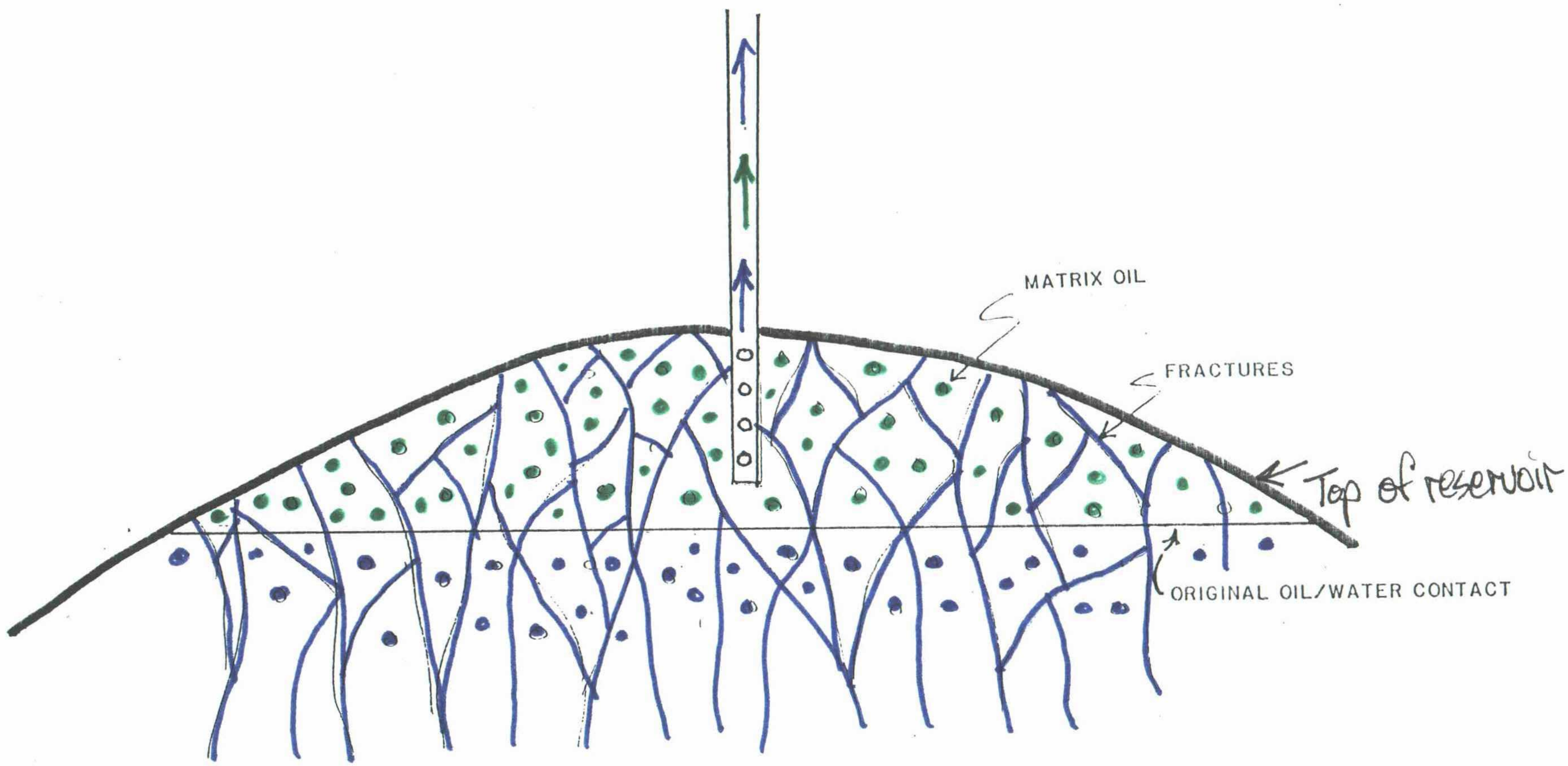
INCREMENTAL OIL PRODUCTION FROM

MATRIX POROSITY WITH H.V.L.



BEFORE THE
OIL CONSERVATION DIVISION
Santa Fe, New Mexico

Case No. 10994 Exhibit No. 5

Submitted by: Enserch Exploration, Inc.

Hearing Date: June 23, 1994

ENSERCH EXPLORATION INC.
WEST TEXAS AREA

H.V.L. CONCEPT
(High Volume Lift)

DATE:
GEOLOGY:

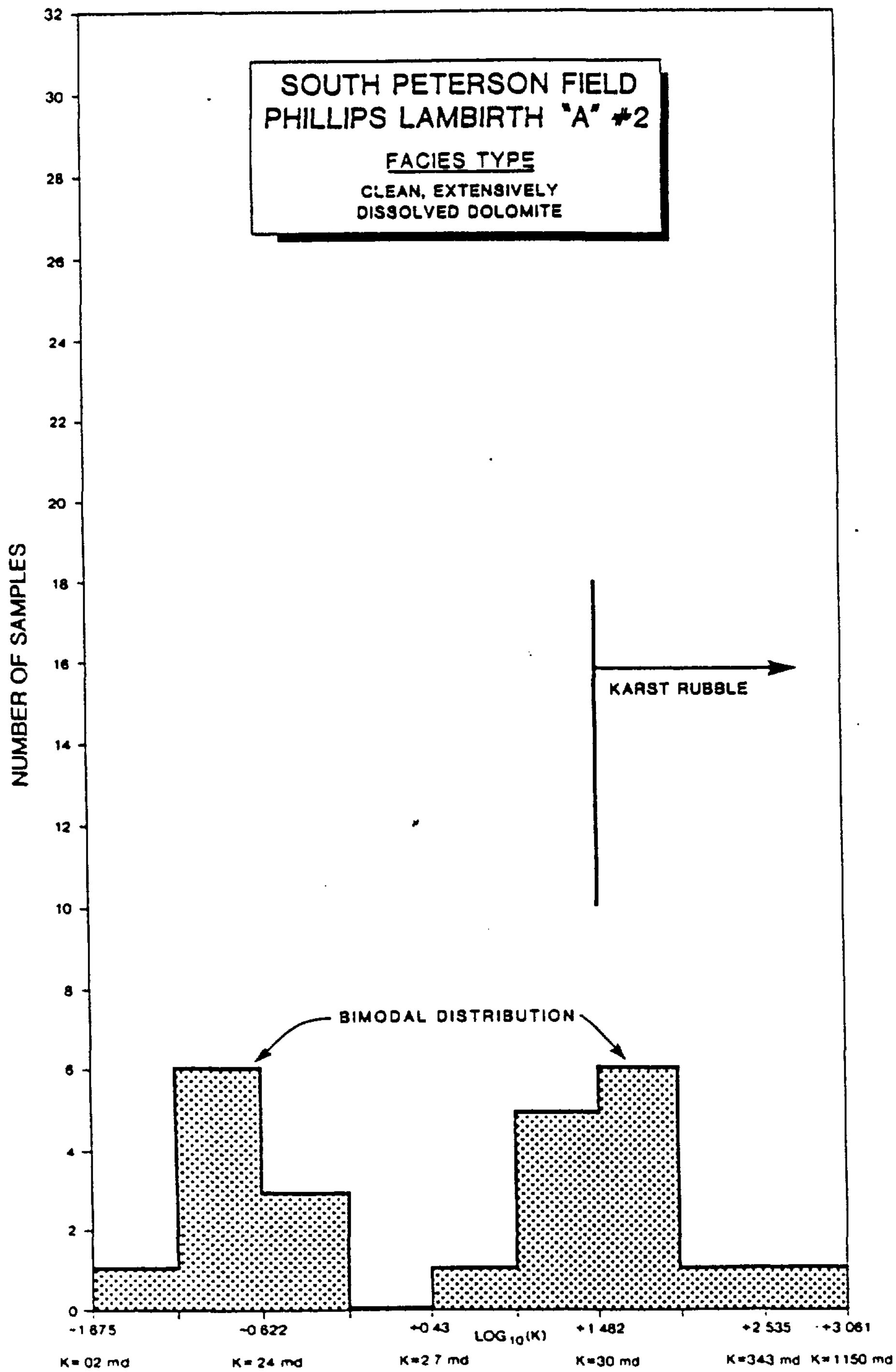


Figure 9.112. Histogram showing frequency of permeability in core samples arranged in classes defined by the logarithm of the permeability. The bimodal distribution reflects the different effects of dolomitization and subaerial exposure on the reservoir rocks.

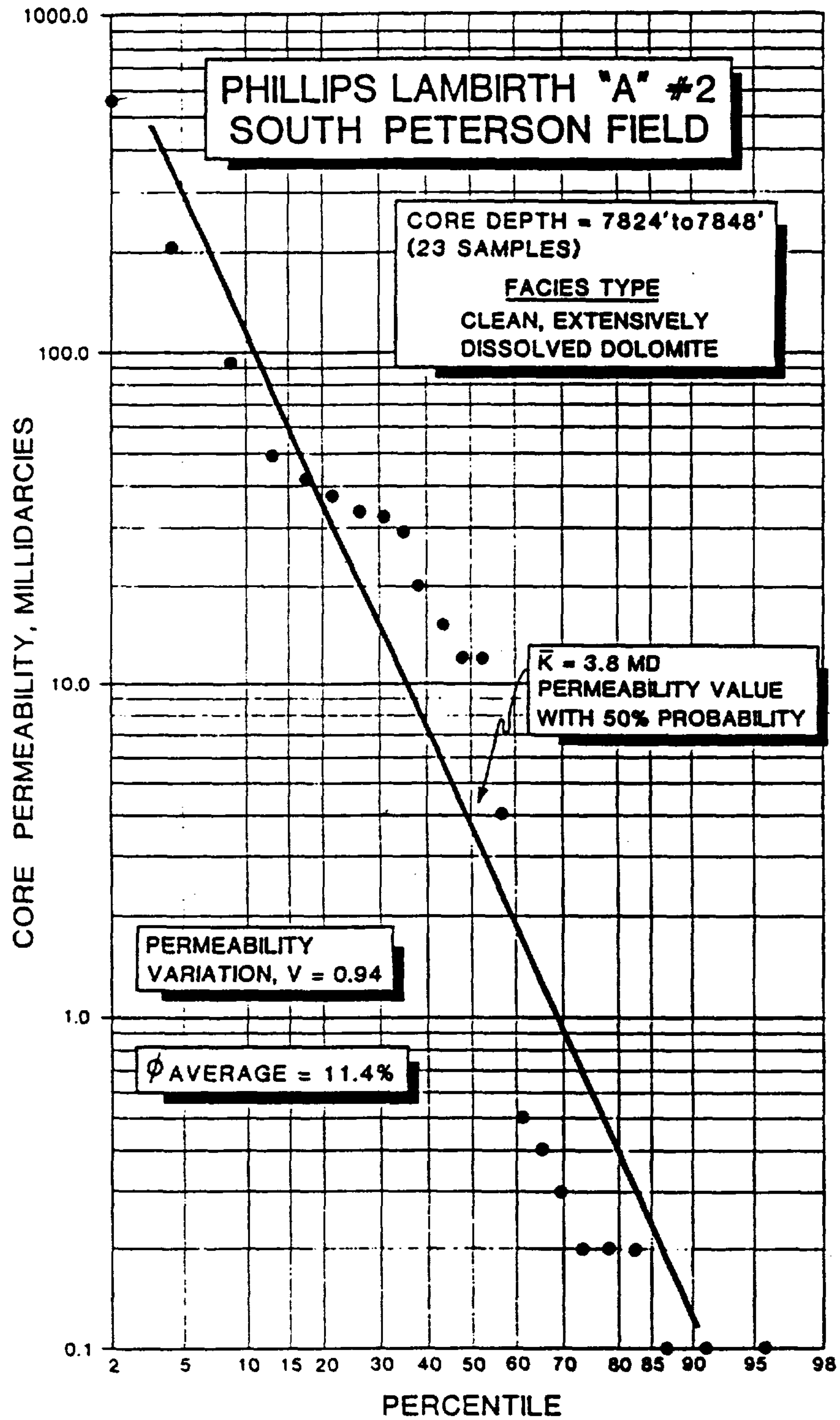


Figure 9.111. Distribution of core permeability for samples from the Phillips Lambirth "A" #2 well. Permeability variation (V) = 0.94, indicating a very heterogeneous distribution. This resulted in premature water breakthrough in the reservoir.

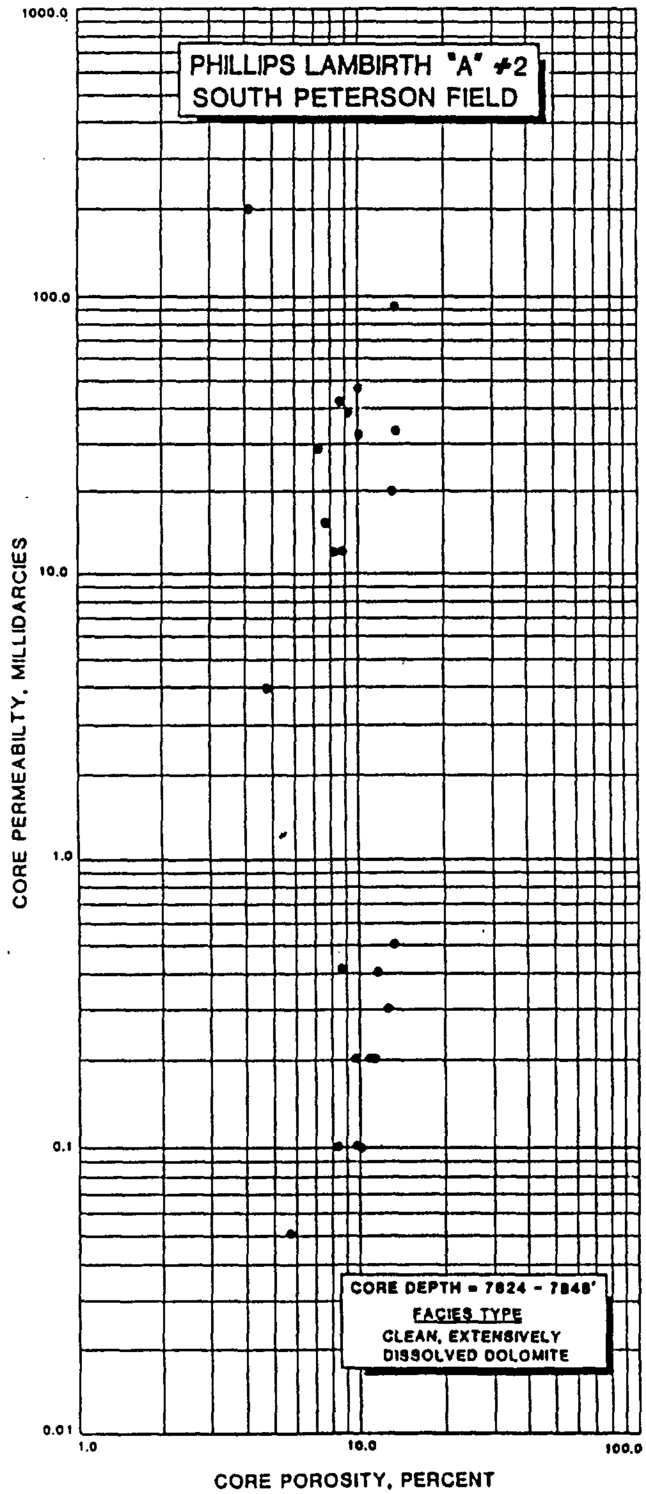
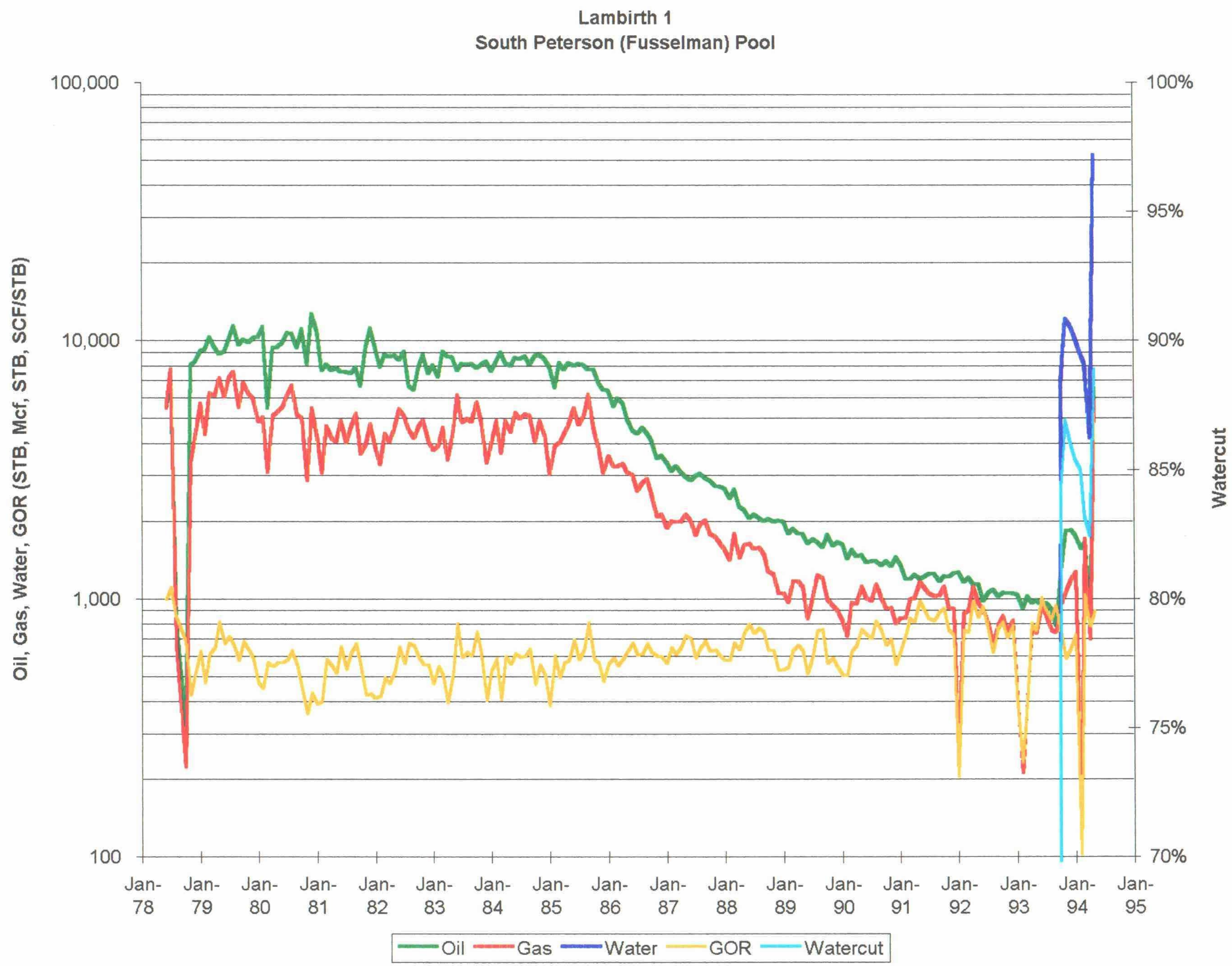


Figure 9.110. Crossplot of core porosity and permeability in the Phillips Lambirth "A" #2 well, a Montoya producer in Peterson South Field. Note the consistency of porosity values, but almost complete absence of points between 0.5 and 10 md permeability. Lower permeability samples are matrix dolomite; higher values represent karst rubble. Average porosity over the cored interval was 9.6%.



Lambirth 1
South Peterson (Fusselman) Pool
Oil, Gas, Water, GOR (STB, Mcf, STB, SCF/STB)
100,000
10,000
1,000
100
Watercut
100%
95%
90%
85%
80%
75%
70%
Jan-78
Jan-79
Jan-80
Jan-81
Jan-82
Jan-83
Jan-84
Jan-85
Jan-86
Jan-87
Jan-88
Jan-89
Jan-90
Jan-91
Jan-92
Jan-93
Jan-94
Jan-95
Oil
Gas
Water
GOR
Watercut

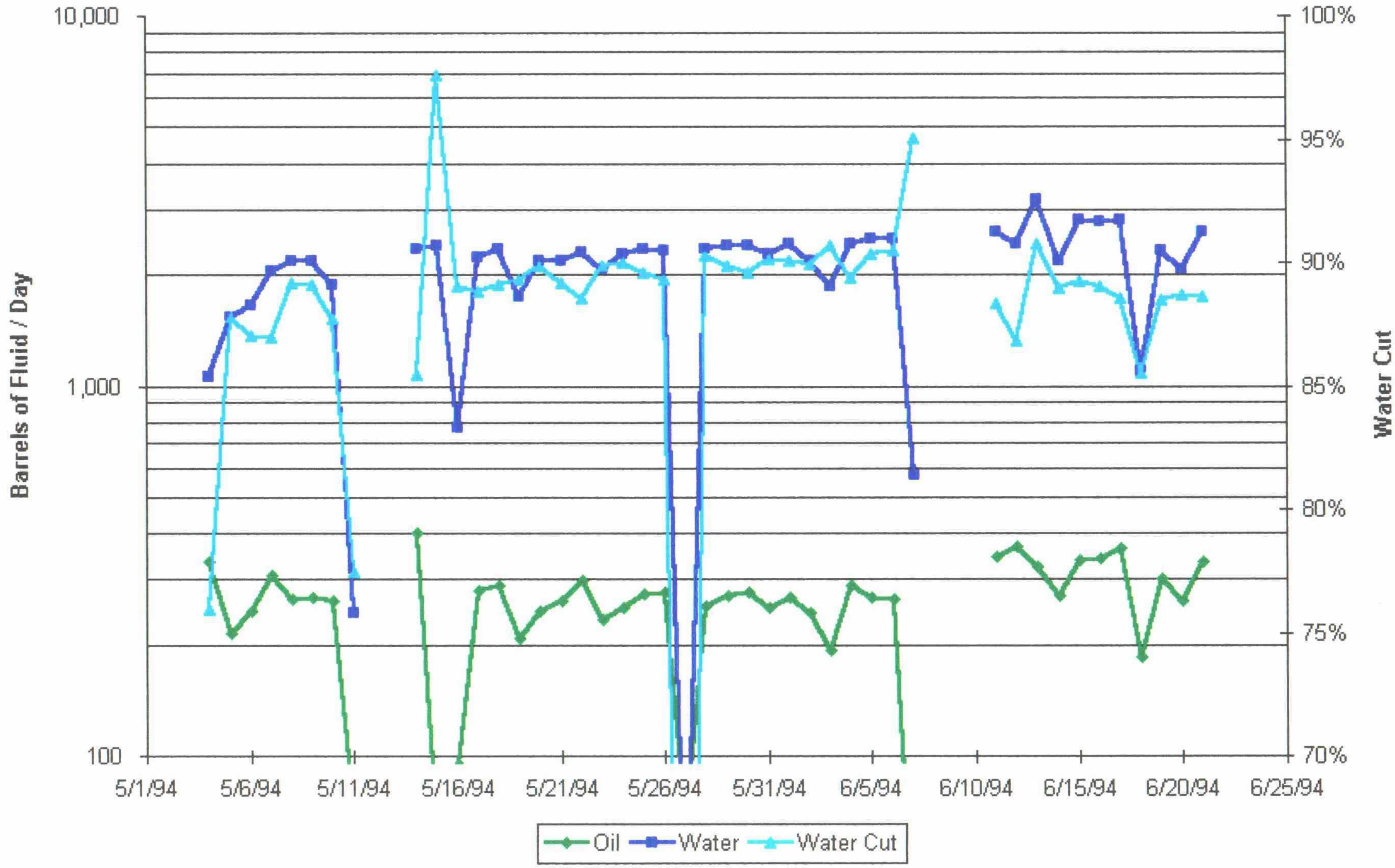
BEFORE THE
OIL CONSERVATION DIVISION
Santa Fe, New Mexico

Case No. 10994 Exhibit No. 6

Submitted by: Enserch Exploration, Inc.

Hearing Date: June 23, 1994

Lambirth No. 1
South Peterson (Fusselman) Pool

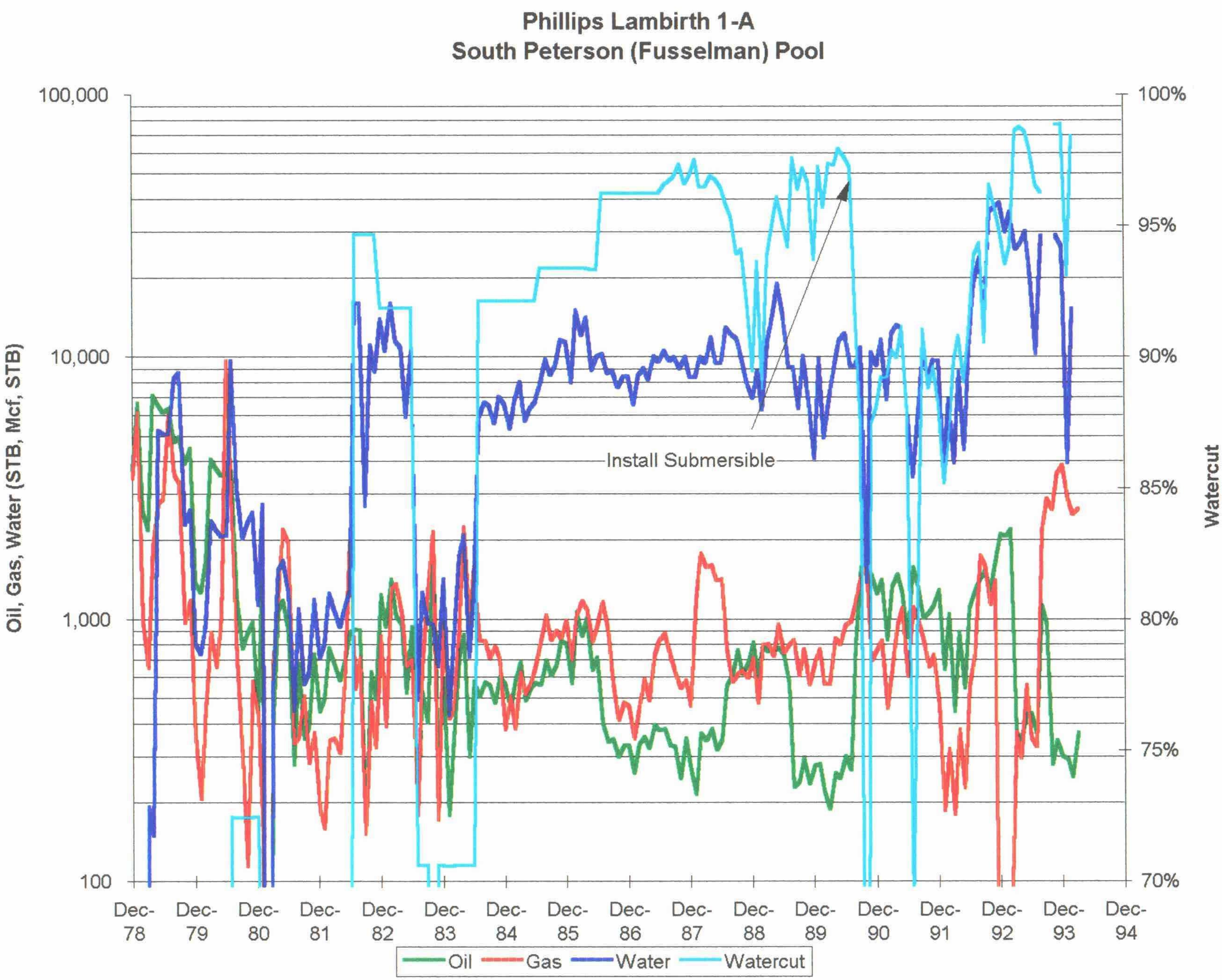


BEFORE THE
OIL CONSERVATION DIVISION
Santa Fe, New Mexico

Case No. 10994 Exhibit No. 7

Submitted by: Enserch Exploration, Inc.

Hearing Date: June 23, 1994



Phillips Lambirth 1-A
South Peterson (Fusselman) Pool
100,000
10,000
1,000
100
Oil, Gas, Water (STB, Mcf, STB)
100%
95%
90%
85%
80%
75%
70%
Watercut
Install Submersible
Dec-78
Dec-79
Dec-80
Dec-81
Dec-82
Dec-83
Dec-84
Dec-85
Dec-86
Dec-87
Dec-88
Dec-89
Dec-90
Dec-91
Dec-92
Dec-93
Dec-94
Oil
Gas
Water
Watercut

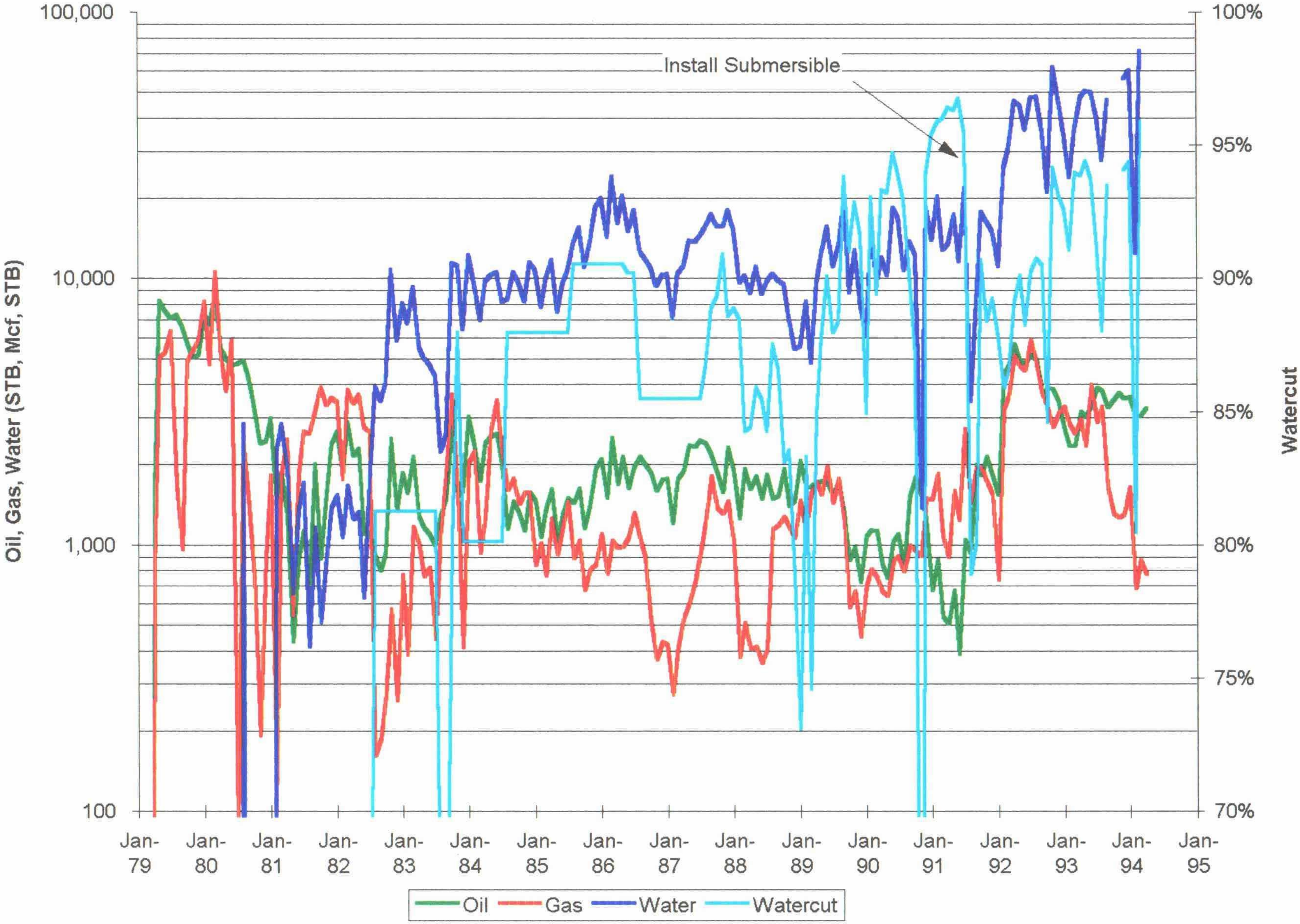
BEFORE THE
OIL CONSERVATION DIVISION
Santa Fe, New Mexico

Case No. 10994 Exhibit No. 8

Submitted by: Enserch Exploration, Inc.

Hearing Date: June 23, 1994

Lambirth 2-A
South Peterson (Fusselman) Pool



BEFORE THE
OIL CONSERVATION DIVISION
Santa Fe, New Mexico

Case No. 10994 Exhibit No. 9

Submitted by: Enserch Exploration, Inc.

Hearing Date: June 23, 1994

SPE

Society of Petroleum Engineers of AIME

SPE 7463

MAXIMIZING RATES AND RECOVERIES IN WEST TEXAS NATURAL WATERDRIVE RESERVOIRS THROUGH APPLICATI[OF HIGH CAPACITY ARTIFICIAL LIFT EQUIPMENT

BEFORE THE
OIL CONSERVATION DIVISION
Santa Fe, New Mexico

Case No. 10994 Exhibit No. 10

Submitted by: Enserch Exploration, Inc.

Hearing Date: June 23, 1994

by Barry A. Langham, Amoco Production Company

This paper was presented at the 53rd Annual Fall Technical Conference and Exhibition of the Society of Petroleum Engineers of AIME, held in Houston, Texas, Oct. 1-3, 1978. The material is subject to correction by the author. Permission to copy is restricted to an abstract of not more than 300 words. Write: 6200 N. Central Expy., Dallas, Texas 75206.

ABSTRACT

Recoveries in West Texas natural waterdrive reservoirs range from 55 to 80% of the original oil-in-place. These recoveries are generally being achieved using conventional artificial lift methods in the late depletion stages. The high recovery factors and possible detrimental effects of higher capacity artificial lift have historically restricted its use in these types of fields. Contrary to general theory and operating practice, it has been demonstrated that high volume lift is an effective means of increasing rate and ultimate recovery in some West Texas natural waterdrive fields.

INTRODUCTION

Historically, operating practices in most West Texas natural waterdrive reservoirs were developed under the premise that they were so efficient that little could be done to enhance their performance. One alternative was the acceleration of recovery by increasing total fluid withdrawal rates within allowable restrictions. However, most of these fields were considered to be subject to water coning. Therefore, theoretically, increased withdrawals would increase water cut, perhaps irreversibly, and possibly reduce ultimate recovery.

With incentives of higher crude prices and the 100% market demand factor in Texas, it was decided to test this theory in some marginal high water cut producers. After significant increases in withdrawal rate, water cut remained relatively constant and in some cases even dropped. Water coning theory indicates that the added production volume should not improve recovery in homogeneous waterdrive reservoirs. If this prediction was valid, larger artificial lift in homogeneous reservoirs would not be feasible. However, based on the performance support of the few experimental high volume lift installations and the fact that real reservoirs are heterogeneous to some degree, several more installations were made. Performance of some of these additional installations is now sufficient to provide meaningful analysis and conclusions.

References and Illustrations at End of Paper

A post installation appraisal was used to evaluate the effectiveness of 55 high volume lift (HVL) installations in 23 West Texas natural waterdrive reservoirs. High volume lift refers to electric submersible pumps and hydraulic pumps capable of total fluid production in excess of 1000 BFPD (159 M^3FPD). These 23 reservoirs are located in 8 Ellenburger, 9 Devonian-Silurian, and 6 Other fields. Figure 1 is a map indicating their general geographical location. This sampling of installations investigates eight different horizons ranging geologically from the Canyon through the Ellenburger. Figure 2 depicts the relative geological position the horizons have with each other and their average depths.

With 3 to 48 months of post installation performance available on 55 electric submersible and hydraulic pumps, production trends have stabilized sufficiently to estimate the incremental volume of oil which will be recovered with HVL versus conventional lift. Also, the magnitude of initial and sustained rate increase achieved with high volume lift over conventional lift is now quantifiable.

To optimize future HVL installation priority for maximum rate and recovery, the HVL analysis was subdivided into three categories. These categories are the Ellenburger, Devonian, which is a combination of Silurian and Devonian, and Other, which is composed of Abo, Canyon, Strawn, Caddo Cambrian, and Penn.

ASSUMPTIONS AND QUALIFICATIONS

1. Observations made as a result of this study are from HVL performance exhibited by West Texas natural waterdrive carbonate reservoirs only.

2. Generally the installation of HVL is the final attempt to increase production and ultimate recovery. That is to say, all the pay has been opened and several stimulations performed such that potential for any further downhole remedial

work is nil.

3. HVL is installed when the maximum size beam lift operated within its physical limitation cannot effectively pump the well off.

4. Although it is recognized that decline curve analysis has limitations in waterdrive reservoirs, the maximum production benefit is early in the life of HVL and the majority of the remaining recovery is obtained within the first few years. Therefore, the later production predicted with decline curve extrapolation is minor and does not have significant effect on the overall economics.

5. Decline curve analysis is representative and well test data accurately reflect production.

6. Other assumptions are that base case or conventional lift production forecasts attain stripper crude prices prior to abandonment while high volume lift production forecasts reach their economic limit at higher producing rates due to higher operating costs and are still receiving lower tier crude prices.

THEORY

Incremental production and recovery are indicated from this study, although performance to date is insufficient to ascertain the origin of the growth. Theoretically there are two potential sources for the increased recovery. It may be coming from the stripping effect associated with moving greater volumes of fluid through the reservoir. This concept is supported by the shape of the fractional flow curve for an oil-wet reservoir. At high water cuts, significant additional recovery is achievable with continued withdrawals as demonstrated by the flattening of the curve. The reservoirs involved in this study tend to be moderately oil-wet. The second contributing factor to reserve growth may be the heterogeneity of the reservoir rock. Additional recovery could be coming from the lower flow capacity intervals as an increased pressure differential is created at the well bore with high volume lift. Figure 3 is a typical Devonian porosity log which shows the inherent heterogeneity of these carbonate reservoirs.

Rate increases experienced with high volume lift over those exhibited by conventional lift are explained by Darcy's Law, in that rate (Q) is proportional to the pressure differential (ΔP) and a greater ΔP is obtained with high volume lift by lowering the producing fluid level.

OPERATING EXPENSE

Due to increased power requirements for the additional lift capacity plus increased salt water disposal capacity needed for the larger fluid withdrawals, operating costs soared to approximately a five fold increase over those with conventional lift. Table 1 illustrates the average operating costs incurred prior to high volume lift and after high volume lift for the three categories investigated. It should be noted that the deeper the horizon, the higher the operating cost. This is primarily due to the increased power requirements with increasing depth of fluid withdrawals. Also, the deeper horizons are generally hotter, thus the equipment failure is more frequent and pulling costs incurred are greater. For example, the average run time between pulling jobs in the Ellenburger is roughly 1/2 that of the Devonian and the average Ellenburger pulling cost is approximately 40% greater than the average Devonian pulling job cost.

ECONOMIC LIMITS

Economic limits for continued operations with conventional lift and projected operations with high volume lift are different because of the variation in operating costs and crude prices. The conventional lift economic limit is calculated using a stripper crude price of \$15.50/bbl (\$97.49/M^3). A lower tier crude price of \$5.50/bbl (\$34.59/M^3) is used to calculate the high volume lift economic limit. The operating costs for high volume lift increase such that stripper production is not achieved prior to reaching the abandonment rate determined by strict interpretation of current price controls and assuming no special price relief is sought. Figure 4 is the calculation used to determine the economic limit and Table 2 illustrates the economic limits calculated. Realistically, it is difficult to believe that wells on HVL would be abandoned at such high rates without first seeking price relief. However, for reserve evaluation purposes, abandonment rates were assumed to be a function of the current price controls.

In many cases, HVL production increases have received upper tier crude prices of about \$12.50/bbl (\$78.62/M^3). Consequently, the indicated reserve results of this analysis present a conservative picture. Due to the complexity of multiple leases and BPCL mixtures, the portion of increased oil recovery which receives upper tier prices and that which receives lower tier prices is difficult to determine. Therefore, lower tier oil prices were used to determine economic limits and therfore, incremental oil obtained from HVL. It is obvious if HVL economics are good using lower tier prices, they will be even better when upper tier prices are applicable.

HVL INVESTMENT

The average high volume lift equipment cost for these 55 installations was \$41,700/installation plus \$19,000/installation for associated salt water disposal costs. HVL sizing requirements, and therefore costs, are a function of depth and the expected fluid volume. For these 55 installations, these sizing factors have varied from 6000' (1829 M) to 12,500' (3810 M) and 1000 BFPD (159 M^3FPD) to 6000 BFPD (954 M^3FPD), respectively. Table 3 shows the average initial investment for the high volume lift installations by category.

ZERO TIME PLOT ANALYSIS

Due to the 48 month span over which these high volume lift installations were made, a zero time plot analysis was employed to evaluate average performance of all the installations. Figure 5 is a typical zero time plot analysis used to provide a common datum for determination of an average performance trend prior to and after high volume lift installation. It should be pointed out, however, that as data extends further away from the zero point, interpretation becomes more difficult because the data sampling size is diminishing.

The base case or conventional lift performance trend established from the 55 well average indicated an oil rate of 80 BOPD (13 M^3OPD) at an 80% water cut with production declining at approximately 30%/year when the performance data for each well was adjusted to time-zero, averaged, and plotted. Based on this trend, an additional 80,000 BO (12,719 M^3O) would be recovered prior to reaching the economic limit for the average well. With installation of high volume lift, the rate initially increased to 230 BOPD (37 M^3OPD), which was an average initial incremental rate of 150 BOPD (24 M^3OPD), then sharply declined over the next 3 to 6 months to a more stabilized decline trend of 12%/year. No significant change in water cut was observed. With the shut-in time required for installation of the high volume lift equipment, a certain amount of flush production is associated with initial startup. This is probably the reason for the initial sharp decline. Using this analysis for the high volume lift installation an average additional 363,000 BO (5,771 M^3O) will be recovered per installation. Based on the before and after installation trends, an incremental 283,000 BO (44,993 M^3O) average per installation is estimated to be recovered.

Two significant characteristics exhibited by these plots were the shallower decline in oil production after HVL installation and the lack of change in the watercut trends. Figure 6 is a zero time plot illustrating the average performance of these 55 installations over 60 months of time. Through 42 months after the HVL installation, the number of wells included in the average decreases from 52 to 10 and the performance trend is stabilized. The last 6 months, where the decline is much steeper, are not felt to be representative because only 9 to 6 wells are included in the sampling. Even if production were to drop to the economic limit immediately, there has already been an estimated average incremental recovery of 100,000 BO (15,899 M^3O)/installation to date over that expected with conventional lift.

Performance of the three categories investigated (Ellenburger, Devonian, and Other) are shown by Figures 7, 8, and 9, respectively. All three categories exhibit similar response characteristics. All three show significant initial increases dropping to a more stabilized trend within 3 to 6 months. The Devonian exhibits the most potential for both recovery and rate increase with a 350,000 BO (5,646 M^3O) incremental recovery and a 176 BOPD (28 M^3OPD) average rate increase per installation. The sudden drop in production exhibited in the Devonian zero time plot after 42 months is also reflected in the total zero time plot (Figure 6). If this sudden drop is to be the predominant characteristic (even though it is only based on a three well sampling), an estimated average per well incremental recovery of 133,000 BO (21,145 M^3O) above the expected ultimate recovery for conventional lift has already been produced by these Devonian high volume lift installations.

A number of observations can be made from these HVL performance analyses. Recognizing that observed performance is a result of analysis of a limited data sampling, it appears that the Devonian category exhibits the most potential for HVL. Perhaps it is better than the Ellenburger because the Ellenburger production is primarily from fracture systems, whereas the Devonian production comes from both fracture and matrix contributions and therefore exhibits a greater degree of heterogeneity than the Ellenburger. Devonian HVL response is probably better than the Other category because the Other category reservoirs were being more efficiently produced with conventional lift. That is, the fluid level changes or differential pressure increases in the Other category were not as great as those experienced in the Devonian when HVL was used instead of conventional lift. Therefore, the incremental increase from HVL was not as great.

There are two distinctive characteristics in the zero time plot for the Other category. The water cut trend prior to high volume lift installation was not as steep as for the Ellenburger and Devonian categories and the decline trend after high volume lift installation was steeper. Both characteristics are probably due to the more efficient conventional recovery in Other category reservoirs as previously discussed. Table 4 illustrates the average per well incremental rate and recovery for the different categories analyzed.

For the 55 installations, the total initial incremental rate was 8,250 BOPD (1,312 M^3OPD) and the total incremental recovery is estimated to be 15,565,000 BO (2,474,600 M^3O). This performance indicates that high volume lift is proving to be an effective means of increasing rate and ultimate recovery in some West Texas natural waterdrive reservoirs.

PERFORMANCE EXAMPLES

Each of the 55 wells analyzed was unique. Three general observations could be made from this analysis. First, wells with a 70% water cut or greater usually had sufficient decline in production such that incremental recovery attributed to high volume lift could be estimated. Second, most well cases studied indicated a significant production increase immediately after HVL installation followed by a rather rapid decline over the next 3 to 6 months before a more stabilized shallower decline trend was established. Third, wells with a 95% water cut or greater generally did not generate enough incremental recovery to be economically attractive. For illustration purposes, a sample well from each of the three categories investigated is shown below. These examples do not necessarily typify average category performance.

EXAMPLE #1

Well "A" is an Ellenburger well which was on rod pump prior to installation of an electric submersible pump (ESP) at zero time. As shown by the zero time plot (Figure 10), Well "A" water production increased in the 12 months prior to the ESP installation from an 18% water cut to a 74% water cut while oil production declined from 300 BOPD (48 M^3OPD) to 35 BOPD (5.6 M^3OPD). With this 91%/yr decline trend, the well would only recover about another 4250 BO (676 M^3O) prior to reaching an economic limit of 2 BOPD (0.3 M^3OPD) on conventional lift. When the ESP was installed, production initially increased to 400 BOPD (64 M^3OPD) and then declined to 300 BOPD (48 M^3OPD) in one month before stabilizing at a 28%/yr decline trend. Remaining recovery with the ESP to an economic limit of 41 BOPD (6.5 M^3OPD) is estimated to be 298,400 BO (47,442 M^3O). Thus, an instantaneous incremental oil rate of 365 BOPD (58 M^3OPD) was achieved and an incremental future recovery of 294,150 BO (46,766 M^3O) is anticipated.

EXAMPLE #2

Well "B" is a Devonian well which was on rod pump prior to installation of electric submersible pump (ESP). Figure 11 is the zero time plot for this well which exhibited stabilized production at about 250 BOPD (40 M^3OPD) water free until 8 months prior to the ESP installation. When water started breaking through, the well established an 80%/yr decline trend and oil production dropped to less than 90 BOPD (14 M^3OPD) just prior to the ESP installation. During this 8 months of oil decline, water cut increased from 0 to 74%. If maintained on rod pump, Well "B" would have recovered only an additional 18,600 BO (2,957 M^3O) before reaching its economic limit. Installation of the ESP brought the oil rate back up to 270 BOPD (43 M^3OPD) initially, but over the next 6 months, production had declined to 100 BOPD (16 M^3OPD) before a decline trend of 43%/yr was established. The water cut increased to 88% initially and has since stabilized to between 96 and 98%. Additional recovery with the ESP to an economic limit of 25.5 BOPD (4.1 M^3OPD) is estimated to be 218,000 BO (34,659 M^3O). Thus, an initial rate increase of 180 BOPD (29 M^3OPD) was achieved and an incremental future recovery of 199,400 BO (31,702 M^3O) is predicted.

EXAMPLE #3

Well "C" is a Strawn well, from the Other horizon category, which was on rod pump prior to the ESP installation. Figure 12 is the zero time plot of Well "C". In the 12 months preceding the ESP installation, production decreased from 65 BOPD (10 M^3OPD) to 25 BOPD (4 M^3OPD) as water cut increased from 67% to 90%. With production declining at 61%/yr, only 8,900 BO (1415 M^3O) remained to be recovered with the rod pump. Installation of the ESP increased production to 178 BOPD (28 M^3OPD) followed by an instantaneous decline of 30%/yr. Producing to an economic limit of 15.7 BOPD (2.5 M^3OPD) an additional 166,100 BO (26,408 M^3O) should be recovered with HVL. Therefore, an initial incremental oil rate of 153 BOPD (24 M^3OPD) was achieved and a future incremental oil recovery of 157,200 BO (24,993 M^3O) is predicted.

CONCLUSIONS

1. High volume lift installations in some West Texas natural waterdrive reservoirs are successful in increasing rate and ultimate recovery over that expected with conventional lift methods.

2. Based on performance of 55 HVL installations, maximum incremental rate and recovery occur in the Devonian category.

3. Maximum benefit from HVL is achieved when installed on wells with producing water cuts in excess of 70% (the lowest water cut exhibiting stabilized decline trends) and less than 95%.

4. Concern over premature water breakthrough and reduced ultimate recovery from application of high volume lift is unsubstantiated in most heterogeneous, West Texas carbonate, oil-wet, natural waterdrive reservoirs.

ACKNOWLEDGEMENTS

I am grateful to Amoco Production Company for giving me the opportunity to publish this paper. Special recognition is extended to Messrs. B. H. Stover, C. H. Kelm, L. J. Sanders, and J. R. Barnett for their contributions and advice in composing this paper.

TABLE 1

AVERAGE OPERATING COSTS $/MONTH/WELL

ALL CASES (PRIOR TO HVL)	739
ELLENBURGER	5500
DEVONIAN	3400
OTHER	2100
ALL CASES (AFTER HVL)	3633

TABLE 2

HORIZON CATEGORY	ECONOMIC LIMIT	
	BOPD/WELL	M^3OPD/WELL
AVERAGE (PRIOR TO HVL)	2	0.3
ELLENBURGER	41.2	6.6
DEVONIAN	25.5	4.1
OTHER	15.7	2.5
AVERAGE (AFTER HVL)	27.2	4.3

TABLE 3

HORIZON	AVERAGE HIGH VOLUME LIFT INVESTMENT/INSTALLATION	
ELLENBURGER	$58,300	Plus $19,000 for salt water dispos
DEVONIAN	$36,400	
OTHER	$32,800	
ALL	$41,700	

TABLE 4

HVL PERFORMANCE SUMMARY

	AVERAGE/WELL			
	INCREMENTAL RECOVERY		INITIAL INCREMENTAL RATE	
HORIZON	MBO	10^3M^3O	BOPD	M^3OPD
ELLENBURGER	152	24	149	24
DEVONIAN	350	56	176	28
OTHER	93	15	126	20
ALL	283	45	150	24

WEST TEXAS HVL LOCATIONS

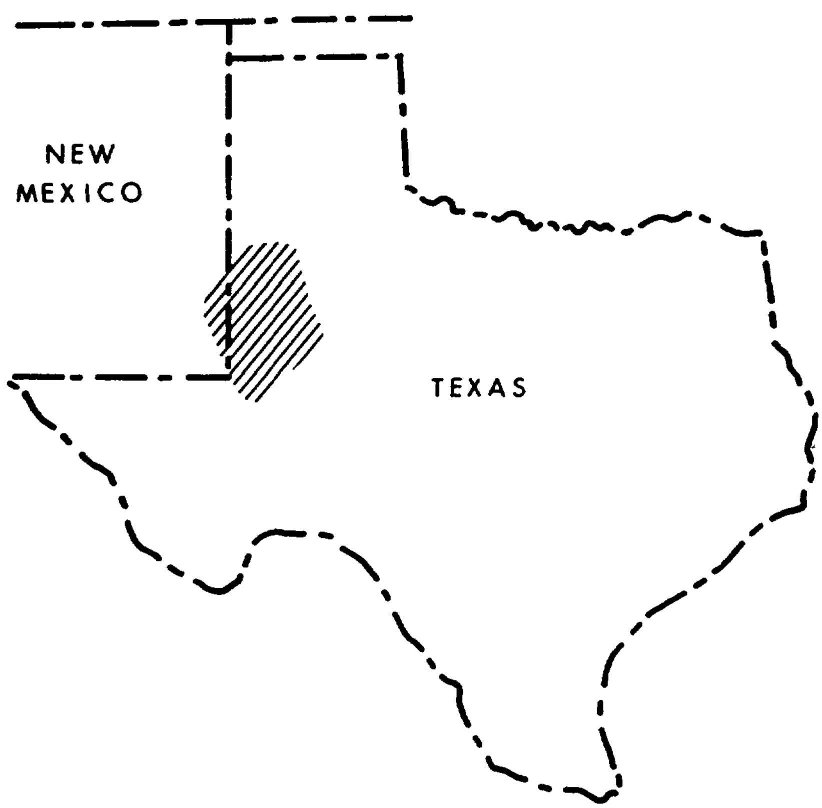


Fig. 1 - Geographical area.

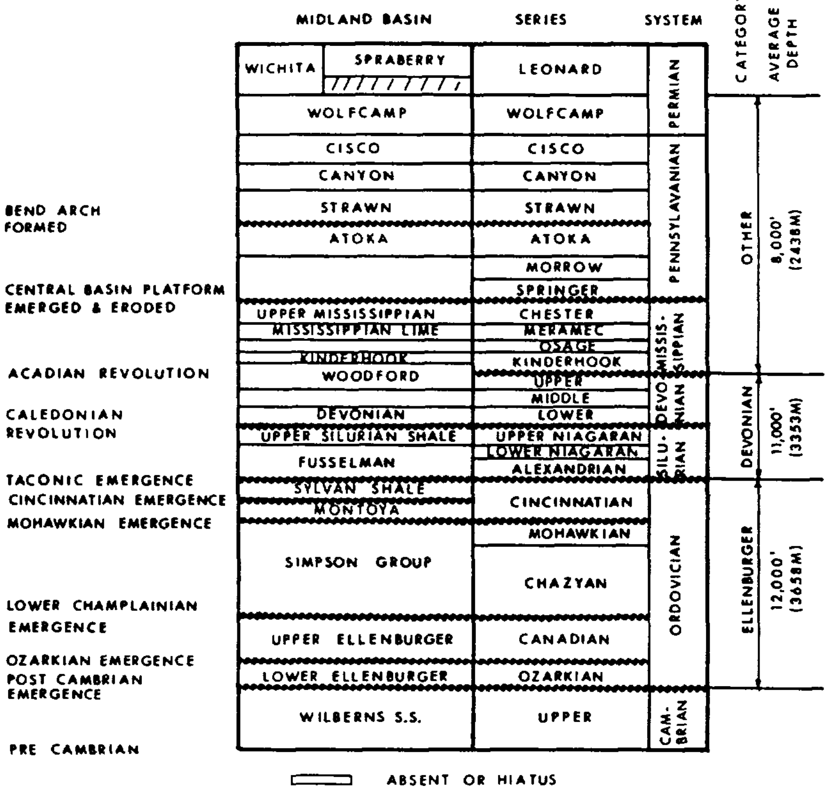


Fig. 2 - Geological Relationship

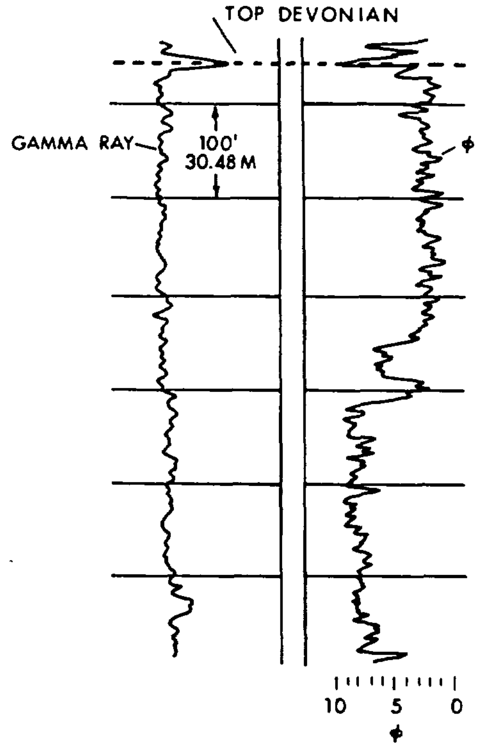


Fig. 3 - Devonian type log.

ECONOMIC LIMIT CALCULATION

$$\text{E.L.(BOPD/WELL)} = \frac{\text{MONTHLY OPERATING COST PER WELL}}{\text{(1-ROYALTY)(1-TAXES)(\$/BBL.)(30.4)}}$$

$$\text{E.L.(M}^3\text{OPD/WELL)} = \frac{\text{MONTHLY OPERATING COST PER WELL}}{\text{(1-ROYALTY)(1-TAXES)(\$/M}^3\text{)(30.4)}}$$

Fig. 4 - Economic limit formula.

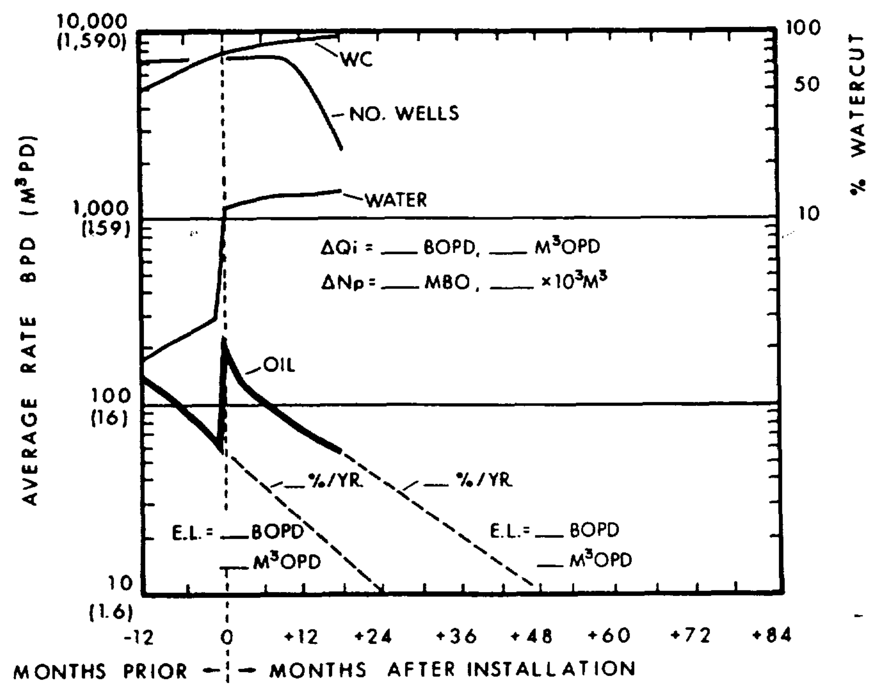


Fig. 5 - Zero time plot.

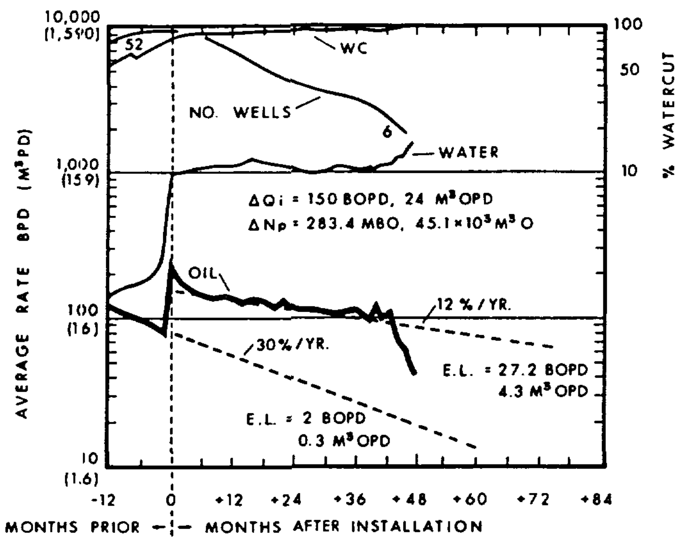


Fig. 6 - Average well zero time plot for all 55 HVL installations.

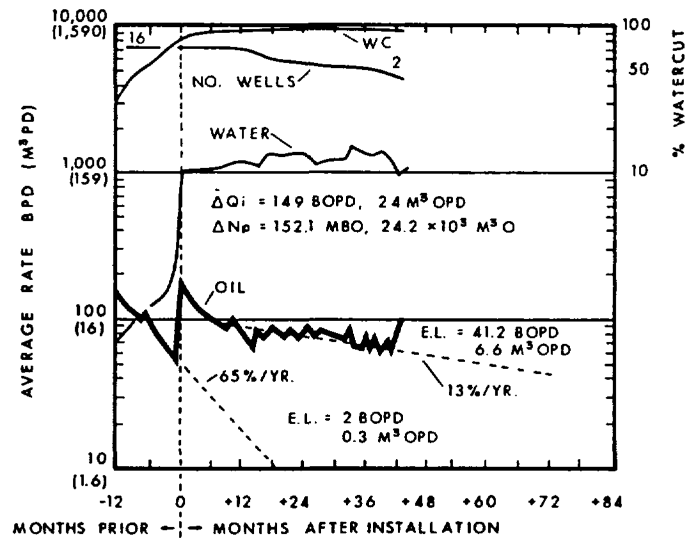


Fig. 7 - Average Ellenburger well zero time plot for 16 HVL installations.

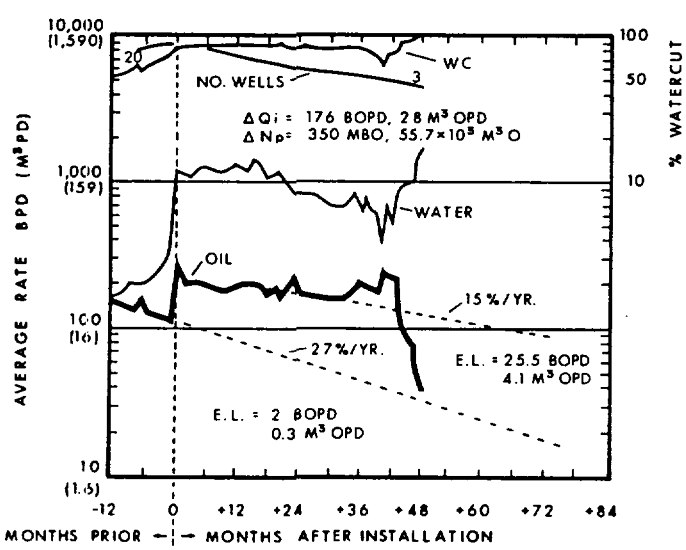


Fig. 8 - Average Devonian well zero time plot for 23 HVL installations.

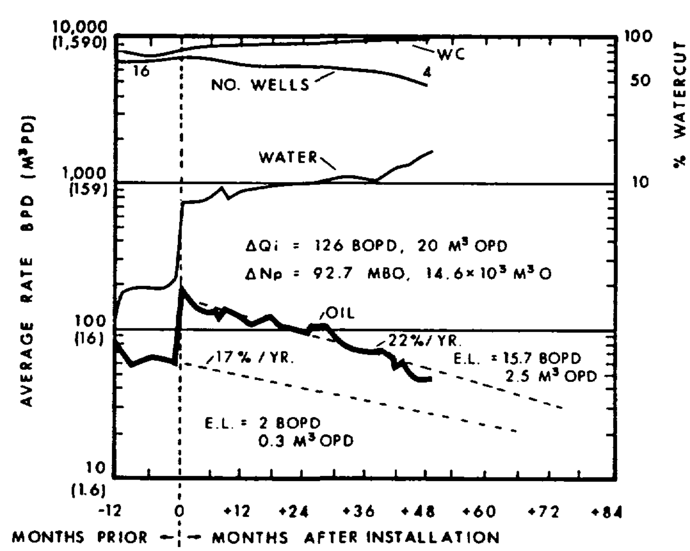


Fig. 9 - Average other well zero time plot for 16 HVL installations.

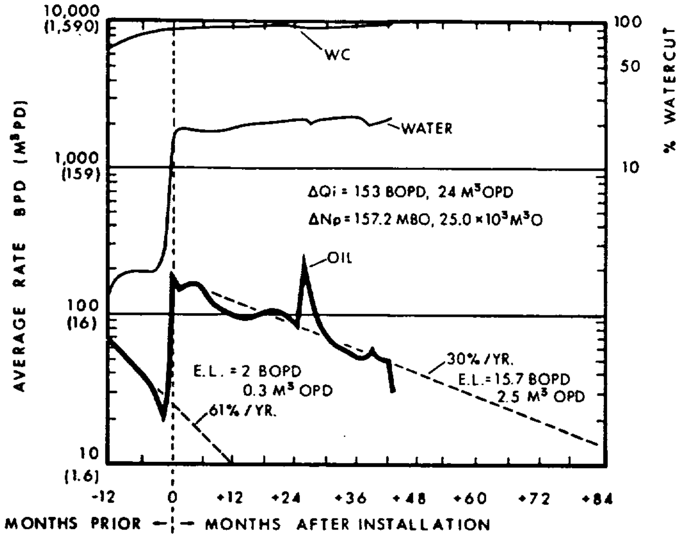


Fig. 10 - Well "A" zero time plot.

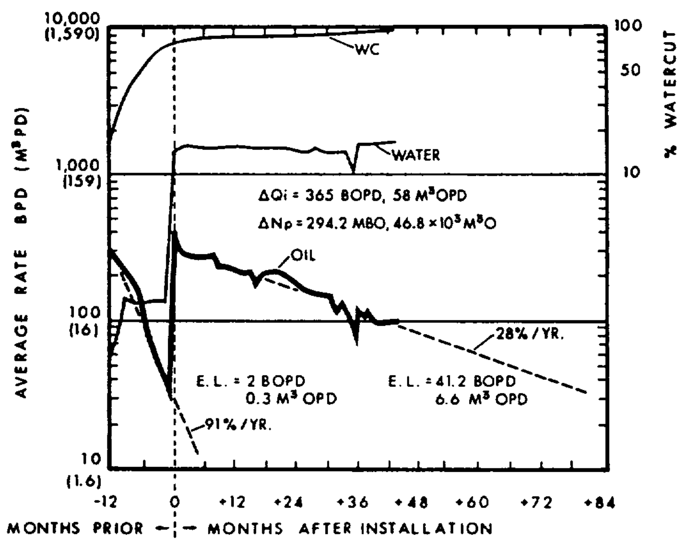


Fig. 11 - Well "B" zero time plot.

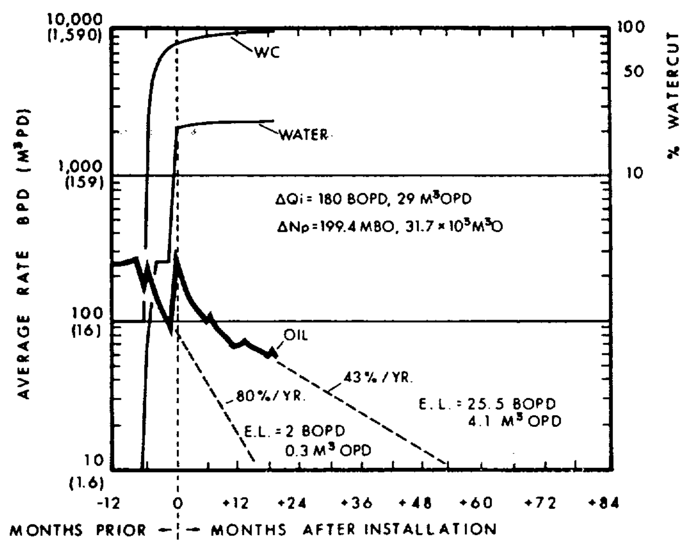


Fig. 12 - Well "C" zero time plot.

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

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(505) 393-6161

May 5, 1994

EP Operating Limited Partnership
ATT: Ralph B Telford
6 Desta Dr., Suite 5250
Midland, TX 79705-5510

RE: Lambirth #1-K
Sec.31, T-5s, T-33e

Gentlemen:

We received your letter stating that you have put this well on a submersible pump, testing with results of 335 BO, 1055 BW, and 128 MCFG in 17 hours. We give you permission to produce this well for 20 days at this rate, after that you must apply for a hearing to increase the allowable for this well or curtail the production.

If you will get back with us when you make out your application for the hearing, we will consider granting addition allowable for production until the hearing. With the understanding that if the application for additional allowable is not granted the production from the well will be curtailed back until the overage is made up.

If you have any questions on this matter, please call the District I Hobbs Office (505) 393-6161.

Yours very truly,

OIL CONSERVATION DIVISION

Jerry Sexton
District I, Supervisor

JS:dp
cc:file

BEFORE THE
OIL CONSERVATION DIVISION
Santa Fe, New Mexico

Case No. 10994 Exhibit No. 11

Submitted by: Enserch Exploration, Inc.

Hearing Date: June 23, 1994

BEFORE THE

OIL CONSERVATION DIVISION

NEW MEXICO DEPARTMENT OF ENERGY, MINERALS AND NATURAL RESOURCES

IN THE MATTER OF THE APPLICATION
OF ENSERCH EXPLORATION, INC.
FOR THE ASSIGNMENT AT A
SPECIAL DEPTH BRACKET OIL ALLOWABLE,
ROOSEVELT COUNTY, NEW MEXICO. CASE NO. 10994

AFFIDAVIT

STATE OF NEW MEXICO)
) ss.
COUNTY OF SANTA FE)

William F. Carr, attorney in fact and authorized representative of Enserch Exploration, Inc., the Applicant herein, being first duly sworn, upon oath, states that in accordance with the notice provisions of Rule 1207 of the New Mexico Oil Conservation Division the Applicant has attempted to find the correct addresses of all interested persons entitled to receive notice of this application and that notice has been given at the addresses shown on Exhibit "A" attached hereto as provided in Rule 1207.

William F. Carr

SUBSCRIBED AND SWORN to before me this 22nd day of June, 1994.

My Commission Expires:

August 19, 1995

BEFORE THE
OIL CONSERVATION DIVISION
Santa Fe, New Mexico

Case No. 10994 Exhibit No. 12

Submitted by: Enserch Exploration, Inc.

Hearing Date: June 23, 1994

EXHIBIT A

Phillips Petroleum Company
4001 Penbrook
Odessa, TX 79762

CAMPBELL, CARR, BERGE
& SHERIDAN, P.A.
LAWYERS

MICHAEL B. CAMPBELL
WILLIAM F. CARR
BRADFORD C. BERGE
MARK F. SHERIDAN
WILLIAM P. SLATTERY

PATRICIA A. MATTHEWS
MICHAEL H. FELDEWERT
DAVID B. LAWRENZ
TANYA M. TRUJILLO

JACK M. CAMPBELL
OF COUNSEL

JEFFERSON PLACE
SUITE 1 - 110 NORTH GUADALUPE
POST OFFICE BOX 2208
SANTA FE, NEW MEXICO 87504-2208
TELEPHONE: (505) 988-4421
TELECOPIER: (505) 983-6043

May 18, 1994

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Phillips Petroleum Company
4001 Penbrook
Odessa, TX 79762

Re: Application of Enserch Exploration, Inc., for Special Pool Rules, Roosevelt County, New Mexico

Gentlemen:

This letter is to advise you that Enserch Exploration, Inc., has filed the enclosed application with the New Mexico Oil Conservation Division seeking an order promulgating Special Rules and Regulations for the South Peterson-Fusselman Pool located in portions of Townships 5 and 6 South, Ranges 32 and 33 East, N.M.P.M., Roosevelt County, New Mexico setting a special oil allowable for the pool of 500 barrels per day.

This application has been set for hearing before an Examiner of the Oil Conservation Division on June 9, 1994. You are not required to attend this hearing, but as an owner of an interest that may be affected by this application, you may appear at the hearing and present testimony. Failure to appear at that time or otherwise become a party of record will preclude you from challenging this application at a later date.

Parties appearing in cases before the Division have been requested to file a Pre-hearing Statement substantially in the form prescribed by the Division (Oil Conservation Division Memorandum 2-90). Pre-hearing statements should be filed by 4:00 o'clock p.m., on the Friday before a scheduled hearing.

Very truly yours,

WILLIAM F. CARR
ATTORNEY FOR ENSERCH EXPLORATION, INC.
WFC:mlh
Enclosure

P 111 332 806

Receipt for Certified Mail

No Insurance Coverage Provided
Do not use for International Mail
(See Reverse)

Sent to: Phillips Petroleum Company	
Street and No.: 4001 Penbrook	
P.O., State and ZIP Code: Odessa, TX 79762	
Postage	$ .29
Certified Fee	1.00
Special Delivery Fee	
Restricted Delivery Fee	
Return Receipt Showing to Whom & Date Delivered	1.00
Return Receipt Showing to Whom, Date, and Addressee's Address	
TOTAL Postage & Fees	$2.29
Postmark or Date	May 18, 1994

PS Form 3800, June 1991

● **SENDER:** Complete items 1 and 2 when additional services are desired, and complete items 3 and 4.
Put your address in the "RETURN TO" Space on the reverse side. Failure to do this will prevent this card from being returned to you. The return receipt fee will provide you the name of the person delivered to and the date of delivery. For additional fees the following services are available. Consult postmaster for fees and check box(es) for additional service(s) requested.
1. ☐ Show to whom delivered, date, and addressee's address. *(Extra charge)*
2. ☐ Restricted Delivery *(Extra charge)*

3. Article Addressed to:
Phillips Petroleum Company
4001 Penbrook
Odessa, TX 79762

4. Article Number
P 111 332 806

Type of Service:
☐ Registered
☒ Certified
☐ Express Mail
☐ Insured
☐ COD
☒ Return Receipt for Merchandise

Always obtain signature of addressee or agent and DATE DELIVERED.

5. Signature — Address
X

6. Signature — Agent
X

7. Date of Delivery
5-20-94

8. Addressee's Address *(ONLY if requested and fee paid)*

PS Form 3811, Mar. 1988 ★ U.S.G.P.O. 1988-212-865 **DOMESTIC RETURN RECEIPT**

Exhibits Submitted by

PHILLIPS PETROLEUM COMPANY

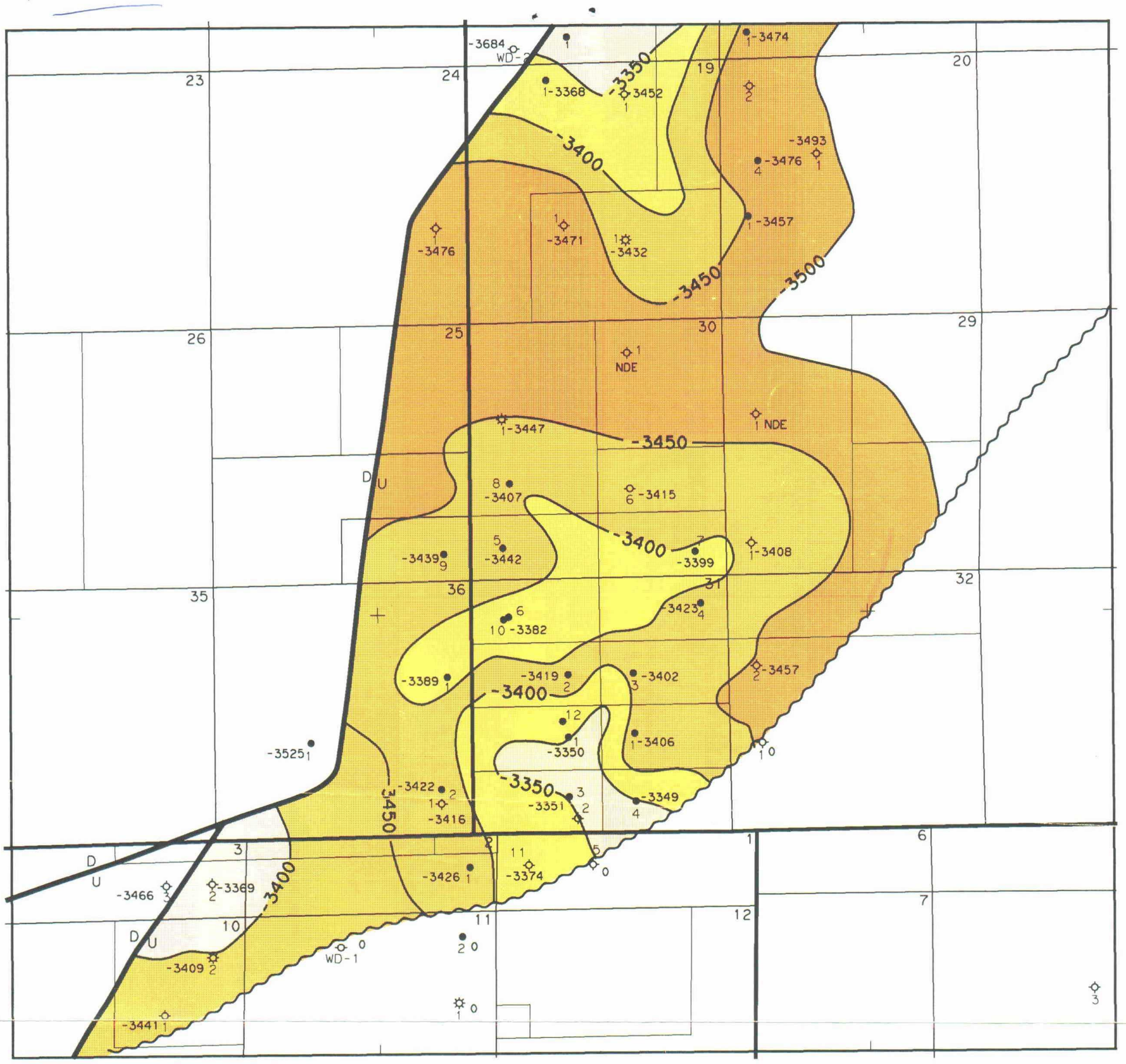
EXAMINER HEARING

June 23, 1994

SOUTH PETERSON FIELD

Roosevelt County, New Mexico

Exhibit #1



FAULTS

EROSIONAL UNCONFORMITY PINCHOUT

PHILLIPS PETROLEUM COMPANY
PERMIAN BASIN GEOLOGY

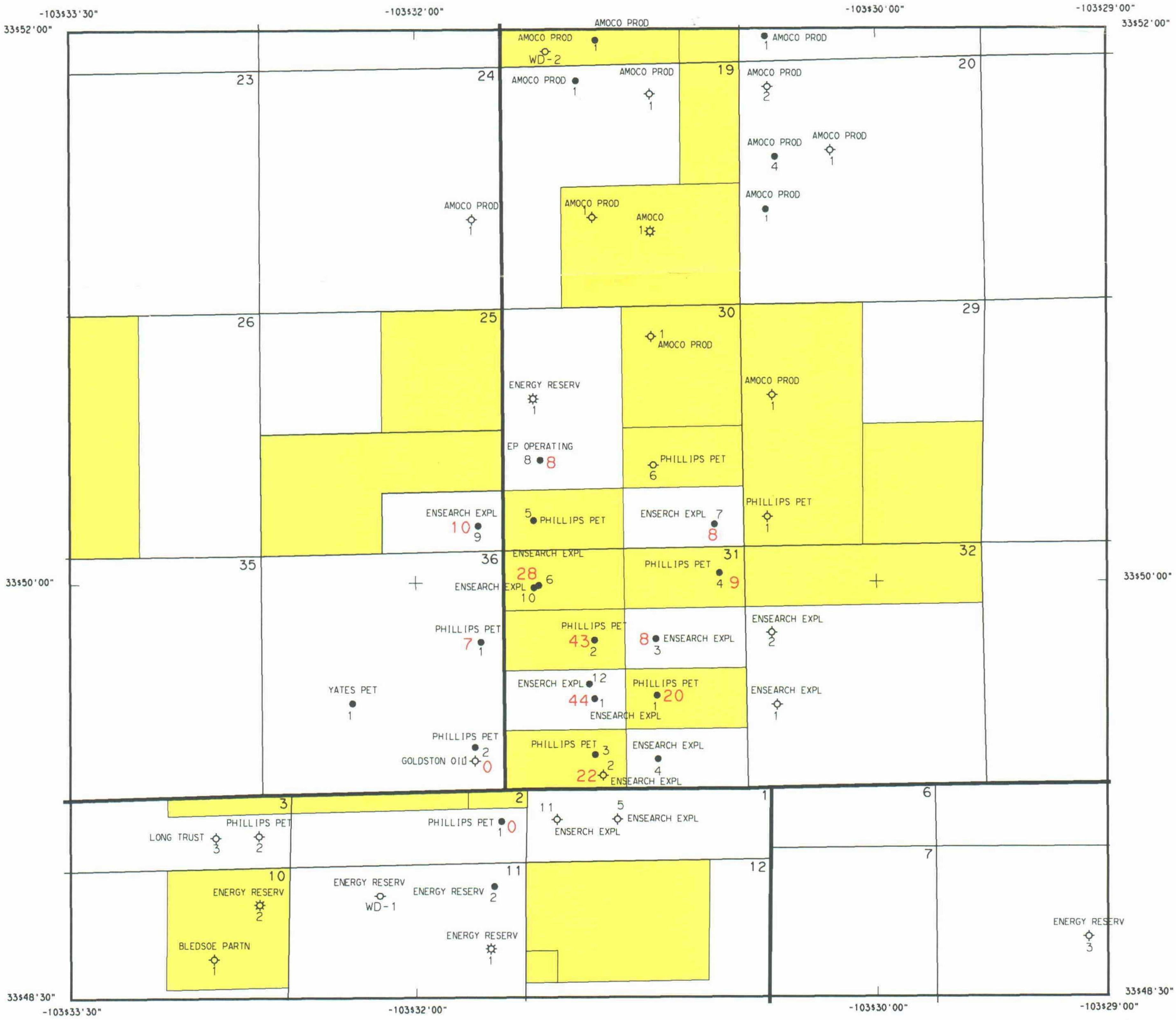
SOUTH PETERSON FIELD

ROOSEVELT CO., NEW MEXICO

0 2,000 4,000
SCALE (FEET)

SCALE	C.I. 50'	GEOLOGY BY SCOTT BALKE	DATE 6-94
CONTOURED ON	TOP OF FUSSELMAN		MAP NO. LAMBIRTH
TYPE INFO			DRAFTING R. COSSIN

Case 10994
Phillips Exhibit #1
6/23/94



9 ⇒ NET PAY ISOPACH OF FUSSELMAN RESERVOIR

Exh. #2

PHILLIPS 66

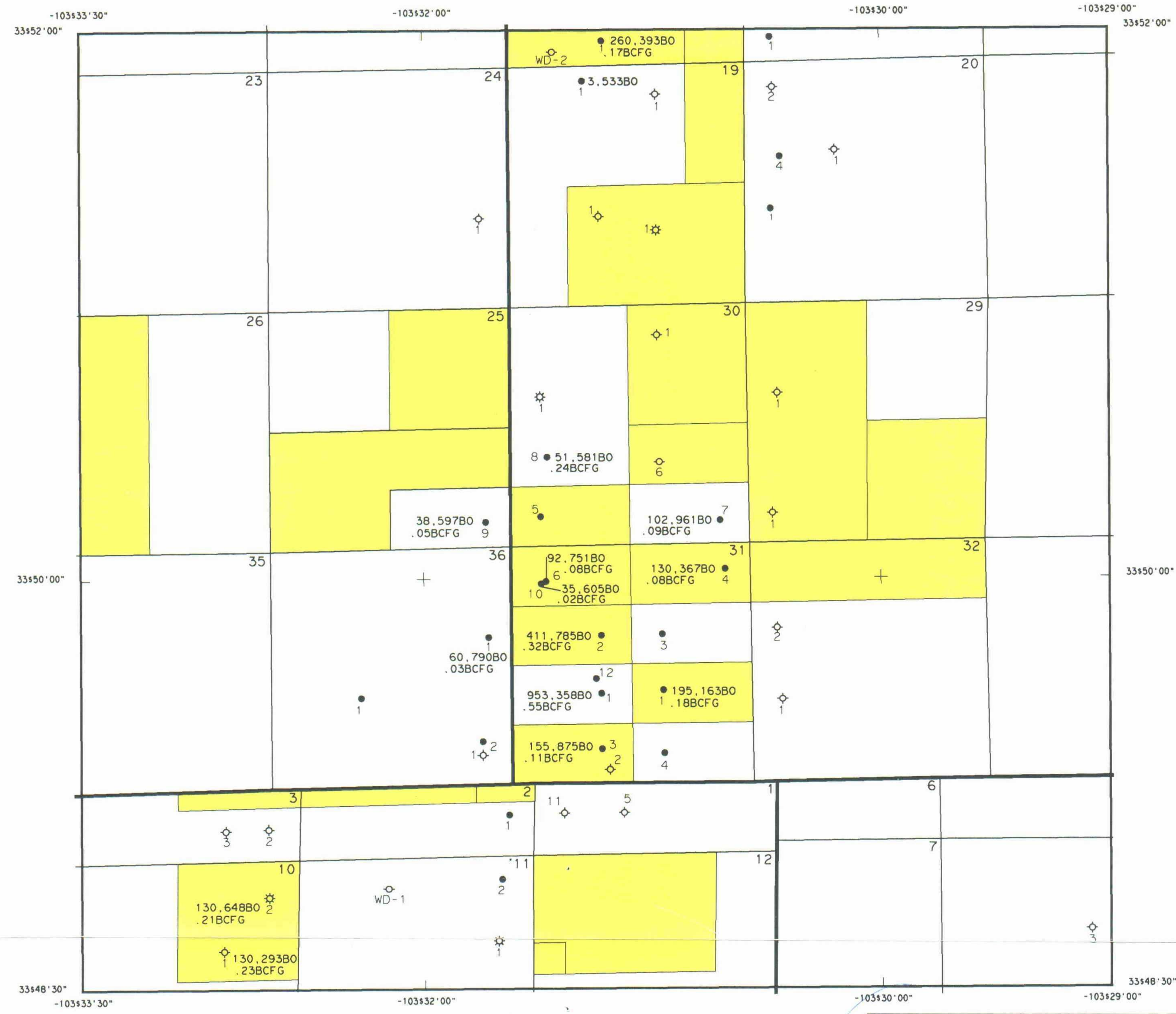
PHILLIPS PETROLEUM COMPANY
PERMIAN BASIN GEOLOGY

SOUTH PETERSON FIELD
ROOSEVELT CO., NEW MEXICO

0 2,000 4,000
SCALE (FEET)

SCALE	C.I.	GEOLOGY BY SCOTT BALKE	DATE 6-94
CONTOURED ON			MAP NO. LAMBIRTH
TYPE INFO			DRAFTING: R.COSSIN

Case No. 10994
June 23, 1994
Phillips Petr.
Ex #2



PHILLIPS PETROLEUM COMPANY
PERMIAN BASIN GEOLOGY

SOUTH PETERSON FIELD
ROOSEVELT CO., NEW MEXICO

0 2,000 4,000
SCALE (FEET)

SCALE	C.I.	GEOLOGY BY SCOTT BALKE	DATE 6-94
CONTOURED ON	PRODUCTION MAP OF FUSSELMAN		MAP NO LAMBIRTH
TYPE INFO	CURRENT THRU 12/93		DRAFTING R. COSSIN

Exh #3

Case No. 10994
June 23, 1994
Phillips Petroleum Co.
Exhibit #3

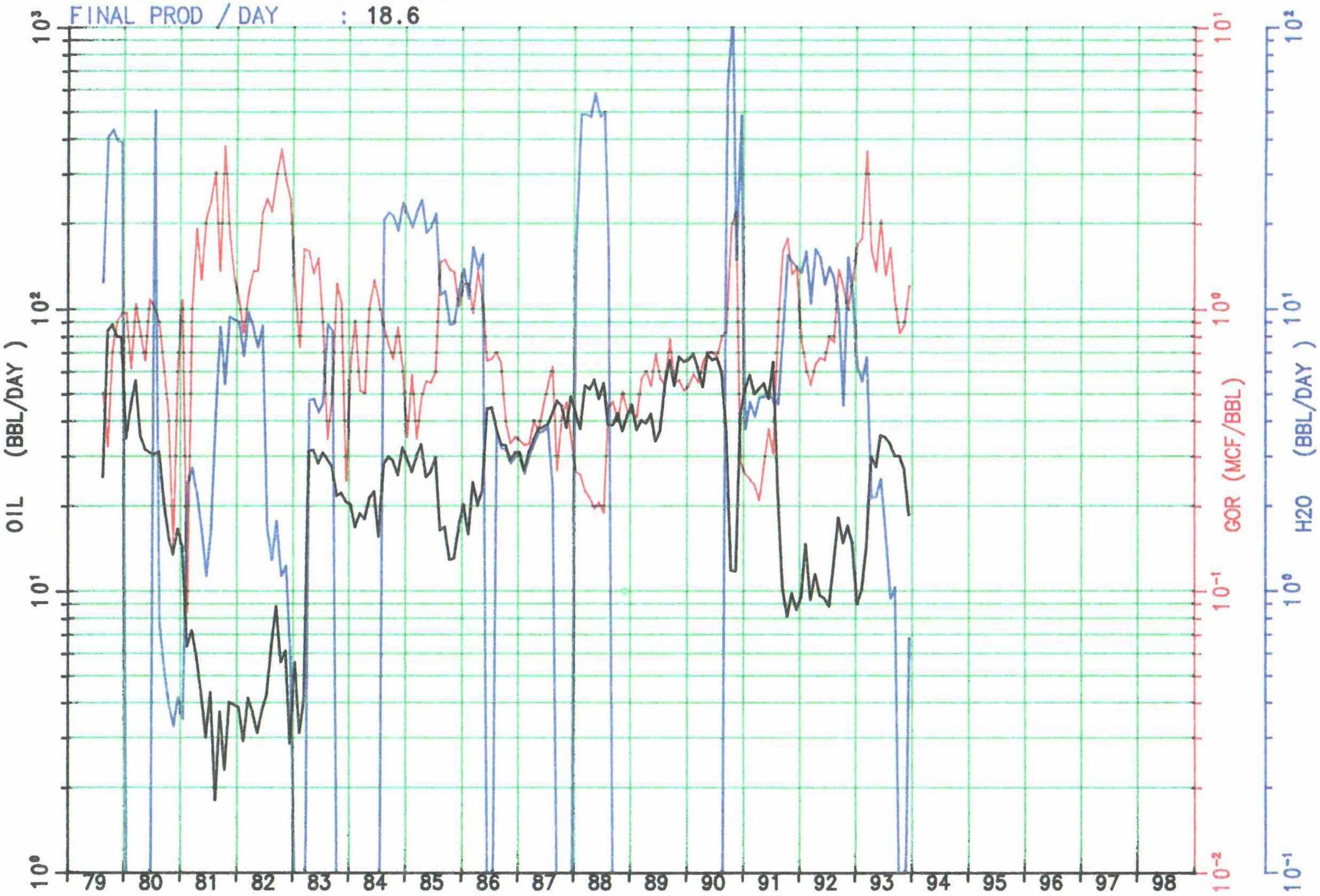
BEFORE THE
OIL CONSERVATION DIVISION
Case No. 10994 Exhibit No. 4
Submitted By:
Phillips Petroleum Corporation
Hearing Date: June 23, 1994

PHILLIPS PETROLEUM: LAMBIRTH-A #3

8/79-12/93

INITIAL PROD / DAY : 25.4
REMAINING LIFE : 14.42
0.00
CUM PRODUCTION : 155791.
FINAL PROD / DAY : 18.6

Current Cums
155791. BBL OIL
110116. MCF GAS
49736. BBL H2O



LEASE- LAMBIRTH A
RESVR- 002 : PETERSON SOUTH (FUSSELMAN)FUSSELMAN
WELL - 000003 CUM BBL =155911. 31N 5S 33E

DWIGHTS ACT
150,041,05S33E31N00FS API-300412048400
PHILLIPS PETROLEUM CO THRU 12/93

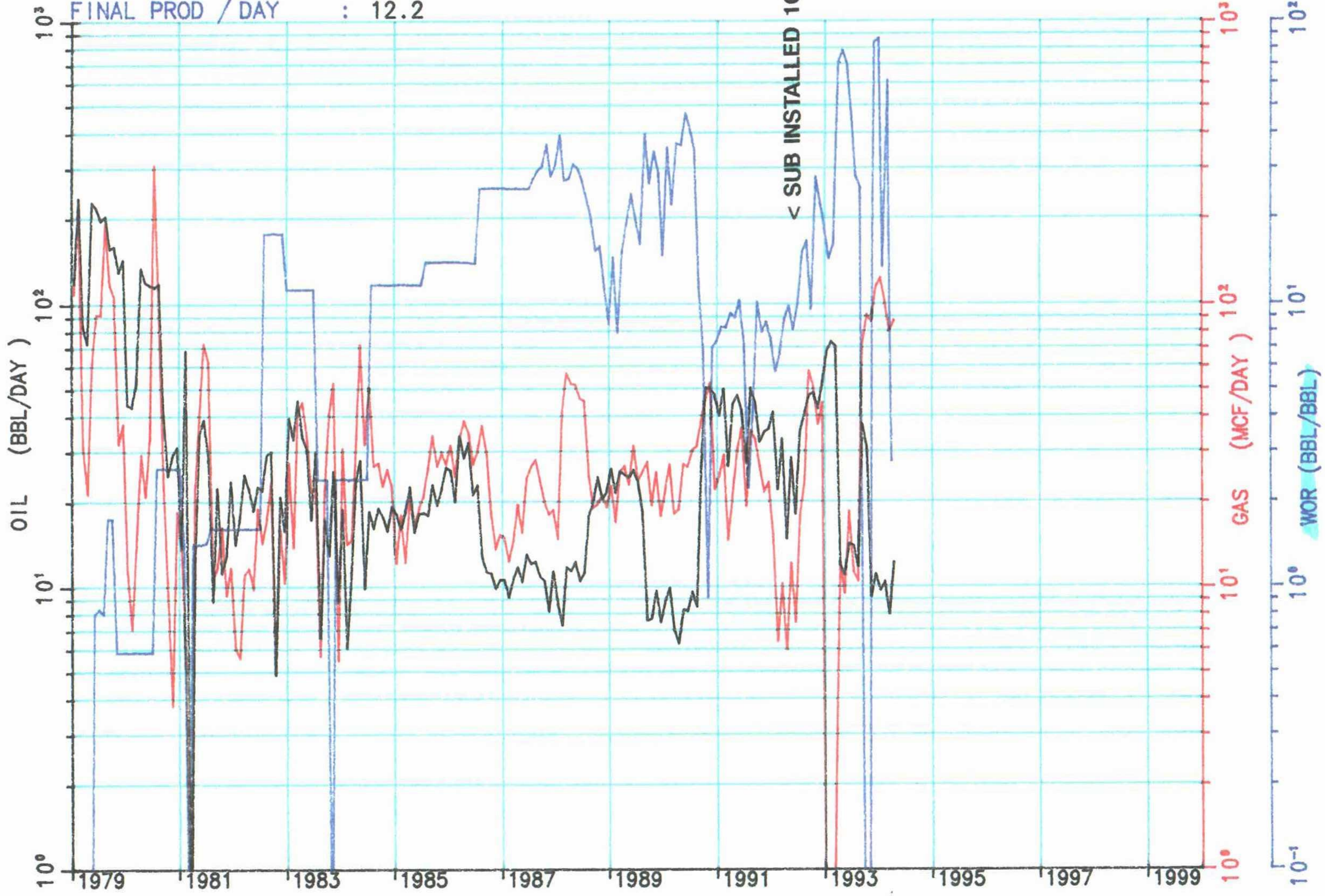
3
#411 06/20/94 12:39

BEFORE THE
OIL CONSERVATION DIVISION
Case No. 10994 Exhibit No. 5
Submitted By:
Phillips Petroleum Corporation
Hearing Date: June 23, 1994

PHILLIPS PETROLEUM: LAMBIRTH-A #1

1/79–4/94
INITIAL PROD / DAY : 119.4
REMAINING LIFE : 15.33
0.00
CUM PRODUCTION : 194808.
FINAL PROD / DAY : 12.2

Current Cums
194808. BBL OIL
187464. MCF GAS
1542. MBBL WTR



LEASE- 600157 : LAMBIRTH-A
RESVR- 078 : PETERSON SOUTH FUSSELMAN
WELL - 000001 PHS WELL PRODUCTION

WELL-600157078000001
API-30041204710000

1
#411 05/31/94 16:20

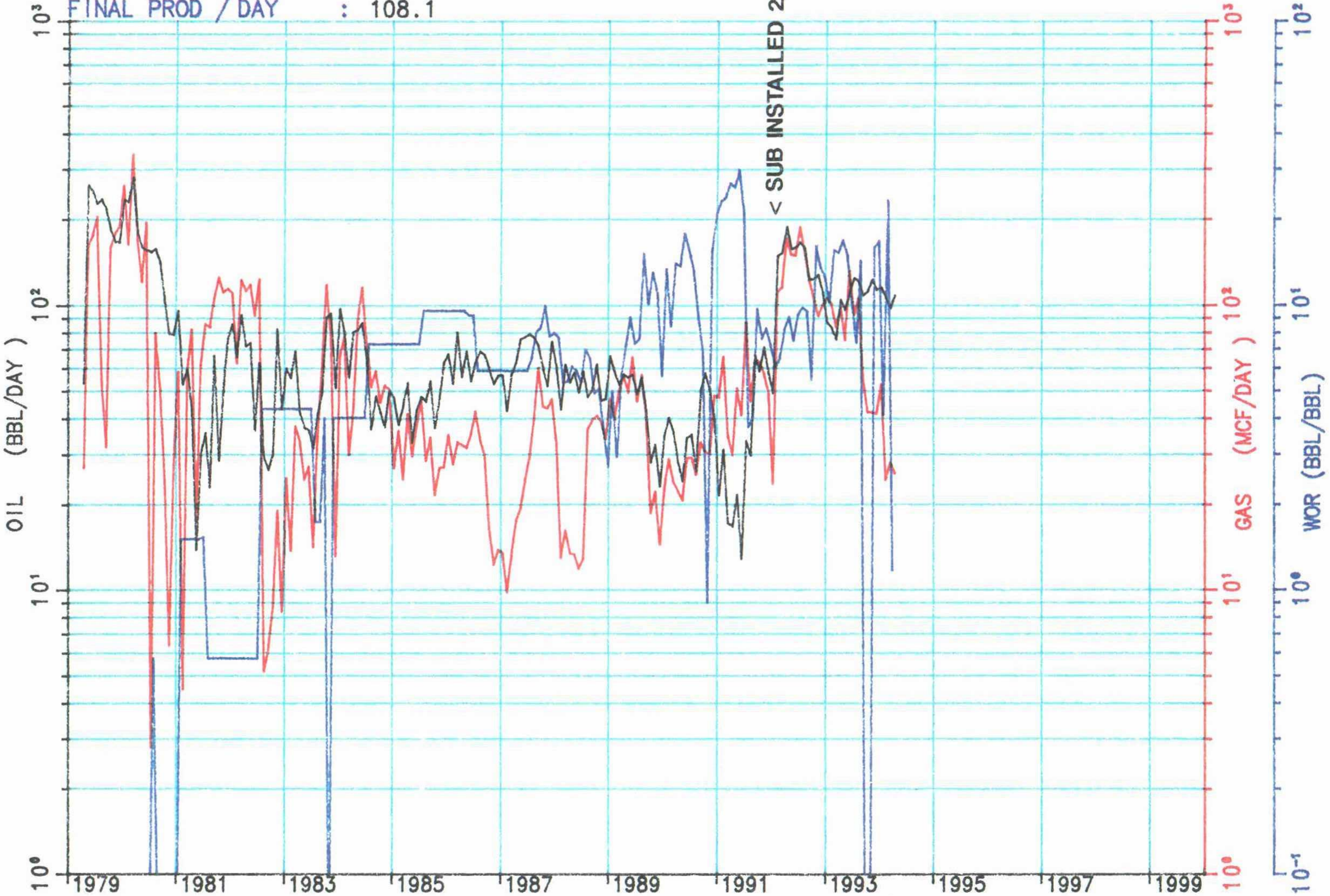
BEFORE THE
OIL CONSERVATION DIVISION
Case No. 10994 Exhibit No. 6
Submitted By:
Phillips Petroleum Corporation
Hearing Date: June 23, 1994

PHILLIPS PETROLEUM: LAMBIRTH-A #2

4/79–4/94

INITIAL PROD / DAY	:	53.4
REMAINING LIFE	:	15.08
		0.00
CUM PRODUCTION	:	426377.
FINAL PROD / DAY	:	108.1

Current Cums
426377. BBL OIL
335882. MCF GAS
2298. MBBL WTR



LEASE- 600157 : LAMBIRTH-A
RESVR- 078 : PETERSON SOUTH FUSSELMAN
WELL - 000002 PHS WELL PRODUCTION

WELL-600157078000002
API-30041204810000

2
#411 05/31/94 16:20

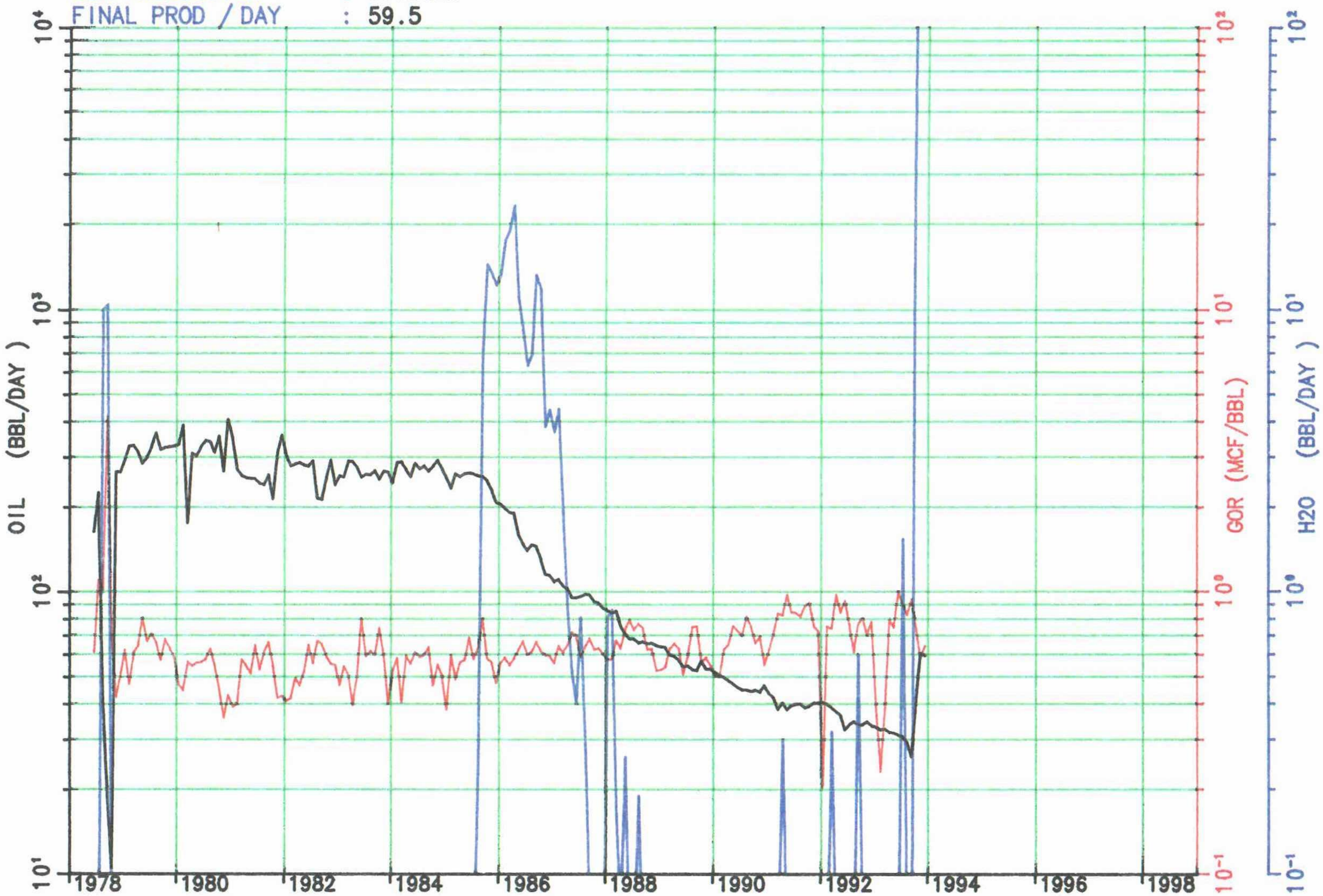
BEFORE THE
OIL CONSERVATION DIVISION
Case No. 10994 Exhibit No. 7
Submitted By:
Phillips Petroleum Corporation
Hearing Date: June 23, 1994

ENSEARCH: LAMBIRTH #1

6/78-12/93

INITIAL PROD / DAY : 165.1
REMAINING LIFE : 15.58
0.00
CUM PRODUCTION : 952552.
FINAL PROD / DAY : 59.5

Current Cums
952552. BBL OIL
554119. MCF GAS
37164. BBL H20



LEASE- LAMBIRTH
RESVR- 002 : PETERSON SOUTH (FUSSELMAN)FUSSELMAN
WELL - 000001 CUM BBL =953358. 31K 5S 33E

DWIGHTS ACT
150,041,05S33E31K00FS API-300412044900
E P OPERATING LTD PRT THRU 12/93

1
#411 06/20/94 13:50

SOUTH PETERSON FUSSELMAN LATEST WELL TESTS

	BOPD	BWPD	WATER/OIL RATIO
Phillips Operated:			
Lambirth A Well No. 1	11	560	51
Lambirth A Well No. 2	115	1900	17
Lambirth A Well No. 3	30	1	0.03
Ensearch Operated:			
Lambirth #1	270	2100	8

BEFORE THE
OIL CONSERVATION DIVISION
Case No. 10994 Exhibit No. 8
Submitted By:
Phillips Petroleum Corporation
Hearing Date: June 23, 1994

ENSEARCH LAMBIRTH NO. 1

Cumulative Production:	953,358 Bbls. Oil
	554,119 MCF Gas
	37,164 Bbls. Water

38% of oil production S. Peterson Fslm Field
8% acreage & wells
22% of net oil pay
20% of OOIP

BEFORE THE
OIL CONSERVATION DIVISION
Case No. 10994 Exhibit No. 9
Submitted By:
Phillips Petroleum Corporation
Hearing Date: June 23, 1994

STATE OF NEW MEXICO
ENERGY AND MINERALS DEPARTMENT
OIL CONSERVATION DIVISION
State Land Office Building
Santa Fe, New Mexico
25 July 1979

EXAMINER HEARING

IN THE MATTER OF:

In the matter of Case 6270 being reopened pursuant to the provisions of Order No. R-5771 which order created the South Peterson-Fusselman Pool, Roosevelt County, New Mexico.) CASE 6270

BEFORE: Daniel S. Nutter

TRANSCRIPT OF HEARING

A P P E A R A N C E S

For the Oil Conservation Division: Ernest L. Padilla, Esq.
Legal Counsel for the Division
State Land Office Bldg.
Santa Fe, New Mexico 87503

For Enserch Exploration: William F. Carr, Esq.
CAMPBELL AND BLACK P. A.
Jefferson Place
Santa Fe, New Mexico 87501

For Phillips Petroleum Co.: W. Thomas Kellahin, Esq.
KELLAHIN & KELLAHIN
500 Don Gaspar
Santa Fe, New Mexico 87501

INDEX

E X H I B I T S

SALLY WALTON BOYD
CERTIFIED SHORTHAND REPORTER

water saturation of 18 percent; and a productivity index of 35 barrels per day per psi.

And the Phillips Lambirth A No. 3 Well had a net pay thickness of 18 feet; average porosity of 15.2 percent; and average water saturation of 20 percent.

These are all based on log calculations, all this petrophysical data.

Q Mr. Kersh, now refer to Exhibit Number Five and explain that to the Examiner.

A Exhibit Number Five is an extended drawdown test and/or reservoir limits test on the Enserch Lambirth No. 1 Well, conducted June 19th through 22nd, 1978.

Our main concern here was that the Enserch Lambirth No. 1 Well was a discovery well of the field; our main concern was to try to determine the drainage area or the reservoir size, the size of the reservoir.

Okay, so what we did, was we conducted approximately a 66-hour extended drawdown, or reservoir limits test, on the Enserch Lambirth No. 1, using a highly sensitive gauge, a Hewlett-Packard pressure gauge, and shown at semi-steady state. This would be on the continuation of the drawdown test, at semi-steady state. dPdT, which is equal to beta, is equal to .15 psi per hour. And employing these -- this slope into our reservoir limits test calculations, we calculated a contributing pore volume of 17.76 million reservoir barrels, which comes out to be an equivalent drainage area of approximately 830 acres.

Q Now refer to what has been marked for identification as Exhibit Number Six and review this for the Examiner.

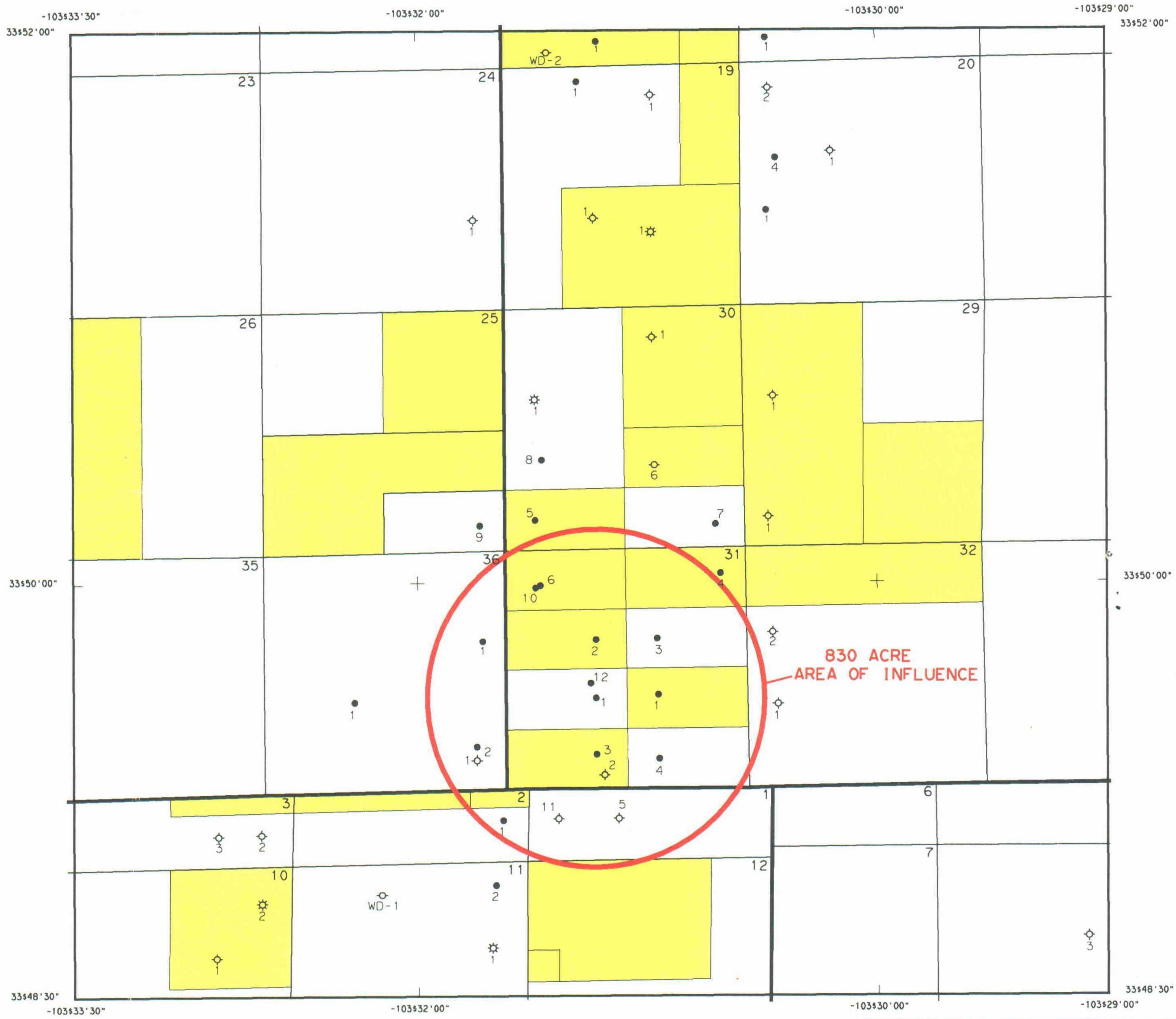
A. Exhibit Number Six is titled Minimum Permeability Required to Drain 30 Acres.

From our Enserch Lambirth No. 1, where we had good buildup data, and so forth, we had a permeability value of 559 millidarcies; however, the majority of the Fusselman completions, we did not have pressure buildup data -- well, pressure buildup data was not available.

So what we decided to do was use a productivity index data, which was -- which we had on all the wells, in order to determine our drainage area.

So what we decided to do was, we said, okay, the well with the lowest -- if we could prove that the well with the lowest productivity index could drain 80 acres, then we're assured that the rest of the wells can drain 80 acres.

As it turned out, this turned out to be the Lambirth No. 6 Well, which had a productivity index of .2. So employing this into Darcy's Law, and assuming 80 acres, we came up with a permeability requirement of four millidarcies would be required to drain 80 acres.



PHILLIPS 66

PHILLIPS PETROLEUM COMPANY
PERMIAN BASIN GEOLOGY

SOUTH PETERSON FIELD
ROOSEVELT CO., NEW MEXICO

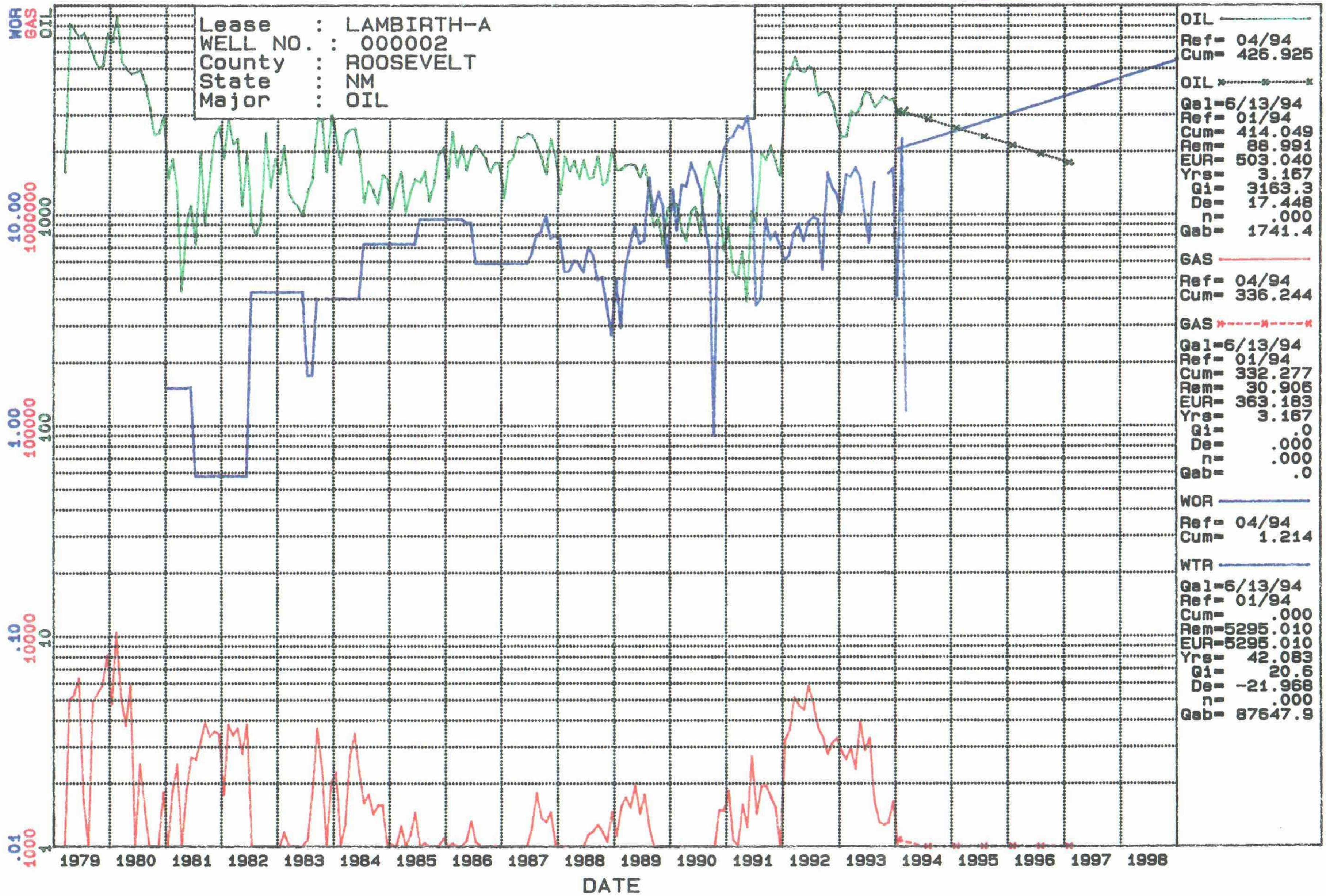
0 2,000 4,000
SCALE (FEET)

SCALE	C.I.	GEOLOGY BY SCOTT BALKE	DATE 6-94
CONTOURED ON			MAP NO LAMBIRTH
TYPE INFO			DRAFTING R. COSSIN

BEFORE THE
OIL CONSERVATION DIVISION
Case No. 10994 Exhibit No. 11
Submitted By:
Phillips Petroleum Corporation
Hearing Date: June 23, 1994

BEFORE THE
OIL CONSERVATION DIVISION
Case No. 10994 Exhibit No. 12
Submitted By:
Phillips Petroleum Corporation
Hearing Date: June 23, 1994

Economic Limit Plot



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ENERGY AND MINERALS DEPARTMENT
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For Enserch Exploration:	William F. Carr, Esq. CAMPBELL AND BLACK P. A. Jefferson Place Santa Fe, New Mexico 87501
For Phillips Petroleum Co.:	W. Thomas Kellahin, Esq. KELLAHIN & KELLAHIN 500 Don Gaspar Santa Fe, New Mexico 87501

BEFORE THE
OIL CONSERVATION DIVISION
Case No. 10994 Exhibit No. 10
Submitted By:
Phillips Petroleum Corporation
Hearing Date: June 23, 1994

I N D E X

SALLY WALTON BOYD
CERTIFIED SHORTHAND REPORTER

SALLY WALTON BOYD
CERTIFIED SHORTHAND REPORTER
Santa Fe, New Mexico

E X H I B I T S

ILLEGIBLE

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