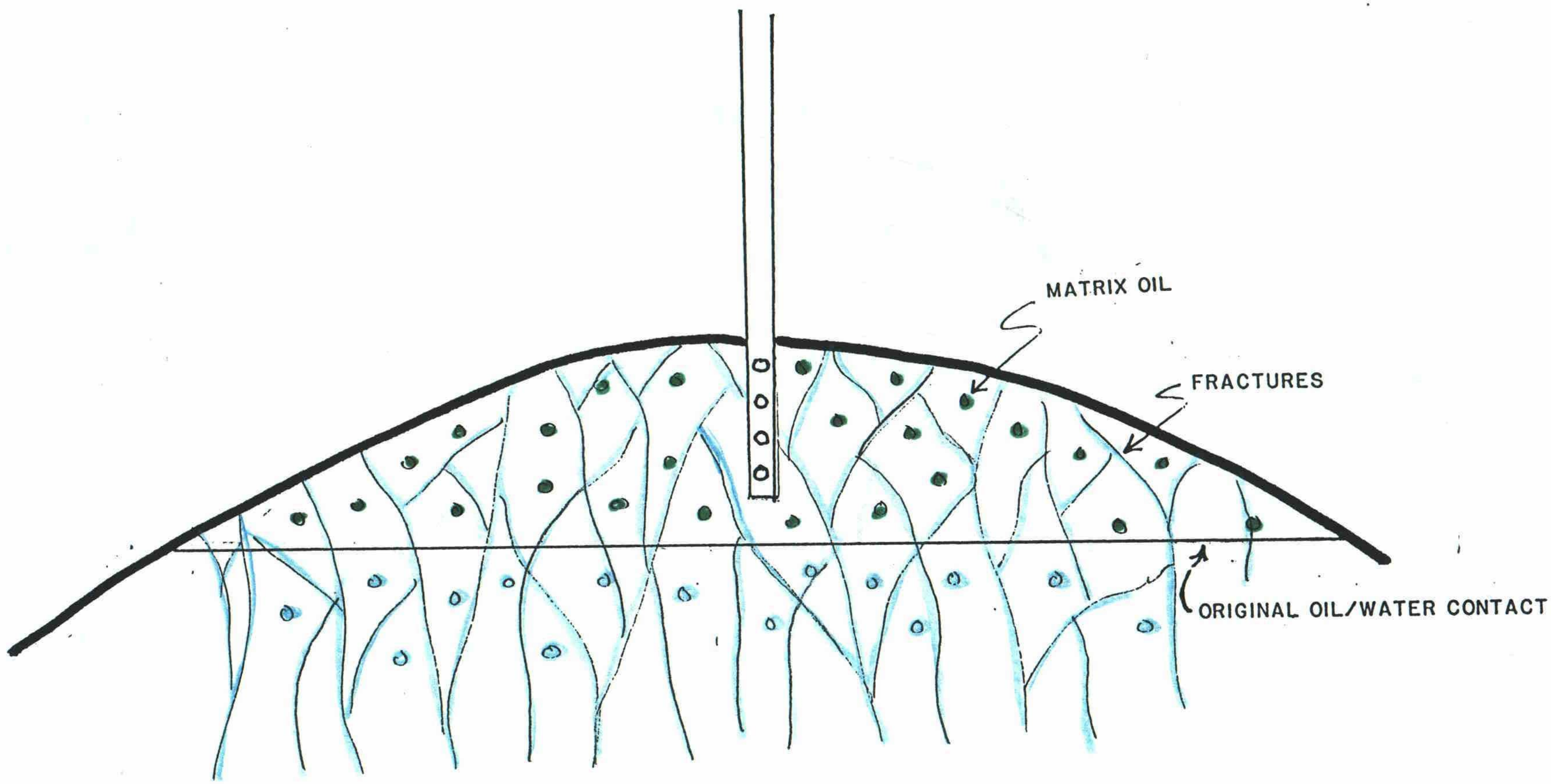
INCREMENTAL OIL PRODUCTION FROM

MATRIX POROSITY WITH H.V.L.



BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case No. 10994 (De Novo) Exhibit No. 6

Submitted by: Enserch Exploration, Inc.

Hearing Date: February 24, 1995

ENSERCH EXPLORATION INC
WEST TEXAS AREA

H.V.L. CONCEPT

DATE:
GEOLOGY:

CASE NO. 10994

CASE HISTORY

July 17, 1978	Pool established and Temporary Special Pool Rules Adopted providing for 80-acre spacing and proration units. (R-5771)
August 16, 1979	Pool Rules Adopted on a Permanent Basis. (R-5771-A)
May 9, 1994	Special Allowable authorized by Oil Conservation Division - Hobbs District Office.
May 17, 1994	Enserch filed application for a special depth bracket allowable.
June 23, 1994 - July 21, 1994	Hearings on Enserch's application.
November 3, 1994	Oil Conservation Division Order No. R-5771-B denying application of Enserch.
November 8, 1994	Enserch files Application for Hearing ***De Novo***.
January 12, 1995	Oil Conservation Commission Hearing continued at the request of Enserch. Phillips advised Commission it had no objection to continuance.
February 24, 1995	Oil Conservation Commission Hearing on application of Enserch.

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case No. 10994 (De Novo) Exhibit No. 7

Submitted by: Enserch Exploration, Inc.

Hearing Date: February 24, 1995

SPE 7463

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

by Barry A. Langham, Amoco Production Company

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case No. 10994 (De Novo) Exhibit No. 9

Submitted by: Enserch Exploration, Inc.

Hearing Date: February 24, 1995

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.

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

References and Illustrations at End of Paper 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^{3}FPD) to 6000 BFPD (954 M^{3}FPD), 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

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

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.

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

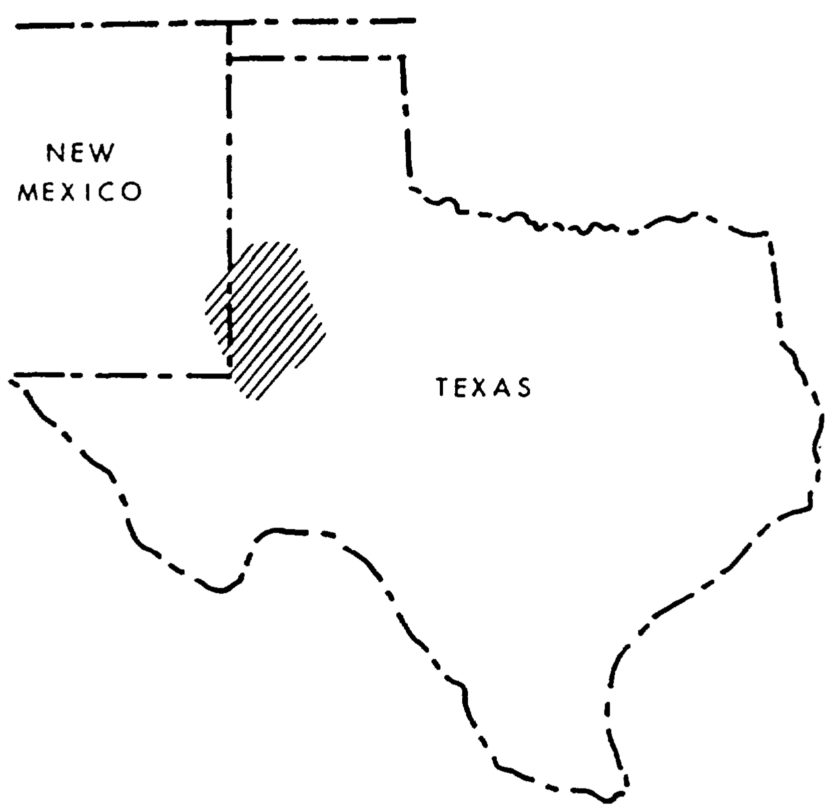


Fig. 1 - Geographical area.

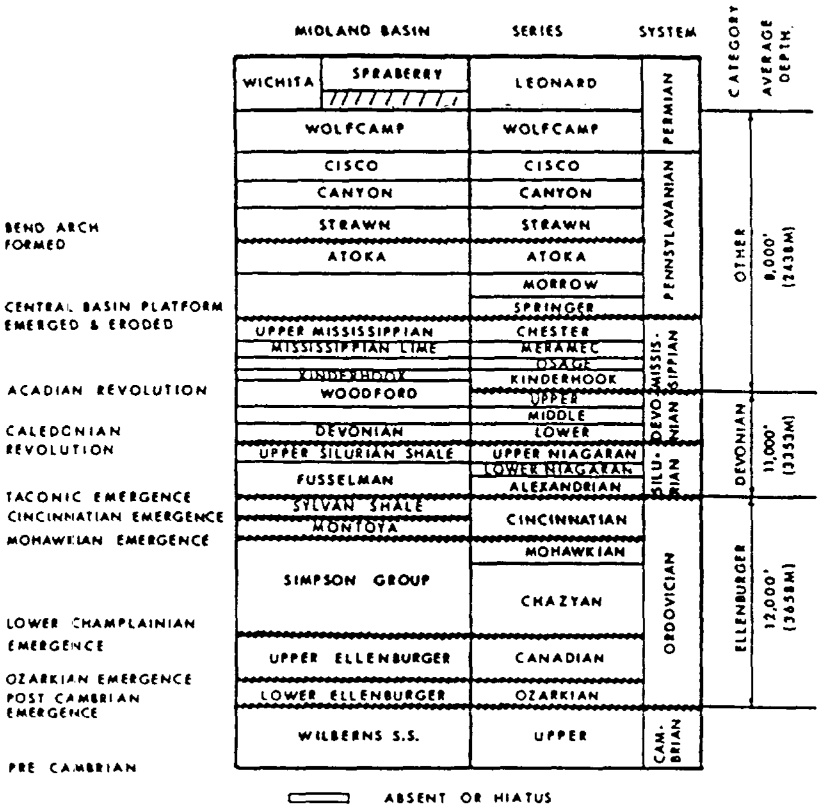


Fig. 2 - Geological Relationship

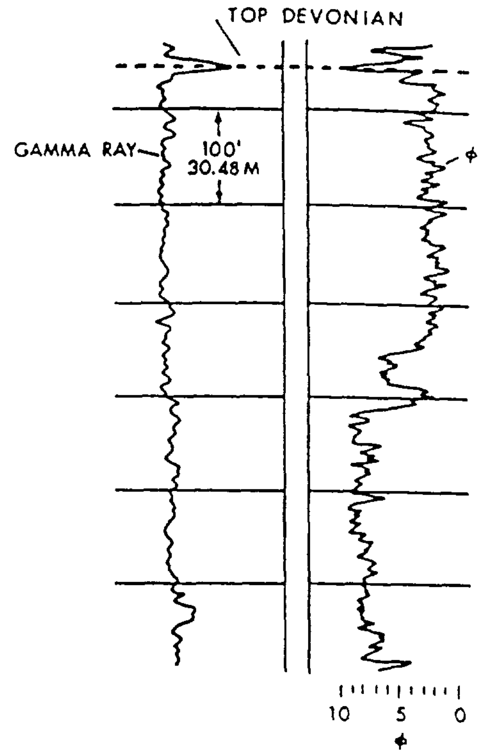


Fig. 3 - Devonian type log.

ECONOMIC LIMIT CALCULATION

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

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

Fig. 4 - Economic limit formula.

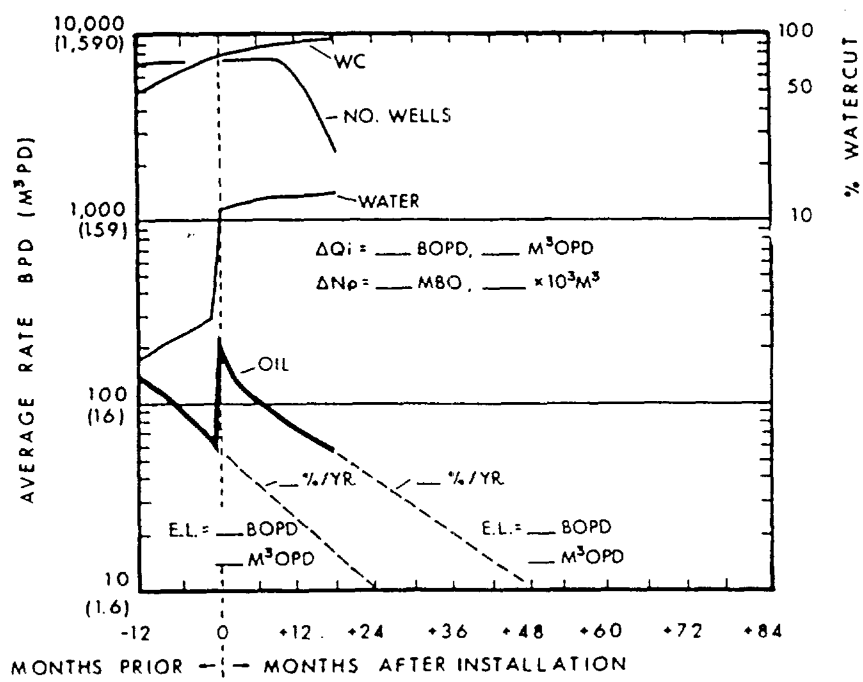


Fig. 5 - Zero time plot.

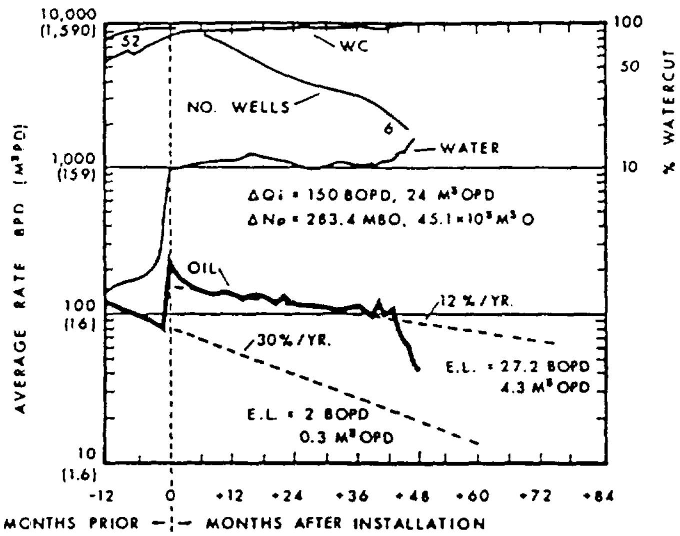


Fig. 6 - Average well zero time plot for all 55 HVL installations.

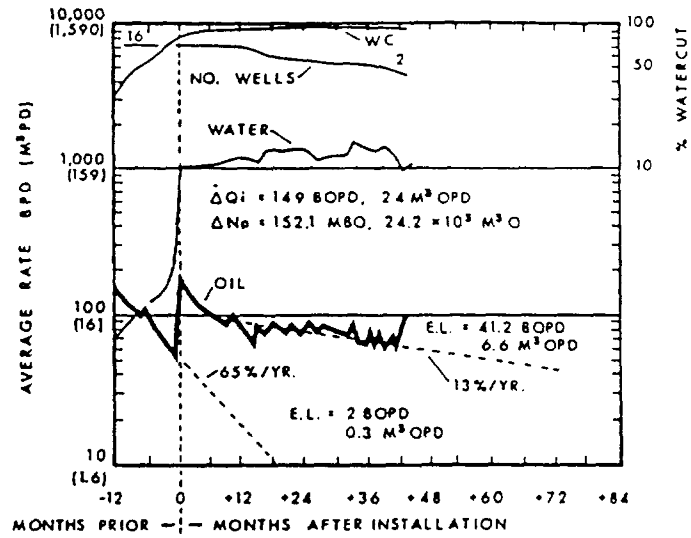


Fig. 7 - Average Ellenburger well zero time plot for 16 HVL installations.

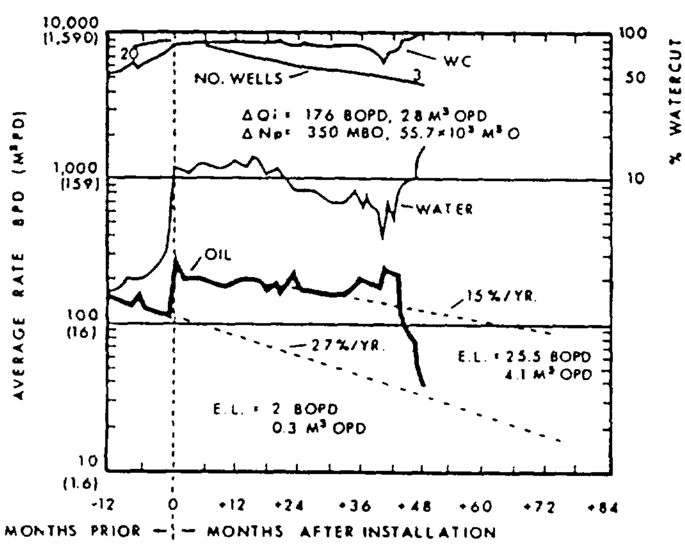


Fig. 8 - Average Devonian well zero time plot for 23 HVL installations.

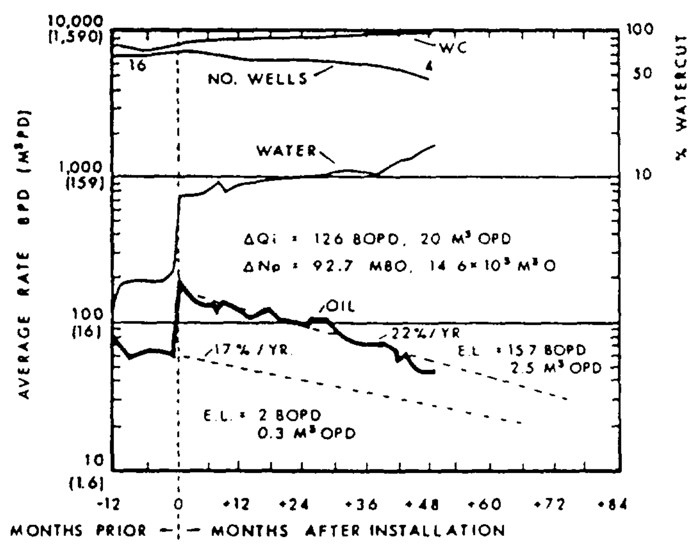


Fig. 9 - Average other well zero time plot for 16 HVL installations.

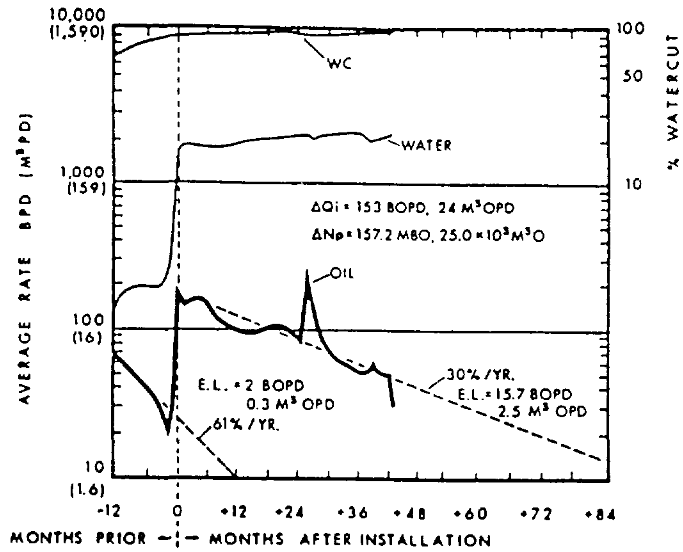


Fig. 10 - Well "A" zero time plot.

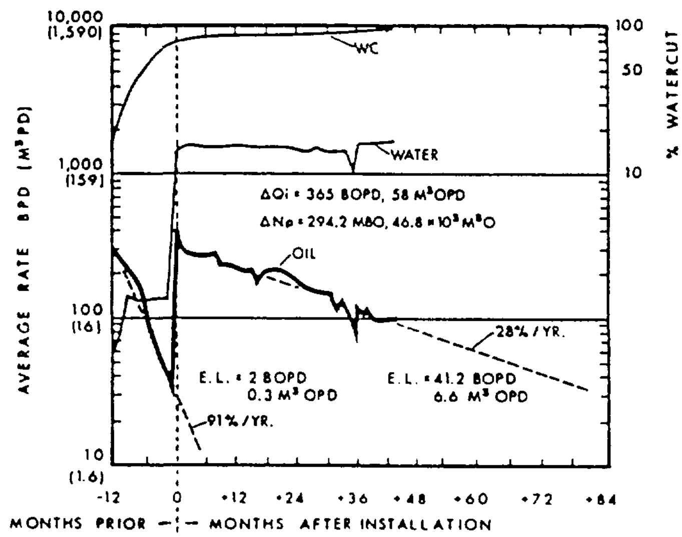


Fig. 11 - Well "B" zero time plot.

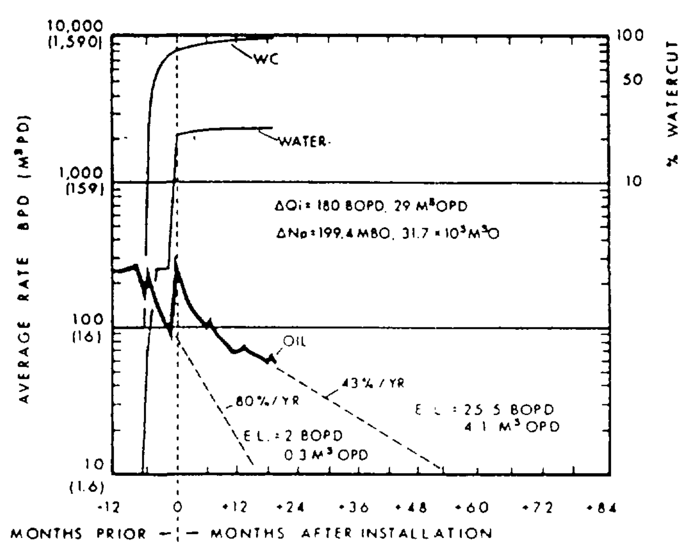


Fig. 12 - Well "C" zero time plot.

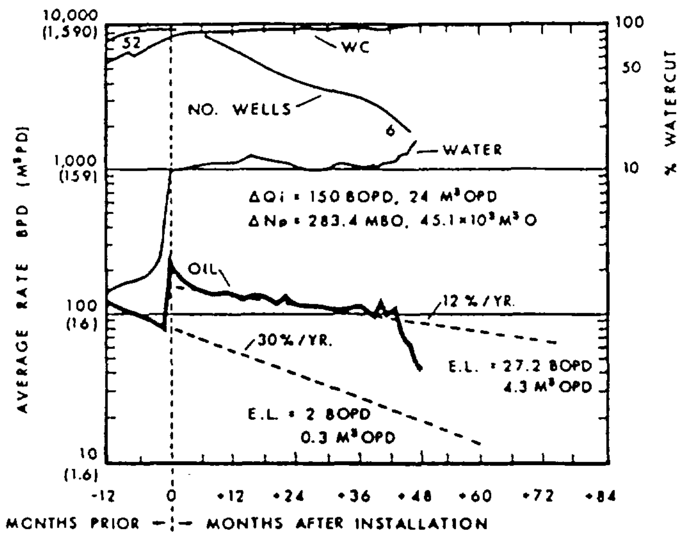


Fig. 6 - Average well zero time plot for all 55 HVL installations.

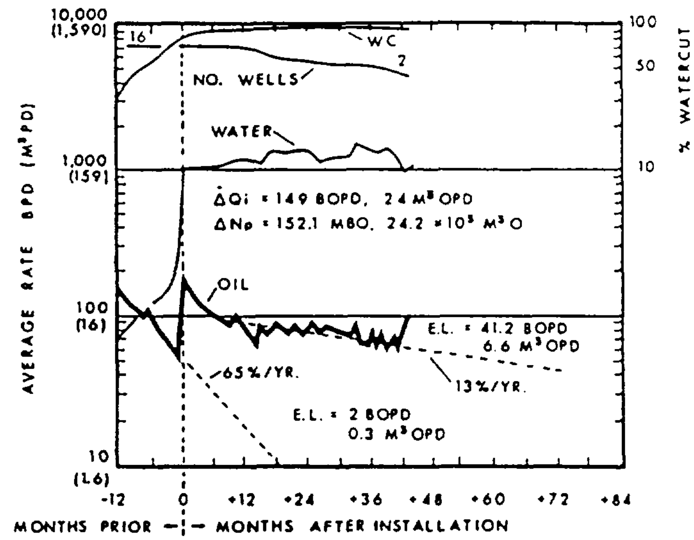


Fig. 7 - Average Ellenburger well zero time plot for 16 HVL installations.

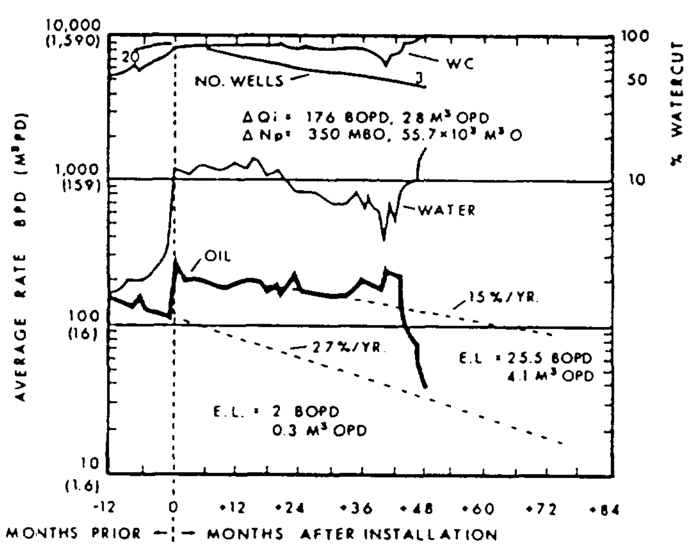


Fig. 8 - Average Devonian well zero time plot for 23 HVL installations.

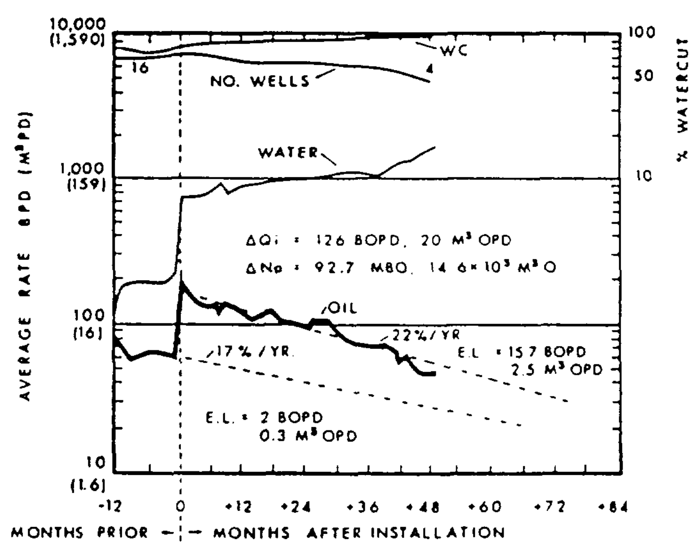


Fig. 9 - Average other well zero time plot for 16 HVL installations.

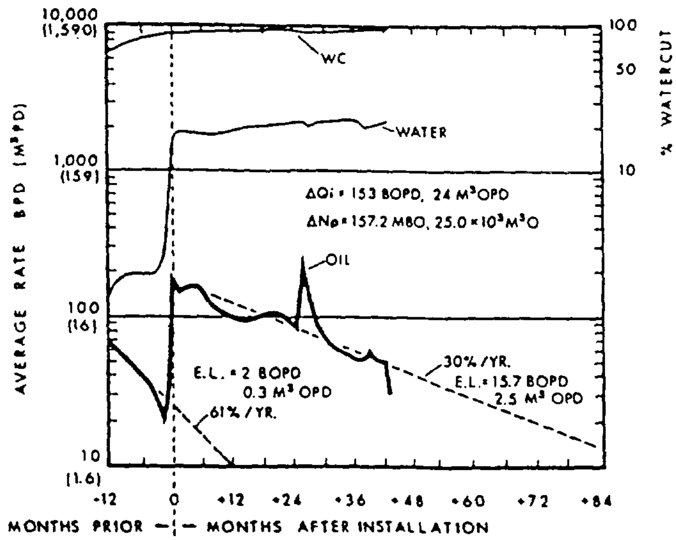


Fig. 10 - Well "A" zero time plot.

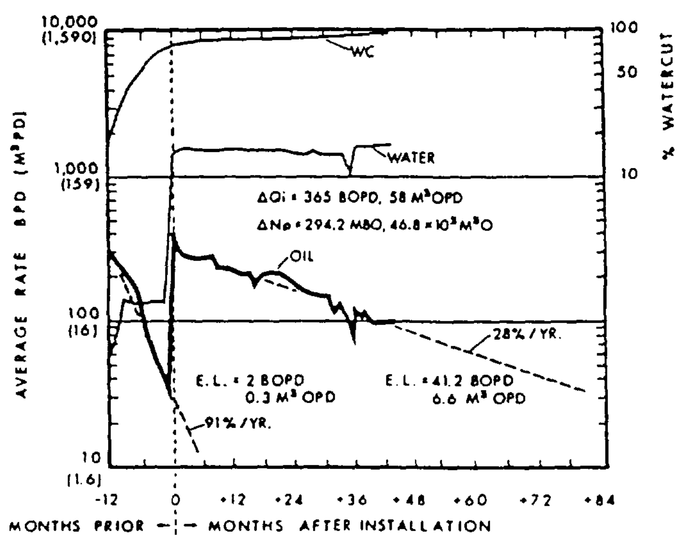


Fig. 11 - Well "B" zero time plot.

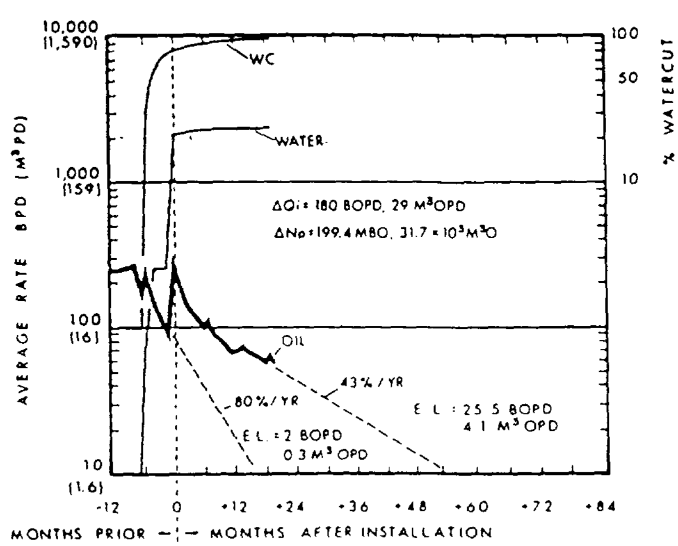
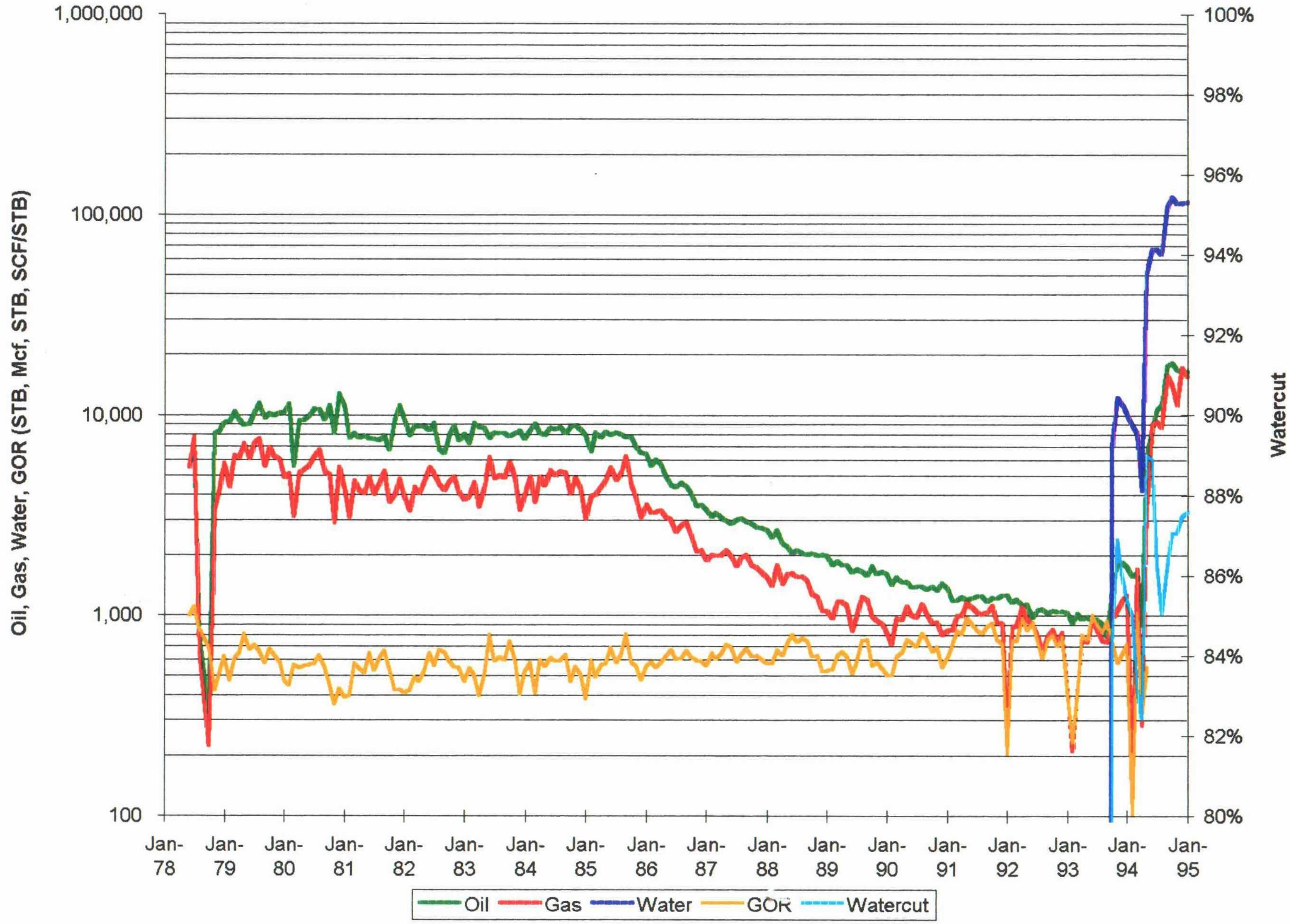


Fig. 12 - Well "C" zero time plot.

Lambirth 1
South Peterson (Fusselman) Pool



BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case No. 10994 (De Novo) Exhibit No. 10

Submitted by: Enserch Exploration, Inc.

Hearing Date: February 24, 1995

PETERSON AREA
ROOSEVELT COUNTY, NEW MEXICO
WELLS LOST TO CASING FAILURE

Well Name	Date Drilled	Date Collapse	Reserves Lost STBO	Reserves Lost MCF Gas
Lambirth 10	August, 1980	October, 1989	62,952	85,495
Lambirth 9	February, 1980	October, 1990	31,260	-
Amoco St #1	June, 1980	April, 1983	99,613	-
Pearl Jordan 1	June, 1981	August, 1983	4,000	-
Franse #1	December, 1981	January, 1982	30,289	81,746
Terry #1	July, 1981	April, 1983	8,283	15,382
Radcliffe 1	May, 1981	July, 1984	9,874	50,239
Collier -A- #1	March, 1981	January, 1993	4,000	19,525
Scott Federal #1	October, 1981	January, 1988	-	-
Lambirth #6	February, 1979	July, 1980	91,885	199,000
Pearl Jordon #2	January, 1981	April, 1993	76,414	-
Lambirth 8	October, 1979	September, 1994	41,480	26,568
Total	12 Wells		460,050	477,955

41% of Enserch Exploration, Inc. wells in this area have been lost to casing failures.

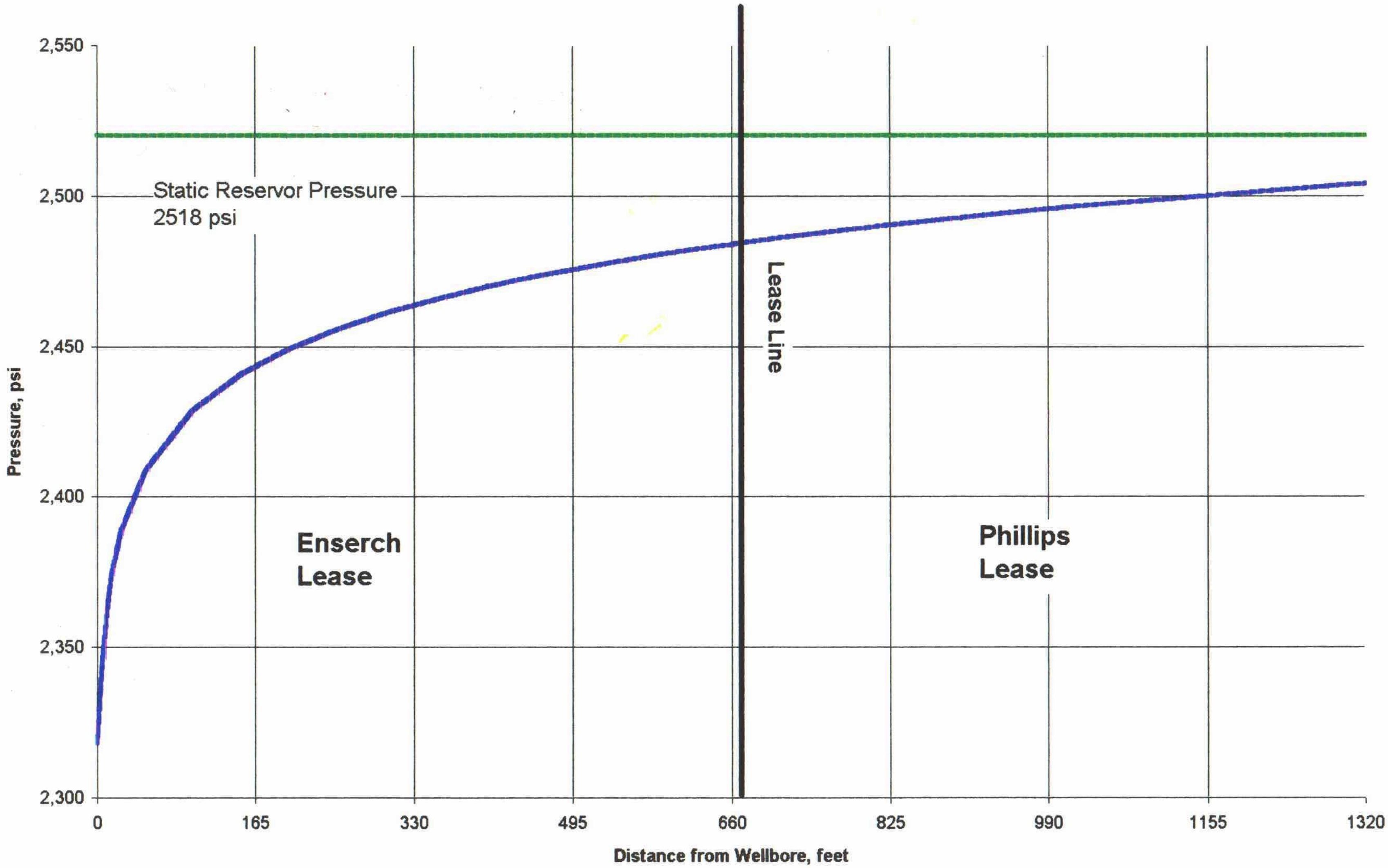
BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case No. 10994 (De Novo) Exhibit No. 12

Submitted by: Enserch Exploration, Inc.

Hearing Date: February 24, 1995

Pressure Drop as a Function of Distance from Wellbore
Enserch Lambirth 1

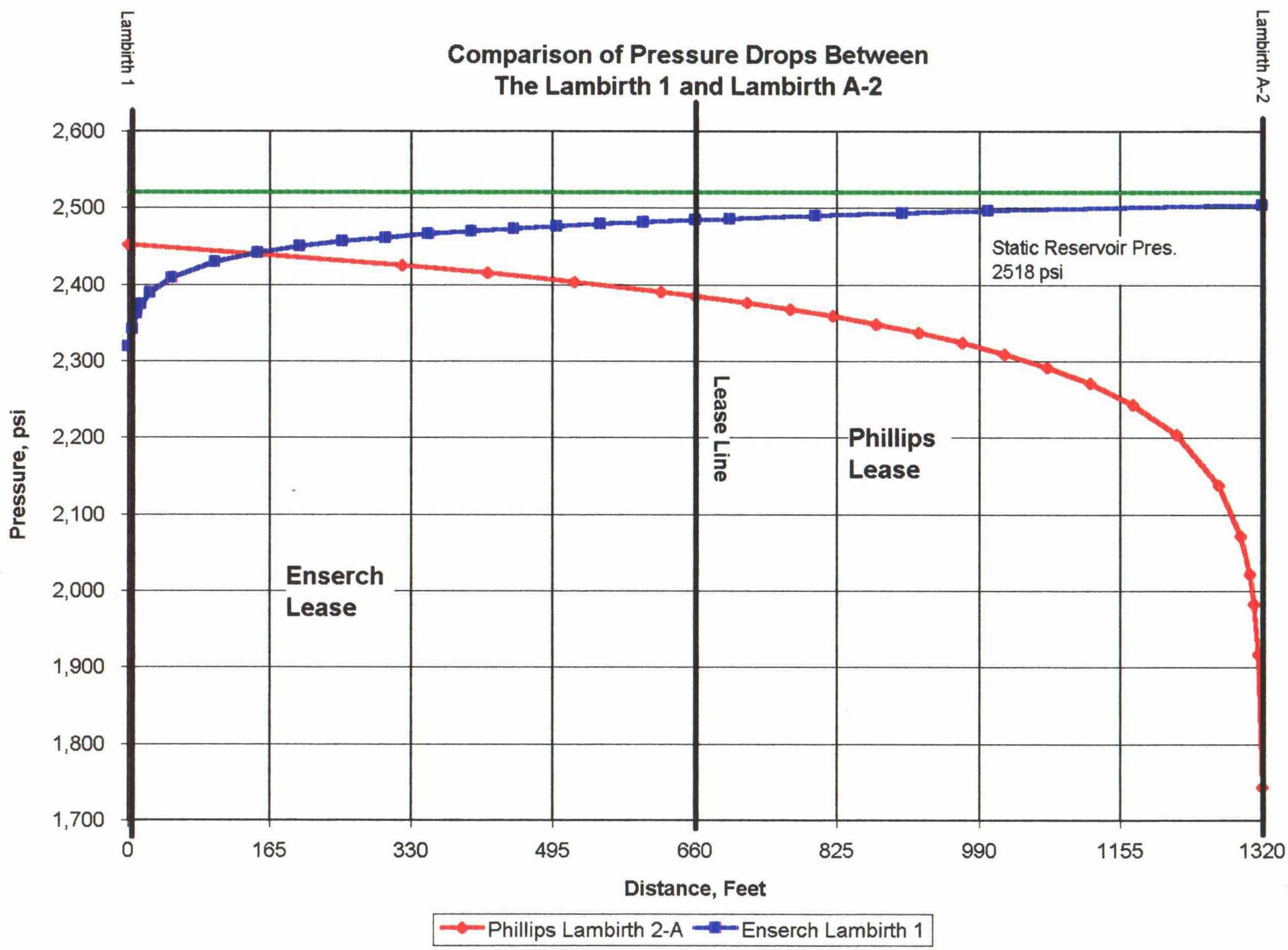


BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case No. 10994 (De Novo) Exhibit No. 13

Submitted by: Enserch Exploration, Inc.

Hearing Date: February 24, 1995


Comparison of Pressure Drops Between
The Lambirth 1 and Lambirth A-2
Lambirth 1
Lambirth A-2
Pressure, psi
2,600
2,500
2,400
2,300
2,200
2,100
2,000
1,900
1,800
1,700
0
165
330
495
660
825
990
1155
1320
Distance, Feet
Static Reservoir Pres.
2518 psi
Lease Line
Phillips
Lease
Enserch
Lease
Phillips Lambirth 2-A
Enserch Lambirth 1

BEFORE THE
OIL CONSERVATION COMMISSION
Santa Fe, New Mexico

Case No. 10994 (De Novo) Exhibit No. 14

Submitted by: Enserch Exploration, Inc.

Hearing Date: February 24, 1995

Exhibits Submitted by

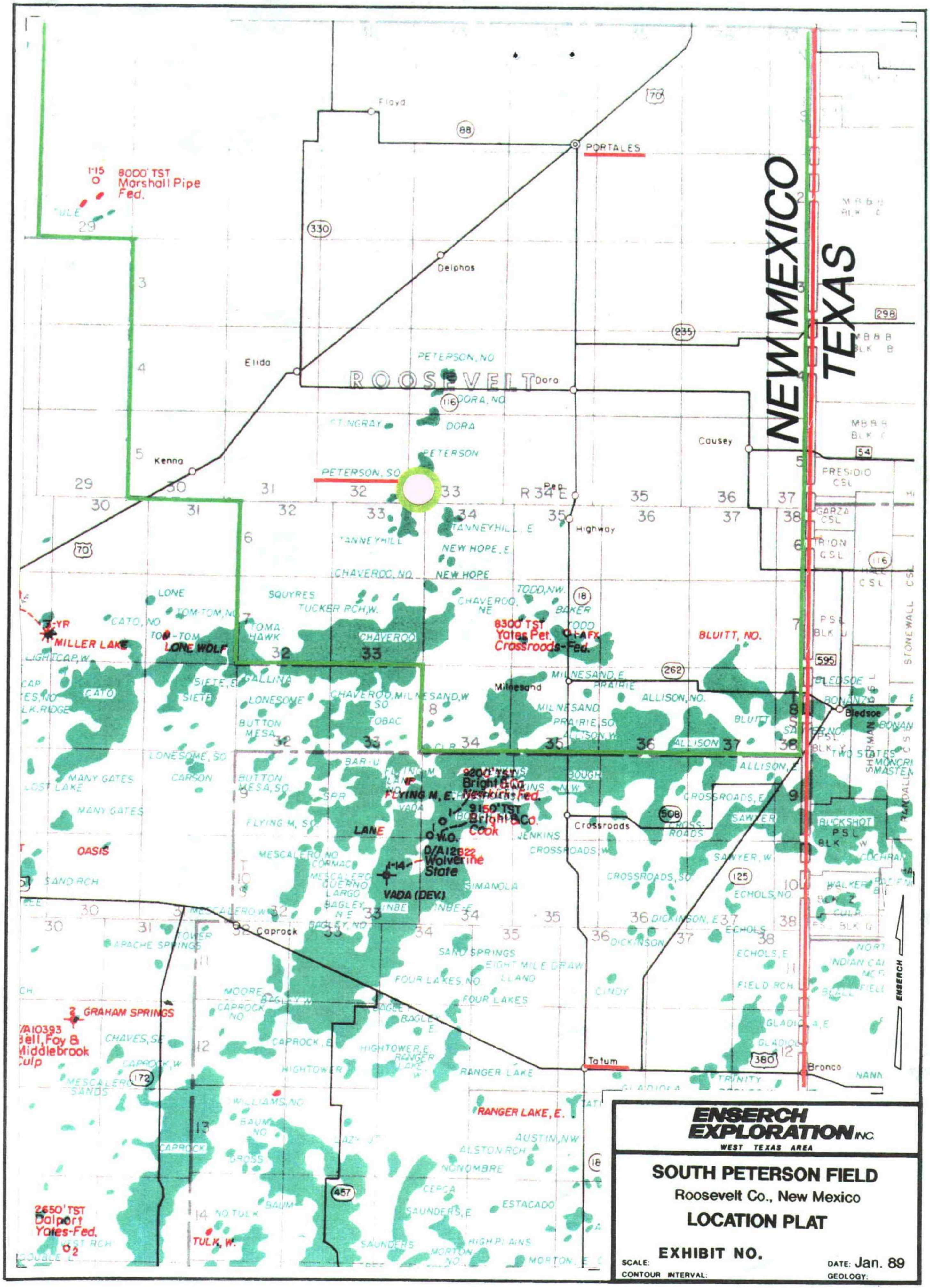
ENSERCH EXPLORATION, INC.

EXAMINER HEARING

June 23, 1994

SOUTH PETERSON FIELD

Roosevelt County, New Mexico



ENSERCH EXPLORATION INC.
WEST TEXAS AREA
SOUTH PETERSON FIELD
Roosevelt Co., New Mexico
LOCATION PLAT
EXHIBIT NO.
SCALE:
CONTOUR INTERVAL:
DATE: Jan. 89
GEOLOGY:
NEW MEXICO
TEXAS
ROOSEVELT
PORTALES
Floyd
Delphos
Elida
Dora
Kenna
Causey
Pep
Milnesand
Crossroads
Caprock
Tatum
Bronco
Bledsoe
PETERSON, SO.
PETERSON, NO.
PETERSON
DORA
DORA, NO.
STINGRAY
TANNEYHILL
NEW HOPE
CHAVEROO
8000' TST Marshall Pipe Fed.
8300' TST Yates Pet. Crossroads-Fed.
9200' TST Bright & Co. Neafkirk Fed.
9150' TST Bright & Co. Cook
2650' TST Dalport Yates-Fed.
MILLER LAKE
LONE WOLF
BLUITT, NO.
OASIS
GRAHAM SPRINGS
RANGER LAKE, E.
TULK, W.
VADA (DEV.)
Wolverine State
R 34 E

BEFORE THE
OIL CONSERVATION DIVISION
Santa Fe, New Mexico

Case No. 10994 Exhibit No. 1

Submitted by: Enserch Exploration, Inc.

Hearing Date: June 23, 1994