

DOE/BC/14982-17
(OSTI ID: 753826)

AN INTEGRATED STUDY OF THE GRAYBURG/SAN ANDRES
RESERVOIR, FOSTER AND SOUTH COWDEN FIELDS, ECTOR
COUNTY, TEXAS

Annual Report
August 1, 1998-July 31, 1999

By
Robert C. Trentham, DGS
William C. Robinson, M.S.
Kevin Widner
Richard Weinbrandt, Ph.D., P.E.

Date Published: April 2000

Work Performed Under Contract No. DE-FC22-94BC14982

Laguna Petroleum Corporation
Midland, Texas



National Petroleum Technology Office
U.S. DEPARTMENT OF ENERGY
Tulsa, Oklahoma

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, expressed or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government.

This report has been reproduced directly from the best available copy.

An Integrated Study of the Grayburg/San Andres Reservoir,
Foster and South Cowden Fields, Ector County, Texas

By
Robert C. Trentham, DGS
William C. Robinson, M.S.
Kevin Widner
Richard Weinbrandt, Ph.D., P.E.

April 2000

Work Performed Under Contract No DE-FC22-94BC14982

Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

Dan Ferguson, Project Manager
National Petroleum Technology Office
P.O. Box 3628
Tulsa, OK 74101

Prepared by
Laguna Petroleum Corporation
1003 N. Big Spring
Midland, TX 79702

TABLE OF CONTENTS

EXECUTIVE SUMMARY	v
ABSTRACT	v
INTRODUCTION	1
GEOPHYSICS	3
Geophysical Objectives	3
Inversion Modeling Recalculation	4
Data Analysis and Utilization	5
GEOLOGY	6
Water Analyses	6
Foster – Pegues #8	6
Witcher #1	7
H. C. Foster #8	7
Brock #8 and Brock #10	8
Production Allocation 1998-1999	8
Permeability/Porosity Transform	9
ENGINEERING	9
Engineering Objectives	9
Summary of Reservoir Simulation and Pressure Transient Testing	10
Cross Flow	10
Pressure Buildup Program	11
Well Work	13

Simulation	14
Identification of Additional Development Potential	15
Results	16
TECH TRANSFER EVENTS	16
ACKNOWLEDGEMENTS	17

EXECUTIVE SUMMARY

For the project area, a part of the Foster and South Cowden (Grayburg-San Andres) oil fields, the production of 148,000 BO incremental production has been accomplished through a careful evaluation of potential workover candidates, the use of modern fracturing technology and 3D inversion modeling, coupled with reservoir simulation. In addition, at least 570,000 barrels of proven reserves have been identified and the field life extended from nine to sixteen years.

The 3D seismic survey acquired in conjunction with this DOE project has been used to calculate a 3D inversion model, which was then used to provide detailed maps of porosity within the productive upper Grayburg Formation. Geologic data, particularly from logs and cores, have been combined with the geophysical interpretation and production history information to develop a model of the reservoir that defines estimations of the remaining producible oil. The results of testing the San Andres and the lower Grayburg in the new drills and workovers led to the decision to concentrate on the upper Grayburg waterflood. This in turn, led to the near term abandonment of the non-floodable lower Grayburg and San Andres reservoirs.

Analysis of the buildup tests has determined that the majority of upper Grayburg producers require re-stimulation to optimize the flood. A series of re-stimulations have resulted in a seven-fold increase in production from the refraced wells. Produced water analyses are now being utilized to complement the engineering data set.

ABSTRACT

A project to recover economic amounts of oil from a very mature oil field is being conducted by Laguna Petroleum Corporation of Midland, Texas, with partial funding from a U. S. Department of Energy grant to study shallow carbonate rock reservoirs. The objectives of the project are to use modern engineering methods to optimize oil field management and to use geological and geophysical data to recover untapped potential within the petroleum reservoirs. The integration of data and techniques from these disciplines has yielded results greater than would have been achieved without cooperation. The cost of successfully accomplishing these goals is to be low enough for even small independent operators to afford. This article is a report describing accomplishments for the fiscal year 1998-1999.

A realignment of the waterflood and all additional well work awaited the completion of a seismic based, geologically guided, history match and engineering simulation. A seismically derived, geology guided porosity map, with the same data density as the simulation, was constructed. A "cook book" method for deriving seismic porosity maps from an inversion-modeled 3D volume has also been developed. A no-flow (low porosity) boundary trending southwest to northeast across the study area was identified. The discovery of this boundary necessitated the rotation of the simulation model. The results of a new history match and simulation have significantly changed the focus of the project. The San Andres and lower Grayburg are being abandoned (for the near

future) in a number of wells, as they are not considered to be economic waterflood targets.

After the decision was made to concentrate on the upper Grayburg as a flood target, build-up tests were run on each well, and produced water samples collected. Cast Iron Bridge Plugs (CIBP's) were set in those wells where the San Andres and lower Grayburg were not significantly contributing to production, in order to isolate the upper Grayburg. A second series of pressure buildup tests were run to determine if the CIBP's had successfully isolated the upper Grayburg reservoir. Water samples were taken in those wells with CIBP's to characterize the produced waters and complement the engineering data set. Together, the build-up tests and water chemistry analyses were used to determine the future course of action in those wells. As a result of the build-up tests, it has been determined that the majority of producing wells lacked significant frac length and require larger refracs to optimize the waterflood.

A program of recompletions is now in progress. Both conventional and non-conventional frac designs have been utilized in the field with good results. The conventional fracs are three times as large as had been utilized in the field prior to the project. Some wells have required only acidization to remove scale and reduce near well bore damage to enhance production.

Produced water chemistry has slowly evolved into valuable tool to complement traditional engineering testing as a means of understanding the reservoir. Periodic field wide testing and testing before and after well work has become standard procedure to complement build-up test data.

The new wells and workovers have resulted in 148,000 BO, incremental, being produced to date. These reserves would not have been produced without the work done as a result of this study. In addition, at least 570,000 barrels of proven reserves have been identified and the field life extended from nine to sixteen years. The realignment of the water flood and additional well work is anticipated to add significant additional reserves.

INTRODUCTION

The objective of this two-phase study is to demonstrate an integrated methodology for reservoir characterization of a shallow shelf carbonate reservoir that is both feasible and cost effective for the independent operator. Furthermore, it will provide one of the first public demonstrations of the enhancement of reservoir characterization using high-resolution three-dimensional (3D) seismic data.

This particular project is evaluating the Grayburg and San Andres reservoirs in the Foster and South Cowden Fields, Ector County, Texas, see Figure 1. This sixty eight (68) year old field was approaching its economic limit and the leases evaluated would have been abandoned in less than ten (10) years. A multi-disciplinary approach to waterflood design and implementation, along with the addition of reserves by selective infill drilling and deepening, is being applied to this field. This approach in reservoir development will be applicable to a wide range of shallow shelf carbonate reservoirs throughout the United States, resulting in increased domestic production.

The first phase of the project included the design, acquisition, and interpretation of a 3D seismic survey, the collection and evaluation of geologic (core and log) data, and engineering (historical production, well test, injection) data from a variety of sources. From this work, a geologically based production history model was simulated. Based on the recommendations made at the end of Phase I, three new wells were drilled, one existing well was deepened, two wells were worked over, one TA'd well was re-entered, and one well was converted to injection. In addition, the quality of the injection water was greatly improved, a necessary step, prior to increasing injection in the project area. The analyses of the seismic data have become a major factor in defining productive properties of the Grayburg reservoir. Seismic inversion is used to convert the seismic data to velocity traces, a form from which a quantitative evaluation of reservoir properties is extracted. Calibration of seismic-derived interval velocity attributes, using well log porosity information, enable mapping the distribution of porosity of the individual upper Grayburg zones comparable to production fluid flow zones. These detailed maps have modified the earlier reservoir description made from sparse subsurface data. This revised picture discloses reservoir compartments not recognized before, serves as a vital parameter in the revised engineering model of the reservoir, and modifies the influence of the production history and the original oil in place values. The new engineering model will guide future drilling.

Initial seismic analyses targeted an understanding of the correlation of basic geology and reservoir factors to seismic wiggle-trace data. Stratigraphy specific to a thick carbonate sequence with few internal seismic reflectors was examined, including a hands-on review of core to establish seismic-to-rock relationships. Consideration of the effect of rock properties, particularly porosity, on seismic data response, focused on those most important factors for continued study. Forward modeling was employed to visualize aspects of the geology with seismic reflection response, to exactly identify key geologic levels in the seismic data. Observations were made of the various seismic waveform attributes, but no strong correlations with important rock properties have been recognized. The studies of the seismic data, including inversion modeling, have been

done entirely using inexpensive, but effective, PC-based seismic interpretation software well suited to analyzing 3D seismic data.

Melding new core and log data (products of Phase I recommendations) with pre-existing data led to the development of a better understanding of the depositional and diagenetic history of the Grayburg and San Andres Formations. Geologic log markers within the Grayburg represent low permeability zones that act as vertical barriers to fluid movement during oil production. Areas of reservoir with low porosity dolomite or anhydrite-filled dolomite result in poor production qualities and reduced water injection capacity. Also, core and log evaluation associate the top of the San Andres with a major karst event, and provide insight for a methodology to identify potential water producing intervals. Thus, the San Andres has been downgraded as a potential waterflood target.

The initial simulation model results, using seismically-derived porosity maps, fit within expectations, although some porosity modifications were made. Continued well testing has provided the data necessary for a more complete simulation. Team members worked closely to develop methodologies to bridge the distances among historically diverse scientific disciplines.

The accomplishments of the previous reporting periods are a foundation for the current results discussed in this report, and the continued monitoring of the effects of that work is part of the goals of the current Phase. During the Phase I period, field management was influenced by preliminary geological work done to define the distribution of porosity within the upper and lower parts of the Grayburg Formation and within the upper part of the San Andres formation.

Implementation of the field development recommendations made at the end of Phase I were based on an engineering simulation run using production history and geologic models. Oil production was doubled as a result of that work. Several wells were worked over and newly drilled wells contributed additional high quality subsurface core and log data. A "pipeline" fracturing technique, designed to double the induced fracture length over other methods, was used to improve fluid production in some wells by more effectively contacting the reservoir. In other wells, large "standard" sand frac designs have resulted in contacting larger volumes of reservoir. The use of long duration pressure build up tests has greatly enhanced understanding of the reservoir. A critical finding deduced from the build up tests was that the great range of pressures in the San Andres, lower Grayburg, and upper Grayburg permitted "U tubing" between the waterflooded upper Grayburg and low pressure lower Grayburg and San Andres. The field-wide setting of CIBP's to isolate the upper Grayburg waterflood zone has been completed and a fracture and/or acid stimulation program of the upper Grayburg is underway. This program has proven successful, and continues in wells identified by the pressure build up tests as having short frac lengths and high pressures.

Significant to the waterflood project was the improvement of injection water quality by system redesign. Monitoring the effect of using improved injection water continues.

Water chemistry analyses, noting the difference of salinity of Grayburg fluids versus San Andres fluids, have been used to determine the reservoir origin of produced water. Analysis of waters sampled periodically from all wells, and from wells before and after well work continues, and has been successful in confirming the results of the well work (See 1997-1998 Annual Report). The produced water analyses are now being used as a real time indicator of the success or failure of day-to-day field operations. Development of a produced and injected water chemistry database also continues.

GEOPHYSICS

Geophysical contribution to the project for this report year was to continue qualification of the previous results of rock property mapping, to conduct reprocessing of the 3D seismic data volume, and to analyze the new inversion model volume for rock property data. These tasks were built on the results of previous work, using those established techniques. (See Annual Report for 1996-1997 and 1997-1998) The scope of the geophysical study was expanded using the entire reprocessed data volume and now incorporates recently acquired data from offset lease operators.

Geophysical Objectives

Geophysically derived rock property parameters reported previously have accuracy and sensitivity significant to engineering model development. The objective of further geophysical work has been to refine the parameter of porosity distribution for the most prominent oil-producing Grayburg reservoir, primarily the upper Grayburg. The scope of geophysical study related to the reservoir simulation was expanded to incorporate the entire 3D seismic survey. Previous work reported analyses restricted to Section 36 because the production model was of primary interest there. Geology and geophysics are more complex in the eastern part of the seismic survey, and very little production data were initially available to this project in Section 31. Comparisons of initial and revised models of seismic data and analyses have been made.

Refining the geophysical model includes improving the vertical resolution of seismic inversion model traces and expanding adequate quality data across the entire seismic survey. Reprocessing the data volume was the basis of optimum success in reaching these objectives. A number of technical aspects of data processing were specifically targeted.

Reflection time errors, in the form of inaccurate time structure, are present in the original data volume. One example is of an anticlinal feature (reflection time) in the southwest part of the survey that is not indicated by close well control. A new refraction statics model was built, and the false structure was removed. Figure 2 demonstrates the accurate tie of time versus depth of the two seismic data volumes.

Improvement of signal-to-noise ratio of stacked traces was a primary objective. Noise rejection methods were tested to reduce the effects of coherent noise, with an offset

dependent technique ultimately being used. Coherent noise is not a severe problem so overall improvement from the noise rejection step is minor. Strong, more random noise and low fold most affect the data quality of the Grayburg reflection, and careful muting of early arrivals was effective.

Optimizing Common Depth Point (CDP) stack accuracy, resulting in optimum frequency bandwidth, is the key to maximum vertical resolution. Automatic statics were applied following the refraction model. Integrated sonic logs tied to the seismic reflection times provided velocity control. Average velocity values applied to correct for normal move out were guided by these well data.

A processing technique not applied to earlier data processing included Dip Move Out (DMO) correction. Little visible difference was noticed in data as a result of DMO application.

Seismic data processing must incorporate proper pre-stack trace amplitude equalization (scaling). Each stacked output trace contains amplitude information that is vital to calculating accurate inversion model velocity values. Traces to be summed must have consistent characteristics of amplitude and bandwidth. Noise in the pre-stack traces must be reduced so that reflection data will determine amplitude-scaling factors. Data traces in field record order (common source and increasing offset distance) are shown in Figure 3. Data with no spectral balancing (left) are compared to the fully processed traces with muting, spectral balancing, and noise attenuation (right). The unprocessed traces show characteristics of random noise, first arrival strength, trace-to-trace amplitude variation, and bandwidth limitations. Processed traces show trace-to-trace amplitude consistency and bandwidth optimization. Also shown is the fold-limiting effect of the shallow reflection time of the Grayburg.

Seismic profile data from two data volumes are shown in Figure 4. The 1996 data volume underwent a "fix" early in the project to optimize the amplitude spectrum bandwidth, but static and dynamic corrections were not modified. The data used for previous studies is on the left, and data used for the re-evaluation are on the right. The inversion model data are exemplified in Figure 5.

Inversion Model recalculation

A new Seismic Inversion Model volume was calculated using the reprocessed data. Model input velocity parameters were modified from previous model values to produce velocity values calibrated to be in line with values from well data, and with research data. Previous results produced good relative velocity values, but better absolute velocity values were achieved with the revision. Inversion model-derived velocity data are compared to log-derived velocity data in Figure 6. The graph for the lower Queen comparison shows the inversion velocity values to be too low, perhaps an effect of constraining two closely spaced reflections. The Grayburg inversion-derived velocity values are very close to the well-derived values.

Data Analysis and Utilization

The analysis methodology used in earlier work was used with the new inversion model. The top of the Grayburg zone "A" was picked on the inversion model traces using the lower Queen isochron as a guide to the Grayburg position. On the structural shelf (Section 36) the top of the Grayburg zone is also a very clear change in the interval velocity (as with well logs). On the slope (Section 31) the top of the "A" zone is not the first carbonate encountered below the Queen clastics. The lower limit of the seismic "A" zone was determined from the zone thickness, converted to time, measured in wells. The values of velocity from the inversion model were averaged across the "A" interval between the two horizons. Then a cross-plot relationship was used to convert those velocity values to porosity values for each seismic bin position. The resulting porosity distribution was used as a parameter in the engineering flow simulation model.

The upper Grayburg reservoir (the "A" zone, about 120 feet thick) is the primary zone of interest of the re-analysis. The cross-plot of the well derived average porosity versus average interval velocity from the inversion model for the Grayburg "A" zone is shown in Figure 7. Wells exhibit some amount of scatter from the two-slope linear function used to convert velocity to porosity. The amount of scatter is comparable to the laboratory-type studies (in several articles published in a Society of Exploration Geophysicists publication). Previous reports of this project have discussed potential errors inherent to both well data and seismic data. Well log-derived porosity values come from a variety of log types from wells drilled over a large span of years. Wide variation in log quality and age is a potential cause for significant scatter. Seismic data-related problems, either unresolved, or beyond resolving, contribute to inaccurate seismic velocity calculation in the inversion model. Noise and acquisition limitations are chief among these problems. Above all, other studies suggest that porosity and velocity have a diffuse relationship, partly caused by factors related to geologic facies type and mineralogy. For a relationship of porosity versus a given value of velocity, an error bar of about 5% wide exists. The cross-plot graphs of data for this project show a similar scatter of points.

The range of porosity shown on the graph in Figure 7 covers just the range of values in wells, but porosity across the survey extends below and above those values. The distribution of points suggests a nonlinear relationship. A higher slope line was used to convert higher velocities to values of less than four percent porosity and a lower slope line was used to convert lower velocities to values of more than four percent porosity.

Figure 8 shows maps of the porosity distribution calculated for each conversion line. The final porosity distribution map uses the porosity values less than 4% from the upper map and values of more than 4% from the lower map. The higher slope curve contributes lower porosity values. The lower slope curve contributes higher porosity values and eliminates negative porosity values.

Figure 9 shows the porosity distribution used in the flow simulation model. Areas of high porosity are displayed in lighter shades and areas of low porosity in darker shades. The shelf-edge low porosity area, significant as a barrier to fluid flow, is a dominant

feature of the map. High porosity areas in Section 36 are major contributors to production and are areas with additional potential. Figure 10 shows the porosity distribution in *Figure 9* with a contour overlay of the depth of the Grayburg. The porosity barrier is coincident with the structural shelf edge.

GEOLOGY

Water Analyses

Monitoring of produced and injected water chemistry continues with periodic, field wide sampling. In 1996, it was determined that poor quality "mixed " injection waters were causing 75 micron filters to be plugged on a regular basis. The water chemistry "problem" was attacked by eliminating the various "make up" waters, and returning the system to a better balance between the injected and connate water (see 1996-1997 Annual Report). Analysis of waters sampled periodically from all wells, and from wells before and after well work continues, and has been successful in confirming the results of the well work. (see 1997-1998 Annual Report).

The produced water analyses are now being used as a real time indicator of the success or failure of day-to-day field operations. Some of the questions that are being addressed are:

- What is the source of produced water? Virgin formation, floodwater or a mix?
- Was the setting of a CIBP successful in isolating a zone or zones?
- Was fracture stimulation successful in producing from a single zone (Pipeline Frac) or multiple zones (conventional frac)?
- What is the cause of a sudden change in production?
- Is water being coned up from a deeper reservoir?

For a more complete review of the uses for water chemistry analyses, see the 1997-1998 Annual Report, and Trentham and Widner (1999b) in Tech Transfer.

This year, three wells were fracture stimulated and three wells acid stimulated. The results of those stimulations were evaluated utilizing water chemistry analyses.

Foster-Pegues #8

Although the producing water - oil ratio was relatively high, the upper Grayburg was re-fraced in the Foster-Pegues #8 (see Engineering for details). Production rates prior to the re-stimulation were 2 BOPD, 15 BWPD and 1 MCFPD. After recovering the frac load, the production rates stabilized at 22 BOPD, 450 BWPD and 1 MCFPD with no sign of decline.

Prior to the frac, the Sodium (Na), Chlorine (Cl), and Total Dissolved Solids (TDS) of produced water were 20986, 37500, and 65999 PPM respectively. Following the frac, the Na, Cl, and TDS of produced water were 20122, 37333, and 65203 PPM. As these numbers are virtually identical, it is believed that the frac was successful in increasing

the production and staying "in zone", but did not contact any additional, previously unproduced reservoir. A water analysis taken two months after the frac (12/15/98) contained 18,700, 33500, and 59700 PPM. There was no change in the oil or water production at that time and the cause of the change in water chemistry was not known. Recently the Foster-Pegues #4, FP4 in Figure 1, injector was shut down as it had watered out the FOSTER-PEGUES #5, (FP5). Almost immediately, the FOSTER-PEGUES #8, which does not offset the FOSTER-PEGUES #4, see Figure1, responded with an increase in oil production and decrease in water production. The injection water is more similar to the water produced from the FOSTER-PEGUES #8 on 12/15/98 than to the water from immediately after the frac (10/19, 10/26, and 11/3/98). Testing of the FOSTER-PEGUES #5 and FOSTER-PEGUES #8 continues in an effort to understand the preferential direction of flow in the Foster-Pegues lease.

Witcher #1

The Witcher #1, WH1 in Figure 1, was drilled in 1940 as an open hole completion and produces from the upper Grayburg only (see ENGINEERING for details). Production rates prior to the re-stimulation were 11 BOPD, 61 BWPD and 2 MCFPD. Initial producing rates following the stimulation were 43 BOPD, 29 BWPD and 44 MCFPD stabilizing at 19 BOPD, 52 BWPD and 15 MCFPD. The high producing GOR of greater than 1000 indicates a previously underdeveloped flow unit was opened.

Prior to the frac, the Na, Cl, and TDS of produced water were 13767, 24008, and 44360 PPM respectively. Following the frac, the Na, Cl, and TDS of produced water were 13772, 24000, and 43778 PPM. The water analyses indicate that although the frac had opened a previously underdeveloped flow unit, that unit was contained within the same waterflooded upper Grayburg interval. One of the most important effects of well work is simply the increase in withdrawal rates. This has been achieved in the Witcher #1.

H. C. Foster #8

Due to low production rates from the H. C. Foster #8, F8 in Figure 1, the upper Grayburg was recommended as a re-frac candidate (see Engineering). As a result of mechanical factors, a small frac, one-third the size of other recent frac's was completed. Production rates prior to the re-stimulation were 3 BOPD, 31 BWPD and 1 MCFPD. After recovering the frac load, the production rates stabilized at 7 BOPD, 97 BWPD and 1 MCFPD. It is felt the small incremental increase in oil production and total fluid volume is a result of the reduction in sand volume pumped during the fracture treatment.

Prior to the frac, the Na, Cl, and TDS of produced water were 19917, 36960, and 64546 PPM respectively. Following the frac, the Na, Cl, and TDS of produced water were 13961, 24850, and 46529 PPM. It is apparent that the frac was successful in contacting a previously underdeveloped flow unit, within the same waterflooded upper Grayburg interval.

Brock #8 and Brock #10

Based on the original simulation, an area of high oil saturation exists on the Brock lease extending from the Brock #5, see Figure 1, on the southeast to the Brock #13 on the northwest. The Brock lease became a target for enhanced recovery, after the Brock #13, was successfully recompleted in the upper Grayburg. The Brock #13 had been one of the original workover recommendations (see First Quarter 1996 Report) for a plug back from the lower Grayburg/San Andres and to restimulate the upper Grayburg. This led to the recommendation to restimulate a number of wells on the Brock Lease. The results of fracture stimulation of the upper Grayburg in the BR #5 and BR #6 were presented in the 1997 – 1998 Annual Report.

It was recommended to acidize the Brock #8, BR8 in Figure 1, and Brock #10 (BR10). The Brock #8 was the first well acidized. Prior to the stimulation the well was producing approximately ½ barrel of oil and ½ barrel of water per day. After stimulation the wells production stabilized at 8 to 10 BOPD and 85 to 90 BWPD. (See Engineering)

Prior to the well being acidized, the Na, Cl, and TDS of produced water were 17179, 31250, and 55703 PPM respectively. Following the work, the Na, Cl, and TDS of produced water were 13356, 24000, and 43890 PPM. It is apparent that the frac was successful in contacting a previously underdeveloped flow unit, within the waterflooded upper Grayburg.

The Brock #10 was also acidized, however the stimulation proved to be unsuccessful as the producing rates remained unchanged at 4 BOPD and 7 BWPD.

Prior to the well being acidized, the Na, Cl, and TDS of produced water were 15993, 28345, and 51272 PPM respectively. Following the work, the Na, Cl, and TDS of produced water were 16487, 39000, and 66885 PPM. This represents a significant change in produced water chemistry with no change in produced rate. This well is currently being evaluated for fracture treatment at a later date.

Production Allocation for 1998-1999

During January 1999, the monthly oil, gas, and water production, for each well, was updated for use in the updated simulation. Based on periodic three-day production well tests, monthly lease totals, and workover reports, production was allocated to each producing well in Section 36. Monthly injection for each injector was determined from lease reports. Production and injection data was also allocated for wells within the simulation boundaries (up to two locations outside Section 36 in most areas) in the sections bordering Section 36.

Until 1996, daily production was allocated on a yearly basis. As part of this project, a periodic testing program has permitted the calculation of daily production on a monthly basis since the beginning of 1996. The production and injection data were then input into a "Master Spreadsheet".

In the "Master Spreadsheet", production and injection is allocated to each zone in each well. For each well, the number of net feet of pay was calculated for each zone (the porosity for each zone is generated in the seismically derived porosity map), summed, and the % of total net porosity determined for each zone. It was then determined which zones were actually contributing to production or receiving injection and a 1/0 switch posted for contributing/not contributing. At this point, field, lease, and well and zone totals are readily available. To determine the production for a single zone, all the zones other than the zone of interest are turned off. The allocated portion of the production from the single zone is then ready to be input into the reservoir simulation and to be summed by field, lease, and well.

This spreadsheet data is updated twice annually for use in revised simulations.

Permeability/Porosity Transform

Although the seismically derived porosity maps are used to generate maps of permeability, using a logarithmic porosity to permeability transform, the slope of the transform equation is initially based on the available core analysis. The intercept was modified during the history matching process, to account for the presence of low porosity high permeability natural fractures in the reservoir, Figure 11. There is significant anecdotal information indicating a preferential direction of permeability bearing 270 to 290 degrees in both Section 36 and Section 31 to the east.

These fractures are observed in the cores and affect the measured core permeability. In wells where core porosity and permeability are measured in plug as opposed to whole core, the amount of fracture porosity can be significantly under reported. In whole core analyses, the amount of fracture porosity can also be under reported. Fractures, which are contained within bed boundaries, are another source of measurement error. Exposure surfaces and associated "Caliche Profiles" which are often not preserved during coring, and thin fenestral tidal flat caps can also serve to increase permeability and still be thin enough not to be measured.

This effectively increases the minimum permeability from approximately 0.2 md up to the range of 2-3 md. This change was necessary in order to produce and inject the measured actual volumes in the simulator. History matching has partially validated this method of developing a permeability map and the history matching work is continuing.

ENGINEERING

Engineering Objectives

Together with the continuous testing and monitoring of bottom hole pressures, individual well production, injection volumes, injection pressures, injection profiles and day to day operations, the engineering objectives of the year were to:

- Continue the focus of the project on the re-alignment of the upper Grayburg waterflood

- Isolate the upper Grayburg in wells producing from multiple intervals
- Continue to utilize the new pressure transient testing procedure field wide
- Implement recommendations derived from bottom hole pressure data and simulation

Summary of the Reservoir Simulation and Pressure Transient Testing

The Grayburg reservoir of the Foster - South Cowden field has been produced since 1938 and waterflooded since 1962. Production had declined to near abandonment level at the start of this project but a significant target of oil remained in place. The initial approach to construction of the flow model was conventional. Logs and cores provided the basis for a geological model. Production data was assembled and validated as were the few measured pressures taken early in the field's history. Production testing of all wells was initiated to provide accurate current production data.

Pressure transient testing of all wells was initiated to provide a diagnosis of current condition and pressure. History matching pressures and water cuts validated the flow model and the flow model has since guided field operation, subject to the limits imposed by the spacing of the well data which was one reliable well log per 32 acres of reservoir. At this scale compartmentalization of the reservoir was obvious, and 3-D seismic was used to define porosity in the area between wells.

Seismic inversion model traces exhibit a high degree of correlation to the well log data and a correlation was developed between seismic velocities and porosity for each geologic zone (see Annual Report 1997-1998). The correlation was used to develop porosity maps for each zone used in the flow model. The resulting flow model was validated through the history matching process and has been used for over the last year to guide the redevelopment of the waterflood. The production response has validated this approach.

Cross Flow

Cross flow in the well bore between zones has been a problem in many water floods and this project is no exception. Section 36, where this project is centered has historically produced from the upper Grayburg, lower Grayburg, and San Andres. In many cases all of these zones have been open in the same well bore. The upper Grayburg has been waterflooded since 1962 using a variety of patterns. The "A" zone of the upper Grayburg has taken about 80% of the injected water and has defied even recent attempts to better vertically redistribute the injection.

The lower Grayburg was identified early in this project as a reservoir that was essentially underdeveloped with only a few completions in it. A few of these lower Grayburg completions were commingled with the upper Grayburg resulting in cross flow from the waterflooded upper Grayburg to the lower Grayburg after the pressure depleted during primary production.

The San Andres has been completed in about 15 wells. In general these completions included the upper Grayburg and lower Grayburg as well. This practice also resulted in

cross flow from the upper Grayburg to the San Andres.

The cross flow was confirmed by the pressure transient testing program where wells with multiple zones show the "humping" behavior characteristic of multiple layers, Figure 12. Water chemistry is also a good tool since the zones have different salinity's. This lead to a project wide installation of CIBP's to stop the cross flow, followed by retesting to confirm success. Water chemistry and production tests were also used to confirm that the CIBP's had stopped cross flow. See previous 1996-1997 and 1997-1998 Annual Reports for details on the success of the Bridge Plug program and the use of water chemistry analysis to evaluate the success.

Pressure Build-up Program

The pressure build-up program has continued this year with 12 wells tested and analyzed. This program has been used to provide pressures for history matching and to identify wells for stimulation. It has also been used post fracture to evaluate effectiveness of the fracture treatment in terms of wing length of the fracture generated and the productivity of the well after the fracture. The post frac data is obtained using a draw down test so that the well does not have to be shut in when it is capable of making high oil rates.

Brock Lease

Previous bottom hole pressure tests on the Brock #8 and Brock #10 were inconclusive due to mechanical failures and excessive wellbore storage during the shut-in periods. The wells were re-tested. However, the tests were again inconclusive with respect to individual well characteristics. The test did indicate the wells should be producing at much greater rates.

The Brock #7 is a directional well completed in the upper Grayburg only. Analysis of the pressure test indicated the well has a bottom hole pressure of 1087 psia, single zone influence and a frac wing length of 32 feet. This well was recommended to be re-fraced at a later date.

Foster-Pegues Lease

The Foster-Pegues #7, Foster-Pegues #8 and Foster-Pegues #9 produced from the upper Grayburg and lower Grayburg/San Andres formations. Initial bottom hole pressure tests in all wells showed evidence of dual zone completions. After setting CIBP's between the upper Grayburg and lower Grayburg/San Andres formations additional pressure tests were performed on the three wells.

The test data from the Foster-Pegues #7 showed conclusive evidence of dual zone effluence, even though a CIBP was in place. This indicates the upper Grayburg and lower Grayburg/San Andres are in communication behind pipe. Therefore, this well was not recommended as a re-frac candidate pending additional well work (see Geology 1997-1998 Annual Report).

Analysis of the Foster-Pegues #8 test indicated the well had waterflood support with a

bottom hole pressure of 2550 psia, which is equal to the bottom hole pressure of offsetting injection wells. There was no evidence of a fracture or dual zone influence. This well was recommended for a fracture treatment (see Well Work).

The test on the Foster-Pegues #9 was inconclusive. However, the test did indicate a very low bottom hole pressure and lack of waterflood support.

H. C. Foster Lease

The H. C. Foster #7 produced from the upper Grayburg and lower Grayburg/San Andres. The pressure test indicated the well had a bottom hole pressure of 1890 psia with some indication of a dual zone completion. It was recommended to set a CIBP between the producing intervals and re-test. However, a review of the well history indicated the two zones communicated behind pipe when the well was fraced in 1981. Thus, further plans for this well were postponed pending further well work.

A pressure test was conducted after setting a CIBP between the upper Grayburg and lower Grayburg/San Andres in the H. C. Foster #8. The test showed very little frac wing length, single zone influence and a bottom hole pressure of 1490 psia. This well was recommended for a fracture treatment (see Well Work).

The H. C. Foster #9 produces from the upper Grayburg and lower Grayburg/San Andres. The pressure test showed the well has a bottom hole pressure of 1625 psia. An attempt was made to set a CIBP between the producing intervals. However, collapsed casing was encountered at the base of the upper Grayburg perforations. Thus, any further plans for this well were canceled.

Witcher Lease

Build-up tests were performed on the Witcher #1, Witcher #3 and Witcher #11.

The Witcher #1 was drilled in 1940 as an open hole completion and produces from the upper Grayburg. The pressure test gave indication of water flood support with a bottom hole pressure of 1350 psia, no frac wing length and single zone influence. This well was recommended for a fracture treatment (see Well Work).

The bottom hole pressure test on the Witcher #3 showed the well had a very low bottom hole pressure of 186 psia, no evidence of frac wing length and single zone influence. This well was recommended for a fracture treatment.

The Witcher #11 was tested prior to setting a CIBP between the upper Grayburg and lower Grayburg/San Andres. The pressure test gave evidence of single zone influence only, a bottom hole pressure of 1145 psia and a short frac wing length of 27 feet. A CIBP was set between the producing intervals. A follow up test has not, as yet, been performed.

Well Work

Isolation of the upper Grayburg, allowed Laguna to concentrate effort on optimization of the waterflood there. Once a good, single zone pressure transient test was obtained, the wells were ranked as refrac candidates. A very important conclusion from the pressure transient testing was that few of the wells showed significant fracture wing length. The only wells that showed fractures were those that were refraced by Laguna as part of this project. This observation led to the conclusion that improving the connection between the wellbore and the reservoir was necessary. Refracs or acid jobs were the techniques chosen. Acid jobs were used on wells where there was the most uncertainty since the cost was only about \$12,000. These wells were viewed as experiments. If a well was mechanically competent and the pressure transient test and water salinity showed the well to be a single zone producer, it was refraced. In a few cases cross flow was possibly due to a bad cement job. Those wells were eliminated from the list of refrac candidates. Seven wells were identified and recommended as re-frac candidates.

Three wells, the Witcher #1, H. C. Foster #8 and Foster-Pegues #8 were re-fraced in 1998 and 1999. It was decided much larger treatments than the smaller re-fracs performed by previous operators in the late 1970's and early 1980's had to be utilized in order to achieve greater frac lengths. The treatments, designed to obtain frac lengths of up to 180', averaged 28,000 gallons of fluid and 104,000 lbs of sand. Gross producing rates in the wells prior to the treatment averaged less than forty barrels of fluid per day. After initial declines following the treatments, the rates stabilized at over 180 barrels of fluid per day resulting in a seven-fold increase in sustained production, Figure 13.

Brock Lease

Due to uncertainty of the pressure transient analysis, it was recommended to acidize the Brock #8 and Brock #10. The Brock #8 was acidized with 2500 gallons of 15% HCL acid. Prior to the stimulation the well was producing approximately ½ barrel of oil and ½ barrel of water per day. After stimulation the production stabilized at 8 to 10 BOPD and 85 to 90 BWPD.

The Brock #10 was also acidized with 2500 gallons of 15% HCL acid. However the stimulation proved to be unsuccessful, as the producing rates remained unchanged at 4 BOPD and 7 BWPD. This well has been recommended for a fracture treatment at a later date.

Foster-Pegues Lease

Analysis of the Foster-Pegues #8 test indicated the well had waterflood support with a bottom hole pressure of 2550 psia, which is equal to the bottom hole pressure of offsetting injection wells. There was no evidence of a frac wing length or dual zone influence.

Although the producing water oil ratio was relatively high, the upper Grayburg was re-

fraced in the Foster-Pegues #8. The interval was fracture treated with 25,174 gallons of 35# cross-linked gel and 118,580# of 16/30 sand. A scale inhibitor in the form of frac beads was incorporated throughout the job. Production rates prior to the re-stimulation were 2 BOPD, 15 BWPD and 1 MCFPD. After recovering the frac load, the production rates stabilized at 22 BOPD, 450 BWPD and 1 MCFPD with no sign of decline.

H. C. Foster Lease

A pressure test was conducted after setting a CIBP between the upper Grayburg and lower Grayburg/San Andres in the H. C. Foster #8. The test showed very little frac wing length, single zone influence and a bottom hole pressure of 1490 psia. Due to low production rates from the well, the upper Grayburg was recommended to be re-fraced. The interval was fracture treated with 19,530 gallons of 35# cross-linked gel and 52,000# of 16/30 sand. Again, a scale inhibitor in the form of frac beads was incorporated throughout the job. Due to high treating pressures encountered during the stimulation, the treatment volume had to be reduced by 9,800 gallons and 31,000# of sand. Production rates prior to the re-stimulation were 3 BOPD, 31 BWPD and 1 MCFPD. After recovering the frac load, the production rates stabilized at 7 BOPD, 97 BWPD and 1 MCFPD. It is felt the small incremental increase in oil production and total fluid volume is a result of the reduction in sand volume pumped during the fracture treatment.

Witcher Lease

The Witcher #1 was drilled in 1940 as an open hole completion and produces from the upper Grayburg only. The pressure test gave indication of water flood support with a bottom hole pressure of 1350 psia, no frac wing length and single zone influence. Since the well was an open hole completion, a fracture stimulation designed for this type of well bore was performed. The well was stimulated with 9,000 gallons of 35# cross-linked gel containing 8000# of 100 mesh sand, and 19,000 gallons of 35# cross-linked gel containing 82,000# of 20/40 resin coated sand. Production rates prior to the re-stimulation were 11 BOPD, 61 BWPD and 2 MCFPD. Initial producing rates following the stimulation were 43 BOPD, 29 BWPD and 44 MCFPD stabilizing at 19 BOPD, 52 BWPD and 15 MCFPD. The high producing GOR of greater than 1000 indicates a previously underdeveloped flow unit was opened.

One of the most important effects of this well work is simply the increase in withdrawal rates achieved. The model has shown that the reservoir has been over injected compared to withdrawals for the entire life of the waterflood. There is sufficient energy in the reservoir now to support many years of increased withdrawals on the current level of injection.

Simulation

In June 1999 the production data was updated to include all production through 1/1/99. Production data from the Johnson lease and the Maurice lease, which offset Section 36 to the east, were added. The simulation model has been reoriented and extended east

to cover a portion of these leases. Production data from the Addis lease, which offsets Section 36 to the west, were added. The simulation model has been reoriented and extended west to cover a portion of this lease. The model was reoriented to be parallel with a shelf break identified by the previous seismic and geologic work. The shelf break is a probable no flow boundary.

The production is entered into a spreadsheet, which allocates the individual wells production to each of the major zones, based on criteria of completed net thickness. The spreadsheet also accumulates production and provides a quality control check for comparison to the simulator.

The production data was also loaded to the Production Data Analysis program for conventional decline curve analysis. The decline curve analysis provides a check on the results of the simulator.

The seismically derived porosity maps for the "A" and the "B" zones have been revised and these revised maps imported to the simulation. The "A" and the "B" zones comprise the upper Grayburg interval, which is our primary waterflood objective. History matching has partially validated this map and the history matching work is continuing.

The seismically derived porosity maps are used to calculate maps of permeability, using a logarithmic porosity to permeability transform. The slope of the transform equation is initially based on the available core analysis, but the intercept was modified during the history matching process, to account for the presence of low porosity high permeability natural fractures in the reservoir. These fractures are observed in the cores and affect the measured core permeability. This effectively increases the minimum permeability from approximately 0.2 md up to the range of 2-3 md (see Geology). This change was necessary in order to produce and inject the measured actual volumes in the simulator. History matching has partially validated this method of developing a permeability map and the history matching work is continuing.

Identification of Additional Development Potential

The porosity development identified by the seismic also influences this direction of migration, with several high porosity "dead zones" being identified in the model. The model shows that these areas have high oil saturation with little withdrawal. One of these is on the southeast corner of the 160-acre Witcher lease, where a lease line injector failed early in the life of the water flood and was never replaced. Several producers also failed in this area and have not been replaced, leading to a situation, which indicates this area has not been adequately swept by waterflood. An additional producer is planned for this area.

To the southwest, on the Foster lease, another unswept zone has been identified. This area has not been supported by any injection to the west and its probable that the older waterflood injectors on Section 36, have displaced oil towards the west side of the Foster lease, where it has not been captured, due to lack of producing wells. One new

drill, the H. C. Foster #11, penetrated the upper Grayburg in this area and is currently completed as a lower Grayburg producer. The resistivity logs for this well through the upper Grayburg, showed high oil saturation that is in agreement with what the model is predicting.

The north portion of the Brock lease shows high oil saturation in the model. A lease line injector, Altura Witcher #3 (AW3) and the Brock #9 injector to the south have interfered with each other to create an area of high oil saturation. A new drill along the north line of this lease is planned at a future date.

Results

As a result of the refocus of the project on the upper Grayburg seven wells were identified and recommended as re-frac candidates. Five of the wells were re-stimulated. Prior to the workovers, total production from the five wells was 20 BO, 127 BW and 5 MCF. Production from the wells after the re-fracs peaked at 102 BO, 754 BW and 51 MCF and has since stabilized at 58 BO, 631 BW and 21 MCF. This represents a 3-fold increase in total sustained production from the three wells, see Figure 13.

A result of the well work has been the arrest of the decline for Section 36 seen in the years prior to the implementation of the project. Since June of 1993, the production from the project area has risen to 7500 BOPM from 6000 BOPM. During 1997 the production peaked at over 10000 BOPM, Figure 14. To date, it is estimated an additional 148,000 barrels of oil have been recovered as a result of work performed during Phase II of the project while increasing the ultimate recovery of the project area by a minimum of 570,000 barrels of oil and extended the field life from nine to sixteen years.

The accomplishments and success of the work performed supports the engineering conclusions from Phase I of the project. Through the integration of modern engineering methods, geological and geophysical data, it is possible to economically recover additional oil from very mature reservoirs.

TECH TRANSFER EVENTS

Trentham, R. C., and K. L. Widner, 1999b, Using Produced Water Analyses to Evaluate Production Problems and Re Completions in an "Old Waterflood": Foster-South Cowden Fields, Ector County, Texas, *in* Lufholm, P. and G. Hinterlong, eds., Permian Basin: Providing Energy for America: West Texas Geological Society Symposium, p 9 – 18.

Trentham, R. C., R. M. Weinbrandt, W. C. Robinson, 1999, Incorporating Seismic Attribute Modeling Into a Flow Model of the Grayburg Reservoir, *in* the Foster-South Cowden Field: an update in 1999 Oil and Gas Conference: Technology Options for Producers Survival: Abstracts and Program A3.4., Dallas, Texas, June 28-30, 1999.

A paper titled "The Role of Seismic Inversion Modeling in Describing Reservoir Characteristics: A Case Study" was presented by William C. Robinson at a noon meeting of the Permian Basin Geophysical Society, January 13, 1999, in Midland, Texas.

Trentham, R. C., and K. Widner, 1999a, Using Produced Water Analyses to Evaluate Production Problems and Recompletions in an "Old Waterflood": Foster-South Cowden Fields, Ector County, Texas, *in* J. Campell, ed., Mapping the Future: Fundamental Geology/New Technology, Transactions and abstracts of the AAPG SW Section Convention, Abilene Geology Society, Publication 99-1, p. 85.

A paper titled "The Role of Seismic Inversion Modeling in Describing Reservoir Characteristics" was presented by William C. Robinson at an evening meeting of the Oklahoma City Geophysical Society, February 15, 1999, in Oklahoma City, Oklahoma.

A paper titled "The Role of Seismic Inversion Modeling in Describing Reservoir Characteristics: A Case Study" was presented by William C. Robinson at a noon meeting of the Permian Basin Geophysical Society, January 13, 1999, in Midland, Texas.

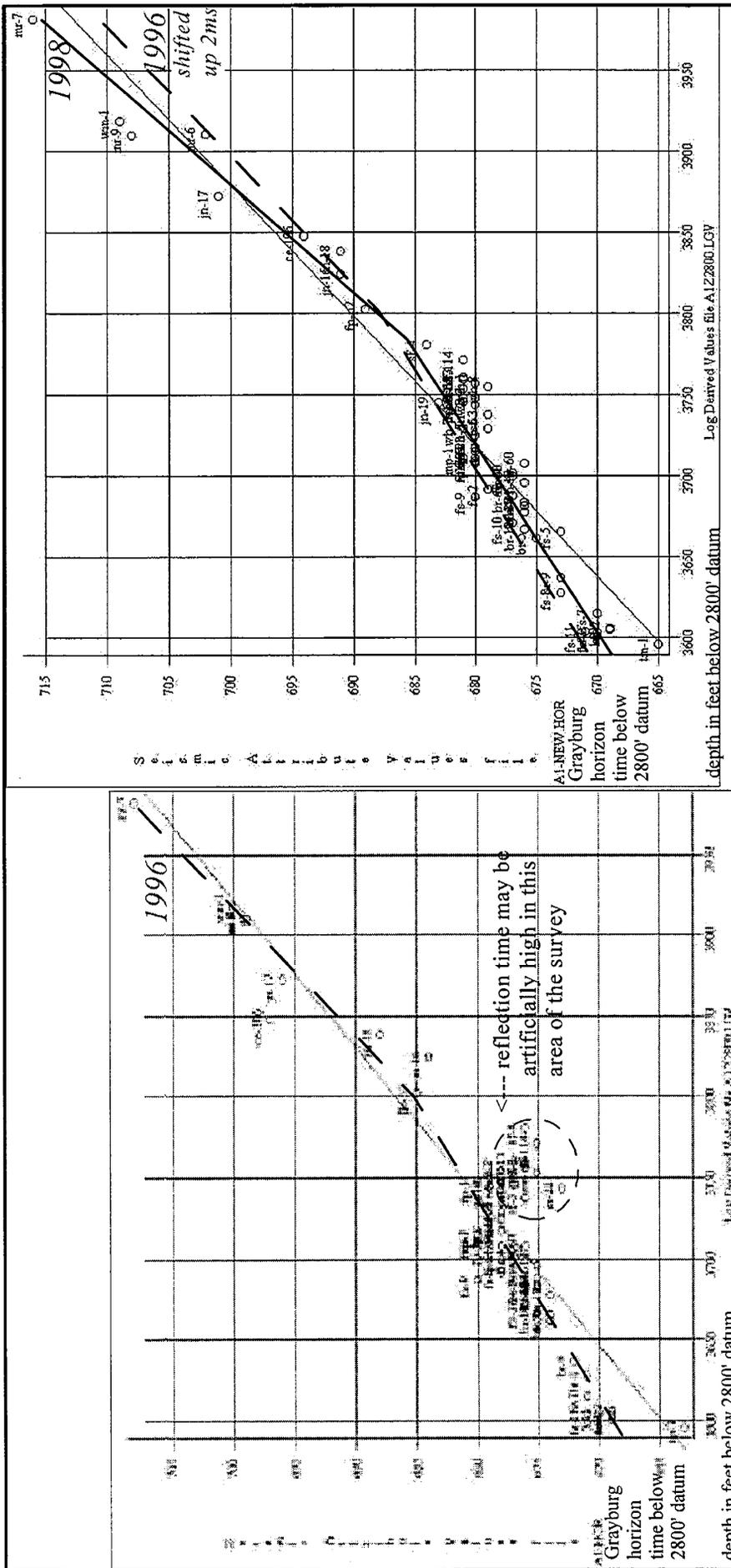
A paper titled "The Role of Seismic Inversion Modeling in Describing Reservoir Characteristics: A Case Study" authored by William C. Robinson. Printed in the West Texas Geological Society Bulletin in two issues: vol. 38, no. 4, pages 4-11, December, 1998 and vol. 38, no. 5, pages 4-14, January, 1999.

A paper titled "The Role of Seismic Inversion Modeling in Describing Reservoir Characteristics: A Case Study" was presented by William C. Robinson at a noon meeting of the Abilene Geological Society, March 18, 1999, in Abilene, Texas.

Weinbrandt, Richard M., R. C. Trentham, W. C. Robinson, 1998, Incorporating Seismic Attribute Porosity Into a Flow Model of the Grayburg Reservoir in the Foster – South Cowden Field SPE#39666. *in*, W. D. DeMis and M. K. Nelis, eds., The Search Continues into the 21ST Century: West Texas Geological Society Symposium, Publication 98-105, p.231 - 238.

ACKNOWLEDGMENTS

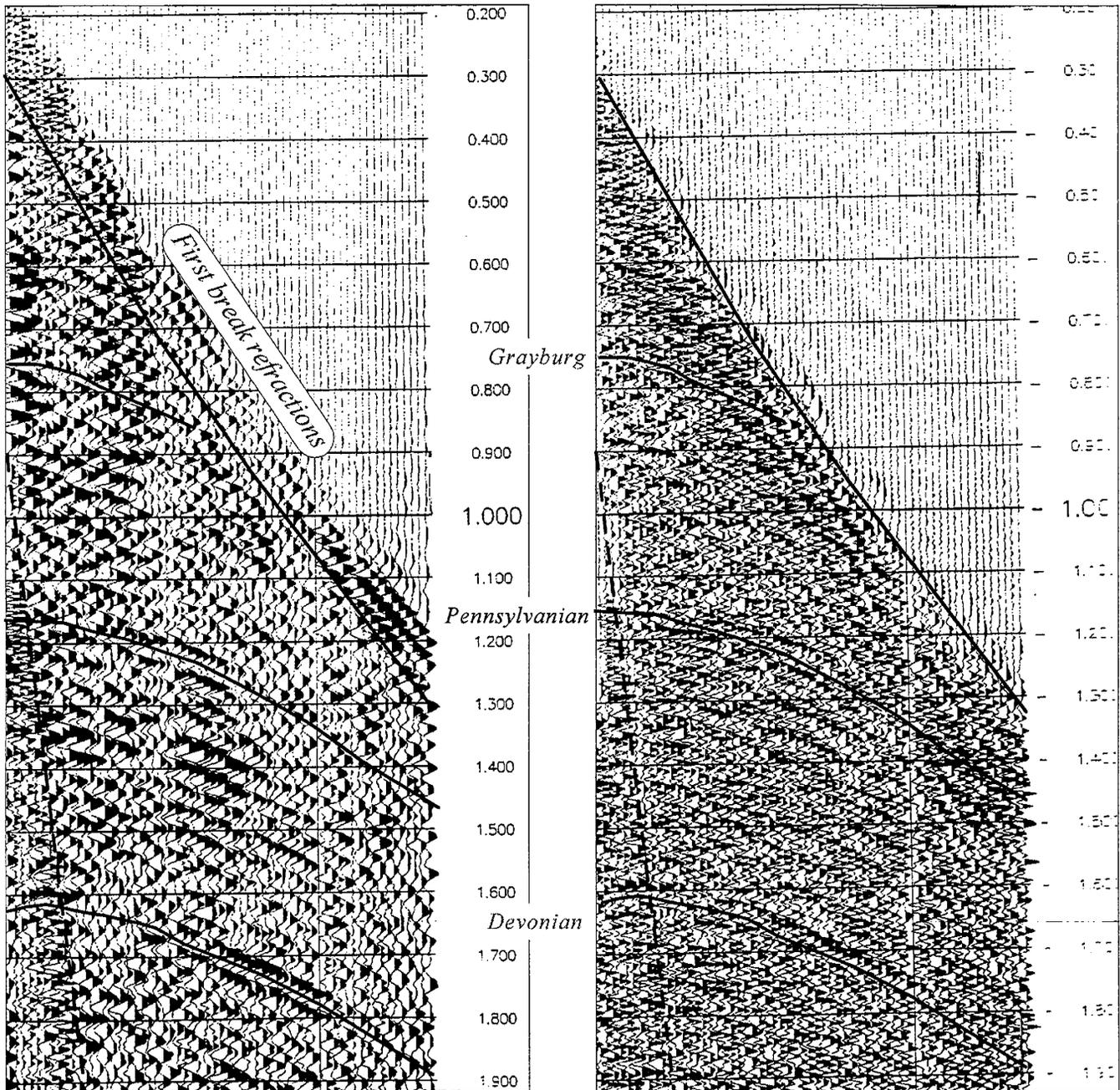
We would like to acknowledge James J. Reeves and Hoxie W. Smith for conceiving and managing the DOE study and for being responsible for the geophysical study until April 1996. Since that date, William C. Robinson has been responsible for reprocessing and reinterpreting the seismic data and for the geophysical study. Also since that date, Robert C. Trentham has been responsible for project management.



Reflection Time vs. Depth of Grayburg. Original processing (1996) 3D seismic data showing showing depth ties of wells with seismic data. A cluster of points off the line represents T-D pairs deviating from a constant velocity relationship.

Reflection Time vs. Depth of Grayburg. Reprocessed (1998) 3D seismic data showing depth ties of wells with seismic data. A tight cluster of points and a straighter linear relationship exist with this data volume. A small time shift between data sets exists.

Figure 2. Comparison of Reflection Time vs. Well Depth values for the top of Grayburg Formation. A tighter grouping of points, achieved in reprocessed data, indicates a slightly more accurate time horizon surface. Over a limited area, such as this 3D survey, a nearly constant time to depth correction is also expected. Refraction statics models differ for the two processed data volumes.



^--- Air blast

Figure 3. Conventional seismic amplitude data, in unstacked field record format. Traces left have an AGC trace scaling applied, and show first break refractions, air blast, and reflections. From these input traces, data (right) have had first breaks muted, air blast rejected, an FK-type noise rejection applied to reduce ground roll (not a significant problem), and spectral balancing applied. Coherent noise types like first breaks and air blast were reduced before spectral balancing was performed so reflection signal most determines scaling values.

The Grayburg reflection occurs around 0.720 seconds. The fold of stacked traces at the Grayburg level is only about one-half of the fold for deep reflectors, but is adequate for ultimate use creating an inversion model. Random noise is more noticeable on the data at right because the effect of noise increases with higher frequency (signal-to-noise ratio decreases with higher frequency). The relative noise is reduced by the trace stacking process to produce high quality, high resolution reflection data.

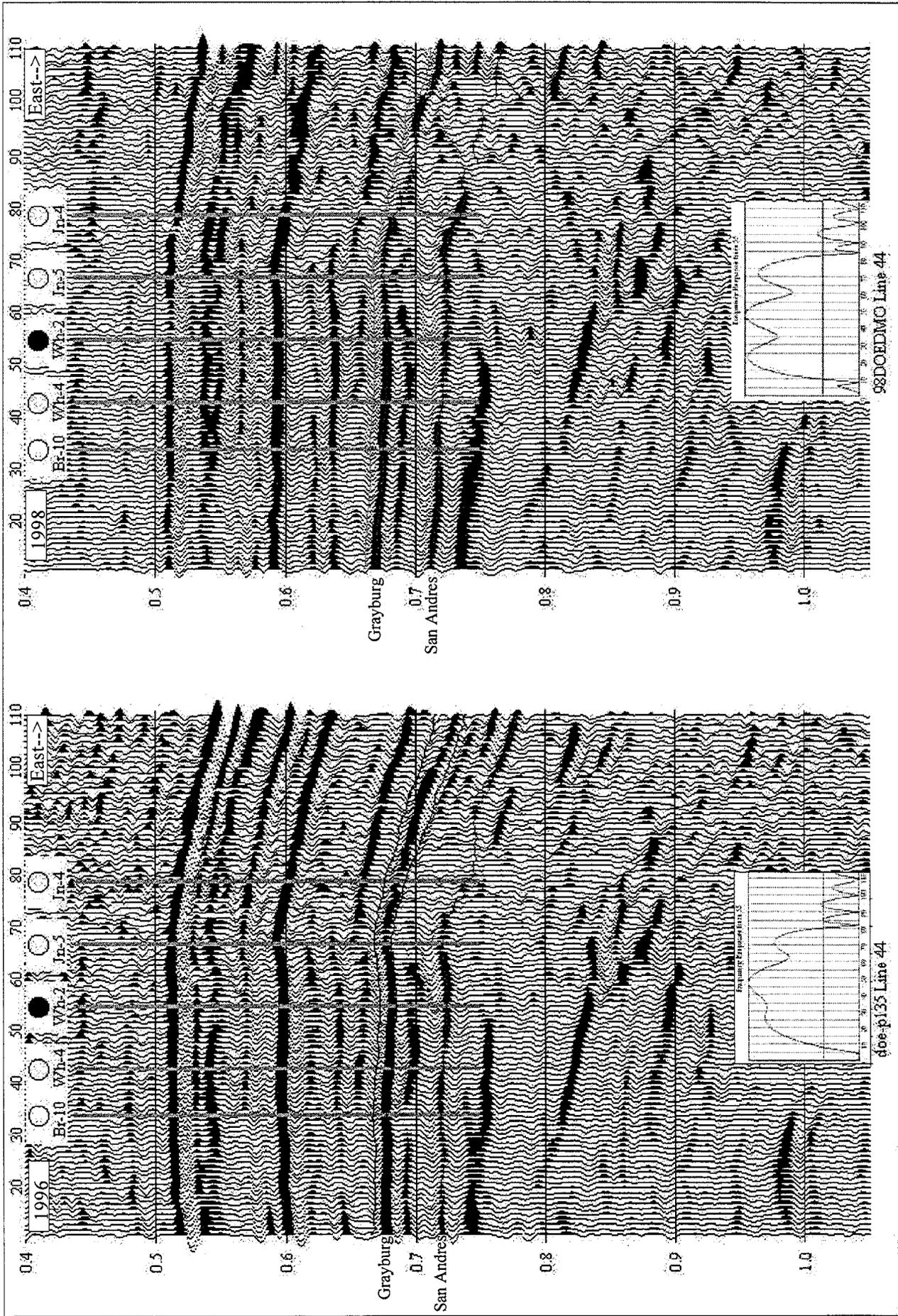


Figure 4. Comparison of conventional amplitude data from the 1996 data volume (left) and the 1998 data volume (right). Incremental improvement is observed as improved time structure accuracy, increased bandwidth, and attention to trace scaling. Time structure differences on the reprocessed data include horizontal strata from 0.5 - 0.6 seconds, and elimination of the small false anticline at SP 35. The shelf margin structure is similar on both data sets. On this profile reflection continuity of the slope strata appear degraded in the reprocessed data, partially a result of increased bandwidth.

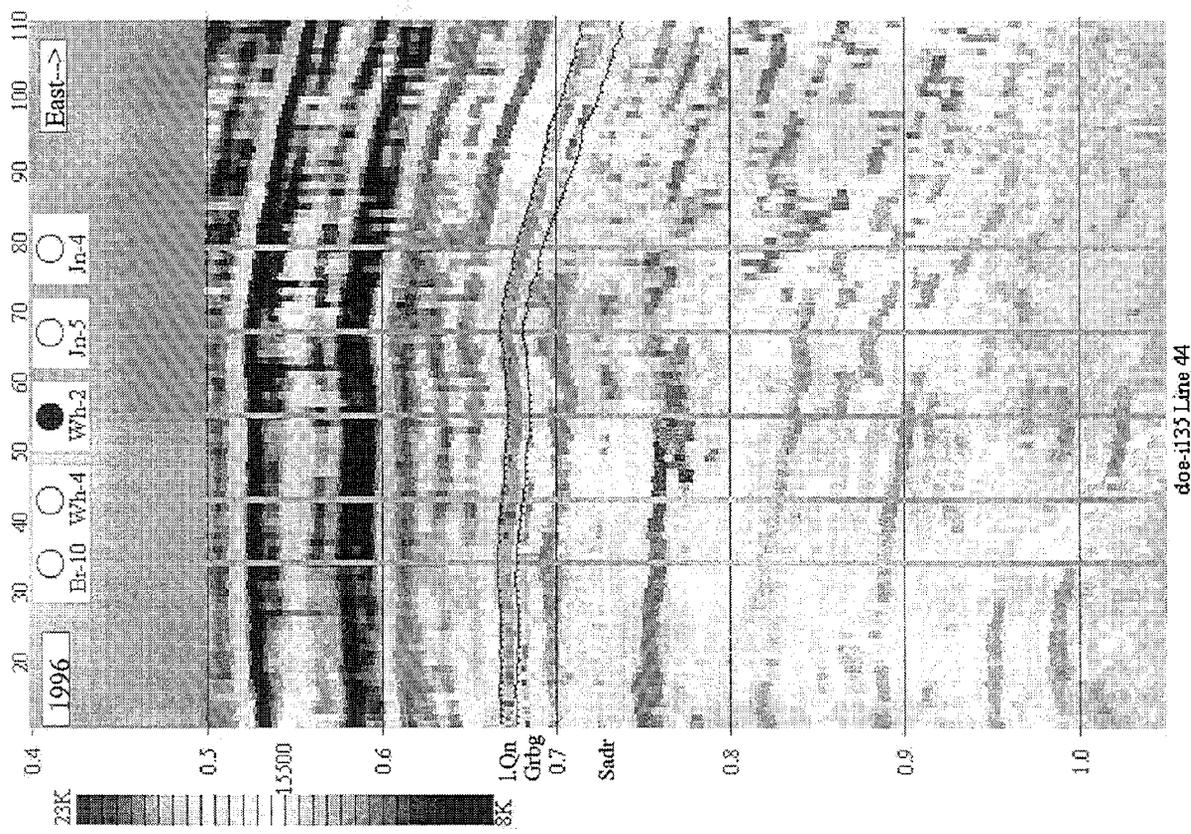
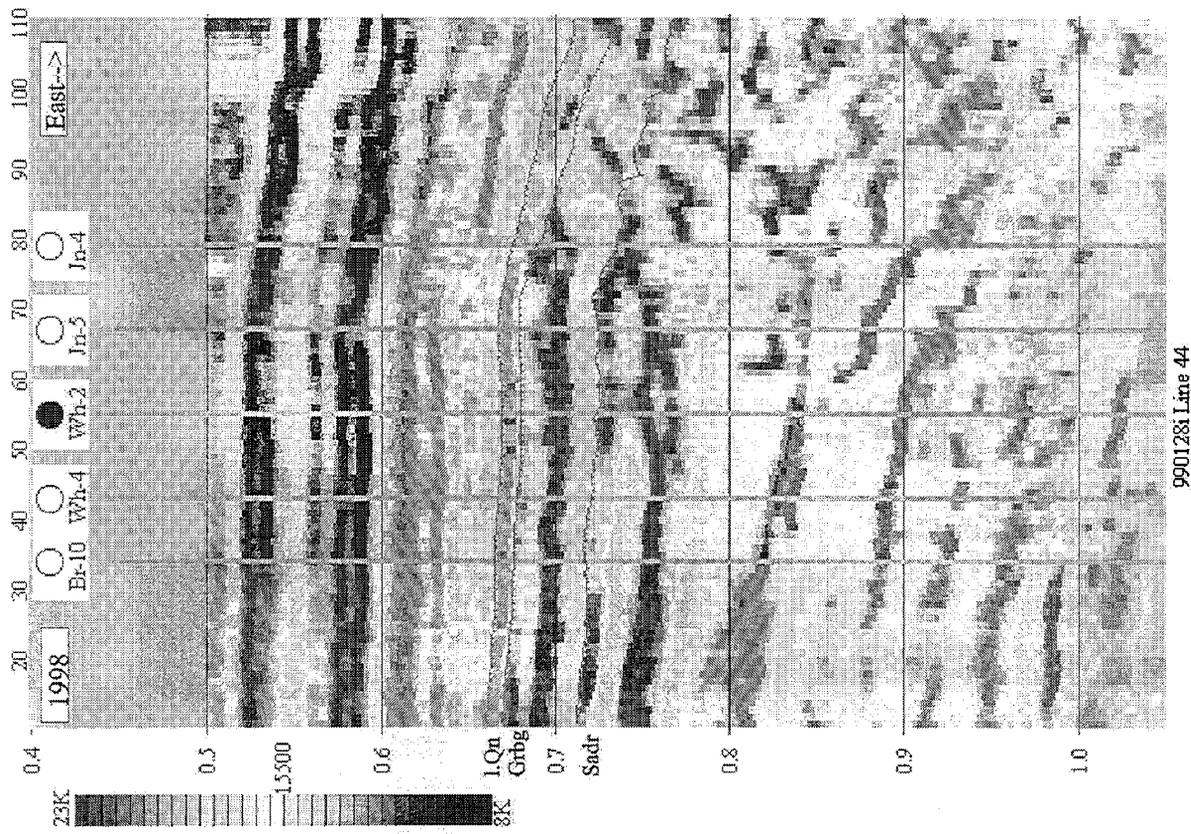
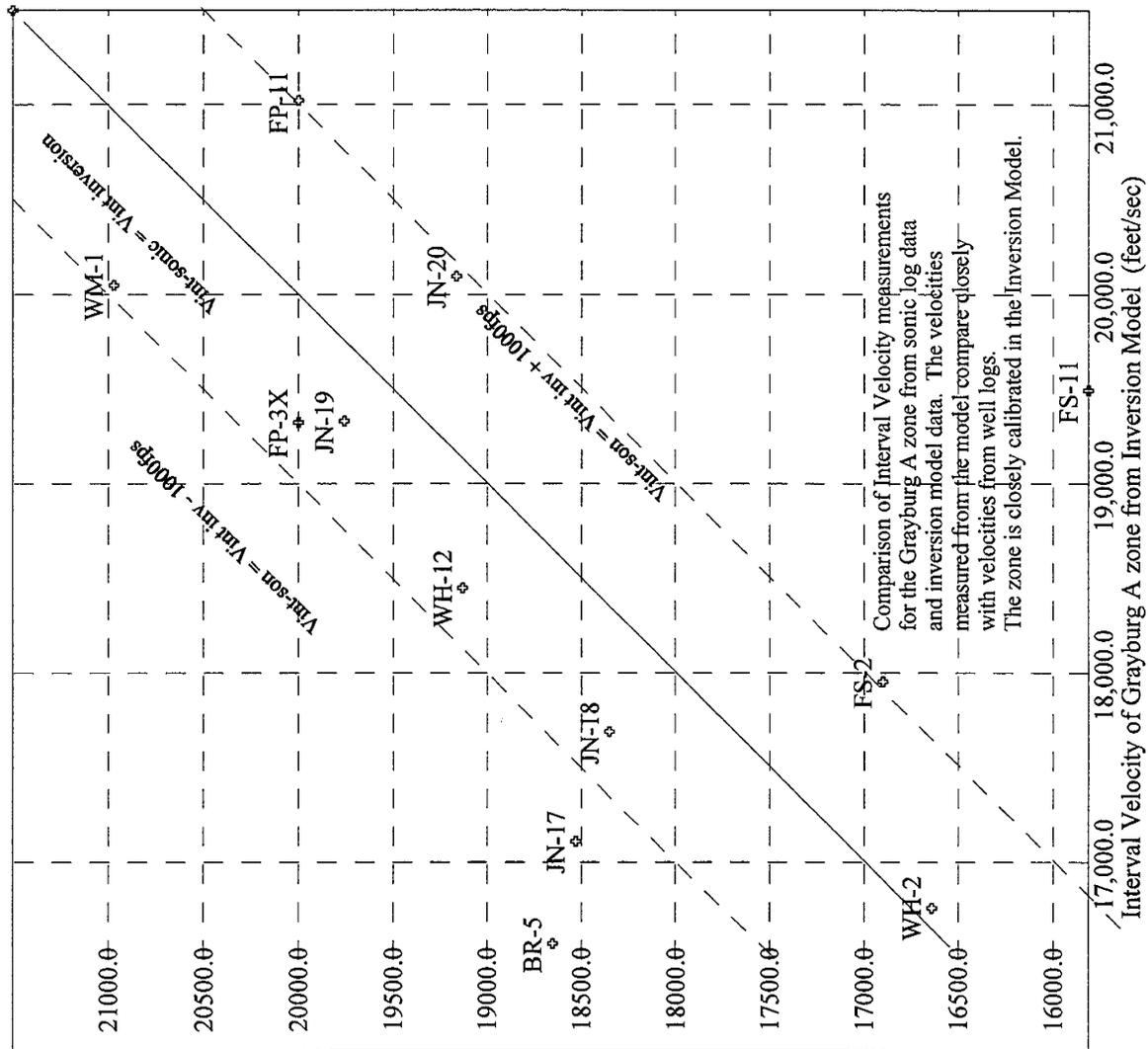
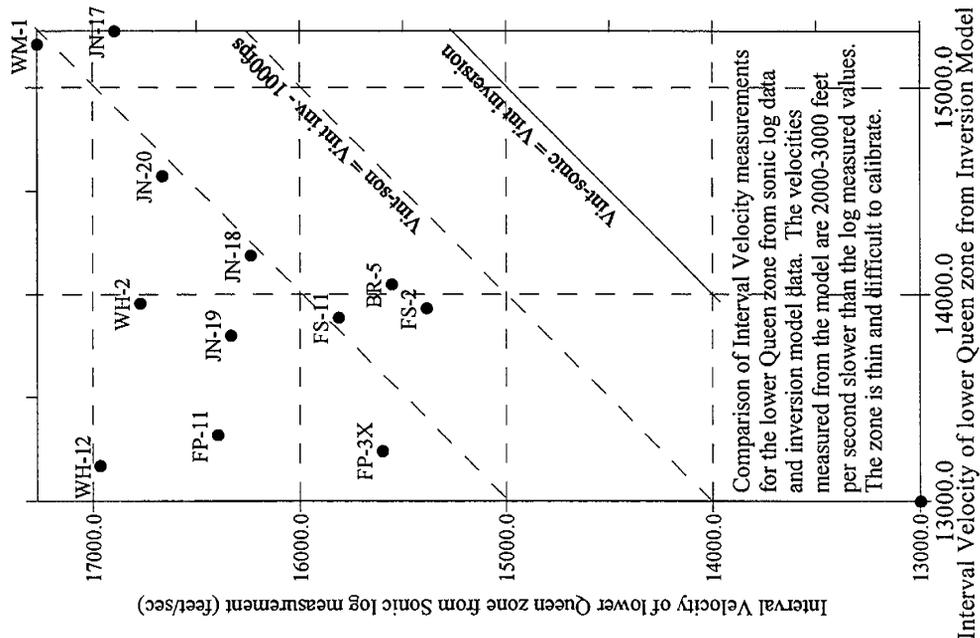


Figure 5. Comparison of profiles from inversion models from the 1996 seismic data volume (left) and the 1998 data volume (right). Velocity constraints for the later model were set higher, resulting in higher absolute velocity values in the inversion traces. The difference in time structure is also apparent.



Interval Velocity of Grayburg A zone from Sonic log measurement (feet/sec)



Interval Velocity of lower Queen zone from Sonic log measurement (feet/sec)

Interval Velocity of lower Queen zone from Inversion Model (feet/sec)

Figure 6. Comparisons of inversion model-derived average velocity with well log-derived velocity.

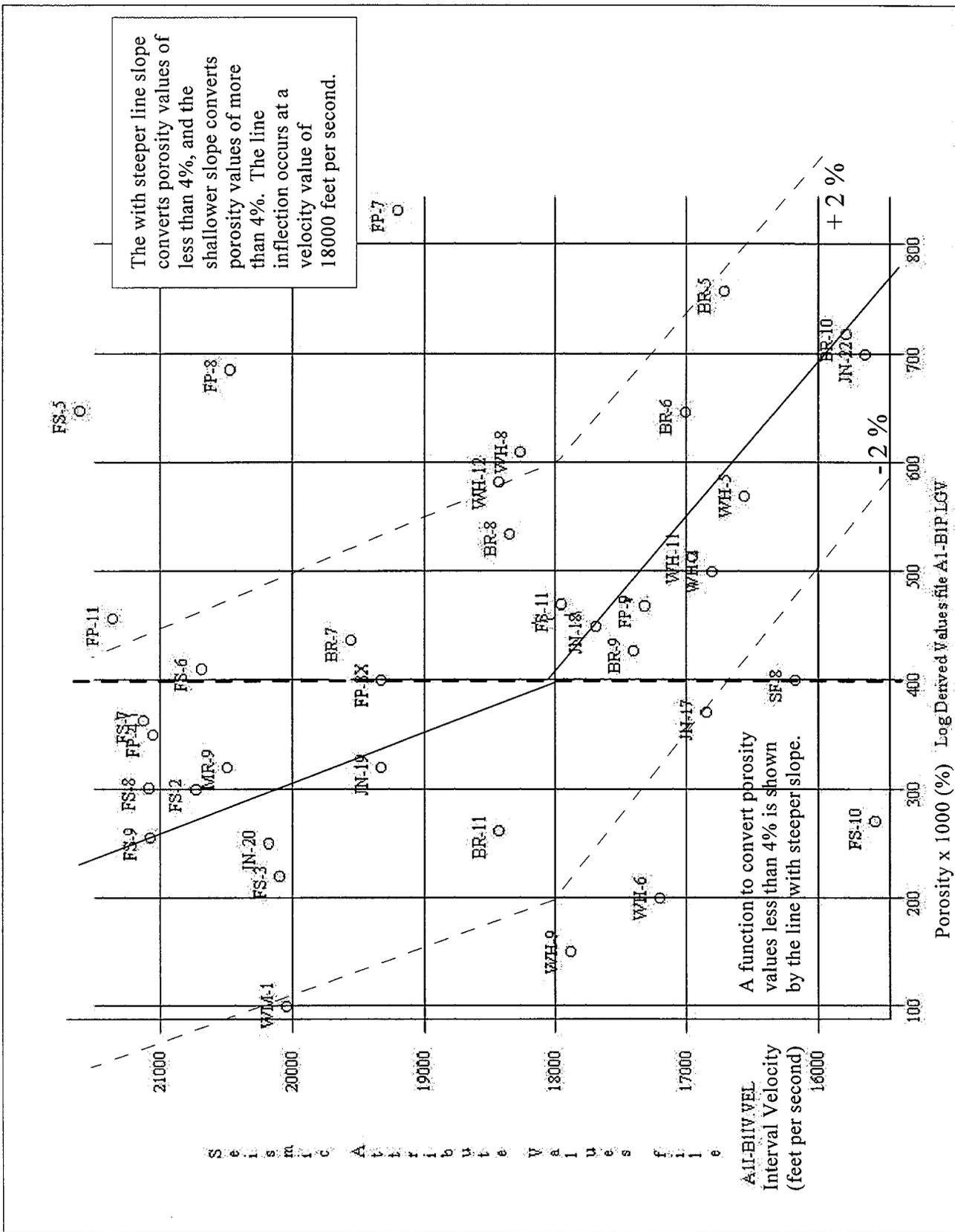


Figure 7. For the Grayburg A zone, a cross-plot is shown of log-derived Gross Average Porosity measured from well logs versus Interval Velocity from analysis of the Seismic Inversion Model. A function to convert velocity values is shown by the two-slope, solid line. The dashed lines show that data fall mostly within a porosity range of plus or minus 2%.

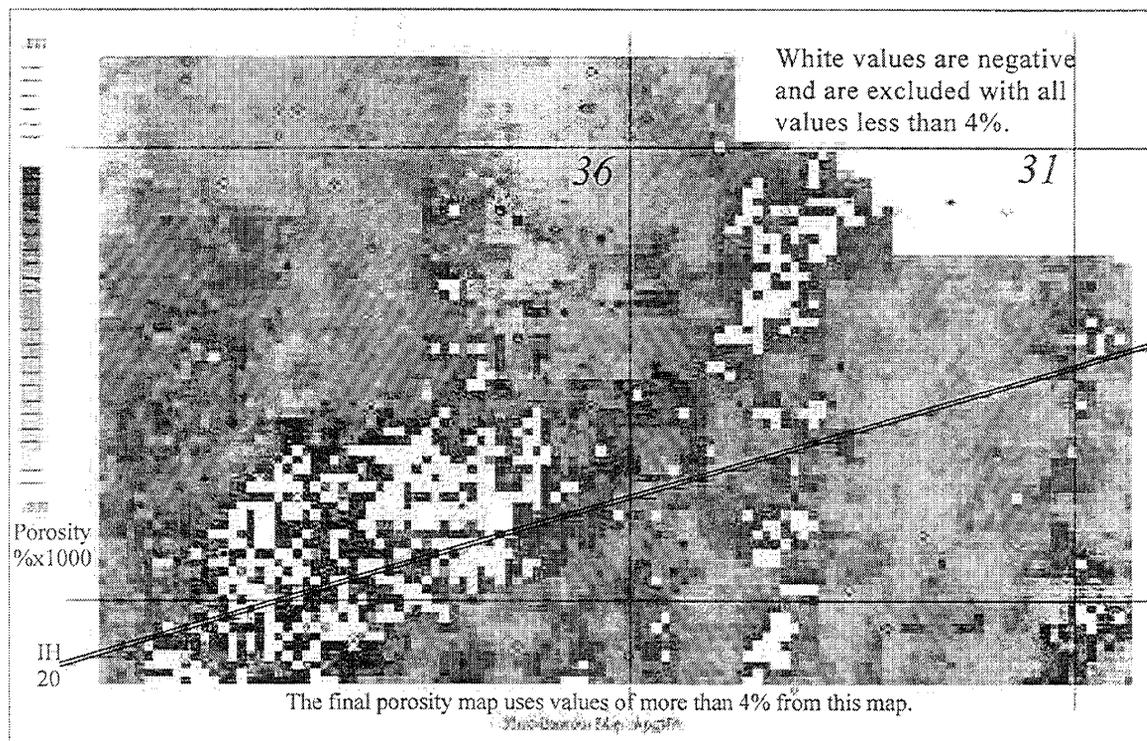
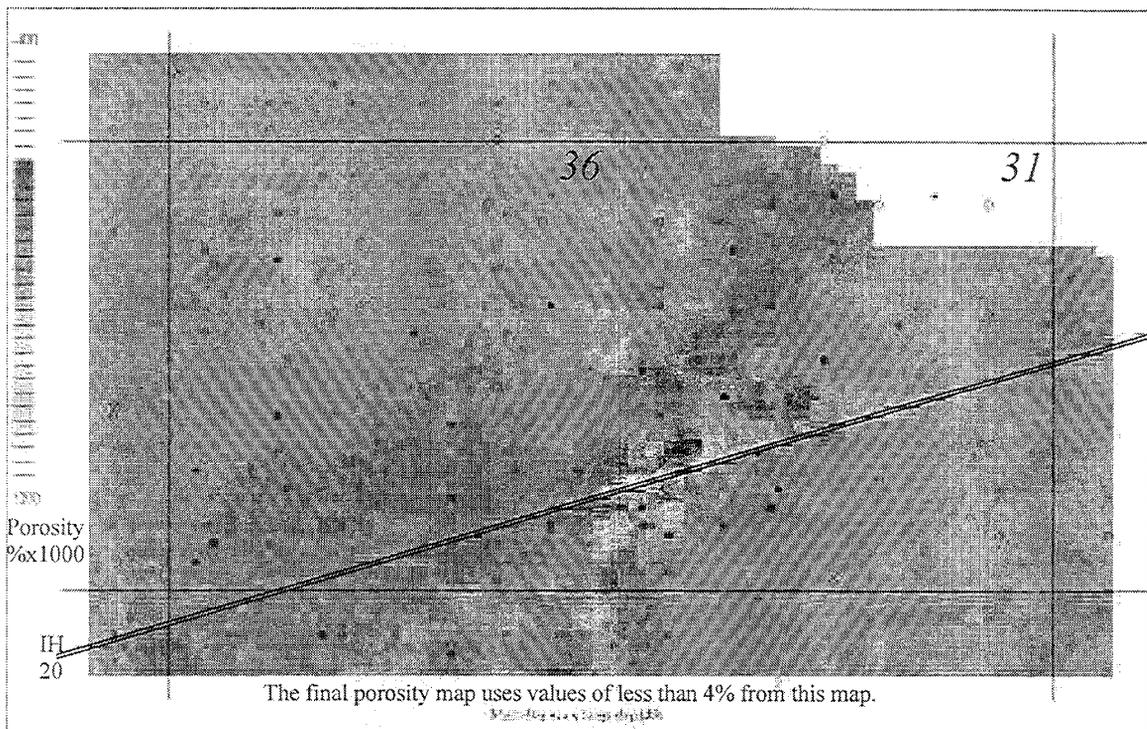


Figure 8. Porosity distributions calculated from inversion model-derived velocity values. Above: Porosity values calculated using the line for porosity less than 4%. Below: Porosity values calculated using the line for porosity more than 4%. The final porosity map uses values from these two maps to create a nonlinear function.

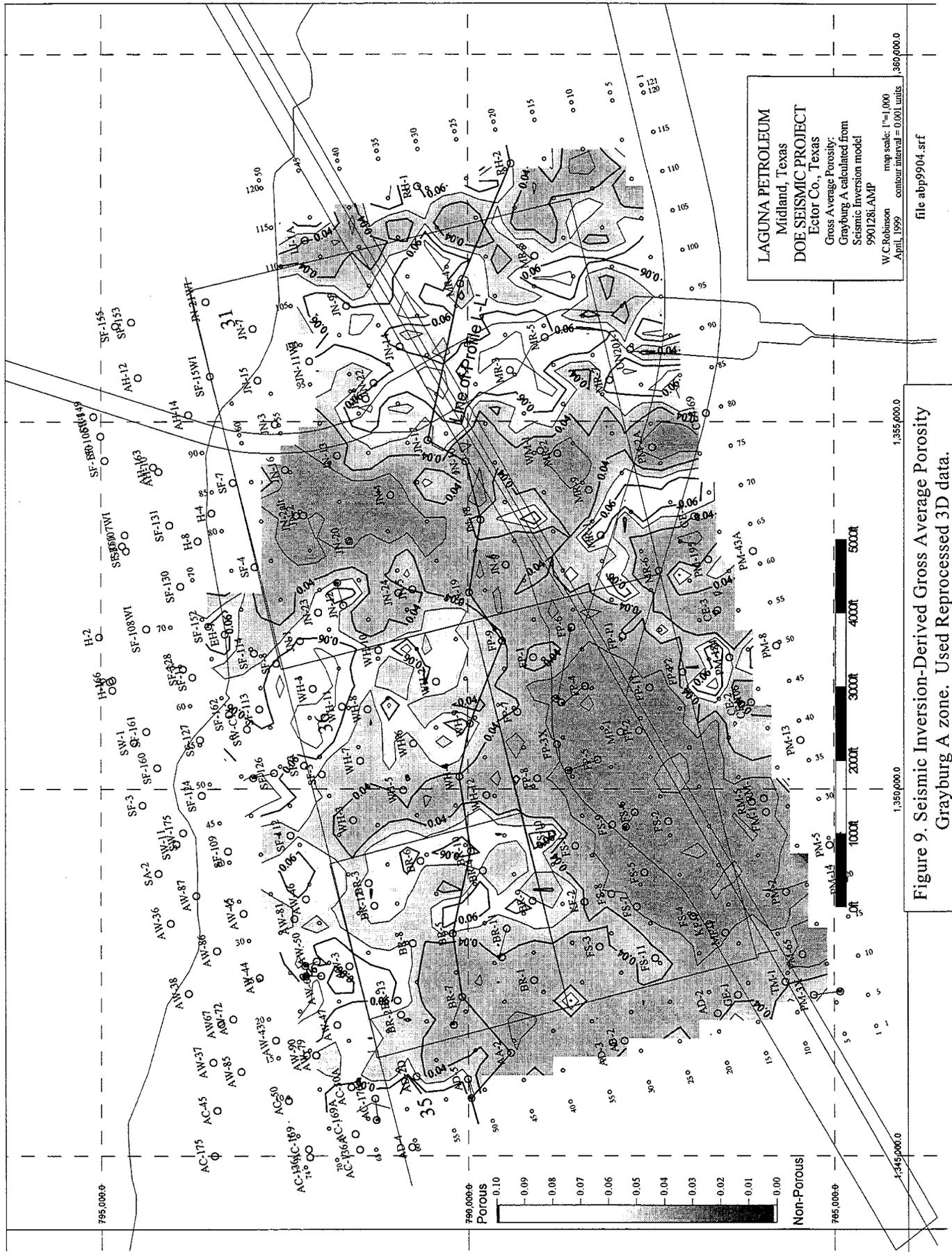


Figure 9. Seismic Inversion-Derived Gross Average Porosity Grayburg A zone. Used Reprocessed 3D data.

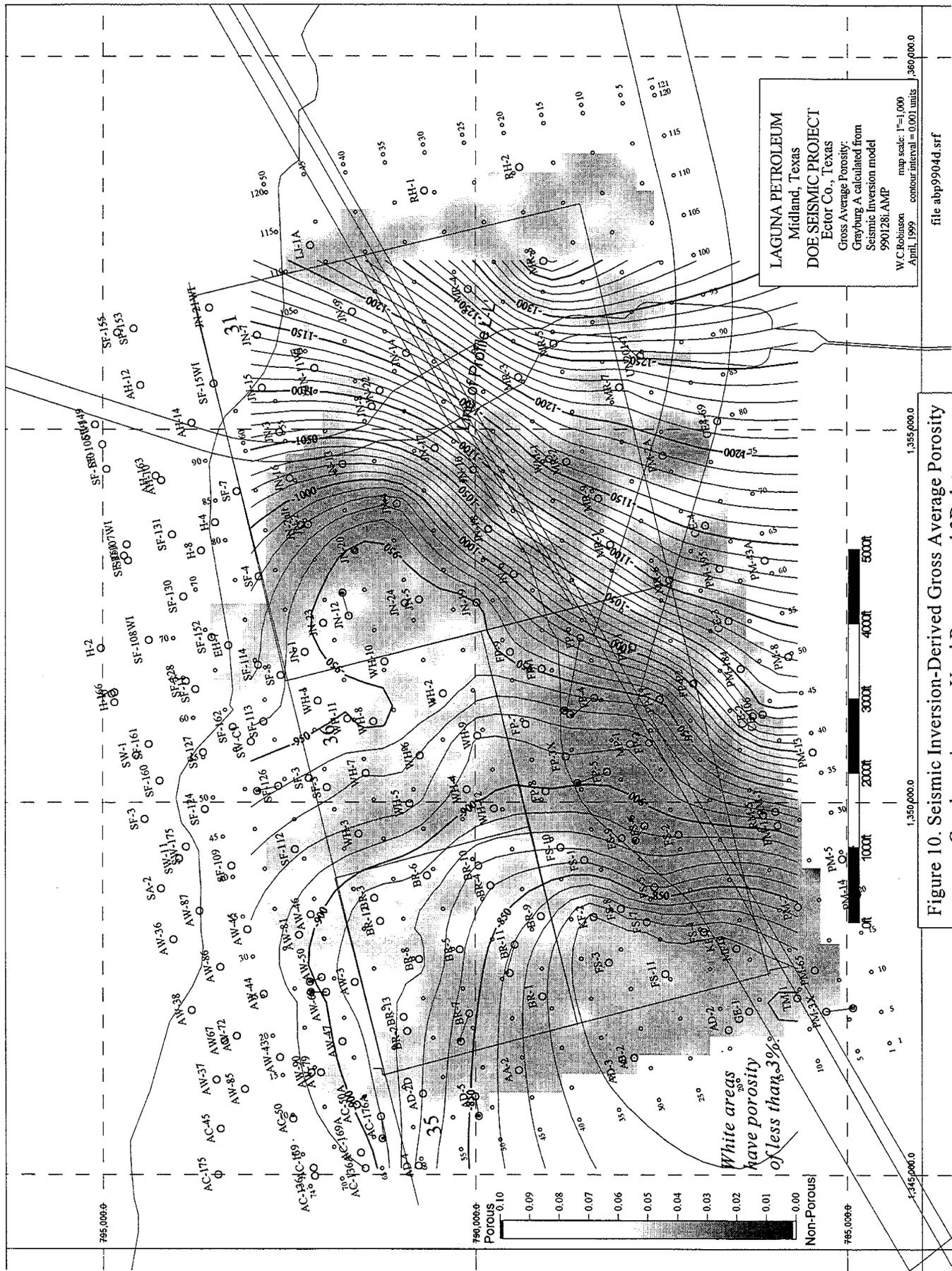


Figure 10. Seismic Inversion-Derived Gross Average Porosity Grayburg A zone. Used Reprocessed 3D data. Contours are of the Grayburg A1 depth.

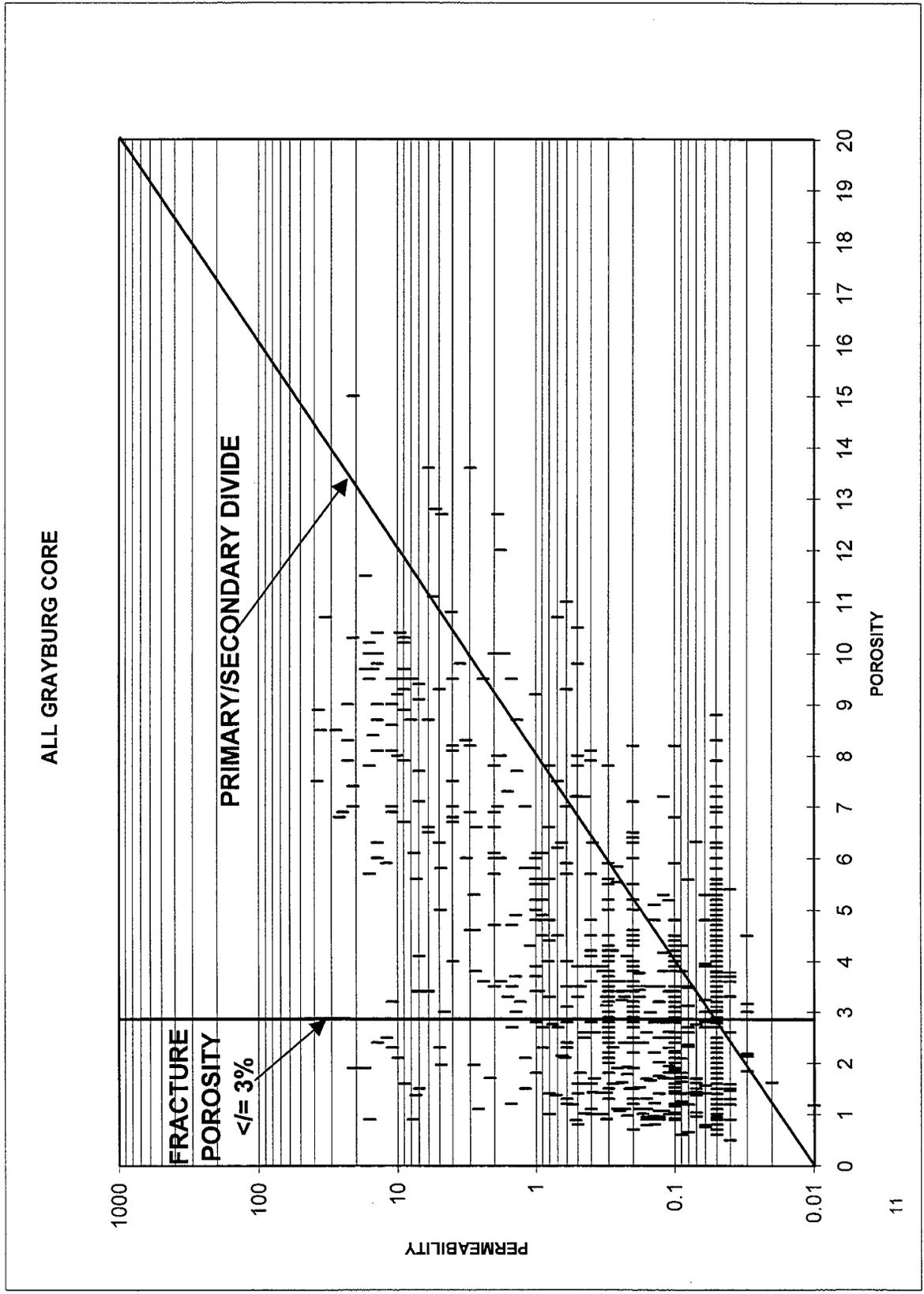


Figure 11. Core data for upper Grayburg. Three (3) % cutoff indicates region dominated by fractures.

**Results of Stimulation Program
Section 36, Ector County Texas**

Well Name	Production Prior to Stim			Initial Production After Stim			Stabilized Production After Stim		
	BOPD	MCFPD	BWPD	BOPD	MCFPD	BWPD	BOPD	MCFPD	BWPD
Foster Pegues #8	2	0	14	25	2	455	20	2	385
H. C. Foster #8	5	1	45	17	2	150	7	1	97
Witcher #1	11	2	61	43	44	29	19	15	52
Brock #8	1/2	0	1/2	12	2	110	8	2	90
Brock#10	4	1	7	5	1	10	4	1	7
Total	22 1/2	4	127 1/2	102	51	754	58	21	631

Figure 13. Results of Stimulation Program in Project Area, Section 36, Foster - South Cowden Field, Ector Co., Texas.

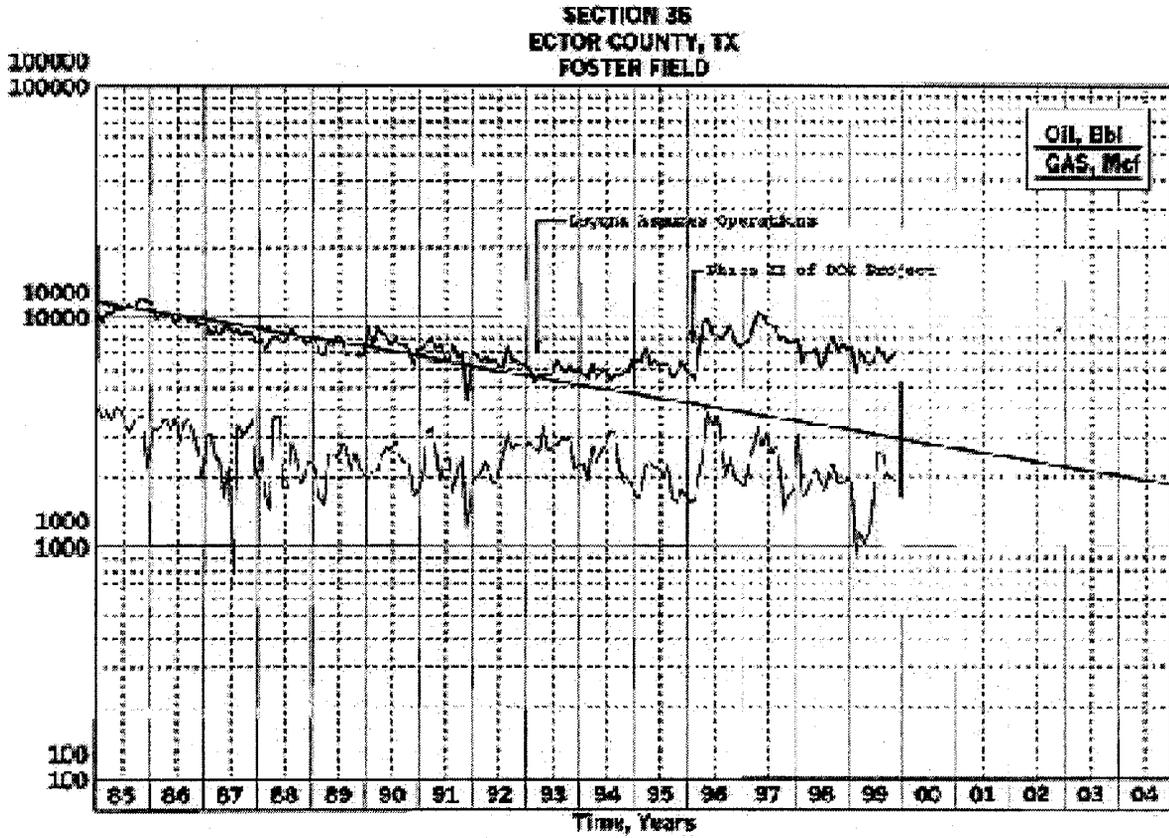


Figure 14. Production from Project Area, Section 36, Foster South Cowden Field, Ector Co., Texas.

