure	1372 PSI
API Oil Gravity	32°

Following discovery, the field was developed on 40-acre spacing with the majority of wells being drilled and completed during the three year period from 1934 through 1937. Peak oil production rate for the unit wells occurred in May, 1937, when the monthly production was 791,800 barrels.

All oil wells within the unit area were classified as Eunice oil wells until 1953, when the New Mexico Oil Conservation Commission created the Eumont Gas pool overlying the Eunice and Monument oil pools. In defining the Eumont Gas pool vertical limits to include the Yates, Seven Rivers, and Queen formations, the Commission contracted the vertical limits of the Eunice and Monument oil pools to contain only the Grayburg and San Andres formations. Subsequent to this decision, in 1956 the Commission ordered that wells which had completion intervals open across the top of the Grayburg formation be identified to the Commission for reclassification. As a result of this action, approximately thirty wells inside the southern and western edges of the proposed unit were reclassified from Eunice Monument oil wells to Eumont oil wells. The Commission did not order remedial work to isolate the two pools, but did order that future wells be completed in such a manner as to prevent communication between the oil and gas pools. We estimate that from 100 to 150 of the proposed unit wells have completion intervals which currently or historically have been simultaneously open in both the Penrose and Grayburg formations.

There are 357 40-acre proration units within the unit area of 14,280 acres. Thirteen of these locations have never produced from the proposed unitized interval because the location was undrilled, a dry hole was drilled, or no well was completed in the oil zone. All other locations have recorded production of Eumont oil, Eunice Monument oil, or both. Only 200 oil wells are currently active within the unit, with the remaining wells being temporarily abandoned, plugged, or recompleted. The producing status of the proposed unit wells is presented in Table 2.

TABLE 2
WELL STATUS BY TRACT
PROPOSED EUNICE MONUMENT SOUTH UNIT
STATUS CODES- P=PRODUCING TA=TEMP. ABANDONED PA=PLUGGED I=SWD
PAYCODES- EUNMON=EUNICE MONUMENT EUMOIL=EUMONT OIL EUMGAS=EUMONTGAS
LASTPAY- CURRENT OR LAST PRODUCTIVE ZONE PREVPAY- PREVIOUS ZONE

TRACT	OPERATOR	LEASE	WELL	STATUS	LASTPAY	PREVPAY	TD	SECTION
1	GETTY	SKELLY_H_STATE	1	TA	EUNMON	NONE	3852	25
	GETTY	SKELLY_H_STATE	2	P	EUNMON	NONE	3852	25
2	ARCO	STATE_P	1	P	EUNMON	NONE	3850	25
	ARCO	STATE_P	2	P	EUNMON	NONE	----	25
3	AMOCO	GILLULLY_A_FED	3	P	EUNMON	NONE	3850	25
	AMOCO	GILLULLY_A_FED	5	P	EUNMON	NONE	3866	25
	AMOCO	GILLULLY_A_FED	6	P	EUNMON	NONE	3854	25
4	AMOCO	GILLULLY_B_FED	1	TA	EUMOIL	NONE	3854	25
5	GULF	WHITE_A	1	P	EUNMON	NONE	3845	25
	GULF	WHITE_A	2	P	EUMGAS	NONE	3845	25
	GULF	WHITE_A	3	P	EUNMON	NONE	3850	25
	GULF	WHITE_A	4	PA	EUMGAS	EUNMON	----	25
	GULF	WHITE_A	5	P	EUNMON	NONE	3855	25
	GULF	WHITE_A	6	PA	EUNMON	NONE	----	25
	GULF	WHITE_A	7	P	EUMGAS	NONE	3750	25
6	EXXON	FOPEANO_FED	1	TA	EUNMON	NONE	----	25
	EXXON	FOPEANO_FED	3	PA	EUMOIL	NONE	----	25
7	HUDSON	PHILLIPS_UNIT	1	P	EUMGAS	EUNMON	3850	30
8	AMERADA	STATE_W	1	P	EUNMON	NONE	3835	30
	AMERADA	STATE_W	2	P	EUMGAS	EUNMON	3838	30
	AMERADA	STATE_W	3	P	EUNMON	NONE	3852	30
	AMERADA	STATE_W	4	TA	EUNMON	NONE	3820	30
9	ARCO	STATE_193	1	PA	EUNMON	NONE	----	30
10	GULF	SUNSHINE	1	P	EUNMON	NONE	3850	30
	GULF	SUNSHINE_STATE	2	P	EUMGAS	EUNMON	3840	30
	GULF	SUNSHINE	3	P	EUNMON	NONE	3832	30
12	GETTY	SKELLY_G_STATE	1	P	EUNMON	EUMGAS	3840	30
13	CITIES_SERVICE	STATE_F	1	P	EUNMON	NONE	3840	30
	CITIES_SERVICE	STATE_F	2	P	EUMGAS	NONE	3835	30
	CITIES_SERVICE	STATE_F	3	PA	EUNMON	NONE	----	30

TABLE 2
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PROPOSED EUNICE MONUMENT SOUTH UNIT
STATUS CODES- P=PRODUCING TA=TEMP. ABANDONED PA=PLUGGED I=SWD
PAYCODES- EUNMON=EUNICE MONUMENT EUMOIL=EUMONT OIL EUMGAS=EUMONTGAS
LASTPAY- CURRENT OR LAST PRODUCTIVE ZONE PREVPAY- PREVIOUS ZONE

TRACT	OPERATOR	LEASE	WELL	STATUS	LASTPAY	PREVPAY	TD	SECTION
17	GULF	BELL_(NCTF)	1	P	EUNMON	NONE	3850	36
	GULF	BELL_(NCTF)	2	P	EUMGAS	EUNMON	3840	36
	GULF	BELL_(NCTF)	3	P	EUNMON	NONE	3849	36
	GULF	BELL_(NCTF)	4	P	EUNMON	NONE	3855	36
	GULF	BELL_(NCTF)	5	P	EUMOIL	NONE	3852	36
	GULF	BELL_(NCTF)	6	P	EUMOIL	NONE	3855	36
	GULF	BELL_(NCTF)	7	PA	EUMOIL	NONE	----	36
	GULF	BELL_(NCTF)	8	P	EUMOIL	NONE	3860	36
18	SHELL	STATE_K	1	P	EUNMON	NONE	3850	36
	SHELL	STATE_K	2	P	EUNMON	NONE	3850	36
	SHELL	STATE_K	3	P	EUNMON	NONE	3850	36
	SHELL	STATE_K	4	P	EUNMON	NONE	3854	36
19	ARCO	STATE_M	1	P	EUNMON	NONE	----	36
	ARCO	STATE_M	2	P	EUNMON	NONE	3875	36
20	GULF	ORCUTT_(NCTC)	1	P	EUNMON	NONE	3870	6
	GULF	ORCUTT_(NCTC)	2	P	EUNMON	NONE	3865	6
	GULF	ORCUTT_(NCTC)	3	P	EUMGAS	EUNMON	3862	6
	GULF	ORCUTT_(NCTC)	4	TA	EUNMON	NONE	3860	6
	GULF	ORCUTT_(NCTC)	5	P	EUNMON	NONE	3847	36
	GULF	ORCUTT_(NCTC)	6	P	EUNMON	NONE	3847	6
	GULF	ORCUTT_(NCTC)	7	P	EUNMON	NONE	3846	36
	GULF	ORCUTT_(NCTC)	8	P	EUNMON	DUAL	3885	6
	GULF	ORCUTT_(NCTC)	8	P	EUMGAS	DUAL	3885	6
21	EXXON	AGGIES_STATE	1	P	EUNMON	NONE	3850	31
	EXXON	AGGIES_STATE	10	P	EUNMON	NONE	3830	31
	EXXON	AGGIES_STATE	11	TA	EUNMON	NONE	3840	31
	EXXON	AGGIES_STATE	12	PA	EUNMON	NONE	----	31
	EXXON	AGGIES_STATE	13	P	EUMGAS	NONE	----	31
	EXXON	AGGIES_STATE	2	P	EUNMON	NONE	3850	31
	EXXON	AGGIES_STATE	3	P	EUNMON	NONE	3845	31
	EXXON	AGGIES_STATE	4	P	EUMGAS	EUNMON	3850	31
	EXXON	AGGIES_STATE	5	TA	EUNMON	NONE	3840	31
	EXXON	AGGIES_STATE	6	P	EUNMON	NONE	3840	31
	EXXON	AGGIES_STATE	7	P	EUMGAS	EUNMON	3835	31
	EXXON	AGGIES_STATE	8	TA	EUNMON	NONE	3840	31
	EXXON	AGGIES_STATE	9	TA	EUNMON	NONE	3840	31
22	TEXACO	STATE_H_(NCT1)	1	PA	EUNMON	NONE	----	31
	TEXACO	STATE_H_(NCT1)	2	PA	EUNMON	NONE	----	31
	TEXACO	STATE_H_(NCT1)	24	P	EUMGAS	NONE	----	31
	TEXACO	STATE_H_(NCT1)	3	P	EUNMON	NONE	3868	31
	TEXACO	STATE_H_(NCT1)	4	P	EUNMON	NONE	3855	31

TABLE 2
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LASTPAY- CURRENT OR LAST PRODUCTIVE ZONE PREVPAY- PREVIOUS ZONE

TRACT	OPERATOR	LEASE	WELL	STATUS	LASTPAY	PREVPAY	TD	SECTION
23	ARCO	STATE_O	1	PA	EUNMON	NONE	----	32
	ARCO	STATE_O	2	P	EUMGAS	EUNMON	3840	32
24	FIELDS	TURNER_STATE	1	P	EUNMON	NONE	----	32
	FIELDS	TURNER_STATE	2	P	EUMGAS	NONE	----	32
	FIELDS	TURNER_STATE	3	P	EUNMON	NONE	----	32
25	GETTY	STATE_AY	1	P	EUMGAS	EUNMON	3860	32
26	ARCO	STATE_196	1	P	EUNMON	NONE	3860	32
	ARCO	STATE_196	2	TA	EUNMON	NONE	3861	32
27	SHELL	STATE_J	1	P	EUNMON	NONE	3845	32
	SHELL	STATE_J	2	P	EUNMON	NONE	3841	32
	SHELL	STATE_J	3	P	EUNMON	NONE	3832	32
	SHELL	STATE_J	4	P	EUNMON	NONE	3846	32
	SHELL	STATE_J	5	TA	EUNMON	NONE	6330	32
	EL_PASO_NATURAL	SHELL_STATE	6	P	EUMGAS	EUNMON	----	32
28	ARCO	STATE_L_BATT_2	3	P	EUNMON	NONE	3857	6
	ARCO	STATE_L_BATT_2	4	P	EUNMON	NONE	3850	6
31	WILBANKS	STATE_G	1	TA	EUNMON	NONE	----	6
	WILBANKS	STATE_G	2	I	EUNMON	NONE	----	6
32	EL_PASO_NATURAL	SHELL_STATE	1	P	EUMGAS	EUNMON	----	6
	SHELL	STATE_EE	1	P	EUNMON	NONE	3886	6
	EL_PASO_NATURAL	SHELL_STATE	6	P	EUMGAS	EUNMON	3886	6
33	SHELL	STATE_F	1	P	EUNMON	NONE	3860	6
	SHELL	STATE_F	2	TA	EUNMON	NONE	3851	6
34	GULF	ORCUTT_(NCTA)	1	P	EUMGAS	EUNMON	3890	5
	GULF	ORCUTT_(NCTA)	2	P	EUNMON	NONE	3895	5
	GULF	ORCUTT_(NCTA)	3	P	EUNMON	NONE	3894	5
	GULF	ORCUTT_(NCTA)	4	P	EUNMON	NONE	3902	6
	GULF	ORCUTT_(NCTA)	5	P	EUNMON	NONE	3890	5
	GULF	ORCUTT_(NCTA)	6	P	EUNMON	NONE	3873	6
35	GULF	BELL_(NCTD)	1	P	EUMOIL	NONE	3880	6
	GULF	BELL_(NCTD)	2	P	EUMOIL	NONE	3888	6
36	ARCO	STATE_K	1	P	EUNMON	NONE	3886	6
	ARCO	STATE_K_COM	2	P	EUMGAS	EUNMON	3867	6
37	GULF	GRAHAM_ST_(NCTE	1	P	EUNMON	NONE	3890	6
	GULF	GRAHAM_ST_(NCTE	2	P	EUMGAS	EUNMON	3885	6

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STATUS CODES- P=PRODUCING TA=TEMP. ABANDONED PA=PLUGGED I=SWD
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LASTPAY- CURRENT OR LAST PRODUCTIVE ZONE PREVPAY- PREVIOUS ZONE

TRACT	OPERATOR	LEASE	WELL	STATUS	LASTPAY	PREVPAY	TD	SECTION
38	GULF	BELL_(NCTB)	1	P	EUNMON	NONE	3895	6
	GULF	BELL_(NCTB)	2	P	EUNMON	NONE	3885	6
39	GULF	HEASLEY_STATE	1	P	EUNMON	NONE	3882	5
	GULF	HEASLEY_STATE	2	P	EUNMON	NONE	3866	5
	GULF	HEASLEY_STATE	3	P	EUNMON	NONE	3859	5
	GULF	HEASLEY_STATE	4	P	EUNMON	NONE	3875	5
	GULF	HEASLEY_STATE	5	P	EUNMON	NONE	3861	5
	GULF	HEASLEY_STATE	6	P	EUNMON	NONE	3862	5
	GULF	HEASLEY_STATE	7	P	EUMGAS	NONE	3630	5
40	GULF	ORCUTT_(NCTB)	1	P	EUMGAS	EUNMON	3865	5
	GULF	ORCUTT_(NCTB)	2	P	EUNMON	NONE	3864	5
42	ARCO	STATE_H	1	P	EUMGAS	EUNMON	3910	5
	ARCO	STATE_H	2	P	EUNMON	NONE	3900	5
	ARCO	STATE_H	3	P	EUMGAS	EUNMON	3894	5
	ARCO	STATE_H	4	P	EUNMON	NONE	3887	5
43	ARCO	STATE_E	1	P	EUNMON	NONE	3897	5
	ARCO	STATE_E	2	P	EUNMON	NONE	3856	5
44	KOCH	STATE_A	1	P	EUNMON	NONE	3873	5
	KOCH	STATE_A	2	P	EUNMON	NONE	3890	5
45	ARCO	STATE_G_COM	1	P	EUMGAS	EUNMON	3890	5
	ARCO	STATE_G	2	P	EUNMON	NONE	3904	5
	ARCO	STATE_G	3	P	EUNMON	NONE	3948	5
46	ARCO	STATE_C	1	P	EUNMON	NONE	3949	5
	ARCO	STATE_C	2	P	EUNMON	NONE	3885	5
47	GULF	BELLRAMSAY_NCTA	10	P	EUNMON	NONE	3844	4
	GULF	BELLRAMSAY_NCTA	13	P	EUNMON	NONE	6050	4
	GULF	BELLRAMSAY_NCTA	5	P	EUMGAS	EUNMON	3868	4
	GULF	BELLRAMSAY_NCTA	6	P	EUNMON	NONE	3896	4
	GULF	BELLRAMSAY_NCTA	7	P	EUNMON	NONE	3893	4
	GULF	BELLRAMSAY_NCTA	8	P	EUMGAS	EUNMON	3890	4
	GULF	BELLRAMSAY_NCTA	9	P	EUNMON	NONE	3870	4

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PAYCODES- EUNMON=EUNICE MONUMENT EUMOIL=EUMONT OIL EUMGAS=EUMONTGAS
LASTPAY- CURRENT OR LAST PRODUCTIVE ZONE PREVPAY- PREVIOUS ZONE

TRACT	OPERATOR	LEASE	WELL	STATUS	LASTPAY	PREVPAY	TD	SECTION
48	CONOCO	MEYER_B4	1	P	EUNMON	NONE	3900	4
	CONOCO	MEYER_B4	10	P	EUNMON	NONE	3860	4
	CONOCO	MEYER_B4	11	P	EUNMON	NONE	3890	4
	CONOCO	MEYER_B4	12	TA	EUNMON	NONE	3860	4
	CONOCO	MEYER_B4	13	P	EUNMON	NONE	3871	4
	CONOCO	MEYER_B4	14	P	EUMGAS	EUNMON	----	4
	CONOCO	MEYER_B4	15	P	EUMGAS	EUNMON	3857	4
	CONOCO	MEYER_B4	16	TA	EUNMON	NONE	3835	4
	CONOCO	MEYER_B4	17	TA	EUNMON	NONE	3832	4
	CONOCO	MEYER_B4	18	TA	EUNMON	NONE	----	4
	CONOCO	MEYER_B4	2	P	EUNMON	NONE	3895	4
	CONOCO	MEYER_B4	3	P	EUNMON	NONE	3870	4
	CONOCO	MEYER_B4	4	P	EUMGAS	EUNMON	----	4
	CONOCO	MEYER_B4	5	P	EUNMON	NONE	3880	4
	CONOCO	MEYER_B4	6	P	EUNMON	EUMGAS	3864	4
	CONOCO	MEYER_B4	7	TA	EUNMON	EUMGAS	3873	4
	CONOCO	MEYER_B4	8	P	EUNMON	NONE	3852	4
	CONOCO	MEYER_B4	9	P	EUNMON	NONE	3870	4
49	ARCO	STATE_L	5	P	EUNMON	NONE	3845	3
50	ME-TEX	WALLACE_STATE	1	P	EUNMON	NONE	3901	3
	ME-TEX	WALLACE_STATE	2	TA	EUNMON	EUMGAS	3866	3
	ME-TEX	WALLACE_STATE	3	P	EUMGAS	EUNMON	----	3
	ME-TEX	WALLACE_STATE	4	TA	EUNMON	NONE	3879	3
	ME-TEX	WALLACE_STATE	8	P	EUMGAS	NONE	----	3
51	SUN	AKENS	1	P	EUMGAS	EUNMON	3885	3
	SUN	AKENS	2	TA	EUNMON	EUMGAS	3872	3
	SUN	AKENS	3	P	EUNMON	NONE	3945	3
	SUN	AKENS	4	TA	EUNMON	NONE	3963	3
	SUN	AKENS	5	P	EUNMON	NONE	3852	3
	SUN	AKENS	6	P	EUMGAS	EUNMON	3834	3
52	APOLLC	J.AKENS	1	P	EUNMON	NONE	----	3
53	ARCO	HOUSTON	1	P	EUMOIL	NONE	3884	7
	ARCO	HOUSTON	2	P	EUMOIL	NONE	3885	7
54	ARCO	HOUSTON_M.A.	1	TA	EUNMON	NONE	----	7
	ARCO	HOUSTON_M.A.	2	TA	EUNMON	NONE	----	7
55	AMERADA	H.L.HOUSTON	1	TA	EUNMON	NONE	3833	7
	AMERADA	H.L.HOUSTON	2	P	EUNMON	NONE	3880	7
	AMERADA	H.L.HOUSTON	3	P	EUMGAS	EUNMON	3895	7
	AMERADA	H.L.HOUSTON	4	P	EUNMON	NONE	3820	7

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PAYCODES- EUNMON=EUNICE MONUMENT EUMOIL=EUMONT OIL EUMGAS=EUMONTGAS
LASTPAY- CURRENT OR LAST PRODUCTIVE ZONE PREVPAY- PREVIOUS ZONE

TRACT	OPERATOR	LEASE	WELL	STATUS	LASTPAY	PREVPAY	TD	SECTION
56	GULF	CAMPBELL	1	PA	EUNMON	NONE	----	7
	GULF	CAMPBELL	2	P	EUMGAS	EUMOIL	----	7
	GULF	CAMPBELL	3	PA	EUNMON	EUMOIL	----	7
	GULF	CAMPBELL	4	P	EUMOIL	NONE	3900	7
57	GULF	HOUSTON	1	PA	EUNMON	NONE	----	7
	GULF	HOUSTON	2	P	EUNMON	NONE	3886	7
	GULF	HOUSTON	3	PA	EUNMON	NONE	----	7
	GULF	HOUSTON	4	P	EUMGAS	EUNMON	3920	7
59	CONOCO	MEYER_B8	1	P	EUNMON	NONE	3870	8
	CONOCO	MEYER_B8	2	P	EUNMON	NONE	3891	8
	CONOCO	MEYER_B8	3	P	EUNMON	NONE	3875	8
	CONOCO	MEYER_B8	4	P	EUMGAS	EUNMON	3855	8
	CONOCO	MEYER_B8	5	P	EUNMON	NONE	4000	8
60	GETTY	STATE_A	1	P	EUNMON	NONE	3984	8
	GETTY	STATE_A	2	P	EUNMON	NONE	3905	8
	GETTY	STATE_A	3	P	EUNMON	NONE	3910	8
	GETTY	STATE_A	4	P	EUMGAS	EUNMON	3887	8
	GETTY	STATE_A	5	P	EUNMON	NONE	4020	8
62	ARCO	STATE_B	1	P	EUNMON	NONE	3901	8
	ARCO	STATE_B	2	P	EUNMON	NONE	3941	8
63	GULF	BELL_(NCTA)	1	P	EUNMON	NONE	----	8
	GULF	BELL_(NCTA)	2	P	EUMGAS	EUNMON	----	8
64	GULF	BELLRAMSAY_NCTA	1	P	EUNMON	NONE	3910	8
	GULF	BELLRAMSAY_NCTA	2	P	EUNMON	NONE	3886	8
	GULF	BELLRAMSAY_NCTA	3	PA	EUNMON	NONE	----	8
	GULF	BELLRAMSAY_NCTA	4	P	EUNMON	NONE	3880	8
65	CONOCO	MEYER_B9	1	P	EUNMON	NONE	3900	9
	CONOCO	MEYER_B9	2	P	EUNMON	DUAL	3824	9
	CONOCO	MEYER_B9	2	P	EUMGAS	DUAL	3824	9
	CONOCO	MEYER_B9	3	TA	EUNMON	NONE	3858	9
	CONOCO	MEYER_B9	4	P	EUNMON	NONE	3884	9
66	ARCO	E.C.ADKINS	1	TA	EUNMON	NONE	3900	9
	ARCO	E.C.ADKINS	10	P	EUNMON	NONE	3900	9
	ARCO	E.C.ADKINS	11	P	EUNMON	NONE	6400	9
	ARCO	E.C.ADKINS	2	P	EUNMON	NONE	3880	9
	ARCO	E.C.ADKINS	3	P	EUNMON	NONE	3915	9
	ARCO	E.C.ADKINS	4	P	EUNMON	NONE	3900	9
	ARCO	E.C.ADKINS	5	P	EUMGAS	EUNMON	3895	9
	ARCO	E.C.ADKINS	6	P	EUNMON	NONE	3895	9
	ARCO	E.C.ADKINS	7	P	EUNMON	NONE	3890	9

TABLE 2
WELL STATUS BY TRACT
PROPOSED EUNICE MONUMENT SOUTH UNIT
STATUS CODES- P=PRODUCING TA=TEMP. ABANDONED PA=PLUGGED I=SWD
PAYCODES- EUNMON=EUNICE MONUMENT EUMOIL=EUMONT OIL EUMGAS=EUMONTGAS
LASTPAY- CURRENT OR LAST PRODUCTIVE ZONE PREVPAY- PREVIOUS ZONE

TRACT	OPERATOR	LEASE	WELL	STATUS	LASTPAY	PREVPAY	TD	SECTION
66	ARCO	E.C.ADKINS	8	PA	EUNMON	NONE	----	9
	ARCO	E.C.ADKINS	9	P	EUMGAS	NONE	3705	9
67	EXXON	ADKINS	1	TA	EUNMON	NONE	3890	10
	EXXON	ADKINS	2	P	EUNMON	NONE	3910	10
	EXXON	ADKINS	3	TA	EUNMON	NONE	3880	10
	EXXON	ADKINS	4	P	EUMGAS	NONE	3867	10
	EXXON	ADKINS	5	TA	EUNMON	NONE	3865	10
	EXXON	ADKINS	6	TA	EUNMON	NONE	3880	10
	EXXON	ADKINS	7	TA	EUNMON	NONE	3890	10
68	BRADY	ADKINS	1	P	EUNMON	NONE	----	10
69	EXXON	KNOX	1	P	EUMGAS	EUNMON	3865	10
	EXXON	KNOX	2	TA	EUNMON	NONE	3852	10
	EXXON	KNOX	3	P	EUNMON	NONE	3880	10
	EXXON	KNOX	4	P	EUNMON	NONE	3866	10
	EXXON	KNOX	5	P	EUNMON	NONE	3885	10
	EXXON	KNOX	6	P	EUNMON	NONE	3890	10
	EXXON	KNOX	7	TA	EUNMON	NONE	3890	10
	EXXON	KNOX	8	P	EUNMON	NONE	3865	10
70	HARTMAN	RASMUSSEN_STATE	1	P	EUNMON	NONE	----	2
71	GULF	BELL_(NCTE)	1	P	EUNMON	NONE	3855	11
	GULF	BELL_(NCTE)	2	P	EUNMON	NONE	3850	11
72	ARCO	STATE_L_BATT_3	1	P	EUNMON	NONE	3877	11
73	TWO_STATES	STATE_B	1	P	EUNMON	NONE	----	11
74	WISER	MCQUATTERS	1	P	EUMGAS	NONE	3886	11
	WISER	MCQUATTERS	2	PA	EUNMON	NONE	3854	11
	WISER	MCQUATTERS	3	P	EUNMON	NONE	3854	11
75	CONOCO	STATE_D_BATT_2	1	P	EUMGAS	EUNMON	----	11
	CONOCO	STATE_D_BATT_2	2	P	EUNMON	NONE	3900	11
	CONOCO	STATE_D_BATT_2	3	P	EUNMON	NONE	3905	11
	CONOCO	STATE_D_BATT_2	4	P	EUNMON	NONE	3890	11
77	ARCO	BERRYMAN	1	P	EUMGAS	EUNMON	3882	11
78	BRUNO	MARSHALL	1	TA	EUNMON	NONE	----	11
	BRUNO	MARSHALL	2	PA	EUNMON	NONE	----	11
79	BRUNO	MARSHALL	3	P	EUNMON	NONE	----	12
	BRUNO	MARSHALL	4	PA	EUNMON	NONE	----	12

TABLE 2
WELL STATUS BY TRACT
PROPOSED EUNICE MONUMENT SOUTH UNIT
STATUS CODES- P=PRODUCING TA=TEMP. ABANDONED PA=PLUGGED I=SWD
PAYCODES- EUNMON=EUNICE MONUMENT EUMOIL=EUMONT OIL EUMGAS=EUMONTGAS
LASTPAY- CURRENT OR LAST PRODUCTIVE ZONE PREVPAY- PREVIOUS ZONE

TRACT	OPERATOR	LEASE	WELL	STATUS	LASTPAY	PREVPAY	TD	SECTION
80	CONOCO	MEYER_B18	1	PA	EUNMON	NONE	----	18
	CONOCO	MEYER_B18	2	P	EUMGAS	NONE	----	18
	CONOCO	MEYER_B18	3	TA	EUMOIL	NONE	----	18
	CONOCO	MEYER_B18	4	TA	EUMOIL	NONE	----	18
81	CONOCO	MEYER_A1	1	P	EUNMON	NONE	3875	8
	CONOCO	MEYER_A1	10	P	EUNMON	NONE	3992	17
	CONOCO	MEYER_A1	11	P	EUMGAS	NONE	----	17
	CONOCO	MEYER_A1	12	P	EUNMON	NONE	3955	17
	CONOCO	MEYER_A1	13	P	EUNMON	NONE	3939	18
	CONOCO	MEYER_A1	14	P	EUMGAS	EUMOIL	----	18
	CONOCO	MEYER_A1	15	P	EUNMON	NONE	4001	17
	CONOCO	MEYER_A1	16	P	EUNMON	NONE	4191	17
	CONOCO	MEYER_A1	17	TA	EUNMON	NONE	4141	17
	CONOCO	MEYER_A1	18	TA	UNKNOWN	----	82	17
	CONOCO	MEYER_A1	2	P	EUNMON	NONE	3914	8
	CONOCO	MEYER_A1	3	P	EUMGAS	EUNMON	3885	8
	CONOCO	MEYER_A1	4	P	EUNMON	NONE	3900	8
	CONOCO	MEYER_A1	5	P	EUNMON	NONE	3914	18
	CONOCO	MEYER_A1	6	P	EUMGAS	NONE	----	18
	CONOCO	MEYER_A1	7	P	EUMOIL	NONE	----	18
	CONOCO	MEYER_A1	8	P	EUNMON	NONE	3933	18
	CONOCO	MEYER_A1	9	P	EUNMON	NONE	3970	17
82	CONOCO	LOCKHART_A	2	PA	EUMOIL	NONE	----	18
	CONOCO	LOCKHART_A	3	P	EUMGAS	NONE	----	18
	CONOCO	LOCKHART_A	4	P	EUMGAS	NONE	----	18
	CONOCO	LOCKHART_A	5	PA	EUMOIL	NONE	----	18
	CONOCO	LOCKHART_A	6	P	EUMOIL	NONE	----	18
83	GETTY	COLEMAN_A	1	P	EUNMON	NONE	3900	17
84	ARCO	COLEMAN	1	P	EUMGAS	EUNMON	4015	17
	ARCO	COLEMAN	2	P	EUNMON	NONE	4003	17
85	GETTY	COLEMAN	1	P	EUNMON	NONE	4147	17
	GETTY	COLEMAN	2	P	EUNMON	NONE	3935	17
	GETTY	COLEMAN	3	P	EUMGAS	EUNMON	3925	17
	GETTY	COLEMAN	4	P	EUNMON	NONE	3943	17
	GETTY	COLEMAN	5	P	EUNMON	NONE	4168	17
86	EL_PASO_NATURAL	COLEMAN	1	P	EUMGAS	EUNMON	----	17
	SHELL	COLEMAN(1Y)	1	P	EUMOIL	NONE	----	17
	SHELL	COLEMAN	2	P	EUNMON	NONE	3961	17
87	CONOCO	MEYER_B17	1	P	EUMGAS	EUMOIL	----	17
	CONOCO	MEYER_B17	2	TA	EUNMON	NONE	3950	17

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LASTPAY- CURRENT OR LAST PRODUCTIVE ZONE PREVPAY- PREVIOUS ZONE

TRACT	OPERATOR	LEASE	WELL	STATUS	LASTPAY	PREVPAY	TD	SECTION
88	GETTY	SKELLY_B_STATE	1	P	EUNMON	NONE	3903	16
	GETTY	SKELLY_B_STATE	2	P	EUNMON	NONE	3902	16
	GETTY	SKELLY_B_STATE	3	P	EUNMON	NONE	3893	16
	GETTY	SKELLY_B_STATE	4	P	EUNMON	NONE	3900	16
	GETTY	SKELLY_B_STATE	6	P	EUNMON	NONE	3911	16
	GETTY	SKELLY_B_STATE	7	P	EUMGAS	NONE	3480	16
89	GETTY	STATE_AW	1	P	EUNMON	NONE	3885	16
90	GETTY	STATE_AX	1	P	EUNMON	NONE	3886	16
91	CITIES_SERVICE	STATE_C	1	P	EUMOIL	NONE	3912	16
	CITIES_SERVICE	STATE_C	2	PA	EUMOIL	NONE	----	16
	CITIES_SERVICE	STATE_C	3	P	EUMGAS	EUMOIL	3851	16
	CITIES_SERVICE	STATE_C	4	P	EUMOIL	NONE	3912	16
92	GETTY	STATE_D	1	P	EUNMON	NONE	3890	16
	GETTY	STATE_D	2	P	EUNMON	NONE	3900	16
93	GETTY	STATE_E	1	P	EUNMON	NONE	3886	16
	GETTY	STATE_E	2	P	EUMGAS	EUNMON	3906	16
	GETTY	STATE_E	3	P	EUNMON	NONE	4058	16
94	GULF	BELL_(NCTC)	1	P	EUNMON	NONE	----	15
	GULF	BELL_(NCTC)	2	P	EUNMON	NONE	----	15
	GULF	BELL_(NCTC)	3	P	EUNMON	NONE	----	15
	GULF	BELL_(NCTC)	4	P	EUNMON	DUAL	----	15
	GULF	BELL_(NCTC)	4	P	EUMGAS	DUAL	----	15
95	GULF	JANDA_(NCTC)	1	P	EUNMON	NONE	3892	15
	GULF	JANDA_(NCTC)	2	PA	EUNMON	NONE	----	15
	GULF	JANDA_(NCTC)	3	P	EUNMON	NONE	3896	15
	GULF	JANDA_(NCTC)	4	P	EUNMON	NONE	3883	15
96	CONOCO	STATE_D	10	P	EUNMON	NONE	3865	15
	CONOCO	STATE_D	11	P	EUNMON	NONE	3878	15
	CONOCO	STATE_D	12	P	EUMGAS	EUNMON	----	15
	CONOCO	STATE_D	5	TA	EUNMON	NONE	3885	15
	CONOCO	STATE_D	6	P	EUNMON	NONE	3865	15
	CONOCO	STATE_D	7	P	EUNMON	NONE	3875	15
	CONOCO	STATE_D	8	P	EUNMON	NONE	3889	15
	CONOCO	STATE_D	9	P	EUNMON	NONE	3880	15

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LASTPAY- CURRENT OR LAST PRODUCTIVE ZONE PREVPAY- PREVIOUS ZONE

TRACT	OPERATOR	LEASE	WELL	STATUS	LASTPAY	PREVPAY	TD	SECTION
97	CONOCO	LOCKHART_B14	1	TA	EUNMON	NONE	3870	14
	CONOCO	LOCKHART_B14	2	TA	EUNMON	NONE	3895	14
	CONOCO	LOCKHART_B14	3	P	EUNMON	NONE	3871	14
	CONOCO	LOCKHART_B14	4	P	EUMGAS	EUNMON	----	14
	CONOCO	LOCKHART_B14	5	P	EUMGAS	EUNMON	----	14
	CONOCO	LOCKHART_B14	6	P	EUNMON	NONE	3867	14
	CONOCO	LOCKHART_B14	8	P	EUMGAS	NONE	----	14
98	GULF	COLLINS	1	PA	EUNMON	NONE	----	14
	GULF	COLLINS	2	PA	EUNMON	NONE	----	14
	GULF	COLLINS	3	P	EUNMON	NONE	3860	14
	GULF	COLLINS	4	P	EUMGAS	NONE	3880	14
	GULF	COLLINS	5	PA	DRY	NONE	----	14
99	GULF	FRONA_LECK	1	P	EUNMON	NONE	----	14
102	GULF	ARNT_RAMSAY_C	10	P	EUNMON	NONE	3905	21
	GULF	ARNT_RAMSAY_C	11	P	EUNMON	NONE	3890	21
	GULF	ARNT_RAMSAY_C	12	P	EUNMON	NONE	3885	21
	GULF	ARNT_RAMSAY_C	13	P	EUNMON	DUAL	3902	21
	GULF	ARNT_RAMSAY_C	13	P	EUMGAS	DUAL	3902	21
	GULF	ARNT_RAMSAY_C	14	P	EUNMON	NONE	3890	21
	GULF	ARNT_RAMSAY_C	2	P	EUNMON	NONE	3924	21
	GULF	ARNT_RAMSAY_C	3	TA	EUNMON	NONE	3898	21
	GULF	ARNT_RAMSAY_C	4	P	EUNMON	NONE	3919	21
	GULF	ARNT_RAMSAY_C	6	TA	EUNMON	NONE	3911	21
	GULF	ARNT_RAMSAY_C	7	P	EUNMON	NONE	3914	21
	GULF	ARNT_RAMSAY_C	9	P	EUNMON	NONE	3916	21
103	GETTY	STATE_G	1	P	EUMOIL	NONE	3906	21
104	AMOCO	STATE_I	1	P	EUNMON	NONE	3908	22
	AMOCO	STATE_I	2	P	EUNMON	NONE	3908	22
105	AMOCO	STATE_J	1	P	EUNMON	NONE	3900	22
106	ARCO	STATE_L_BATT_4	2	P	EUNMON	NONE	3900	22
107	GULF	H.LEONARD_NCTA	1	P	EUNMON	NONE	3892	22
	GULF	H.LEONARD_NCTA	10	P	EUMOIL	NONE	3950	22
	GULF	H.LEONARD_NCTA	11	P	EUMOIL	NONE	3950	22
	GULF	H.LEONARD_NCTA	2	TA	EUNMON	NONE	3890	22
	GULF	H.LEONARD_NCTA	3	P	EUMGAS	EUNMON	3895	22
	GULF	H.LEONARD_NCTA	4	PA	EUNMON	NONE	----	22
	GULF	H.LEONARD_NCTA	5	P	EUNMON	NONE	3874	22
	GULF	H.LEONARD_NCTA	9	P	EUMOIL	NONE	3950	22

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LASTPAY- CURRENT OR LAST PRODUCTIVE ZONE PREVPAY- PREVIOUS ZONE

TRACT	OPERATOR	LEASE	WELL	STATUS	LASTPAY	PREVPAY	TD	SECTION
113	RASMUSSEN	STATE_G	1	TA	EUNMON	NONE	3852	2
	RASMUSSEN	STATE_G	2	TA	EUNMON	NONE	3842	2
114	AMOCO	STATE_C	1	P	EUMGAS	NONE	----	2
	AMOCO	STATE_C	2	P	EUNMON	NONE	----	2
115	AMOCO	MCQUATTERS	1	P	EUMGAS	NONE	----	11
	AMOCO	MCQUATTERS	2	P	EUNMON	NONE	----	11
116	CONOCO	LOCKHART_B13	7	P	EUMGAS	NONE	----	13
117	GETTY	MEXICO_V_COM	1	P	EUMGAS	EUNMON	3900	16

PRIMARY RECOVERY

The primary performance plot for the unit area is shown in Figure 6. Cumulative production for the unit area has been 119,785,804 barrels, as of September 30, 1982, giving an average production of 8,680 barrels per developed acre. The maximum production rate for the area occurred during 1937, when 321 wells produced an average of 720,000 barrels of oil per month for the year. Currently, approximately 200 wells are producing an average of 65,000 barrels of oil per month at an average decline rate of 4% per year. Figures 7 through 14 are 2-D and 3-D contour presentations of cumulative and current oil production, current water production, and current gas production for the unit area.

Individual lease decline curves are presented in Figures 15 through 95, and summarized in Table 3. Final decline rates were assigned by the Technical Committee for each active lease in the Unit. The production data for these decline curves was extracted from New Mexico Oil Conservation Commission production records, and corrected by actual production records of the individual operators when necessary. The Remaining Primary Reserve figure shown on each curve was calculated to an economic limit of 30 barrels per month per active well, using the Committee approved decline rate. The Ultimate Primary Recovery number is the simple summation of Cumulative Recovery to October 1, 1982, and Remaining Primary Reserves. The total remaining reserve for the Unit is approximately 14.5 million barrels when values for the individual leases are summed. This value is reasonably close to the 14 million barrel remaining primary reserve which can be extrapolated from the unit decline curve. Based upon either of these estimates, the primary reserves are approximately

90% depleted in the unit area. An examination of production records for the proposed unit area for 1980 and 1981 shows that oil production for each year was approximately 800,000 barrels, and water production for each year was approximately 3,100,000 barrels, giving an apparent field wide watercut of 79.5%. However, after analyzing individual well production records it is obvious that the water production is not evenly distributed throughout the field. For example, in 1980, only 19% of the active wells produced more than 50 barrels of water per day for a total of 75% of all produced water. Similarly, in 1981, 16% of the wells produced in excess of 50 barrels of water per day for a total of 71% of all produced water in the unit area. When the effect of these wells is removed from production statistics, the average watercut is less than 60% for the unit area, with production averaging 10 barrels of oil and 13 barrels of water per day per well.

An attempt was made to correlate the high water production areas to the formation structure to determine if a portion of the unit might be experiencing uniform water encroachment. After comparing water production, decline rates, and structural position for active leases in the field it was determined that no clear trend could be established. The water production is not uniform throughout the area and does not relate to decline rates or projected ultimate recoveries in any obvious way.

Considering the entire unit area, the water production history does not indicate a strong or uniform water drive mechanism. Furthermore, the early field production behavior exhibits the characteristics of a typical solution gas drive reservoir, having a rapid decline in reservoir pressure without a rapid rise in water production. Consequently, solution gas drive is considered to be the predominant drive mechanism.

TABLE 3
EUNICE MONUMENT SOUTH UNIT
TRACT DECLINE, PRODUCTION, AND RESERVE SUMMARY

TRACT	LEASE	DECLINE FACTOR PER YEAR	ULT RECOVERY AT ECONOMIC LIMIT (STB)	TOTAL PRODUCTION TO DATE (STB)	PRIMARY RESERVES (STB)	ECONOMIC LIMIT
1	SKELLY'H'	.071	596614	547732	48882	60
2	STATE'P'	.040	693684	615785	77899	60
3	GILLULLY'A'	.088	1083731	1051814	31917	90
4	GILLULLY'B'	.000	64868	64868	0	0
5	WHITE'A'	.041	1061900	971608	90292	90
6	FOPEANO	.000	362290	362290	0	0
7	PHILLIPS	.000	69517	69517	0	0
8	STATE'W'	.027	319564	317682	1882	60
9	STATE193	.000	132941	132941	0	0
10	SUNSHINE	.028	627739	577034	50705	60
12	SKELLY'G'	.116	151897	150924	973	30
13	STATE'F'	.107	512389	506027	6362	30
17	R_R_BELL'F'	.043	3528777	2949963	578814	180
18	STATE'K'	.039	3618342	2384372	1233970	120
19	STATE'M'	.022	1081545	925110	156435	60
20	ORCUTT'C'	.054	4396074	3851334	544740	180
21	AGGIES	.093	3577050	3460262	116788	150
22	STATE'H'	.028	1020828	944770	76058	60
23	STATE'O'	.000	120665	120665	0	0
24	TURNER_STATE	.036	318361	285631	32730	60
25	STATE'AY'	.000	21573	21573	0	0
26	STATE'196'	.063	381373	363854	17519	30
27	STATE'J'	.052	427681	398468	29213	120
28	STATE'L'_BATT2	.069	922598	897087	25511	60
31	STATE'G'	.000	529686	529686	0	0
32	STATE'EE'	.140	848320	819677	28643	30
33	STATE'F'	.000	569390	569390	0	0
34	ORCUTT'A'	.123	2566750	2426863	139887	150
35	R_R_BELL'D'	.073	924772	840869	83903	60
36	STATE'K'	.069	444679	433937	10742	30
37	GRAHAM_STATE'E'	.036	949266	907372	41894	30
38	R_R_BELL'B'	.041	2635327	1735275	900052	60
39	HEASLEY_STATE	.026	2791516	2213016	578500	180
40	ORCUTT'B'	.028	569443	525076	44367	30
42	STATE'H'	.054	1576492	1490025	86467	60
43	STATE'E'	.041	2010710	1365768	644942	60
44	STATE'A'	.147	711506	706600	4906	60
45	STATE'G'	.098	1227053	1181096	45957	60
46	STATE'C'	.041	1325255	1081610	243645	60
47	BELL_RAMSAY'A'	.039	2057392	1855285	202107	150
48	MEYER'B4'	.048	8387823	7321758	1066065	330
49	STATE'L'	.027	174053	155639	18414	30
50	WALLACE	.041	583429	566804	16625	30
51	AKENS	.092	1114003	1105175	8828	60
52	AKENS	.117	528833	479649	49184	30
53	HOUSTON	.067	927409	895397	32012	60
54	H_L_HOUSTON'MA'	.000	461791	461791	0	0

TABLE 3
EUNICE MONUMENT SOUTH UNIT
TRACT DECLINE, PRODUCTION, AND RESERVE SUMMARY

TRACT	LEASE	DECLINE FACTOR PER YEAR	ULT RECOVERY AT ECONOMIC LIMIT (STB)	TOTAL PRODUCTION TO DATE (STB)	PRIMARY RESERVES (STB)	ECONOMIC LIMIT
55	HOUSTON	.181	2065502	2013216	52286	60
56	HOLLIE_CAMPBELL	.041	368264	358518	9746	30
57	A_F_HOUSTON	.141	1508803	1505329	3474	30
59	MEYER'B8'	.024	5435382	2876588	2558794	120
60	STATE'A'	.074	2569125	2369336	199789	120
62	STATE'B'	.091	1330887	1279320	51567	60
63	BELL'A'	.164	1004752	1004016	736	30
64	BELL_RAMSAY'A'2	.098	1629966	1606697	23269	90
65	MEYER'B9'	.042	1991625	1826619	165006	90
66	ADKINS	.029	4395649	3820702	574947	210
67	ADKINS	.068	2146758	2137045	9713	30
68	ADKINS	.049	537239	472750	64489	30
69	J_D_KNOX	.053	2789776	2657560	132216	150
70	RASMUSSEN_ST	.042	159151	157193	1958	30
71	BELL'E'	.073	689225	672445	16780	60
72	STATE'L'BATT3	.040	404721	370034	34687	30
73	STATE'B'	.000	165071	165071	0	0
74	MCQUATTERS	.000	502736	502736	0	0
75	STATE'D'BATT2	.045	949474	926018	23456	90
77	BERRYMAN	.000	122116	122116	0	0
78	MARSHALL	.000	283207	283207	0	0
79	MARSHALL	.000	212949	212949	0	0
80	MEYER'B18'	.000	610333	610333	0	0
81	MEYER'A1'	.046	10294096	8966471	1327625	390
82	LOCKHART_'A'	.076	1872355	1831365	40990	60
83	COLEMAN'A'	.060	635821	602851	32970	30
84	COLEMAN	.095	725405	710979	14426	30
85	COLEMAN	.065	2421222	2306058	115164	120
86	COLEMAN	.084	1006394	965363	41031	60
87	MEYER'B17'	.000	774162	774162	0	0
88	SKELLY_STATE'B'	.085	2535772	2479035	56737	150
89	STATE'AW'	.067	350913	345202	5711	30
90	STATE'AX'	.058	390324	385906	4418	30
91	STATE'C'	.126	1539256	1516980	22276	60
92	STATE'D'	.037	1131006	983003	148003	60
93	STATE'E'	.065	1013875	978165	35710	60
94	BELL'C'	.031	2518212	1949372	568840	120
95	JANDA	.091	1913123	1849230	63893	90
96	STATE'D'	.031	2786097	2511730	274367	180
97	LOCKHART'B14'	.114	1288965	1265171	23794	60
98	COLLINS	.014	852187	754307	97880	30
99	FRONA_LECK	.121	169580	165393	4187	30
102	ARNOTT_RAMSAY'C'	.093	4592500	4392116	200384	270
103	STATE'G'	.068	416222	385550	30672	30
104	STATE'I'	.052	787325	767101	20224	60
105	STATE'J'	.070	393803	375283	18520	30
106	STATE'L'BATT4	.109	433191	412916	20275	30

TABLE 3
EUNICE MONUMENT SOUTH UNIT
TRACT DECLINE, PRODUCTION, AND RESERVE SUMMARY

TRACT	LEASE	DECLINE FACTOR PER YEAR	ULT RECOVERY AT ECONOMIC LIMIT (STB)	TOTAL PRODUCTION TO DATE (STB)	PRIMARY RESERVES (STB)	ECONOMIC LIMIT
107	LEONARD	.115	1380115	1326091	54024	150
113	STATE"G"	.000	155642	155642	0	0
114	ST."C"_TR11	.000	76388	76388	0	0
115	MCQUATTERS	.088	474168	465831	8337	30
116	LOCKHART"B13"	.000	169815	169815	0	0
117	MEXICO"V"	.000	329459	329459	0	0
118	TURNER_ST_BATT2	.000	0	0	0	0
TOTAL			134307003	119785802	14521201	

SECONDARY RECOVERY

The Grayburg and San Andres formations are being flooded successfully in numerous locations in New Mexico and Texas, with secondary recovery production varying from 50% to 100% of primary production. The Eunice Monument is believed to be a typical carbonate reservoir, and based upon recoveries from similar reservoirs in the vicinity, is expected to become a successful operation.

In the absence of a definitive reservoir characterization of the Eunice Monument, conventional analytical models and methods could not be used to construct a secondary recovery prediction. A number of empirical and analog predictions were also investigated without good results. Finally, a method developed by Messrs. Bush and Helander and reproduced in SPE Reprint Series No. 2a was used with some variation to construct the 'minimum recovery' prediction.

Basically, the Bush and Helander empirical model is not directly applicable to New Mexico and West Texas carbonates because it is based upon data taken from eighty-six shallow (average depth 2,650') sandstone and limestone Oklahoma floods with average lives of 11.5 years. In lieu of a direct application of the parameters of the Bush and Hellander model, a similar technique was developed from two mature floods in the area of the Eunice Monument to define new parameters by which the Eunice Monument performance might be predicted. The parameters which were eventually used included the following: (1) peak oil rate as a percent of injection rate; (2) percent of total life required to produce 50% and 75% of total waterflood reserves; (3) percent of total life in incline and decline periods; (4) total flood life in years. The resulting 'minimum recovery' prediction shown in Figure 96 is obviously a pessimistic case because the projected secondary recovery to primary recovery ratio of

19% is considerably less than normal recoveries for Grayburg/San Andres floods.

In an effort to construct a more reasonable recovery prediction Gulf investigated a number of similar southwest waterfloods, to develop the 'Optimum Recovery' prediction on Figure 96. This prediction reflects a more realistic secondary to primary recovery ratio of approximately 48% and a life of 30 years.

The injection rate at peak oil production is expected to be approximately 2.7 MM BWPM, based on an average maximum injection rate of 500 BWPD per well. Initially the number of injection wells will be limited to a maximum of 136 until cooperative injection agreements can be negotiated with offset operators. Full development of the injection well pattern will create a total of 179 injectors, assuming the pattern depicted in Figure 97.

FACILITY DESIGN

The initial cost estimate for the unit is based on a preliminary facility design depicted in Figures 109 and 110. This design was based on the following assumptions:

1. The unit will be fully developed using an 80-acre five spot pattern. Edge wells will be completed as producers pending negotiation of cooperative injection agreements.
2. Peak injection requirement will be 2.7 MM barrels per month in the fillup phase of flooding.
3. Peak oil production is estimated at 676,000 barrels per month.
4. Only Class A equipment will be installed for unit facilities.
5. All undrilled locations will be drilled to complete the unit pattern.
6. Plugged and abandoned wells will be redrilled.
7. Remedial activity will be estimated based upon the best available estimate of well conditions.
8. All wells will become single completions in the unitized interval.

The resulting facility design consists of two major parts, the production system and the injection/water supply system. The production system design is based on an operational concept using a single central battery with twelve satellite batteries located throughout the field. Each satellite battery will have well test facilities, gas separation equipment, and a gas sales point. Liquids from the satellite batteries will be transferred to the central battery for treatment and water separation. The single oil sales point for the unit will be at the central battery.

The water injection plant and treating facilities will be located at the central battery site. Water will be transferred under pressure to the primary distribution headers located at each satellite battery site, then to secondary headers located in the field, each serving from three to five injection wells.

The total water requirement will be provided by reinjection of produced water, and from make-up water provided by nine San Andres supply wells. For this cost estimate, the assumption was made that new water supply wells would be drilled; however, there is a possibility that existing wellbores may be available which could be purchased and completed in the San Andres.

COST ESTIMATE

The cost estimate for the above preliminary design can be summarized into seven major categories as listed below:

	Item	Tangibles	Intangibles
1.	Production and Injection Facilities	$ 12,548,200	$ 6,681,450
2.	Drill & Equip 9 Water Supply Wells	3,051,000	1,989,000
3.	Drill & Equip 19 Producers	2,726,500	3,543,500
4.	Drill & Equip 16 Injectors	1,336,000	2,984,000
5.	Remedial Work - 208 Wells	10,060,000	9,295,000
6.	Coring Cost - 20 Wells		1,000,000
7.	Pumping Unit Replacements	6,726,000	570,000
	Subtotal	$ 36,447,700	$ 26,062,950
	Grand Total	$ 62,510,650	

1. Production and Injection Facilities

   This item includes all storage, transfer, treatment, metering and sales equipment. This item also includes costs for electrifying the unit, retiring existing facilities as they are replaced, and settling right-of-way and damage claims due to construction.

2. Drill and Equip 9 Water Supply Wells

   This item provides for drilling, completing, and equipping nine wells to provide water from the lower San Andres formation. The wells will be required to provide the water injection requirement which is expected to peak at 2.7 MM barrels per month during fillup.

3. Drill and Equip 19 Producers

This item includes the cost to drill, complete and equip the 19 wells required on producing well locations. Five of these wells would be drilled on locations which had no previous wells and the other twelve wells will be replacements for abandoned wells.

4. Drill and Equip 16 Injectors

This item includes the cost to drill, complete and equip the 16 wells which will be required to complete the injection pattern. Three wells will be drilled on undeveloped locations and thirteen are replacement wells.

5. Remedial Work - 208 Wells

After evaluating the well status information provided by some operators, expected remedial activity was divided into ten categories for which cost estimates could be generated. The categories and costs varied from simple clean out and stimulation of a producer which would cost $45,000, to a major effort which could include cleaning out an abandoned Eunice Monument zone, squeezing a previously productive Eumont gas zone, setting an injection liner, perforating and treating the Eunice Monument, and equipping the well for operation at a total cost in excess of $115,000.

6. Coring Cost

In order to perform the reservoir analysis required to optimize secondary recovery operations, and provide a data base lease for future study of enhanced recovery applications, coring must be performed on newly drilled unit wells. The cost estimate in this item is intended to cover coring of twenty wells, which can include injectors, producers, or water supply wells.

7. Pumping Unit Replacements

This item includes costs for purchasing and installing higher capacity pumping units which will be required as the flood begins to respond to injection.

Cost estimates for equipment and labor were based on published and currently applicable rates. No effort was made to adjust these rates for the reductions which would be realized by competitively bidding labor and installation costs, or by ordering equipment and material in the quantities which will be required for this unit.

ECONOMICS

Economics were calculated for the unit based on the cost estimate given on page 30, and the two recovery cases illustrated in Figure 96. A schedule of expenditures is shown in Table 4, and basically illustrates an effort designed to complete the unit within three years following unitization. The majority of tangible costs are evenly divided between the first two years following unitization, with the majority of intangible costs occurring in the second year to reflect the time delay between the purchase and installation of equipment.

Assumptions made to facilitate the economic evaluation included the following:

1. Operating expenses were based on average values for 10 similar floods in Southeast New Mexico, beginning at $2,000 per month per producing well.
2. Oil price was based on a 1984 base price of $31.50 with taxes calculated by assuming all oil is classified as Tier 1 for tax purposes, although a high but unknown percentage of the oil now being produced from proposed unit leases is being taxed as Tier 2 oil.
3. An average gas price of $.57 per MCF was used for this economic evaluation. All gas was assumed to be NGPA Section 104. No estimate of the value of liquids was made for this appraisal.

The three economic summaries shown in Tables 5, 6, and 7 present the results from evaluation of the base case, minimum recovery incremental case, and optimum recovery incremental case, respectively. The minimum recovery case yields a discounted cash flow rate of return in excess of 23%, with profit in excess of $312,000,000 after tax. This case represents a viable project even though it represents a very low secondary to primary recovery ratio of 18%. The optimum recovery case is an excellent project which will yield a discounted cash flow rate of return in excess of 37%, with profit in excess of $1,000,000,000 after tax.

The only economic factor which does not meet normal criteria for smaller projects is the After-Tax payout calculation. The two parameters which cause this factor to be unusually high (greater than 7 years) are the low initial production rate due to the anticipated long fill-up time and the large investment made in the early years of the unit. The actual payout is expected to occur sooner than this calculated payout because of the very large remedial effort which is planned to occur during the first three years following unitization. The expected increase in production due to remedial work was not estimated for the recovery projection, or added to the economic evaluations.

In summary, the two economic cases are based upon reasonable assumptions of recoveries, expenses and investments, and represent an acceptable economic project.

TABLE 4
PRELIMINARY COST ESTIMATE
PROPOSED EUNICE MONUMENT SOUTH UNIT

PART 1. TANGIBLE COSTS - AMOUTS IN THOUSANDS

ITEM	TOTAL	1984	1985	1986	1987	1988
INJECTION LINES	$ 3306.7	$ 1653.4	$ 1653.3	$	$	$
INJECTION HEADERS	212.7	106.4	106.3			
WATER SUPPLY LINES	259.2	129.6	129.6			
PRODUCTION LINES	1706.6	853.3	853.3			
METER ASSEMBLIES	356.0	178.0	178.0			
SATELLITE BATT. (12)	960.0	480.0	480.0			
CENTRAL BATTERY	1771.0	885.5	885.5			
INJECTION PLANT	2176.0	1632.0	544.0			
ELECT. DIST. SYS.	1800.0	450.0	450.0	900.0		
WATER SUPPLY WELLS (9)	3051.0	1356.0	1695.0			
PRODUCTION WELLS (19)	2726.5	861.0	1865.5			
INJECTION WELLS (16)	1336.0	501.0	835.0			
REMEDIAL COSTS (208)	10060.0	2418.3	4836.5	2805.2		
PUMPING UNITS (114)	6726.0			2006.0	2360.0	2360.0
SUBTOTALS	$ 36447.7	$ 11504.5	$ 14512.0	$ 5711.2	$ 2360.0	$ 2360.0

PART 2: INTANGIBLE COSTS - AMOUNTS IN THOUSANDS

ITEM	TOTAL	1984	1985	1986	1987	1988
INJECT LINE CONST.	$ 1345.0	$ 336.2	$ 672.6	$ 336.2		
WATER SUPPLY LINE CONST.	216.0	108.0	108.0			
PROD. LINE CONST.	1319.5	659.8	659.7			
SATELLITE BATT. CONST.	480.0	240.0	240.0			
CENTRAL BATT. CONST.	400.0	100.0	300.0			
INJ. PLANT CONST.	400.0	100.0	300.0			
ELECTRICAL SYS. CONST.	500.0	125.0	250.0	125.0		
ROAD $ SITE CONST.	121.0	60.5	60.5			
RETIREMENT OF FACILITIES	1100.0	275.0	550.0	275.0		
ROW $ DAMAGES	800.0	200.0	400.0	200.0		
WATER SUPPLY WELLS (9)	1989.0	884.0	1105.0			
PRODN WELLS (19)	3543.5	1119.0	2424.5			
INJECTION WELLS (16)	2984.0	1119.0	1865.0			
REMEDIAL	9295.0	2234.4	4468.7	2591.9		
CORING COSTS	1000.0	500.0	500.0			
PUMPING UNITS	570.0			170.0	200.0	200.0
SUBTOTALS	$ 26063.0	$ 8060.9	$ 13904.0	$ 3698.1	$ 200.0	$ 200.0

TANGIBLE SUBTOTALS	$ 36447.7	$ 11504.5	$ 14512.0	$ 5711.2	$ 2360.0	$ 2360.0
INTANGIBLE SUBTOTALS	26063.0	8060.9	13904.0	3698.1	200.0	200.0
TOTAL	$ 62510.7	$ 19565.4	$ 28416.0	$ 9409.3	$ 2560.0	$ 2560.0

TABLE 5

EUNICE MONUMENT SOUTH UNIT — BASECASE

DATE 03/21/83 — SUMMARY OF PROFITABILITY — AMOUNTS IN THOUSANDS

ECONOMIC AND FINANCIAL MEASURES - AFTER TAX

MODIFIED CALENDAR YEAR CASH FLOWS - YR 1 HAS 12 MONTHS

DCF RATE OF RETURN - %		NONE
GROWTH RATE OF RETURN (@ 15.0%) - %		NONE
NET PRESENT VALUE @ 10.0%		55915.0
ZERO POINT @ 15.0%		37351.4
1/01/84 @ 20.0%		27632.2
PRODUCTIVE LIFE - YEARS 31.0	PAYOUT DATE	1/1984
A.TAX BORR. RATE 6.21 %	BEFORE INT.	AFTER INT.
PAYOUT FROM INIT. EXP.(1/1/84)-YRS	0.0	0.0
PAYOUT FROM START-UP (1/1/84)-YRS	0.0	0.0
PROFIT TO INVESTMENT RATIO	0.0	0.0

OPERATING MEASURES

	WORKING	NET	N.PROF.
INIT. INTEREST %	1.00000	0.87500	0.0
FIRST CHNG. - 0/ 0	0.0	0.0	0.0
SECOND CHNG. - 0/ 0	0.0	0.0	0.0
THIRD CHNG. - 0/ 0	0.0	0.0	0.0

VOLUMES-	GROSS PROD.	NET SALES	NET SALES AFTER P.O.
BARRELS OIL & COND.	12445.0	10887.0	10887.0
MCF GAS	49276.0	43117.0	43117.0
EQ.VOL.(PRICE) - BBLS	13277.8	11618.1	
EQ.VOL. (BTU) - BBLS	21236.7	18582.1	

	$	$/UNIT (PRICE)	$/UNIT (BTU)
REVENUES			
GROSS	1218578.0	91.78	57.38
NET OF ROYALTY	1066256.0	91.78	57.38
INVESTMENTS			
LEASE COST	0.0	0.0	0.0
PRODUCING EQUIPMENT	0.0	0.0	0.0
INTANGIBLE DRILLING	0.0	0.0	0.0
MULTI-LEASE & OTHER	0.0	0.0	0.0
SALVAGE	0.0	0.0	0.0
TOTAL	0.0	0.0	0.0
OPERATING EXPENSES			
FED. EXCISE TAXES	368307.0	31.70	19.82
PRODUCTION EXPENSES	133440.0	11.49	7.18
PROD. & PROP. TAXES	134634.0	11.59	7.25
OVERHEAD	28024.0	2.41	1.51
OTHER	0.0	0.0	0.0
TOTAL	664405.0	57.19	35.76
NON-OPER. CASH FLOW	0.0	0.0	0.0
TOT. CASH PROFIT BTAX	401854.0	34.59	21.63
TOT. U.S. INCOME TAXES	192891.0	16.60	10.38
TOT. CASH PROFIT ATAX	208965.0	17.99	11.25

INCREMENTAL

TABLE 6

INCREMENTAL TRIAL - MIN RECOV W/ 30YR

SUMMARY OF PROFITABILITY

AMOUNTS IN THOUSANDS

ECONOMIC AND FINANCIAL MEASURES - AFTER TAX

MODIFIED CALENDAR YEAR CASH FLOWS - YR 1 HAS 12 MONTHS

DCF RATE OF RETURN - % ZERO PT. 1/01/84			23.4
GROWTH RATE OF RETURN (@ 15.0%) - %			28.1
NET PRESENT VALUE @ 10.0%			71955.4
ZERO POINT @ 15.0%			31563.7
1/01/84 @ 20.0%			9434.2
PRODUCTIVE LIFE - YEARS 31.0	PAYOUT DATE		8/1991
A.TAX BORR. RATE 6.21 %		BEFORE INT.	AFTER INT.
PAYOUT FROM INIT. EXP.(1/1/84)-YRS		7.6	7.9
PAYOUT FROM START-UP (1/1/84)-YRS		7.6	7.9
PROFIT TO INVESTMENT RATIO		5.0	4.9

OPERATING MEASURES

	WORKING	NET	N.PROF.
INIT. INTEREST %	0.0	0.0	0.0
FIRST CHNG. - 0/ 0	0.0	0.0	0.0
SECOND CHNG. - 0/ 0	0.0	0.0	0.0
THIRD CHNG. - 0/ 0	0.0	0.0	0.0

VOLUMES-	GROSS PROD.	NET SALES	NET SALES AFTER P.O.
BARRELS OIL & COND.	23651.0	20698.0	17822.5
MCF GAS	-12830.0	-11230.0	-2795.8
EQ.VOL.(PRICE) - BBLS	23434.9	20508.9	
EQ.VOL. (BTU) - BBLS	21361.5	18694.0	

	$	$/UNIT (PRICE)	$/UNIT (BTU)
REVENUES			
GROSS	1962887.0	83.76	91.89
NET OF ROYALTY	1717535.0	83.75	91.88
INVESTMENTS			
LEASE COST	0.0	0.0	0.0
PRODUCING EQUIPMENT	18434.0	0.90	0.99
INTANGIBLE DRILLING	27460.0	1.34	1.47
MULTI-LEASE & OTHER	16511.0	0.81	0.88
SALVAGE	0.0	0.0	0.0
TOTAL	62405.0	3.04	3.34
OPERATING EXPENSES			
FED. EXCISE TAXES	568994.8	27.74	30.44
PRODUCTION EXPENSES	221192.9	10.79	11.83
PROD. & PROP. TAXES	222686.9	10.86	11.91
OVERHEAD	46450.9	2.26	2.48
OTHER	0.0	0.0	0.0
TOTAL	1059325.0	51.65	56.67
NON-OPER. CASH FLOW	0.0	0.0	0.0
TOT. CASH PROFIT BTAX	595795.9	29.05	31.87
TOT. U.S. INCOME TAXES	283326.9	13.81	15.16
TOT. CASH PROFIT ATAX	312466.8	15.24	16.71

INCREMENTAL

TABLE 7

INCREMENTAL TRIAL - OPT RECOV W/ 30YR

SUMMARY OF PROFITABILITY

AMOUNTS IN THOUSANDS

ECONOMIC AND FINANCIAL MEASURES - AFTER TAX

MODIFIED CALENDAR YEAR CASH FLOWS - YR 1 HAS 12 MONTHS

DCF RATE OF RETURN - %	ZERO PT. 1/01/84		37.2
GROWTH RATE OF RETURN (@ 15.0%) - %			45.5
NET PRESENT VALUE	@ 10.0%		284977.9
ZERO POINT	@ 15.0%		154271.4
1/01/84	@ 20.0%		83466.1
PRODUCTIVE LIFE - YEARS 31.0	PAYOUT DATE		3/1991
A.TAX BURR. RATE 6.21 %		BEFORE INT.	AFTER INT.
PAYOUT FROM INIT. EXP.(1/1/84)-YRS		7.2	7.4
PAYOUT FROM START-UP (1/1/84)-YRS		7.2	7.4
PROFIT TO INVESTMENT RATIO		17.5	17.4

OPERATING MEASURES

	WORKING	NET	N.PROF.
INIT. INTEREST %	0.0	0.0	0.0
FIRST CHNG. - 0/ 0	0.0	0.0	0.0
SECOND CHNG. - 0/ 0	0.0	0.0	0.0
THIRD CHNG. - 0/ 0	0.0	0.0	0.0
VOLUMES-	GROSS PROD.	NET SALES	NET SALES AFTER P.O.
BARRELS OIL & COND.	63170.0	55274.0	52456.5
MCF GAS	25704.0	22490.0	31325.2
EQ.VOL.(PRICE) - BBLS	63672.0	55713.2	
EQ.VOL. (BTU) - BBLS	67756.5	59287.3	
	$	$/UNIT (PRICE)	$/UNIT (BTU)
REVENUES			
GROSS	5219569.0	81.98	77.03
NET OF ROYALTY	4567129.0	81.98	77.03
INVESTMENTS			
LEASE COST	0.0	0.0	0.0
PRODUCING EQUIPMENT	18434.0	0.33	0.31
INTANGIBLE DRILLING	27460.0	0.49	0.46
MULTI-LEASE & OTHER	16511.0	0.30	0.28
SALVAGE	0.0	0.0	0.0
TOTAL	62405.0	1.12	1.05
OPERATING EXPENSES			
FED. EXCISE TAXES	1548960.0	27.80	26.13
PRODUCTION EXPENSES	221192.9	3.97	3.73
PROD. & PROP. TAXES	593337.8	10.65	10.01
OVERHEAD	46450.9	0.83	0.78
OTHER	0.0	0.0	0.0
TOTAL	2409942.0	43.26	40.65
NON-OPER. CASH FLOW	0.0	0.0	0.0
TOT. CASH PROFIT BTAX	2094778.0	37.60	35.33
TOT. U.S. INCOME TAXES	1002838.1	18.00	16.91
TOT. CASH PROFIT ATAX	1091939.0	19.60	18.42

UNITIZATION PARAMETERS

The Technical Committee was asked to investigate the following six possible unitization parameters:

1. Net Acreage
2. Primary Ultimate Recovery
3. Cumulative Recovery
4. Remaining Primary Reserves
5. Current Oil Production Rate
6. Secondary Reserves

Data has been assembled for all parameters except Secondary Reserves. Due to the lack of modern logs and cores for the unit, no accurate projection of secondary recovery could be made for individual tracts. The Technical Committee elected to recommend deletion of this parameter from further consideration.

Table 8 is the completed list of parameters, with participation percentages assigned to individual Working Interest Owners. Four operators have not provided a confirmed list of owners for their leases, and are being shown as 100% owners of their properties. These operators are designated with an asterisk (*) in the table.

Regarding the individual parameters, the following comments should be noted. Net acreage was provided by individual operators and allocated to individual owners. Cumulative recovery information was taken from New Mexico Oil Conservation Commission records, with corrections provided by individual operators when necessary. Remaining primary reserves were calculated for each active tract based upon the individual tract decline curves. Future production was extrapolated to an economic limit of

30 barrels of oil per month per active well on each lease. Primary ultimate was calculated to the same economic limit. The 1982 oil production was also taken from New Mexico State records from January 1, 1982, through September 30, 1982.

TABLE 8B
EUNICE MONUMENT SOUTH UNIT
PARAMETER TABLE

OWNER	NET ACREAGE TOTAL	NET ACREAGE PERCENT	PRIMARY ULTIMATE AT ECONOMIC LIMIT TOTAL-STB	PRIMARY ULTIMATE AT ECONOMIC LIMIT PERCENT	CUMULATIVE RECOVERY TO 10/1/82 TOTAL-STB	CUMULATIVE RECOVERY TO 10/1/82 PERCENT	REMAINING PRIMARY RESERVES TOTAL-STB	REMAINING PRIMARY RESERVES PERCENT	1982 OIL PRODUCTION 1/1/82 THRU 9/30/82 TOTAL-STB	1982 OIL PRODUCTION 1/1/82 THRU 9/30/82 PERCENT
AMERADA	320.00	0.022410	2385066	0.017750	2330898	0.019459	54168	0.003730	10680	0.017989
AMOCO	1003.40	0.070268	9931012	0.073943	8579013	0.071620	1351999	0.093105	43606	0.073447
APOLLO*	40.00	0.002801	528833	0.003937	479649	0.004004	49184	0.003387	5952	0.010025
ARCO	2255.97	0.157986	24944337	0.185726	21744490	0.181528	3199847	0.220357	107901	0.181741
BRADY	20.00	0.001401	268620	0.002000	236375	0.001973	32245	0.002221	1435	0.002417
BRUNO	160.00	0.011205	496156	0.003694	496156	0.004142	0	0.000000	145	0.000244
CATRON	120.00	0.008404	967282	0.007202	917838	0.007662	49444	0.003405	3043	0.005125
CHEVRON	630.00	0.044119	7706139	0.057377	6410571	0.053517	1295569	0.089219	38563	0.064953
CITIES	280.00	0.019608	2051645	0.015276	2023007	0.016889	28638	0.001972	4283	0.007214
CONOCO	1110.00	0.077733	11441710	0.085191	9848319	0.082216	1593392	0.109729	49066	0.082643
EXXON	1180.00	0.082636	9144494	0.068087	8853532	0.073911	290962	0.020037	21632	0.036435
FIELDS	30.00	0.002101	79590	0.000593	71408	0.000596	8183	0.000564	343	0.000578
GETTY	1085.70	0.076032	11909322	0.088672	11227721	0.093732	681601	0.046938	44484	0.074926
GULF	4022.90	0.281724	39582316	0.294715	35227694	0.294089	4354623	0.299880	199122	0.335387
HARTMAN*	40.00	0.002801	159151	0.001185	157193	0.001312	1958	0.000135	329	0.000554
HEDDLEY	15.00	0.001050	62842	0.000468	62842	0.000525	0	0.000000	0	0.000000
HUDSON,ER	15.75	0.001103	16397	0.000122	15784	0.000132	614	0.000042	26	0.000044
HUDSON,W&E	89.25	0.006250	92915	0.000692	89436	0.000747	3478	0.000240	146	0.000246
KOCH	80.00	0.005602	711506	0.005298	706600	0.005899	4906	0.000338	2097	0.003532
LANDRETH	51.60	0.003614	507734	0.003780	492111	0.004108	15623	0.001076	935	0.001575
ME-TEX	240.00	0.016807	583429	0.004344	566804	0.004732	16625	0.001145	474	0.000798
RASMUSSEN*	40.00	0.002801	155642	0.001159	155642	0.001299	0	0.000000	0	0.000000
SHELBY	30.00	0.002101	79590	0.000593	71408	0.000596	8183	0.000564	343	0.000578
SHELL	640.00	0.044819	6470127	0.048174	5137270	0.042887	1332857	0.091787	52239	0.087988
SUN	320.00	0.022410	1756284	0.013077	1697509	0.014171	58775	0.004048	4209	0.007089
TEXACO	160.00	0.011205	1020828	0.007601	944770	0.007887	76058	0.005238	1880	0.003167
TURNER	75.00	0.005252	119385	0.000889	107112	0.000894	12274	0.000845	514	0.000866
TWO-STATES	85.00	0.005953	353597	0.002633	353597	0.002952	0	0.000000	261	0.000440
WILBANKS*	80.00	0.005602	529686	0.003944	529686	0.004422	0	0.000000	0	0.000000
WISER	60.00	0.004202	251368	0.001872	251368	0.002098	0	0.000000	0	0.000000
TOTAL	14279.57	1.000000	134307003	1.000000	119785803	1.000000	14521206	1.000000	593708	1.000000

NOTES: (1) REVISED 12/2/83 TO REFLECT CORRECT WORKING INTEREST IN TRACT 54
(2) DATA CUTOFF DATE IS 10/1/82
(3) * INDICATES WORKING INTEREST OWNERSHIP NOT CONFIRMED

UNITIZED INTERVAL

During Technical Committee meetings in February and May of 1982, a major discussion item was the definition of the vertical interval to be unitized. A number of wells which are classified as Eunice Monument oil wells are actually producing from open hole completions exposing both the Eumont and Eunice Monument pools. In addition, many of the Eumont oil wells located along the western and southern edges of the proposed unit are producing from both pools.

An evaluation of the few available logs, cross-sections and production data indicates that the oil column within and adjacent to the unit is continuous from approximately -325 feet to -100 feet subsea, and includes oil being classified as both Eumont (Penrose and Queen) and Eunice Monument (Grayburg) production. Because of structural variations throughout the field, the upper limit of -100 feet subsea varies from mid-Grayburg in the eastern portion of the field to upper-Queen in the southwestern area of the field. In general, gas wells are completed above the -100 foot datum, and oil wells are completed below the -100 foot datum, regardless of their classification as Eumont or Eunice Monument wells. This is easily seen in the completion interval diagrams shown in Figures 98 through 106, and the geologic cross sections shown in Figures 107 and 108.

Originally the fact that many wells were open hole completions across the top of the Grayburg was of no consequence since the Eunice pool included both Queen and Grayburg formations. However, separation of the Eunice pool into the Eumont Gas Pool and Eunice Monument Oil Pool in the early 1950's created an accounting and classification problem for oil produced in the area. Because the oil wells were allowed to remain on production in their original completion status, a number of problems are evident which affect this unitization effort. First, there is no practical method to isolate the Eumont and Eunice Monument pools in future operations except by installing liners and selectively perforating the individual zones. Approximately one-half of all proposed unit wells would require this remedial work. Second, because it is impossible to allocate historical production between the two pools in these wells, cumulative production, predicted future production, and ultimate production cannot be calculated for approximately one-half of the leases in the proposed unit; and these parameters cannot be used in the proposed formulas for negotiations of equity.

The Technical Committee, in addressing these problems determined that the following facts should be considered:

1. The entire oil column must be included in the unitized interval if secondary recovery is to be effective and efficient.
2. There is no indication that a barrier to communication exists between the Grayburg and Penrose formations.
3. Oil production in the unit area occurs at and below approximately -100 feet subsea, regardless of whether the productive formation is designated as Eumont or Eunice Monument.
4. Oil produced from Eunice Monument and Eumont oil wells is similar in composition and quality.

In view of the above factors, the technical committee recommended the following definition be proposed to describe the vertical unitized interval:

> "The Unitized Interval shall include the formations from a lower limit defined by the base of the San Andres formation, to an upper limit defined by the top of the Grayburg formation or a -100 foot subsea datum, whichever is higher."

UNIT BOUNDARY

After selection of the recommended unitized interval, the committee considered recommendations for establishing the geographical boundary.

The current boundary was selected to include virtually all current and historical Eunice Monument oil production in the southern portion of the field. The boundary was drawn in a manner which would allow for reasonable development of the flood, with a minimum number of "window" areas or unfloodable locations.

Two operators have presented requests to have their leases excluded from unitization. The operators, Messrs. Hartman and Rasmussen, have leases covering S/2 SW/4 Section 2, Township 21 South, Range 36 East, and are designated as Tracts 70 and 113 (Figure 2). During the committee meeting of May 4, 1982, members voted to recommend that these tracts not be deleted from the unit. These tracts have a contiguous oil column to the rest of the unit and if deleted would create boundary problems and reduce the overall unit secondary recovery.

Prior and subsequent to this vote Mr. Hartman has requested release of his property by letters which are included in the Correspondence section.

MISCELLANEOUS

During the Technical Committee meeting of February 2, 1982, the committee discussed the possibility of recommending 'Useable Wellbores' as a unitization parameter. Operators were requested to determine which wellbores would be committed for unit operation, and which wellbores would be withheld for other use.

In evaluating this request operators discovered that they were unable to determine the disposition of every wellbore. The major cause of concern involved wells which have been recompleted into the Eumont pool, or which are dual completions in the Eumont and Eunice Monument. These wells could not be economically evaluated with the information and guidelines that were available. The various problems were further outlined in a Conoco letter dated August 25, 1982, and the Gulf letter dated September 22, 1982, which appear in the Correspondence section of this report.

As a result of the numerous questions involved in this decision, Gulf proposed that 'Useable Wellbores' be eliminated as a possible parameter. Gulf suggested that the inequities which would arise from some members withholding wellbores, or not having operational wellbores, could be resolved in the inventory adjustment process rather than in the parameter table. Gulf initiated a ballot to remove 'Useable Wellbores' from further consideration, and the ballot was approved by a vote of 13 to 2, with 9 operators failing to respond.

CORRESPONDENCE

Minutes of Operators
Proposed Eunice Monument Waterflood
5-10-79

A meeting of the Working Interest Owners was held at 9:30 A.M. on Thursday May 10, 1979 in ARCO's 1st floor conference room in Midland, Texas. Representatives that attended the meeting are shown on the attached list.

Mr. J. L. Tweed (ARCO) opened the meeting by stating the purpose was to review a waterflood study ARCO had done on the Eunice Monument Field. As he indicated the proposed flood was in Lea County, New Mexico and centered in Township 21 S, R36E, as identified on the handouts.

Mr. Bob Malaise (ARCO) explained that a cursory study had been completed at the request of ARCO's management. This study had not been intended as a unitization study but much of the data could be unitilized in future unitization efforts. He continued by stating the area studied included the South end of the Eunice Monument Field, more specifically, it included 9,760 acres as shown by a cross-hatch outlined area on a handout. He indicated that ARCO realizes that there may be additional areas with waterflood possibilities that could be included as an addition to this proposed boundary. ARCO feels this would be a good waterflood candidate based on the high cumulative production of 86 MMSTBO, as of 1-1-79. In addition, cross sections indicated the pay continuity to be good within the area.

Mr. Malaise described the main zone as being the Grayburg which is at a depth of 3750'. The Grayburg is surrounded by the Queen on the top and the San Andres on the bottom. This zone is a fine crystalline, gray dolomite, interbedded with sand stringers. Mr. Malaise pointed out a generally southwesterly dip to the Grayburg as indicated on a structure map, drawn on the Grayburg top. It was shown on the structure map also a very pronounced dip in the west and southwest proportion of the unit area. Looking at a type log from the Conoco B-8 #5, ARCO estimated the gas-oil contact to be at 3740' (-150'ss) and a water-oil contact to be 3915' (-325'ss). At this point, Mr. Tweed interjected the comment that he felt the gas-oil contact was reliable based on production data and log data, but that the oil water contact may vary in certain parts of the field. He further stated that this study used a gross oil column of 175', porosity of 7-8%, and averaged air permeability to be 10-15 MD. Additional fluid and rock properties were shown on a separate handout. Mr. Tweed stated again some of the parameters would be changed when a more detailed study was completed. In reviewing a north/south cross section through the middle of the unit, Mr. Malaise pointed out that to the North the Grayburg contains oil, the Queen gas, and the San Andres appears to be wet. Moving South the oil column is found in the upper Grayburg and lower Queen. In the extreme West area much of the production appears to have been produced from the Queen interval.

Mr. Bob Malaise explained that the development of the Eunice Monument GB started in 1929. Many of the wells were completed open hole with a large number being shot w/nitro. Original-oil-in-place within the proposed unit is 575 MMSTBO based on the parameters already listed. Decline curve analysis on a lease basis, indicated 5 MMSTBO remain to be recovered as of 1-1-79. Ultimate recovery will be between 16-17% of the original oil-in-place. Current GB production is approximately 1700 BOPD. Mr. Malaise stated that the secondary opportunities within the proposed area appear to be very attractive. A A stratified waterflood analysis indicate a secondary potential of 56 MMSTBO or approximately 55% of estimated primary production. He also concluded that the secondary reserves were conservative in nature based on three variables used in the analysis. They were the initial gas saturation at the start of the flood, Sgx (19%), the initial water saturation Swc (35%) and the residual oil saturation, Sor (35%).

In summary, Mr. Malaise stated within the studied area the following parameters were found:

1. Cumulative oil, as of 1-1-79, 87 MMSTO *
2. Acres - 9760
3. Remaining primary - 5.2 MMSTBO
4. Ultimate primary - 95 MMSTBO
5. Estimated secondary - 56 MMSTBO

At this time, Mr. Tweed suggested that a vote be taken concerning the formation of an Engineering Sub Committee for the purpose of studying the Eunice Monument area for possibilities of future waterflooding. All the companies that were represented voted yes concering this vote. In addition, it was pointed out that AMOCO was interested in waterflooding the area but due to a conflict in scheduling, were unable to attend the meeting. At this point, Mr. Tweed indicated that Gulf Oil would have the largest interest within the studied area. He felt that by the time the initial Engineering Sub Committee was formed, Gulf should indicate any desire to expedite and operate a future unit. Mr. R. L. Borgan (Gulf) acknowledged this request.

Mr. Buck (Shell) questioned the reason for the proposed unit outline. Mr. Tweed explained that the unit line had been chosen as much by convenience as anything, although, there were reservoir boundaries to the East and West that would define a logical unit area. To the East, the continuity and quality of pay deteriates. To the West, the structure dips are very deep and there would be a loss of both pay quality and oil column. Mr. Buck suggested that there may be some area both to the North and South that should be included within any future study done. After additional discussion on this matter, Mr. Tweed suggested to charge an Engineering Sub Committee with the responsibility of studying two additional sections North and 1 section South

* contains some Eumont oil

of the proposed area. It was indicated that they would include the Eumont oil zone in a future waterflood study.

Listed below are the agreed charges to be determined by a future Engineering Sub Committee:

1. Update and correct a base map
2. Define area of waterflood study (include 2 sections North and one south of proposed area)
3. Establish a parameter table to include the following:
    1. Current oil/gas rate (12 month period)
    2. Cumulative oil production
    3. Total acres
    4. Remaining primary
    5. Ultimate primary
    6. Secondary reserves (if recommended by Engineering Sub Committee)
4. Prepare water flood study and plan of operation.
5. Define vertical interval to be unitized.

Concerning a future voting procedure, after a lengthy discussion it was decided that the future unit expeditor will send out a letter ballot or will request a vote at the first Engineering Sub Committee meeting concerning the same. The Working Interest Owners requested that ARCO send out a letter with the minutes asking for company representatives for a future Working Interest Owners' Committee and Engineering Sub Committee. The general opinion concerning a voting procedure within the Engineering Sub Committee phase was that each active participant would have one vote. The expeditor would try to get as much agreement as possible during the Engineering Sub Committee phase but would not be required to meet a certain percentage. Also, it was decided any pre unitization expense would be handled by letter ballot once the unit expeditor was confirmed.

It was agreed that the next meeting will be of the Engineering Sub Committee which will be held in the next 4 to 5 weeks. Gulf will determine by this time if they want to expedite and operate. The Engineering Sub Committee will discuss what type of study will be required to meet their charges.

The Working Interest Owners will be notified by letter when the Engineering Sub Committee meeting will be held and will be informed as to the time and place of the meeting. The meeting concluded at 11:20 A.M.

Gulf Oil Exploration and Production Company

J. M. Thacker
GENERAL MANAGER PRODUCTION
SOUTHWEST DISTRICT

September 22, 1982

P. O. Drawer 1150
Midland, TX. 79702

Engineering Committee Members
Address List Attached

Gentlemen:

Re: Eunice Monument South Unit
Lea County, New Mexico

Inquiries have been made to Gulf concerning the economic and operational implications of designating specific wellbores to be contributed to the proposed Unit. A copy of one inquiry from Conoco is attached. Since few operators have responded to the request for data in our August 3, 1982 letter, we assume that most committee members are experiencing the same problems with the evaluation of wellbores.

We have found that several basic questions must be answered before an operator can determine whether to contribute or withhold a wellbore from the Unit. These questions include the following:

1. Will the working interest owners allow dual completions in Unit wellbores? If yes, under what conditions?

2. What penalty will be assessed an operator for not contributing an operational wellbore on each 40-acre proration unit credited with production?

3. How can the inequity arising from the failure of some operators to contribute useable wellbores best be resolved?

4. If dual completions are allowed, what is the probability of recovering the "other zone" production if the well is killed to recomplete or recondition the unitized interval?

5. Will operators receive the Section 103 gas price if a new well is drilled for Eumont Gas?

Some of the above questions cannot be resolved at this time without additional Engineering Committee meetings. Also, question 5 cannot be answered without action from the New Mexico Oil Conservation Division. Since this information is not available, it is impossible to make the economic decisions necessary to complete the proposed "Useable Wellbore" parameter at this time.

A DIVISION OF GULF OIL CORPORATION

As an alternative to delaying the completion of the parameter table, Gulf proposes that the "Useable Wellbore" parameter be eliminated from the final table. In our opinion, the inequity arising from the failure of some operators to contribute wellbores can be more effectively resolved through inventory adjustment procedures than in the participation formula. Specifically, owners should receive a credit to inventory for operational wellbores contributed to the Unit, and should be assessed a penalty for not furnishing a wellbore on any 40-acre proration unit which has been credited with production.

By the attached ballot, we request that you approve or disapprove the above proposal. Please complete the ballot and return it to this office, to the attention of Mr. Tom Wheeler, by October 5, 1982. If your Company has multiple addressees on the mailing list, please coordinate a single reply.

You will be notified of the results of this ballot and of a future Committee meeting as soon as the results can be tabulated.

Please continue to prepare and submit the list of Royalty and Overriding Royalty Owners for your individual tracts, as we requested in our letter of August 3, 1982.

Your continued assistance in this unitization effort is appreciated.

Yours very truly,

J. M. THACKER

TSW:mc

Enclosures

CONOCO

David L. Wacker
Division Engineer
Production Department
Hobbs Division
North American Production

Conoco Inc.
P.O. Box 460
726 E. Michigan
Hobbs, NM 88240
(505) 393-4141

1509

RECEIVED
AUG 25 1982
J. M. THACKER

August 20, 1982

Gulf Oil Exploration & Production Co.
P.O. Drawer 1150
Midland, Texas 79702

Attention: Mr. J. M. Thacker

Re: Proposed Eunice Monument, South Unit
Lea County, New Mexico

Gentlemen:

Reference is made to your letter of August 3, 1982, same subject.

Before furnishing the list of wells which would be committed to the unit, we need to know the following:

1. Would dual completed wells be acceptable to the unit?
2. What penalty would Gulf propose if the operator did not furnish a wellbore?

We also request that you furnish us your proposed waterflood pattern and a unit waterflood performance prediction so that we can evaluate our options.

Yours very truly,

D. L. Wacker

D. L. Wacker
Division Engineer

CCW:vrm

EXXON COMPANY, U.S.A.
POST OFFICE BOX 1700 • MIDLAND, TEXAS 79702 (915) 685-9648

PRODUCTION DEPARTMENT
MIDCONTINENT DIVISION

R R HICKMAN
JOINT INTEREST MANAGER

2314

RECEIVED
DEC 15 1982
J. M. THACKER

December 10, 1982

Proposed Eunice Monument South Unit
Lea County, New Mexico

Gulf Oil Explo. & Prod. Co.
P.O. Drawer 1150
Midland, TX 79702

Attention: J. M. Thacker

We received your letter of October 25, 1982 regarding the request of three operators to reconsider the decline curves assigned to their tracts. We are of the opinion that a review of this type is not appropriate unless all of the tracts are reviewed in the same manner. A significant amount of time has passed since the curves were set, and many operators may feel that their tracts should be reviewed. In our own case, there are two tracts which have maintained higher production rates than what is indicated by the assigned decline. Therefore, we feel that the committee should either re-evaluate every tract or leave the matter as was previously agreed upon. If negotiations continue for a period of as much as one year from the last "cut-off" date, we are of the opinion that all parameters should be updated.

Yours very truly,

R. R. Hickman

R. R. Hickman

WGL:slp

A DIVISION OF EXXON CORPORATION

DOYLE HARTMAN
Oil Operator
500 N. MAIN
P. O. BOX 10426
MIDLAND, TEXAS 79702
(915) 684-4011

December 10, 1981

Gulf Oil Corporation
P. O. Box 1150
Midland, Texas 79702

Attention: Mr. Tom Wheeler

Re: W/2 S/3 S/2 Section 2
T-21-S, R-36-E
Lea County, New Mexico

Gentlemen:

Reference is made to our telephone conversation today concerning our Rasmussen State No. 1, located W/2 S/3 S/2 Section 2, T-21-S, R-36-E, Lea County, New Mexico, and Gulf's proposed Eunice-Monument waterflood project in the area. This was our first notice from Gulf of any plans they might have for any future secondary oil recovery project in the vicinity of our tract in Section 2, T-21-S, R-36-E.

The Rasmussen State No. 1, situated on the subject tract in Unit U, was drilled in late 1978 and completed in early 1979, and qualifies for both the maximum oil price and maximum gas price allowed under Federal regulations. Furthermore, the Rasmussen State No. 1 has, since its completion, produced at a highly satisfactory producing rate. Therefore, because of the good economics we are receiving from the Rasmussen State No. 1, we are in no way interested in including our tract in any future secondary oil recovery project in the area of our well. It is also our opinion that any secondary oil recovery project in the Grayburg-San Andres reservoirs would be a highly risky project and would yield only moderate economic results at best.

It is the position of Doyle Hartman as operator, and the other working interest participants in the Rasmussen State No. 1 that it would be to our financial detriment for us to include this tract in any secondary recovery project, and therefore we would be unwilling to commit our well to Gulf's proposed secondary recovery project. We would appreciate it very much if Gulf would omit this tract from this outlined proposed secondary recovery unit.

Please notify us promptly of any opinions you may have to the contrary.

Very truly yours,

Doyle Hartman

Doyle Hartman

WILLIAM P. AYCOCK & ASSOCIATES, INC.
Petroleum Engineering Consultants
308 WALL TOWERS WEST
MIDLAND, TEXAS 79701
PHONE 915/683-5721

Feburary 3, 1982

Gulf Oil Exploration and Production Co.
P.O. Box 1150
Midland, Texas 79702

Attention Mr. Thomas S. Wheeler

Subject: Doyle Hartman-Proposed
Eunice Monument South Unit
Lea County, New Mexico

Gentlemen:

After the meeting yesterday , I reported to Mr. Hartman as I had indicated to you that I would.

Mr. Hartman desires to contact Gulf directly about his situation. He understands that, as far as Gulf is concerned, elimination of his Rasmussen-State lease from the proposed secondary recovery unit will be a decision for the Techinical Committee.

I thought you and your cohorts made an effective presentation, and I enjoyed making your acquaintance.

Very truly yours,

Wm. P. Aycock, P.E.

DOYLE HARTMAN
Oil Operator
500 N. MAIN
P. O. BOX 10426
MIDLAND, TEXAS 79702
(915) 684-4011

August 6, 1982

Gulf Oil Exploration and Production Company
Post Office Box 1150
Midland, Texas 79702

Attention: Mr. J. M. Thacker
General Manager Production
Southwest Division

Re: Gulf's Proposed Eunice
Monument South Unit
Lea County, New Mexico

Gentlemen:

Reference is made to your letter of August 3, 1982, concerning your proposed Eunice Monument South Unit in Lea County, New Mexico.

As has been pointed out by our representatives at several unit meetings, and also in all of our previous correspondence concerning this matter, it is not, nor has it ever been, our intention to commit our 40 acre tract consisting of the W/2 of the S/3 of the SW/4 of Section 2, T-21-S, R-36-E, Lea County, New Mexico to Gulf's proposed secondary recovery unit.

In order to make the numbers less complicated in the future, we suggest that you start the paper work necessary to delete our acreage from the proposed unit at this time.

Very truly yours,

Doyle Hartman

DOYLE HARTMAN

DH:be

cc: Campbell, Byrd and Black, P.A.
Post Office Box 2208
Santa Fe, New Mexico 87501

Attention: Mr. William F. Carr

DOYLE HARTMAN
Oil Operator
500 N. MAIN
P. O. BOX 10426
MIDLAND, TEXAS 79702
(915) 684-4011

September 27, 1982

Gulf Oil Exploration and Production Company
Post Office Box 1150
Midland, Texas 79702

Attention: Mr. J. M. Thacker
General Manager Production
Southwest Division

Re: Gulf's Proposed Eunice
Monument South Unit
Lea County, New Mexico

Gentlemen:

On August 6, 1982, our office wrote to you concerning the above captioned Unit. In this letter we mentioned that we had pointed out in all of our correspondence concerning this Unit, that it was not, nor had it ever been, the intention of Doyle Hartman to commit his 40 acre tract consisting of the W/2 of the S/3 of the SW/4 of Section 2, T-21-S, R-36-E, Lea County, New Mexico to Gulf's proposed secondary recovery unit.

On September 24, 1982, we received from Gulf a letter dated September 22, 1982 to the Engineering Committee Members, in which you have included Mr. Doyle Hartman. We can not stress enough that we will not nor had we ever intended to commit our acreage.

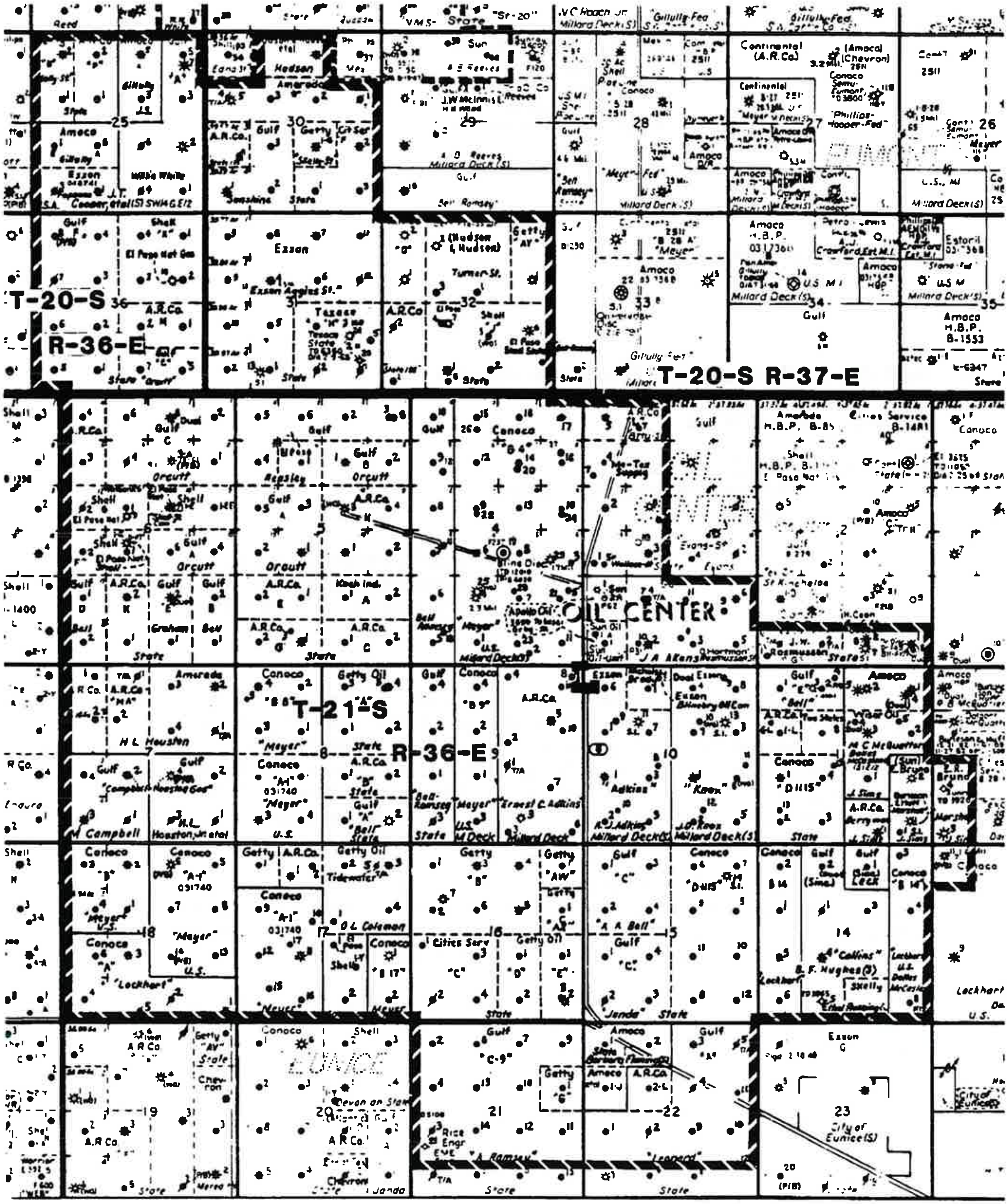
Once again, we ask that Mr. Hartman's name be taken off your mailing list immediately. Our acreage also needs to be deleted so that there can not be any confusion on yours or anyone else's part that our acreage is included in this Unit.

We appreciate your expedient handling of this matter.

Very truly yours,

Doyle Hartman

cc: Mr. William F. Carr
Campbell, Byrd and Black, P.A.
Post Office Box 2208
Santa Fe, New Mexico 87501



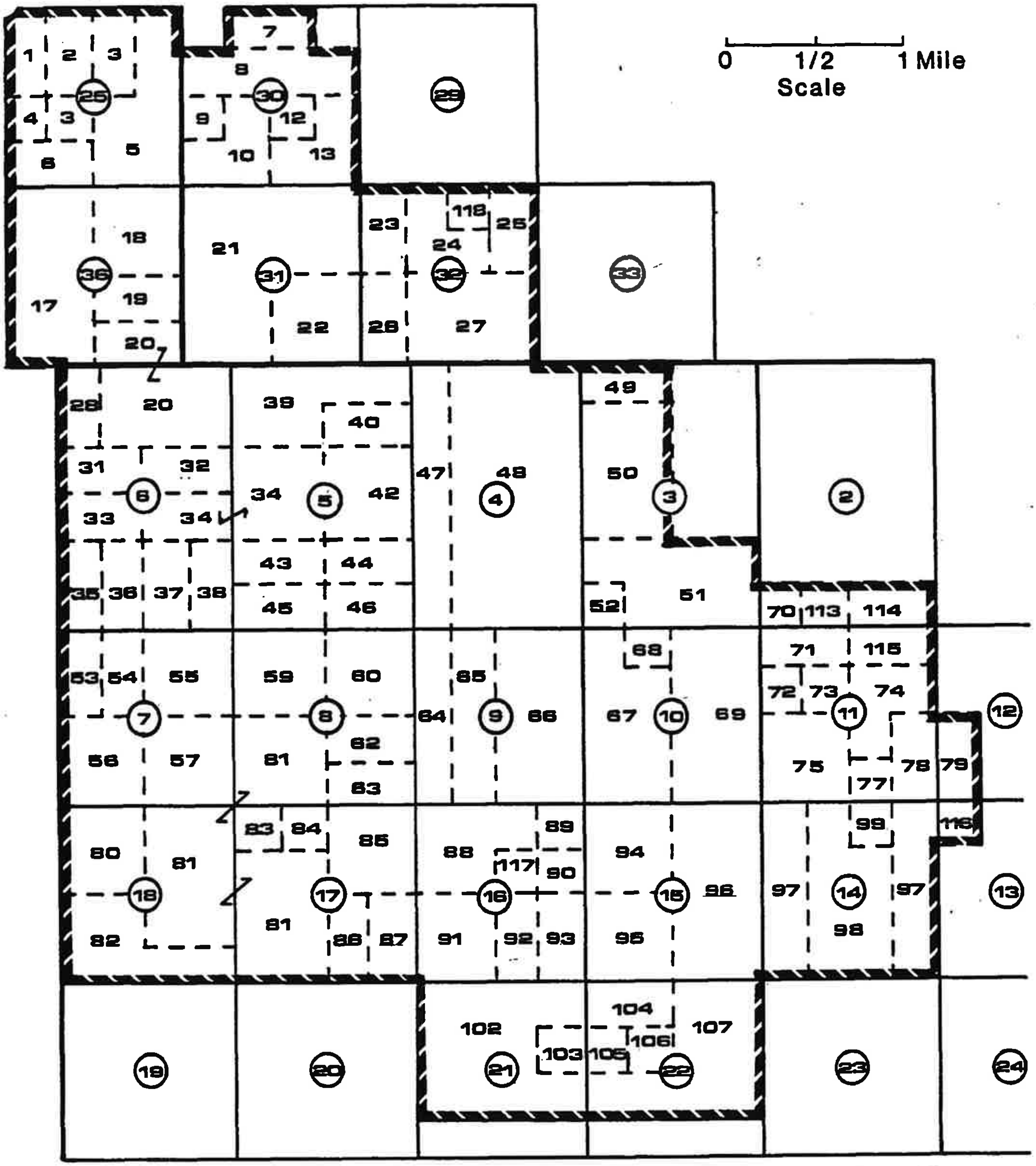
EUNICE MONUMENT SOUTH UNIT
LEA COUNTY, NEW MEXICO

0 1/2 1 Mile
Scale

Figure 1

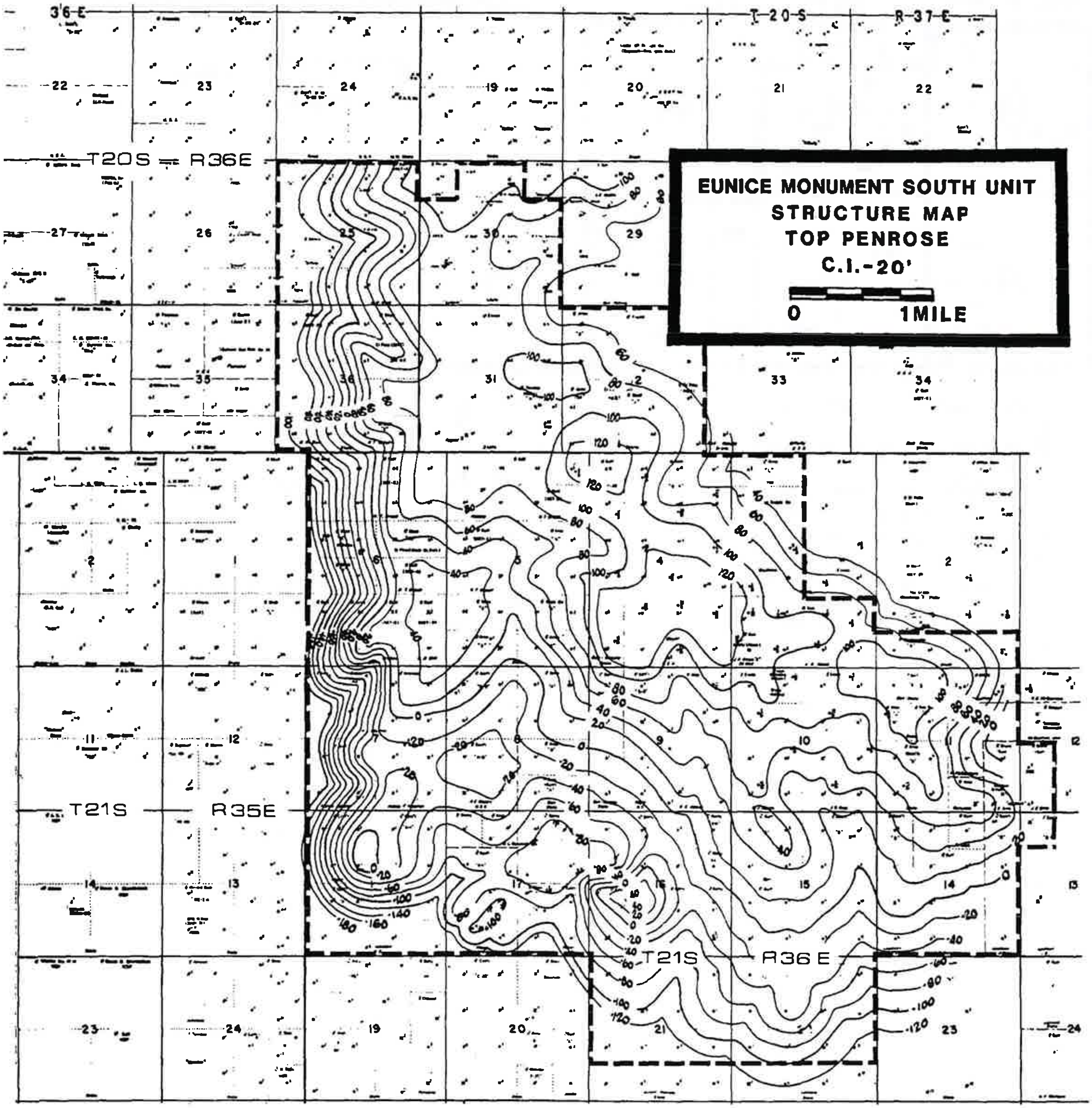
TRACT INDEX MAP
EUNICE MONUMENT SOUTH UNIT
LEA COUNTY, NEW MEXICO

T-20-S, R-36-E T-20-S, R-37-E



T-21-S, R-36-E

Figure 2


EUNICE MONUMENT SOUTH UNIT
STRUCTURE MAP
TOP PENROSE
C.I.-20'
0 1MILE
T20S R36E
T-20-S R-37-E
T21S R35E
T21S R36E

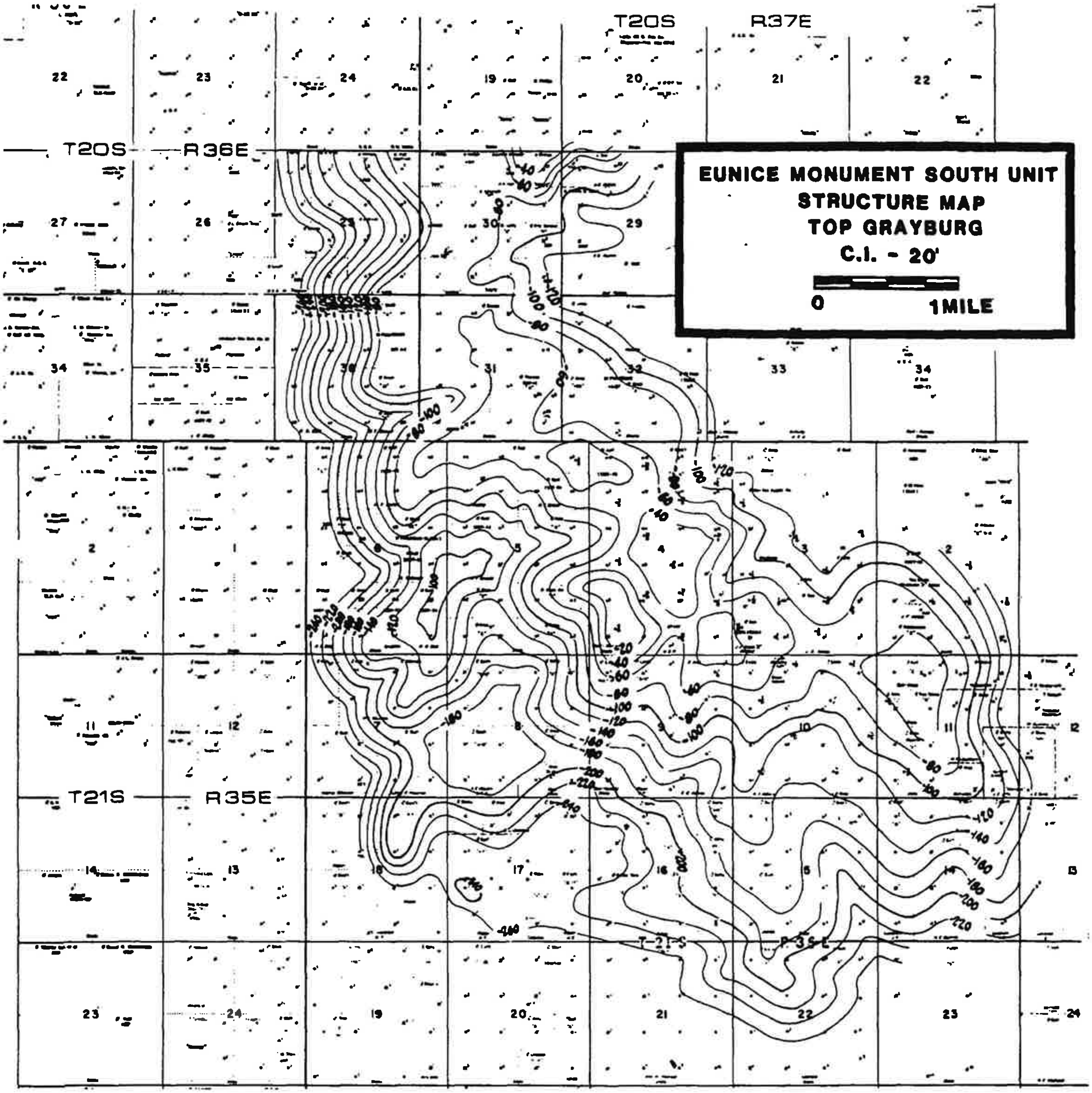

EUNICE MONUMENT SOUTH UNIT
STRUCTURE MAP
TOP GRAYBURG
C.I. - 20'
0
1MILE
T20S
R37E
T20S
R36E
T21S
R35E

Figure 4

TYPE LOG

TIDEWATER OIL CO.
O.L. COLEMAN #5
660 FNL, 900 FEL, SEC. 17, T21S-R36E
LEA CO., NEW MEXICO

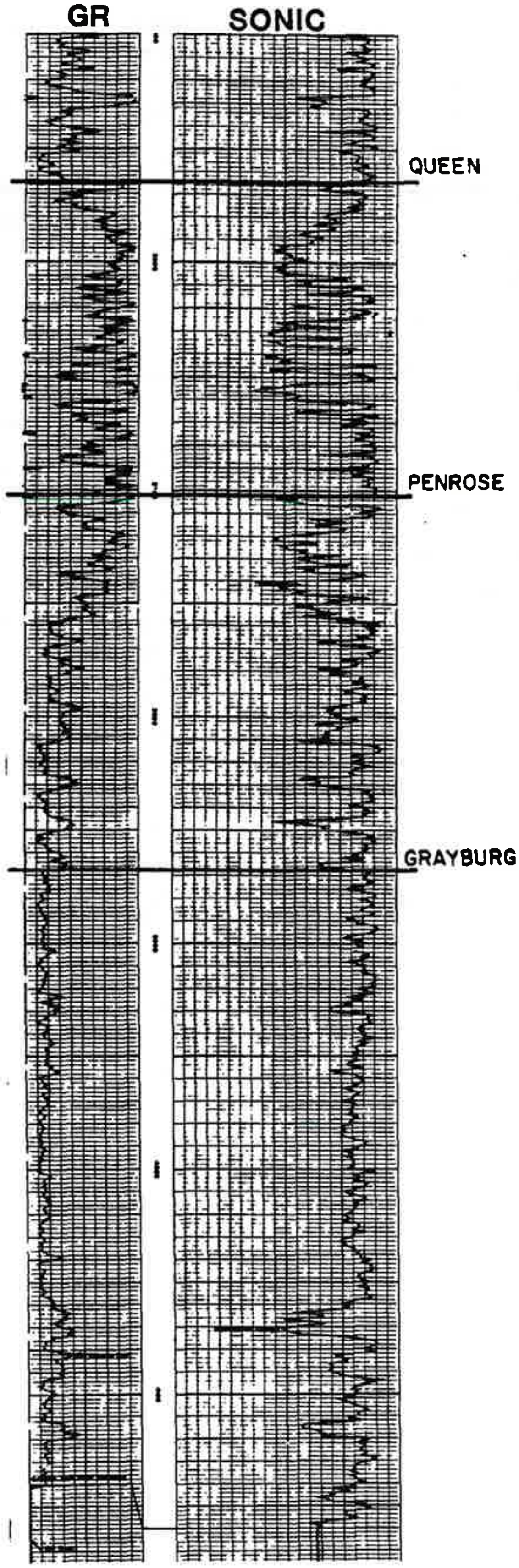


Figure 5

DECLINE CURVE ANALYSIS
RATE VS TIME
PROPOSED EUNICE MONUMENT SOUTH UNIT

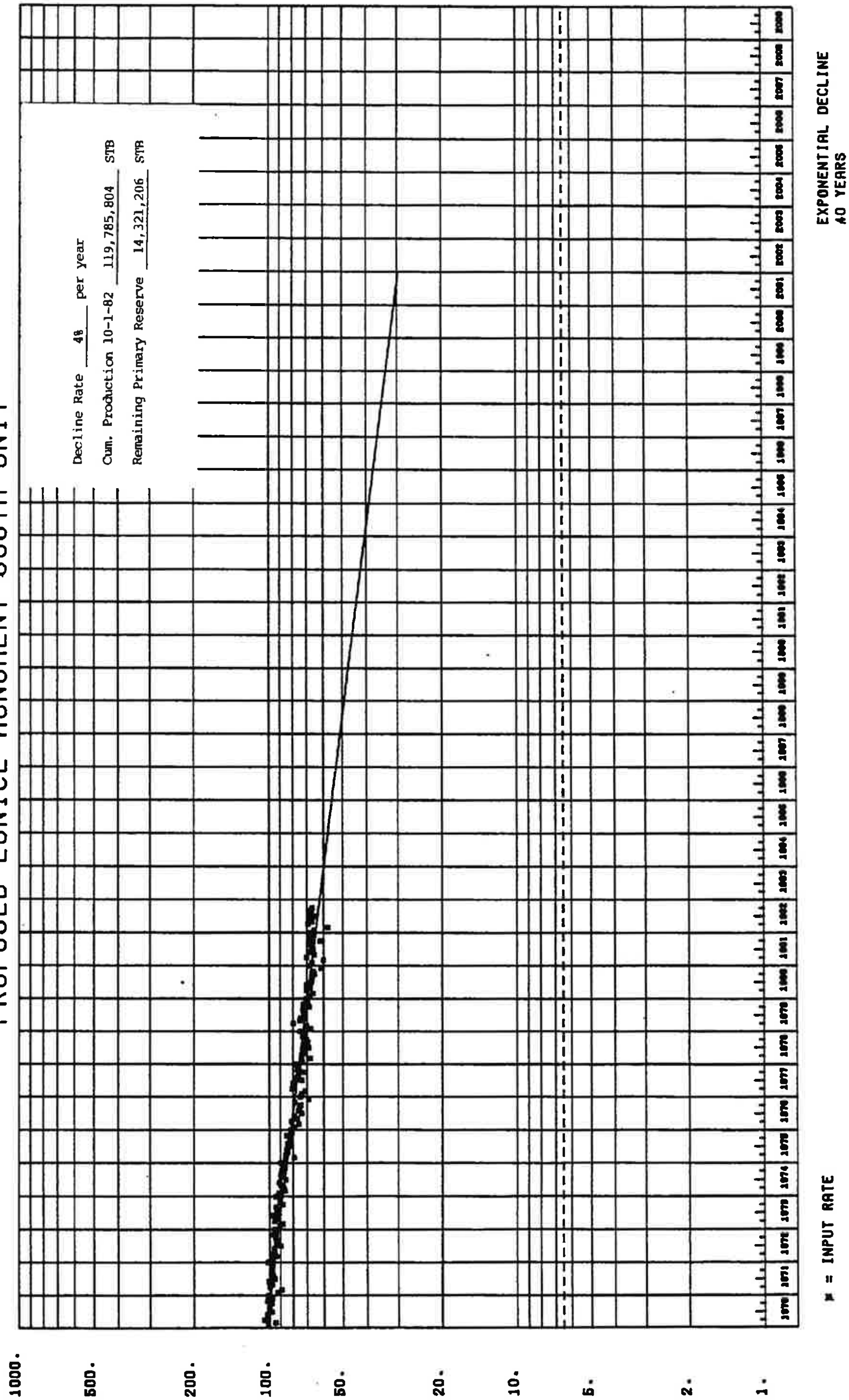
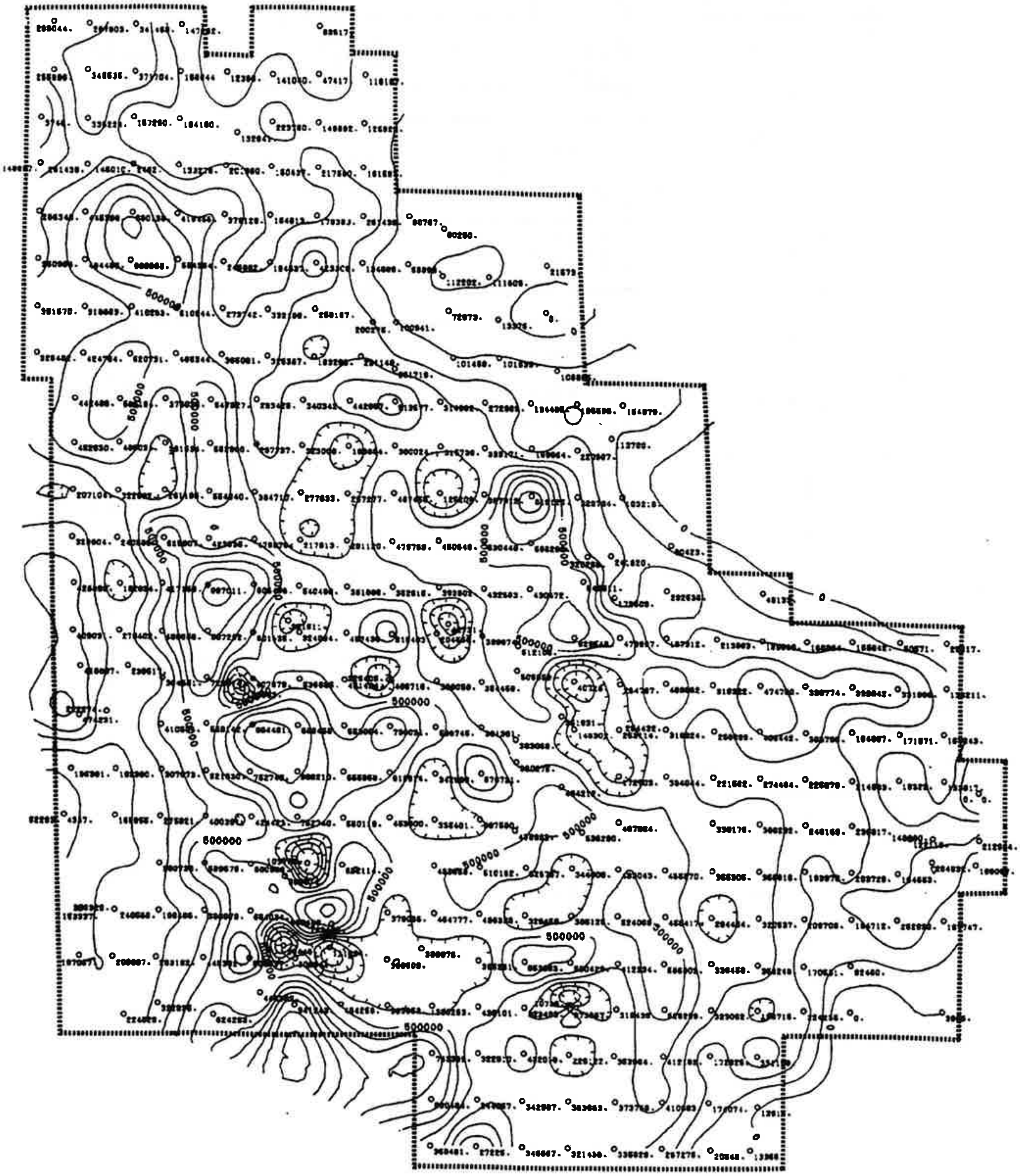
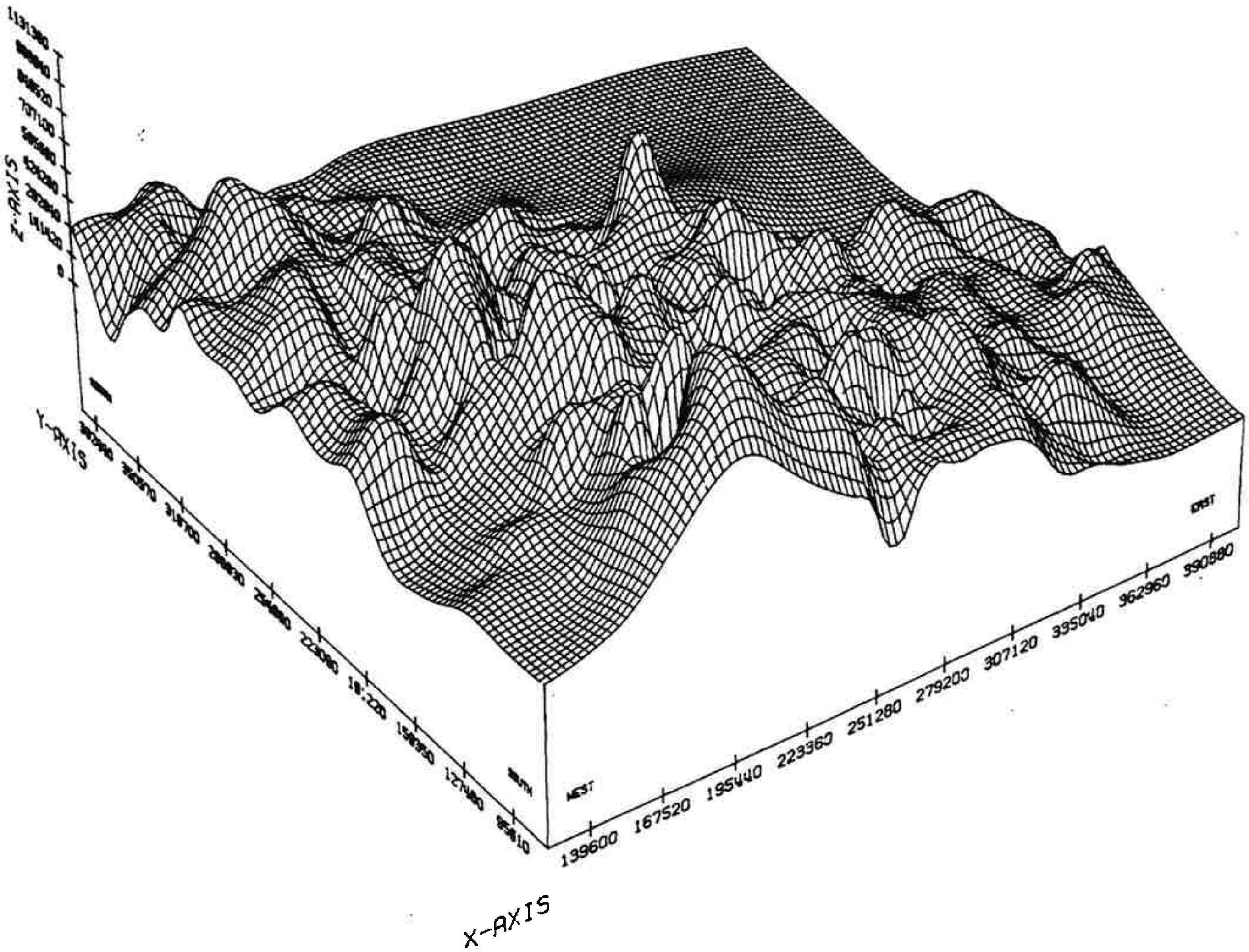


Figure 6



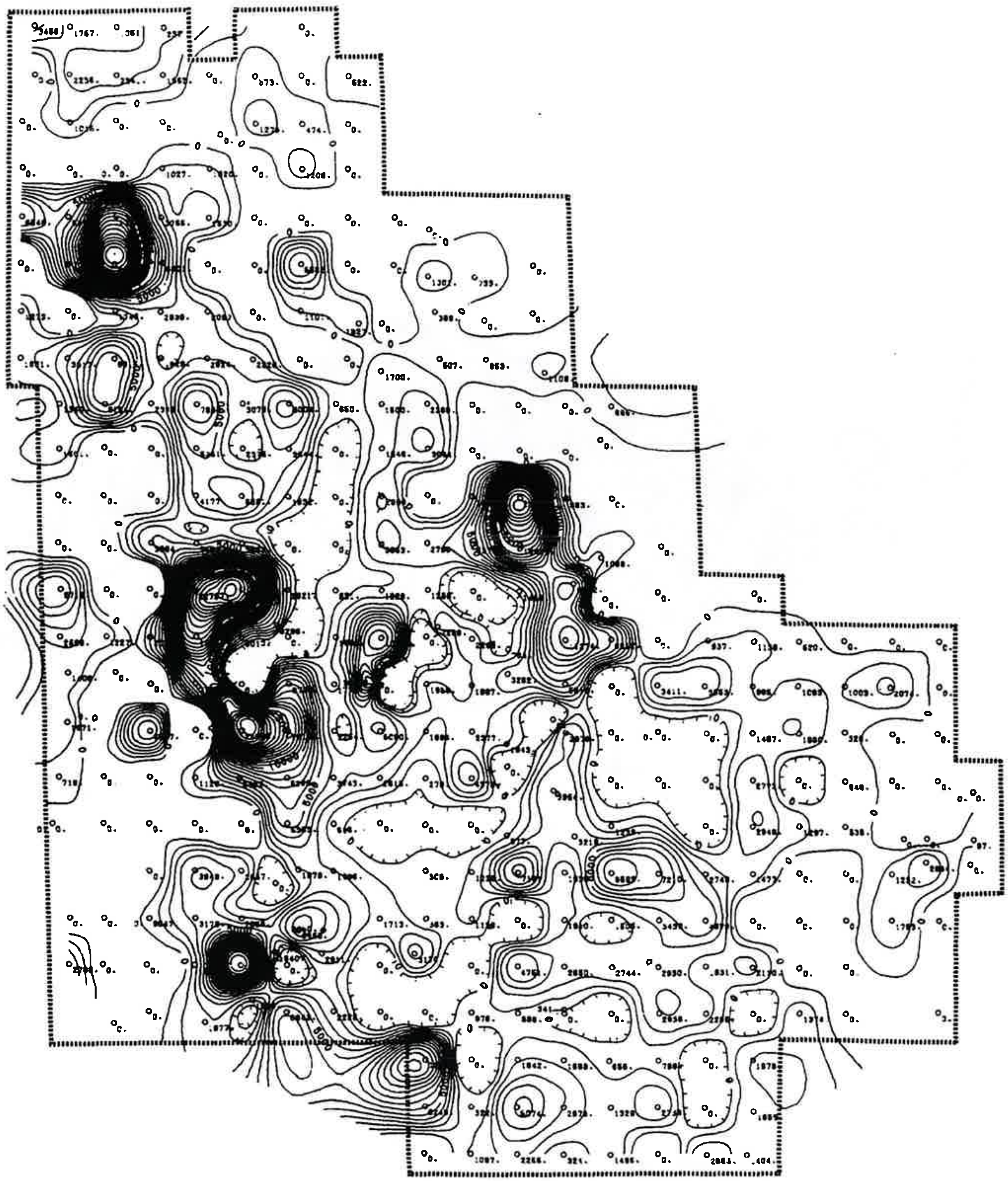
EUNICE MONUMENT SOUTH UNIT
CONTOUR ON CUMULATIVE OIL PRODUCTION THROUGH 1981
CONTOUR INTERVAL = 100,000 STB
SCALE: 1"= 4000'

Figure 7



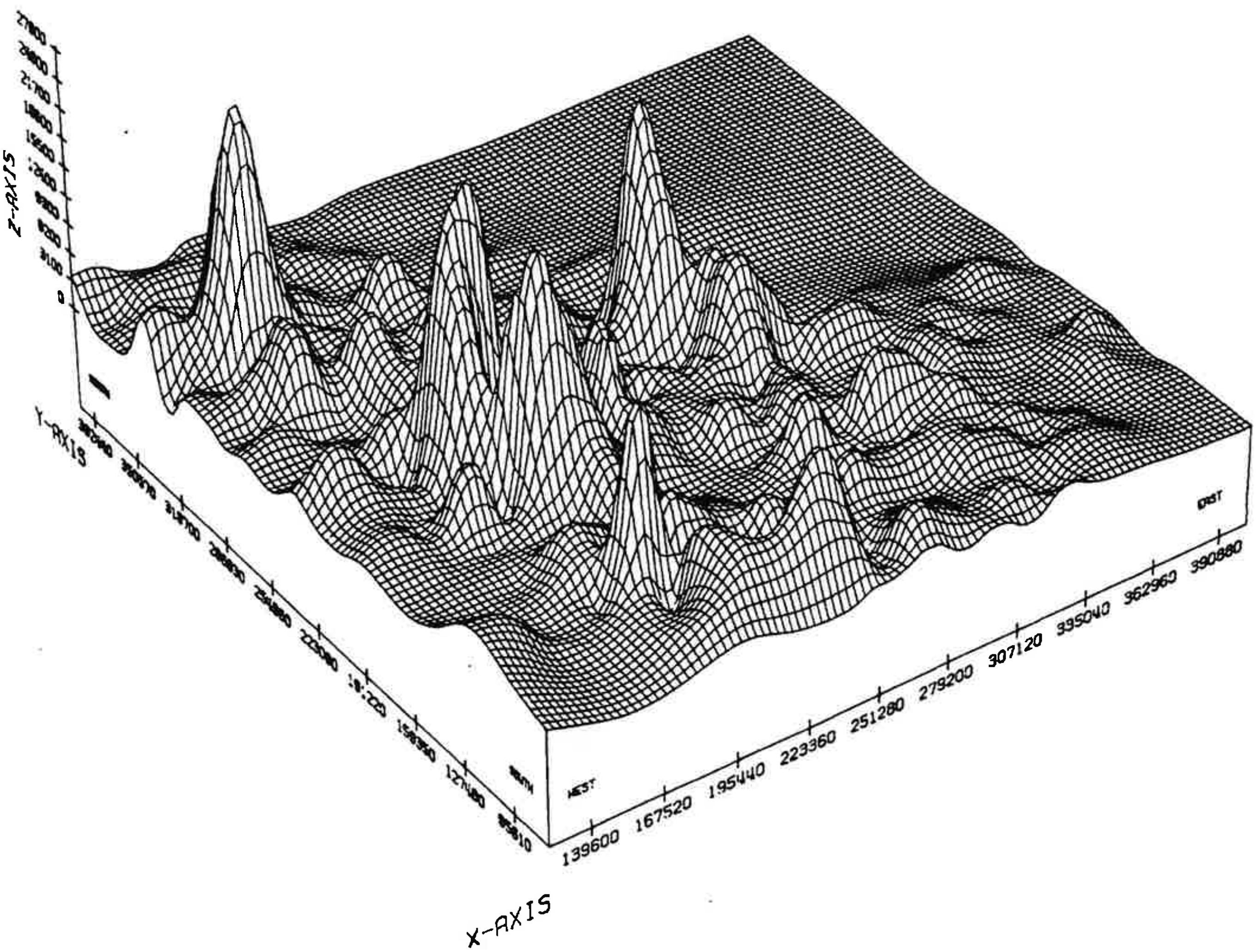
EUNICE MONUMENT SOUTH UNIT
MESH PERSPECTIVE ON CUMULATIVE OIL PRODUCTION
THROUGH 1981

Figure 8



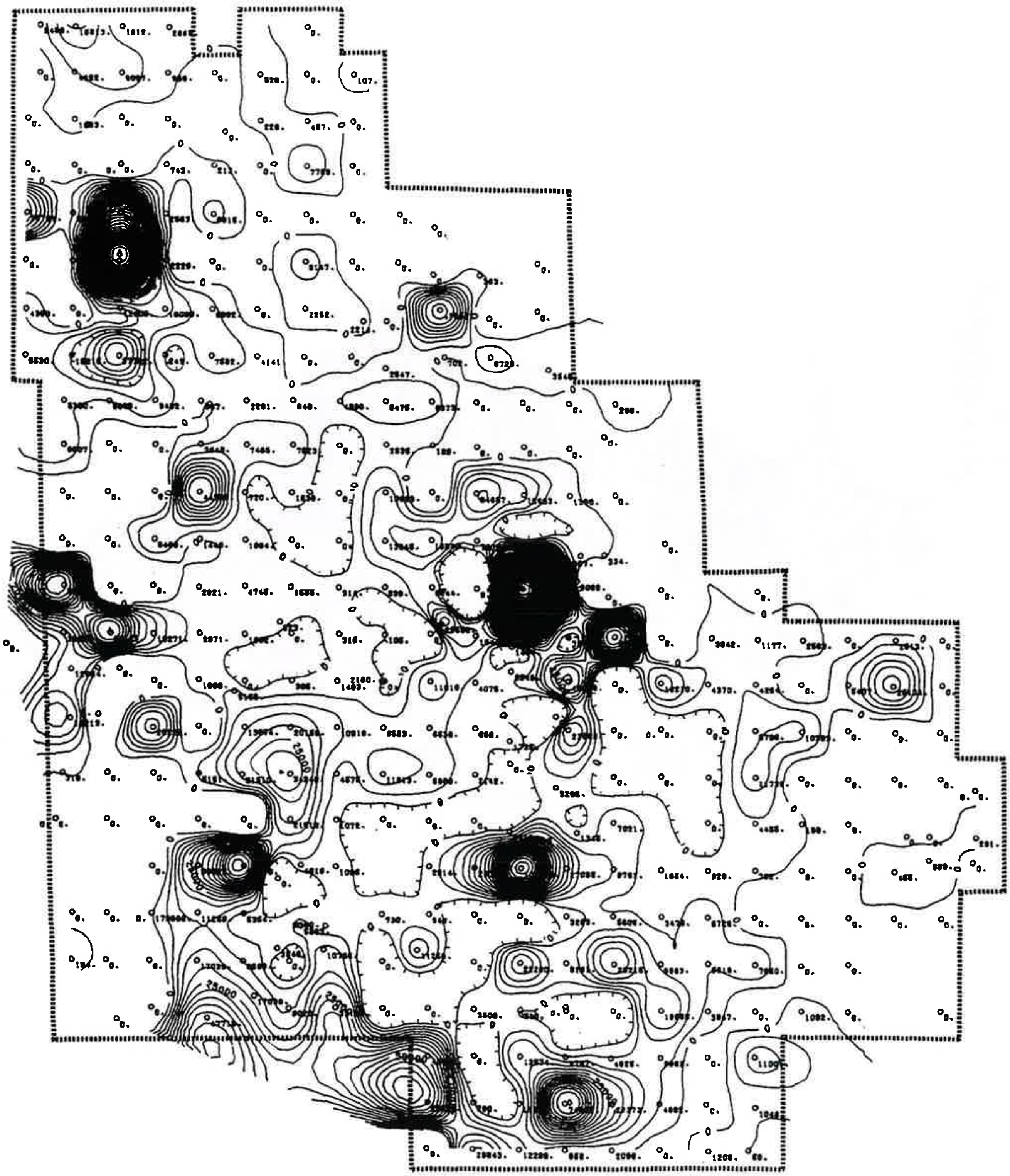
EUNICE MONUMENT SOUTH UNIT
CONTOUR ON 1981 OIL PRODUCTION
CONTOUR INTERVAL = 1000 STB
SCALE: 1"= 4000'

Figure 9



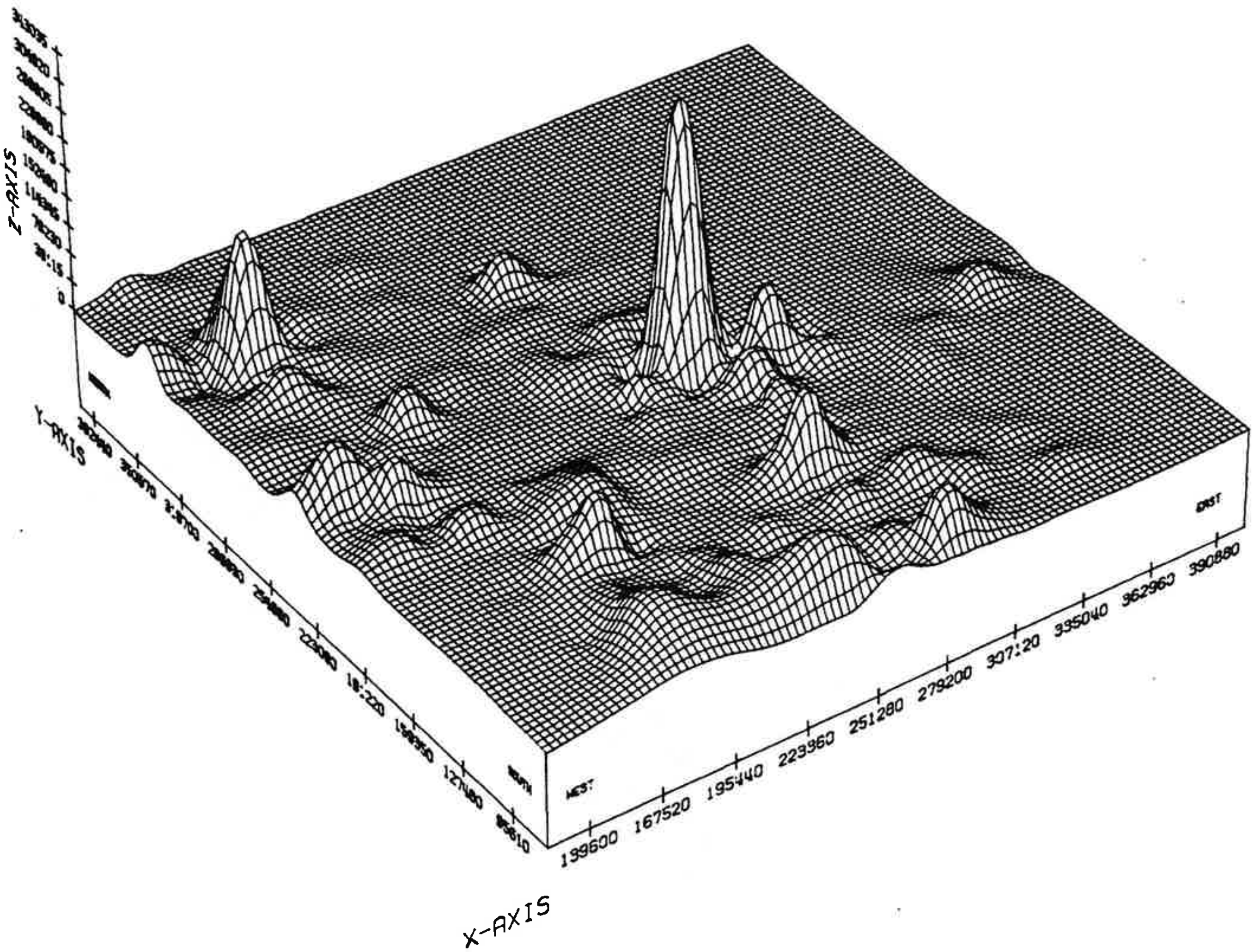
EUNICE MONUMENT SOUTH UNIT
MESH PERSPECTIVE ON 1981 OIL PRODUCTION

Figure 10



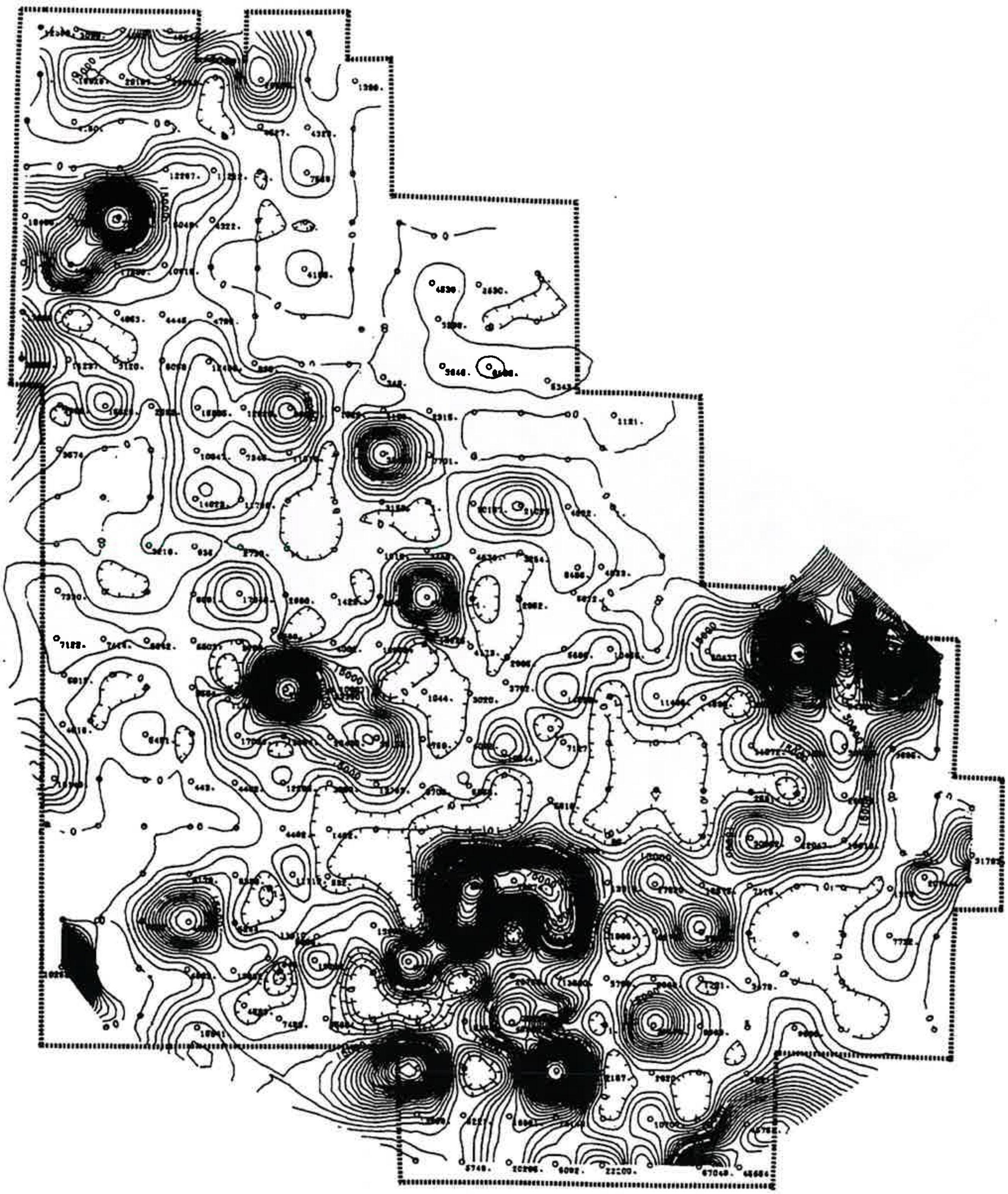
EUNICE MONUMENT SOUTH UNIT
CONTOUR ON 1981 WATER PRODUCTION
CONTOUR INTERVAL = 5000 BBL.
SCALE: 1"= 4000'

Figure 11



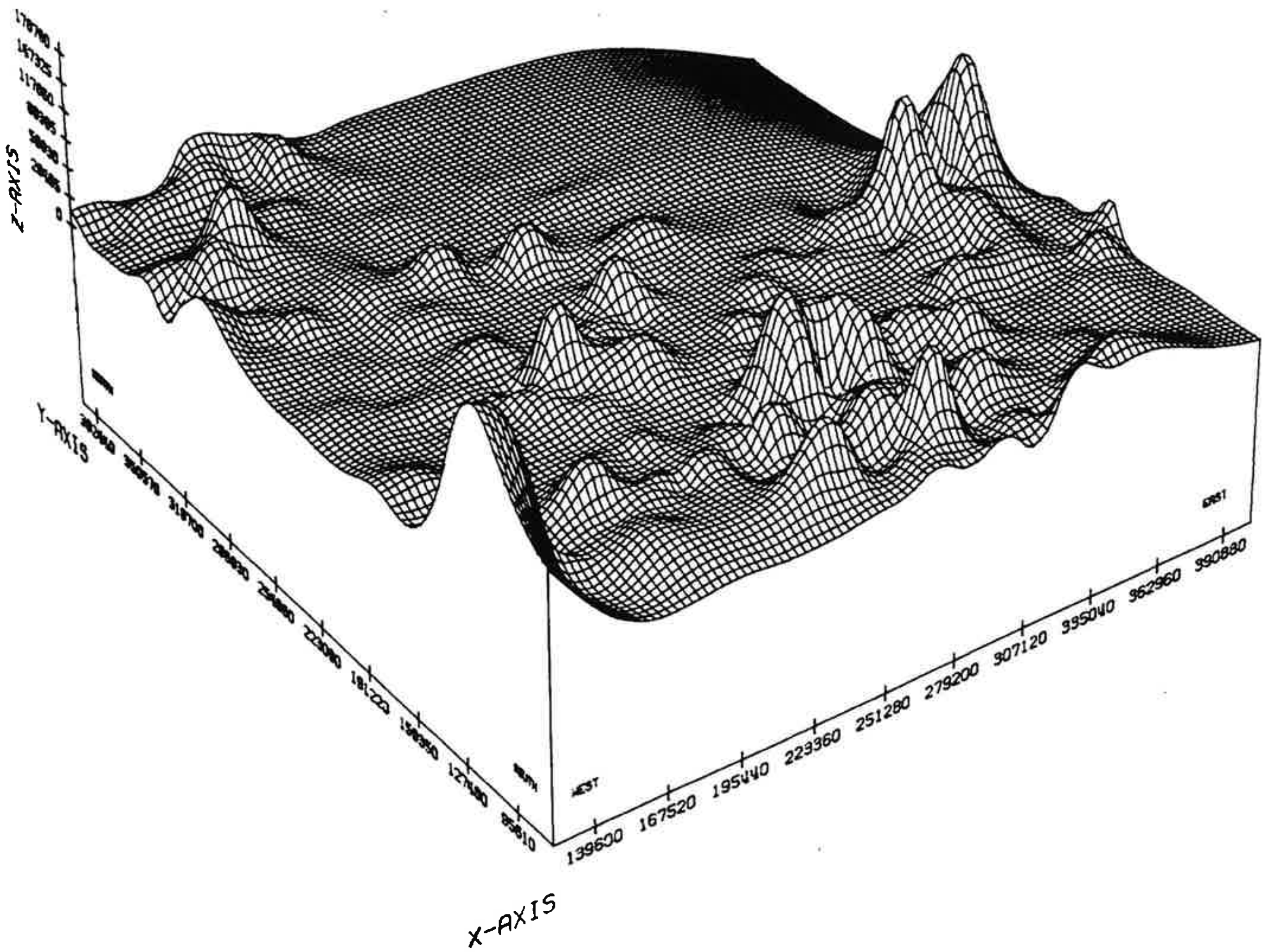
EUNICE MONUMENT SOUTH UNIT
MESH PERSPECTIVE ON 1981 WATER PRODUCTION

Figure 12



EUNICE MONUMENT SOUTH UNIT
CONTOUR ON 1981 GAS PRODUCTION
CONTOUR INTERVAL = 3000 MCF
SCALE : 1" = 4000'

Figure 13



EUNICE MONUMENT SOUTH UNIT
MESH PERSPECTIVE 1981 GAS PRODUCTION

Figure 14

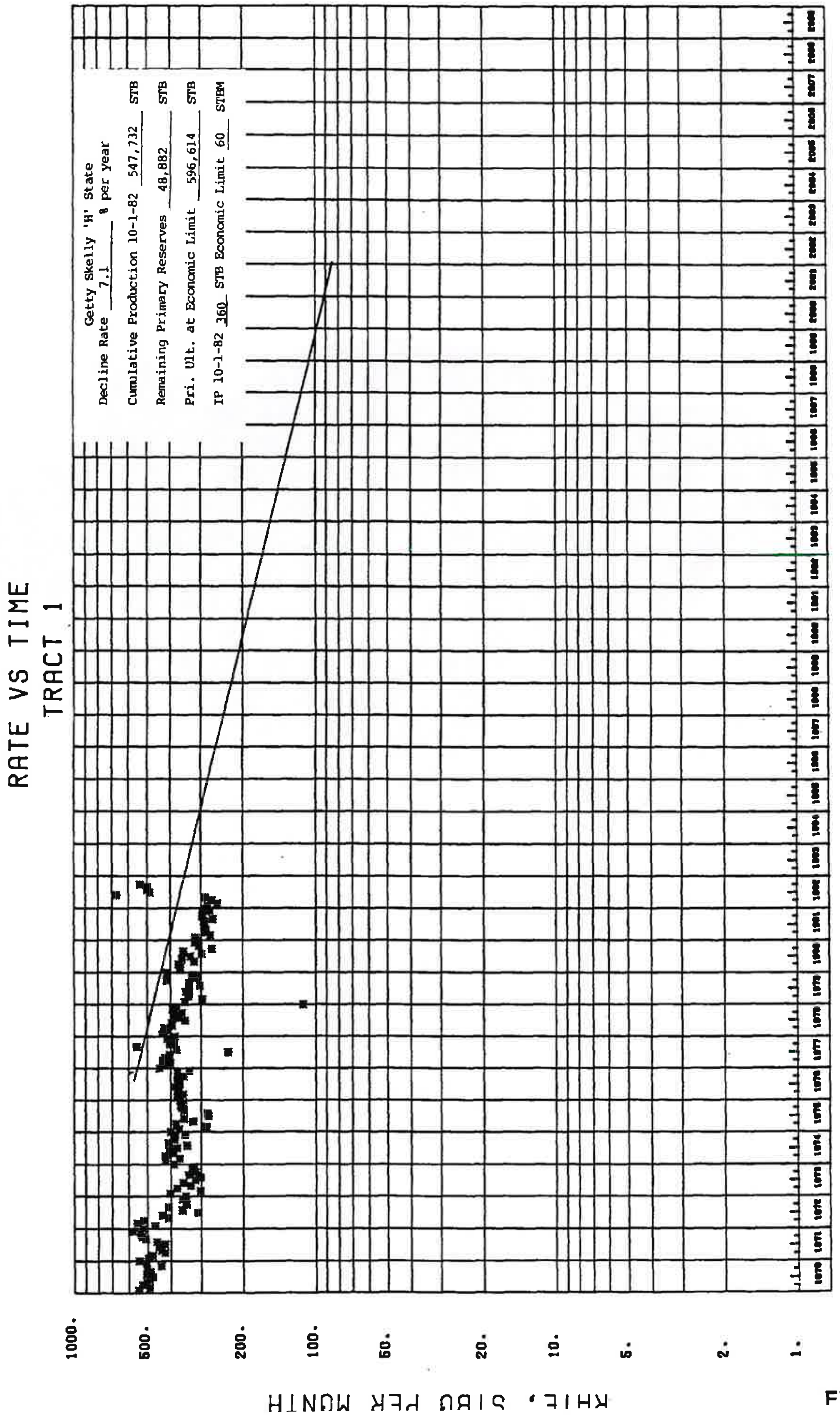

RATE VS TIME
TRACT 1
Getty Skelly 'H' State
Decline Rate 7.1 % per year
Cumulative Production 10-1-82 547,732 STB
Remaining Primary Reserves 48,882 STB
Pri. Ult. at Economic Limit 596,614 STB
IP 10-1-82 360 STB Economic Limit 60 STBM
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.
RATE, STBO PER MONTH

Figure 15

RATE VS TIME
TRACT 2

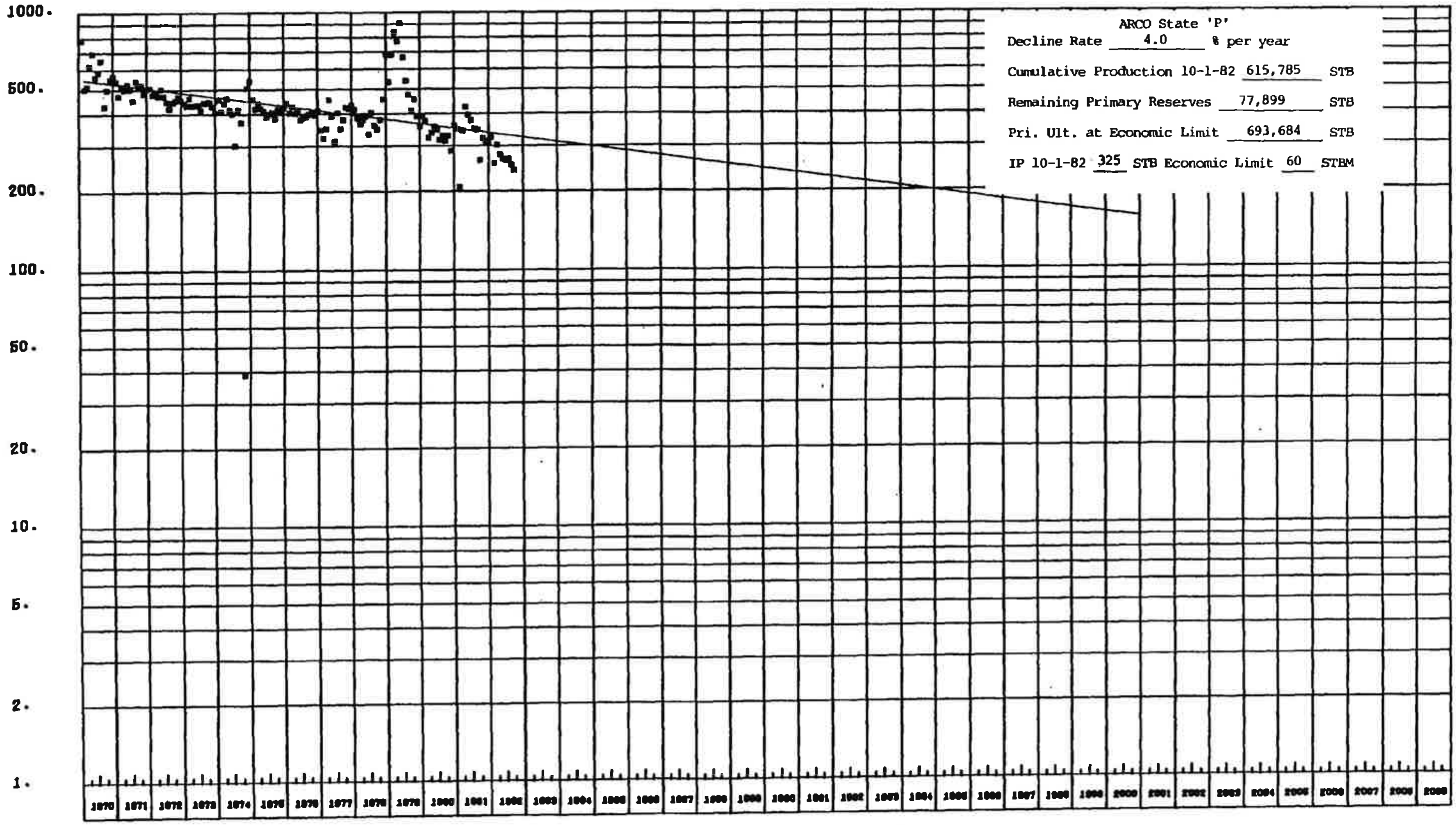


Figure 16

RATE VS TIME
TRACT 3

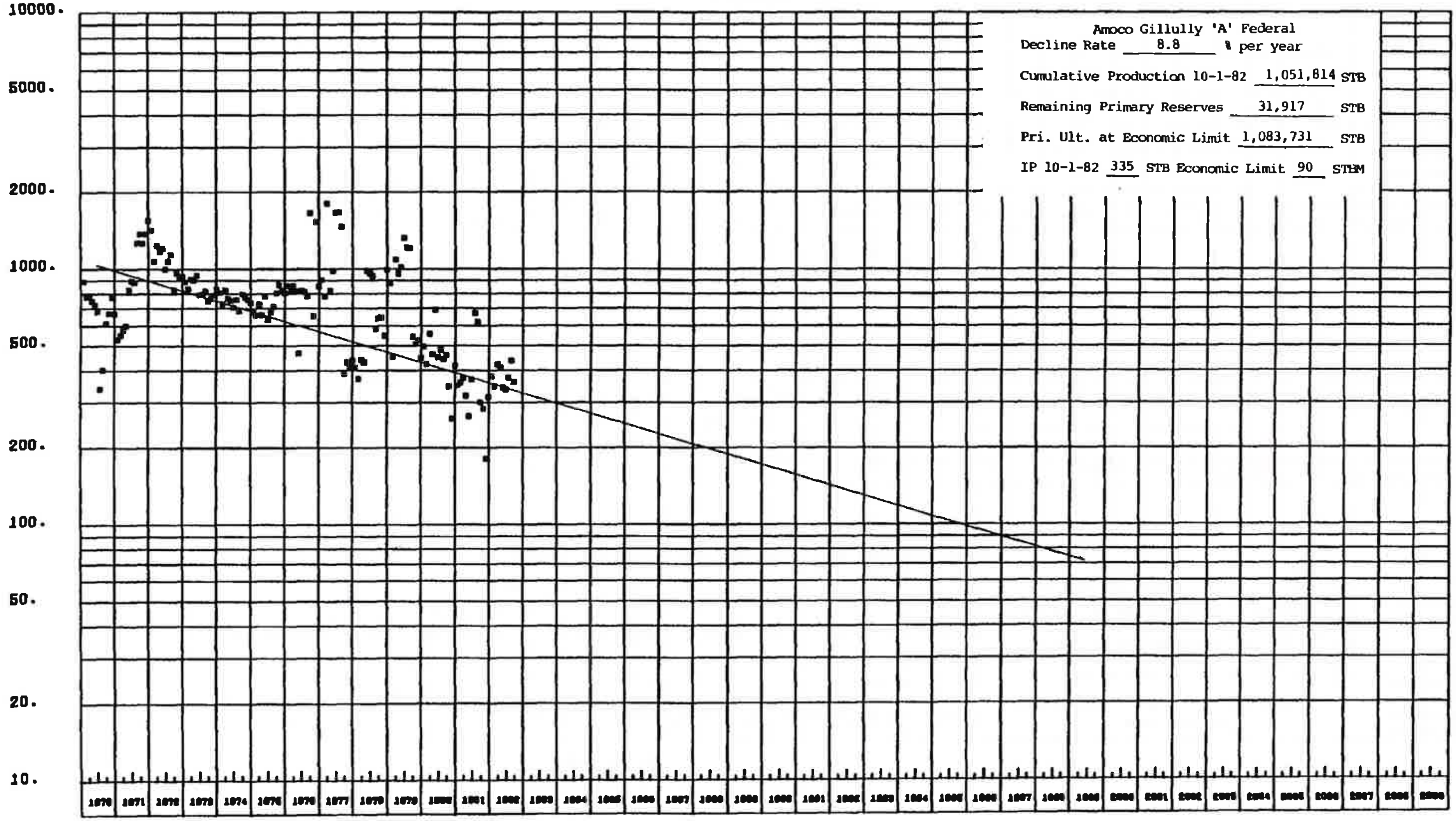


Figure 17

RATE VS TIME
TRACT 5

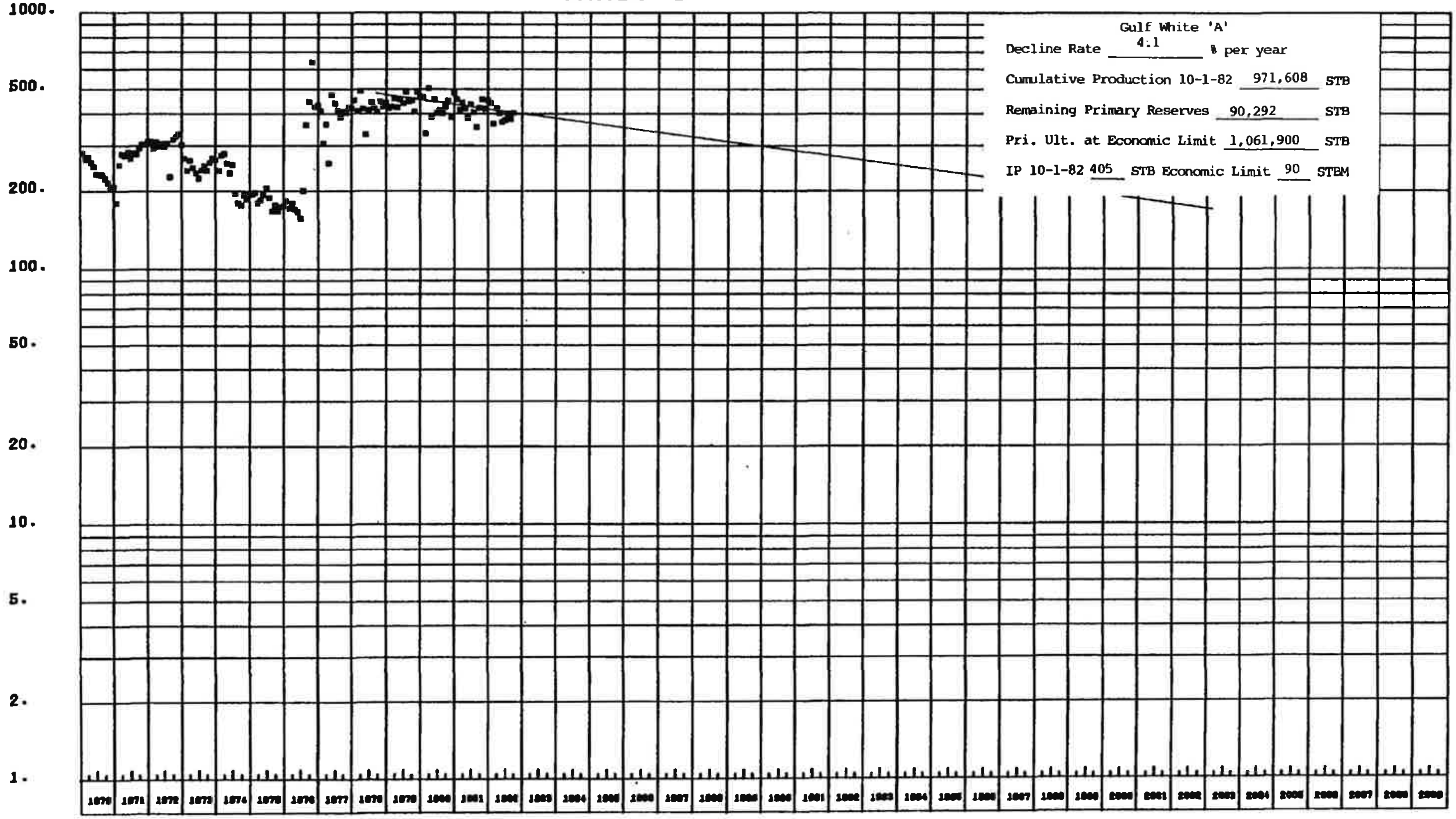


Figure 18

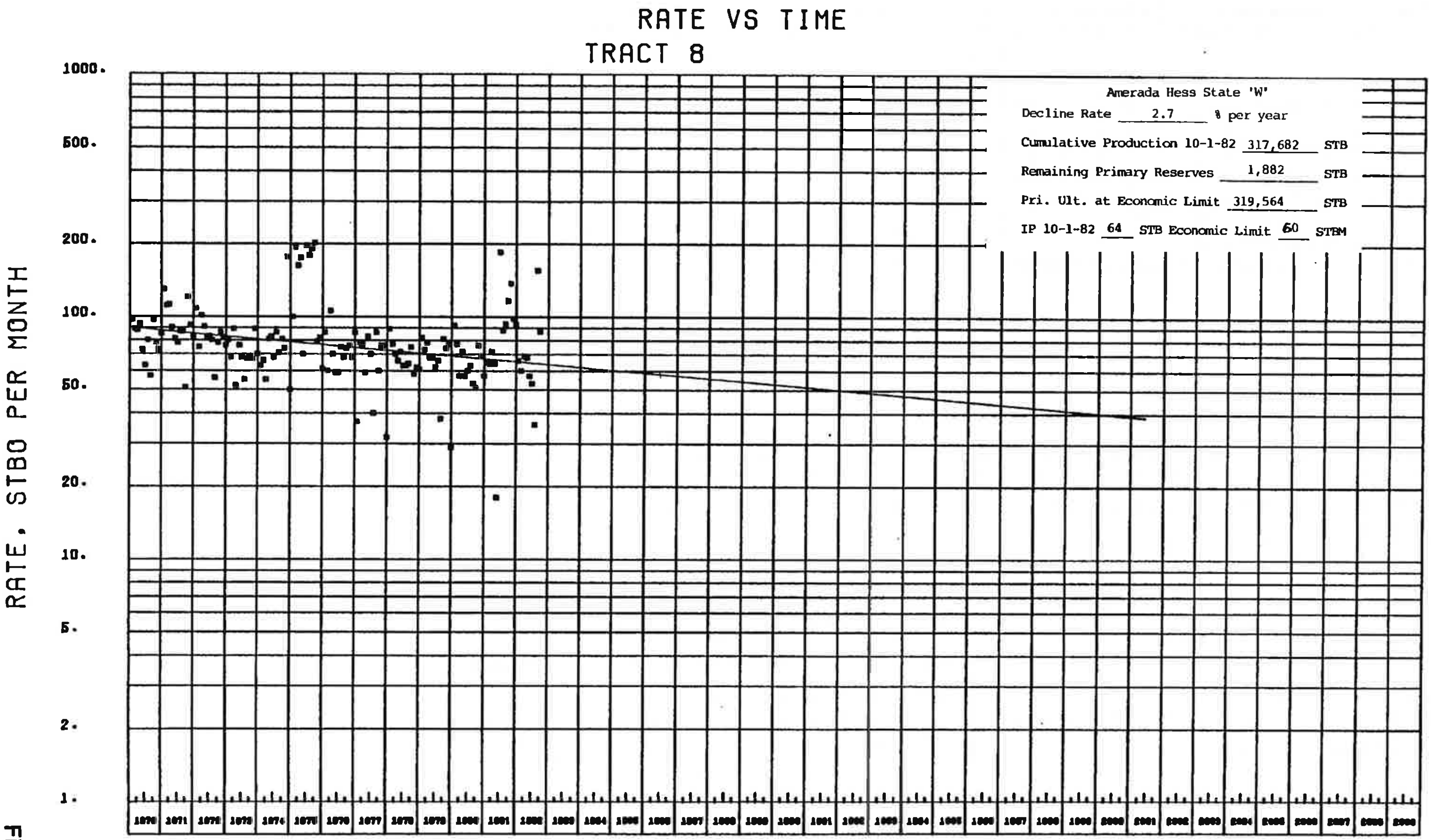

RATE VS TIME
TRACT 8
Amerada Hess State 'W'
Decline Rate 2.7 % per year
Cumulative Production 10-1-82 317,682 STB
Remaining Primary Reserves 1,882 STB
Pri. Ult. at Economic Limit 319,564 STB
IP 10-1-82 64 STB Economic Limit 60 STBM
RATE, STBO PER MONTH
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.

Figure 19

RATE VS TIME
TRACT 10

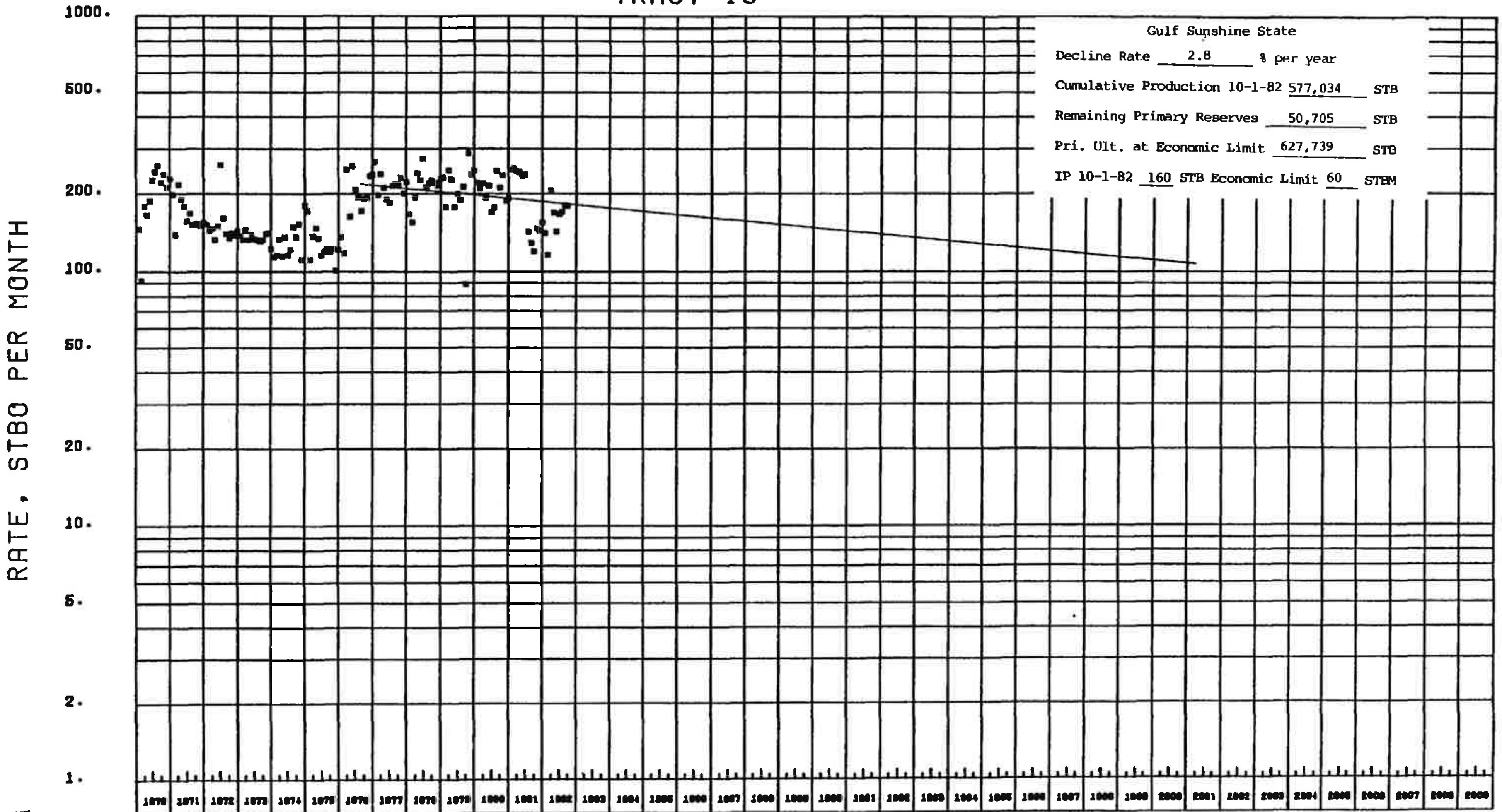


Figure 20

RATE VS TIME
TRACT 12

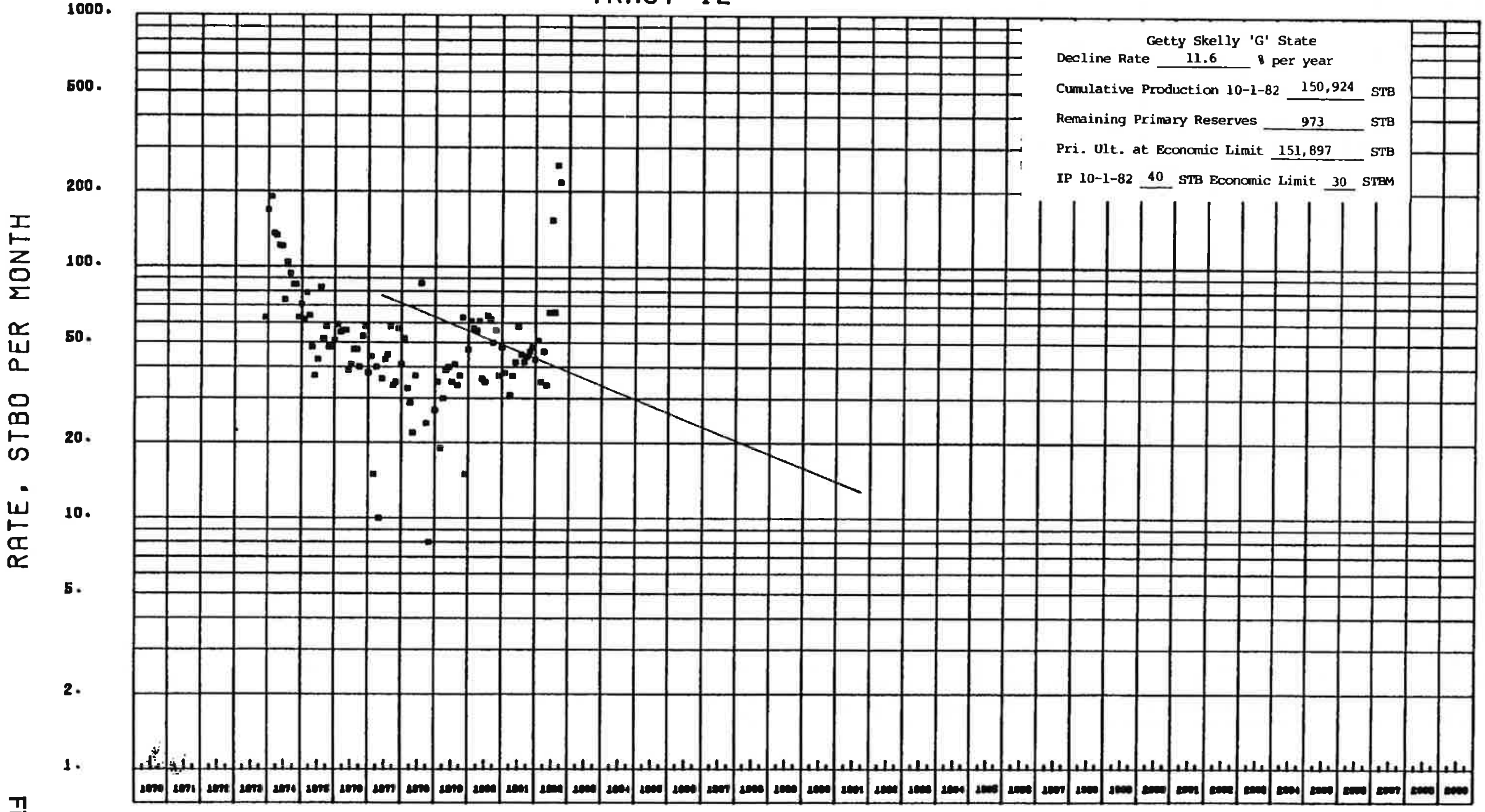


Figure 21

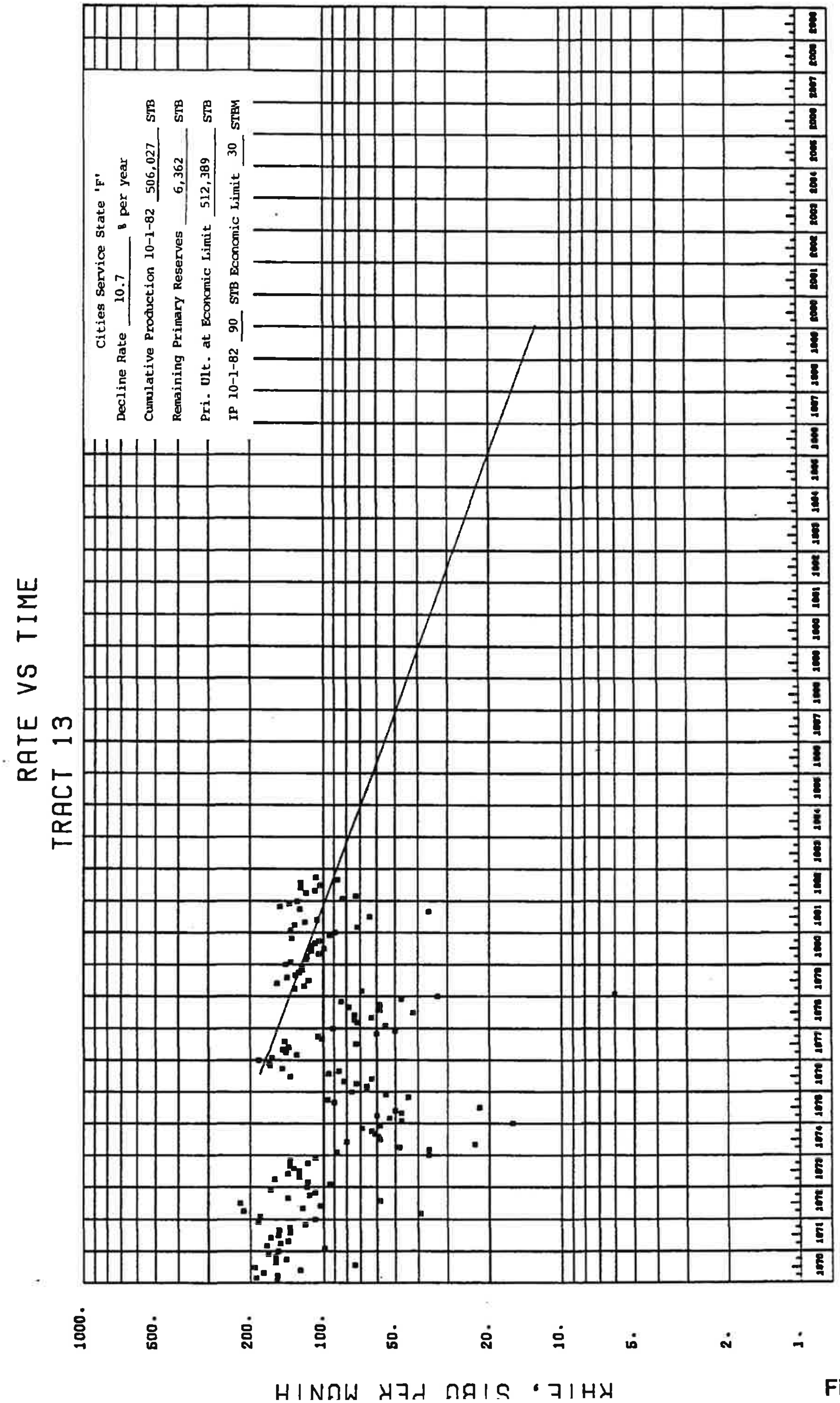

RATE VS TIME
TRACT 13
Cities Service State 'F'
Decline Rate 10.7 % per year
Cumulative Production 10-1-82 506,027 STB
Remaining Primary Reserves 6,362 STB
Pri. Ult. at Economic Limit 512,389 STB
IP 10-1-82 90 STB Economic Limit 30 STBM
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.
RATE, STBO PER MONTH

Figure 22

RATE VS TIME
TRACT 17

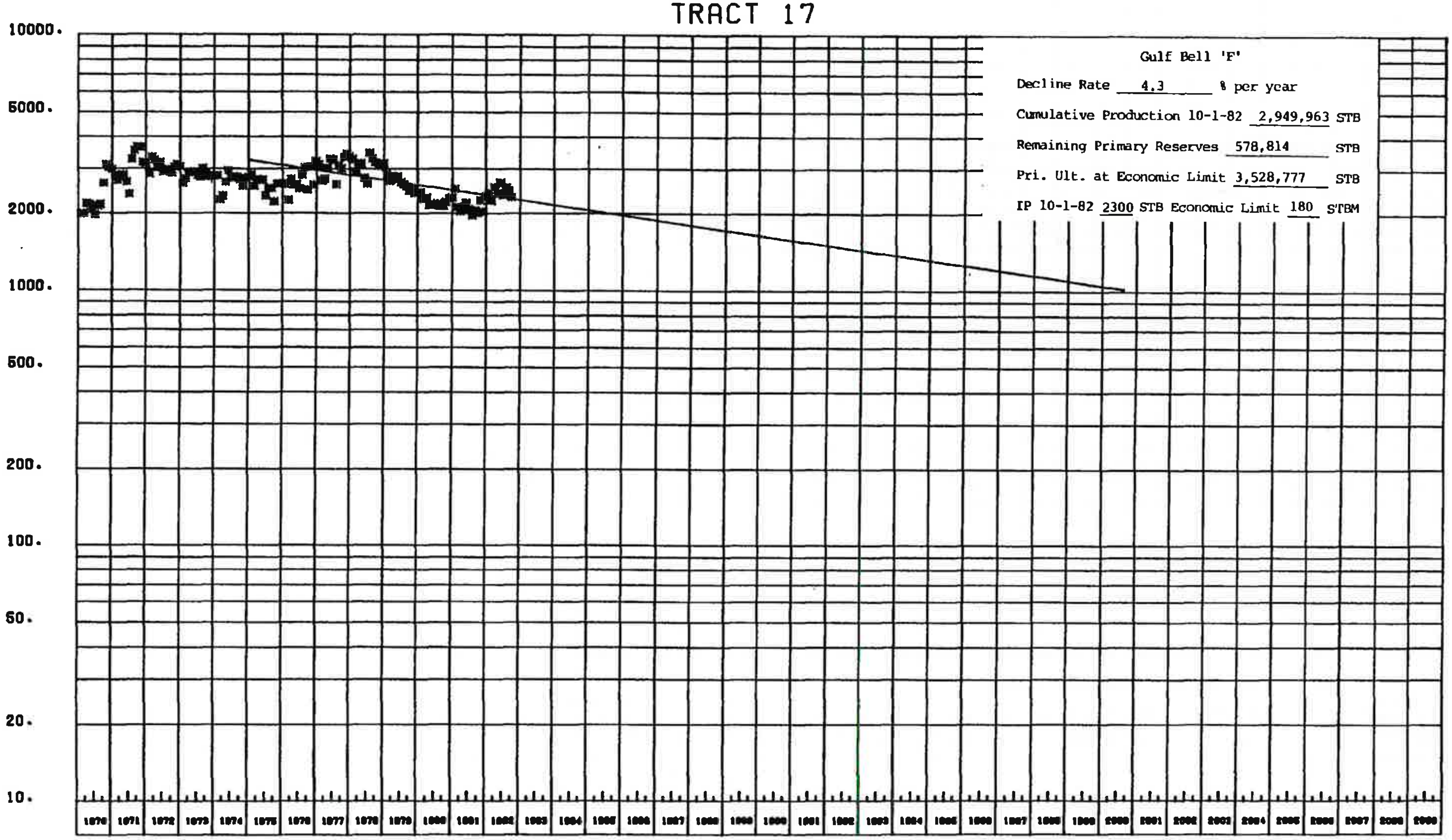


Figure 23

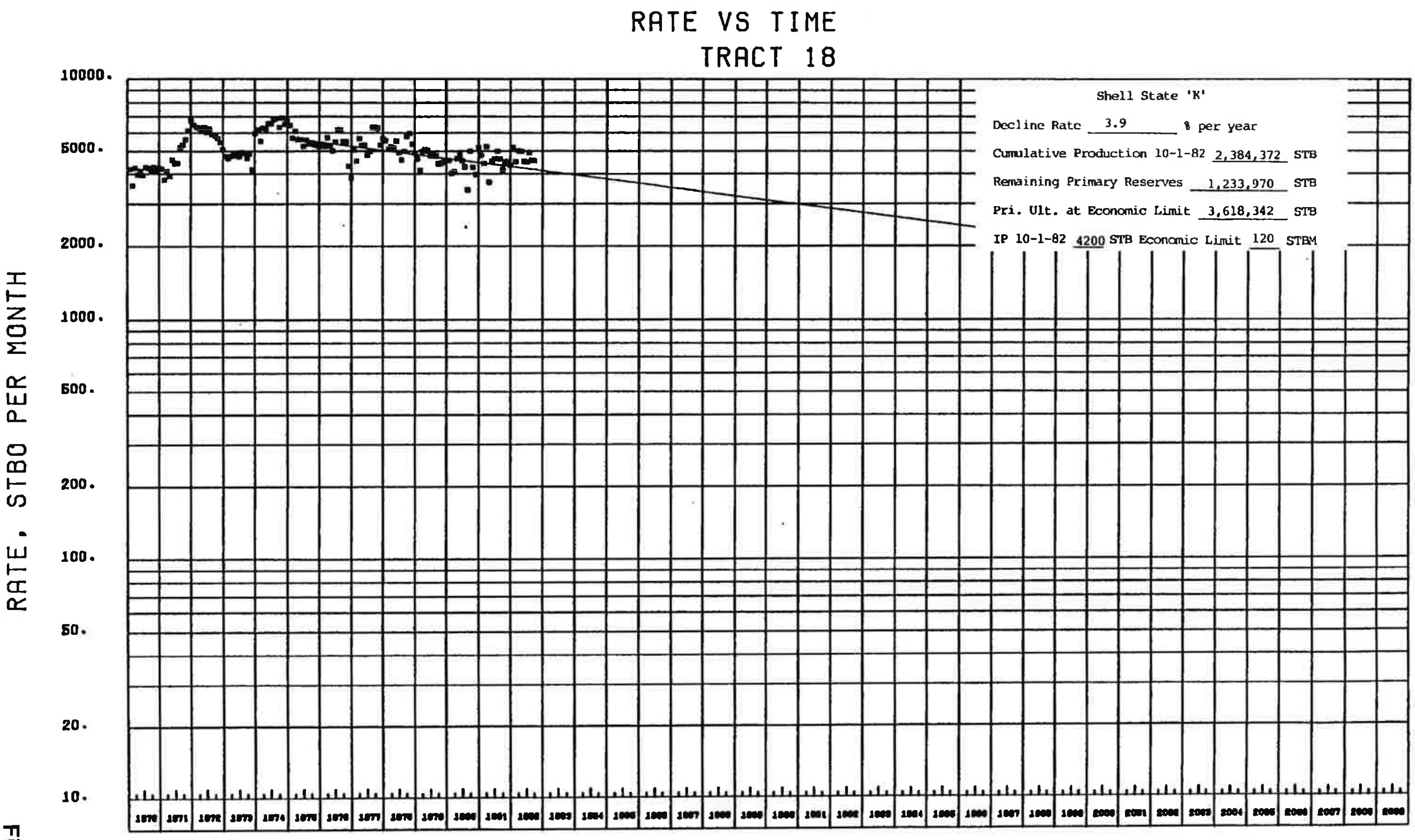

RATE VS TIME
TRACT 18
RATE, STBO PER MONTH
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.
Shell State 'K'
Decline Rate 3.9 % per year
Cumulative Production 10-1-82 2,384,372 STB
Remaining Primary Reserves 1,233,970 STB
Pri. Ult. at Economic Limit 3,618,342 STB
IP 10-1-82 4200 STB Economic Limit 120 STBM

Figure 24

RATE VS TIME
TRACT 19

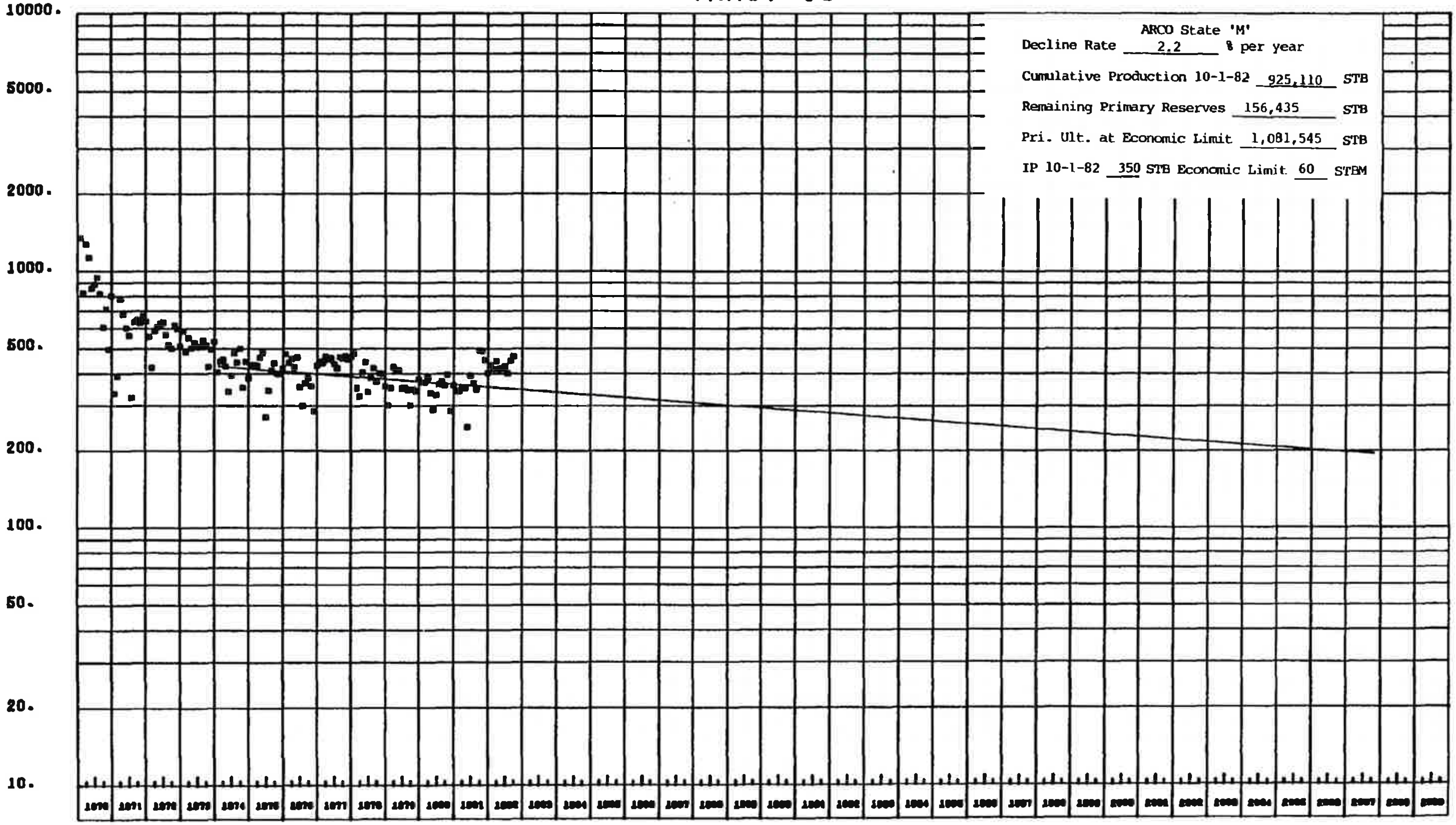


Figure 25

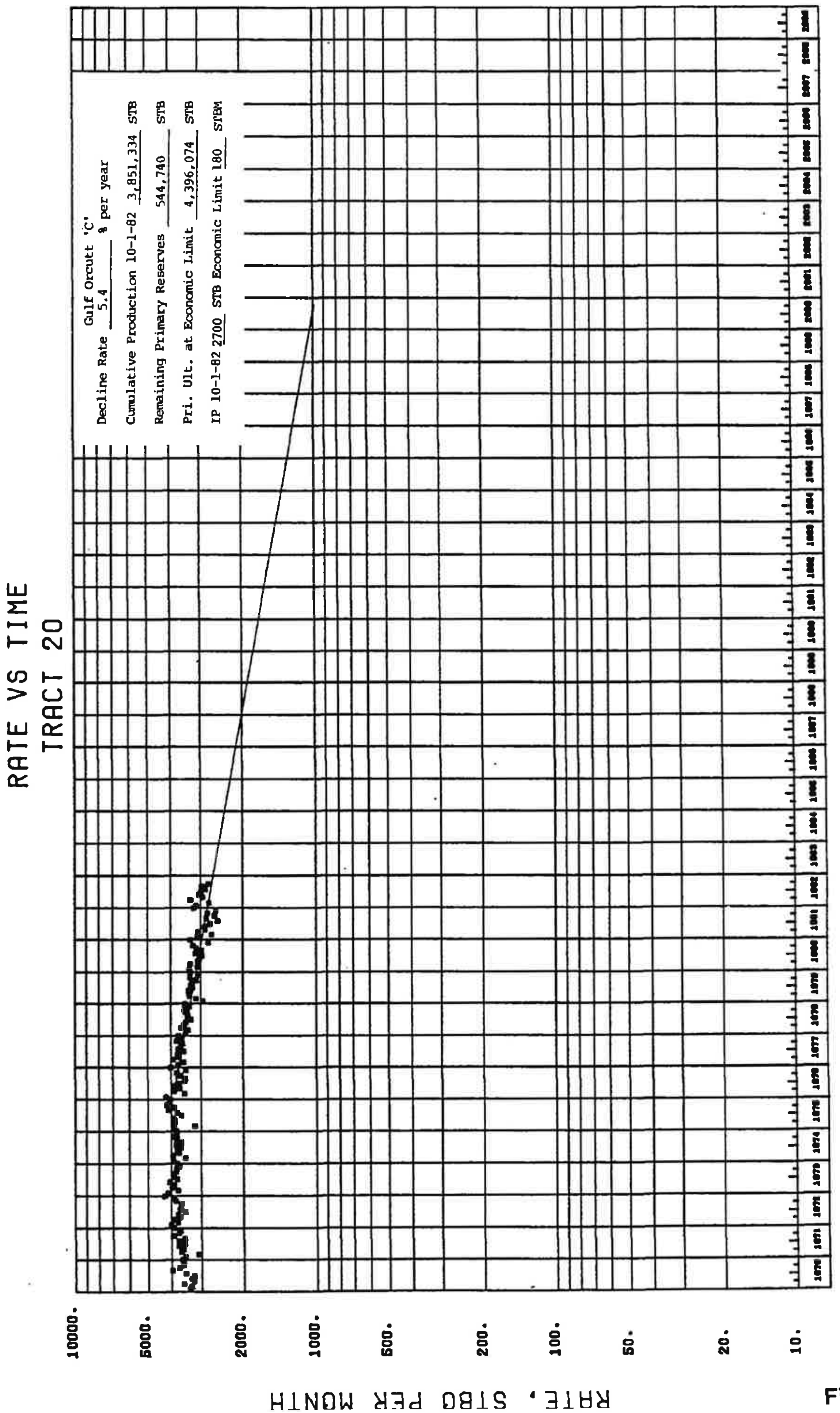

RATE VS TIME
TRACT 20
Gulf Orcutt 'C'
Decline Rate 5.4 % per year
Cumulative Production 10-1-82 3,851,334 STB
Remaining Primary Reserves 544,740 STB
Pri. Ult. at Economic Limit 4,396,074 STB
IP 10-1-82 2700 STB Economic Limit 180 STBM
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.
RATE, STBO PER MONTH

Figure 26

RATE VS TIME
TRACT 21

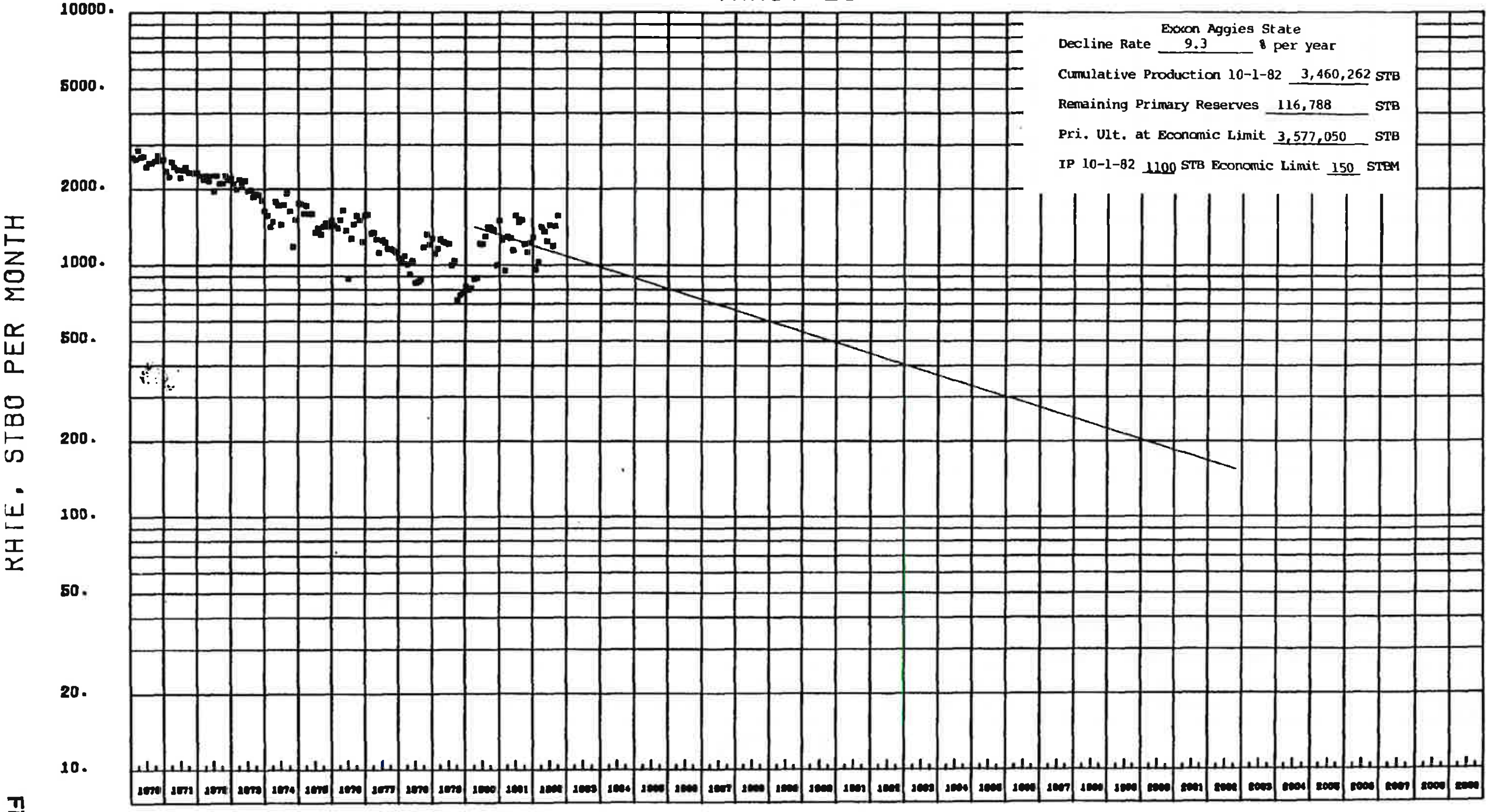


Figure 27

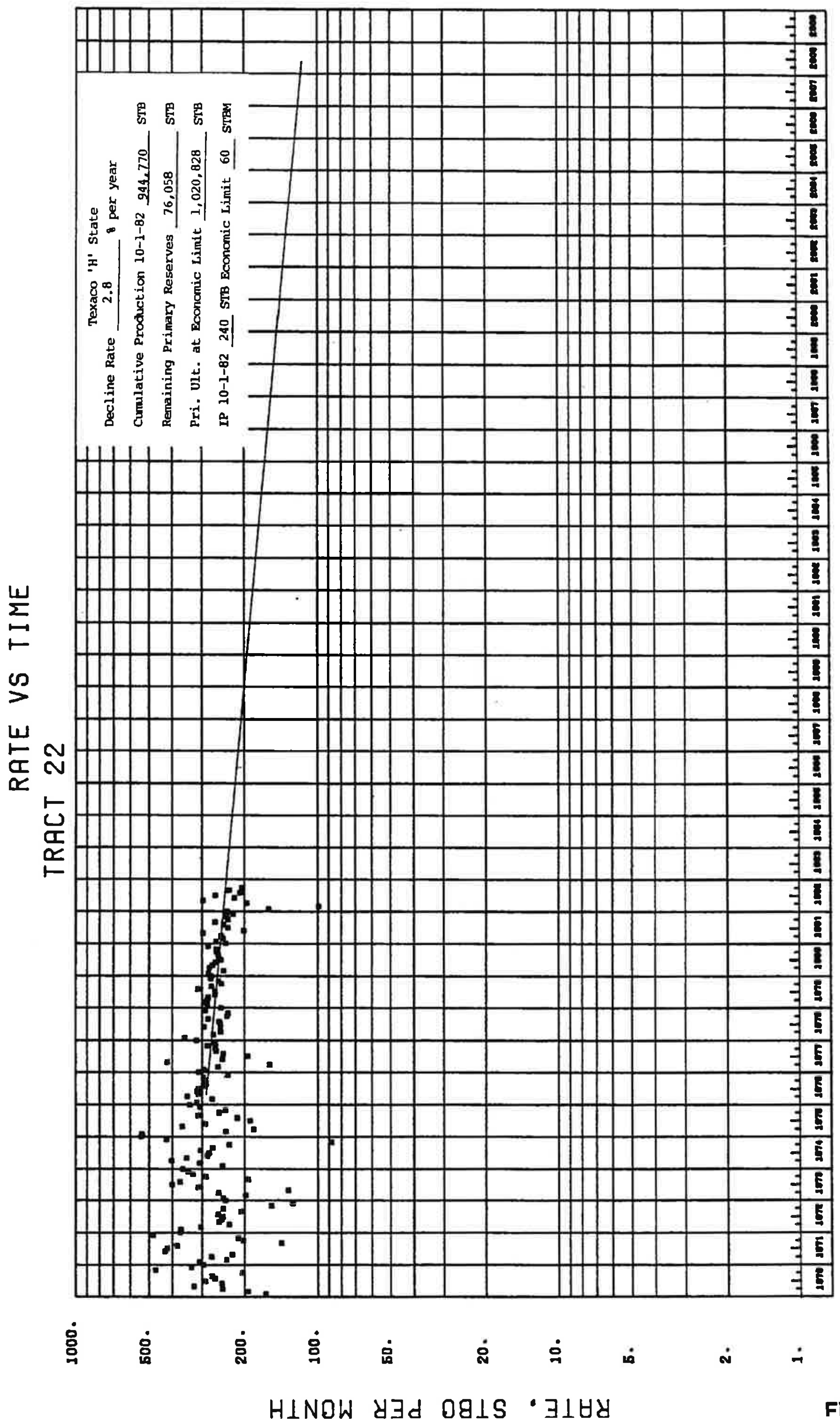

RATE VS TIME
TRACT 22
Texaco 'H' State
Decline Rate 2.8 % per year
Cumulative Production 10-1-82 944,770 STB
Remaining Primary Reserves 76,058 STB
Pri. Ult. at Economic Limit 1,020,828 STB
IP 10-1-82 240 STB Economic Limit 60 STBM
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.
RATE, STBO PER MONTH

Figure 28

RATE VS TIME

TRACT 24

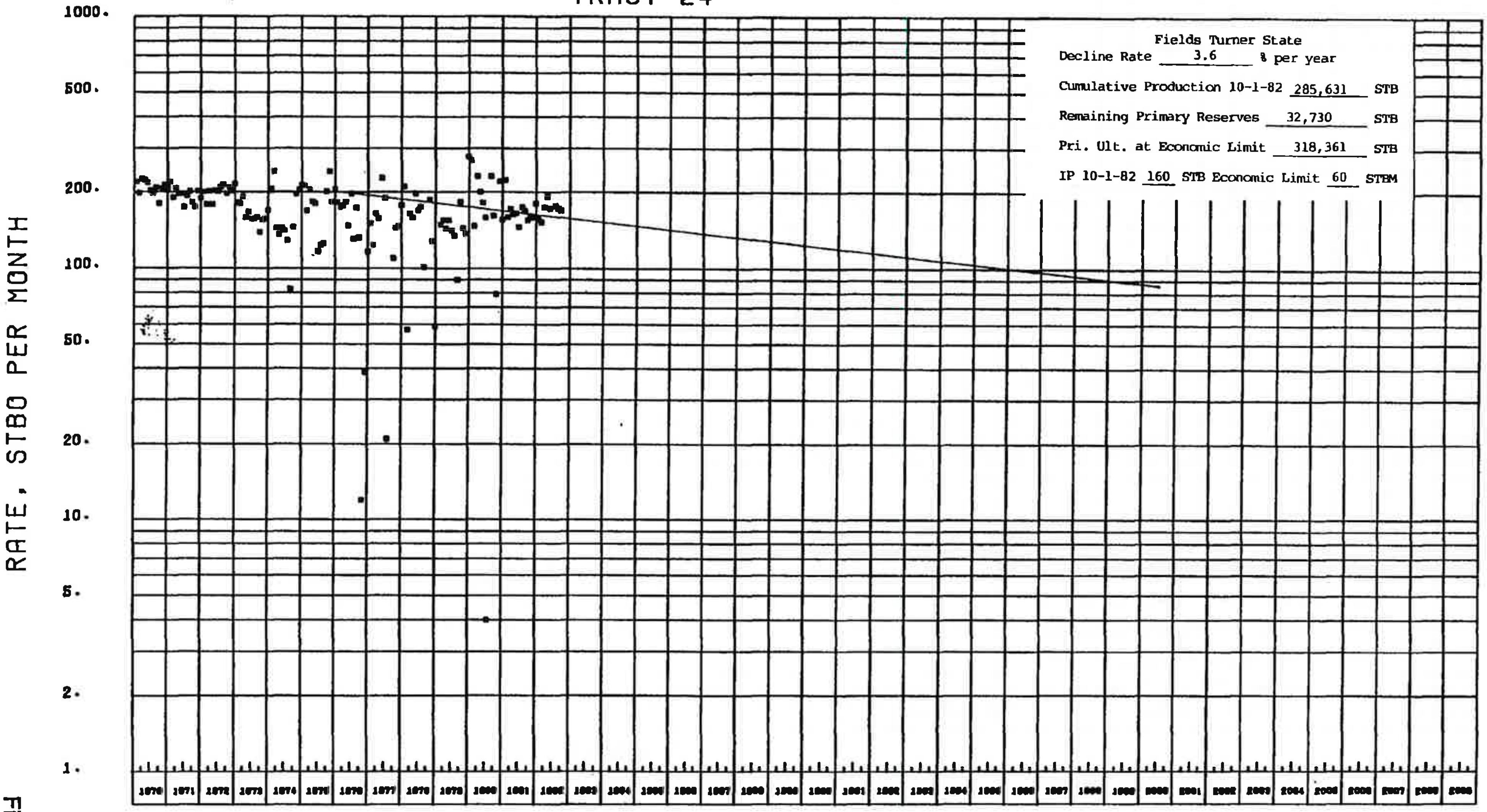


Figure 29

RATE VS TIME

TRACT 26

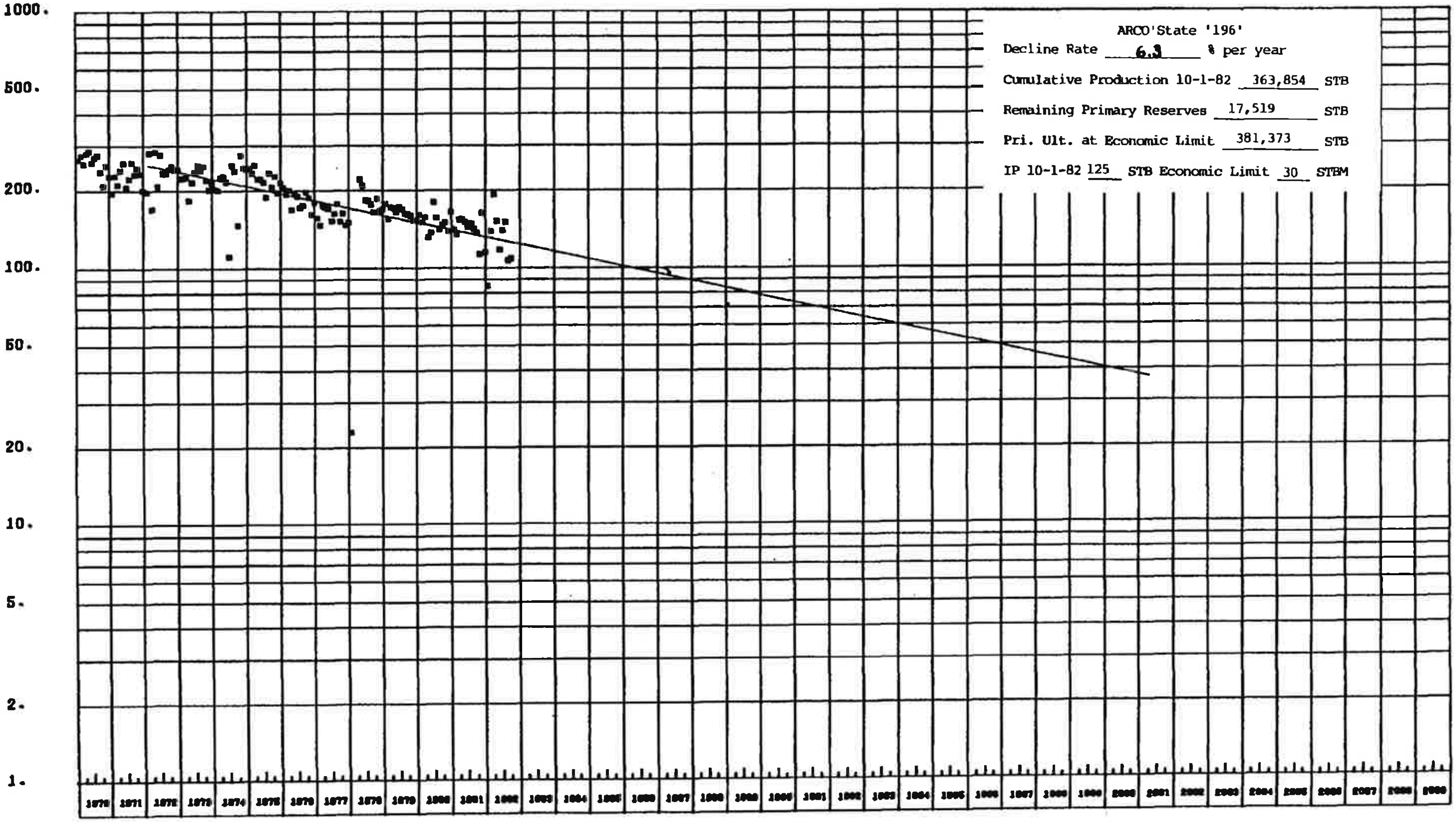


Figure 30

RATE VS TIME
TRACT 27

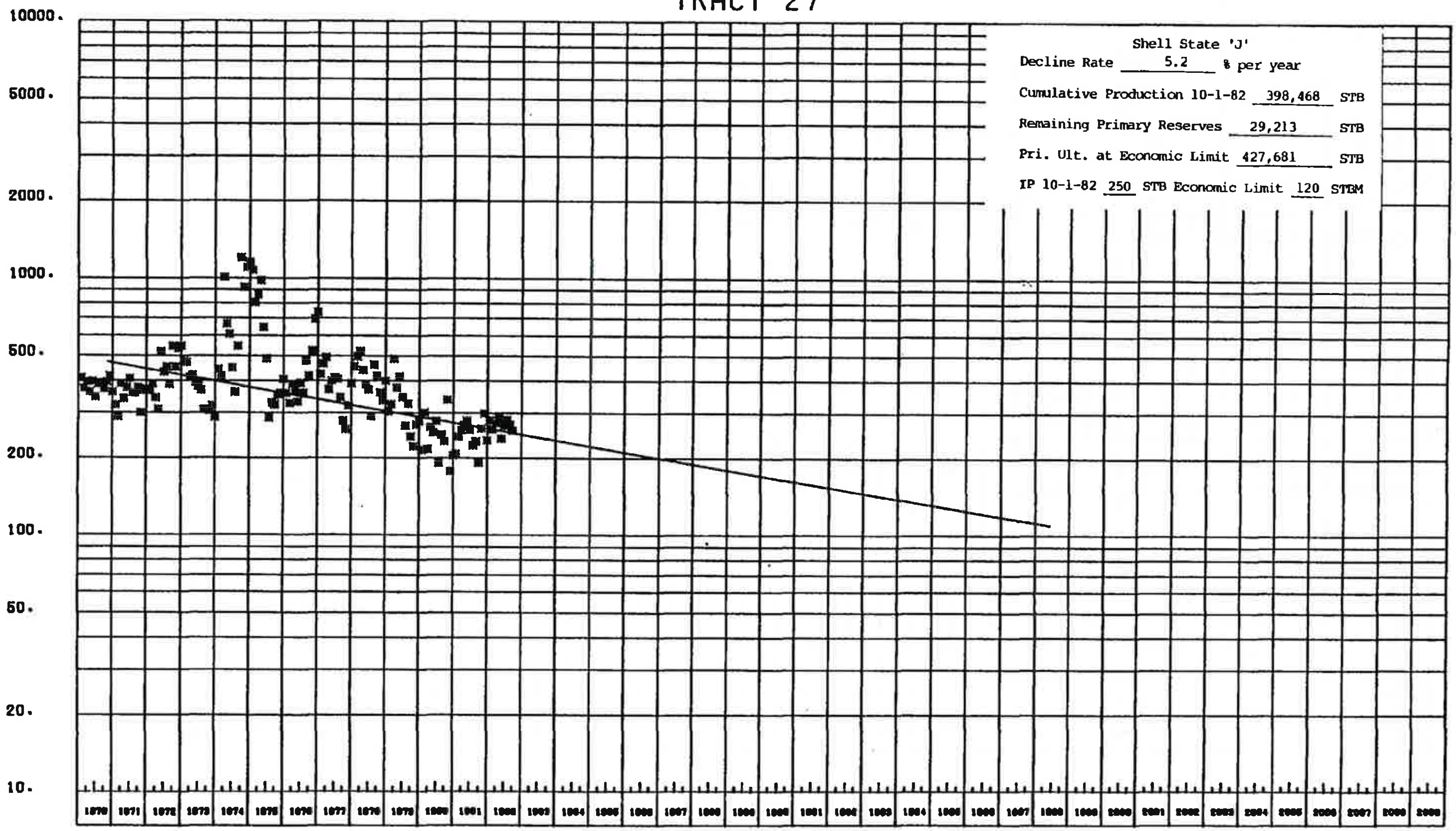


Figure 31

RATE VS TIME
TRACT 28

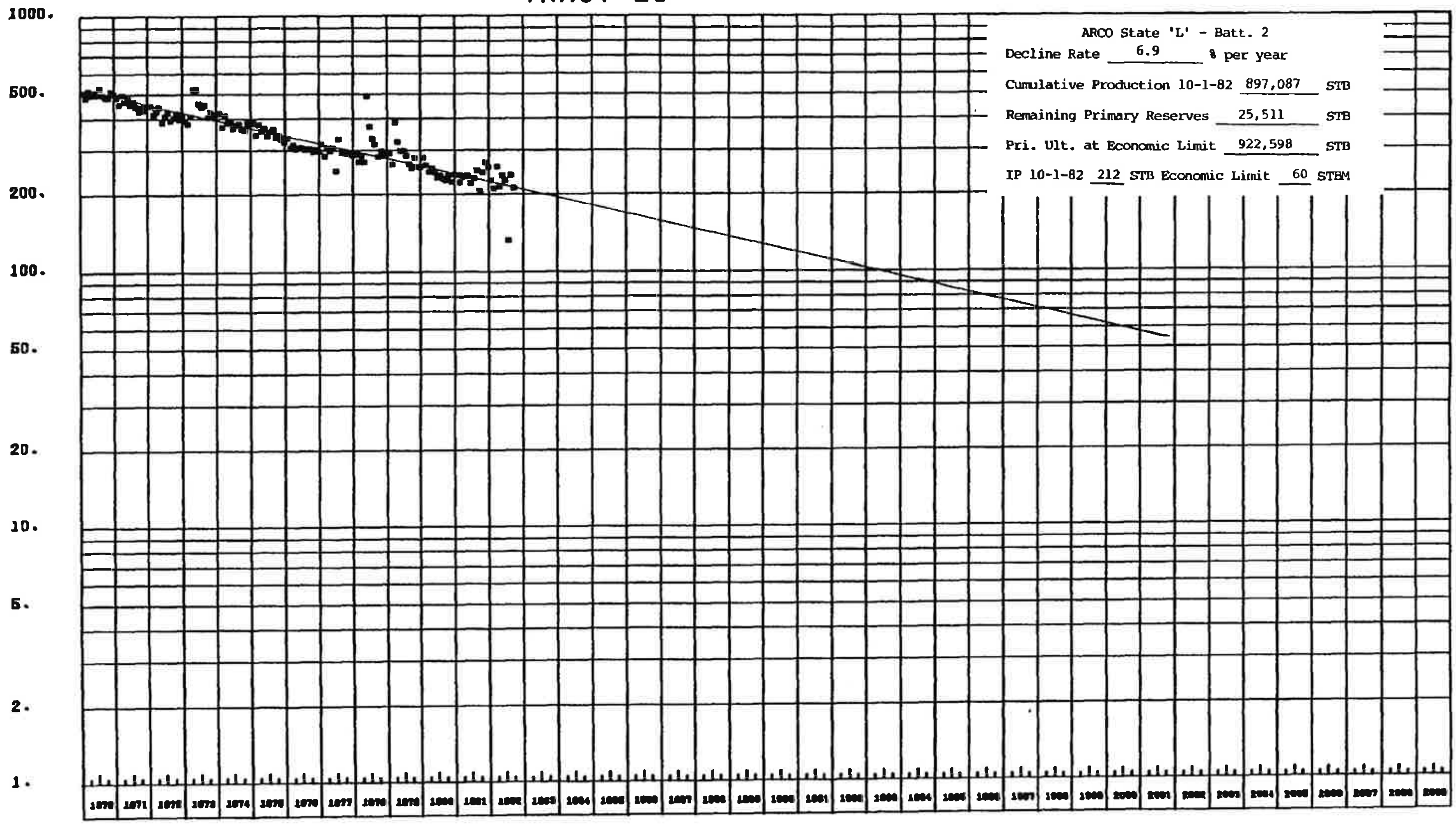


Figure 32

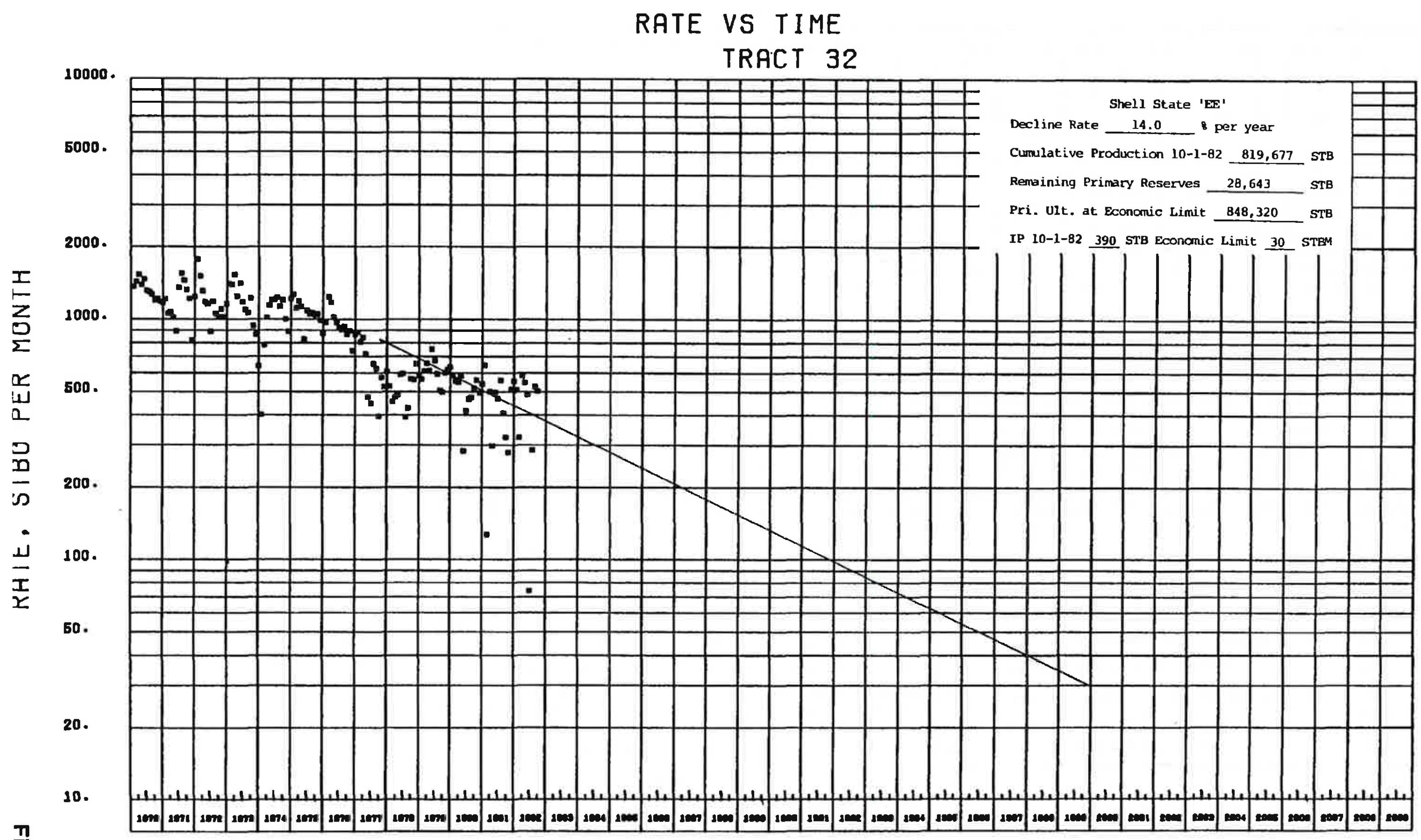

RATE VS TIME
TRACT 32
Shell State 'EE'
Decline Rate 14.0 % per year
Cumulative Production 10-1-82 819,677 STB
Remaining Primary Reserves 28,643 STB
Pri. Ult. at Economic Limit 848,320 STB
IP 10-1-82 390 STB Economic Limit 30 STBM
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.
RATE, STBO PER MONTH

Figure 33

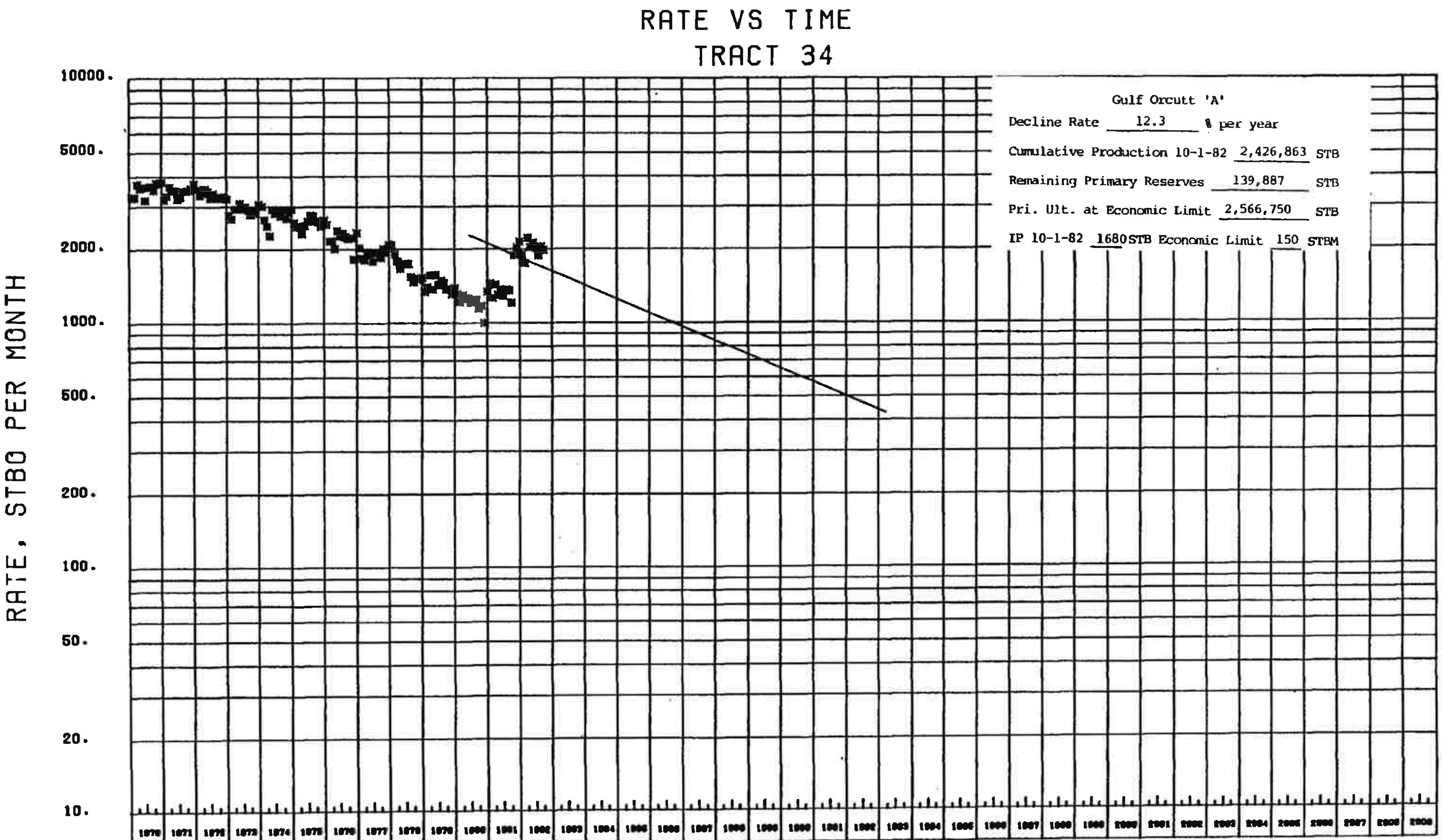

RATE VS TIME
TRACT 34
Gulf Orcutt 'A'
Decline Rate 12.3 % per year
Cumulative Production 10-1-82 2,426,863 STB
Remaining Primary Reserves 139,887 STB
Pri. Ult. at Economic Limit 2,566,750 STB
IP 10-1-82 1680 STB Economic Limit 150 STBM
RATE, STBO PER MONTH
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.

Figure 34

RATE VS TIME
TRACT 35

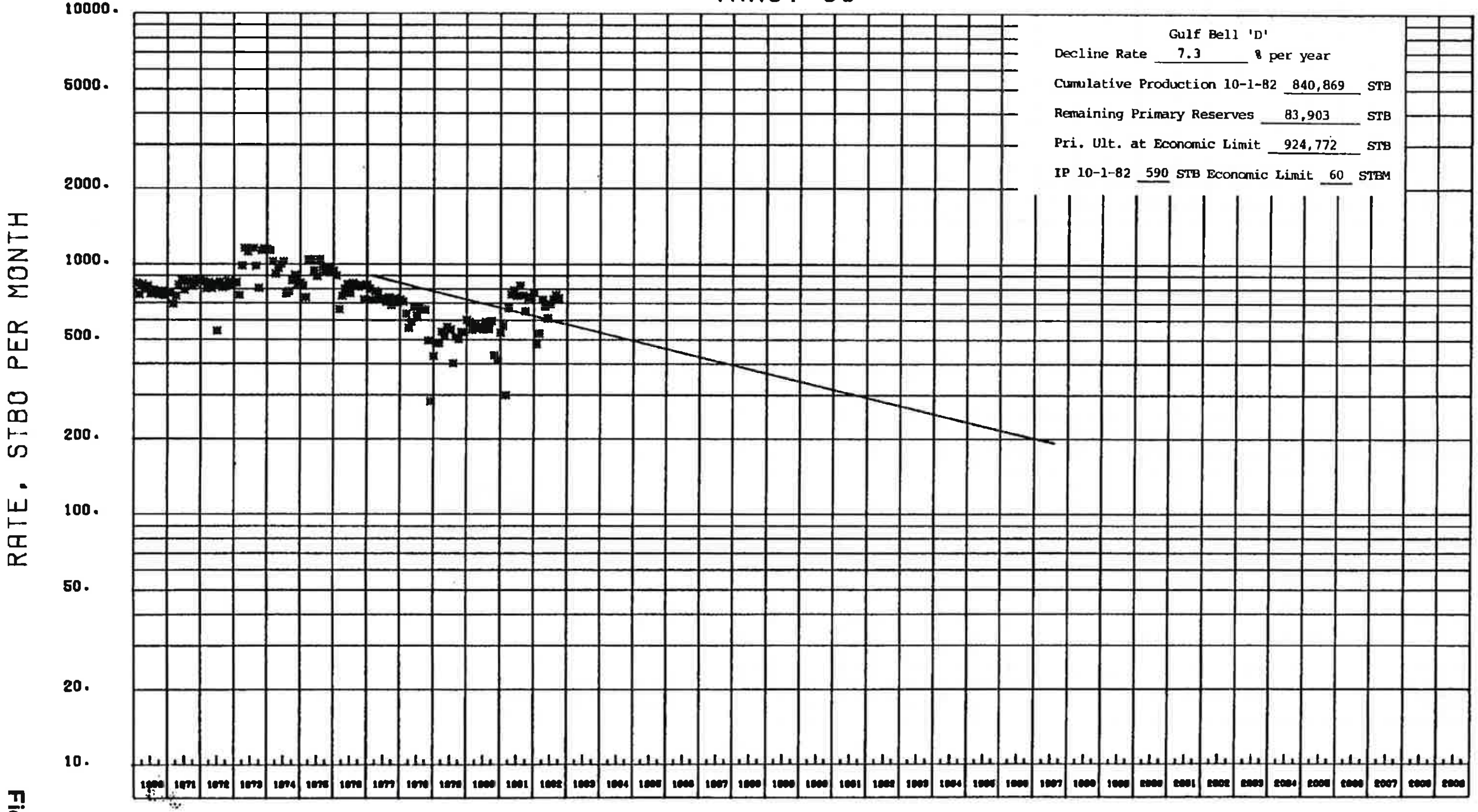


Figure 35

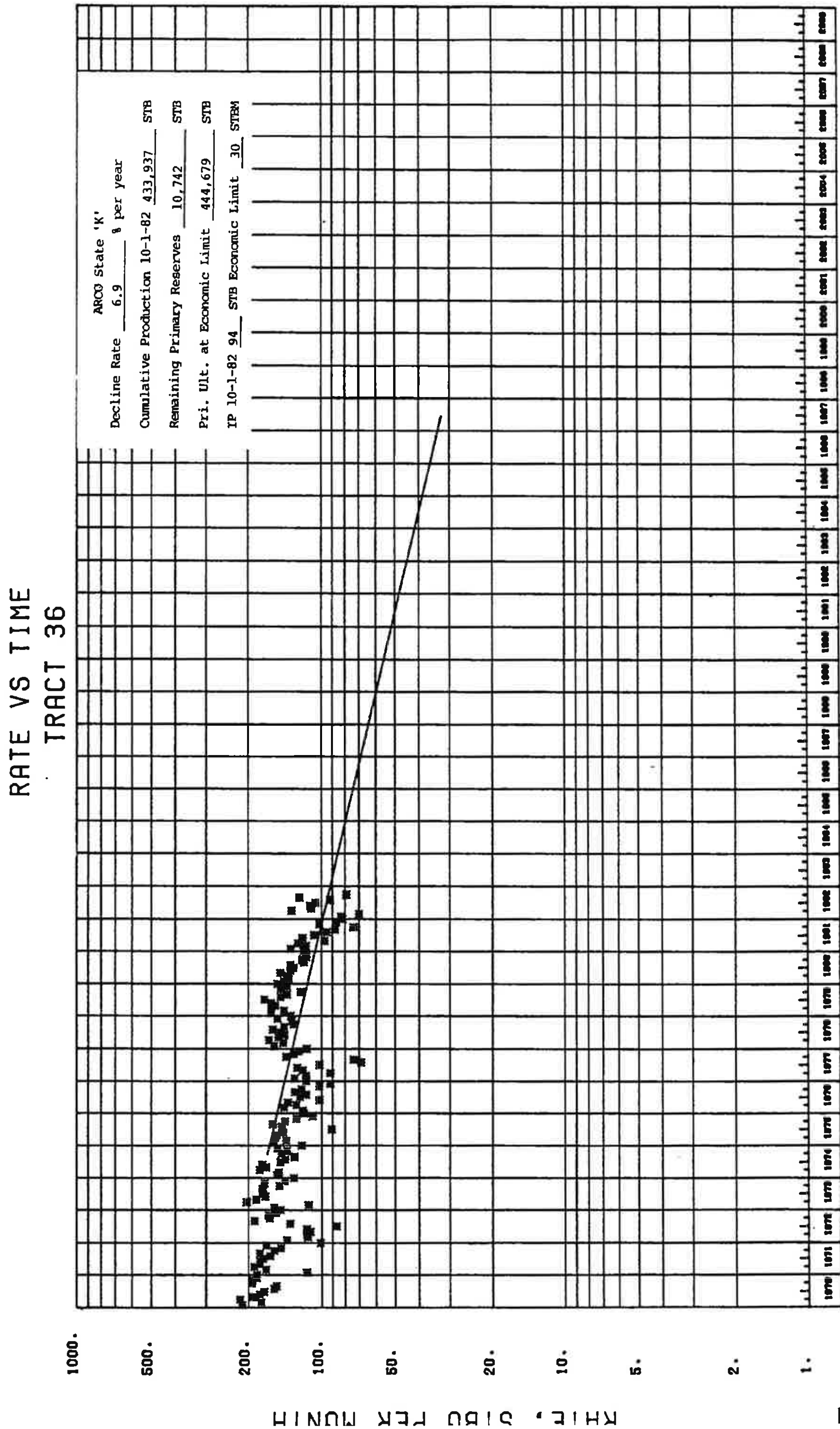

RATE VS TIME
TRACT 36
ARCO State 'K'
Decline Rate 6.9 % per year
Cumulative Production 10-1-82 433,937 STB
Remaining Primary Reserves 10,742 STB
Pri. Ult. at Economic Limit 444,679 STB
IP 10-1-82 94 STB Economic Limit 30 STBM
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.
RATE, STBO PER MONTH

Figure 36

RATE VS TIME
TRACT 37

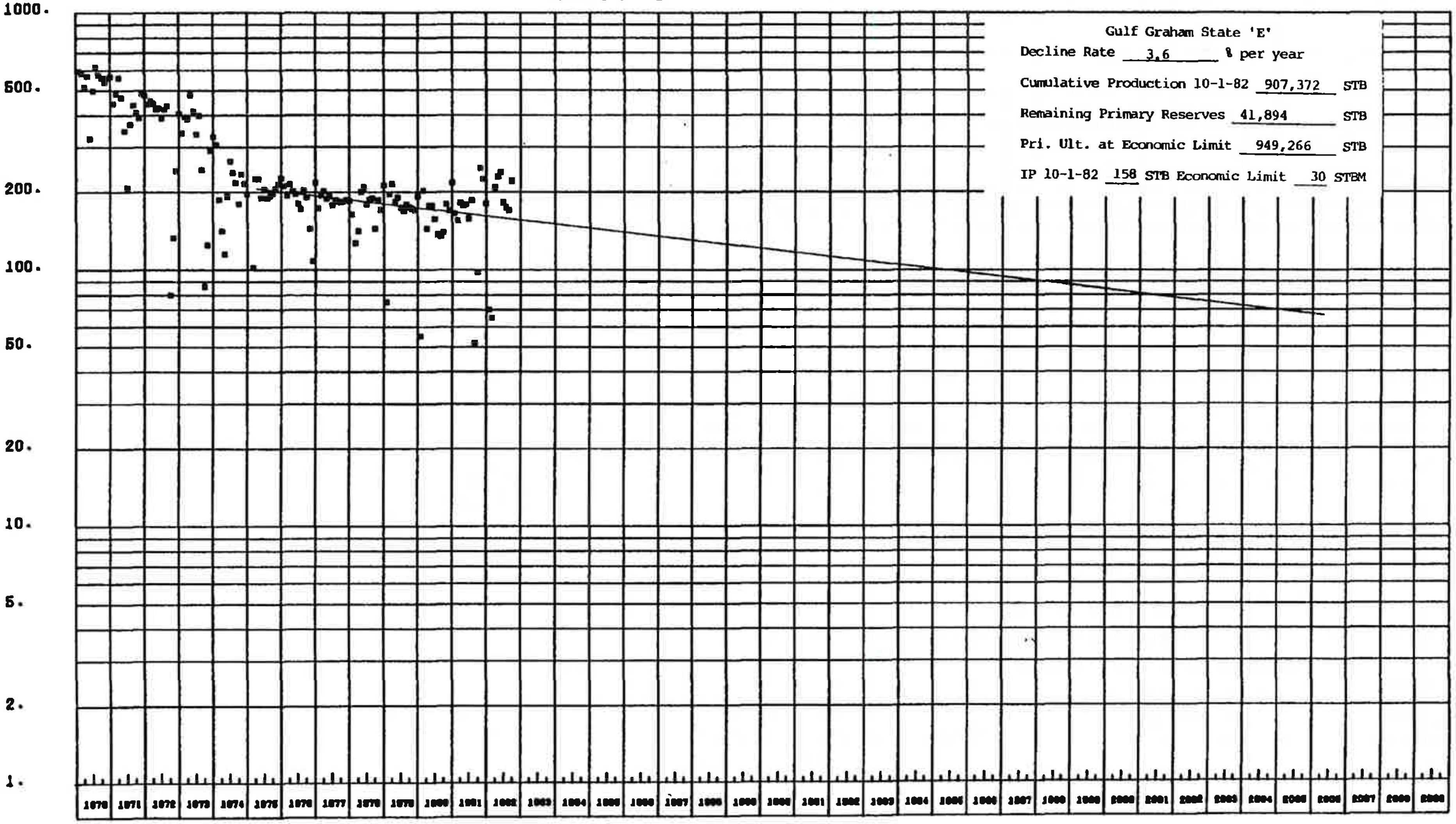


Figure 37

RATE VS TIME
TRACT 38

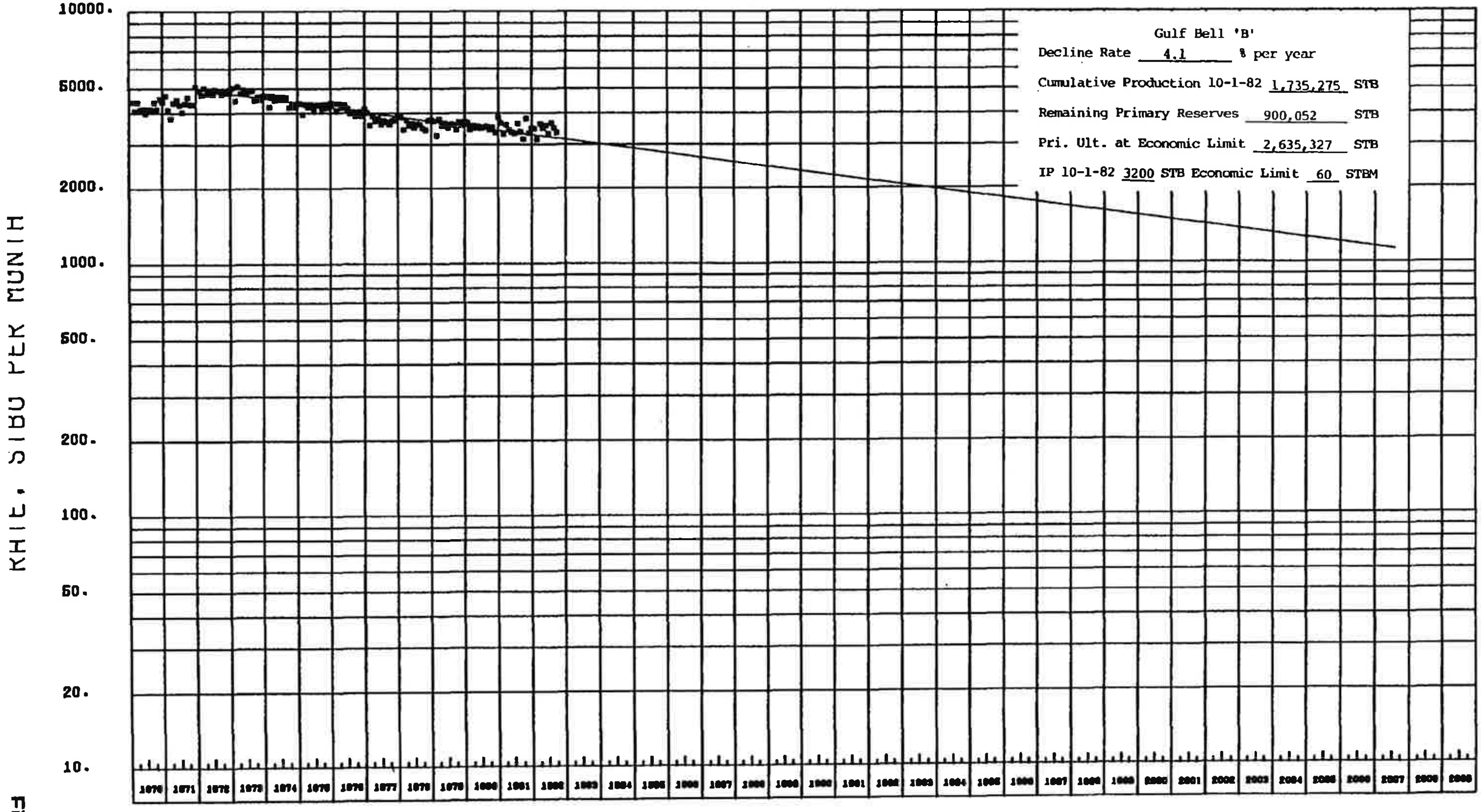


Figure 38

RATE VS TIME
TRACT 39

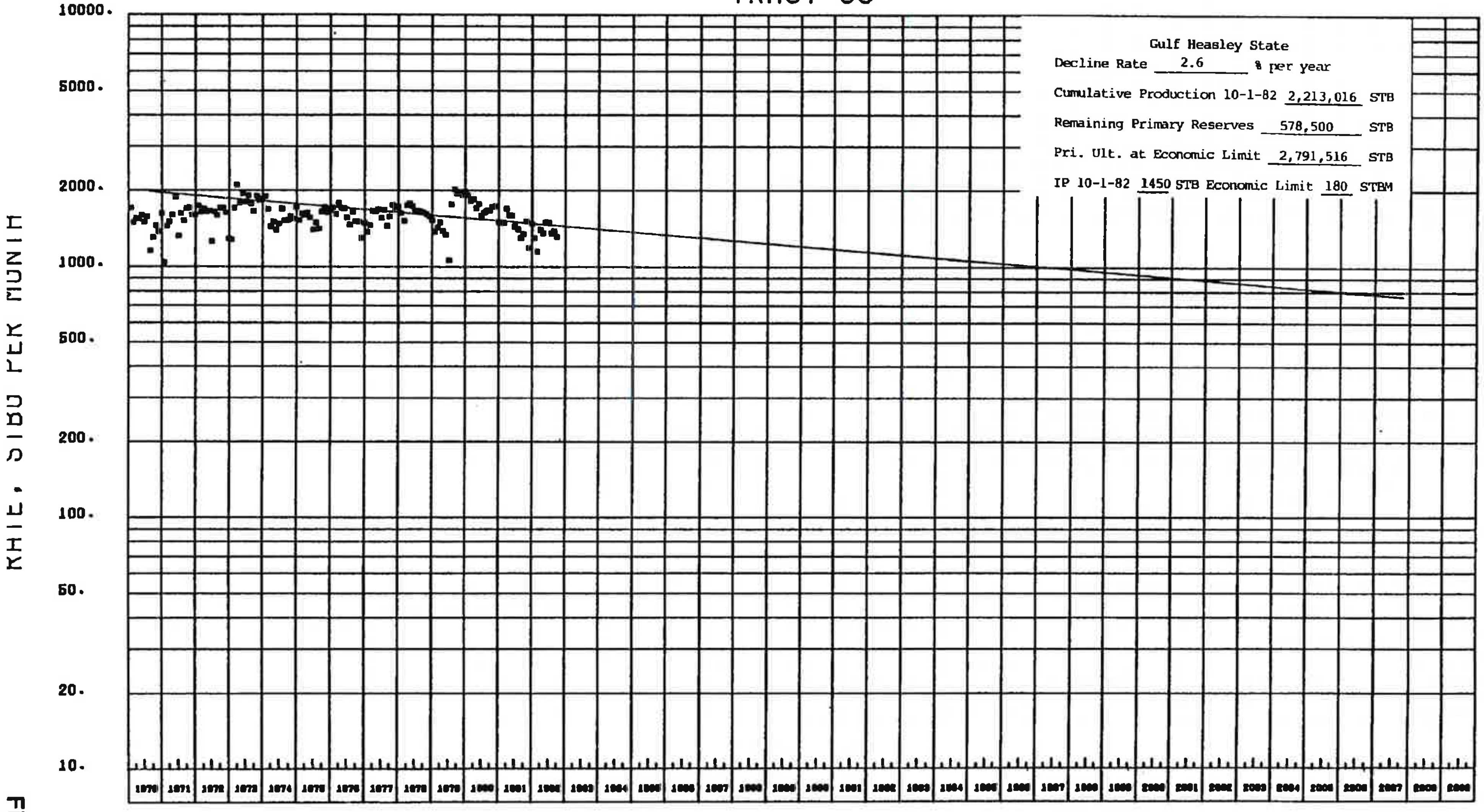


Figure 39

RATE VS TIME
TRACT 40

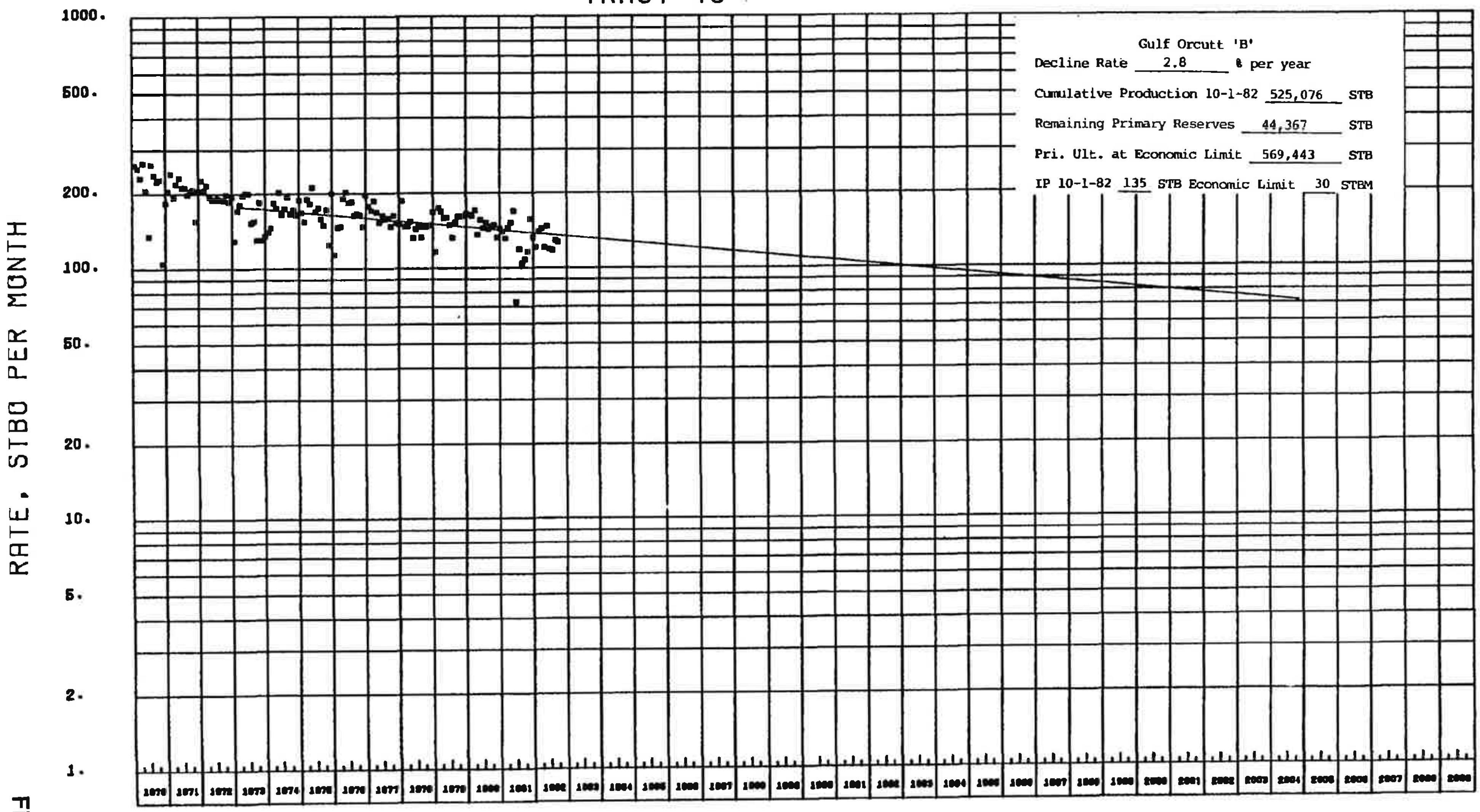


Figure 40

RATE VS TIME
TRACT 42

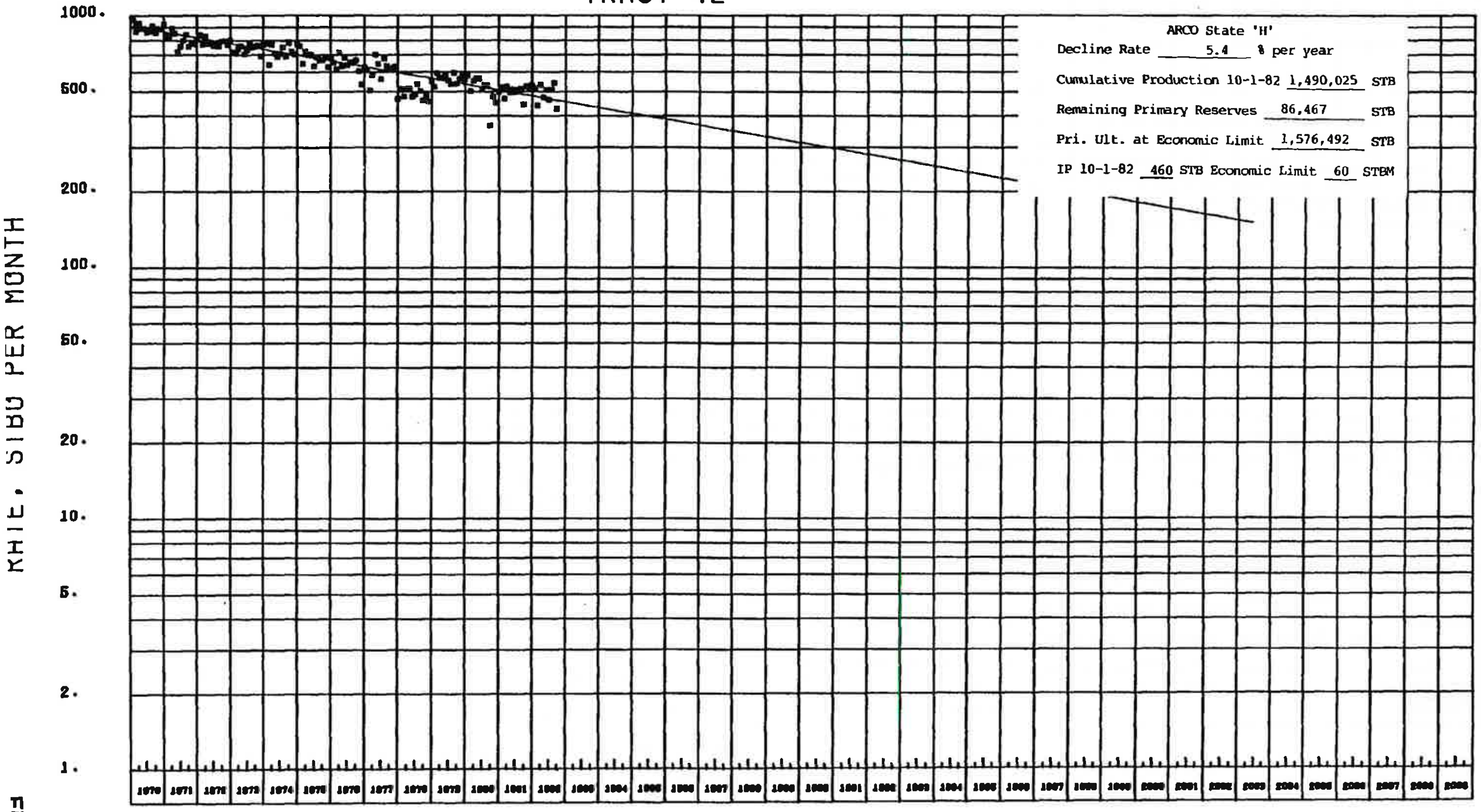


Figure 41

RATE VS TIME
TRACT 43

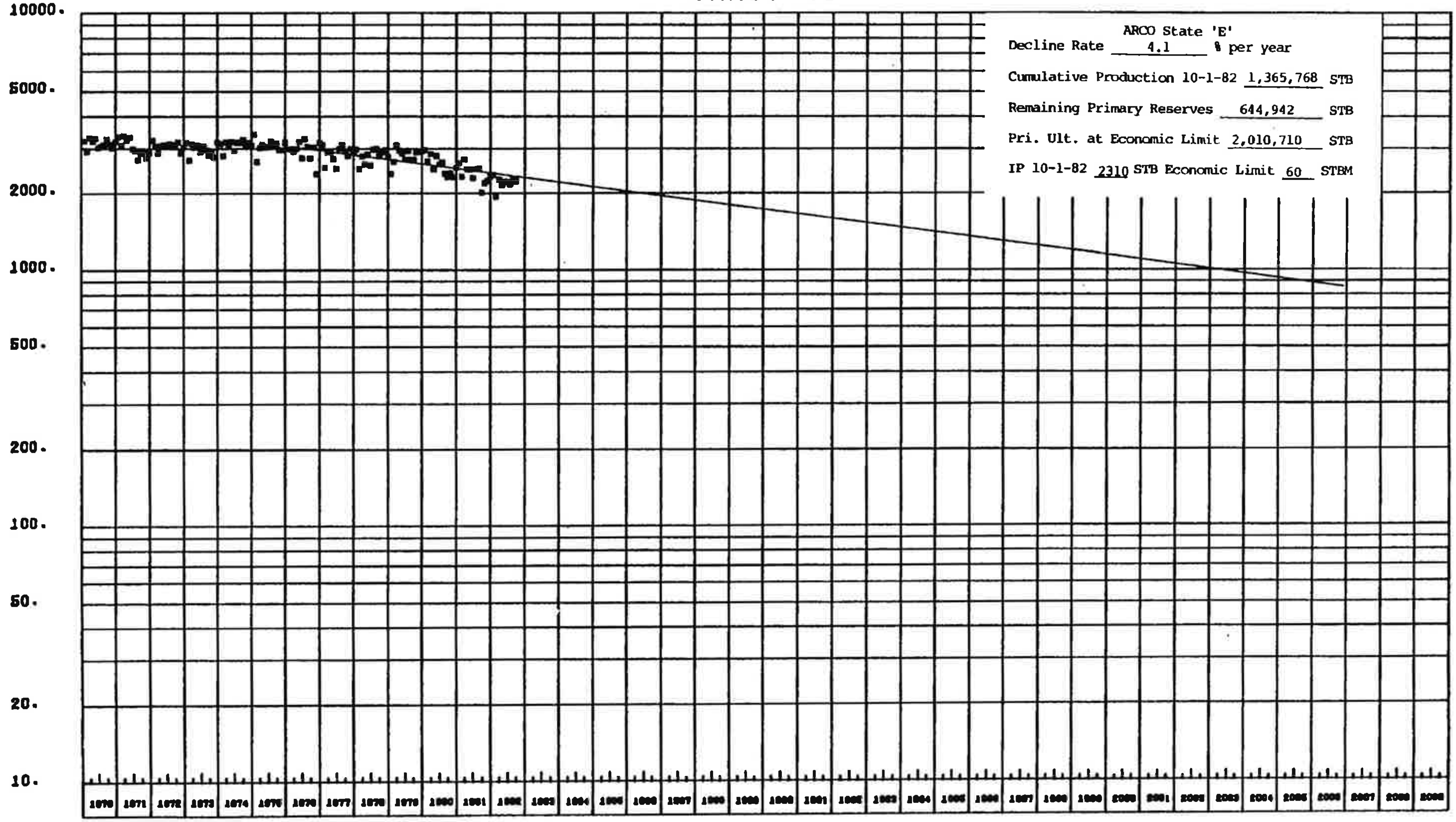


Figure 42

RATE VS TIME
TRACT 44

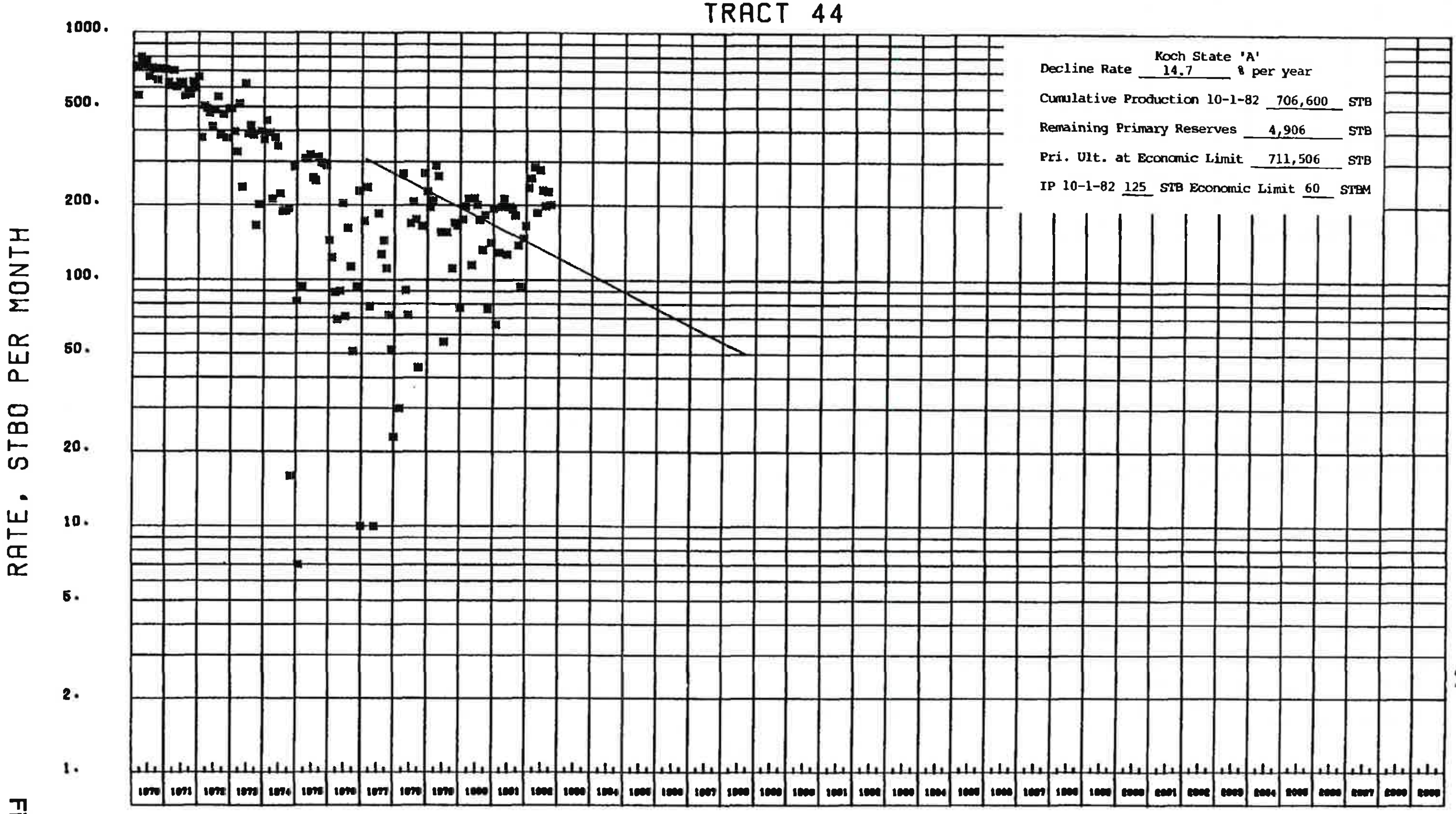


Figure 43

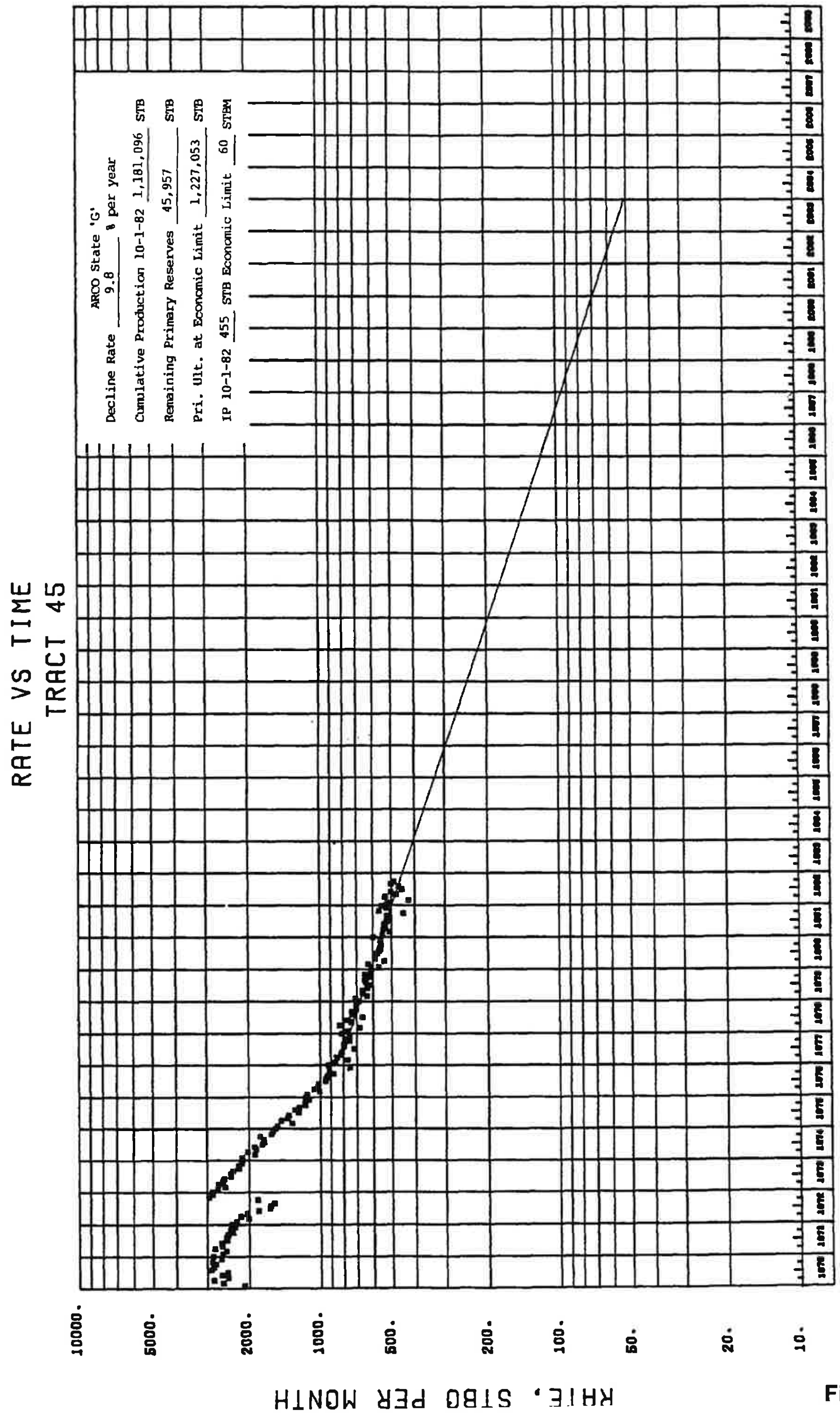

RATE VS TIME
TRACT 45
ARCO State 'G'
Decline Rate 9.8 % per year
Cumulative Production 10-1-82 1,181,096 STB
Remaining Primary Reserves 45,957 STB
Pri. Ult. at Economic Limit 1,227,053 STB
IP 10-1-82 455 STB Economic Limit 60 STBM
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.

Figure 44

RATE VS TIME
TRACT 46

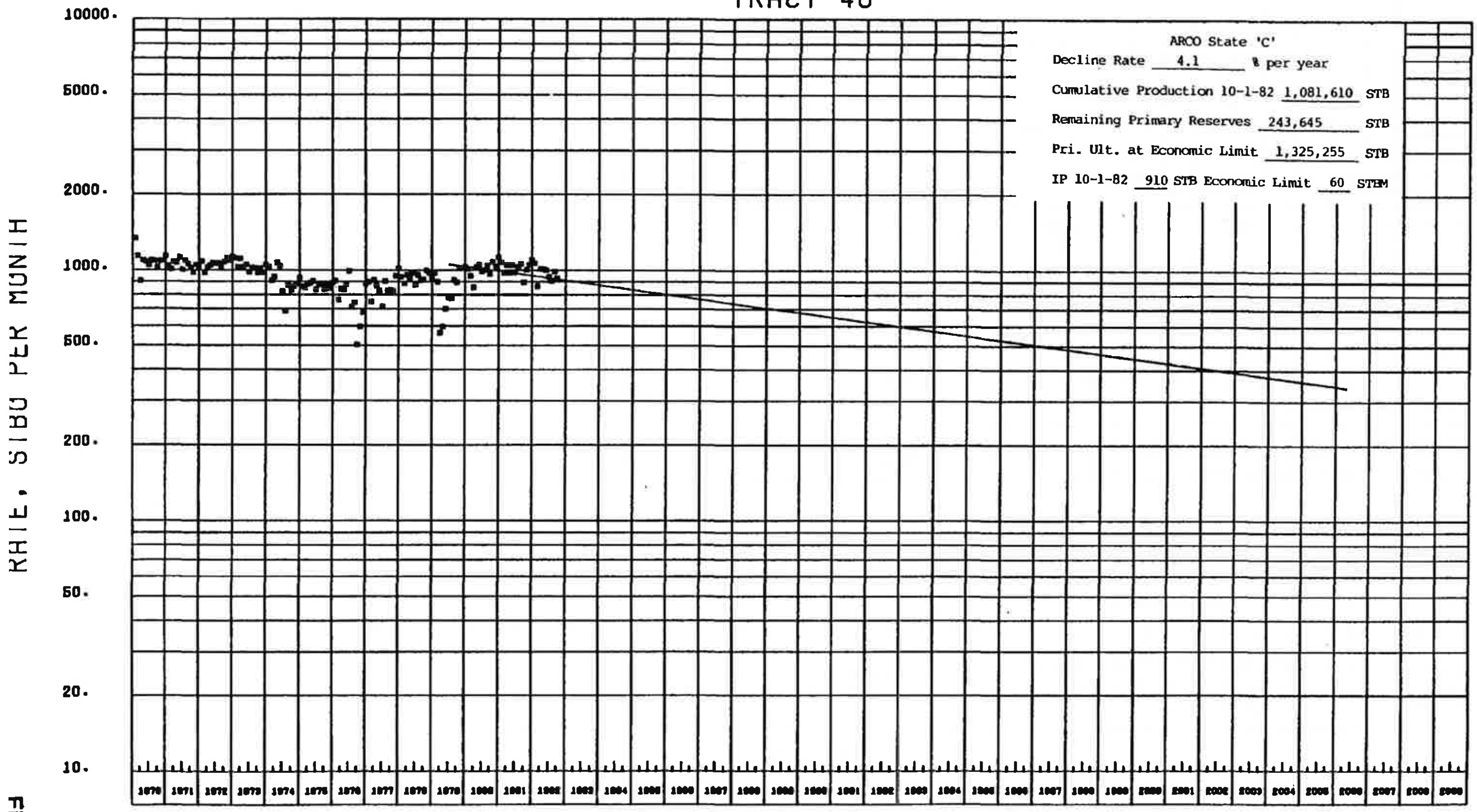


Figure 45

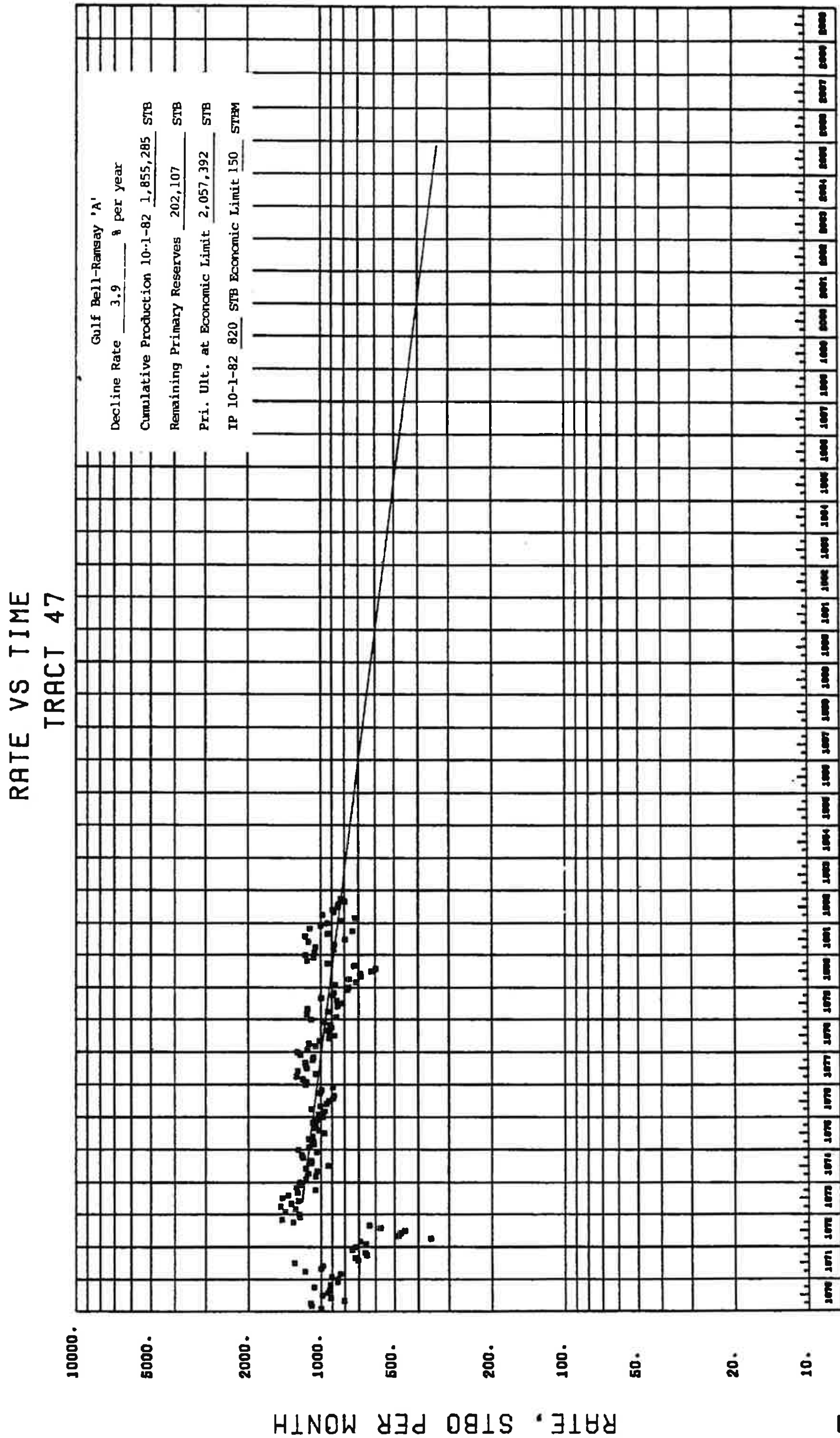

RATE VS TIME
TRACT 47
Gulf Bell-Ramsay 'A'
Decline Rate 3.9 % per year
Cumulative Production 10-1-82 1,855,285 STB
Remaining Primary Reserves 202,107 STB
Pri. Ult. at Economic Limit 2,057,392 STB
IP 10-1-82 820 STB Economic Limit 150 STBM
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.
RATE, STBO PER MONTH

Figure 46

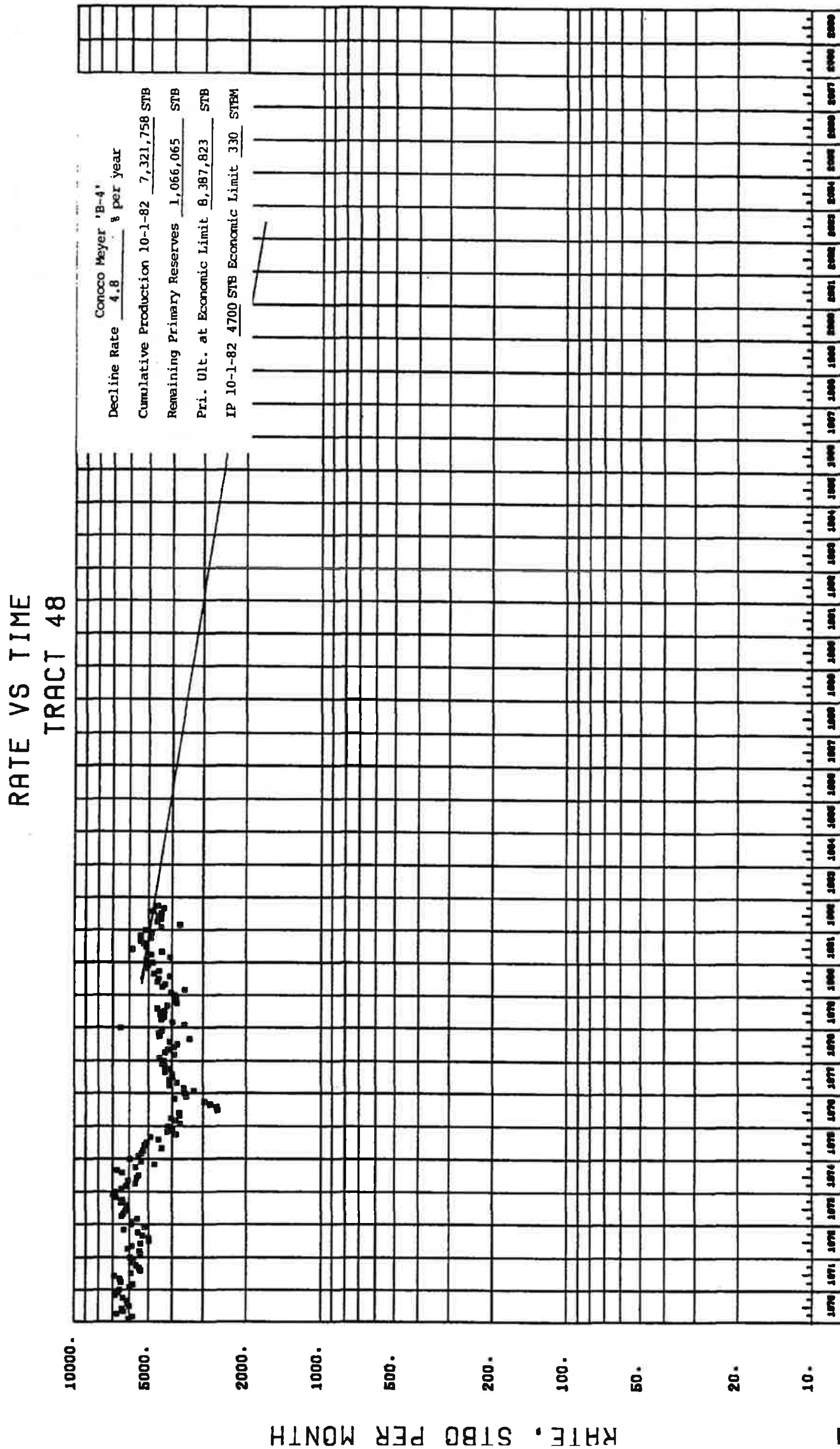

RATE VS TIME
TRACT 48
Conoco Meyer 'B-4'
Decline Rate 4.8 % per year
Cumulative Production 10-1-82 7,321,758 STB
Remaining Primary Reserves 1,066,065 STB
Pri. Ult. at Economic Limit 8,387,823 STB
IP 10-1-82 4700 STB Economic Limit 330 STBM
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.
RATE, STBO PER MONTH

Figure 47

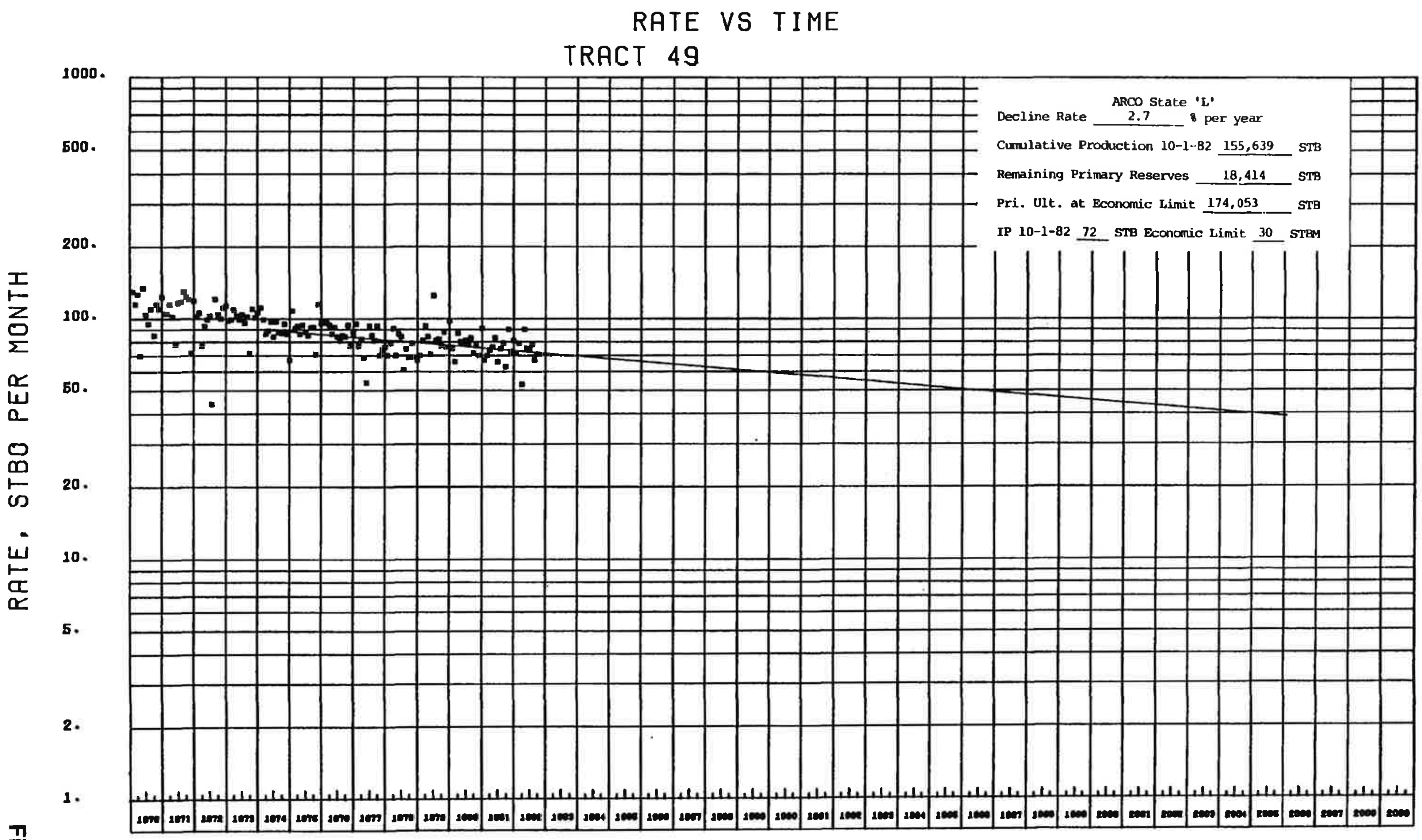

RATE VS TIME
TRACT 49
ARCO State 'L'
Decline Rate 2.7 % per year
Cumulative Production 10-1-82 155,639 STB
Remaining Primary Reserves 18,414 STB
Pri. Ult. at Economic Limit 174,053 STB
IP 10-1-82 72 STB Economic Limit 30 STBM
RATE, STBO PER MONTH
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.

Figure 48

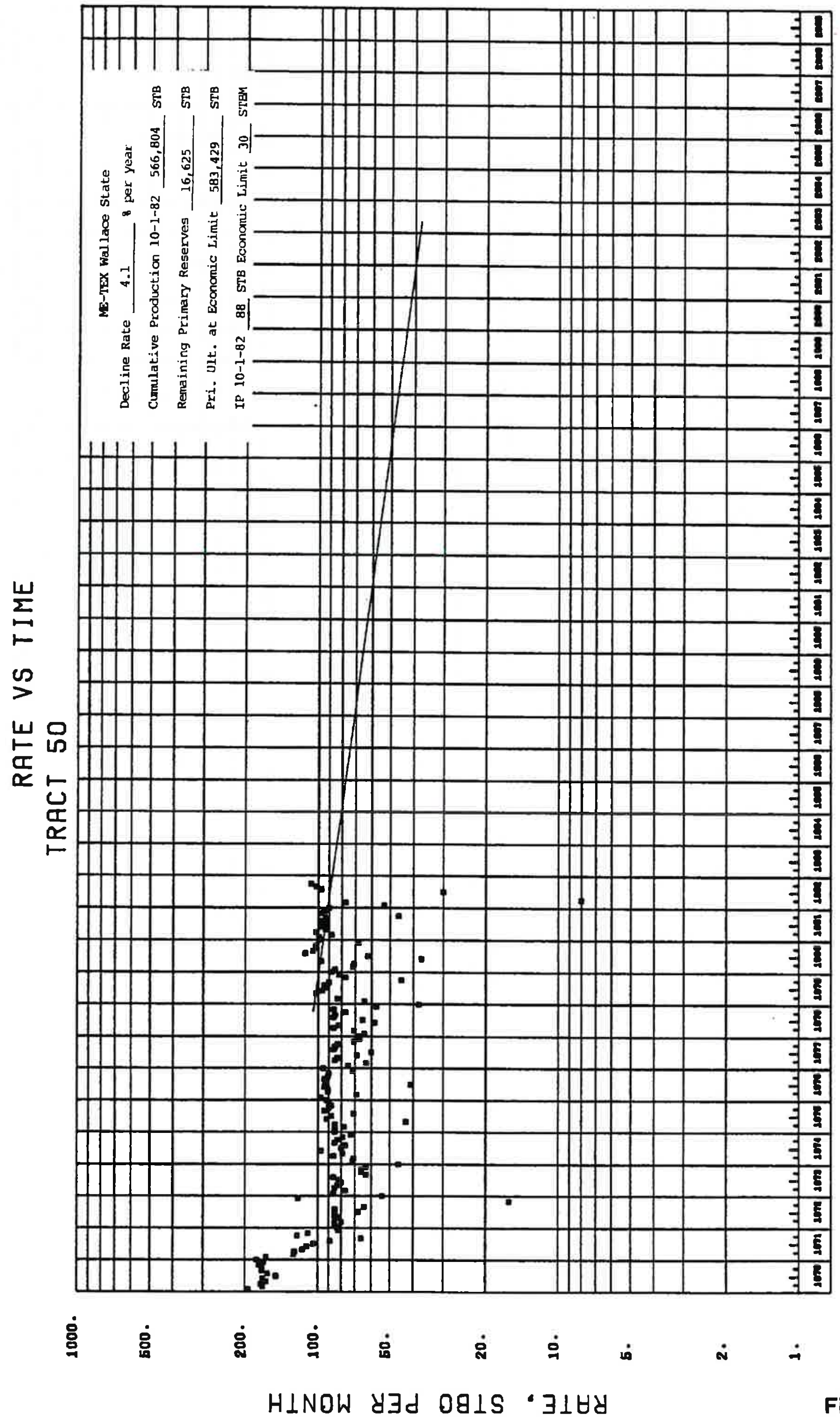

RATE VS TIME
TRACT 50
ME-TEX Wallace State
Decline Rate 4.1 % per year
Cumulative Production 10-1-82 566,804 STB
Remaining Primary Reserves 16,625 STB
Pri. Ult. at Economic Limit 583,429 STB
IP 10-1-82 88 STB Economic Limit 30 STBM
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.
RATE, STBO PER MONTH

Figure 49

RATE VS TIME
TRACT 51

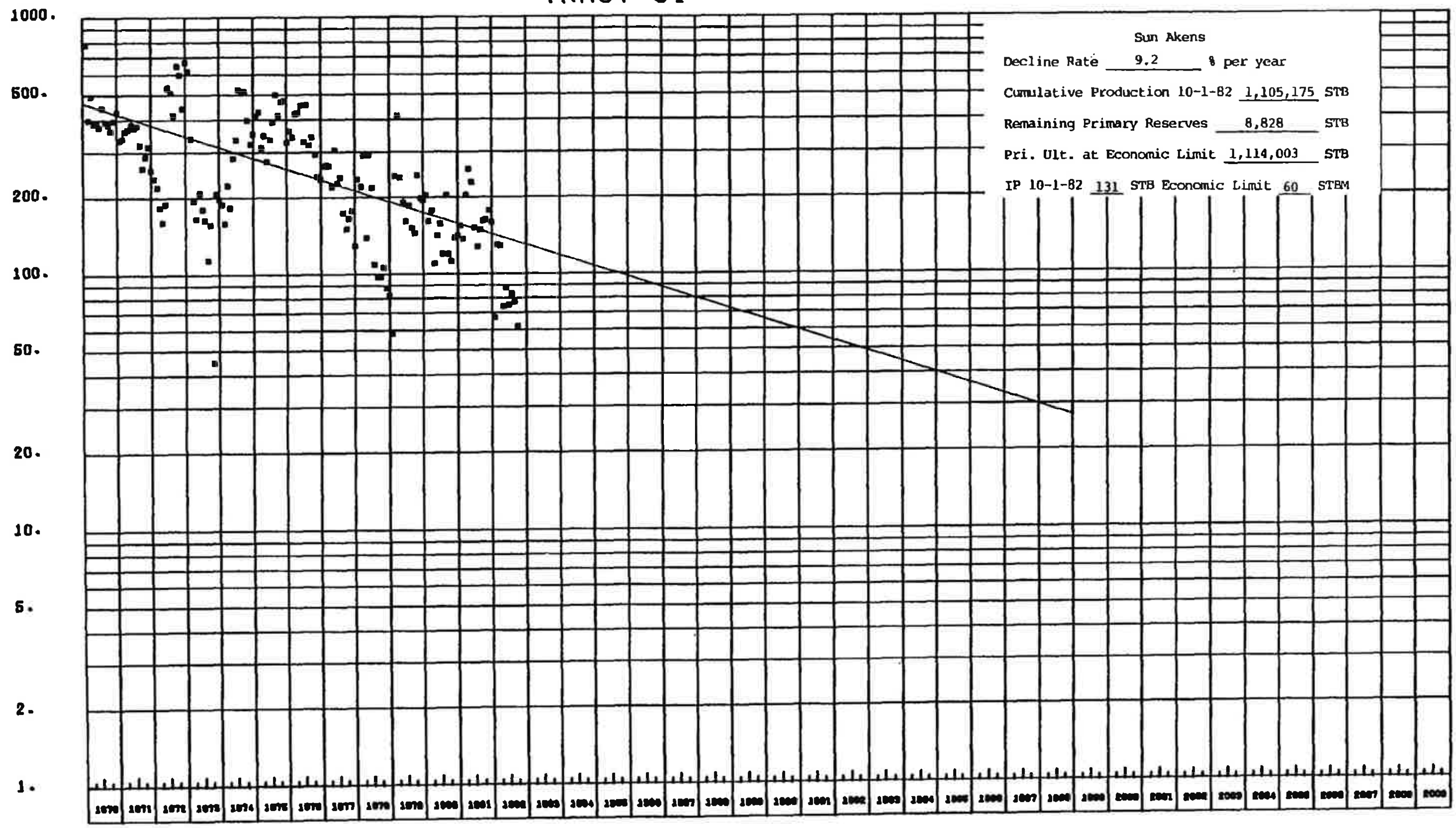


Figure 50

RATE VS TIME
TRACT 52

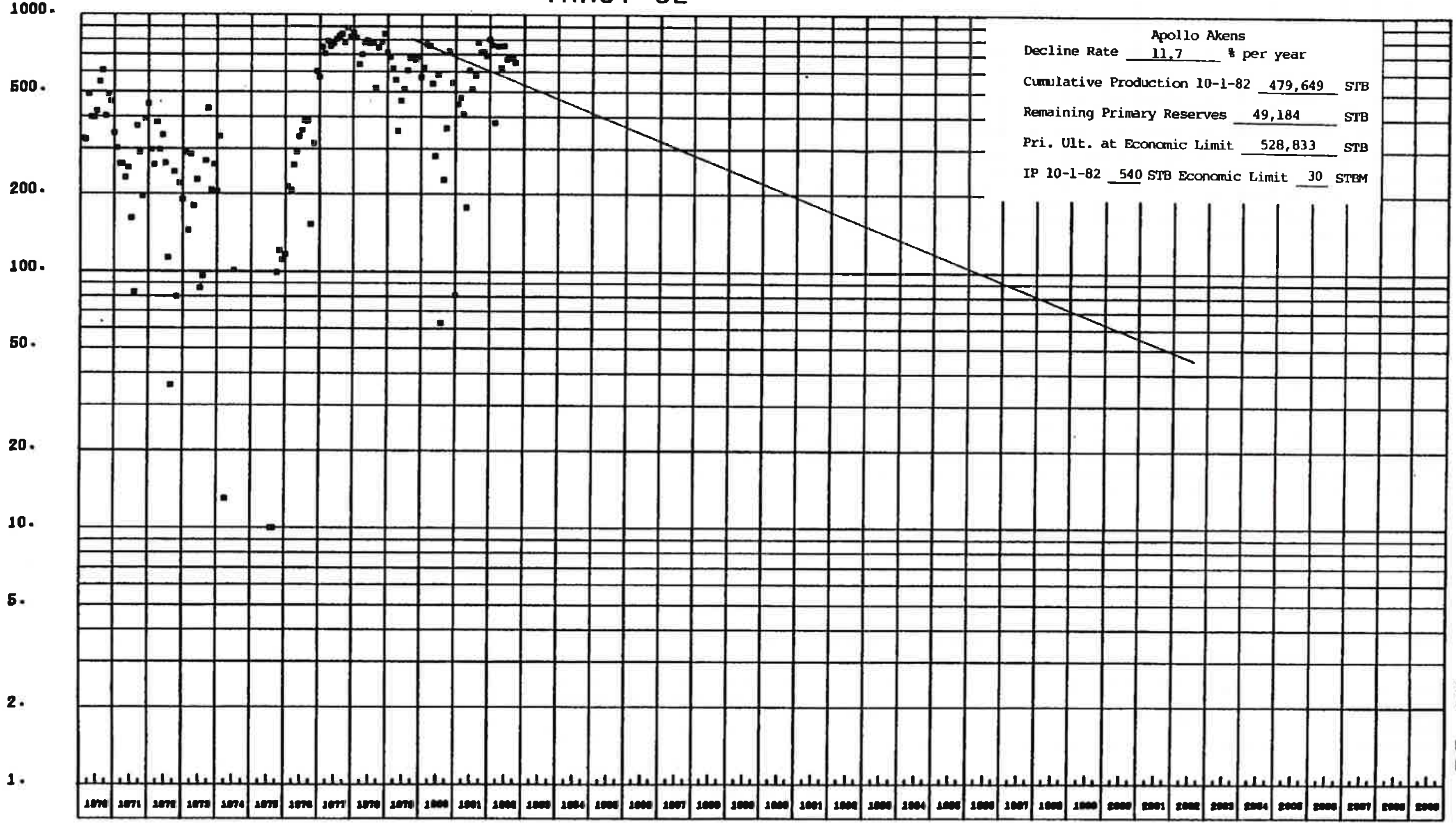


Figure 51

RATE VS TIME
TRACT 53

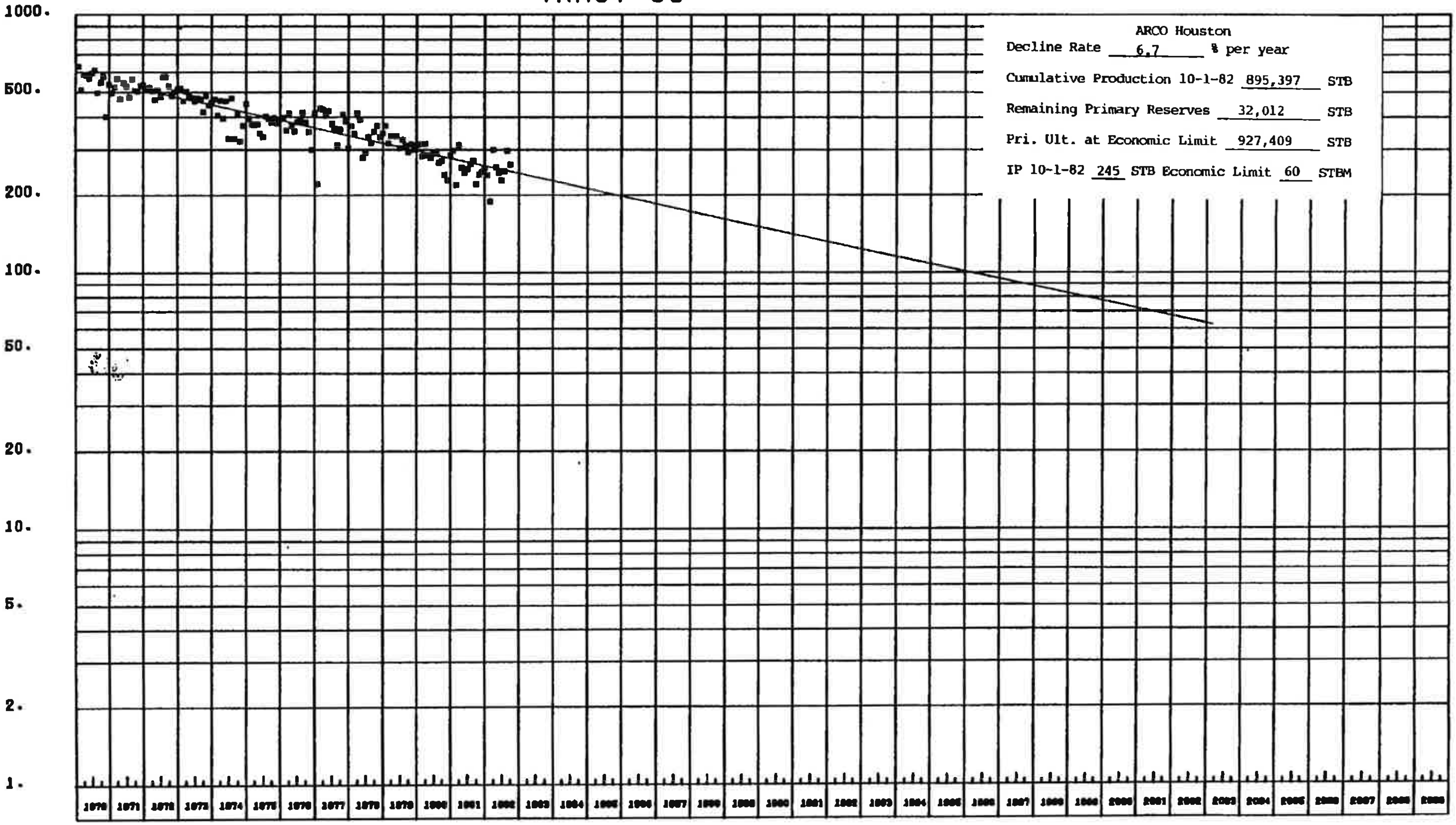


Figure 52

RATE VS TIME
TRACT 55

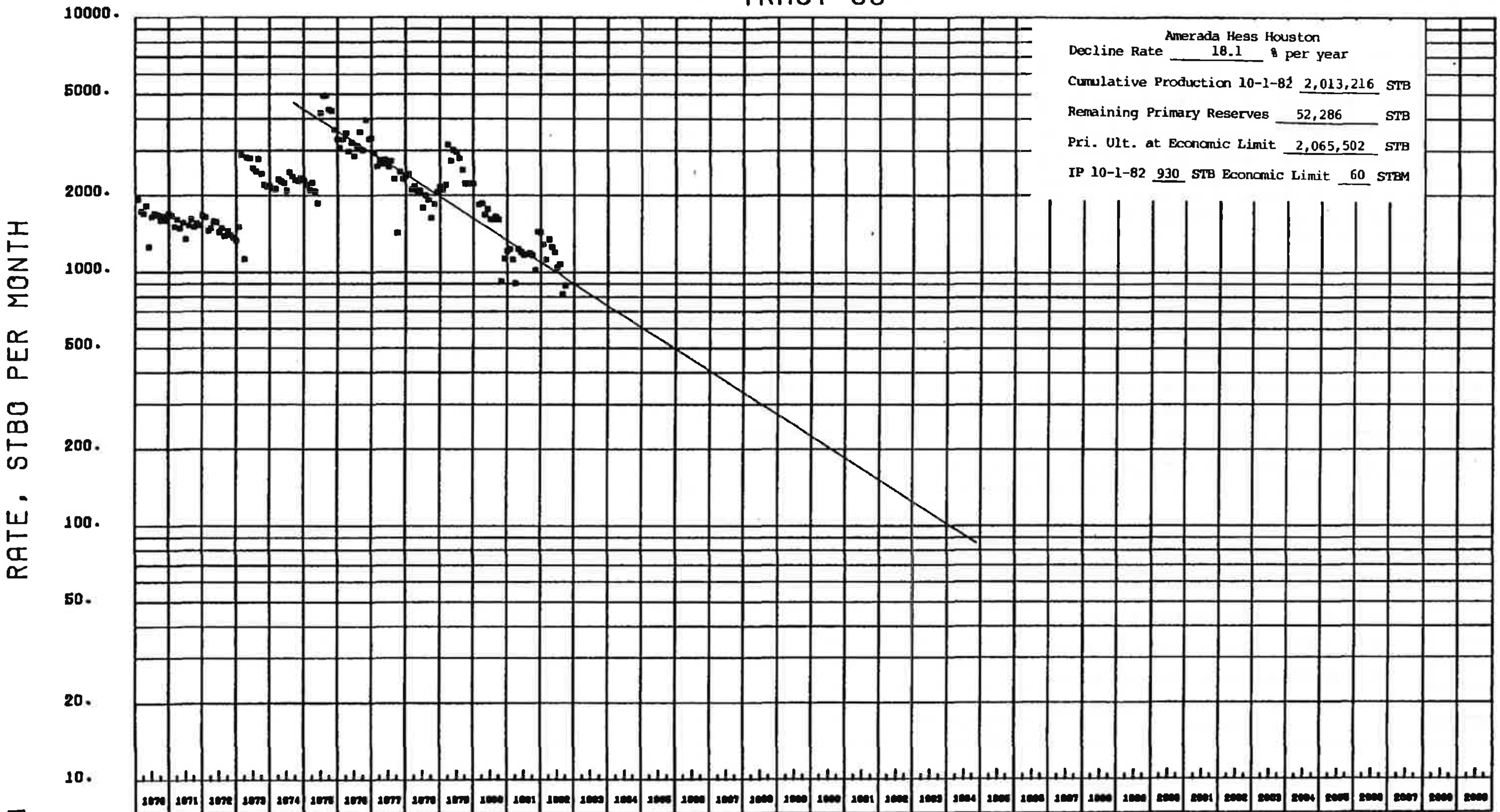


Figure 53

RATE VS TIME
TRACT 56

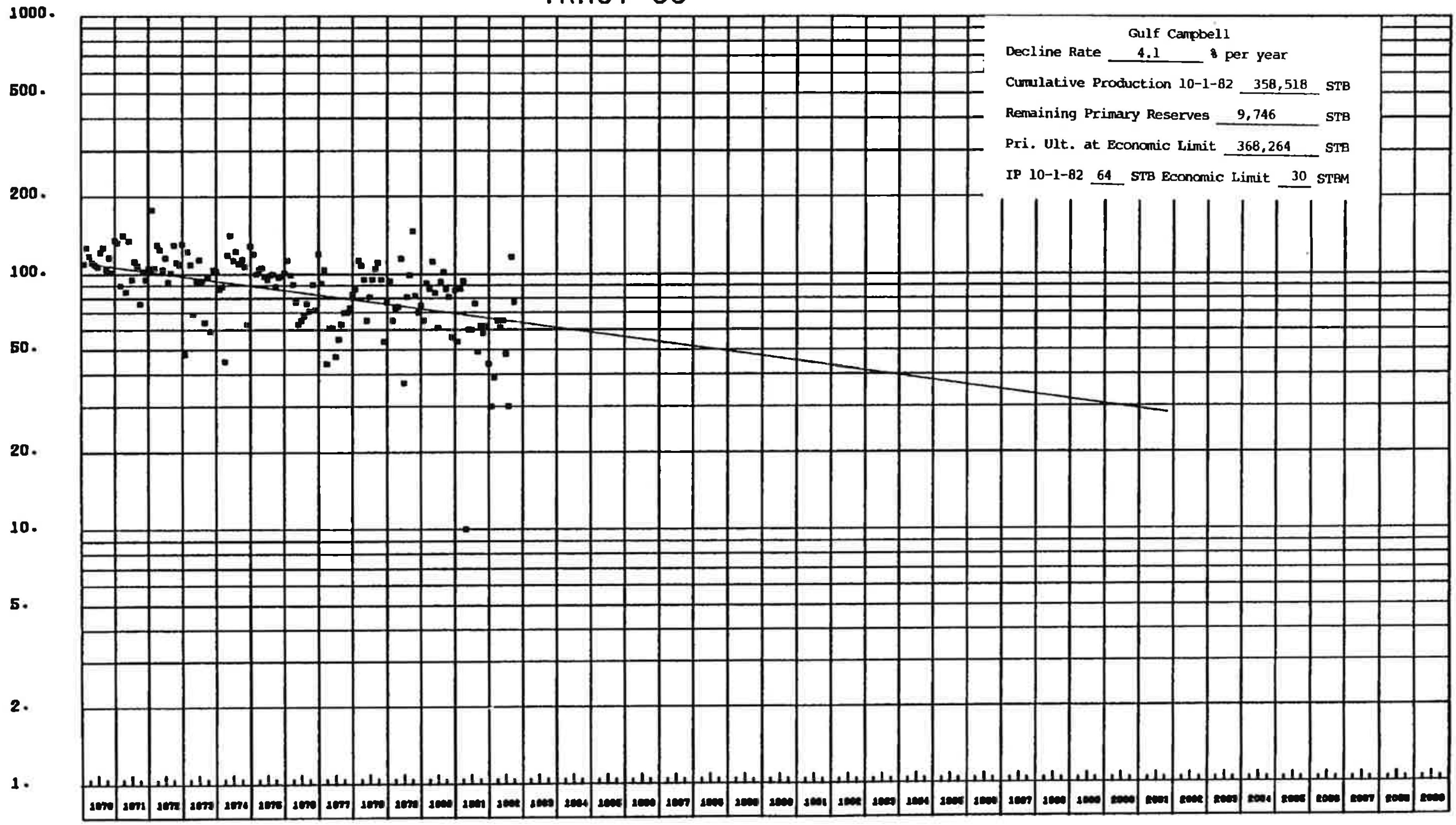


Figure 54

RATE VS TIME
TRACT 57

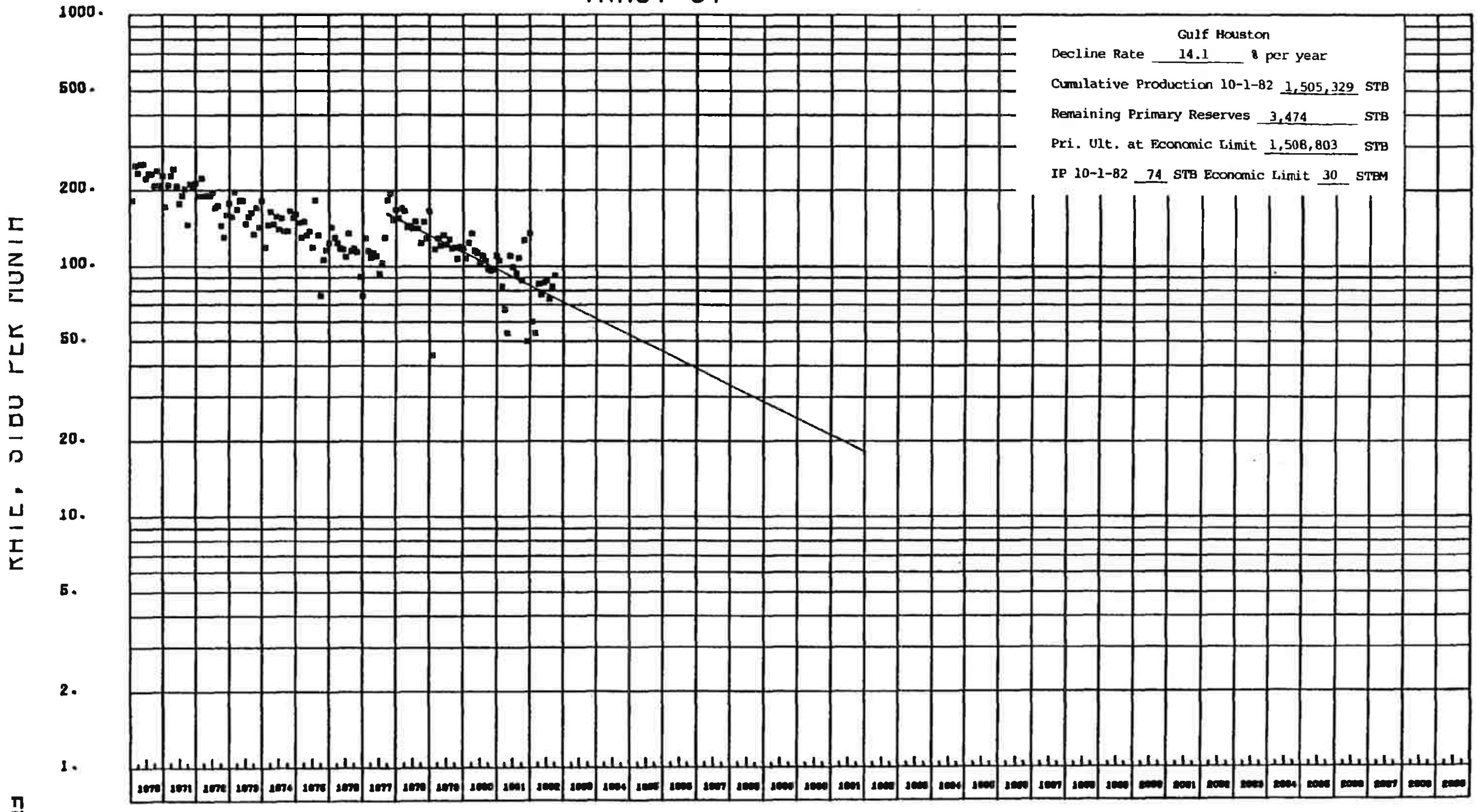


Figure 55

RATE VS TIME
TRACT 59

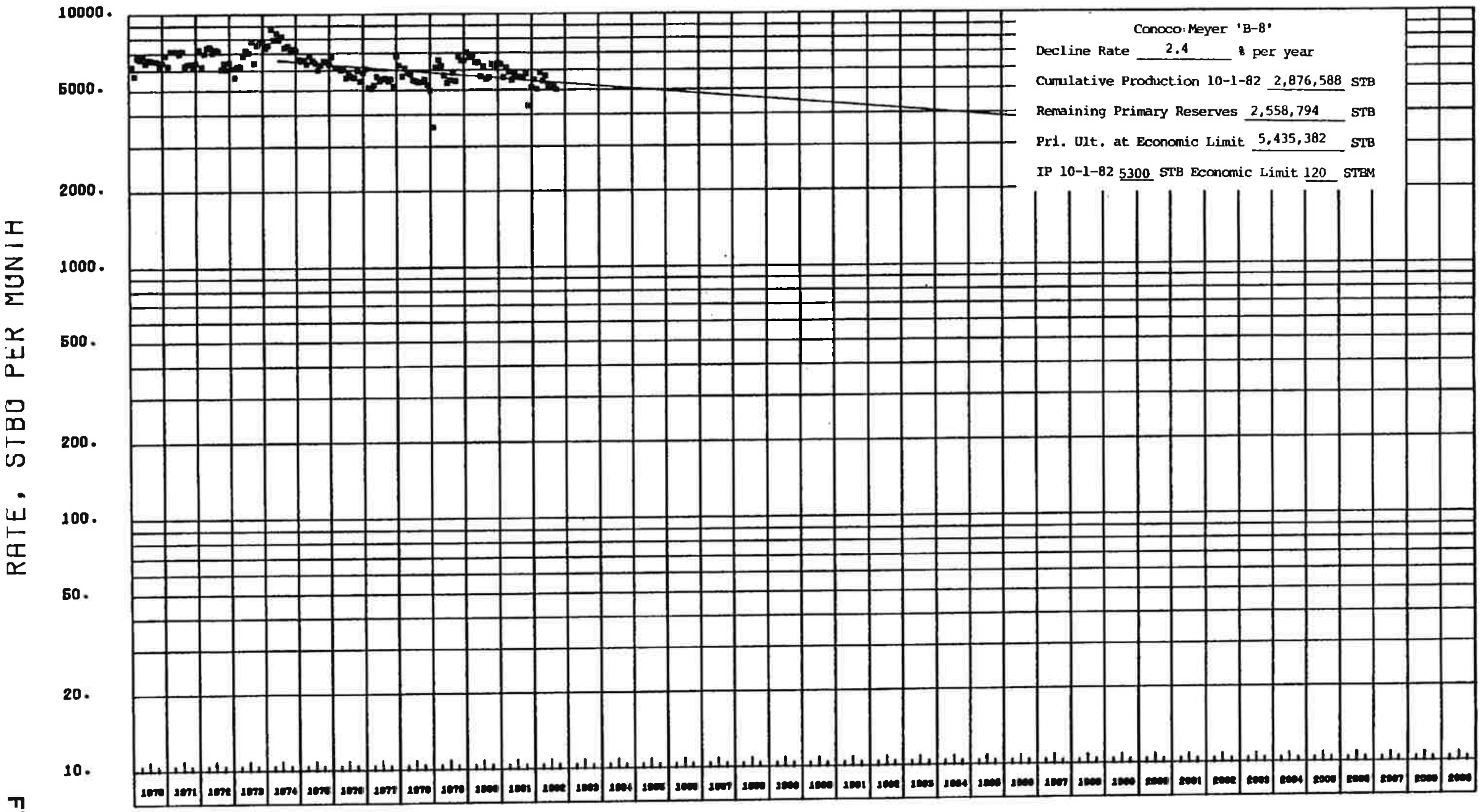


Figure 56

RATE VS TIME
TRACT 60

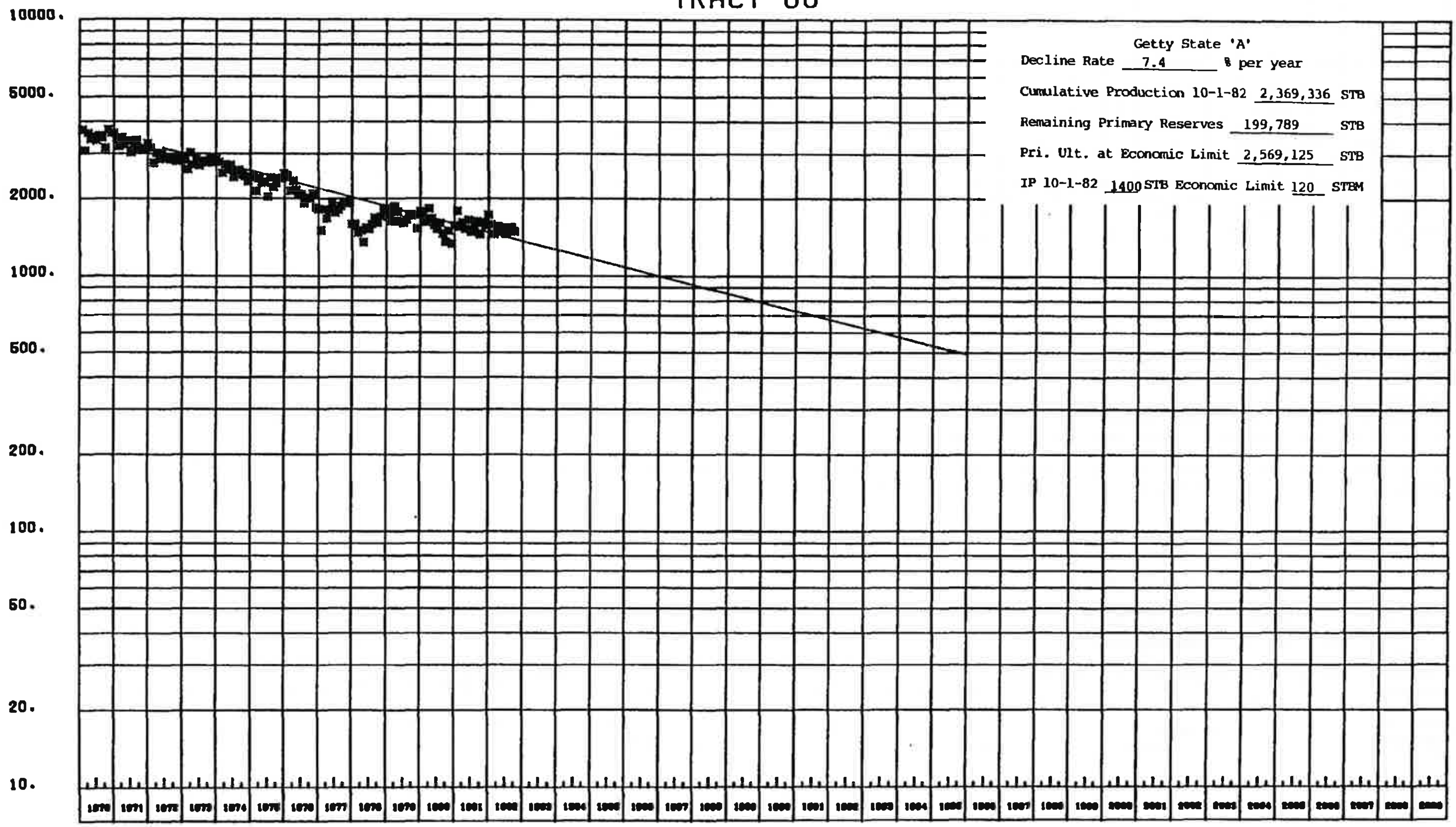


Figure 57

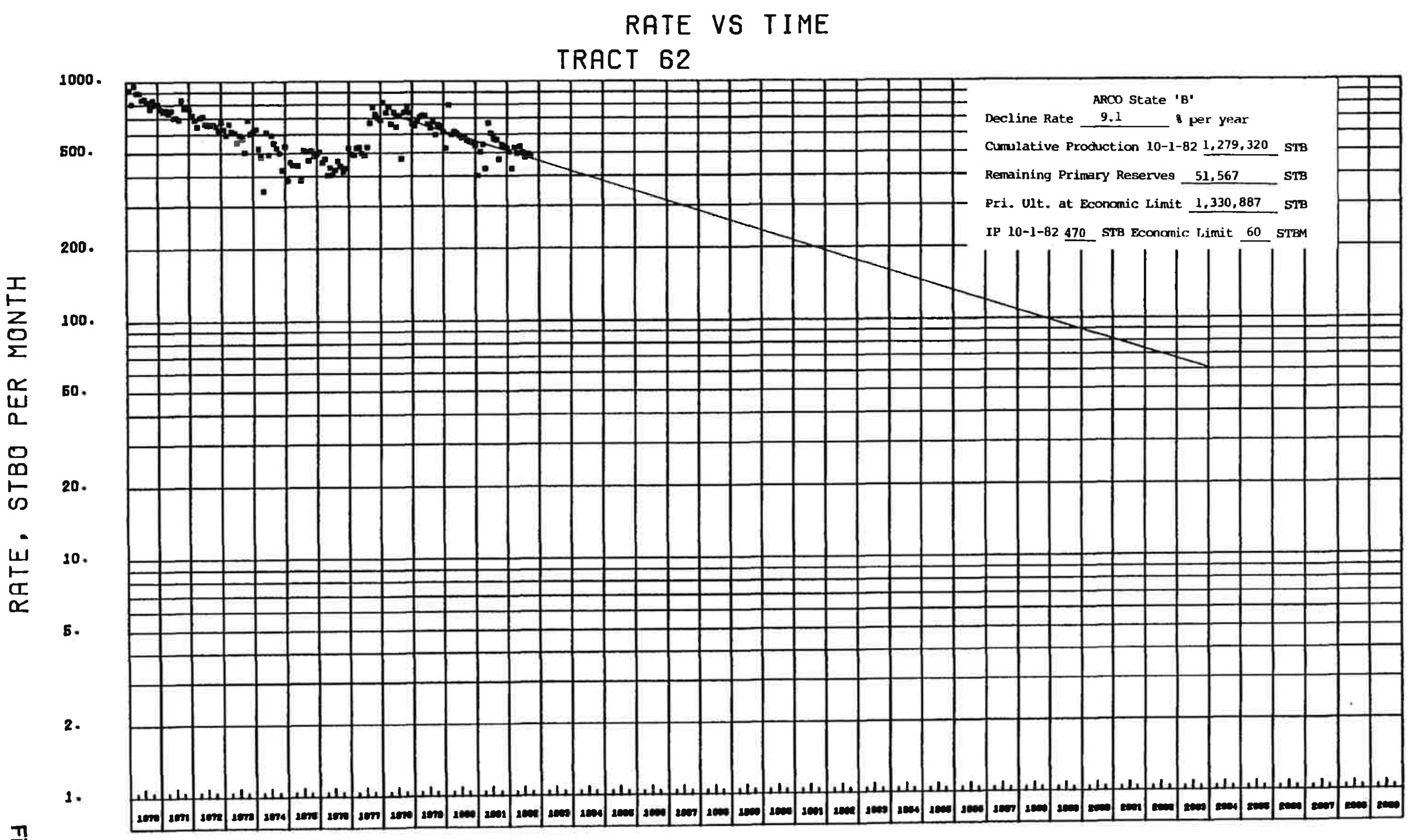

RATE VS TIME
TRACT 62
ARCO State 'B'
Decline Rate 9.1 % per year
Cumulative Production 10-1-82 1,279,320 STB
Remaining Primary Reserves 51,567 STB
Pri. Ult. at Economic Limit 1,330,887 STB
IP 10-1-82 470 STB Economic Limit 60 STBM
RATE, STBO PER MONTH
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.

Figure 58

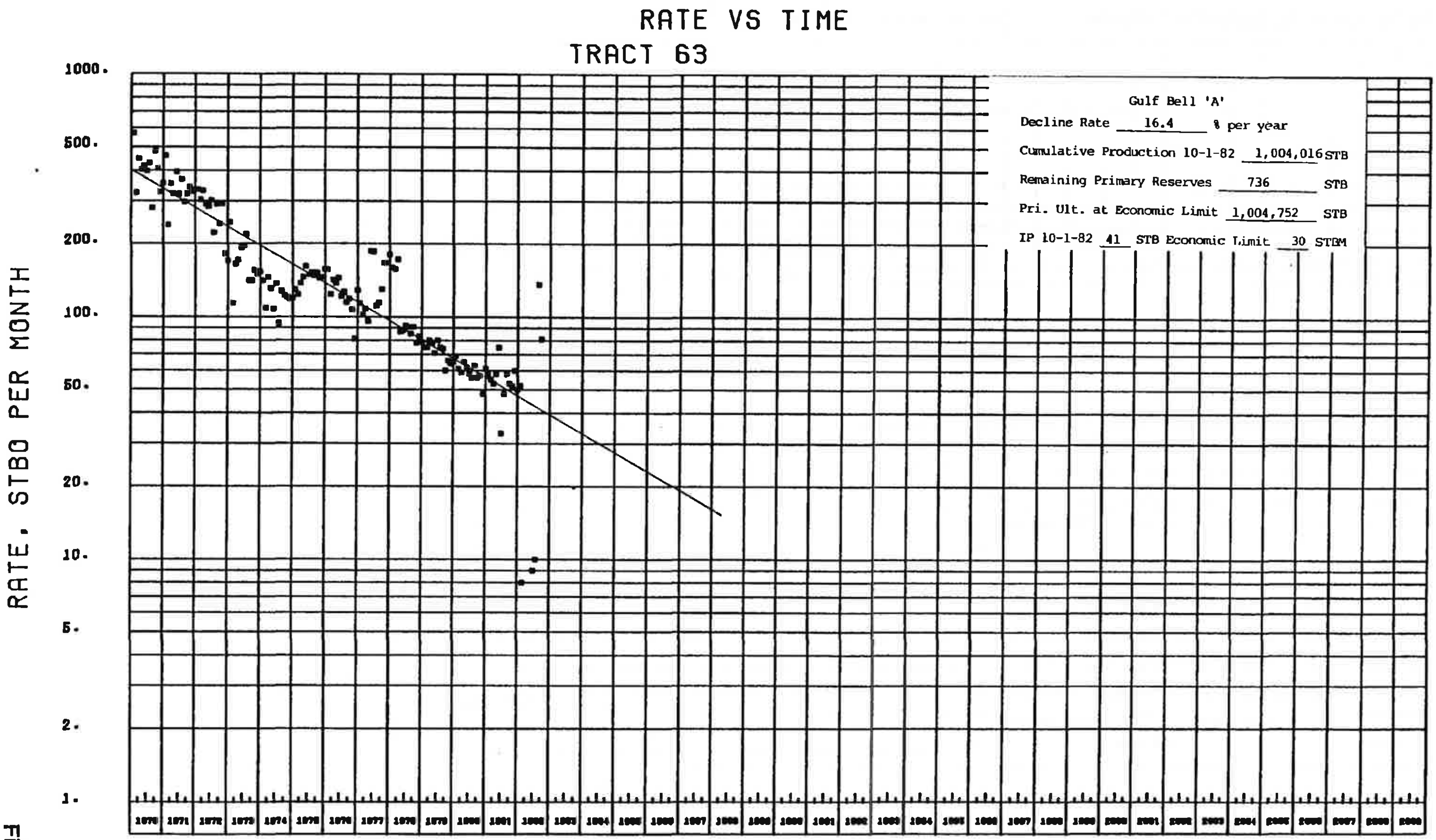
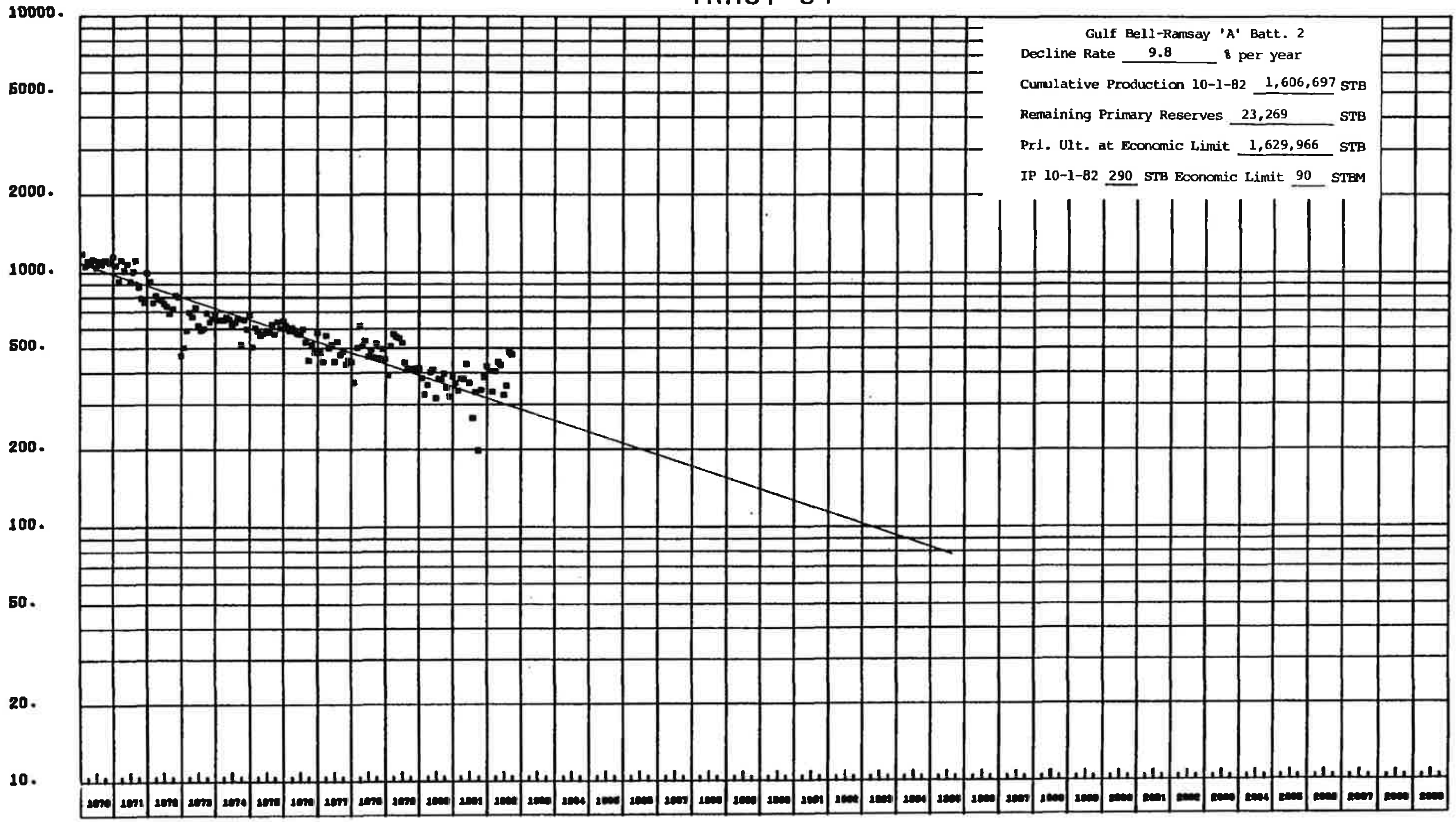

RATE VS TIME
TRACT 63
Gulf Bell 'A'
Decline Rate 16.4 % per year
Cumulative Production 10-1-82 1,004,016 STB
Remaining Primary Reserves 736 STB
Pri. Ult. at Economic Limit 1,004,752 STB
IP 10-1-82 41 STB Economic Limit 30 STBM
RATE, STBO PER MONTH
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.

Figure 59

RATE VS TIME
TRACT 64



RATE, STBO PER MONTH

Figure 60

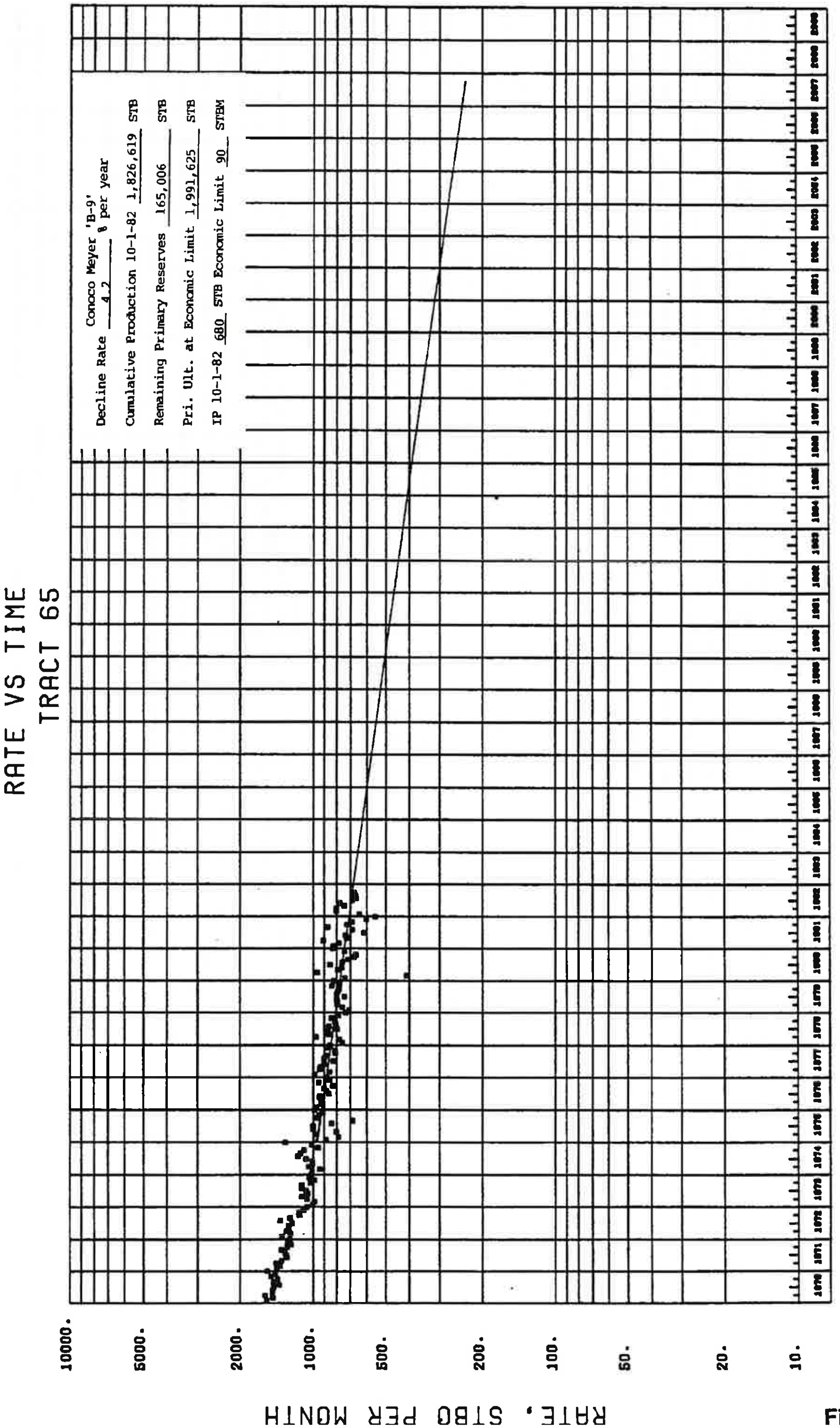

RATE VS TIME
TRACT 65
Conoco Meyer 'B-9'
Decline Rate 4.2 % per year
Cumulative Production 10-1-82 1,826,619 STB
Remaining Primary Reserves 165,006 STB
Pri. Ult. at Economic Limit 1,991,625 STB
IP 10-1-82 680 STB Economic Limit 90 STBM
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.
RATE, STBO PER MONTH

Figure 61

RATE VS TIME
TRACT 66

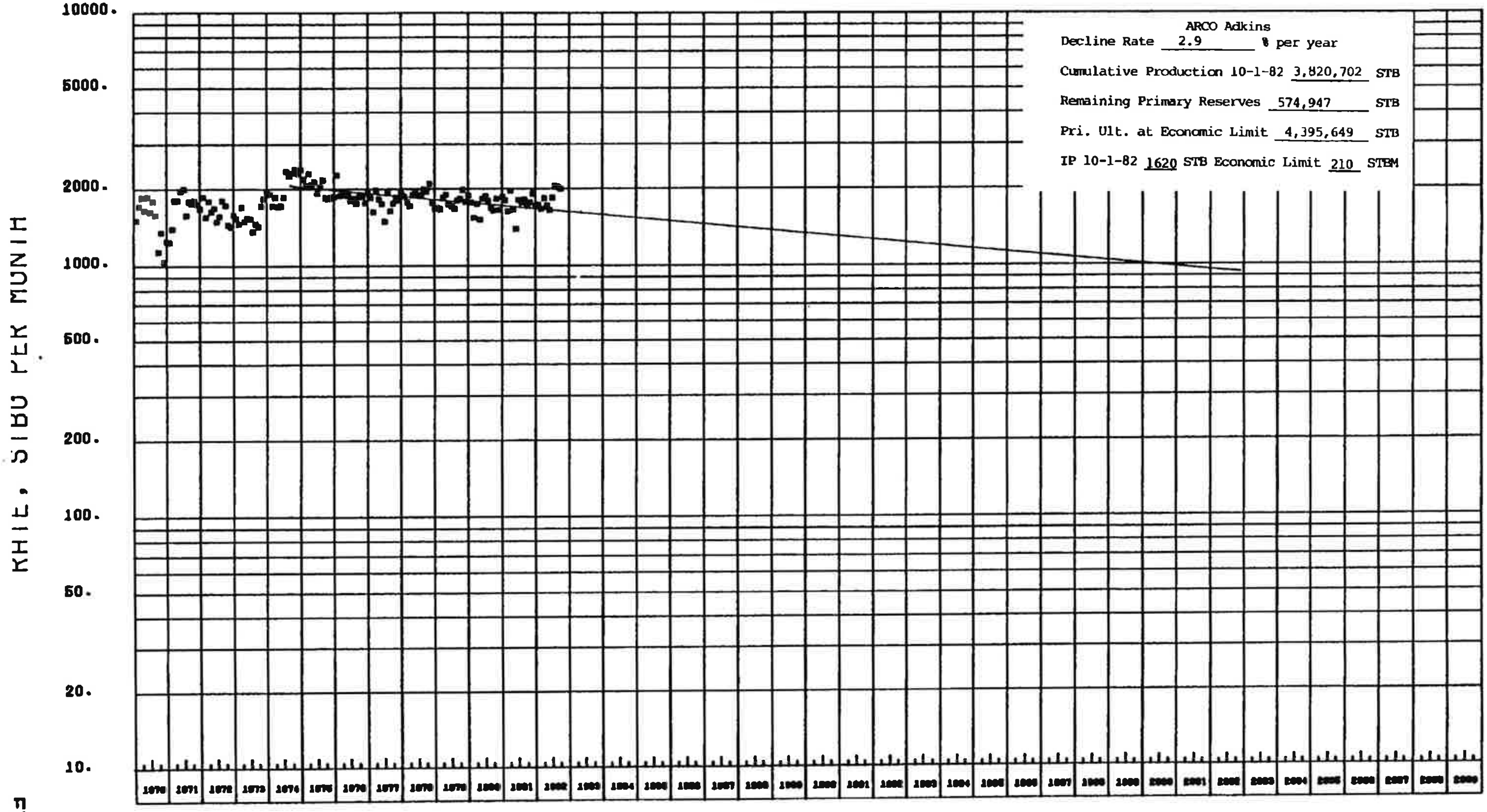


Figure 62

RATE VS TIME
TRACT 67

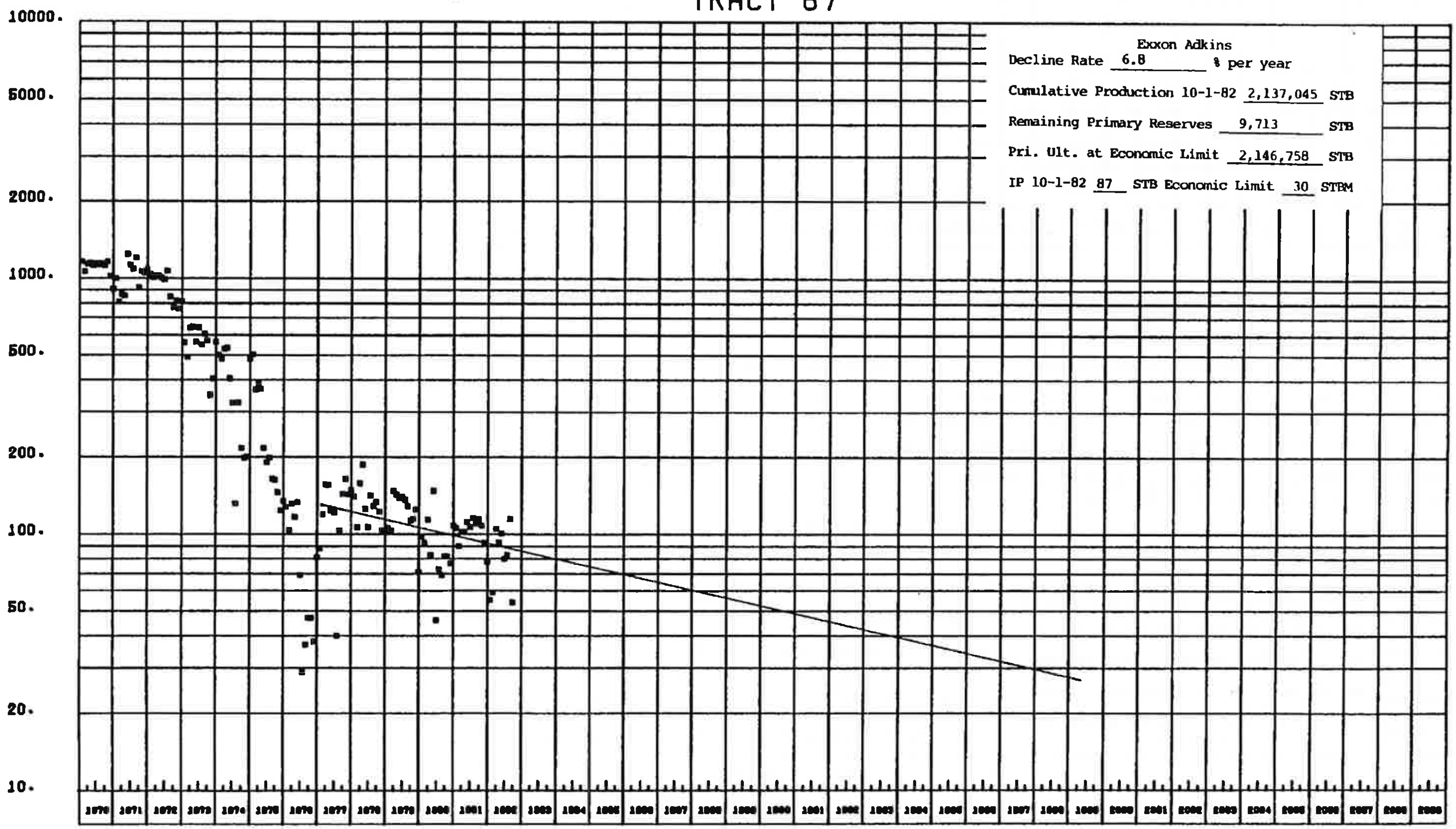


Figure 63

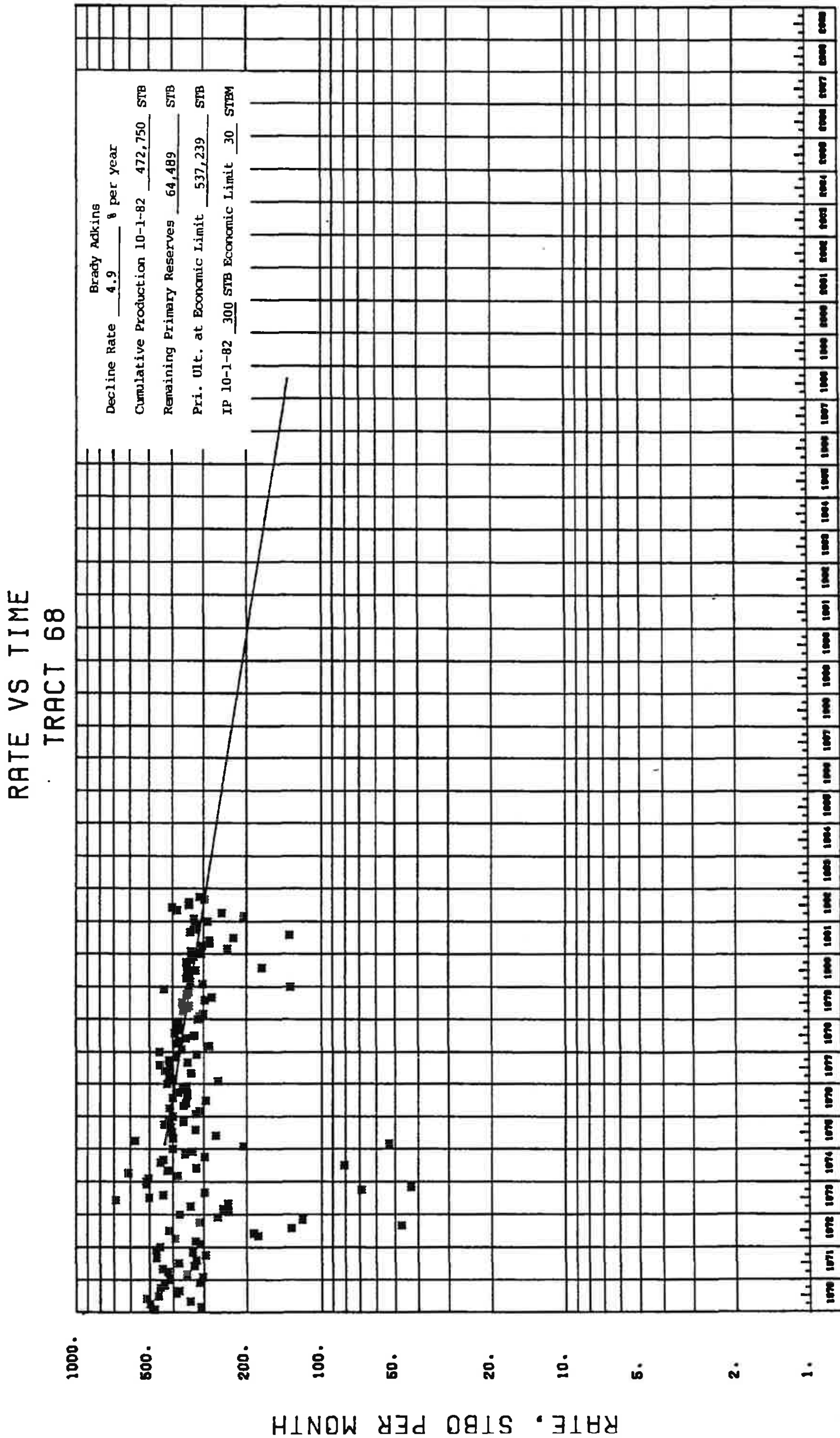

RATE VS TIME
TRACT 68
Brady Adkins
Decline Rate 4.9 % per year
Cumulative Production 10-1-82 472,750 STB
Remaining Primary Reserves 64,489 STB
Pri. Ult. at Economic Limit 537,239 STB
IP 10-1-82 300 STB Economic Limit 30 STBM
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.
RATE, STBO PER MONTH

Figure 64

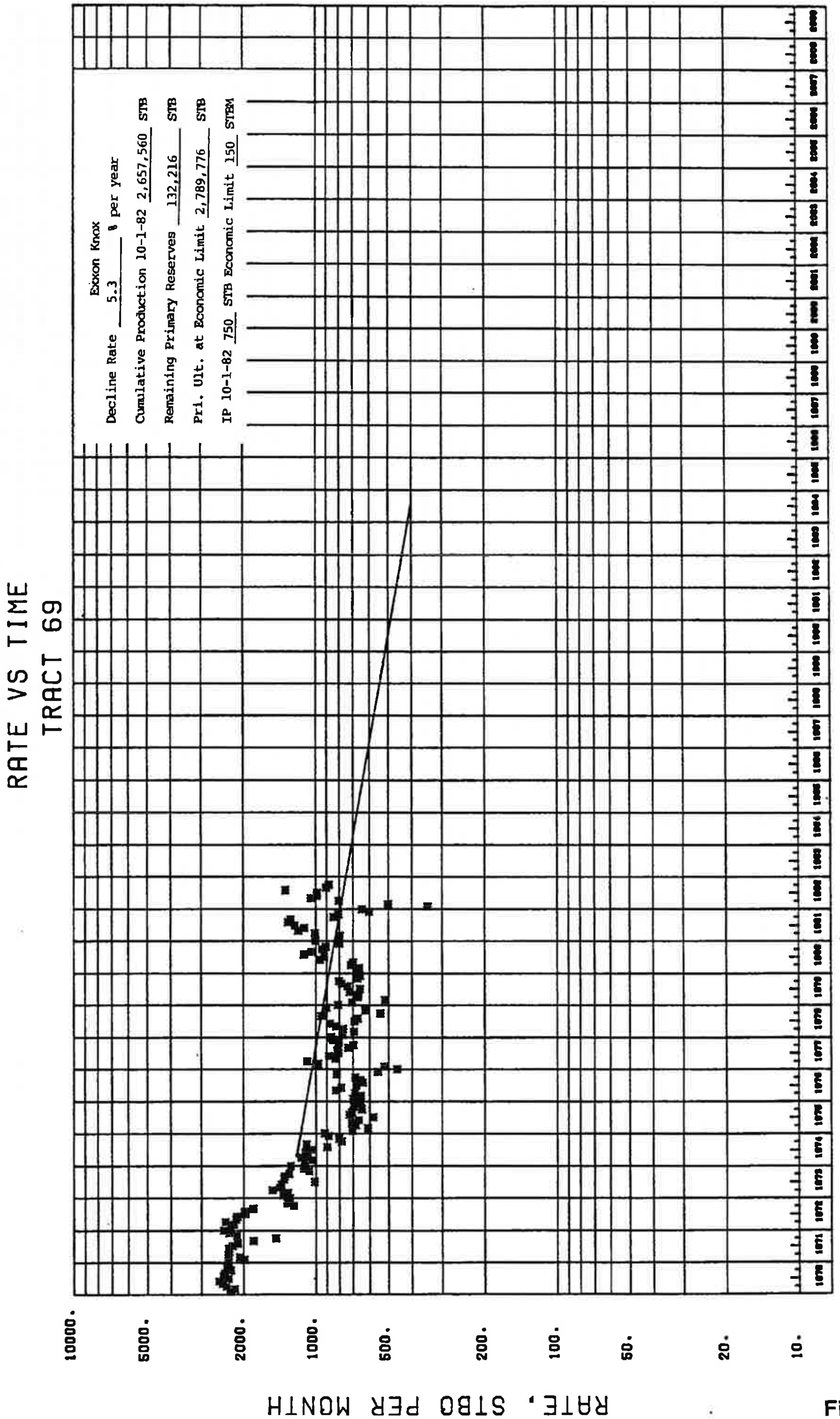

RATE VS TIME
TRACT 69
Exxon Knox
Decline Rate 5.3 % per year
Cumulative Production 10-1-82 2,657,560 STB
Remaining Primary Reserves 132,216 STB
Pri. Ult. at Economic Limit 2,789,776 STB
IP 10-1-82 750 STB Economic Limit 150 STBM
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.
RATE, STBO PER MONTH

Figure 65

RATE VS TIME
TRACT 70

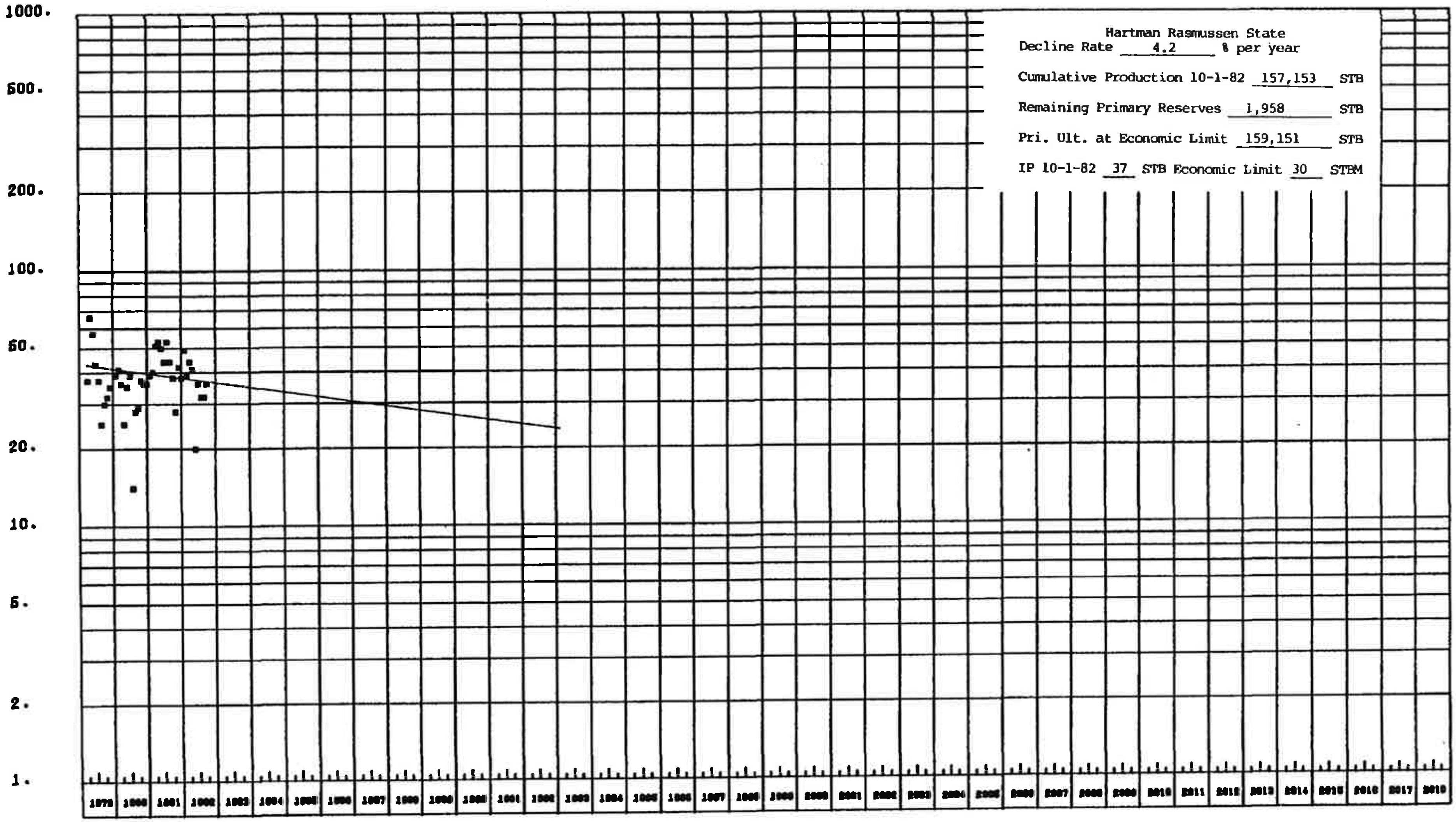


Figure 66

RATE VS TIME
TRACT 71

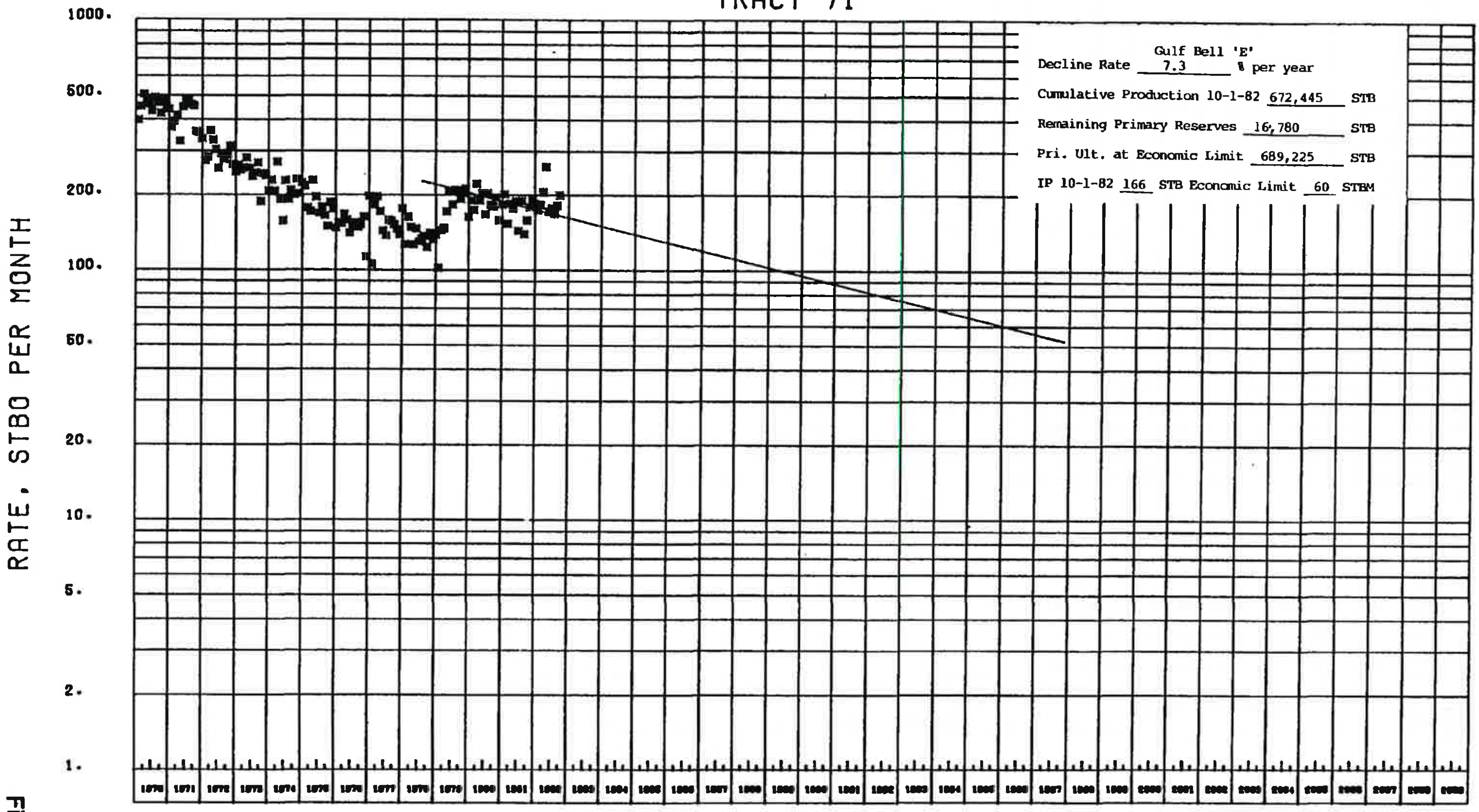


Figure 67

RATE VS TIME
TRACT 72

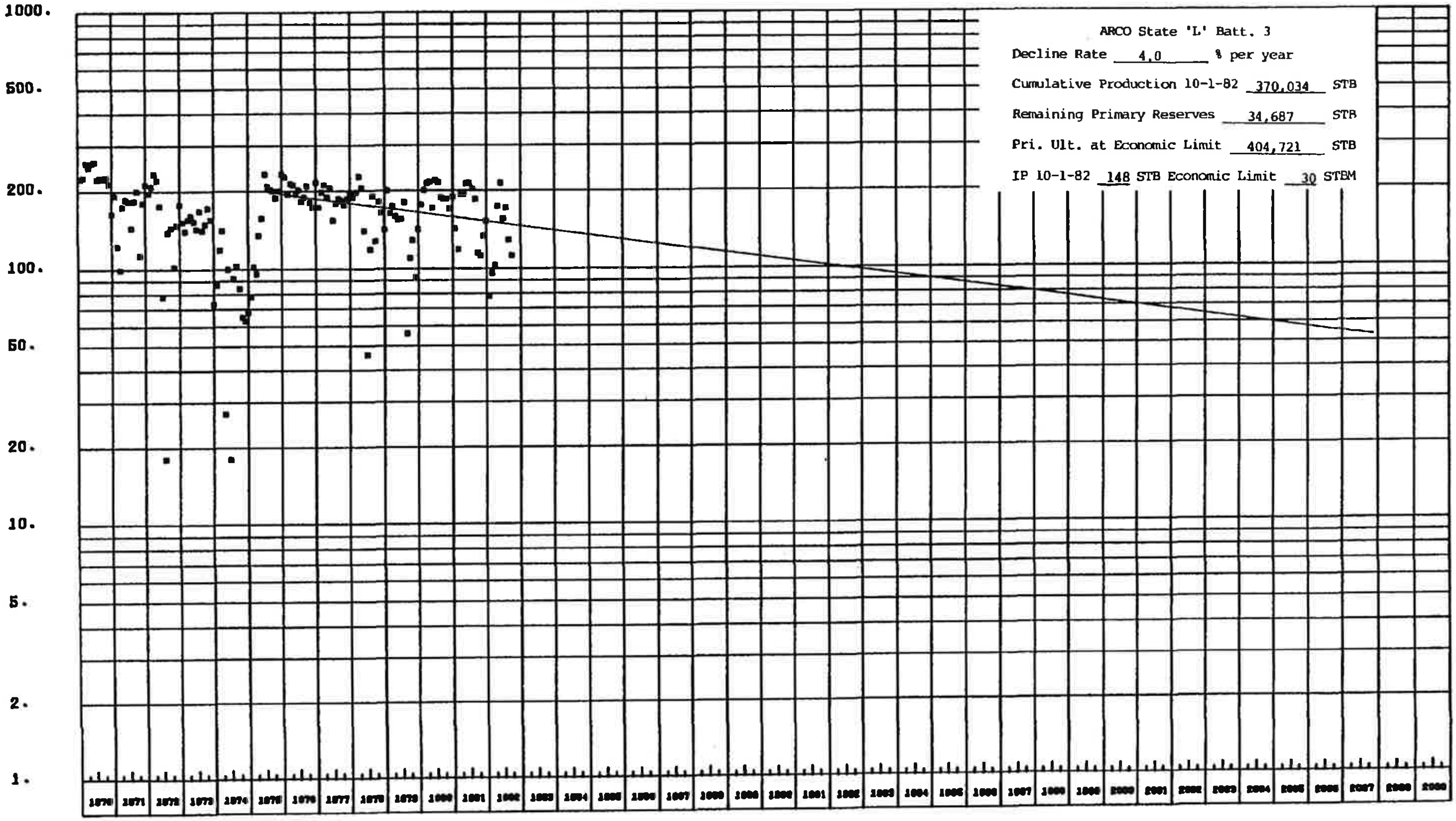


Figure 68

RATE VS TIME
TRACT 73

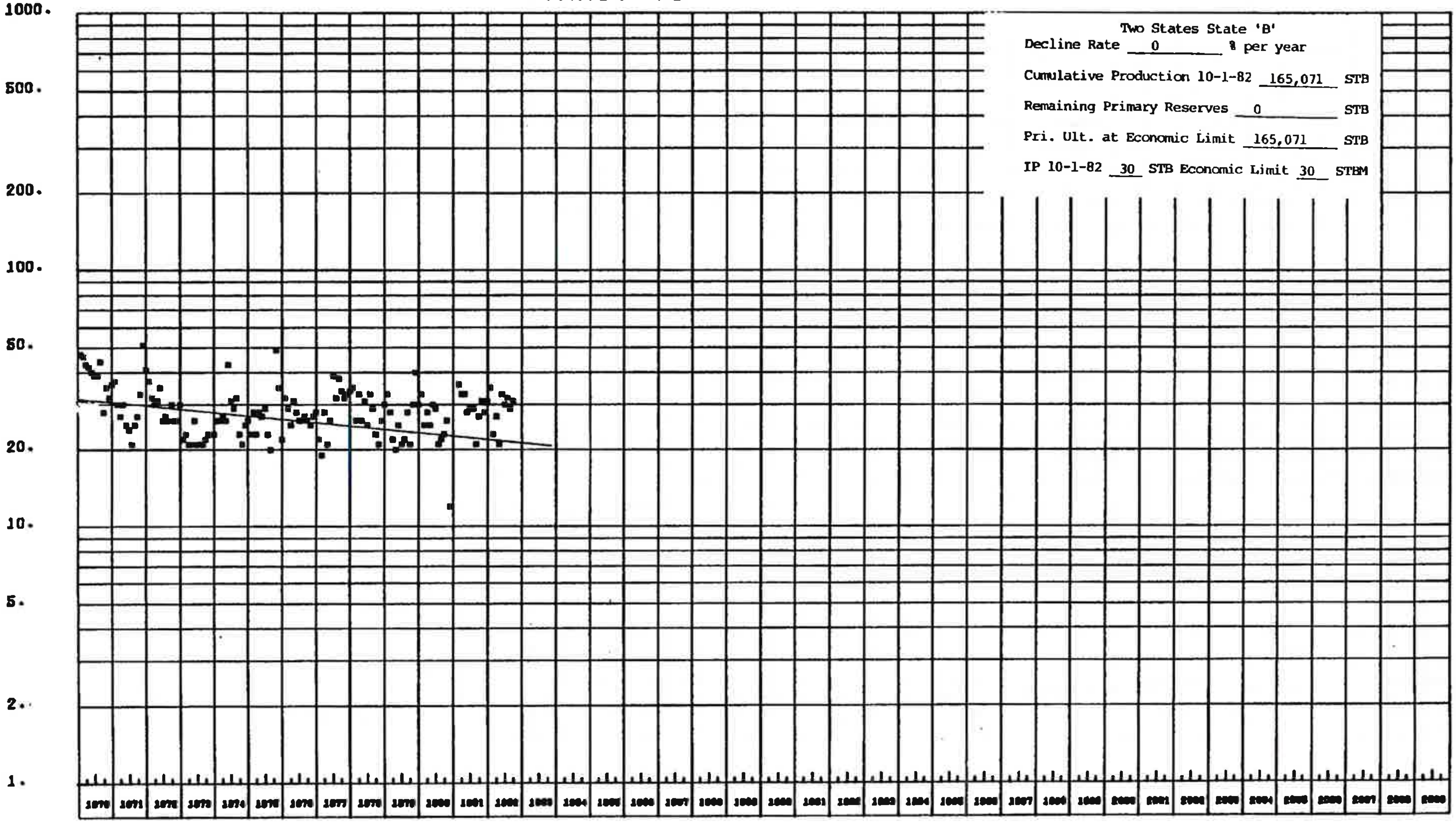


Figure 69

RATE VS TIME
TRACT 75

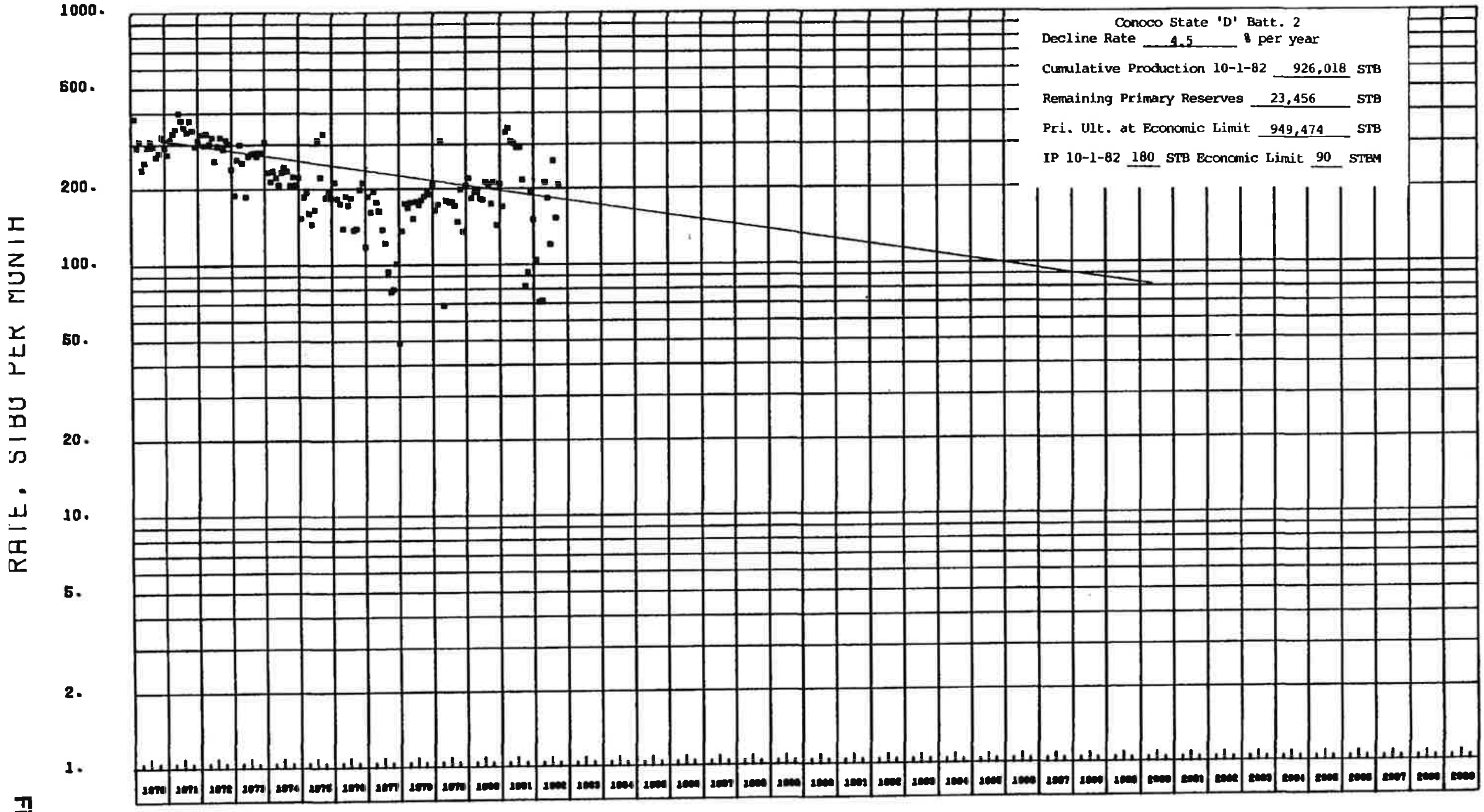


Figure 70

RATE VS TIME
TRACT 81

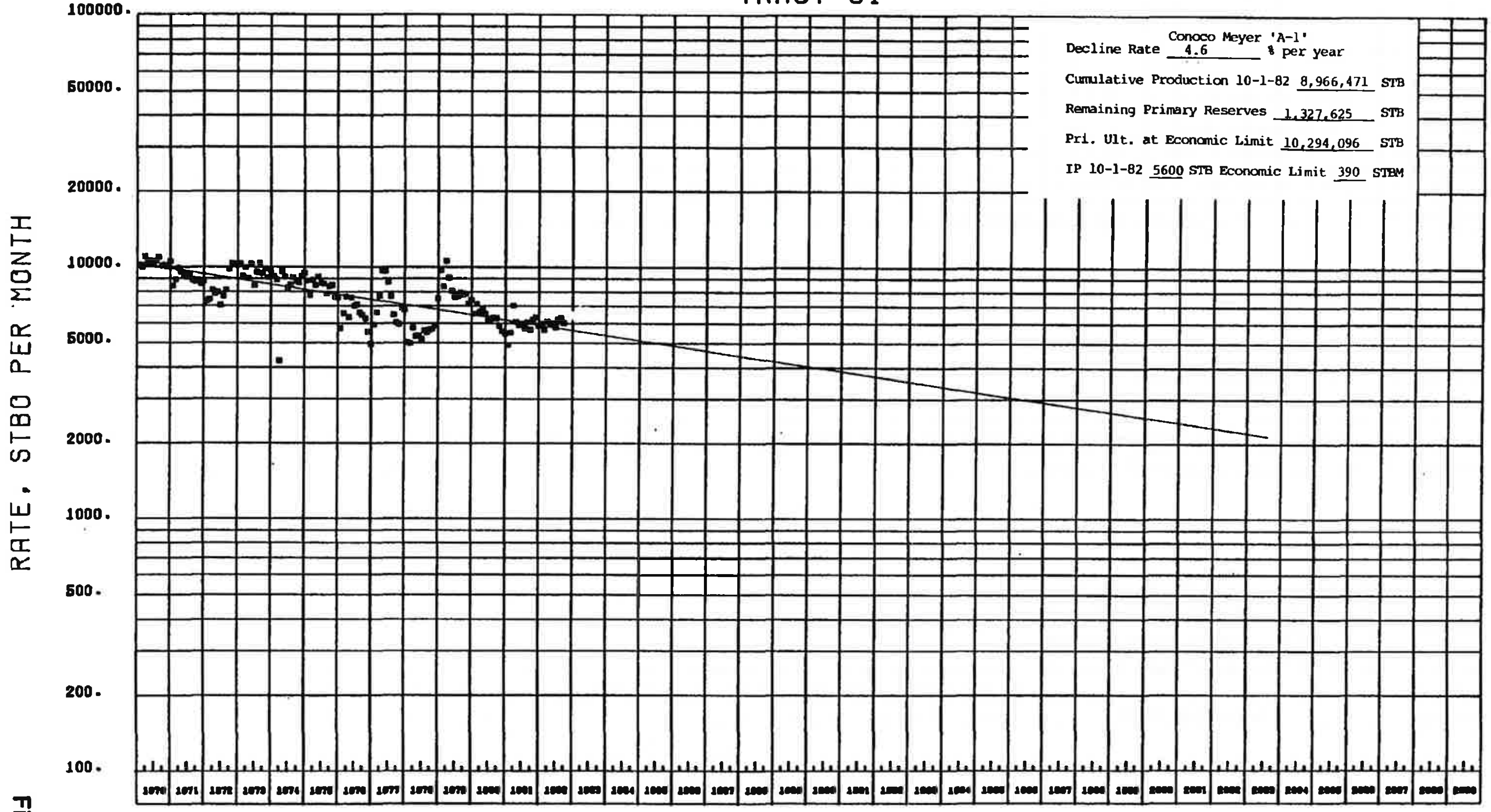


Figure 71

RATE VS TIME
TRACT 82

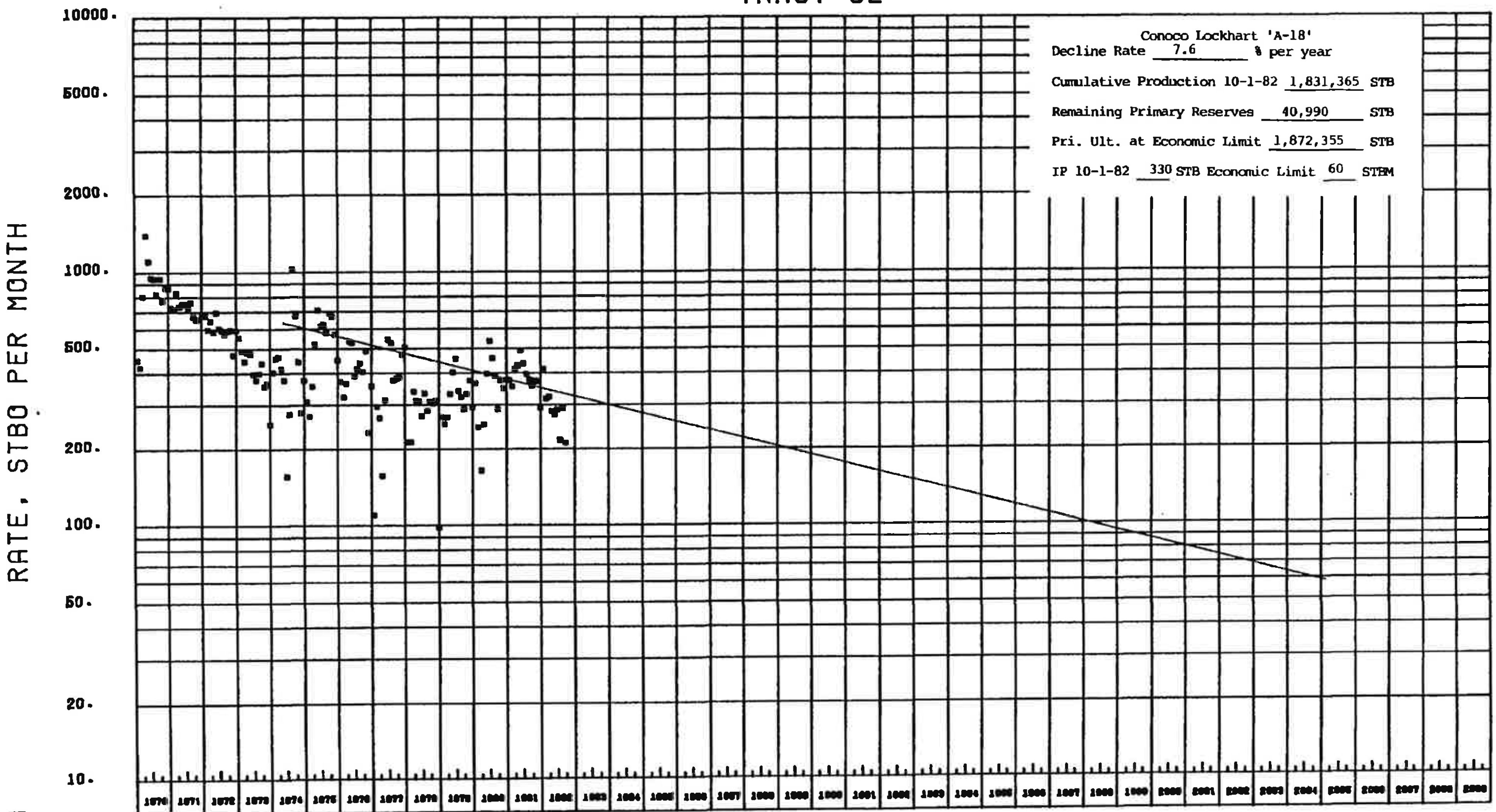
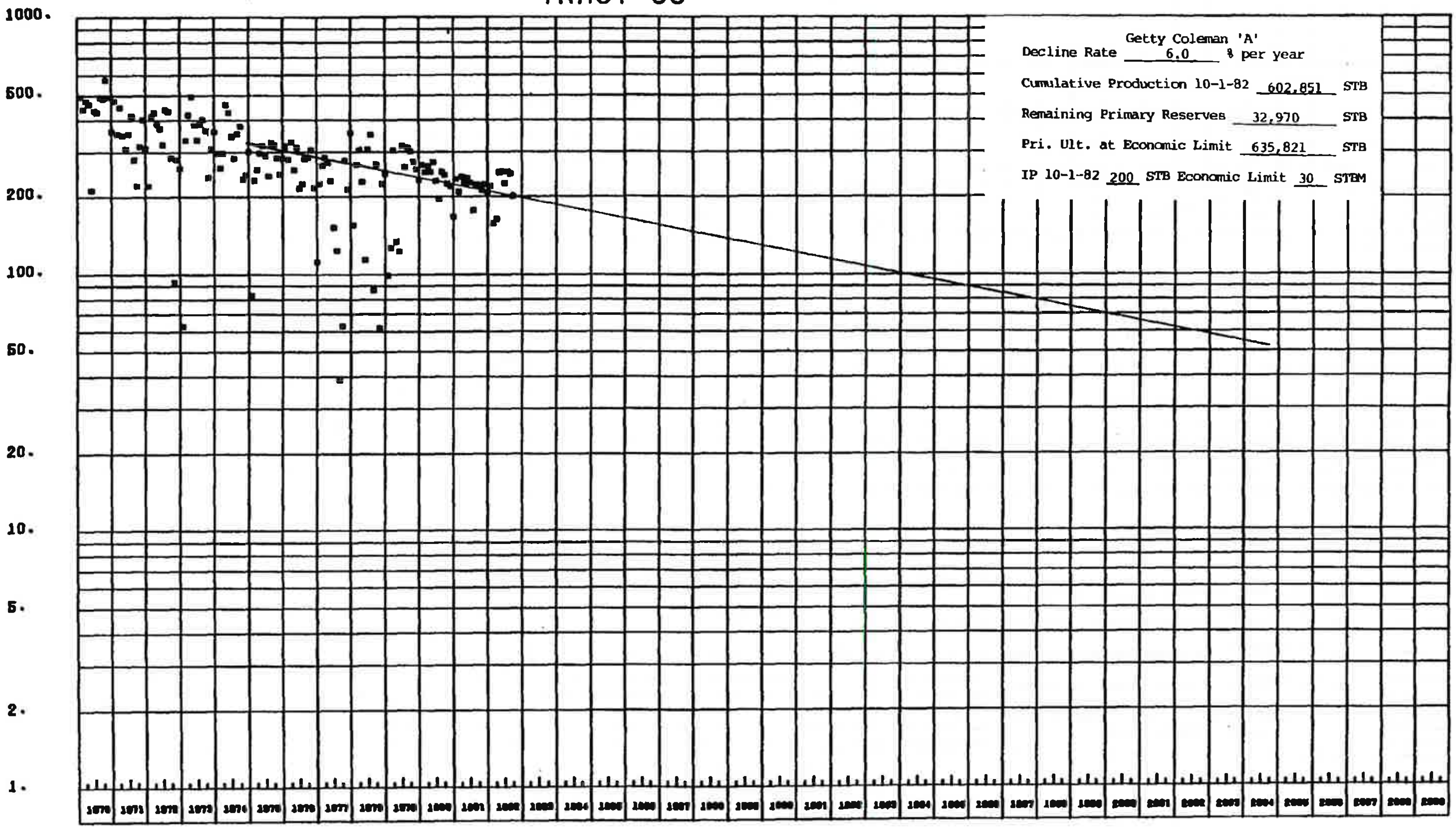


Figure 72

RATE VS TIME
TRACT 83



RATE VS TIME
TRACT 84

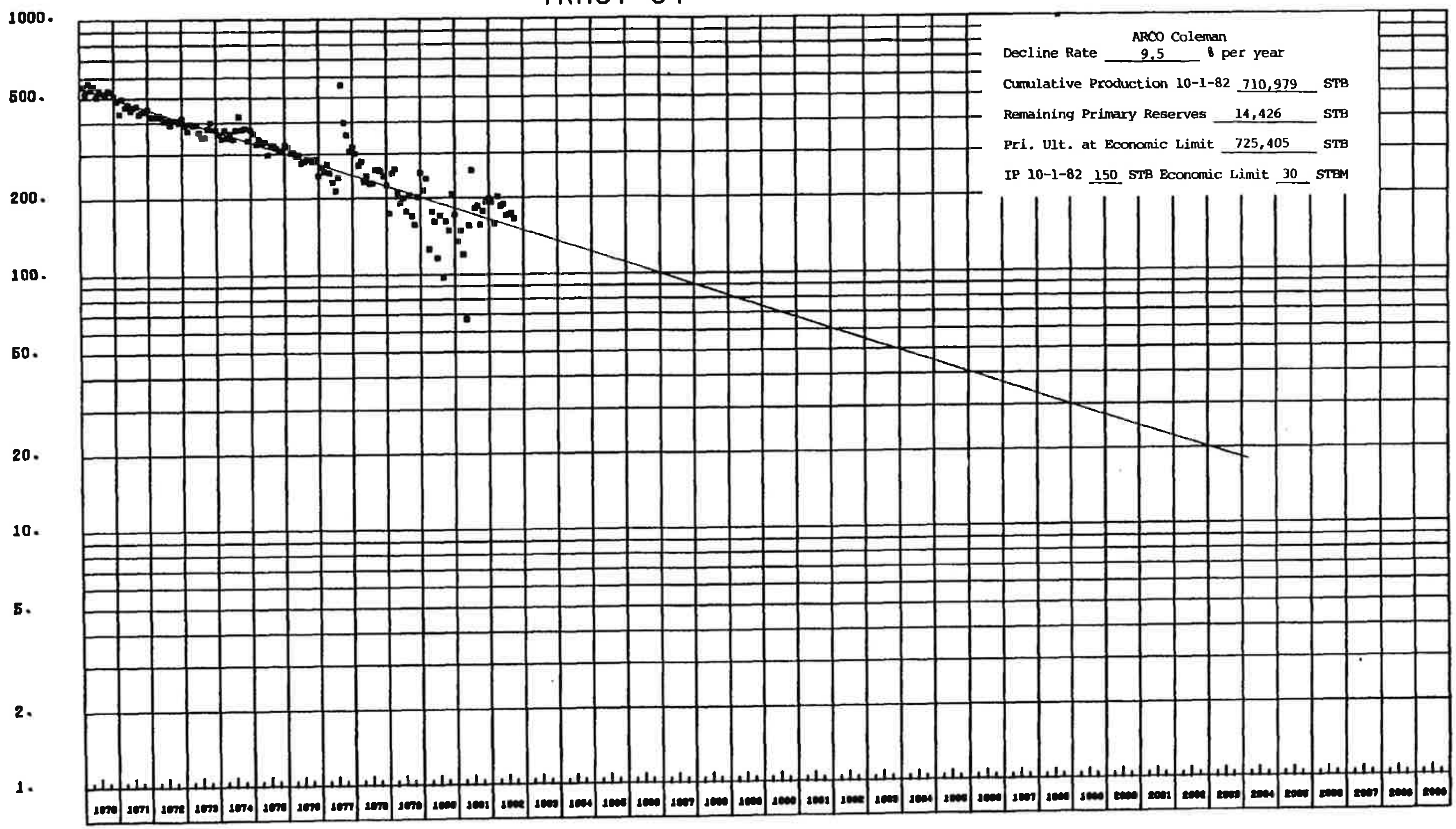


Figure 74

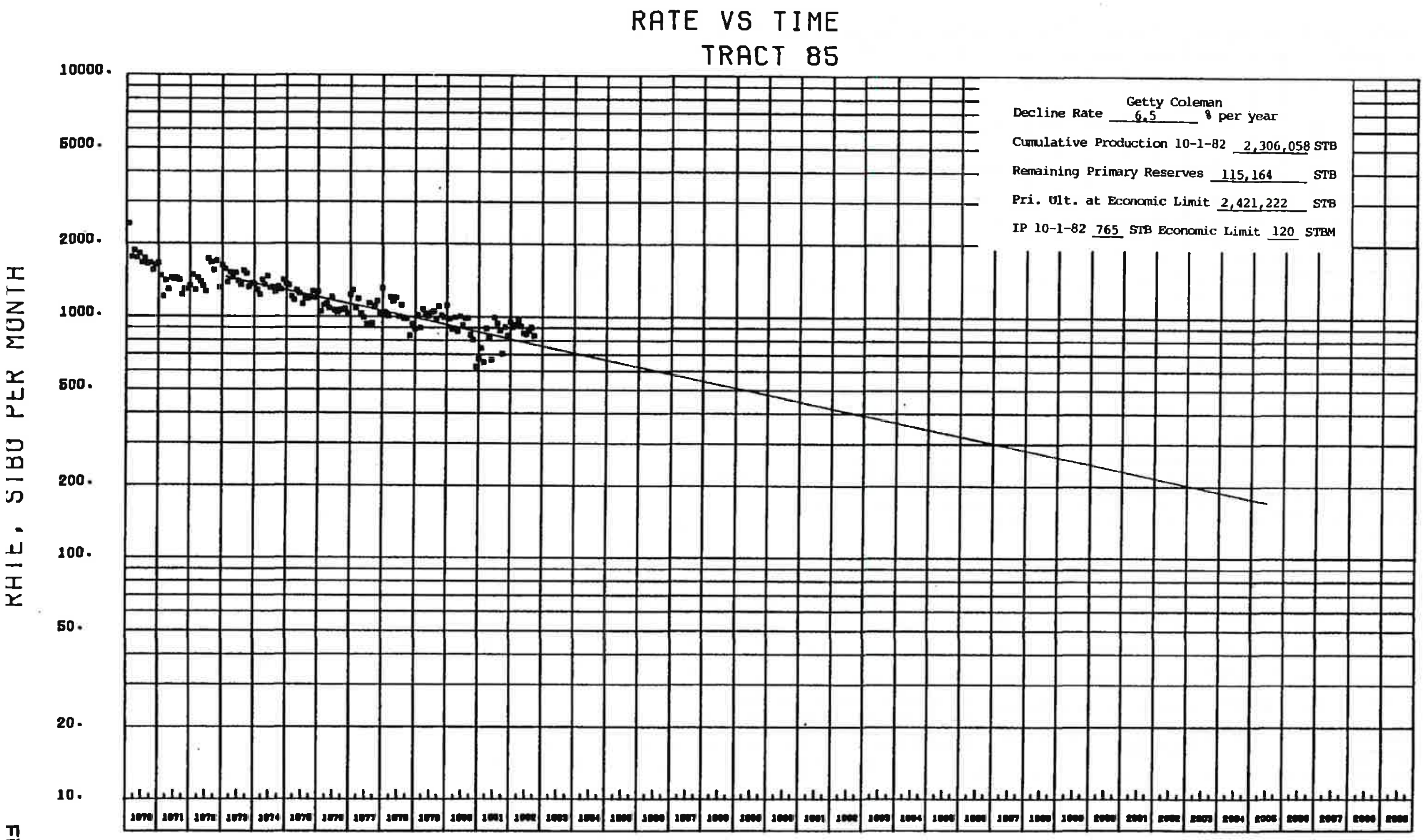

RATE VS TIME
TRACT 85
RATE, STBO PER MONTH
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.
Getty Coleman
Decline Rate 6.5 % per year
Cumulative Production 10-1-82 2,306,058 STB
Remaining Primary Reserves 115,164 STB
Pri. Ult. at Economic Limit 2,421,222 STB
IP 10-1-82 765 STB Economic Limit 120 STBM

Figure 75

RATE VS TIME
TRACT 86

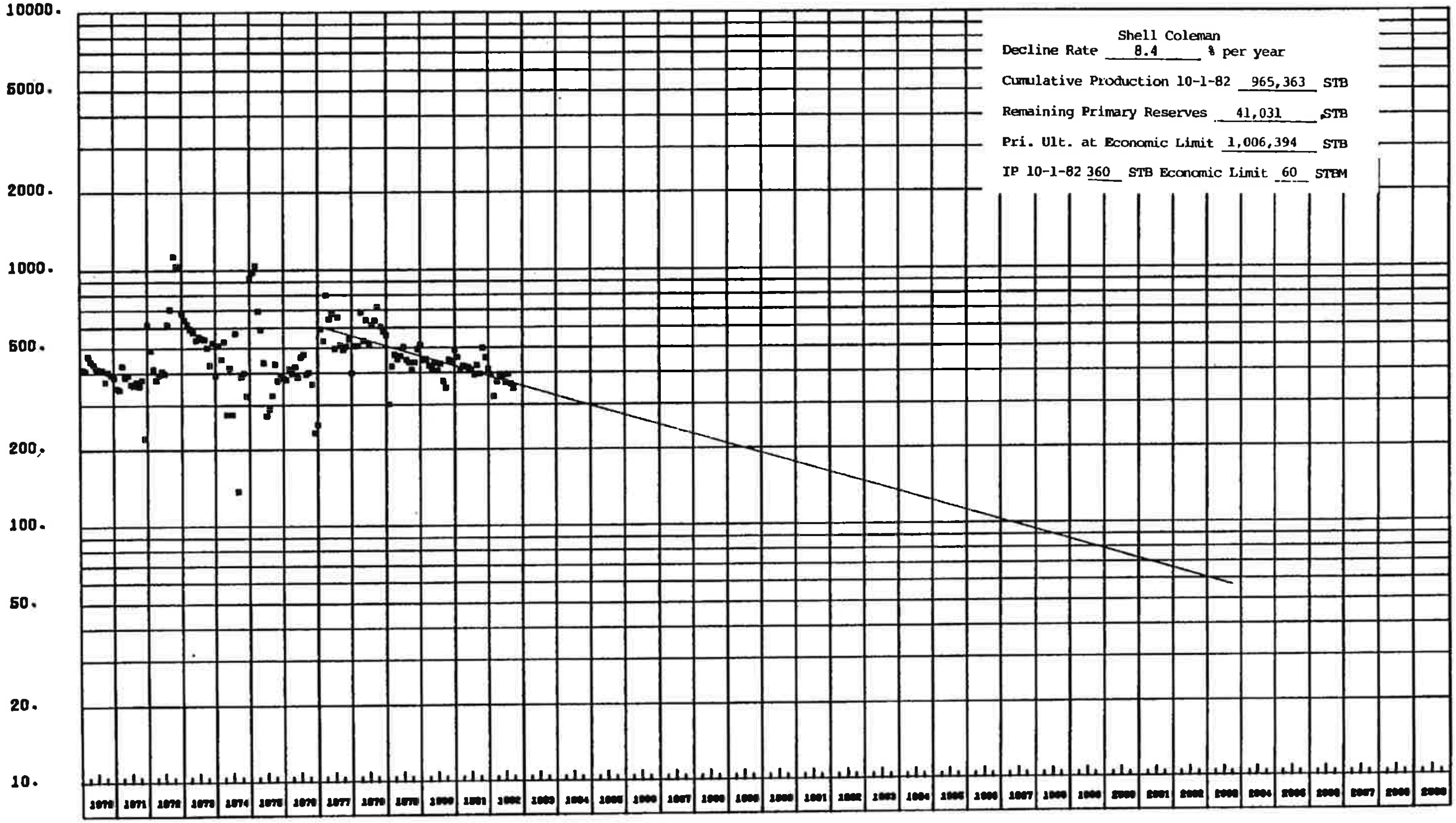


Figure 76

RATE VS TIME
TRACT 88

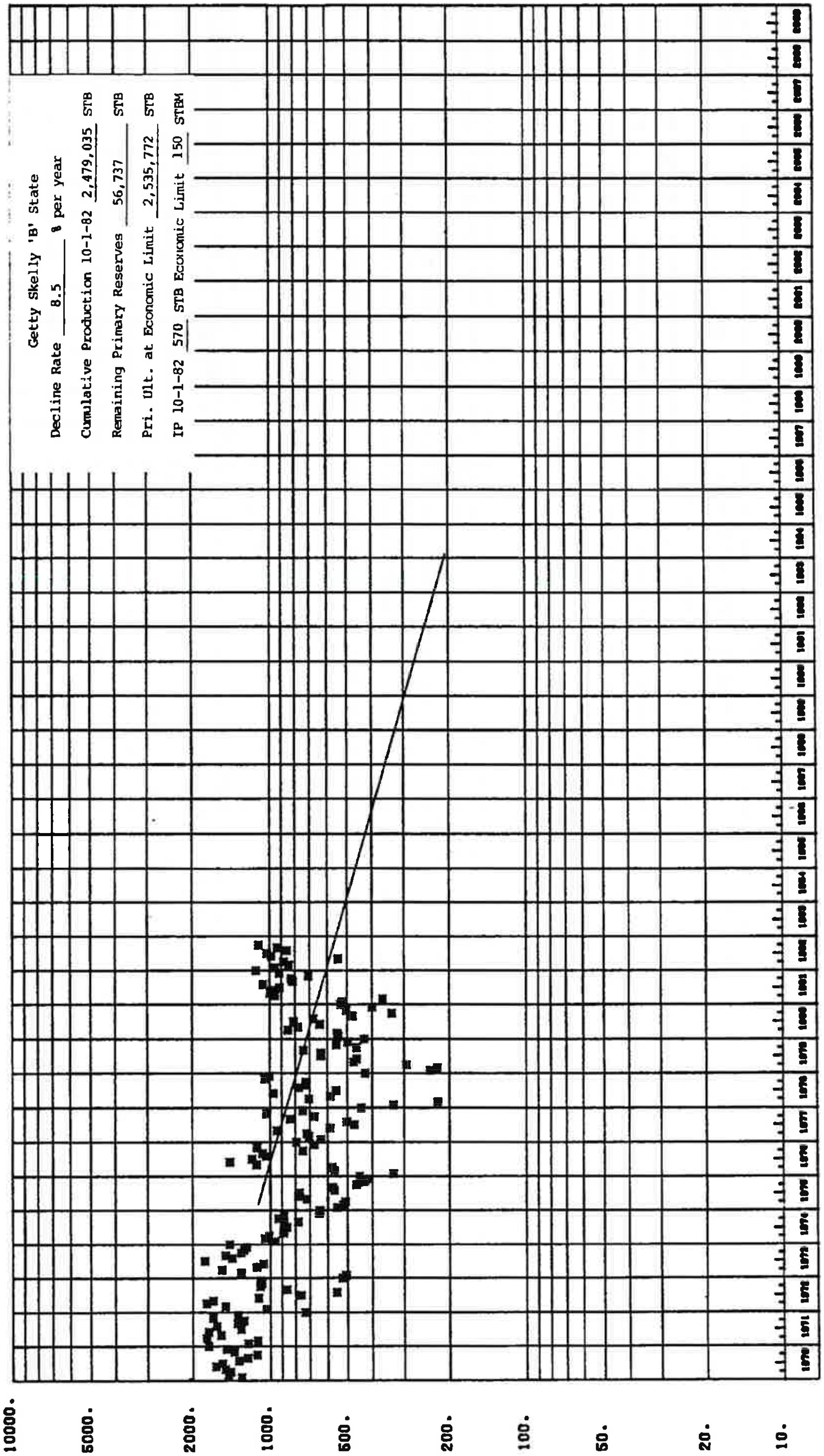


Figure 77

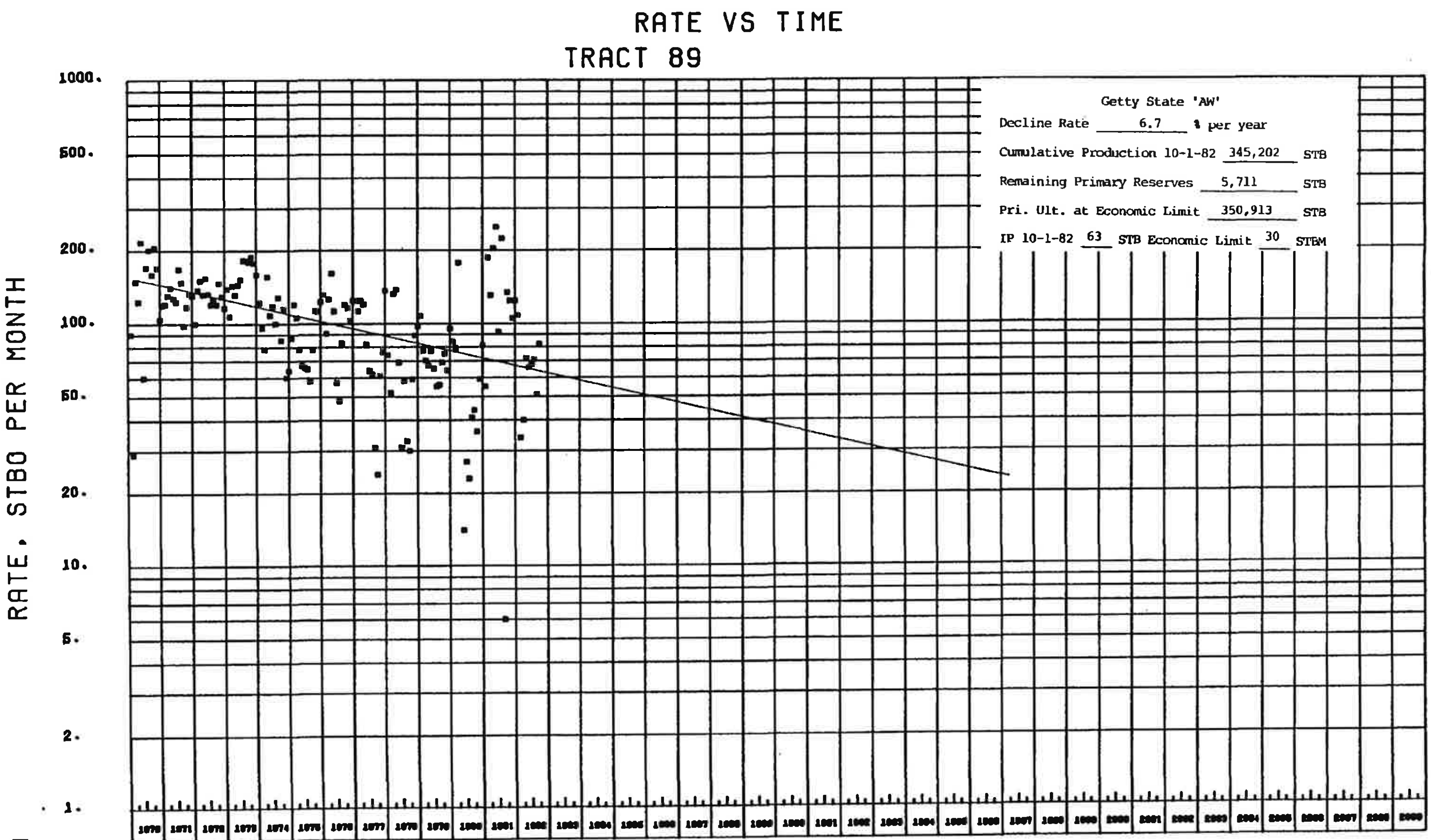
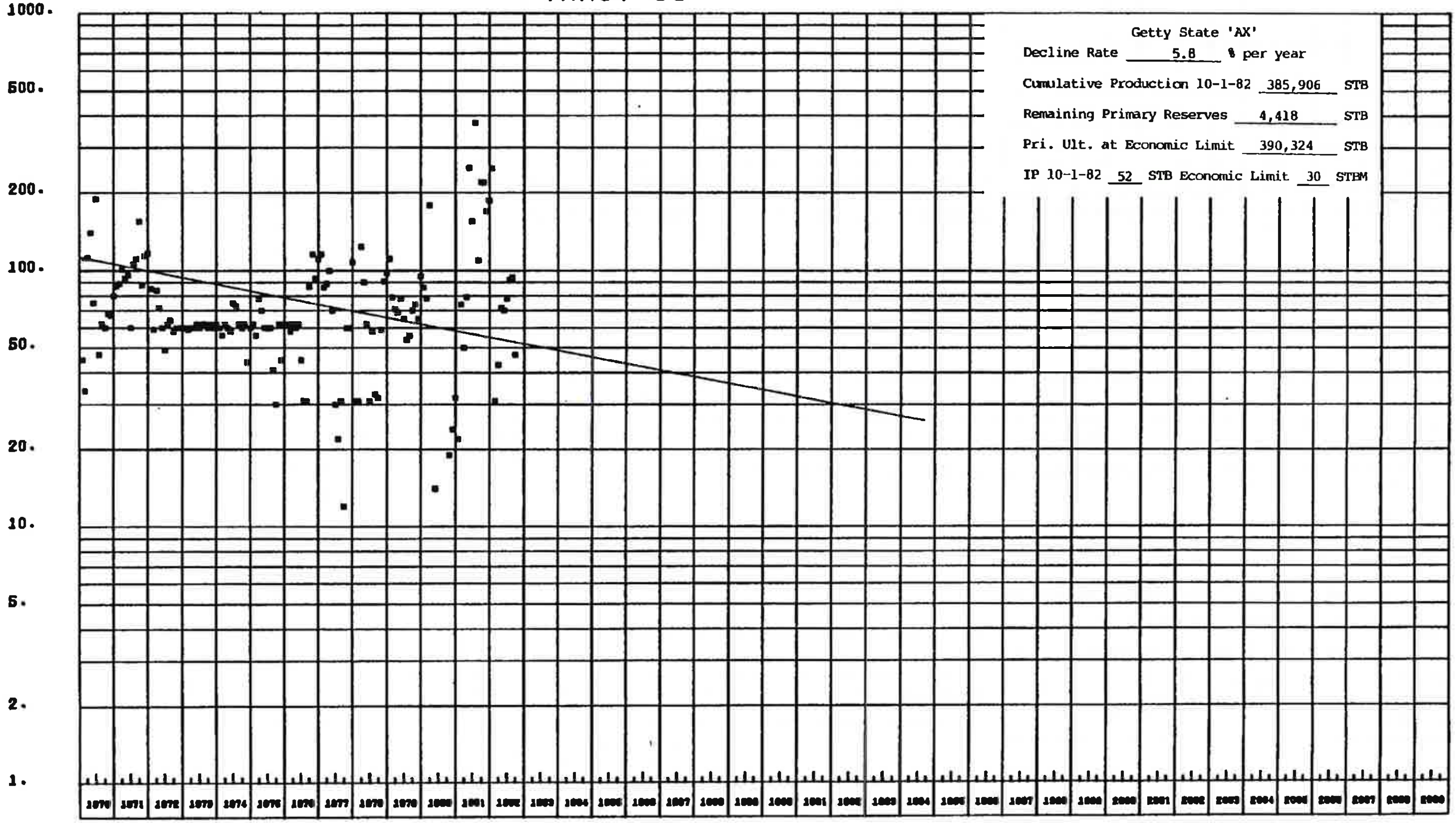

RATE VS TIME
TRACT 89
Getty State 'AW'
Decline Rate 6.7 % per year
Cumulative Production 10-1-82 345,202 STB
Remaining Primary Reserves 5,711 STB
Pri. Ult. at Economic Limit 350,913 STB
IP 10-1-82 63 STB Economic Limit 30 STBM
RATE, STBO PER MONTH
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.

Figure 78

RATE VS TIME

TRACT 90



RATE, STBO PER MONTH

Figure 79

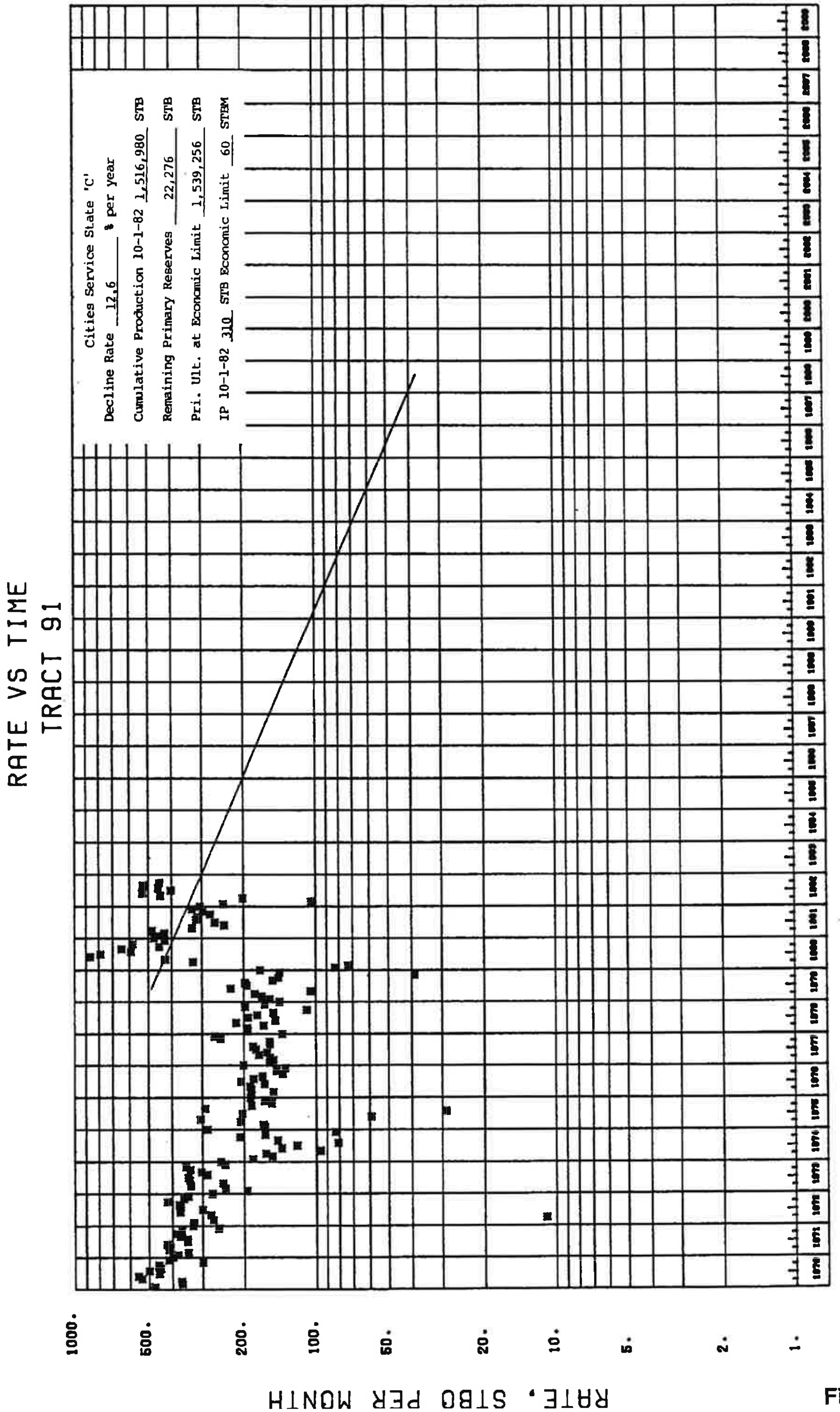

RATE VS TIME
TRACT 91
Cities Service State 'C'
Decline Rate 12.6 % per year
Cumulative Production 10-1-82 1,516,980 STB
Remaining Primary Reserves 22,276 STB
Pri. Ult. at Economic Limit 1,539,256 STB
IP 10-1-82 310 STB Economic Limit 60 STBM
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.
RATE, STBO PER MONTH

Figure 80

RATE VS TIME
TRACT 92

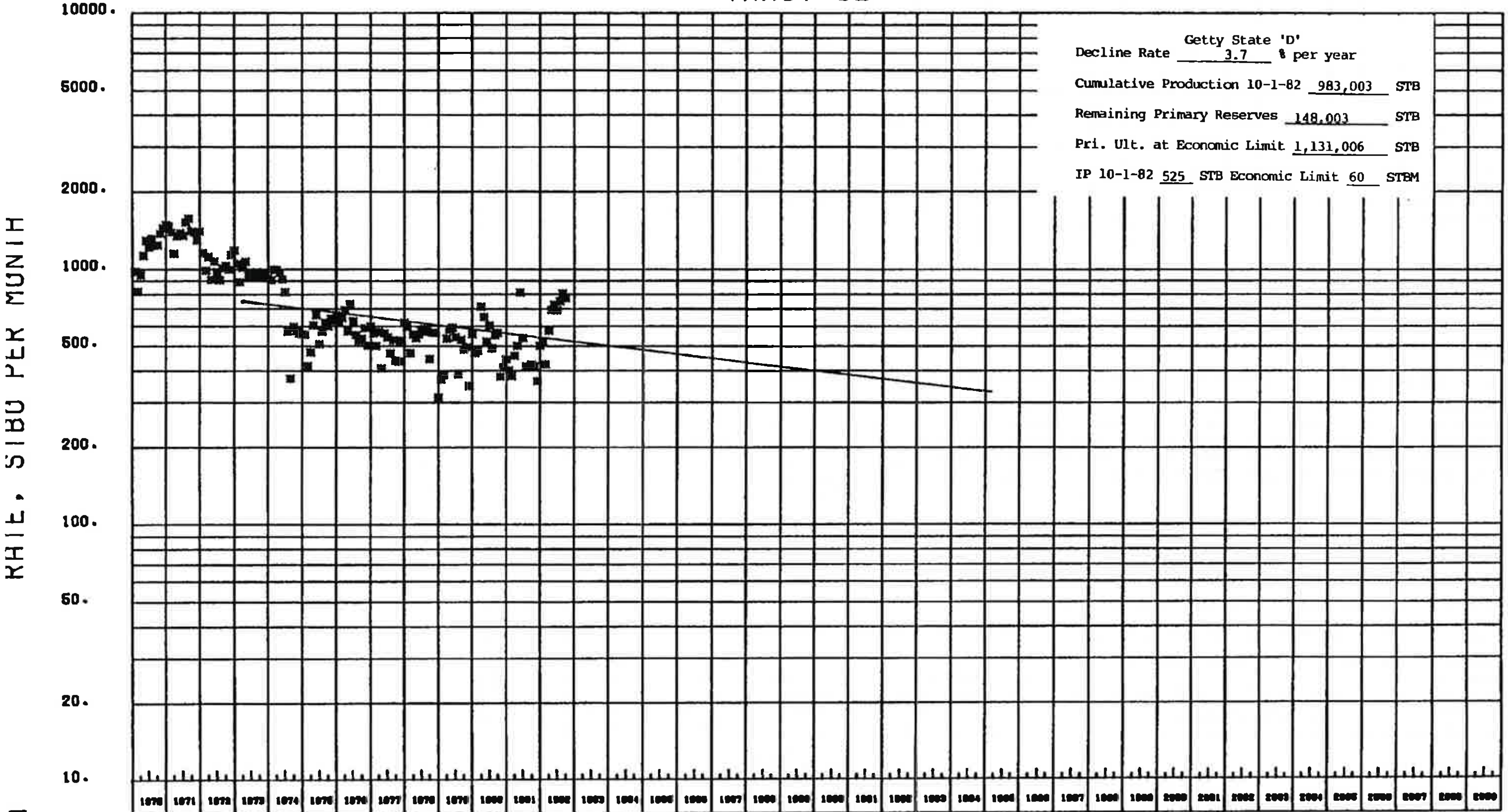


Figure 81

RATE VS TIME
TRACT 93

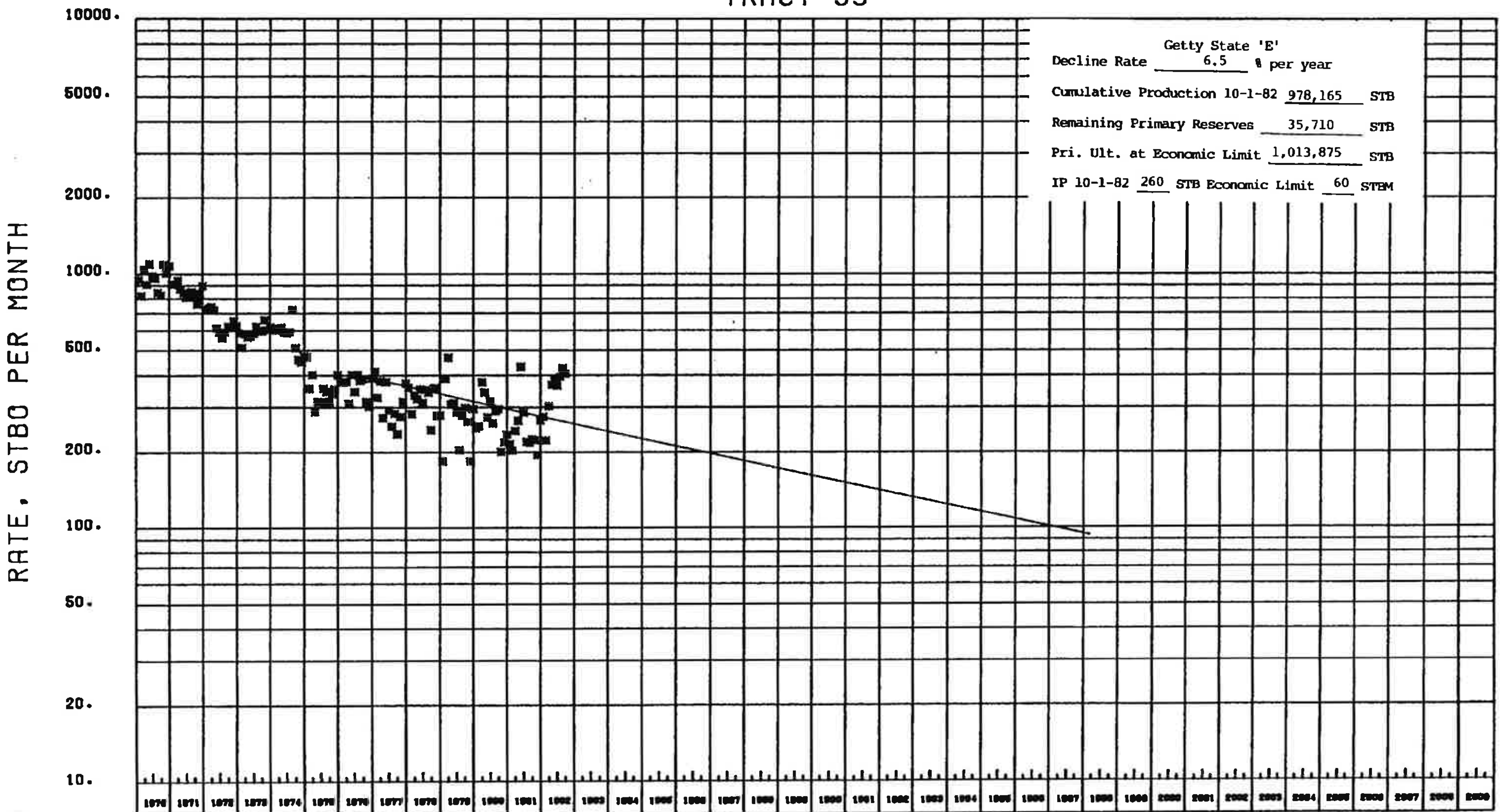


Figure 82

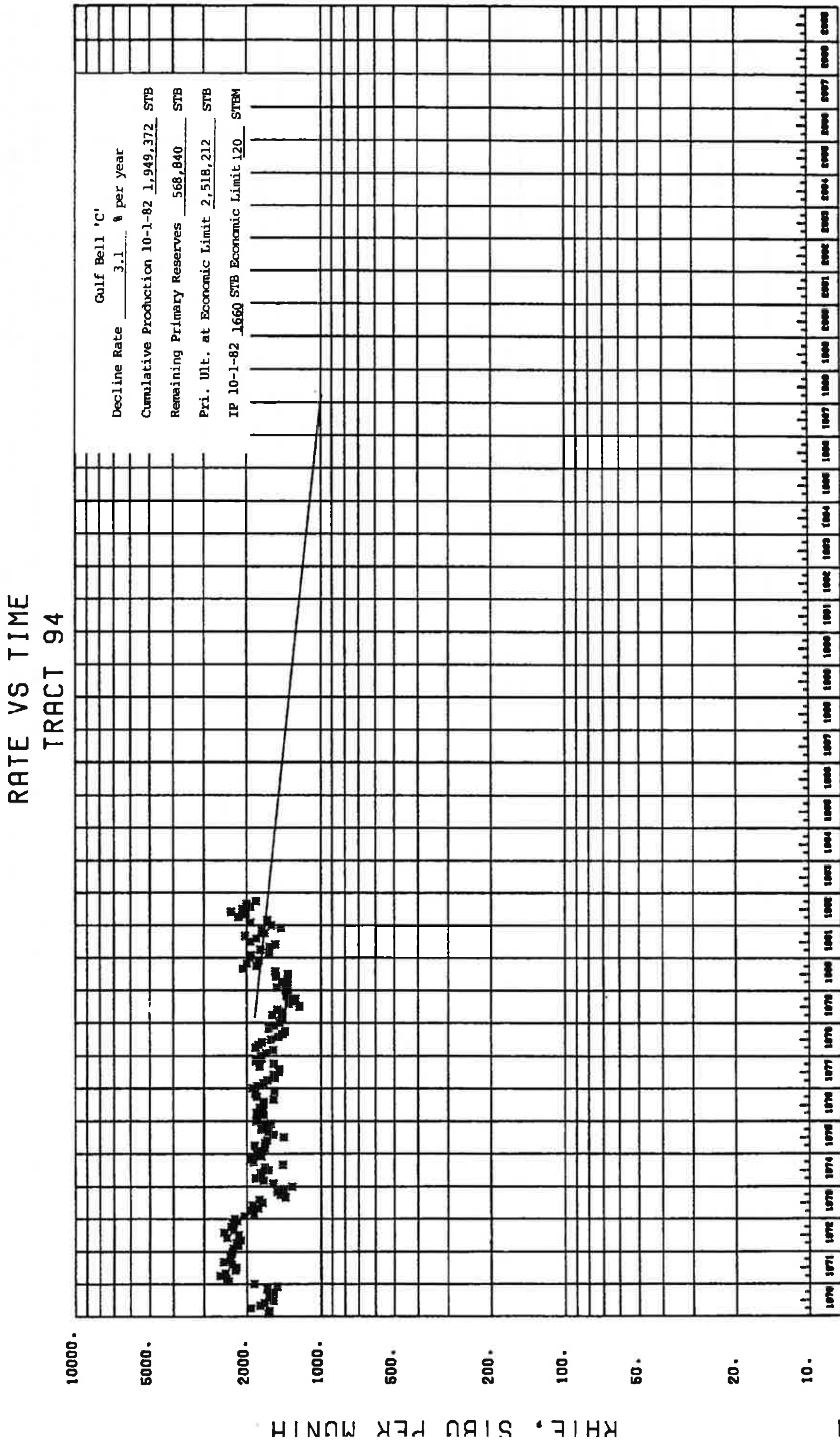

RATE VS TIME
TRACT 94
Gulf Bell 'C'
Decline Rate 3.1 % per year
Cumulative Production 10-1-82 1,949,372 STB
Remaining Primary Reserves 568,840 STB
Pri. Ult. at Economic Limit 2,518,212 STB
IP 10-1-82 1660 STB Economic Limit 120 STBM
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.
RATE, STBO PER MONTH

Figure 83

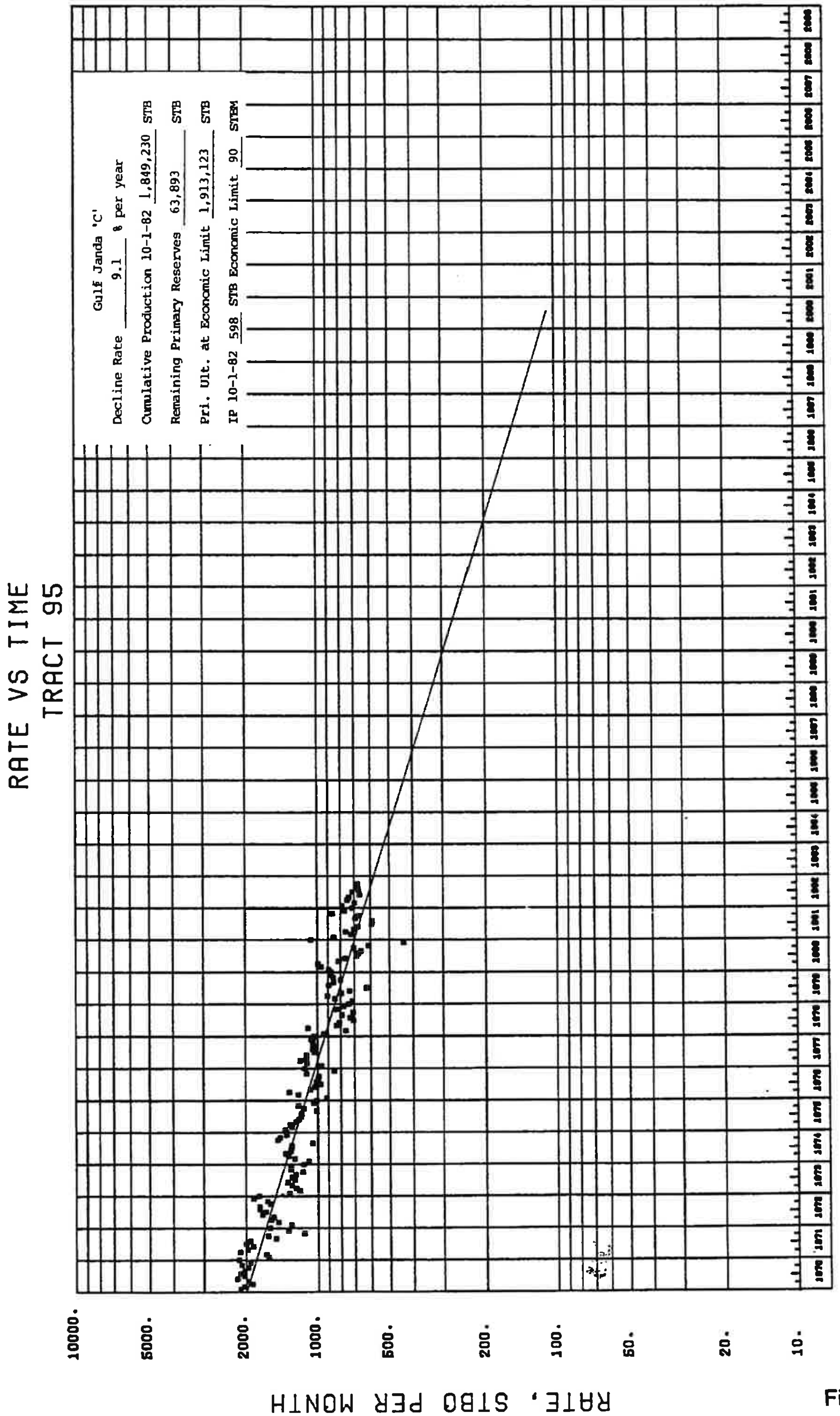

RATE VS TIME
TRACT 95
Gulf Janda 'C'
Decline Rate 9.1 % per year
Cumulative Production 10-1-82 1,849,230 STB
Remaining Primary Reserves 63,893 STB
Pri. Ult. at Economic Limit 1,913,123 STB
IP 10-1-82 598 STB Economic Limit 90 STBM
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.
RATE, STBO PER MONTH

Figure 84

RATE VS TIME
TRACT 96

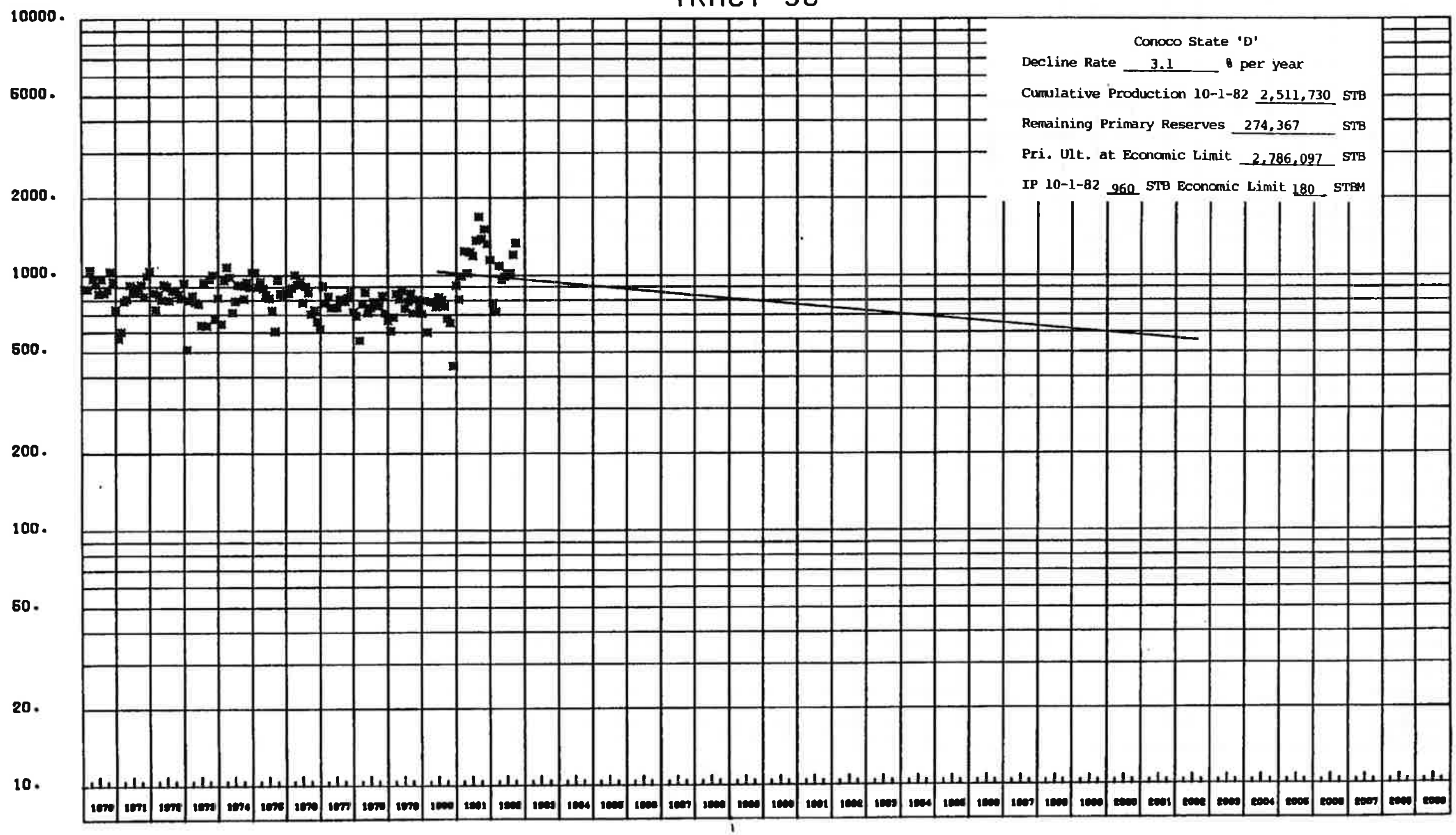


Figure 85

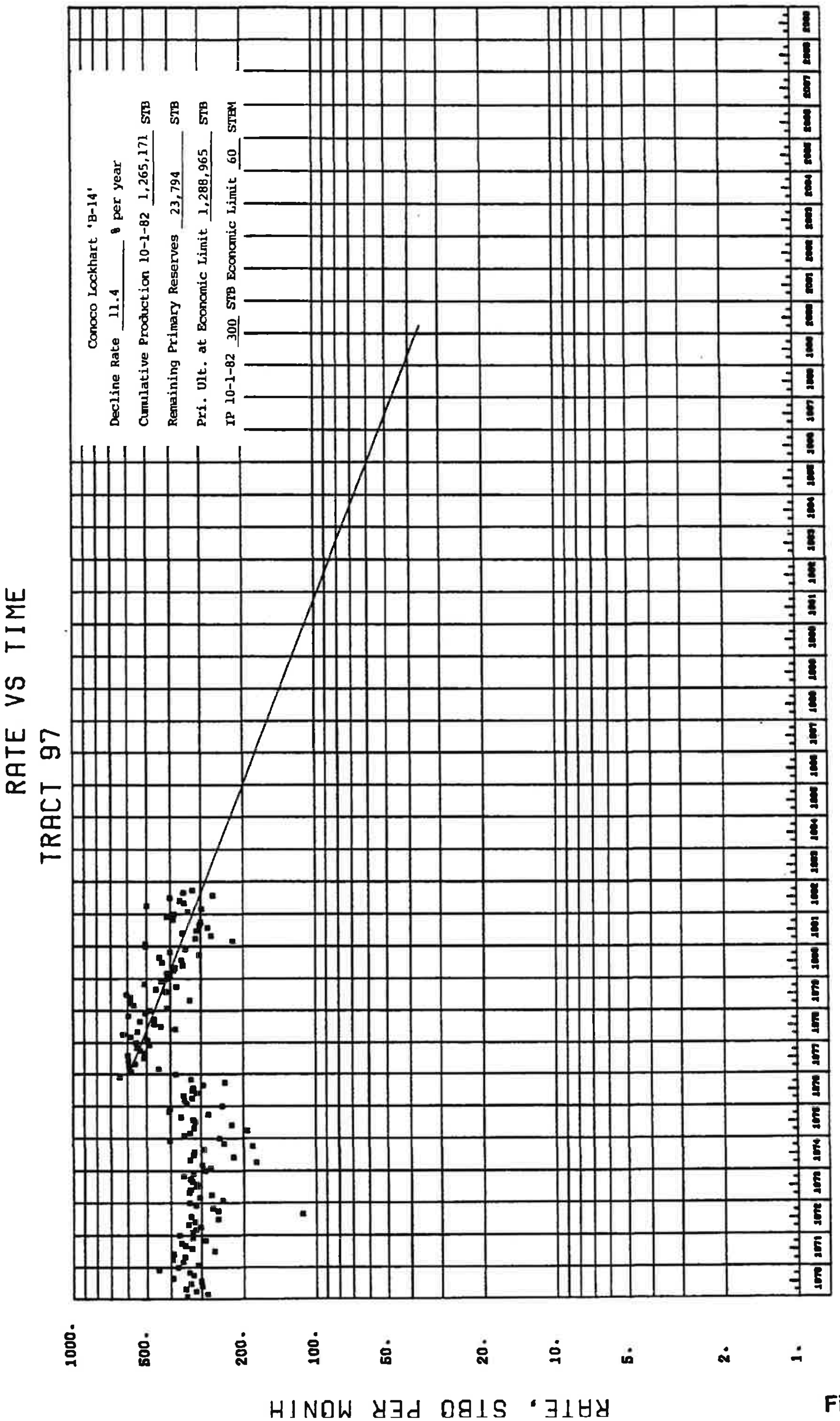

RATE VS TIME
TRACT 97
Conoco Lockhart 'B-14'
Decline Rate 11.4 % per year
Cumulative Production 10-1-82 1,265,171 STB
Remaining Primary Reserves 23,794 STB
Pri. Ult. at Economic Limit 1,288,965 STB
IP 10-1-82 300 STB Economic Limit 60 STBM
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.
RATE, STBO PER MONTH

Figure 86

RATE VS TIME
TRACT 98

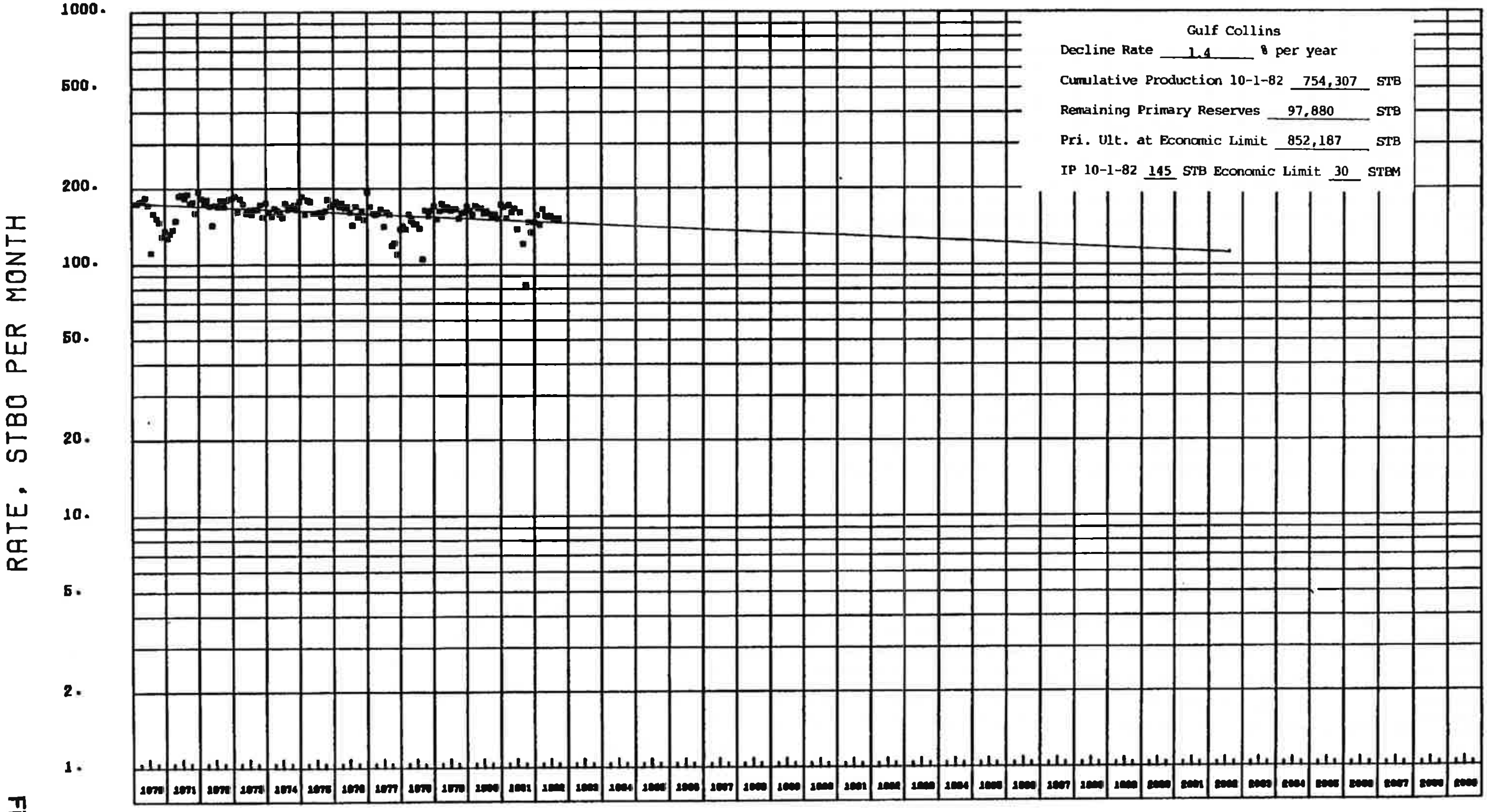


Figure 87

RATE VS TIME

TRACT 99

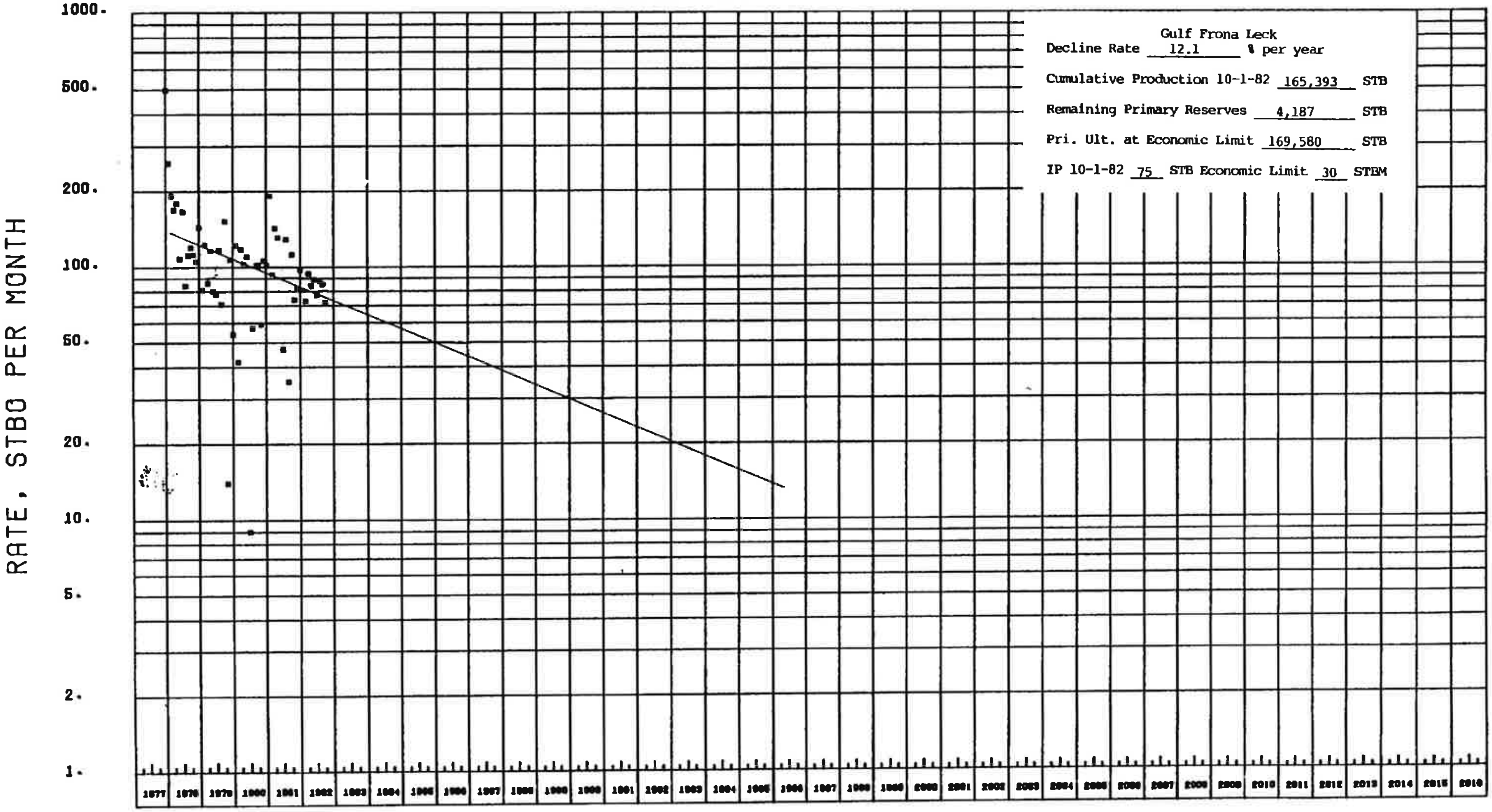


Figure 88

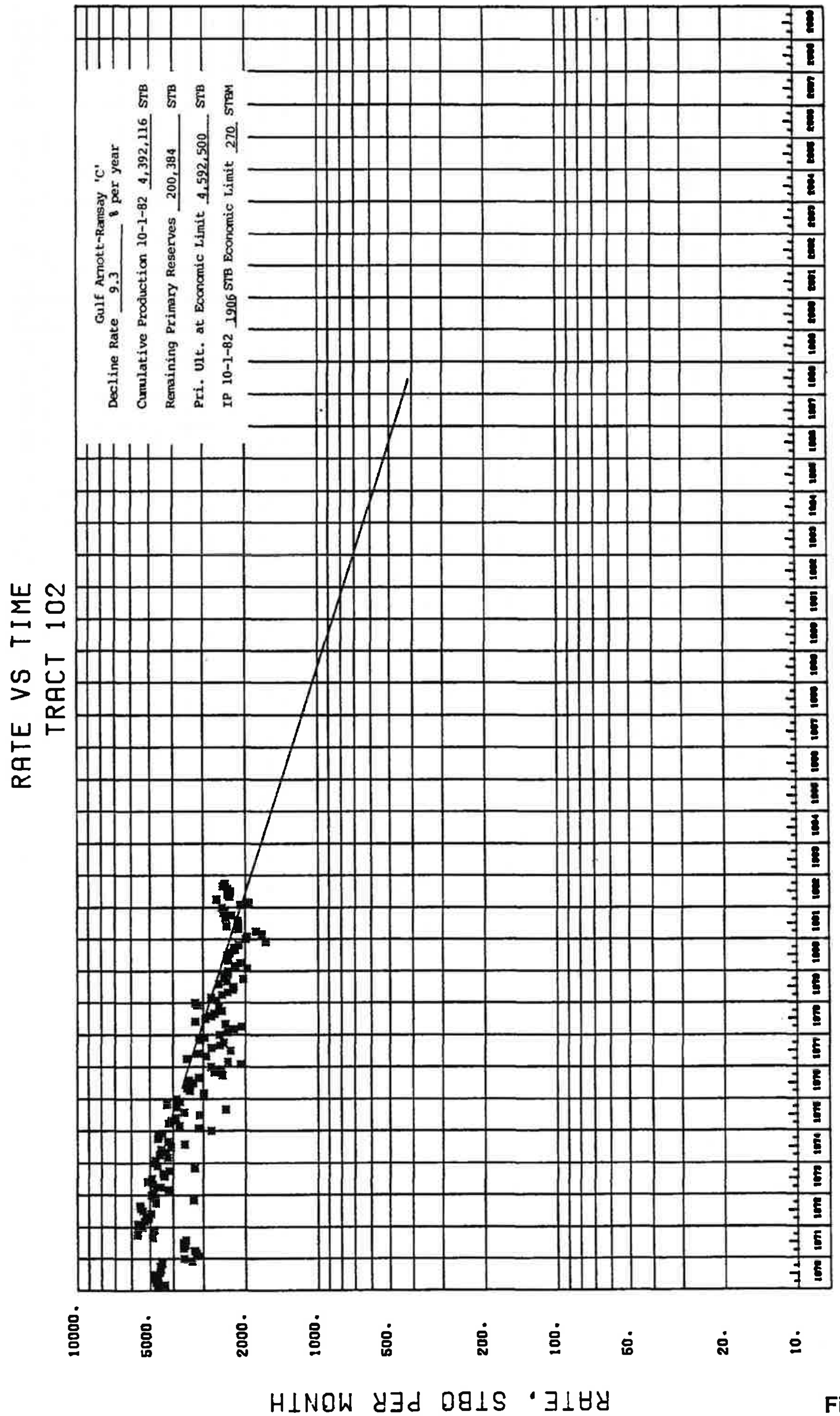

RATE VS TIME
TRACT 102
Gulf Arnott-Ramsay 'C'
Decline Rate 9.3 % per year
Cumulative Production 10-1-82 4,392,116 STB
Remaining Primary Reserves 200,384 STB
Pri. Ult. at Economic Limit 4,592,500 STB
IP 10-1-82 1906 STB Economic Limit 270 STBM
10000.
5000.
2000.
1000.
500.
200.
100.
50.
20.
10.
RATE, STBO PER MONTH

Figure 89

RATE VS TIME
TRACT 103

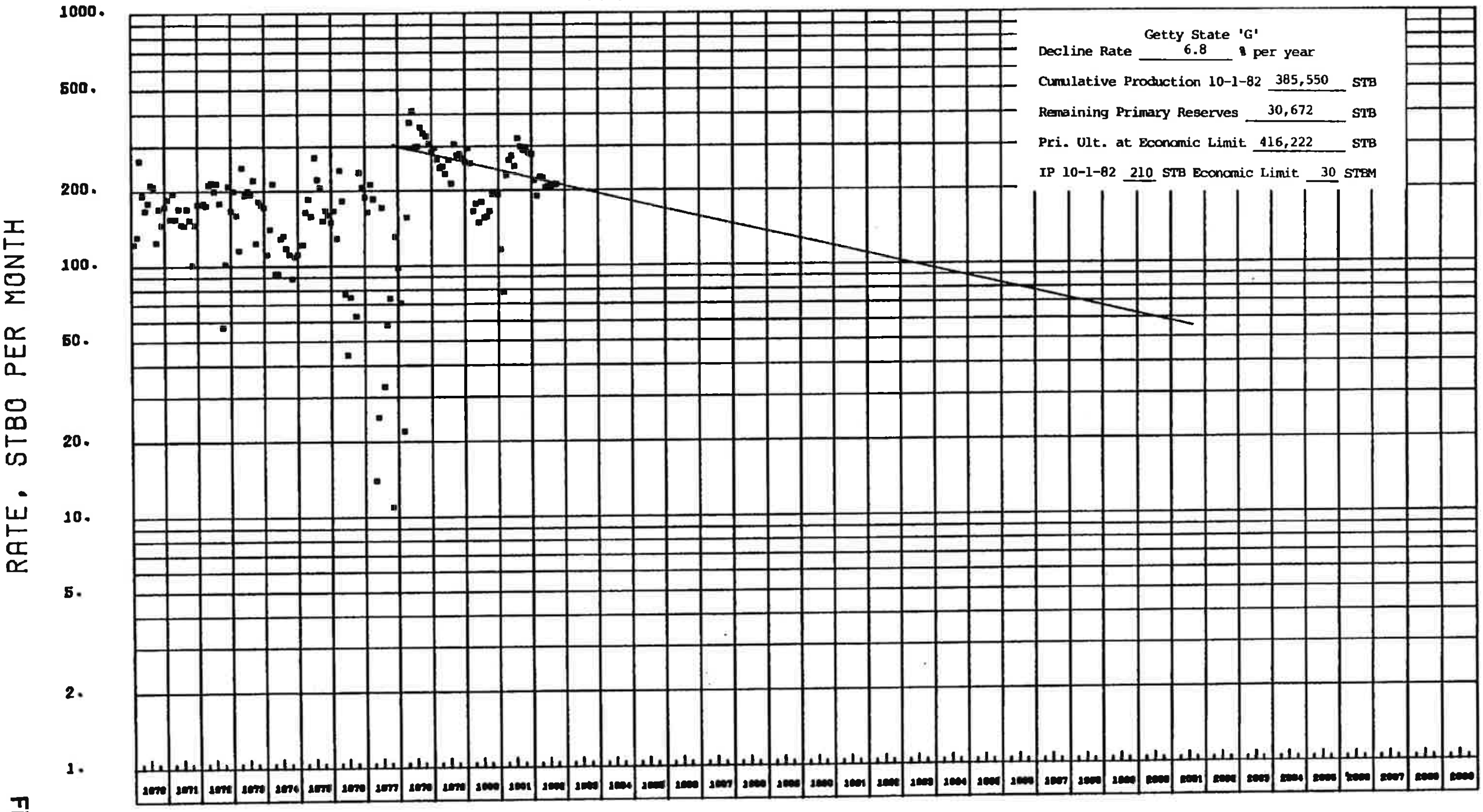


Figure 90

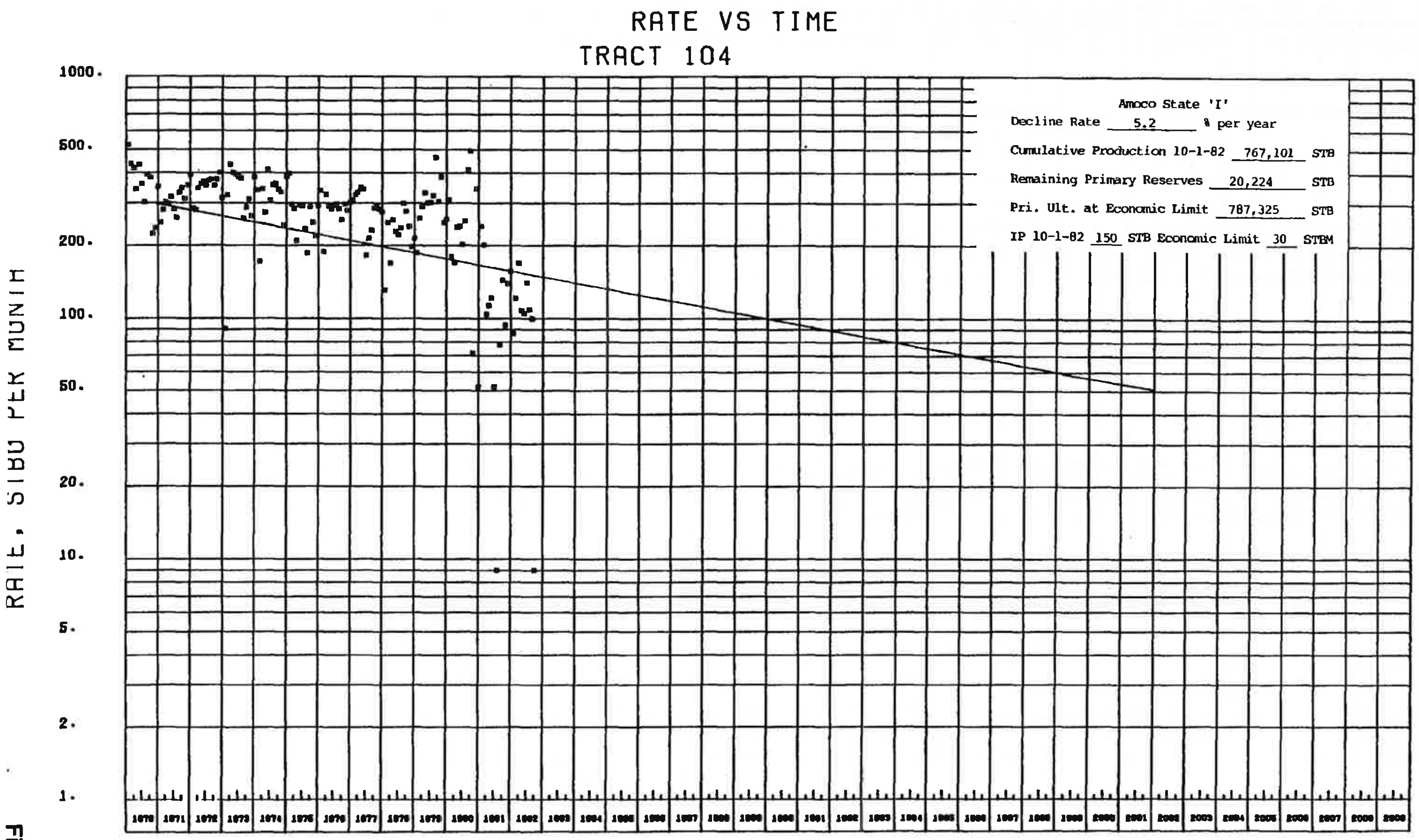

RATE VS TIME
TRACT 104
Amoco State 'I'
Decline Rate 5.2 % per year
Cumulative Production 10-1-82 767,101 STB
Remaining Primary Reserves 20,224 STB
Pri. Ult. at Economic Limit 787,325 STB
IP 10-1-82 150 STB Economic Limit 30 STBM
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.
RATE, STBO PER MONTH

Figure 91

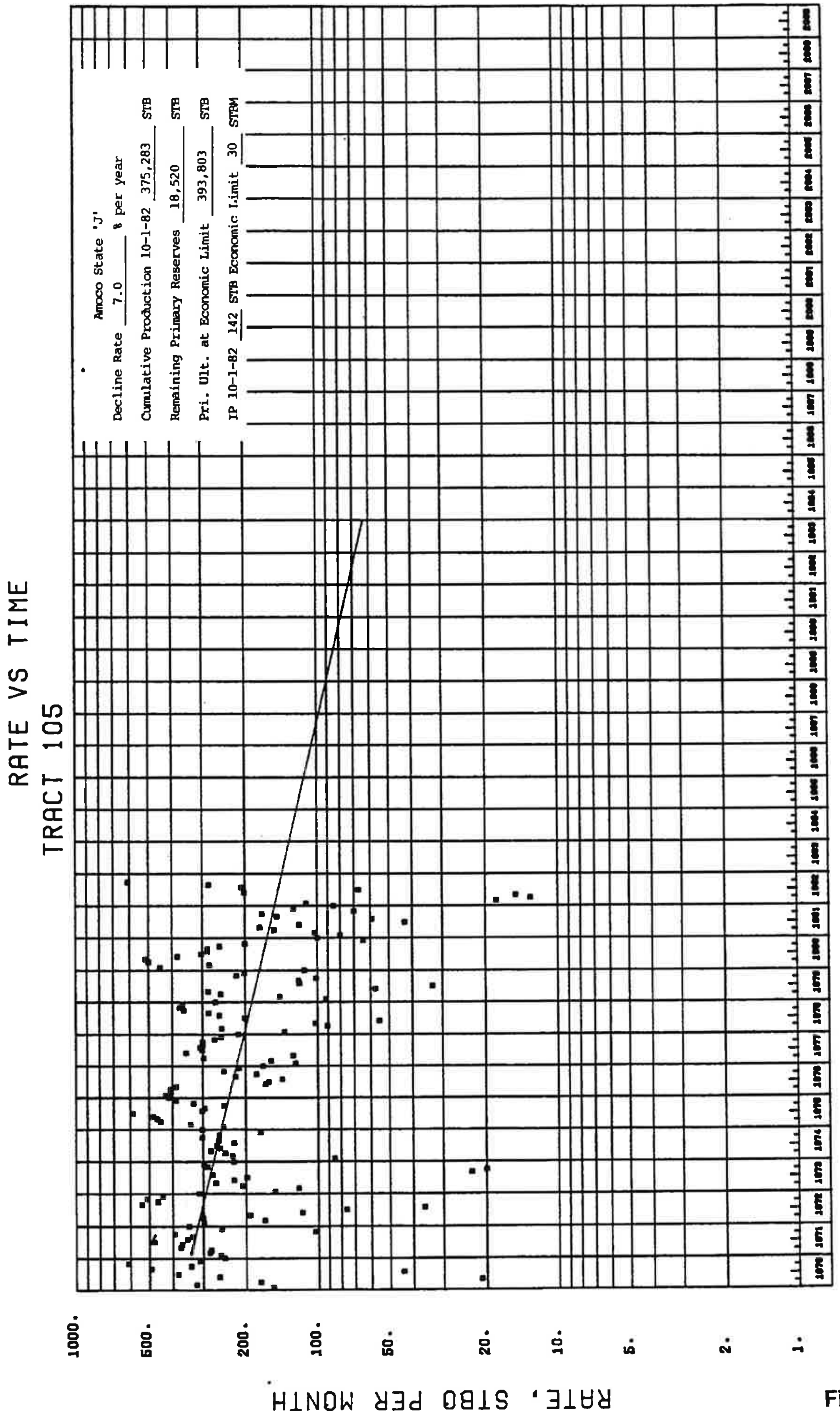

RATE VS TIME
TRACT 105
Amoco State 'J'
Decline Rate 7.0 % per year
Cumulative Production 10-1-82 375,283 STB
Remaining Primary Reserves 18,520 STB
Pri. Ult. at Economic Limit 393,803 STB
IP 10-1-82 142 STB Economic Limit 30 STBM
1000.
500.
200.
100.
50.
20.
10.
5.
2.
1.
RATE, STBO PER MONTH

Figure 92

RATE VS TIME
TRACT 106

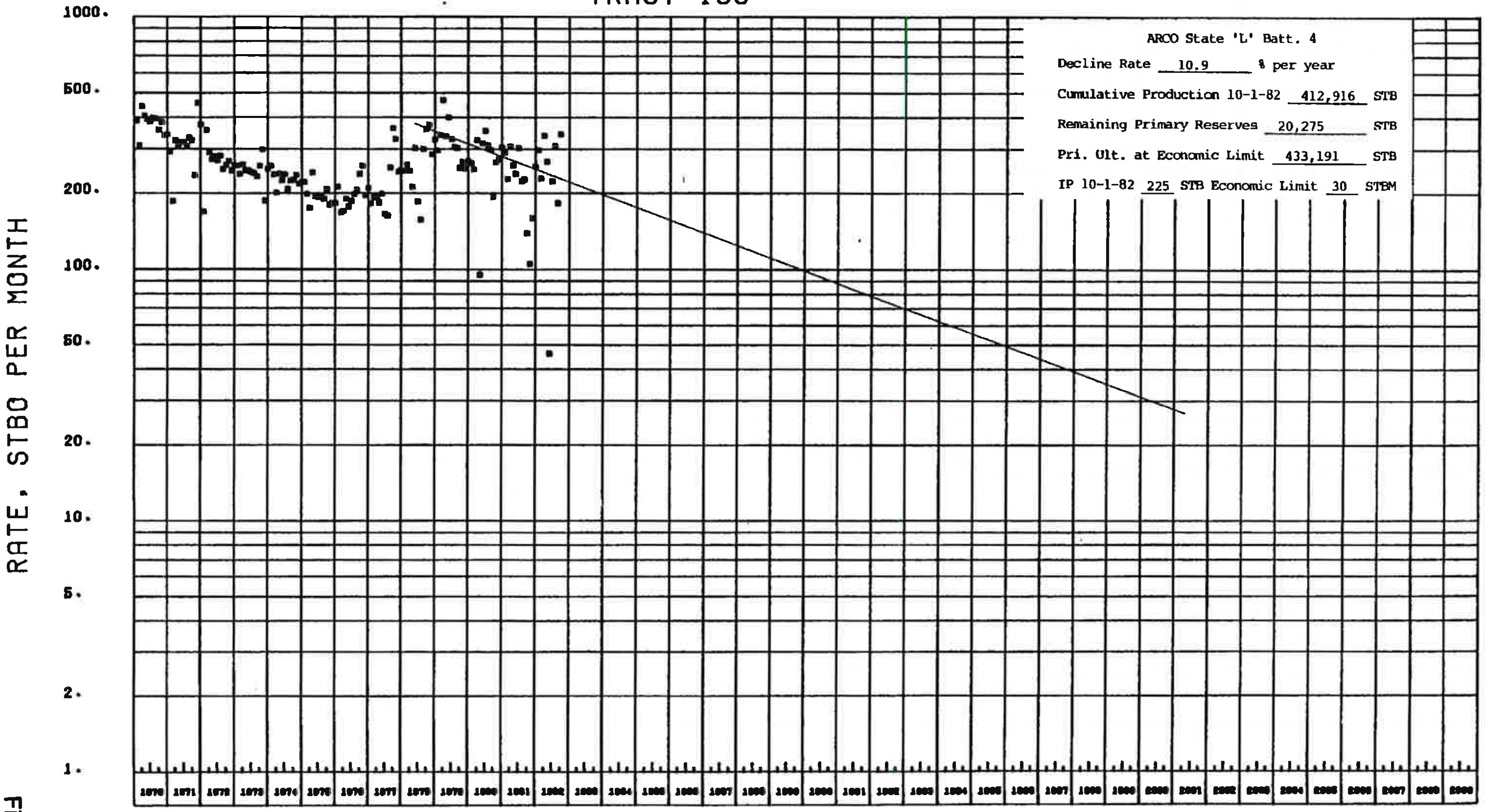


Figure 93

RATE VS TIME
TRACT 107

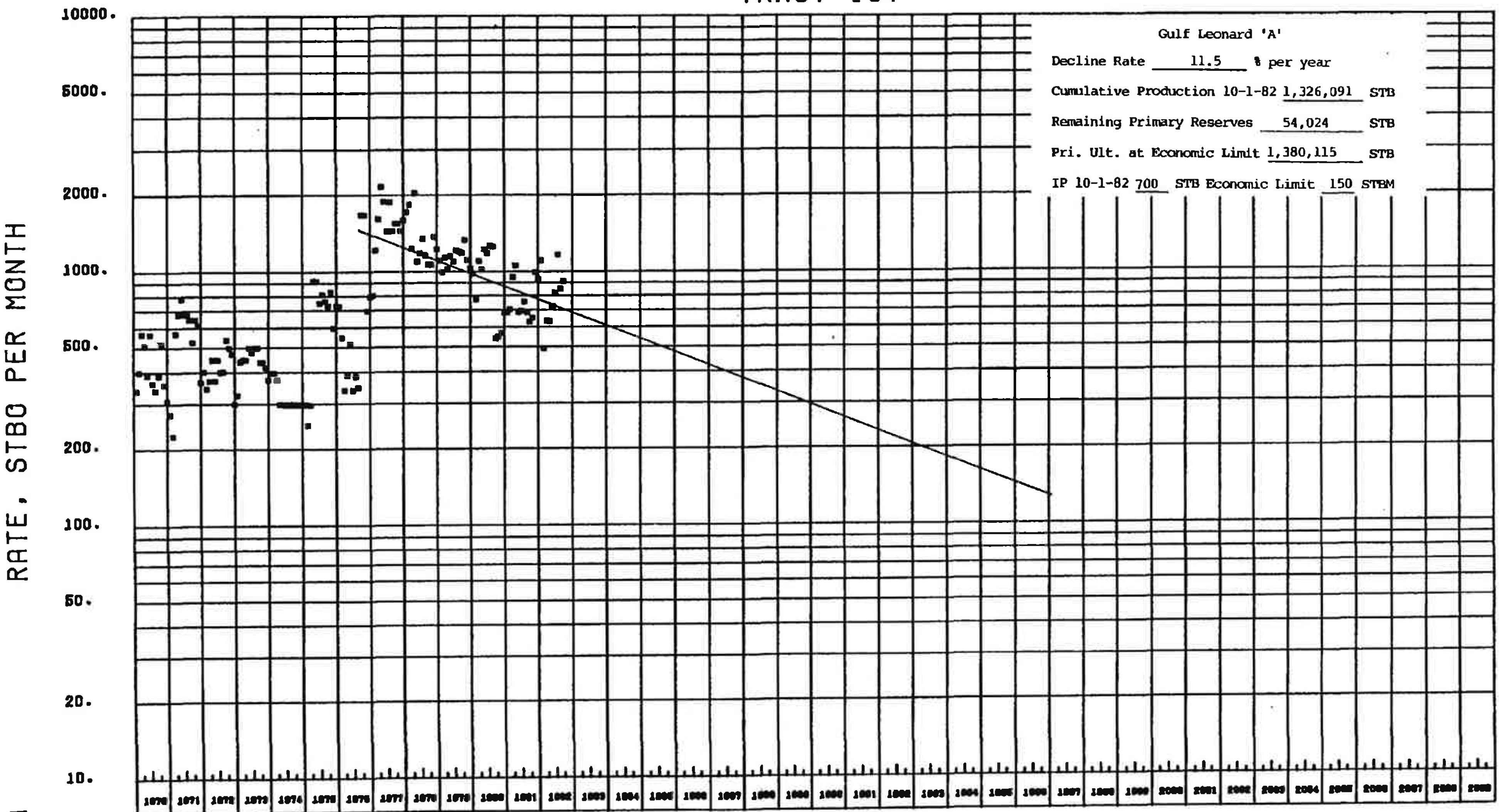


Figure 94

RATE VS TIME

TRACT 115

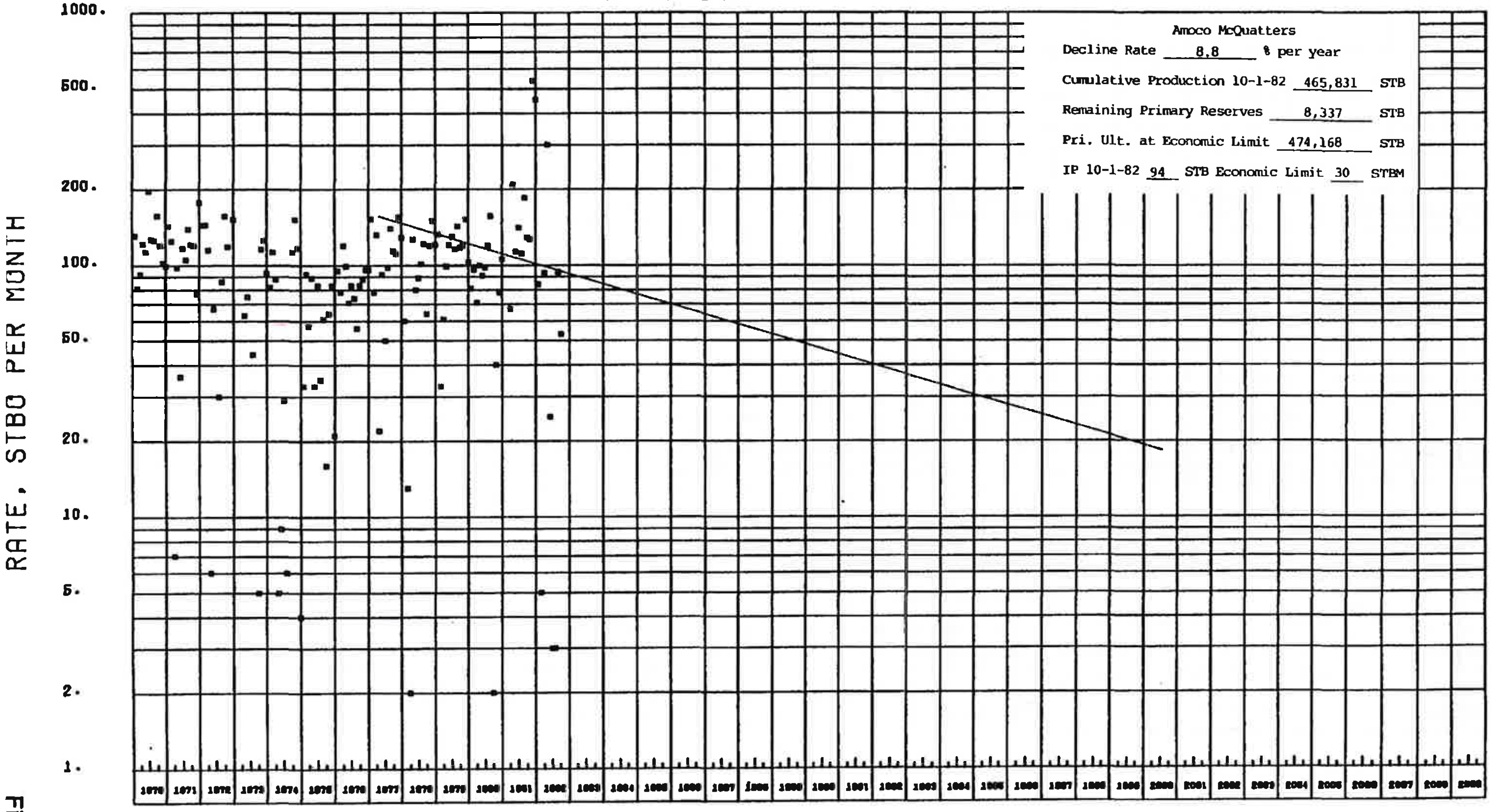


Figure 95

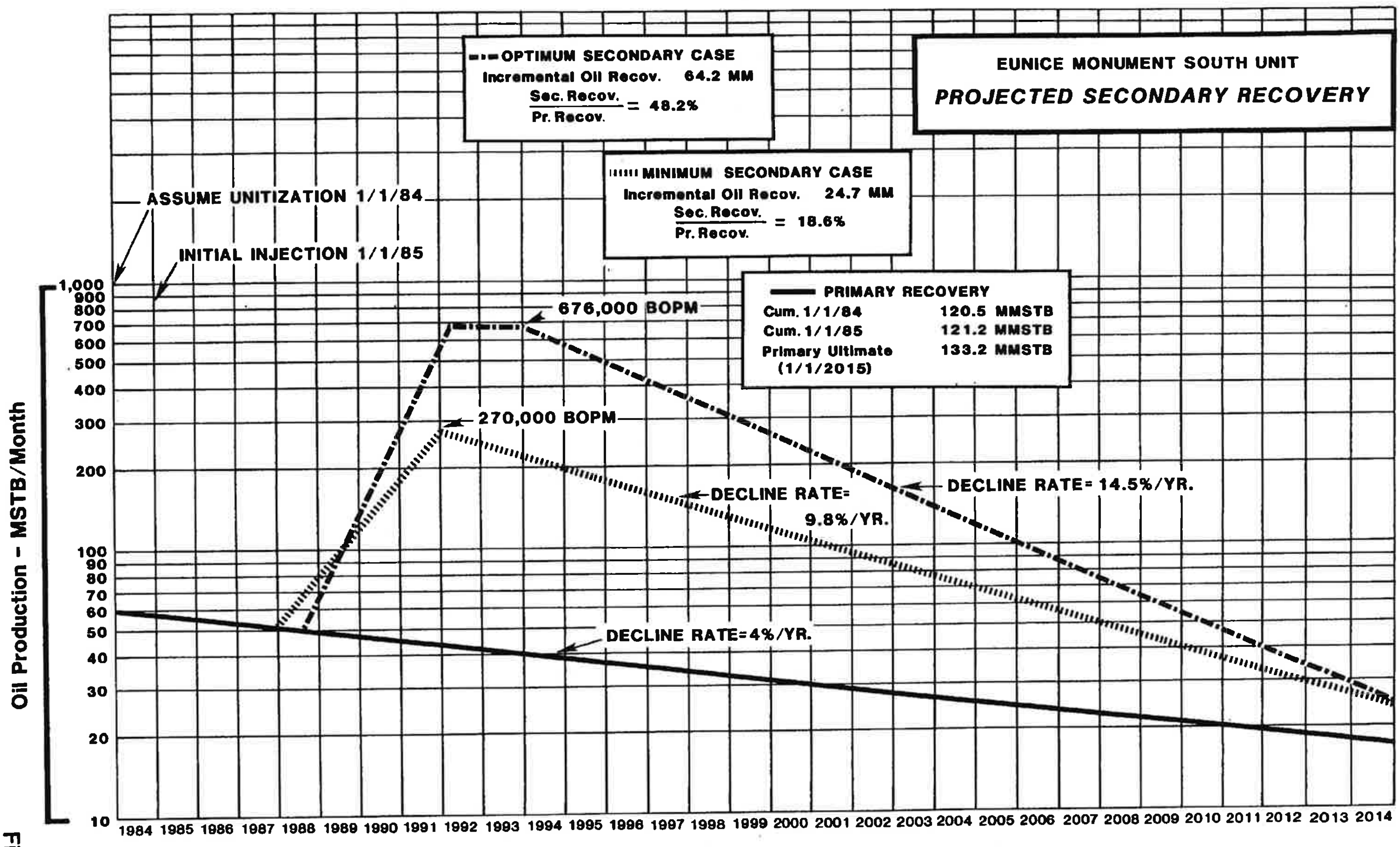
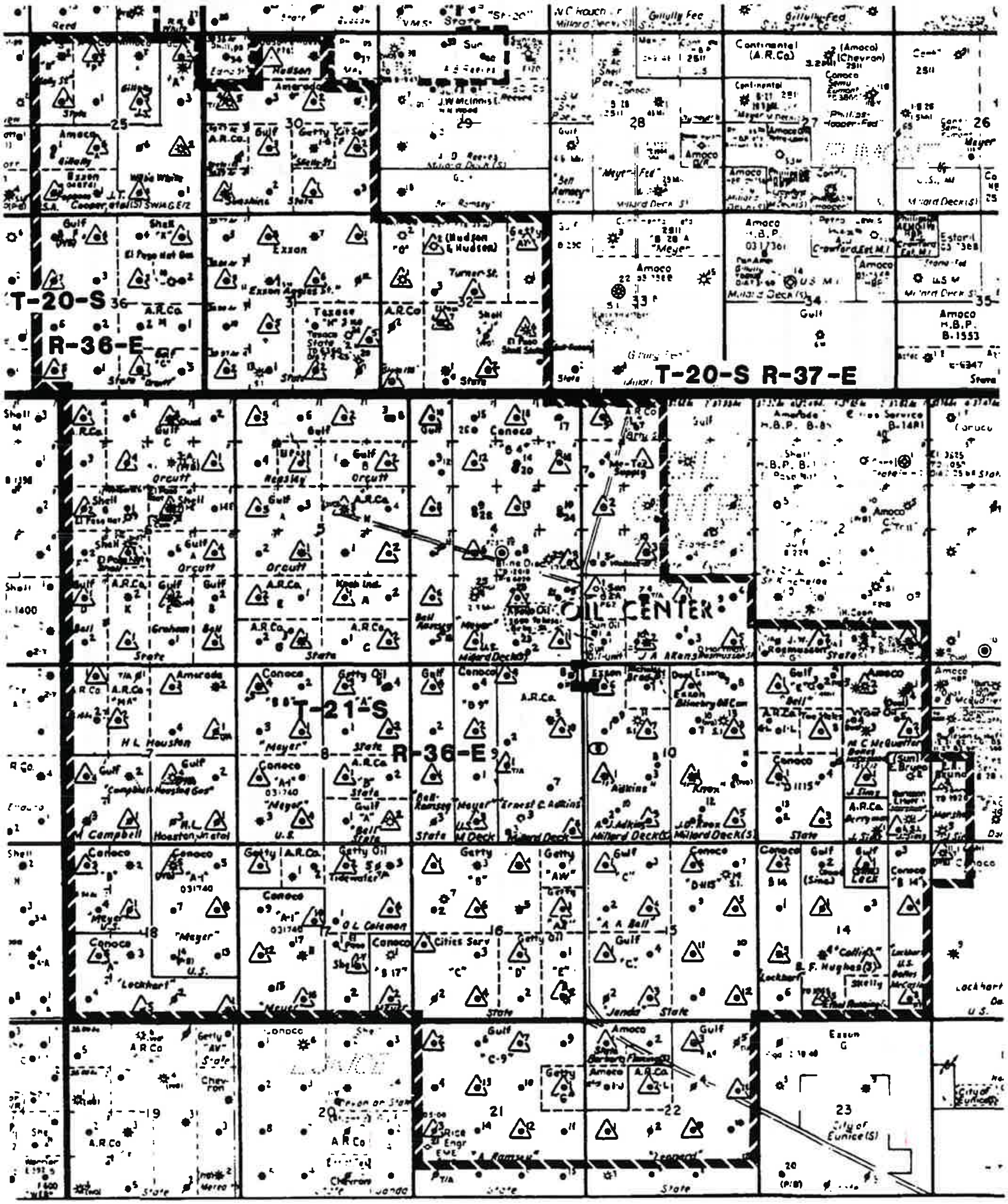

EUNICE MONUMENT SOUTH UNIT
PROJECTED SECONDARY RECOVERY
OPTIMUM SECONDARY CASE
Incremental Oil Recov. 64.2 MM
Sec. Recov. / Pr. Recov. = 48.2%
MINIMUM SECONDARY CASE
Incremental Oil Recov. 24.7 MM
Sec. Recov. / Pr. Recov. = 18.6%
PRIMARY RECOVERY
Cum. 1/1/84 120.5 MMSTB
Cum. 1/1/85 121.2 MMSTB
Primary Ultimate (1/1/2015) 133.2 MMSTB
ASSUME UNITIZATION 1/1/84
INITIAL INJECTION 1/1/85
676,000 BOPM
270,000 BOPM
DECLINE RATE= 9.8%/YR.
DECLINE RATE= 14.5%/YR.
DECLINE RATE=4%/YR.
Oil Production - MSTB/Month
1,000
900
800
700
600
500
400
300
200
100
90
80
70
60
50
40
30
20
10
1984 1985 1986 1987 1988 1989 1990 1991 1992 1993 1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2005 2006 2007 2008 2009 2010 2011 2012 2013 2014

Figure 96



EUNICE MONUMENT SOUTH UNIT
LEA COUNTY, NEW MEXICO
PROPOSED INJECTION PATTERN
△ - INJECTION WELL

0 1/2 1 MILE

Figure 97

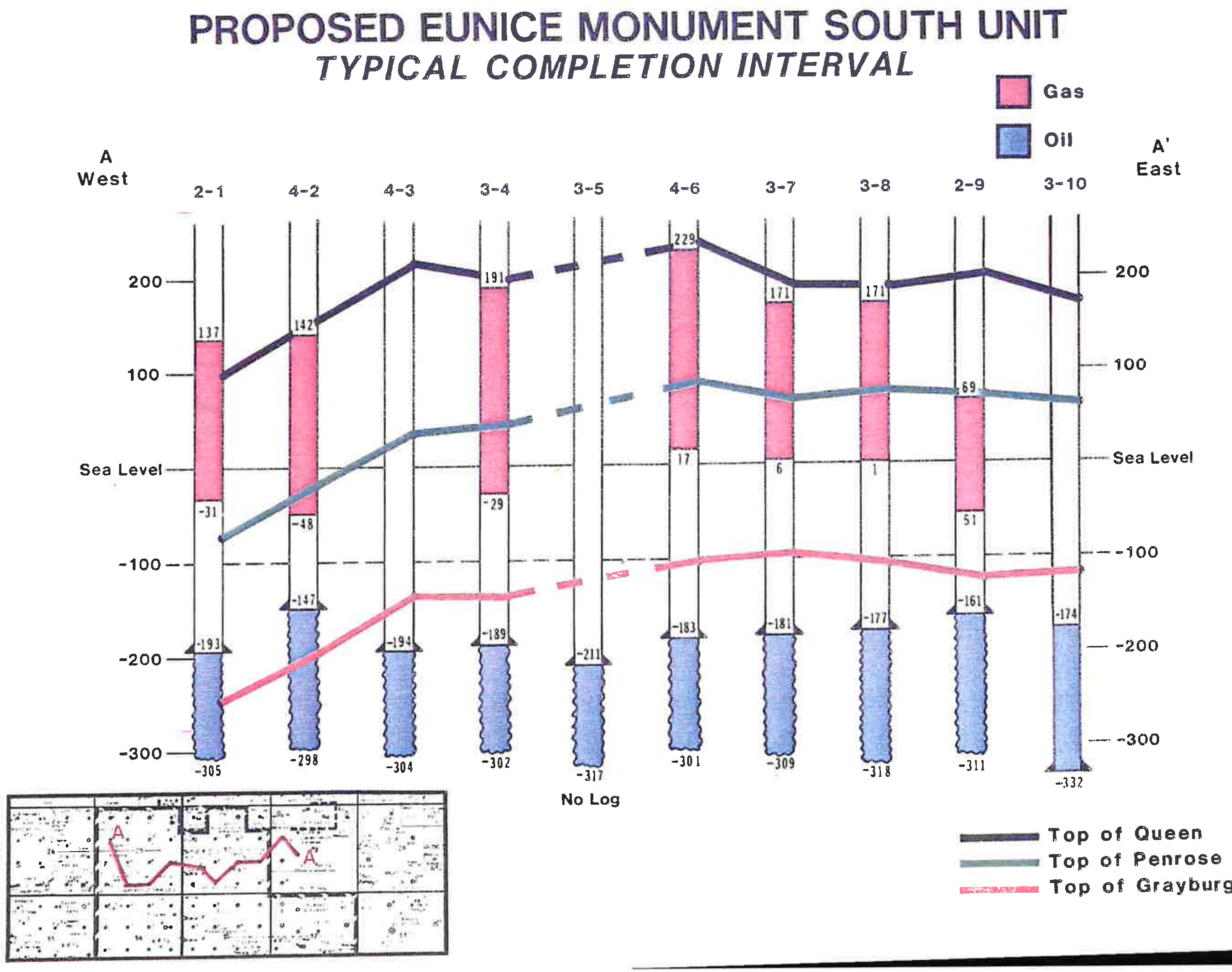

PROPOSED EUNICE MONUMENT SOUTH UNIT
TYPICAL COMPLETION INTERVAL
Gas
Oil
A
West
A'
East
2-1
4-2
4-3
3-4
3-5
4-6
3-7
3-8
2-9
3-10
200
100
Sea Level
-100
-200
-300
137
-31
-193
-305
142
-48
-147
-298
-194
-304
191
-29
-189
-302
-211
-317
No Log
229
17
-183
-301
171
6
-181
-309
171
1
-177
-318
69
51
-161
-311
-174
-332
Top of Queen
Top of Penrose
Top of Grayburg
A
A'

Figure 98

PROPOSED EUNICE MONUMENT SOUTH UNIT

TYPICAL COMPLETION INTERVAL

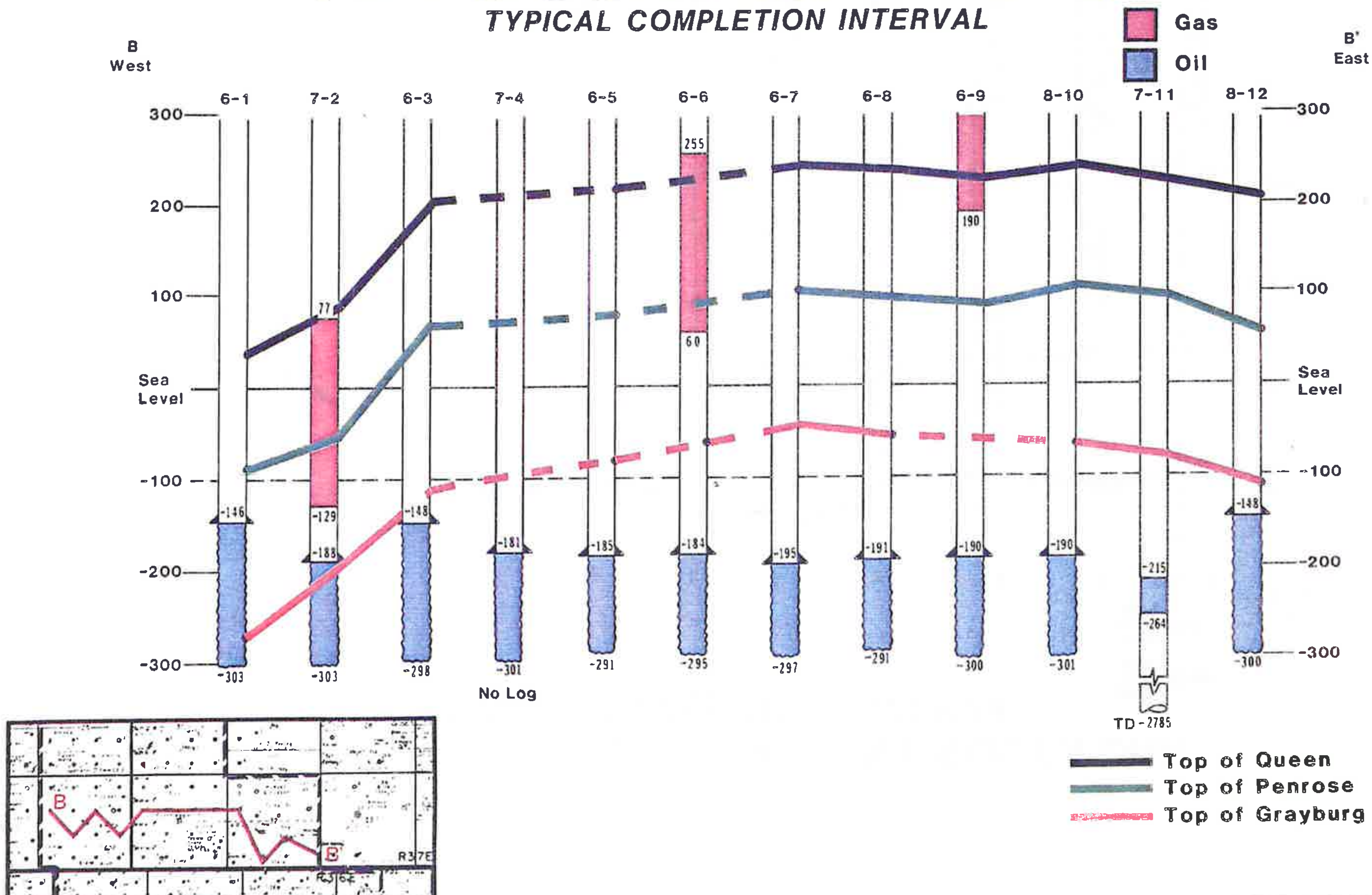
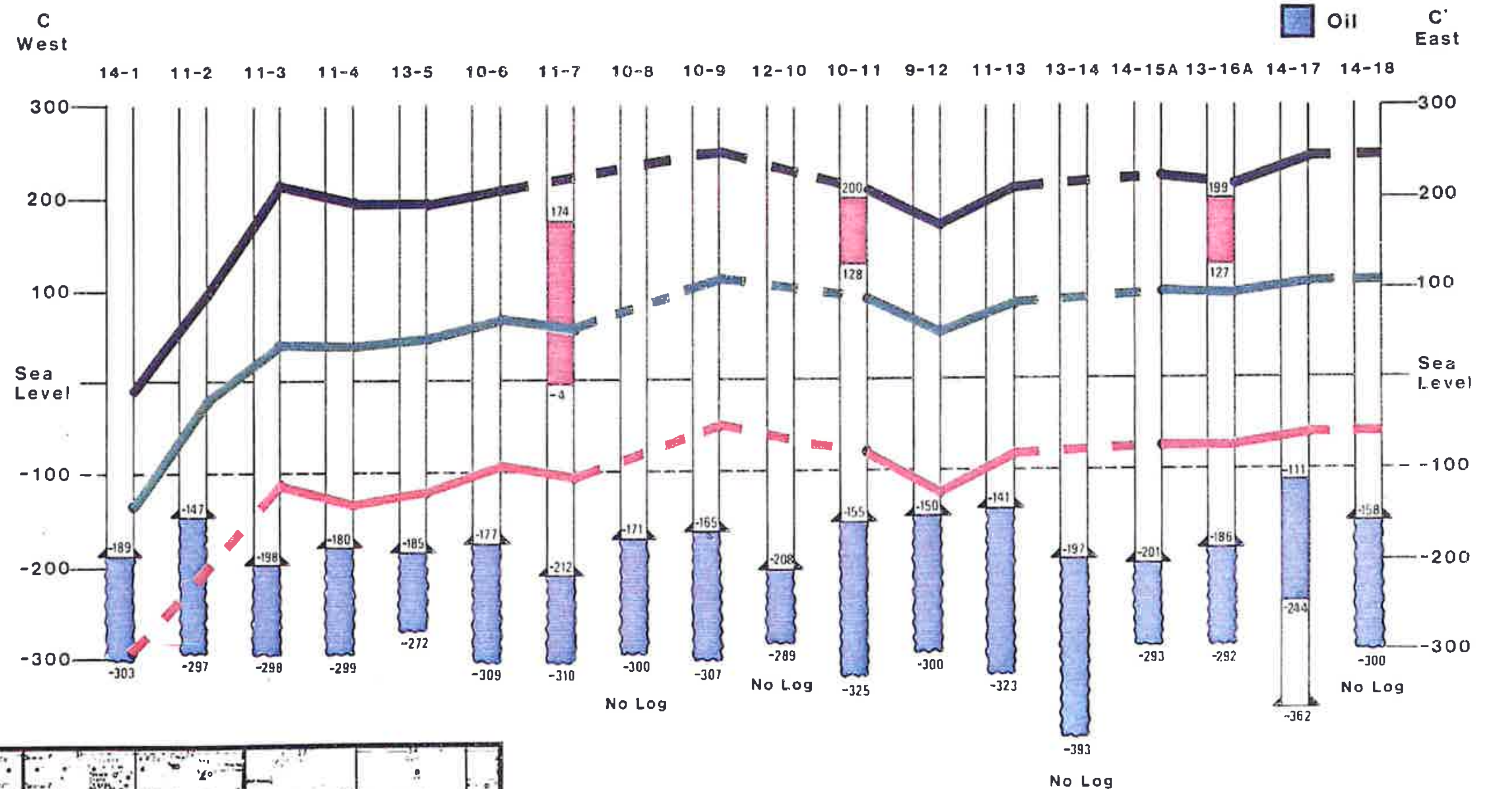


Figure 99

PROPOSED EUNICE MONUMENT SOUTH UNIT
TYPICAL COMPLETION INTERVAL



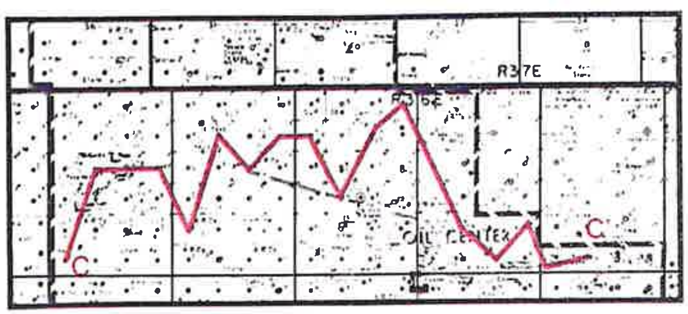
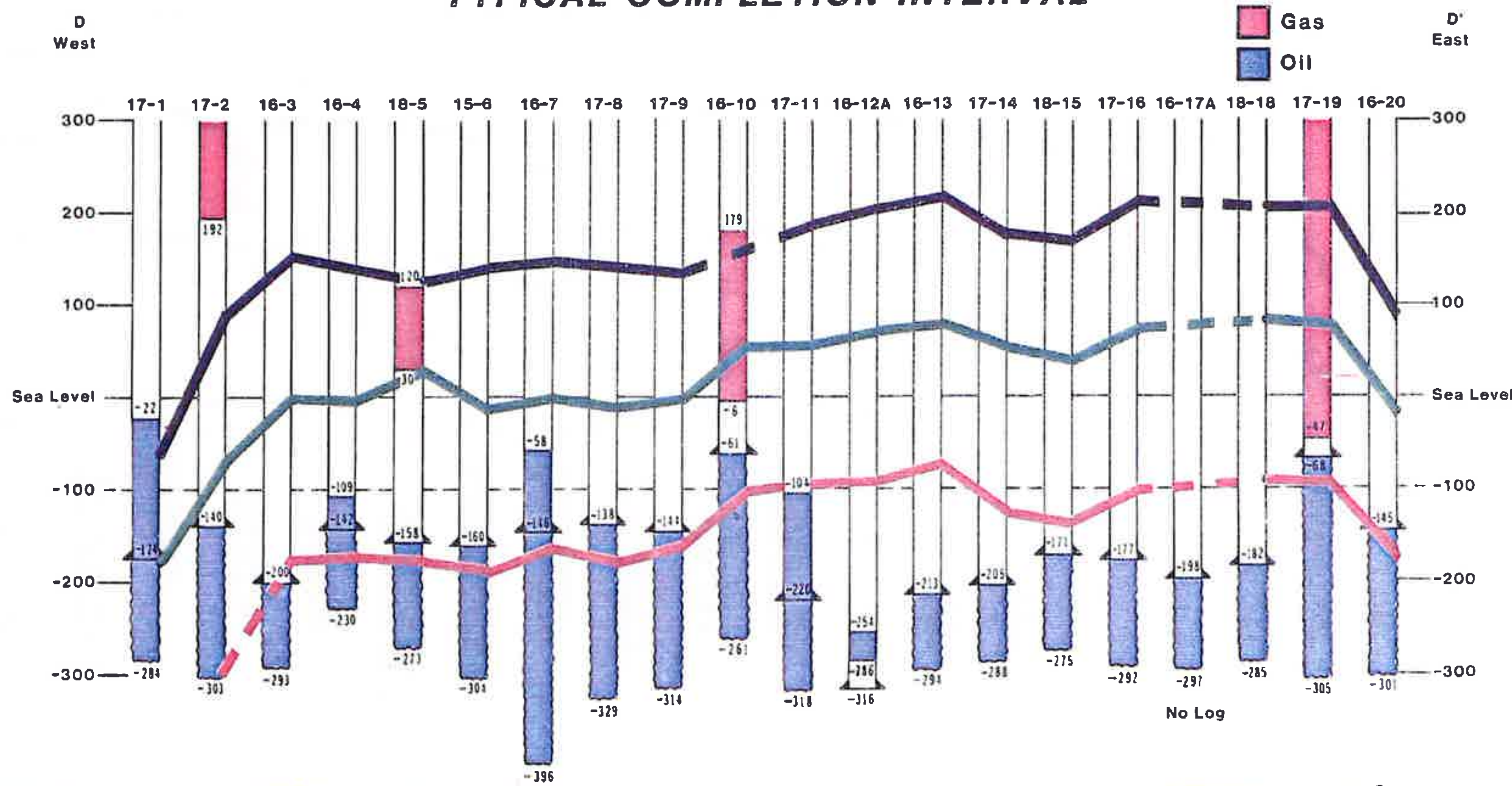


Figure 10

PROPOSED EUNICE MONUMENT SOUTH UNIT

TYPICAL COMPLETION INTERVAL



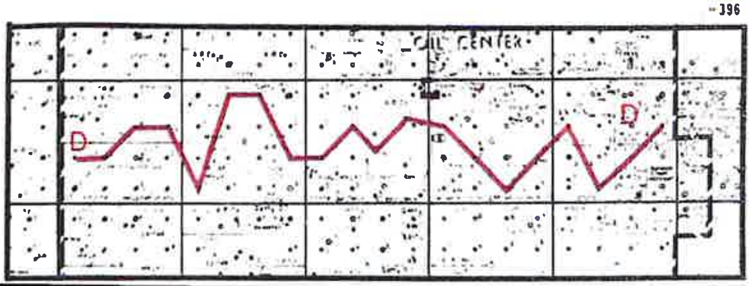


Figure 10

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PROPOSED EUNICE MONUMENT SOUTH UNIT

TYPICAL COMPLETION INTERVAL

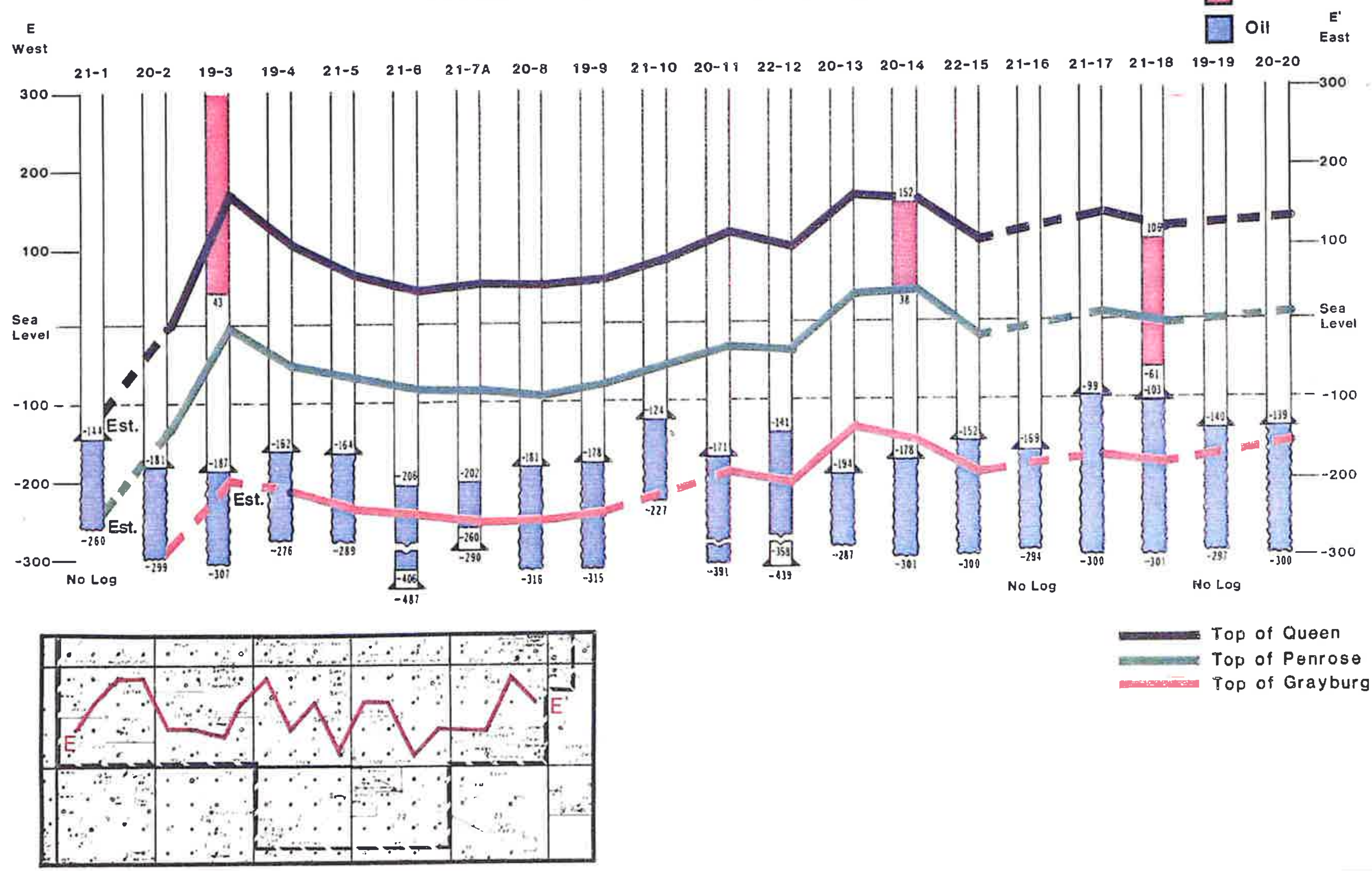

Figure 102

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PROPOSED EUNICE MONUMENT SOUTH UNIT

TYPICAL COMPLETION INTERVAL

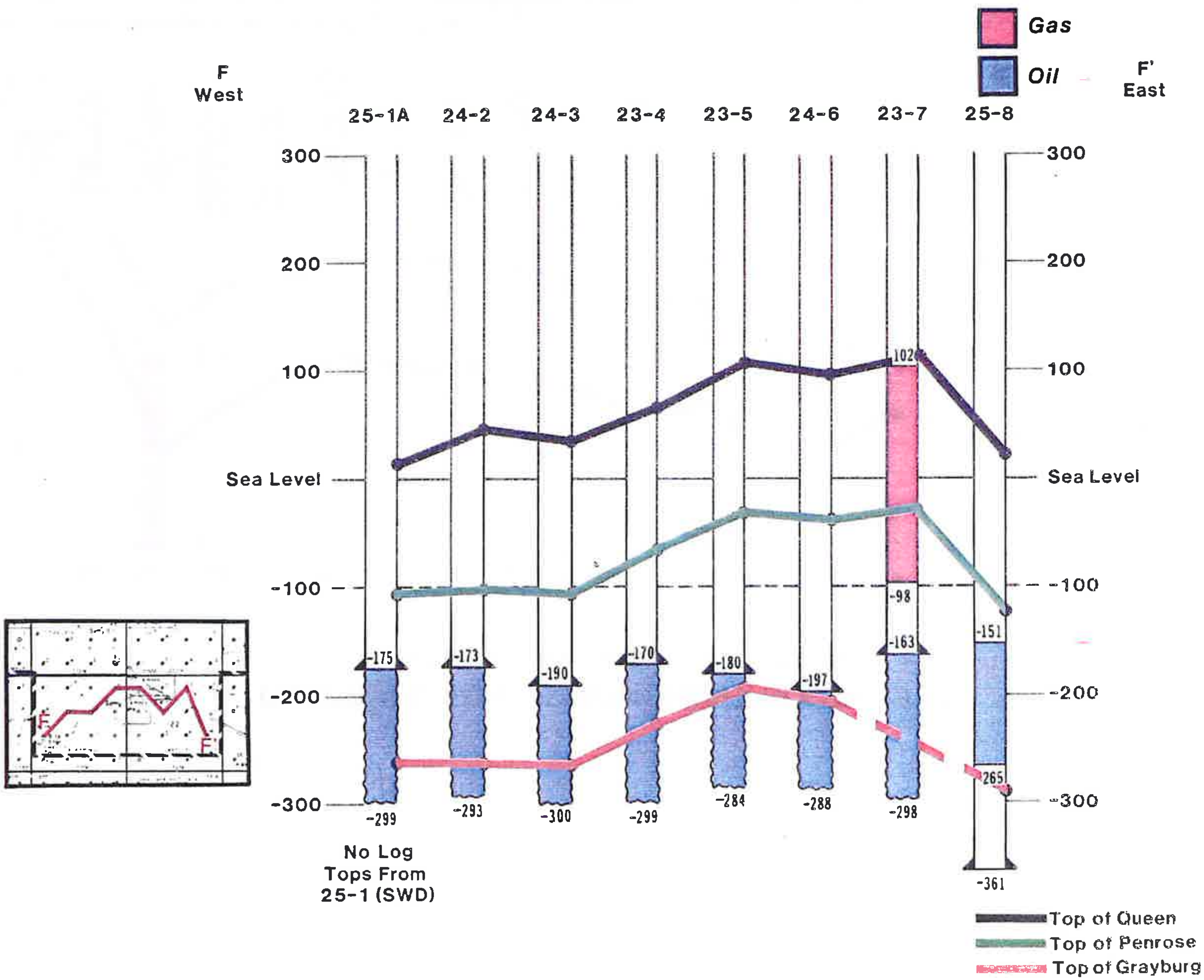
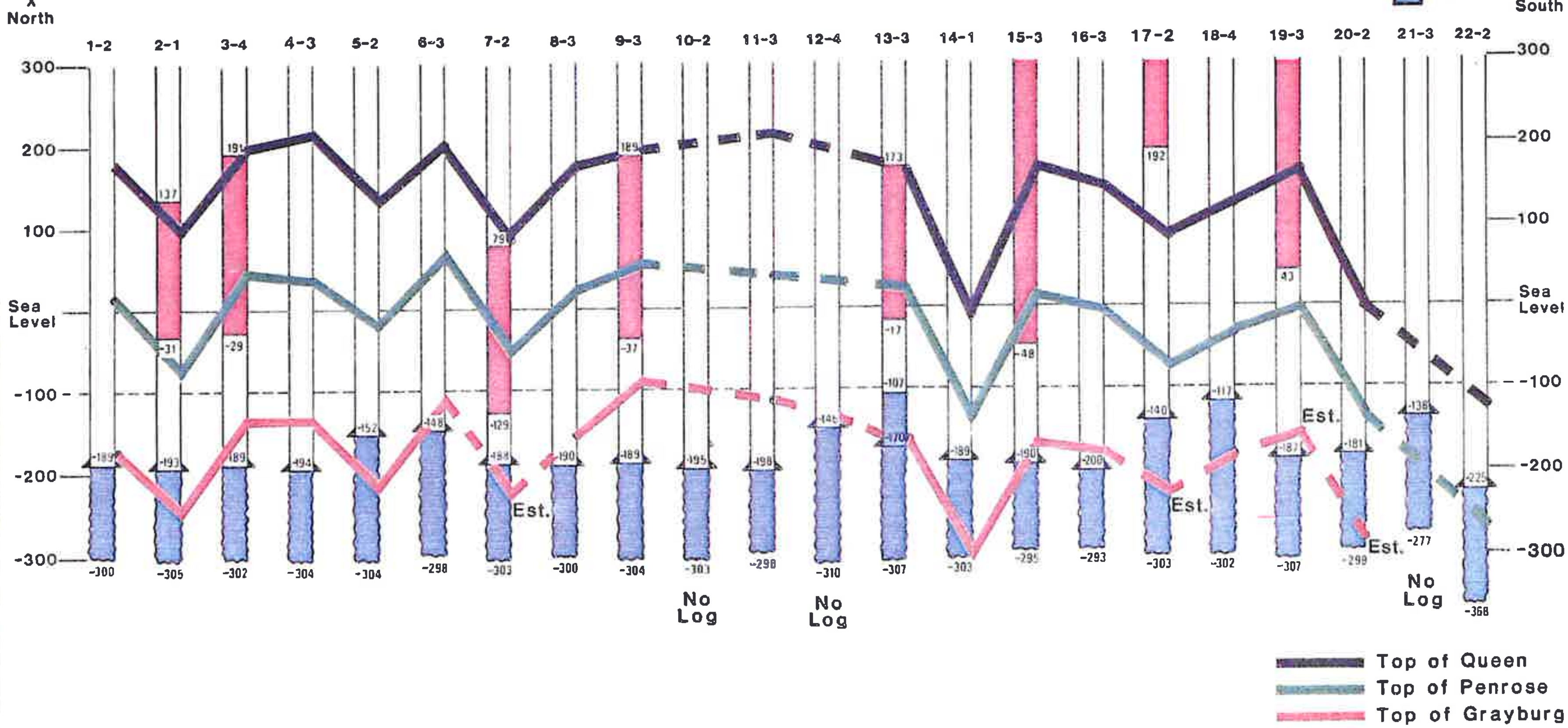


Figure 103

PROPOSED EUNICE MONUMENT SOUTH UNIT
TYPICAL COMPLETION INTERVAL



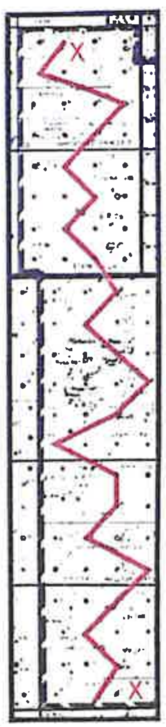
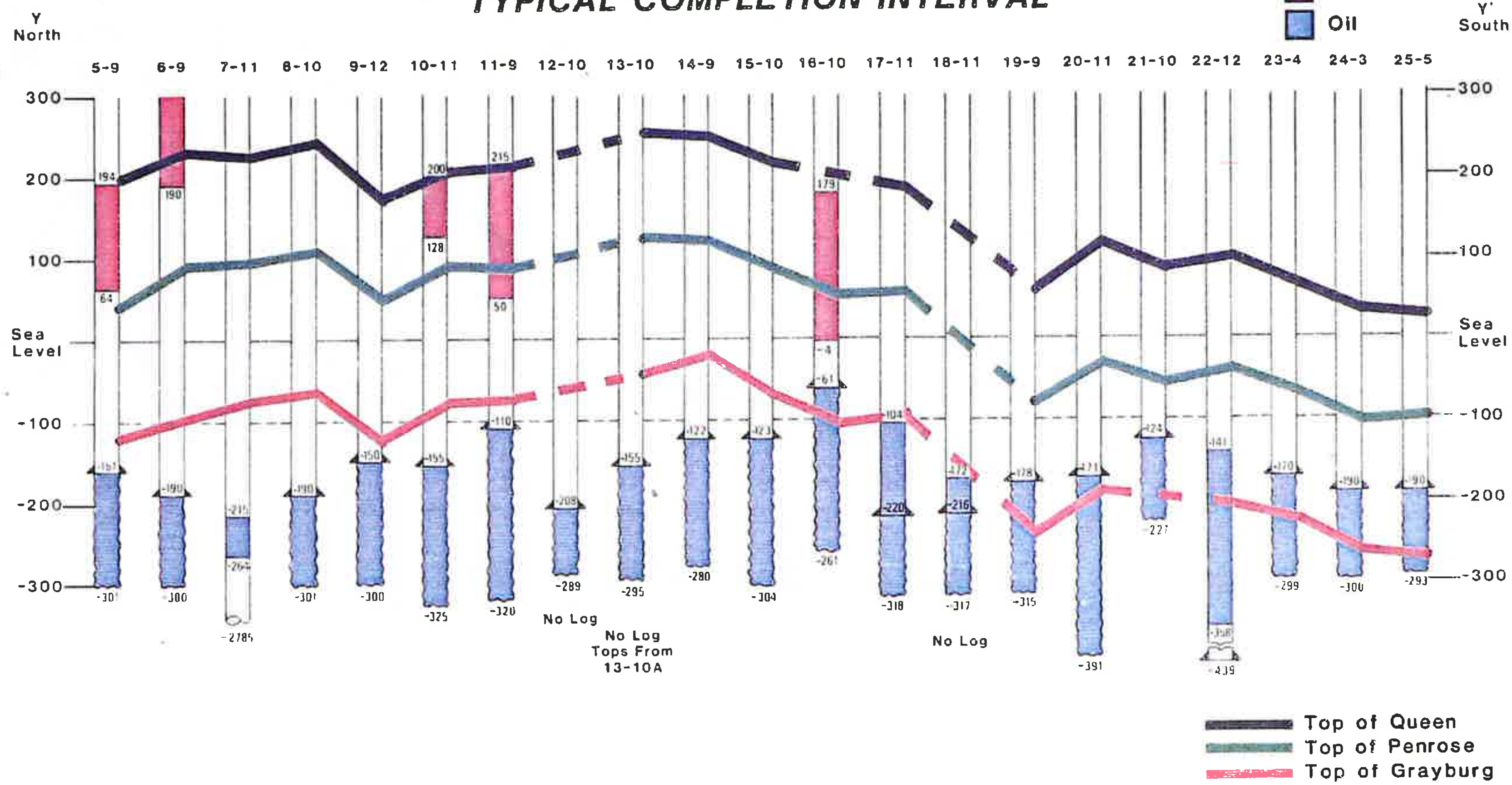


Figure 104

PROPOSED EUNICE MONUMENT SOUTH UNIT

TYPICAL COMPLETION INTERVAL



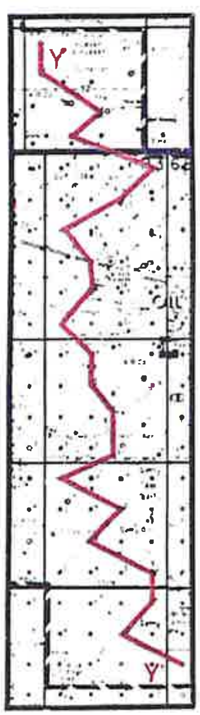
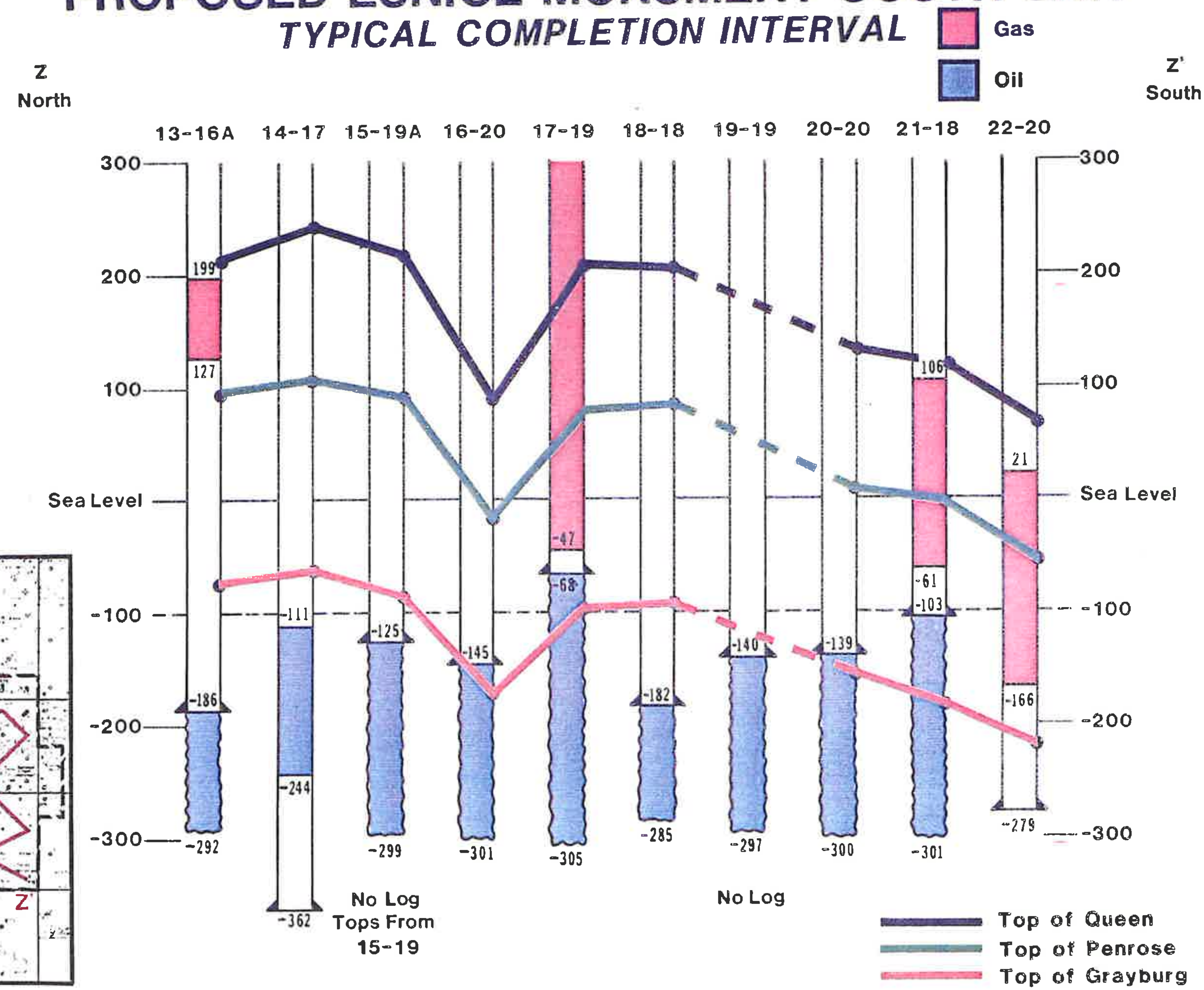


Figure 105

PROPOSED EUNICE MONUMENT SOUTH UNIT

TYPICAL COMPLETION INTERVAL



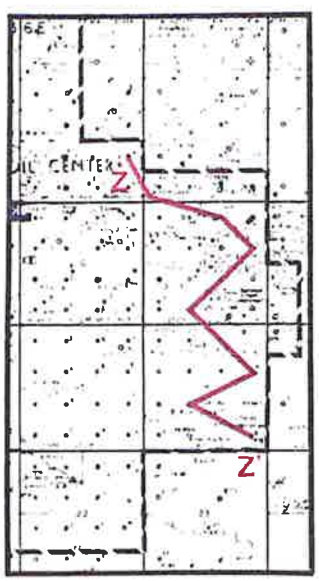
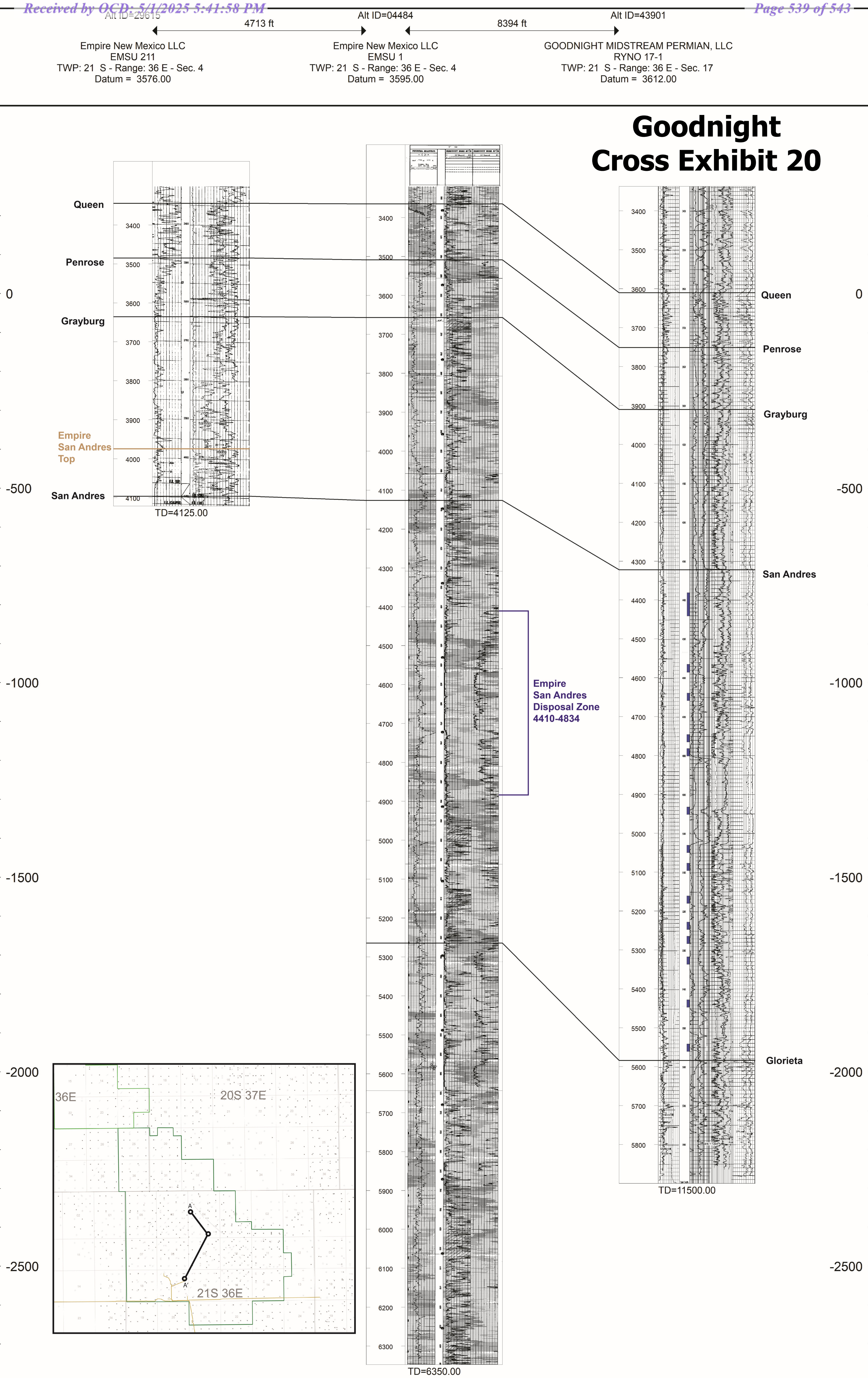


Figure 106

Goodnight Cross Exhibit 20



Goodnight Cross Exhibit 21

Form 3160-5
(November 1983)
(Formerly 9-331)

UNITED STATES
DEPARTMENT OF THE INTERIOR
BUREAU OF LAND MANAGEMENT

SUBMIT IN TRIPLICATE* (Other instructions on reverse side)

Form approved.
Budget Bureau No. 1004-0135
Expires August 31, 1985

SUNDRY NOTICES AND REPORTS ON WELLS

(Do not use this form for proposals to drill or to deepen or plug back to a different reservoir. Use "APPLICATION FOR PERMIT—" for such proposals.)

5. LEASE DESIGNATION AND SERIAL NO.: LC031740B

6. IF INDIAN, ALLOTTEE OR TRIBE NAME:

1. OIL WELL ☐ GAS WELL ☐ OTHER Salt Water Disposal

7. UNIT AGREEMENT NAME: Eunice Monument South Unit

2. NAME OF OPERATOR: Chevron U.S.A. Inc.

8. FARM OR LEASE NAME: SWD

3. ADDRESS OF OPERATOR: P.O. Box 670, Hobbs, New Mexico 88240

9. WELL NO.: 1

4. LOCATION OF WELL (Report location clearly and in accordance with any State requirements.* See also space 17 below.)
At surface
Unit W 660' FSL and 1980' FEL

10. FIELD AND POOL, OR WILDCAT: Eunice Monument(San Andre

11. SEC., T., R., M., OR BLK. AND SURVEY OR AREA: Sec.4,T21S,R36E

14. PERMIT NO.:

15. ELEVATIONS (Show whether DF, RT, GR, etc.): 3584

12. COUNTY OR PARISH: Lea

13. STATE: NM

16. Check Appropriate Box To Indicate Nature of Notice, Report, or Other Data

NOTICE OF INTENTION TO:

TEST WATER SHUT-OFF	☐	PULL OR ALTER CASING	☐
FRACTURE TREAT	☐	MULTIPLE COMPLETE	☐
SHOOT OR ACIDIZE	☐	ABANDON*	☐
REPAIR WELL	☐	CHANGE PLANS	☐
(Other)			

SUBSEQUENT REPORT OF:

WATER SHUT-OFF	☐	REPAIRING WELL	☐
FRACTURE TREATMENT	☐	ALTERING CASING	☐
SHOOTING OR ACIDIZING	☐	ABANDONMENT*	☐
(Other) Recomp. as salt water disp.			X

(NOTE: Report results of multiple completion on Well Completion or Recompletion Report and Log form.)

17. DESCRIBE PROPOSED OR COMPLETED OPERATIONS (Clearly state all pertinent details, and give pertinent dates, including estimated date of starting any proposed work. If well is directionally drilled, give subsurface locations and measured and true vertical depths for all markers and zones pertinent to this work.) *

Work performed 3-18-87 thru 3-24-87

POOH w/production equipment. Set CIBP at 5315', dump 35' cmt on CIBP. Run GR,CCL,CBL f/4800' to surf. Run CBL f/4800' to 3000', Test csg to 1000psi, ok. Perf w/4" guns, 4JHPF, 216 holes total in 5 zones at 4414-24, 4427-37,4448-58, 4464-78, 4480-90. Acidize w/8000 gallons 15% NEFE HCL. Perf w/ 3 3/8" guns 120° phased, 280 holes in 7 zones at 4526-40', 4546-56, 4558-72, 4582-90, 4594-4602, 4612-16, 4622-34. Acdz perfs f/4526- 4634 w/ 8500 gallons 15% NEFE HCL. Perf w/ 3 3/8" guns, 120° phased, 4 JHPF, 208 holes total in 5 zones at 4680-90, 4696-4706,4710-18, 4746-60, 4766-76, Acidize f/4680-4776 w/8000 gallons 15% HCL, swab. TIH w/ 2 7/8" IPC J-55, 6.5#, EUE 8rd tbg to 4369'. Pump 70bbls pkr fluid, ND BOP, set pkr at 369' w/6000 comp, NU WH, load csg w/ pkr fluid, work air out, test 600psi f/30min, ok. RDMOPU. Left SI pending injection line hookup.

RECEIVED SEP 7 ... 1988

18. I hereby certify that the foregoing is true and correct

SIGNED M. E. Akins TITLE Staff Drilling Engineer DATE Sept. 6, 1988

(This space for Federal or State office use)

ACCEPTED FOR RECORD

APPROVED BY ______ TITLE ______ DATE ______
CONDITIONS OF APPROVAL, IF ANY:

SEP 15 1988
SJS
CARLSBAD, NEW MEXICO

*See Instructions on Reverse Side

Title 18 U.S.C. Section 1001, makes it a crime for any person knowingly and willfully to make to any department or agency of the United States any false, fictitious or fraudulent statements or representations as to any matter within its jurisdiction.

Goodnight Cross Exhibit 22

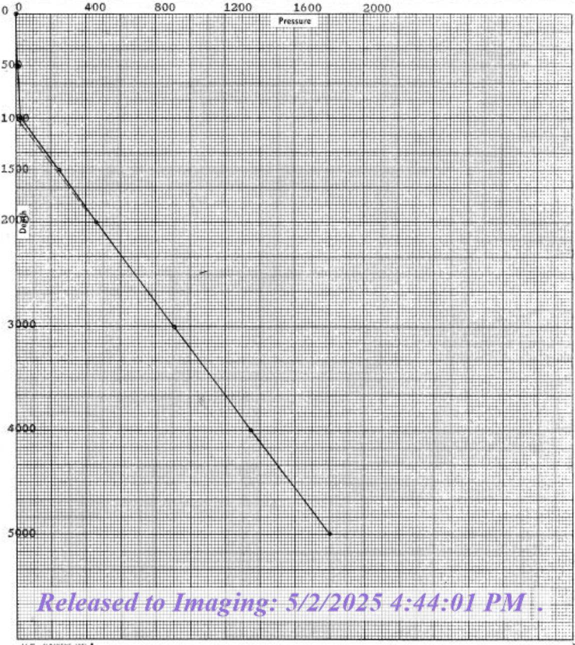
JOHN W. WEST ENGINEERING COMPANY
412 NORTH DAL PASO, HOBBS, NEW MEXICO

BOTTOM HOLE PRESSURE SURVEY REPORT

OPERATOR Rice Engineering & Operating Inc.
LEASE
WELL NO. E. M. E. H-20 (Before injection)
FIELD
DATE July 15, 59 TIME 2:50 P. M.

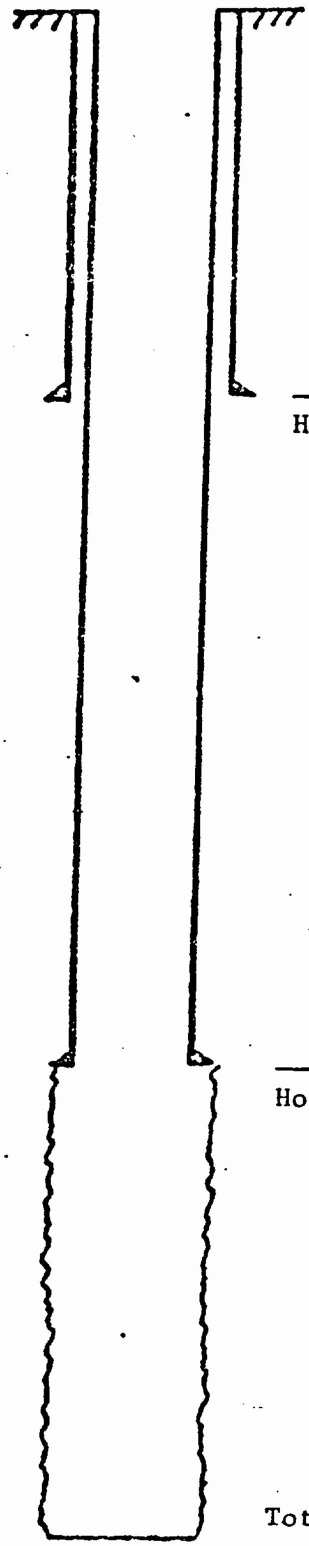
STATUS Shut in TEST DEPTH 5000
TIME S.I. LAST TEST DATE Initial test
CAS. PRES. BHP LAST TEST
TUB. PRES. 0 BHP CHANGE
ELEV. FLUID TOP 1050
DATUM WATER TOP
TEMP RUN BY B. T.
CLOCK NO. 2547 GAUGE NO. 12434
ELEMENT NO. 14659-N

DEPTH	PRESSURE	GRADIENT
000	0	
500	7	.014
1000	26	.038
1500	247	.442
2000	462	.430
3000	905	.443
4000	1347	.442
5000	1800	.453



Goodnight Cross Exhibit 23

FIELD	OPERATOR		DATE
MONUMENT	RICE ENG & OPR, INC		APRIL 27, 1976
LEASE	**WELL No**	**LOCATION**	
EME SWD SYSTEM	H-20	SE/4 NE/4 SEC. 20-T20S-R37E	



9 5/8" casing set at 812 ' with 500 sx of REG NEAT cement
Hole size 12 1/4 " CEMENT CIRCULATED.

300SX SULFATE RESISTANT CMT + 4% GEL
W/300 CU FT · POZZOLAN + 50# FLOCELE &

7 " casing set at 4446 ' with 150 sx of REG NEAT cement
Hole size 8 3/4 " TOP OF CEMENT @ 875/SURVEY.

5 1/2" OD TUBING SET @ 4437' W/ANNULUS OIL BLANKET – NO PACKER

Total Depth 5000 '

(Revised 7/1/58)
(Form C-105)

AREA 640 ACRES
LOCATE WELL CORRECTLY

x

NEW MEXICO OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

WELL RECORD

Mail to District Office, Oil Conservation Commission, to which Form C-101 was sent not later than twenty days after completion of well. Follow instructions in Rules and Regulations of the Commission. Submit in QUINTUPLICATE. If State Land submit 6 Copies

Rice Engineering & Operating, Inc. (Company or Operator) Eunice - Monument - Eumont SWD (Lease)

Well No. H-20, in SE ¼ of NE ¼, of Sec. 20, T. 20 S, R. 37 E, NMPM.

Monument Pool, Lea County.

Well is 2475 feet from North line and 165 feet from East line of Section 20. If State Land the Oil and Gas Lease No. is Business Lease 147

Drilling Commenced June 13, 19 59 Drilling was Completed July 11, 19 59

Name of Drilling Contractor Stout & McQueen

Address 905 W. 15th Street, Odessa, Texas

Elevation above sea level at Top of Tubing Head 3506' The information given is to be kept confidential until Not confidential, 19

OIL SANDS OR ZONES

No. 1, from to No. 4, from to

No. 2, from to No. 5, from to

No. 3, from to No. 6, from to

IMPORTANT SALT WATER SANDS

Include data on rate of water inflow and elevation to which water rose in hole.

No. 1, from 4451' to 4503' feet.

No. 2, from 4600' to 4726' feet.

No. 3, from 4882' to 4939' feet.

No. 4, from to feet.

CASING RECORD

SIZE	WEIGHT PER FOOT	NEW OR USED	AMOUNT	KIND OF SHOE	CUT AND PULLED FROM	PERFORATIONS	PURPOSE
9-5/8"	32.3	New	793'	Texas			Surface Casing
7"	20	New	4430'	Guide			Injection Csg.

MUDDING AND CEMENTING RECORD

SIZE OF HOLE	SIZE OF CASING	WHERE SET	NO. SACKS OF CEMENT	METHOD USED	MUD GRAVITY	AMOUNT OF MUD USED
12-1/4	9-5/8"	812'	500	Howco 1 plug	Water	
8-3/4	7"	4446'	750	Howco 1 plug	Water	

RECORD OF PRODUCTION AND STIMULATION

(Record the Process used, No. of Qts. or Gals. used, interval treated or shot.)

Acidized 4882 - 4939' w/2500 gal. 15 %, 4600 - 4726 w/5200 gal. 15%, and 4451 - 4503' w/2300 gal. 15%.

Result of Production Stimulation Gravity injection rate down 7" casing before acid-16BWPH
Gravity injection rate down 7" casing after acid-2400 BWPH

Depth Cleaned Out 5004'