Report Title: **Application of Reservoir Characterization and Advanced Technology to Improve Recovery and Economics in a Lower Quality Shallow Shelf SanAndres Reservoir**

Report Type: ANNUAL	Reporting Period Start Date: 08/03/2000 End Date: 08/02/2001
Principal Author(s): OXY USA Inc. P. O. Box 50250 Midland, TX 79710-0250	
Report Issue Date: 05/05/2003	DOE Award No.: DE- FC22 -94BC14990

Submitting Organization(s) Name & Address

T. Scott Hickman & Associates, Inc.
505 N. Big Spring, Ste 105
Midland, TX 79701 (1)

Advanced Reservoir Technologies
P. O. Box 985
Addison, TX 75001-0985 (2)

(3)

(4)

(5)

APPLICATION OF RESERVOIR CHARACTERIZATION AND ADVANCED TECHNOLOGY TO IMPROVE RECOVERY AND ECONOMICS IN A LOWER QUALITY SHALLOW SHELF CARBONATE RESERVOIR

Cooperative Agreement No. DE-FC22-94BC14990

Prepared by
OXY USA, Inc.
Midland, Texas

May 5, 2003

Award Date: August 3, 1994

Anticipated Completion Date: September 30, 2002

Government Award for Current Fiscal Year: $2,230,300

Principal Investigator: Tom Beebe (OXY)

Project Manager: Gary Walker, Bartlesville Project Office

Reporting Period: August 3, 2000 - August 2, 2001

TABLE OF CONTENTS

ABSTRACT

The OXY-operated Class 2 Project at West Welch is designed to demonstrate how the use of advanced technology can improve the economics of miscible CO_2 injection projects in lower quality Shallow Shelf Carbonate reservoirs. The research and design phase (Budget Period 1) primarily involved advanced reservoir characterization. The current demonstration phase (Budget Period 2) is the implementation of the reservoir management plan for an optimum miscible CO_2 flood design based on the reservoir characterization. Although Budget Period 1 for the Project officially ended 12/31/96, reservoir characterization and simulation work continued during the Budget Period 2.

During the seventh annual reporting period (8/3/00-8/2/01) covered by this report, work continued on interpretation of the interwell seismic data to create porosity and permeability profiles which were distributed into the reservoir geostatistically. The initial interwell seismic CO_2 monitor survey was conducted and the acquired data processed and interpretation started. Only limited well work and facility construction were conducted in the project area. The CO_2 injection initiated in October 1997 was continued, although the operator had to modify the operating plan in response to low injection rates, well performance and changes in CO_2 supply. CO_2 injection was focused in a smaller area to increase the reservoir processing rate. By the end of the reporting period three producers had shown sustained oil rate increases and six wells had experienced gas (CO_2) breakthrough.

EXECUTIVE SUMMARY

The West Welch Unit is one of the four large waterflood units in the Welch field located in the northwestern portion of Dawson County, Texas. The Welch field was discovered in the early 1940's and the oil production is from the San Andres formation at approximately 4800 feet. The primary production mechanism is solution gas drive. The field has been under waterflood for 35 years and mostly infill drilled on 20-acre spacing. A CO_2 Injection Pilot on the offsetting South Welch Unit done during 1982-86 provided encouraging results. The availability of CO_2 from a new pipeline near the field allowed a phased development of a miscible CO_2 injection project in the South Welch Unit.

The reservoir quality is poorer in the West Welch Unit due to relatively shallow sea level during deposition. Because of the close proximity to a CO_2 source and the CO_2 operational experience gained in the South Welch Unit, the West Welch is ideally located for demonstrating methods that can enhance economics of Improved Oil Recovery for Lower Quality Shallow Shelf Carbonate Reservoirs.

The West Welch DOE Class 2 Project is divided into Budget Period 1 and 2. Budget Period 1, which ended 12/31/96, involved a detailed reservoir characterization effort based primarily on advanced petrophysics. The resulting "geologic" model was used to design a CO_2 flood. An economic analysis, based on the model predictions, resulted in the project's continuation into Budget Period 2, which comprises the completion of project installations and field demonstration of the project.

Much of the reservoir characterization effort was carried over into Budget Period 2. A methodology had been developed to extract porosity estimates from the three-dimensional (3D) seismic data set. The seismic-derived porosity was used to constrain the interwell estimates of porosity from the geologic model. This "surface seismic-enhanced" model gave better total-fluid history match over the geologic model. Other changes to the model included altering the mix of rock types and the relative permeability relationships for specific rock types for an improved water-oil ratio match. This enhanced model was used as the basis for the final optimization of the CO_2 flood.

The bulk of the prior interwell seismic activity (8/3/98-8/2/00) to the current reporting period involved the reprocessing and interpretation of the interwell seismic data. The high frequency (600-700Hz) at which the data is recorded offers an opportunity for a much finer vertical resolution and therefore more detailed interwell characterization than has ever been possible. Still, the conditions under which the interwell seismic surveys are conducted create serious challenges in the acquisition, processing and interpretation of the data. A number of obstacles had to be overcome before any useful interpretations of the reflection data could be obtained.

Work that was started in the prior annual reporting period to develop methods to identify rock types using the relationship between shear and compressional wave velocities from the interwell seismic data was completed in the current reporting period. The ability to identify rock types allows porosity and permeability profiles to be created along the interwell survey lines. Variograms were created from the profiles and used to distribute porosity and permeability geostatistically into the 3D reservoir model. Data were successfully acquired on the second interwell seismic CO_2 monitoring survey. The data were processed and preliminary representations of the CO_2 saturation along the survey lines constructed using the difference in apparent porosity between the baseline, first monitor survey and second monitor survey.

Before this reporting period, all of the work associated with the wells and surface facilities for distributing CO_2 for injection and gathering produced CO_2 was completed. Per the optimization plan, water injection rates were reduced in the project area to reduce the injection pressure below the formation parting pressure. This resulted in significant drop in the oil-producing rate. CO_2 injection was initiated October 1997 and a total of 4.8 BCF of CO_2 had been injected through 7/31/01.

Attempts to develop the 23 CO_2 injectors included in the original flood design for the demonstration area encountered numerous problems including reservoir quality, wellbore integrity, anomalous performance and CO_2 supply. To help ensure that sufficient hydrocarbon pore volume (HCPV) would be processed by the CO_2 to give an adequate evaluation, the CO_2 injection was limited to six injectors in a 400-acre "focus" area. Consequently, the operating plan has changed to the extent that the reservoir model's forecast had little value in evaluating performance. By 6/30/00, only 9.4% of the focus area HCPV had been processed, while experience indicates that at least 15% is required for significant response. A request to extend the project termination date from 10/31/00 to 10/31/01 was granted by the DOE. An additional six-month (no fund) extension to 4/30/02 has been granted by the DOE and another six-month (no fund) extension request to 10/31/02 is pending. By 7/31/01 a total of 13.0% of the HCPV in the focus area had been processed by CO_2. During the reporting period three wells have shown sustained oil response and 10 wells have shown gas (CO_2) breakthrough.

INTRODUCTION

DOE-Funded Project Proposal

In response to the DOE's 1992 solicitation for Class 2 Shallow Shelf Carbonates (SSC) Reservoir demonstration projects, OXY USA Inc. in Midland, Texas submitted a proposal titled "Application of Reservoir Characterization and Advanced Technology Improves Economics in a Lower Quality Shallow Shelf San Andres Reservoir." The proposal was aimed at proving lower quality San Andres reservoirs can be economically CO_2 flooded by applying advanced reservoir characterization and a combination of EOR methods that are not widely utilized. The reservoir characterization efforts would demonstrate new technologies, using 3D and interwell seismic methods. The proposal generally focused on using commercially available resources. The EOR methods involved both miscible CO_2 flooding and cyclic CO_2 stimulation.

Because of the large area that West Welch Unit covers, it contains reservoirs of varying quality and connectivity. The West Welch is therefore a good representative of lower quality shallow shelf carbonate reservoirs. Several factors favored the selection of West Welch Unit as a test site. As an operator of both South Welch Unit and West Welch Unit, OXY had a large working database for the field which included the logs from 770 wells, core data from 147 wells, and a 3D seismic survey. In addition, several PVT fluid analyses were also available. The infrastructure for CO_2 supply and gas processing plant was available at the adjacent South Welch Unit. Due to the ongoing CO_2 flood in South Welch, OXY personnel were experienced in the modeling and field implementation of CO_2 flooding.

The proposed project was to have used six technologies to enhance the probability of success for the CO_2 flood. These technologies included: 1) detection of directional fracture propagation with passive seismic measurements, 2) using the fracture stimulation of injectors to enhance sweep and thus eliminate the need for drilling of infill injectors, 3) using interwell seismic data to refine the interwell geologic model and to monitor the CO_2 flood front, 4) integrating the 3D seismic and the interwell seismic interpretations to enhance the reservoir characterization, 5) using an enhanced compositional reservoir simulator to improve the prediction of CO_2 flood response, and 6) investigate the use of mobility control agents with CO_2 injection to improve vertical sweep. The investigation of the first five technologies is either complete or well underway.

Project Progress

The DOE selected the OXY proposal as one of the successful candidates for a mid-term Class 2 project. A contract was finalized during 1994 which provided for a 50-50 cost sharing arrangement of the $22.2 MM estimated budget. The project officially started August 3, 1994 and was divided into two phases. Budget Period 1 was the design phase in which advanced reservoir characterization was used to build a geologic model for use in a reservoir simulator. This characterization included detailed petrophysical analysis leading to the identification of rock type from log response. This methodology permitted detailed estimates of permeability and fluid saturation from log data. The MORE Compositional Simulator was used to optimize the miscible CO_2 flood design and maximize the economics. Based on a favorable economic analysis, it was recommended that the project be continued into the demonstration phase in Budget Period 2 which officially began on January 1, 1997.

To further support the reservoir characterization effort in Budget Period 1, a pre-existing 3D seismic data set was reprocessed and interpreted for the San Andres horizon. This reprocessing ultimately yielded a vertical resolution of 50'. This enhanced resolution enabled the geophysicist to describe the reservoir in two layers. Furthermore, by relating the seismic response to sonic log response, the average porosity and thickness for each layer could be estimated. In Budget Period 2, this detailed interpretation of the 3D seismic data set was used to constrain the porosity-thickness estimate of the grid blocks in the interwell regions. The seismic-constrained geologic model was the basis for the "seismic-enhanced" model that gave an improved history match over the Budget Period 1's "geologic" model and the current predictive run for the CO_2 flood.

The updated seismic interpretation indicated that additional oil could be recovered by drilling wells south of the DOE-funded project area. The maps indicated good porosity and pay thickness in that area. Since OXY had earlier success in extending the southward development in the West Welch Unit, the project area was expanded in October 1997 for drilling new wells to test the seismic interpretation. Seven wells were drilled in the fourth annual reporting period in the expanded area. Well logs confirmed the seismic-based estimates of porosity to within one- percent porosity unit and reservoir thickness. The top of the pay section was within the accepted error margin; however, it was 15' lower than predicted. Because of the low structural position, the predicted net pay in these wells was reduced. Most recent estimates indicate that these wells will recover a total of 180,000 bbls of incremental oil. These reserves are insufficient to provide an acceptable rate of return. During this period, two pre-existing injectors were also converted to CO_2 injection in the expansion area but have since been converted back to water injection service.

Another technology that was investigated in Budget Period 1 was cyclic CO_2 stimulation. This process involves injecting CO_2 into producing wells, allowing a time for soaking, and then producing tertiary oil from the near-producer region. The cyclic CO_2 process can provide an almost immediate production increase, and thus reduce the payout time, compared to a conventional CO_2 flood. CO_2 stimulations were conducted in Budget Period 1 to determine if performance could be predicted accurately using the enhanced compositional simulator or some other method. The results proved to be ambiguous, and the use of cyclic CO_2 stimulation for project enhancement was not pursued into Budget Period 2. Any further testing of cyclic CO_2 injection was precluded so long as sour CO_2 was being injected.

During Budget Period 1, the use of fracture stimulations to eliminate the need for infill drilling injection wells in a part of the project area was investigated. To test this technology, a foamed frac treatment was pumped in an existing injection well while seismic receivers placed in three offset wells monitored the fracture growth. The interpretation yielded a four-dimensional map of fracture growth. This work was completed and reported in Budget Period 1. In Budget Period 2, this stimulated injector was converted to CO_2 injection. Anomalous breakthrough of CO_2 and nitrogen in September 1998 occurred in wells outside the injector's pattern, indicating a lack of control in the fracture growth.

The drilling of the expansion area wells to test the predictive capabilities of the 3D seismic interpretation offered the operator an opportunity to test a fracture simulation model. Refined by the actual results of seven fracture stimulations, this model predicts that the propped half-length of a fracture is limited to 80 to 100' before the fracture will grow dramatically out-of-zone. This technology was tested in the northwest part of the DOE area where performance suggests the presence of permeability barriers between injectors and producers. After the fracture stimulation, the injector indicated that communication was successfully extended beyond lateral barriers in the pay interval.

At the beginning of Budget Period 2, well bores were prepared and facilities were upgraded for CO_2 injection which was initiated in October 1997. Flood monitoring, well injectivity, wellbore issues, acquisition of the second interwell seismic monitor survey and the drilling of a horizontal lateral were the main field demonstration activities in the 2001 annual reporting periods.

PROJECT AREA OVERVIEW

GEOLOGIC SETTING - The Welch Field is located in the north part of the Midland Basin and in the northwestern portion of Dawson County, Texas. Production is from the Permian-Age dolomite of the San Andres formation. The determination of the depositional environment and diagenetic history was established from detailed interpretations of core samples within and surrounding the project area. The cyclic pattern of alternating depositional environments has been documented throughout the Permian Basin. The depositional cycles were put into a sequence stratigraphic framework in order to ensure that the correlation of individual reservoir layers remained consistent from well to well. The Bureau of Economic Geology was consulted to bring the Welch San Andres sequences into an established hierarchy.

The San Andres deposits were emplaced on a shallow shelf ramp near the paleoshoreline. Structural relief was very low; probably less than 3' of slope per mile; hence, minor fluctuations in sea level moved the shoreline several miles at a time. These depositional environments produced broad bands of sediments with variable textural characteristics depending on the sub-environments associated with each major environment. Tidal flat deposits are produced along the strand line as well as on islands within the lagoon. Higher energy tidal channels are seen dissecting the low energy tidal flats, producing coarse-grained sediments encased in lime muds. Small amounts of grainier rocks can also appear within the lagoonal settings.

The post-depositional history describes the diagenetic events that changed the physical properties of the reservoir rock. From the time of deposition, the sediments have been altered extensively in places to the point that the original fabric of the sediment is no longer recognizable. These processes are sometimes termed random, because the controlling factors are often not known. However, their effect is manifested at Welch in terms of dolomitization, pore-filling anhydrite, leaching and precipitation of quartz and calcite cements, and the presence of stress fields that produce directional trends in permeability.

PETROPHYSICS - A common problem in discerning petrophysical relationships from log and core data is reconciling the differences in data acquisition methodologies through time. As the industry's knowledge of factors affecting the measurements of porosity and permeability has evolved, so have the methods and practices used for their measurements. The extensive data collected in Welch field are useful for correlation and for pay quality comparisons, but can not provide simple and direct correlation between porosity and permeability. For a single porosity value, the porosity-permeability semi-log cross-plots produced a standard error estimate of several orders of magnitude.

In Sept/Oct 1994 two observation wells, WWU 4852 and WWU 7916, were drilled and cored in the West Welch Unit project area. An extensive suite of logs was run on these wells. The data from these wells were used to calibrate the logs and cores in the project area and are the basis for the detailed petrophysical data used in various project area models.

The mineralogy of the productive San Andres interval is simple, with dolomite comprising 77%, anhydrite comprising 17%, quartz comprising 4% and gypsum, calcite, and clay minerals each comprising less than 1% of the rock matrix. However, the pore structure is highly complex. David K. Davies and Associates described four different rock types for the section. Comparison of these rock types to the normally determined features of depositional environment and fabric found little in the way of correlation. This poor correlation demonstrates the importance of diagenetic processes to flow characteristics at Welch. Any rock type can occur in any depositional facies, and basing reservoir parameters on inferred depositional environments can result in erroneous interpretations.

A methodology was needed that would allow the geologist to recognize rock type from log response. Furthermore, the relationships between log response and the various reservoir parameters needed for complete reservoir characterization had to be derived for each rock type. Relative permeability tests indicated that the reservoir is of mixed wettability. The resulting uneven distribution of fluids in the pore system affected the resistivity log response. The resistivity logs therefore could not be used to identify rock type, and a nonstandard log interpretation approach was needed. The methodology that was developed was published in 1996[1].

RESERVOIR DESCRIPTION - The reservoir interval at West Welch Unit occurs at an average depth of 4800-4900', approximately 400' below the top of the formation. The West Welch Unit covers 12,000 acres. The general structure of the field is a monocline, gently dipping to the south-southeast. The present structure is a result of pre-depositional movement of deeper fault blocks. No fault cuts the San Andres at West Welch and the appearance of actual fractures in core is rare. The average gross thickness of the producing interval is 100' with net pay thickness of 50'. The porosity in the reservoir interval ranges between 0 and 22%, with an average value of 9% for the entire Unit and 12% for the project area. The average permeability for the project area is less than 5 md.

The reservoir is highly stratified as a result of depositional processes, with Dykstra-Parsons coefficient values in the 0.75 range. The producing interval is divided into two hydraulically separated intervals: the Main Pay and the Lower Pay. The oil/water contact (depth of 100% water production) for the Main Pay is at a subsea depth of -1890 ft. Lower Pay is wet in this part of the field. The oil/water contact varies slightly across the field due to the capillarity of the reservoir rock. The underlying water provides little pressure support and the primary drive mechanism is solution gas. An anhydrite seal at the top of the reservoir section creates the trap. The productive limits of Welch field are controlled by a combination of structure and permeability variations. The Main Pay loses permeability moving northward in the updip direction and produces excess water in the downdip direction. At West Welch, production is from the Main Pay in the south and from the Lower Pay in the north. Production in the project area is from the Main Pay. Many of the original wells in the south and central part of the Unit have produced in excess of 300 MBO. Cumulative oil production tends to be less in the north.

From a comparison of permeability profiles and gamma ray logs, it was recognized that certain gamma ray spikes within the Main Pay correlate with the thin, low permeability intervals. These boundaries could be correlated from well to well through the entire project area and form the basis of the layering for the model. Basically, the reservoir is described in nine layers separated by ancient flooding surfaces. Each layer is a continuous rock unit across the model area. Because of variability in the diagenetic processes, these layers do not have uniform properties throughout but should exhibit bounded flow character. Lateral discontinuities within a layer are expressed by rapid changes in porosity and permeability. This variability has an adverse affect on the sweep efficiency of any flooding mechanism.

In the original "geologic" model, reservoir parameters were simply contoured between the wells for each layer. This model was used to justify the continuation of the project into Budget Period 2, the demonstration phase. In Budget Period 2, the model was enhanced by using the 3D seismic data to constrain the total porosity-thickness in the interwell locations.

DEVELOPMENT HISTORY - Welch field was discovered in 1941 and was initially developed with 40-acre well spacing. West Welch Unit has been under waterflood since 1963. Unit production peaked at 9000 BOPD in 1971. Infill drilling from 1980 to 1991 stabilized the producing rate at 2000 to 3000 BOPD. Later, limited infill drilling and well maintenance work reduced the annual decline rate to 4%, but the economic margin associated with this work has become increasingly narrow and it is anticipated that the Unit decline rate will increase from 7 to 10% as such work can no longer be justified economically.

West Welch Unit consists of approximately 350 producers and 200 injectors in a line drive pattern of varying density. Currently the Unit is producing around 2,500 BOPD and 23,000 BWPD. The average well produces 7 BOPD and 65 BWPD. All produced water is reinjected at West Welch Unit.

Most of the producers in West Welch Unit were completed openhole. Casing was set at the top of the pay interval, and then the producing zone was drilled out. All of the producers have been hydraulically fractured with fluid and sand. Attempts to stimulate production by a second fracture treatment have generally failed, leading to the conclusion that the initial fractures are still open and sufficiently clean to contribute to the well's flow rate. The combination of the openhole completions and the fracture treatments limits the determination of the layers which are contributing to the production. Profile modification in producers is difficult because of the open-hole completion.

The earlier injectors at West Welch Unit are also open-hole completions. Many of these wells, which were producers prior to their conversion, were also fracture stimulated. Injectors drilled since 1980 are typically cased-hole completions. These wells were rarely frac treated, though they may have been acidized several times. The problem in determining the injected water distribution into individual layers is complicated by the field-wide practice of injecting above the formation parting pressure in order to get a sufficient volume of water into the reservoir. In various areas of the Unit and in the project area, attempts have been made to reduce injection pressure below the parting pressure. In every case, some reduction of water and oil production was seen. This indicates that some water cycling was happening at higher injection pressures, while the oil reduction suggests that the high injection pressure probably resulted in the flooding of low permeability areas.

Common producing problems at West Welch Unit include corrosion, scale precipitation in producers, paraffin precipitation in well bores and flow lines, and casing leaks. Corrosion is controlled through the use of chemicals to protect steel from corrosive fluids. Scale formation rarely seems to adversely affect production. Scale most often accumulates in the lower part of the reservoir section, and communication with the wellbore can still be maintained through the propped fracture. Experience has shown that except for cases of extreme accumulation, scale cleanouts rarely improve producing rates and are not generally justified. Paraffin is removed by pumping heated fluids down well bores and flow lines. Casing leaks generally occur in the older wells and are most often repaired by the installation of steel liners. All the producers in the West Welch Unit are on beam pumping units. They are sized on the total fluid production of the individual wells. Installation of additional pump-off controllers has reduced the electricity usage and prolonged the life of the pumping components.

STATEMENT OF WORK STATUS

Appendix A is the Statement of Work (SOW) that was included in the original proposal to the DOE and serves as the guideline for conducting the project. The activities were divided into Budget Period 1 - project design and economic projection - and Budget Period 2 - project execution and evaluation. Budget Period 1 ended December 31, 1996 after the projected economics justified initiating the actual CO_2 field demonstration phase, i.e. Budget Period 2. All of the subtasks listed under Budget Period 1 in the SOW were successfully accomplished except for Subtask 1.4.3 Baseline Tomography Survey. While the interwell seismic was acquired and processed, much of the technology involved had to be developed by Advanced Reservoir Technologies (ART). Consequently, the interwell seismic contribution to the reservoir characterization was not available for enhancing the reservoir model used in the simulation at the end of Budget Period 1 that produced the performance projections and economics on which the demonstration phase was justified.

The interwell seismic interpretation and application to reservoir characterization has continued into Budget Period 2 and expanded to include Subtask 2.4.2 Tomography Surveys for Front Tracking. Although the 3D seismic interpretations contributed to the reservoir characterization in Budget Period 1 (Subtask 1.4.5), some activity continued in the early part of Budget Period 2 as part of Subtask 2.3.1 Update Existing Reservoir Characteristics. Similarly, reservoir computer simulation continued into the second budget period. If the interwell seismic interpretations are incorporated into the reservoir model then additional simulation will be required under Subtask 2.3.1 and possibly under Subtask 2.4.3 Project Evaluation. Two of the subtasks under Task 2.3 Project Area Preparation - 2.3.3 Fracture Stimulation and 2.3.4 Facilities Upgrade - have been completed by September 2, 2000. The remaining three subtasks are still active through this annual reporting period. Task 2.1 Project Management, Task 2.2 Technology Transfer and Subtasks 2.4.1 and 2.4.2 under Task 2.4 Reservoir Management Plan Initiation and Operations are ongoing through the demonstration phase. Subtask 2.4.3 Project Evaluation and Task 2.5 Final Data Set do not start until the demonstration phase has ended.

DISCUSSION

INTERWELL SEISMIC

INTRODUCTION - In the design of this project, interwell seismic was included as one of the new technologies to be demonstrated. There are two components to interwell seismic - tomography (direct waves) and reflective waves. Both aspects had the potential to refine the interwell reservoir characterization beyond the resolution that could be accomplished with surface 3D seismic interpretations. Also, reshooting some of the baseline survey lines after CO_2 injection began might allow imaging of the CO_2-invaded areas with tomography. At the beginning of Budget Period 1, fourteen lines of interwell seismic (baseline survey) were obtained using two source wells and 13 receiver wells (Figure 1). The bulk of Budget Period 1 was spent developing the technology for processing both the tomography and reflective data.

In Budget Period 2 further improvements were made in the processing, particularly the reflective data, but the majority of the effort was spent on interpretation of the processed data. This effort resulted in the construction of profiles that depict the distribution of rock type, porosity and permeability along survey lines that tied into well log and surface 3D seismic data. These realizations were used to derive spatial geostatistics that were combined with hard data to create porosity and permeability maps which were integrated into the 3D reservoir model. The first interwell seismic monitoring survey was planned and successfully executed over five of the original Phase 1 survey lines and one new line in the southern pattern. The data were processed and interpreted, utilizing velocity differences between baseline and monitor data to image the CO_2 invasion along two survey lines.

During the current reporting period work continued on imaging the CO_2 saturated area and a second monitor survey was conducted over the southern pattern. After processing and interpretation, the new monitor data allowed the advance of the CO_2 saturation to be imaged in terms of relative percentage. The techniques developed in the southern pattern also were applied to the baseline survey data from the northern pattern to create porosity and permeability profiles along survey lines that were integrated into the reservoir volume geostatistically.

Overall, during the reporting period, progress was made in characterizing the reservoir and understanding CO_2 performance through the use of interwell seismic. Because this is a new technology, particularly as it relates to the length of the survey lines, developing the techniques for processing and interpretation the data has extended over the project life to date. Hence, these results have not yet impacted the design of the project and the field demonstration phase. The availability of time and funds will determine if the reservoir characterization developed from the interwell seismic will be fully utilized by the project. Regardless, the database acquired and the techniques developed have advanced the technology and will be available to industry.

DATA ACQUISITION - Beginning on January 29, 2001, the second round of interwell seismic monitor surveys was acquired on six of the same survey lines (south pattern) used for the first monitor survey conducted in December 1999. The data acquisition was completed in February and was of good quality. Since the injection system had been switched back to sweet CO_2 it was not necessary to deploy the 100-ft plus lubricator, which sped up the process considerably.

DATA INTERPRETATION - Previous work had indicated that replacement of original pore fluid by CO_2 in the Welch reservoir results in an apparent change in porosity on the order of two to six percent. This change in apparent porosity is a direct result of an approximate 1,000 fps decrease in compressional wave velocity caused by replacement of original pore fluid by CO_2. After the first monitor survey data were processed in early 2000, ART used the difference between baseline survey porosity and monitor survey apparent porosity to image the CO_2 saturated along the survey lines.

To develop a full 3D model of the CO_2 saturation, it was necessary to first construct a 3D porosity model for the first monitor interwell seismic surveys, using the methodology developed for the baseline survey porosity model. This involved using the spatial statistics derived from the interwell seismic porosity profile created for each survey line to integrate the interwell porosity data into the reservoir volume . The 3D model of the injected CO_2 saturation was computed as the difference between the two porosity models with the results converted to Vest files for use on a seismic interpretation workstation. Figure 5 shows a perspective view of the 3D CO_2 saturation model. The injector 4811 is shown in dark gray, with surrounding wells shown in light gray. The X-Y axis is laid out in a 200 ft x 200 ft grid. The vertical axis represents formation thickness with the CO_2-invaded area shown by five-foot contours of varying shades of grey. Hence, the maximum CO_2 thickness mapped is 30'.

The shear and compressional interwell seismic data from the second monitor survey were processed to derive detailed apparent porosity distributions for each survey line. The apparent porosity difference between two surveys along the same line shows in two dimensions exactly where the saturation changes have occurred. This is illustrated along the line from the source well 4852 to 4843 by Figure 2, which is the difference between the baseline survey and the first monitor survey, and by Figure 3, which is the difference between the first and second monitor surveys. Injector 4811 is located at the left axis and producer 4843 at the right axis. The darker grey is the CO_2-saturated reservoir. Note that CO_2 movement between the two monitor surveys occurred in the bottom of the reservoir. Figure 4 is the saturation representation at the time of the second monitor survey, i.e. the sum of Figures 2 and 3.

The estimation of CO_2 saturation directly from the interwell compressional and shear wave tomograms was investigated. There is a nonlinear relationship between change in compressional wave velocity and percent of CO_2 saturation in the pore space that can be modeled theoretically. A technique was developed using a combination of the Biot-Gassman equations together with Woods equation (Table 1), which allows an estimate of the compressibility for a mixture of two fluids based on compressibility and relative saturations of each. To date ART has been unable to establish a method for calibrating CO_2 saturations in the Welch study area. The results can only be scaled as estimated relative saturation based on the highest indicated saturation being designated as 100%. The main benefit of estimates of absolute saturation would be for comparison to time equivalent CO_2 saturations generated by the simulator, allowing further calibration of the reservoir model. The relative saturation estimates, however, provide useful information in understanding current performance in the CO_2 focus area.

Work was also begun during the third quarter of 2000 to develop the porosity and permeability models for the north interwell seismic pattern based on the interwell baseline seismic surveys acquired as part of the Phase 1 program. The goal was to produce integrated 3D reservoir porosity and permeability models of the entire study area. The interwell data sets acquired by the baseline survey in the northern pattern were converted to porosity and permeability cross-sections using the methodology developed for the southern pattern. These cross-sections were used to estimate spatial statistics and to generate variograms for porosity and permeability distributions. Spatial geostatistics were developed from these variograms and combined with the geostatistics from the southern pattern variograms to extrapolate interwell porosity and permeability data from the survey lines into the full 3D reservoir volume using kriging. The result was a smooth reservoir model more suitable for geological correlation than reservoir simulation. The smoothness is a function of the kriging being relatively unconstrained by honoring hard data.

Next the spatial geostatistics were distributed into the reservoir volume using cokriging which allowed the neutron log data (porosity) to be honored, further constraining the kriging. For simulation purposes it is desirable to create a reservoir model that honors the hard and soft data while maximally randomizing the results. There are numerous procedures for doing this. Conditional simulation was used to produce the final reservoir model that honored all the well data. However, this was done without input from the reservoir engineers involved in the project who would undoubtably had added additional data controls, further constraining the randomization process. A sample north-south cross-section from the integrated porosity model is shown in Figure 6. This cross-section runs through the north observation well (7916) and passes near the south observation well (4852). The blockiness of the image results from the fact that the data have been partitioned into bins (voxels, or cells) which measure 50 feet laterally and 1 foot vertically for the purpose of reservoir simulation.

3D SEISMIC INTEGRATION

No activities involving 3D surface seismic were undertaken during the annual reporting period.

NUMERIC SIMULATION

The latest version of the reservoir model that had been enhanced by integration of the surface 3D seismic data and used for performance forecasts in Budget Period 1 was retrieved from storage and tested in the MORE compositional simulator. The model was found to be operational. Some work was done on updating the database for performance and revising the model actual injection pattern. The validity of the model will need to be rechecked by performing an updated history match before running any performance forecasts. The modeling requirements have been developed. Several future scenarios will be modeled, including various slug sizes, different WAG schedules and stopping CO_2 injection in September 2001 when the project terminates.

FIELD DEMONSTRATION PHASE

AREA PREPARATION AND CONSTRUCTION - There has been no construction or installation work in the project area during the annual reporting period

HORIZONTAL DRILLING - The slow reservoir process rate that is being experienced was recognized initially as one of the problems that had to be overcome to economically CO_2 flood a marginal reservoir. Industry's usual approach to increasing reservoir throughput has been infill drilling, which is usually not economical in a marginal reservoir. The OXY West Welch Unit DOE project proposed to increase throughput, i.e. CO_2 injection, by optimizing injection well fracture treatment design to create an extended fracture wing without going out of zone. Years of injecting water in the West Welch Unit above the parting pressure had demonstrated the formation's preference for induced fracture orientation in a general east-west direction. ENE-WSW line drive injection patterns were being utilized at West Welch for this reason. If east-west oriented fracture wings of extended length could be established along a row of injectors on 40-ac spacing, the increase in injectivity and sweep that are normally obtained through infill drilling could be achieved at a much lower cost.

During Budget Period 1 a considerable effort was spent on rock mechanics studies and related investigations to help construct an induced fracture model for use in a simulator to design the optimum fracture treatments required. The WWU4807 injector was fracture-treated with the model -esigned treatment[2]. Passive seismic techniques were used to map the fracture wing locations. With the continuation of water injection into the treated well, the results looked favorable in terms of increased injectivity and sweep while containing the fracture growth within the zone. However, 11 months after CO_2 injection started, gas breakthrough occurred in two producers located two locations northeast from the WWU4807 injector, but not in the direct east and northeast offset producers. Also, the casing annulus of the WWU4816 injector two locations north of WWU4807 began to pressure up although the producer located between the two injectors showed no response. The source of the CO_2 that caused the annulus pressure in WWU4816 was traced directly to WWU4807 because of the nitrogen content which could only come from the special fracture treatment. It was concluded that frac wings of the desired length could not be obtained without extending the fracture vertically out of zone, which is not acceptable in a CO_2 flood.

A horizontal lateral would also have the potential of increasing sweep and throughput in both a producer or injector at a lower cost than vertical infill drilling. Various operators in the Permian Basin have drilled horizontal laterals both as producers and injectors in several San Andres waterfloods and miscible CO_2 projects. Not much in the way of definitive results has been published. Apparently the success of horizontal laterals in improved oil recovery projects has varied greatly. The fact that drilling horizontal laterals is not yet a widespread practice in the hundreds of Permian Age carbonate reservoirs that are under secondary and/or tertiary recovery in the Permian Basin suggests that the overall results have been questionable. This is understandable in view of the stratification in Permian carbonates that restrict vertical drainage. Also the relatively low permeability (0.1-5.0 md) is a problem since it is difficult to achieve an efficient completion in a horizontal lateral.

Horizontal completion technology has been advancing rapidly. Halliburton Energy Services has developed a completion technique called "Surgi-frac" that is designed to initiate, extend and prop a fracture at multiple locations along an uncased lateral without the use of any pack off elements. OXY tried it with success on a short horizontal lateral in a West Welch producer outside the DOE Demonstration Area that was treated with acid instead of a sand fracture treatment. The decision was made to re-enter WWU4853 located in the south expansion of the DOE Demonstration Area and drill a horizontal lateral due north the entire width of the current CO_2 focus area (Figure 7). The more conventional application of horizontal laterals in an injection project would be to replace or extend a row of vertical producers or injectors, which at West Welch would require east-west laterals. However, due to the short remaining life of the demonstration project, a north-south lateral was judged to have the best chance to have a near term impact on project economics by penetrating unswept areas of oil saturation.

The lateral was designed to intercept two rows of injectors midway between wells. Since the permeability of the pay zone is relatively low and nearly all newly drilled wells require fracture simulation before producing any appreciable volume of fluid, selective completion in the open hole lateral should avoid direct communication with the injectors. This situation would be attained if the Surgi-frac technology could efficiently complete selective intervals opposite the producer rows. A successful lateral would greatly increase the withdrawals and sweeps currently being achieved by the two vertical producers (Nos. 4828 and 4829) that would be replaced.

The re-entry was started on October 16, 2000. A medium radius turn (217 ft) was made out of the casing at 4782 ft and the lateral drilled to a measured depth of 8410 ft (4897 ft TVD) by November 18, 2000 as detailed on Table 2, the daily activity log covering the drilling and completion operations.. The CO_2 injectors were shut in as the lateral wellbore approached them. The bottom hole location of the lateral at TD was 3500.5 ft N 12.1° W from the surface location. The proposed and actual (surveyed) wellbore path is shown by Figure 8. The wellbore path penetrated the main pay interval (M-3) for most of its length (Figure 9). Since the lateral was going updip to the north, it was necessary to incline the second half of the well path to stay in the main pay zone and out of the water -earing lower zone.

The Halliburton Surgi-frac tool was to be used to initiate, extend and prop a radial fracture at preselected intervals (stages). The Surgi-frac technique pumps sand slurry down the tubing and out jets oriented to the plane of minimum stress, allowing the hydraulic horsepower to be focused at one point. The formation is notched by erosion and at the point of impact the kinetic energy of the jetted stream is converted to pressure. When this "stagnation" pressure is slightly greater than the ambient pressure a fracture is initiated. The fracture is propagated and propped open by continuing to pump the sand slurry down the tubing. The jetting action creates an area of low pressure at the mouth of the fracture due to the Bernoulli effect. Fluid is pumped down the back side to maintain pressure in the wellbore. In theory all of the fluid and sand is drawn into fracture by the low pressure zone and there is no leak off into other fractures.

This procedure is designed to allow multiple fractures to be created at selected points without the use of pack-off elements, which greatly lowers the mechanical risk in a horizontal lateral. Otherwise, fracturing in an open hole lateral is a random affair where a single fracture is created usually in the heel. Horizontal drilling has had only limited success in the vertically stratified Permian Age carbonate reservoirs (San Andres and Clear Fork) of the Permian Basin for two primary reasons. Nearly all San Andres and Clear Fork vertical completions require an acid or sand frac treatment to get beyond the wellbore damage and enhance the normal low permeability. Secondly, the stratified pay intervals limit the vertical drainage of the horizontal wellbore to a few feet. A technique such as the Surgi-frac, if successful, would overcome both of these problems.

Six intervals along the lateral (8385 ft, 7850 ft, 7250 ft, 6520 ft, 5900 ft and 5300 ft MD) were chosen for Surgi-frac completion and spaced so that no completion would be in line with either of the two rows of injectors that had been intersected. A summary of the initial Surgi-frac completion attempt on November 29, 2000 is given on Table 3. The first of six planned treatment intervals was near the toe of the lateral at 8385 ft (MD). After notching and initiating the fracture, 19,285 lbs of proppant and 19,714 gals of gelled water were pumped away at 18 BPM. The formation broke down at a bottom hole pressure (BHP) of 4250 psi and treated around 4000 psi (Figure 10). The maximum tubing pressure was 8500 psi, but tubing pressure is not a good indicator of bottom hole performance because of the large pressure loss due to friction and the pressure drop across the jets. The treatment at this interval appears to have successfully initiated and propagated a fracture as indicated by the BHP, which built nearly straight up at the start and then broke over sharply as the formation broke down.

Unfortunately, toward the end of the treatment one of the jets washed out as indicated by the drop-off in tubing pressure. The Surgi-frac tool was repositioned and the second and third intervals were treated. The tubing pressure was much lower at the same pump rate (18 BPM) due to the elimination of pressure drop across the jets and the BHP did not show the sharp breakover caused by the formation parting. Only shallow erosion of the wellbore probably occurred at the second and third intervals and the sand slurry flowed toward the initial fracture in the toe of the lateral at 8385 ft (MD). Sand fill occurred from 8051 ft to 8410 ft (MD) The proppant had been tagged with radioactive material, but a tracer log run 12/07/00 failed to give any definitive interpretation (Figure 11). The well was placed on rod pump 12/25/00 and achieved a maximum oil rate of 41 BOPD and 610 BWPD with 1206 MCF of gas (CO_2). The CO_2 breakthrough had occurred immediately upon producing the well. In the second half of January it was necessary to cut back on CO_2 injection to reduce the gas volume being produced in WWU4853. A severe scale problem was discovered in late January when pulling the production tubing.

The second Surgi-frac completion attempt was conducted 1/25/01 starting with the second interval from the toe at 7246 ft (MD). As shown on Table 4, the five remaining intervals were treated with an average of 15,900 gals of gelled water and 22,200 lbs of proppant at rates varying from 14.8 to 17.5 BPM. The BHP performance (Figure 12) shows that the first two intervals broke back sharply, indicating that a fracture had been initiated and propagated. For the remaining three intervals, the BHP broke over sharply to a fairly constant treating pressure but did not break back to a lower pressure as often occurs when the formation is parted. While the tracer log (Figure 13) again failed to give any definitive answer as to the placement of proppant, a majority of the tracer activity was at the end of the lateral, implying that most of the stimulation went toward the toe. However, pressure performance suggests that the second and third intervals were treated and it is possible that the other three were also.

Sand and scale were reversed out from 7759 ft to TD at 8410 ft (MD). After treating the well for scale, an electrical submergible pump was run in the vertical hole and the well placed on production 2/8/01. The first reported test was 0 BOPD and 1271 BWPD with 131 MCF of gas on 2/15/01. The well was shut down in late March and has produced only sporadically since as discussed in the Operations and Performance section of this report. Due to the scale problem and the breakthrough of CO_2, it is impossible to judge the effectiveness of the second Surgi-frac completion attempt based on well tests.

OPERATIONS AND PERFORMANCE - The average monthly performance during the reporting period for the CO_2 focus area is summarized on Table 5 and the producing and injection rates are shown as a function of time on Figure 14. The production from the WWU4853 horizontal lateral has not been included in the focus area statistics because it would distort the trends and some of the well's data is of questionable accuracy. Through July 2001 a total of 3.8 BCF of CO_2 had been injected into the focus area and 4.8 BCF into the total project area since initiation of injection in October 1997. CO_2 injection averaged only 2.6 MMCF for the reporting period due to some of the injectors being shut in or restricted from November 2000 through February 2001 because of the horizontal lateral drilling and the second interwell seismic monitor survey acquisition. Oil production averaged 176 BOPD compared to the baseline rate of 131 BOPD indicating a 45 BOPD increase due to CO_2 injection. As of July 31, 2001, three producers had experienced an increased oil rate response to CO_2 injection and six wells had experienced gas (CO_2) breakthrough.

The four injectors offsetting the 4853 horizontal wellbore path were either shut in or the injection rate cut back in November and December 2000 as the lateral approached them. In January and early February 2001 some of the injectors were temporarily shut in to facilitate the acquisition of the second interwell seismic monitor survey. Because of the large volume of CO_2 being produced out of the WWU4853 horizonal lateral the injection rate continued to be restricted in some of the offsetting injectors through January and February 2001 into early March.

The rate at which the hydrocarbon pore volume in the focus area is being processed continues to be a concern. At the beginning of the reporting period, the DOE approved a no fund 12-month extension of the project to 9/30/01 so more of the reservoir could be processed, allowing a fuller evaluation of the process. Due to the reduction in the CO_2 injection rate only 3.2 % of the hydrocarbon pore volume (HCPV) within the focus area was processed during the 12-month reporting period. Once all the injectors were restored to their maximum injection rates, a processing rate of 4.8% HCPV per annum was achieved in May and June 2001. Priority has been given to increasing the CO_2 injection rate even higher, consistent with prudent operating practices, so the focus area can be fairly evaluated within the remaining life of the project.

Bottom hole pressure surveys were run in five of the CO_2 injectors. Injector WWU4805 was on water injection to control gas breakthrough in an offset producer at the time of the survey but was wagged back to CO_2 injection in March 2001. The survey results indicated that the bottom hole pressure in all five wells was close to the parting pressure calculated several years ago, so CO_2 rates couldn't be increased by simply increasing the injection pressure. However, even in the larger gas producing wells GORs are not high compared to mature CO_2 projects in the San Andres formation. The operating personnel began developing the techniques for operating high GOR wells so it wouldn't be necessary to cut back on the CO_2 input rate to reduce gas volume. Since sufficient funds exist to allow CO_2 to be purchased for some months past the 9/30/01 termination date, another no fund extension will be requested to extend the termination date to 3/31/02. Injectivity profile surveys have been scheduled for all six injectors during the third quarter of 2001 in an effort to improve injector efficiency. The performance of the individual injectors is shown on Figures 15-20.

The horizontal lateral was drilled due north from the WWU4853 wellbore with the well path passing midway between two sets of CO_2 injectors - WWU4810-4806 and WWU4809-4811. Initial well tests indicated a good oil rate, which was immediately overwhelmed by the breakthrough of CO_2 into the wellbore. WWU4853 was shut in during March 2001 because of problems that reduced the gas plant capacity. The gas breakthrough into the lateral was initially thought to be coming from a gas-saturated area near the toe of the lateral as opposed to a direct channel with an injector. As discussed in the Horizontal Lateral Section, there is some evidence that most of the Surgi-frac treatments went into the initial fracture interval near the toe of the lateral, possibly creating an extended frac wing just north of the WWU4809 and WWU4811injectors. The gas producing capacity of WWU4853 (greater than 1.4 MMCFPD) is about twice as large as the individual average injection rate for any of the four injectors offsetting the lateral. A direct channel between an injector and the lateral should be evidenced by a significant change in the injection pressure as the lateral was shut in or opened up and this has not been observed in any of the four injectors.

A pressure falloff test was conducted on injector WWU4810 in an effort to determine if it was in direct communication with the WWU4853 lateral. Two hundred thirteen (213) hours into the test WWU4853 was opened for two hours. A pressure transient analysis of the data using curve matching techniques shows that the slope of the pressure derivative changes between 220 and 230 hours into the test (Figure 23). This indicates that WWU4810 is in communication with the lateral. What this means in quantitative terms is not known, but neither the injection pressure performance or the pressure falloff data suggest a direct channel. In view of the large volume of CO_2 that WWU4853 is capable of producing, other injectors are undoubtedly contributing CO_2 also. The lateral has also communicated with one of the two producers near to the lateral well path, resulting in WWU4829 being shut in due to high gas (CO_2) production. After being shut down in March 2001 due to gas plant capacity WWU4853 was only produced in June 2001 for the remainder of the reporting period.

Remedial operations were conducted on two producers, WWU4842 and WWU4846, in May 2001 to remove any "skin" damage around the wellbore. The basic procedure was to jet wash the perforation and treat the wells with scale converter and 4000 gal acid. The initial production increases were on the order of 15 to 20 bopd for each wells, but had declined by the end of the reporting period. The most recent test data showed a 5 BOPD increase for WWU4842 and a 7 BOPD increase for WWU4846. The gas volume increased several fold, particularly on WWU4842. These two wells were selected for remedial work because they were two of only three out of nine direct offsets to the six CO_2 injectors that hadn't experienced increased gas (CO_2) and/or oil production. It definitely appears that gas breakthrough has occurred on WWU4842 and is possibly starting to occur on WWU4846. The performance of both wells will have to be studied for a longer period of time to determine if oil production in either well is responding to CO_2 injection.

Producer WWU4827 was entered in April 2001 to repair a tubing leak. The well was also treated for scale and acidized with 3000 gal. Larger sucker rods were installed to increase the lift capacity. The well went from 6 BOPD and 33 BWPD to 0 BOPD and 350 BWPD. Apparently the earlier plugback from a lower zone failed during the remedial operations, allowing bottom water to encroach up the wellbore.

Determining when response to CO_2 occurs in a producer is not an exact science in a reservoir with the injection and withdrawal history of West Welch. The classic response of a producer to CO_2 injection is a lowering of water production and increase in gas (mainly CO_2) as the miscible front encroaches into the well's drainage area followed by increased oil rate as the front approaches the wellbore. Several variations to this pattern have occurred in the demonstration area as wells are influenced not only by changes in CO_2 injection rates, i.e. pinching back or wagging, but also the changes in what was the established waterflood injection pattern and resulting reservoir pressure distribution. Certainly the large decrease in CO_2 injection that occurred for four months in this reporting period further complicates the problem of determining response. Obtaining frequent and valid well tests for performance monitoring and the accurate allocation of production has been an ongoing problem. The testing problem has been continually improved and the allocated production database periodically corrected. Prior to the initiation of CO_2 injection a composite baseline oil decline projection was established in the demonstration area for the existing waterflood. This approach has some validity in measuring the composite oil response to CO_2 injection over a long period of time, but is of little use in identifying the onset of oil response in individual wells.

The magnitude of the problem is illustrated by the fact that as of August 3, 2000 the reported data indicated that three wells had significant oil rate response to CO_2 injection and 10 wells had experienced gas (CO_2) breakthrough. Analysis of performance during the reporting period showed that one of the oil responses and four of the gas breakthrough interpretations were not valid. The only significant change in well performance due to CO_2 injection during the reporting period was a sustained oil increase in WWU4850. This well responded in the classic manner of a well in the path of an approaching miscible oil bank with an initial decrease in water production followed by an increase in gas before the oil response. The individual producing well performance curves are shown by Figures 22-42. By August 2, 2001 a total of three wells were responding to the miscible flood with significant oil rate increases. All three are direct north and/or south offsets to injectors. Interestingly only one of these wells (WWU4847) has full time CO_2 injectors to both the north and south. Injector WWU4844 has a full time injector to the north, but the south injector has been on water injection more than it has been on CO_2. Injector WWU4850 is located on the south boundary of the focus area and there is no row of injectors below it. Well response status is shown by Figure 43. The limited oil response to date is very likely a function of the limited amount of reservoir that has been processed by the CO_2.

TECHNOLOGY TRANSFER

Technology transfer during the reporting period included a presentation entitled "Interwell Seismic for CO_2 Monitoring in a DOE Class II Oil Project", presented at the annual meeting of the SEG in Calgary, Alberta Canada by Jim Justice. In addition, an article entitled "Interwell Seismic Imaging Aids in EOR Design and Monitoring" appeared in *Inside Tech Transfer,* published by the Department of Energy's National Petroleum Technology Office. This latter publication was distributed by the DOE at the annual SPE meeting in Dallas, Texas.

REFERENCES

1. "Application of Reservoir Characterization and Advanced Technology to Improve Recovery and Economics in a Lower Quality Shallow Shelf San Andres Reservoir," annual report 8-3-1998 through 8-2-2000, DOE Award No. DE-FC22-94BC14990, OXY USA Inc., Midland (Jan. 2002)

2. "Application of Reservoir Characterization and Advanced Technology to Improve Recovery and Economics in a Lower Quality Shallow Shelf San Andres Reservoir," annual report 8-3-1997 through 8-2-1998, DOE Award No. DE-FC22-94BC14990, OXY USA Inc., Midland (Jan. 2001)

Table 1

EFFECTS OF PORE FLUID COMPRESSIBILITY ON SEISMIC VELOCITY

<u>Biot-Gassman Model</u>

Rock = Frame (m) + Pore-Filling Fluid (f) + Solid Grains (g)

<u>Biot-Gassman Equations</u>

$$PV_s^2 = G_m$$

$$PV_\rho^2 = \underbrace{K_m + \frac{4}{3}G_m}_{\text{"pores"}} + \underbrace{\frac{\left(1 - \frac{K_m}{K_g}\right)^2}{\left(1 - \Phi - \frac{K_m}{K_g}\right)\frac{1}{K_g} + \frac{\Phi}{K_f}}}_{\text{"frame"}}$$

<u>Terms</u>

Φ = porosity

P = rock density

K = bulk modulus

G = shear modulus

V = velocity

S = fluid saturation

<u>Woods Equation</u>

$$\frac{1}{K_f} = \frac{S_{f1}}{K_{f1}} + \frac{1 - S_{f1}}{K_{f2}}$$

<u>Subscripts</u>

m = frame

f = pore filling fluid

g = solid grains

s = shear

ρ = compressional

TABLE 2
DRILLING AND COMPLETION ACTIVITY LOG
HORIZONTAL LATERAL—WWU NO. 4853
WELCH FIELD
DAWSON CO., TX

I. ORIGINAL VERTICAL WELL

1. Spudded 3/17/97
2. Drilled to TD 5050'
3. Set 5 ½ in csg @ 5050' Circulated cement to surface.
4. Perforated San Andres 4925-55' and 4973-79'
5. Acidized w/3000 gal HCL
6. Fraced 13,000# sand
7. Initial Potential 6/13/97: 47 BOPD; 310 BWPD; Gas tstm

II. HORIZONTIAL LATERAL

10/16/00

1. POOH with rods & tbg
2. Picked up 5 ½ in. csg scraper, RIH to TD
3. POOH
4. Set CIBP on wireline at 4795'
5. Pressure tested csg to 2000 psi

11/04/00

1. RIH w/ Baker Hughes whipstock and 4 3/4 in. starter mill.
2. Set whipstock at 4782' with 344 ° azimuth (az) orientation.

11/05/00

1. Milled 18 inches of 5 ½ csg
2. Circulated hole clean
3. RIH with 4 3/4 in. window mill and 4 3/4 in. watermelon mill
4. Completed milling window in 5 ½ csg
5. POOH and laid down mills
6. RIH with 4 3/4 in. Hughes Star 30 button bit, downhole motors and MWD steering tool.
7. Gyro oriented downhole assembly into window
8. Started drilling curve

11/06/00

1. Continued to drill curve. Became increasingly difficult to build angle. Appeared that whipstock rotated to right during milling operation. Well path was 7.4 ° az v. the 344° az target.
2. Installed motor assemble with bent sub angle. Finish drilling curve at 4999' with 348 ° az and 88 ° inclination (incline).
3. POOH with curve building assemble.

11/07/00

1. RIH with lateral drilling assembly.
2. Drilled lateral from 4999' to 5081' MD. (82' in 24 hrs)
3. Directional survey confirmed correct whipstock slide orientation at 342° az. (well path in top of curve had walked to the right before being corrected back to target)

11/08/00

1. Drilled lateral from 5081' to 5140'MD.
2. Drilling rate slowed. Pull bit and found inserts dislodged.
3. RIH with Hughes ST-382 rock bit and lateral drilling assemble.
4. Drilled lateral to 5832' MD. (692' in 24 hrs)

5. Well path at 5821' MD (4942' TVD) was 348° az and 91.8° incline.

11/09/00

1. Drilled lateral from 5832' to 6196' MD.
2. Changed bit.
3. Drilled lateral to 6235' MD. (403' in 24 hrs)

11/10/00

1. Drilled lateral to 6693' MD. (458' in 24 hrs)
2. Average fluid loss at 17 BPH.
3. Well path at 6628' MD (4941' TVD) was 350° az and 91.3° incline.

11/11/00

1. Drilled lateral to 6698' MD. (405' in 24 hrs)
2. Average fluid loss was 13 BPH.
3. Well path at 7030' MD (4930' TVD) was 345° az and 91.5° incline.

11/12/00

1. Drilled lateral to 7155'.
2. POOH to change bit and repair downhole motor.
3. Drilled lateral to 7480' MD. (325' in 24 hrs)
4. Well path at 7433' MD (4921' TVD) was 348° az and 92.6° incline.

11/13/00

1. Drilled lateral to 8053' MD. (573' in 24 hrs)
2. No fluid loss.
3. Well path at 8000' MD (4905' TVD) was 346° az and and 91.1° incline.

11/14/00

1. Drilled lateral to final TD of 8410' MD (4897' TVD).
2. Well path at TD was 345° az and 89.9° incline.
3. Circulated hole clean.
4. POOH with bottom hole assembly.
5. Well flowed while rigging down.

11/19/00

1. S/I pressure 110 psi.

11/20/00

1. MIRU well service unit for completion.

11/22/00

1. Logged lateral with Halliburton Well Service.

11/28/00

1. RIH with pressure bombs and Halliburton's Surgi-frac tool. Planned to fracture lateral in separate treatments at six different intervals in the San Andres.

11/30/00

1. Started frac treatment.
2. Toward end of first treatment unexpected pressure drop occurred.
3. After treating the second and third intervals at abnormally low pressures, aborted job and pulled up out of lateral.

12/01/00

1. POOH
2. Surgi-frac tool jet was washed out. Sent to Halliburton lab for exam.

12/04/00

1. RIH with tbg and bit.
2. Tagged fill at 8051'. TD is 8410'. (359' of fill)
3. Pulled up out of lateral.

12/05/00

1. Ran bit and tbg back in lateral,
2. Worked through sand bridge at 6785'.
3. Wash sand fill from 8088' to TD at 8410'.

12/06/00

1. POOH
2. RIH with Halliburton logging tool.

12/06/00

1. Logged lateral coming out of hole.

12/14/00

1. RIH with 2 7/8 in. tbg.

12/15/00

1. RIH with rods and pump.

12/16/00

1. Set pumping unit.

12/17/00

1. Connected electric power.

12/25/00

1. Well pumped/flowed 0 BOPD and 488 BWPD, gas not measured.

12/27/00

1. Well pumped/flowed 30 BOPD, 565 BWPD and 1306 MCFPD (GOR 2.3 MCF/BBL).

12/28/00– 1/21/01

1. Well on production (see Table 3).

1/22/01

1. Kill well with brine.
2. POOH w/rods and pump.

1/23/01

1. POOH w/ tubing.
2. RIH w/2-7/8 work string.
3. Tagged up @ 7434' (TD 8410'). Unable to circulate.

1/24/01

1. Reversed out scale from 7434- 8019'.
2. POOH w/ tbg.
3. RIH w/ pressure gauge and bottomhole Surgi-frac assemble.

1/25/01

1. Initiate Surgi-frac in five stages from 7850- 5298 ft(MD).
2. PUH to vertical section.

1/26/01

1. Opened well, flowed 70 bbl to tank.
2. POOH w/ tbg and tools.
3. RIH w/ 4 3/4 bit, jet sub and tbg.

1/27/01

1. Reversed out sand from 7759- 8019' and scale from 8019 - 8116'.
2. PUH to vertical section.

1/28-30/01

1. Shut down.

1/31/01

1. RIH TO 8116'.
2. Reversed out sand and scale from 8116 - 8410'.
3. POOH to vertical section.

2/01/01

1. Killed well with brine.
2. POOH w/ tbg.
3. RIH w/ radioactive logging tool and tbg to 8410'.
4. POOH logging.

2/02/01

1. RIH w/ tbg.
2. Pumped scale converter.

2/03/01

1. Swabbed 90 bbl.
2. Acidized w/ 3500 gal 20% CCA.
3. Flowed and swabbed back 100 bbl.

2/04-05/01

1. Shut down.

2/06/01

1. Pumped scale squeeze.

2/07/01

1. Killed well w/ brine.
2. POOH w/ tbg.

2/08/01

1. RIH w/ Reda pump and 2-3/8 tbg.
2. Started pump.
3. Final report.

Table 3

Treatment Summary
Initial Attempt 11/29/00
OXY-WWU 4853

Treatment Depth (md)	Stage	Fluid Volume (gal)	Prop in Formation (lb)	Average Concentration (lb/gal)	Rate (bbl/min)	Max. Surface Treating Pressure (psi)
8385'	4	9,968	1,888	0.30	18	8508
	5	2,001	141	1.03	18	7724
	6	2,005	2,225	2.01	18	7432
	7	2,028	4,403	3.01	18	7034
	8	1,727	5,213	3.00	18	6219
	9	1,985	5,415		18	6404
	Subtotal	19,714	19,285			
7850'	12	9,990	1,125	0.16	18	5905
	13	1,985	414	1.12	18	5639
	14	1,995	2,593	2.08	18	5524
	15	1,992	4,635	3.07	18	5580
	16	2,290	7,648	3.38	18	5787
	17	1,903	5,235		18	5835
	Subtotal	20,155	21,650			
7250'	20	9,974	1,584	0.20	18	5907
	21	1,993	495	1.13	18	5644
	22	1,996	2,703	2.06	18	5453
	23	1,785	3,780	2.89	18	5417
	24	1,042	2,704	2.53	18	4681
	25	1,726	4,106		18	5381
	Subtotal	18,516	15,372			
	Grand Total	58,385	56,307			

Notes:
1 Proppant for initial stage at each interval was 20/40 Sintered Bauxite
2 Proppant for subsequent stages was 20/40 resin-coated sand
3 Fluid is cross link gelled water (Deltafrac)

Table 4

Treatment Summary
Second Attempt 1/25/01
OXY-WWU 4853

Treatment Depth (md)	Stage	Fluid Volume (gal)	Prop in Formation (lb)	Concentration (lb/gal)	Rate (bbl/min)	Surface Treating Pressure (psi)
7850'	3	10,004	452	0.1	13.5	8044
	4	2,000	1,844	0.1-1.6	15.4	8563
	5	2,000	3,657	1.7-2.4	15.4	8593
	6	2,000	5,960	2.5-4.0	14.8	8795
	7	3,220	10,648	4.0-0.3	15.3	8883
	Subtotal	19,224	22,561			
7246'	10	8,650	2,076	0.4-1.7	15.9	8415
	11	2,100	4,184	1.7-2.7	15.8	8308
	12	2,150	6,429	2.8-4.3	16.0	8204
	13	2,145	3,918	4.3-0.8	15.8	8784
	14	1,520	57	0.4	14.9	8716
	Subtotal	16,565	16,664			
6525'	16	2,046	1,565	0.0-2.2	15.0	7139
	17	8,750	4,214	2.3-3.1	16.2	7829
	18	1,298	6,546	3.2-4.4	17.2	7731
	19	1,567	8,287	4.4-1.3	17.3	8063
	20	1,662	961	0.9-0.5	17.5	8431
	Subtotal	15,323	21,573			
5906'	23	2,019	1,766	0.6-2.3	14.9	7137
	24	8,250	3,982	2.3-3.4	16.0	7486
	25	1,289	6,079	3.4-3.9	16.3	7239
	26	1,579	13,530	4.0-1.1	16.3	7666
	27	1,672	611	0.7-0.3	16.5	7940
	Subtotal	14,809	25,968			
5299'	30	1,996	1,926	0.8-2.2	15.8	7011
	31	8,580	4,160	2.2-3.0	16.6	7192
	32	1,279	6,296	3.1-5.3	16.8	6976
	33	1,569	11,745	2.4-1.2	16.7	7415
	Subtotal	13,424	24,127			
	Grand Total	79,345	110,893			

Notes:
1 Proppant for initial stage at each interval was 20/40 Sintered Bauxite
2 Proppant for subsequent stages was 20/40 resin-coated sand
3 Fluid is cross link gelled water (Deltafrac)

Table 5

CO2 Focus Area Performance
AUG 2000 THRU JUL 2001
West Welch Unit DOE Project
Dawson County, Texas

		AUG	SEPT	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN	JUL	SUMMARY
Injection														
	Average CO2 injection rate (mcfd)	3115	3158	3112	1025	1622	1211	1390	3101	3216	3624	3969	2709	2604
	# of Injectors on CO2	5	5	5	5	4	4	5	6	6	6	6	5	5.2
	Average rate per injector (mcfd)	623	632	622	205	405	303	278	527	536	604	662	542	495
	% HCPV injected	0.3	0.3	0.3	0.1	0.2	0.3	0.1	0.2	0.3	0.4	0.4	0.3	3.2
	Cum % HCPV injected	10.1	10.4	10.7	10.8	11.0	11.3	11.4	11.6	11.9	12.3	12.7	13.0	13.0
	Average water injection rate (bwpd)	174	181	176	190	193	192	186	0	0	0	0	0	108
	# of Injectors on water	1	1	1	1	1	1	1	0	0	0	0	0	0.6
	Average rate per injector	174	181	176	190	193	192	186	0	0	0	0	0	108
	Water+CO2 % HCPV injected	0.4	0.3	0.4	0.1	0.2	0.2	0.2	0.3	0.3	0.4	0.4	0.3	3.5
	Water+CO2 Cum % HCPV injected	11.0	11.3	11.7	11.8	12.0	12.2	12.4	12.7	13.0	13.4	13.8	14.1	14.1
Production														
	Base oil production (bopd)	135	134	133	132	131	131	130	129	129	128	127	127	131
	Actual oil production (bopd)	181	184	179	176	175	178	180	186	163	164	172	176	176
	Incremental oil production (bopd)	46	50	46	44	44	47	50	57	34	36	45		46
	Gas production (mcfd)	615	702	599	797		348	207		546	589	633	541	558
	Gas production as % injection	20	22	19	78	0	29	15	0	17	16	16	20	21
	Base WOR	13	31	13	13	13	13	13	13	13	13	13	13	
	WOR	4.8	5.1	5.0	5.0	5.1	5.3	5.2	5.1	5.2	4.8	5.1	4.2	5.0

Table 6

Daily Well Test History
OXY-WWU 4853

Test Date	Oil (bbl)	Gas (mcf)	Water (bbl)	Casing Gas	Tubing Gas	Water Cut %	GOR
01/04/01	41	1206	610				
01/05/01	39	1389	572			93.6	35615
01/06/01	38	1335	526	1.4		93.4	35132
01/07/01	39	1396	504			93.0	35795
01/08/01	36	1330	463			92.8	36944
01/09/01	41	1476	481			92.1	36000
01/10/01	35	1483	469			93.0	42371
01/11/01	32	1421	453			93.4	44406
01/12/01	19	1003	363			95.0	52789
01/13/01	23	1323	398	300	1023	94.5	57522
01/14/01	23	1230	380	240	990	94.3	53478
01/15/01	23	969	391			94.4	42130
01/16/01	22	893	375			94.5	40591
01/17/01	10	426	178			94.7	42600
01/18/01	1	159	121			99.2	159000
01/19/01	4	227	209			98.1	56750
01/20/01	3	243	212			98.6	81000
02/15/01	0	131	1271			100.0	
02/16/01	0	67	1294			100.0	
02/17/01	4	40	1103			99.6	10000
02/18/01	0	124	33			100.0	
02/19/01	0	0	0			100.0	
02/21/01	0	70	871			100.0	
02/22/01	2	0	1180			99.8	0
02/23/01	7	248	1069			99.3	35429
02/27/01	2	12	273			99.3	6000
02/28/01	0	110	928			100.0	
03/01/01	0	295	974			100.0	
03/02/01	9	496	861			99.0	55111
03/03/01	9	555	882			99.0	61667
03/04/01	0	495	619			100.0	
03/05/01	10	1044	869			98.9	104400
03/06/01	4	559	867			99.5	139750
03/07/01	10	801	909			98.9	80100
03/10/01	7	456	933			99.3	65143
03/11/01	7	669	1001			99.3	95571
03/12/01	7	464	919			99.2	66286
03/13/01	19	706	981			98.1	37158
03/14/01	8	703	904			99.1	87875
03/15/01	19	674	945			98.0	35474
03/16/01	9	653	922			98.4	72556
03/17/01	9	653	922			99.0	72556
03/18/01	9	693	995			99.1	77000
03/19/01	9	691	992			99.1	76778
03/20/01	17	740	1016			98.4	43529

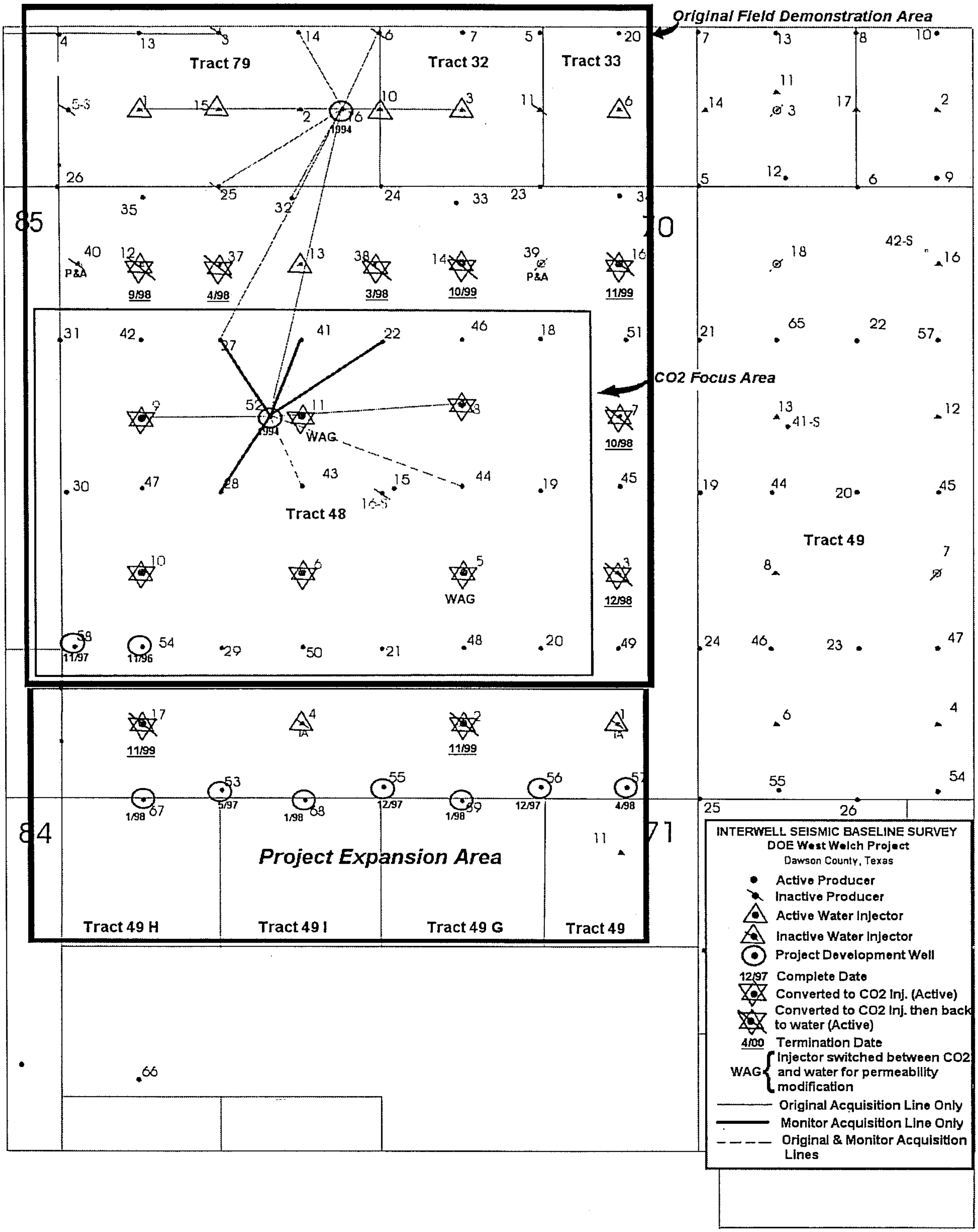


Figure 1 - Interwell Seismic Acquisition Lines

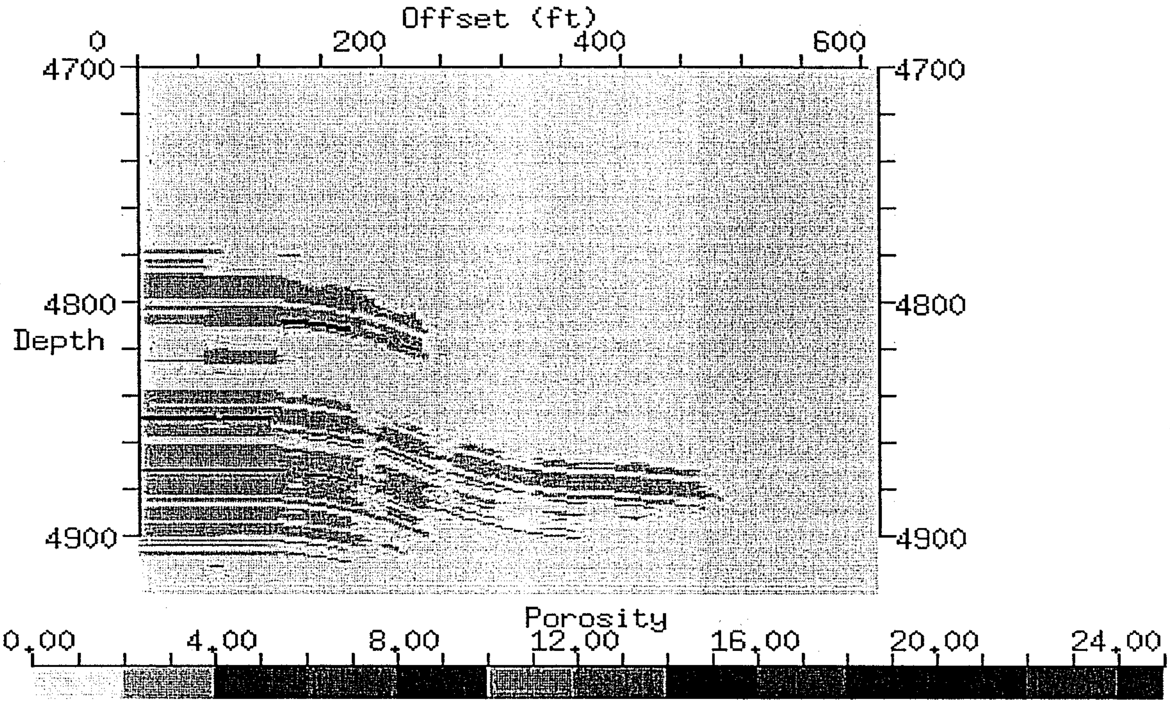


Fig. 2 - Changes in CO2 Saturation Between 3Q94 and 4Q99 Along Survey Line 4852-4843.

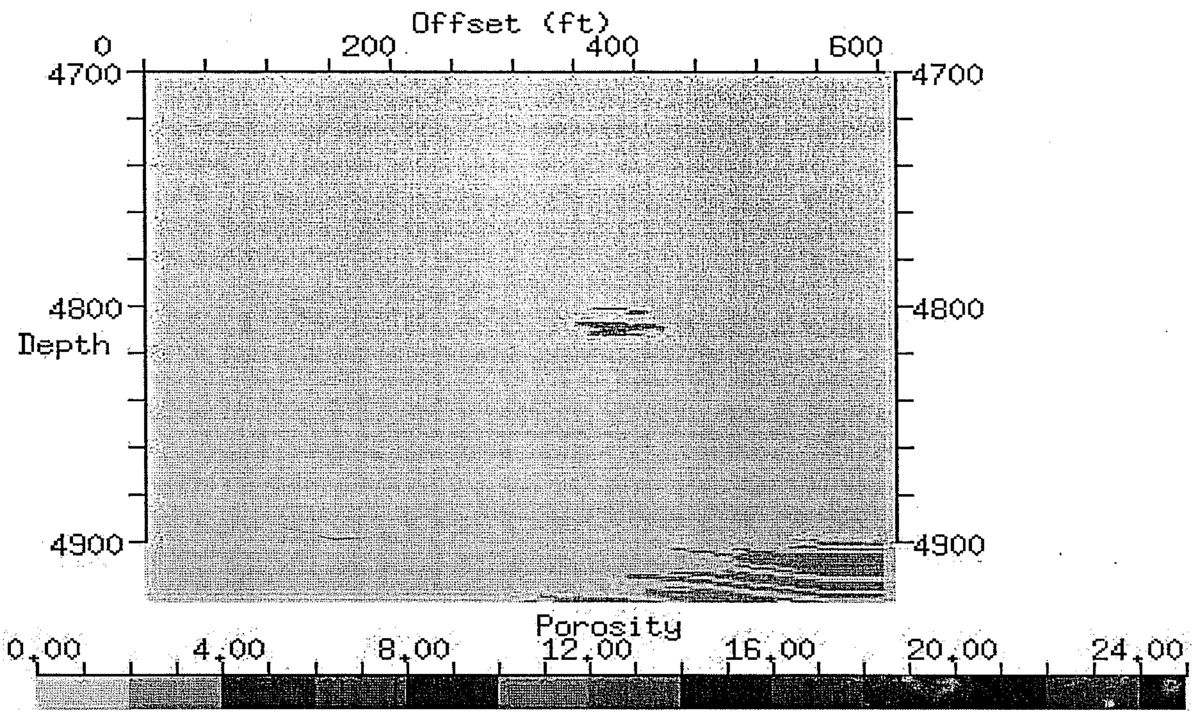


Fig. 3 - Changes in CO2 Saturation Between 4Q99 and 1Q01 Along Survey Line 4852-4843

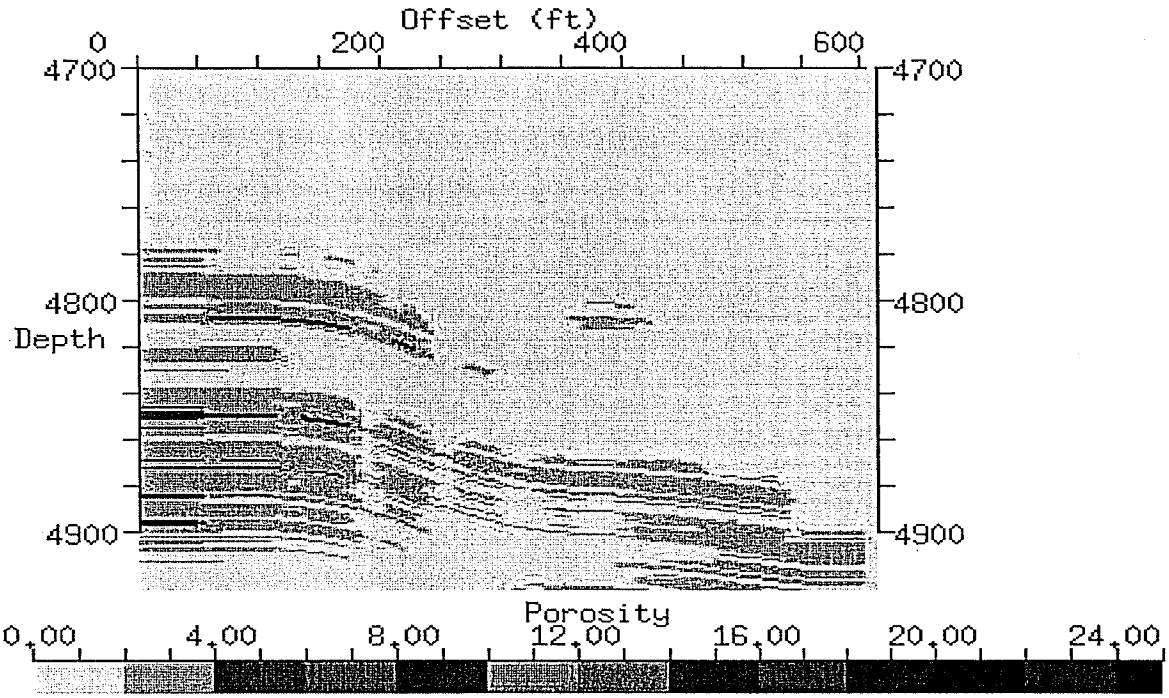


Fig. 4 - CO2 Saturation Representation as of 1Q01 Along Survey Line 4852-4843

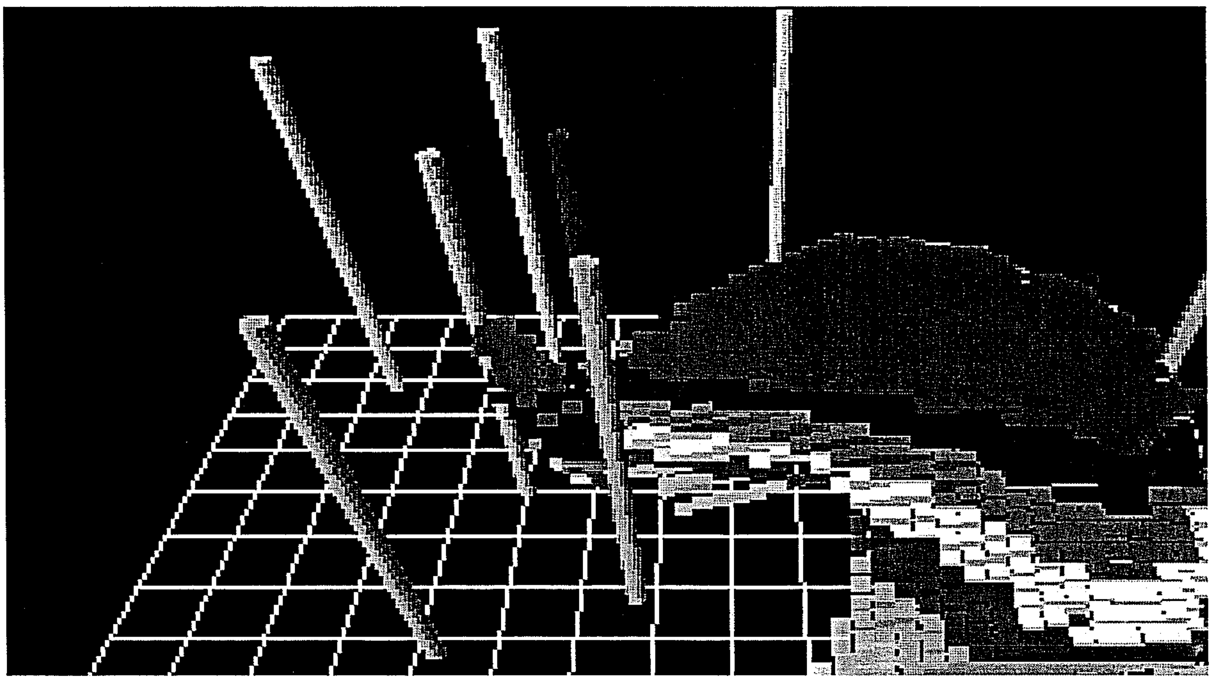


Figure 5 - 3D Perspective of CO2 Invaded Area as of 4Q99

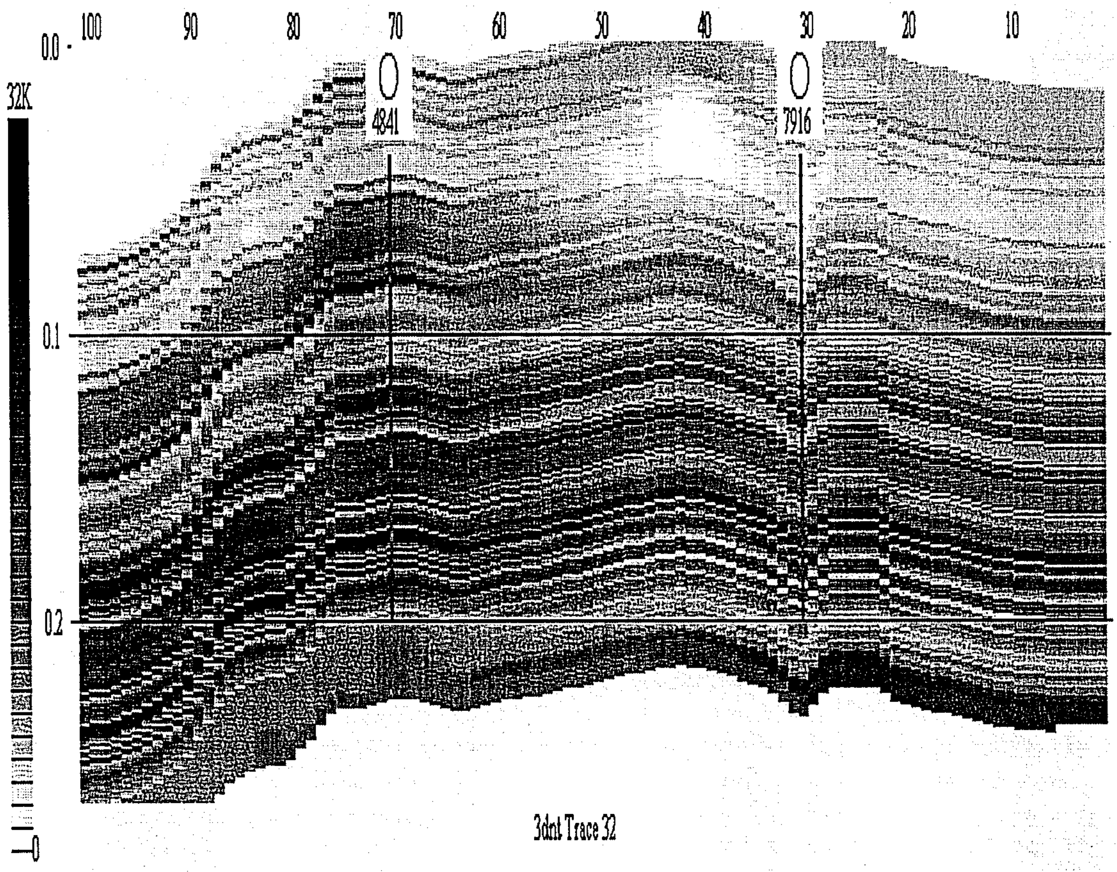


Fig 6 - N-S Cross Section from 3D Porosity Model Band on Interwell Seismic

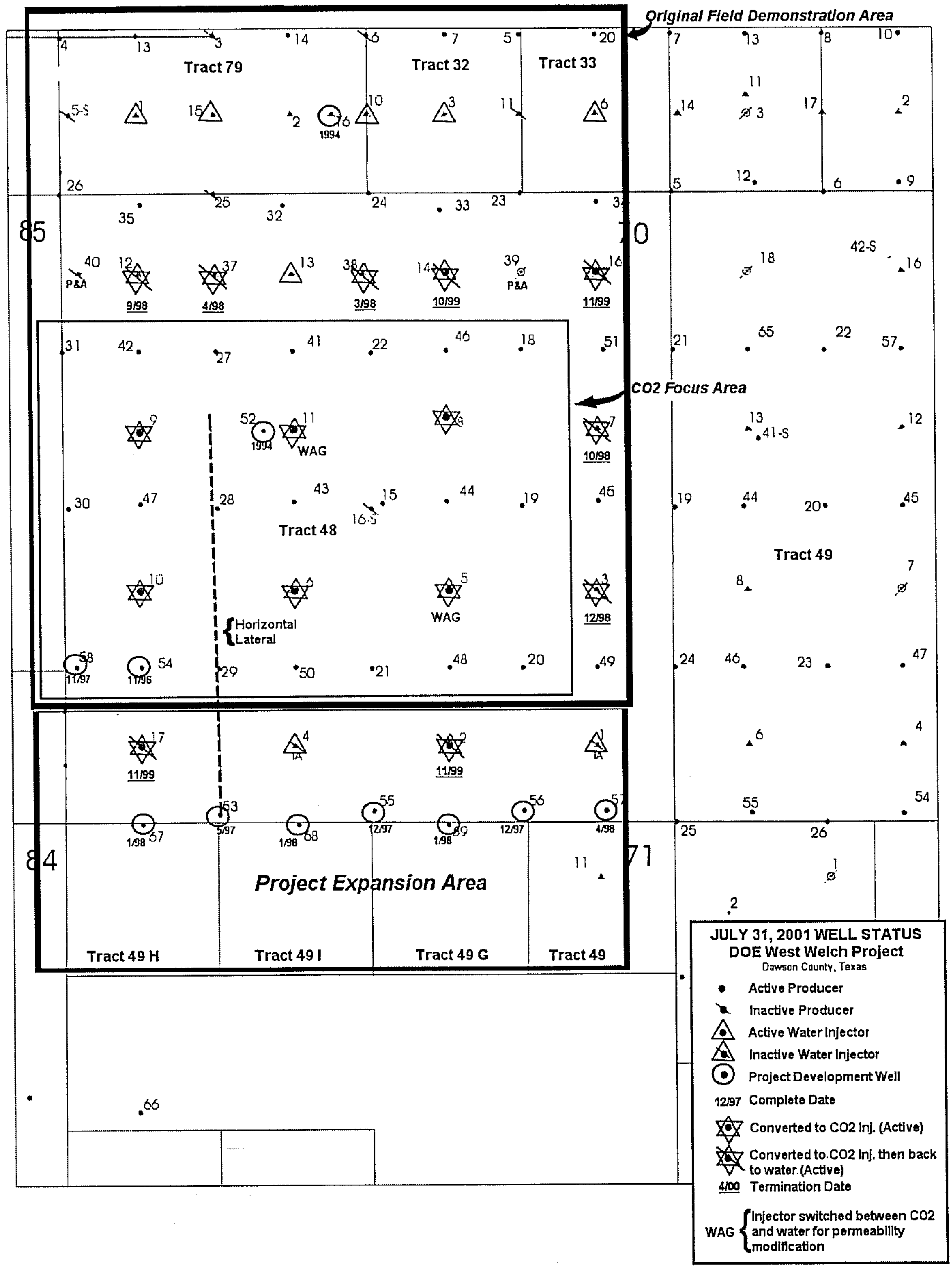


Figure 7 - Wellbore Path - WWU 4853 Horizontal Lateral

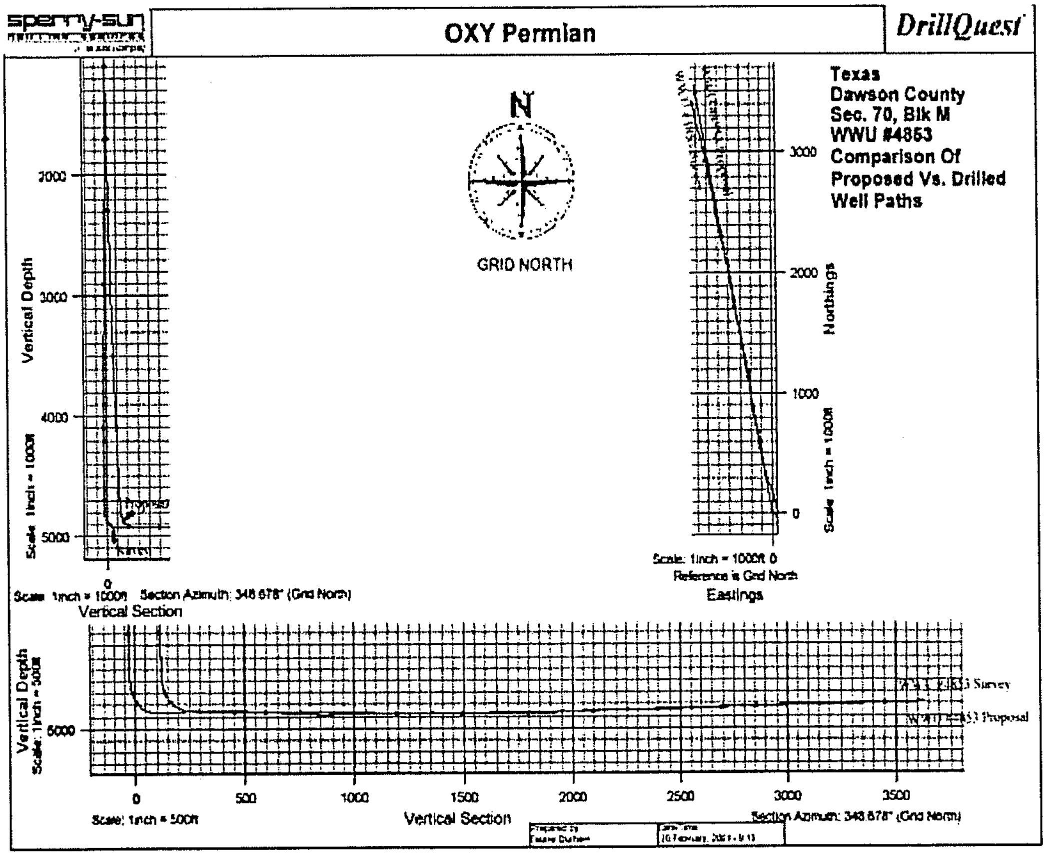


Fig. 8 - Planned vs Final Well Path - WWU 4853 Horizontal Lateral

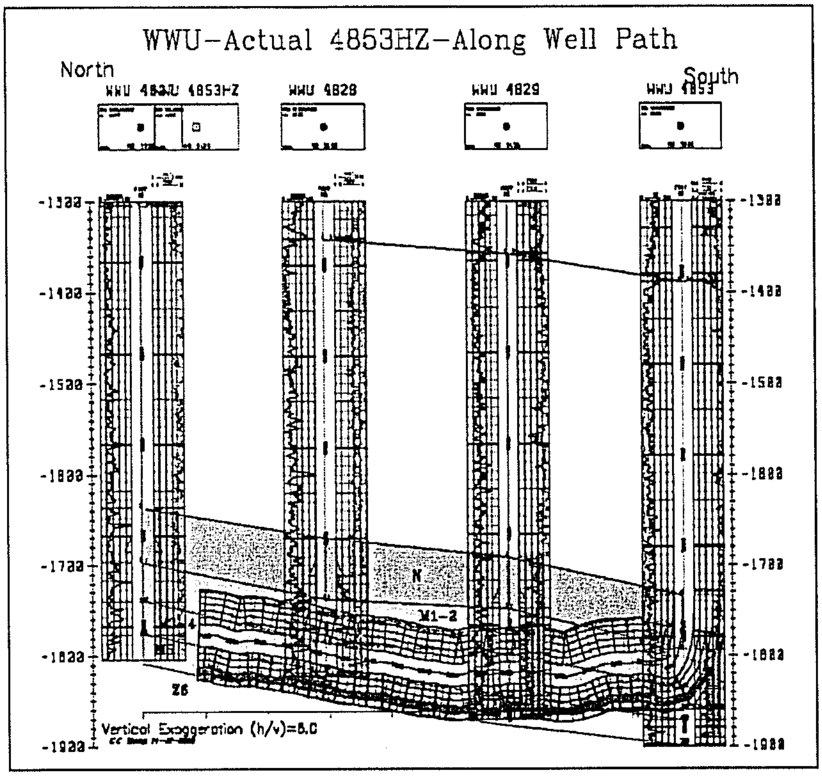


Fig. 9 - Wellbore path through Reservoir - WWU 4853 Horizontal Lateral

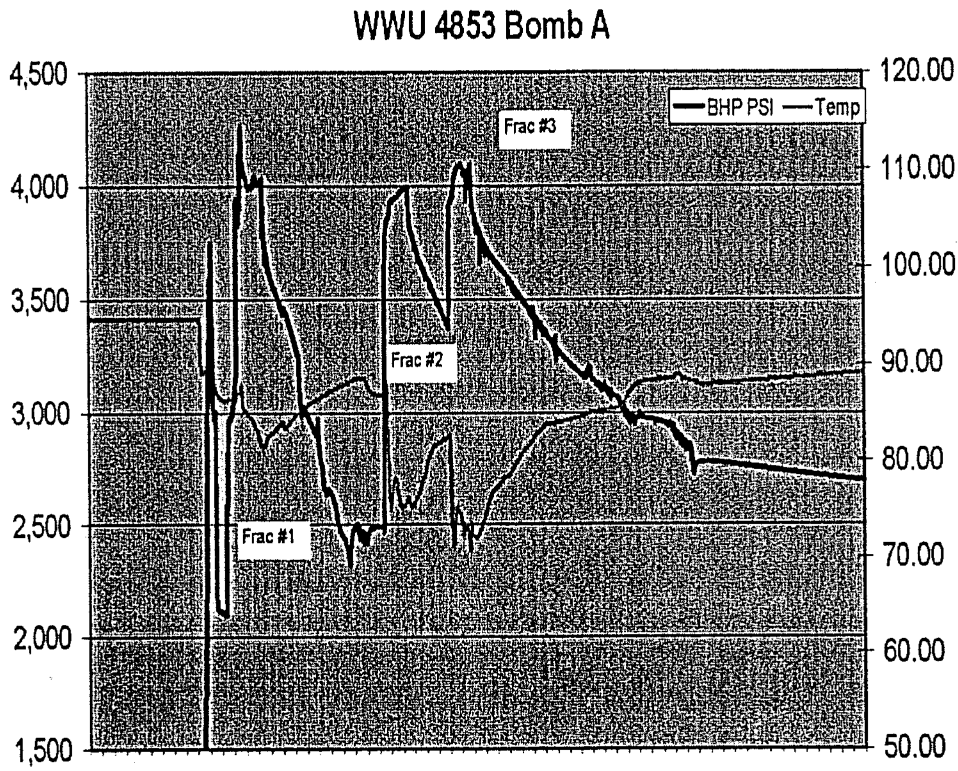


Fig. 10 - BHP & TempChart - WWU 4853 Lateral-Initial Surgi-frac Completion Attempt 11/29/00

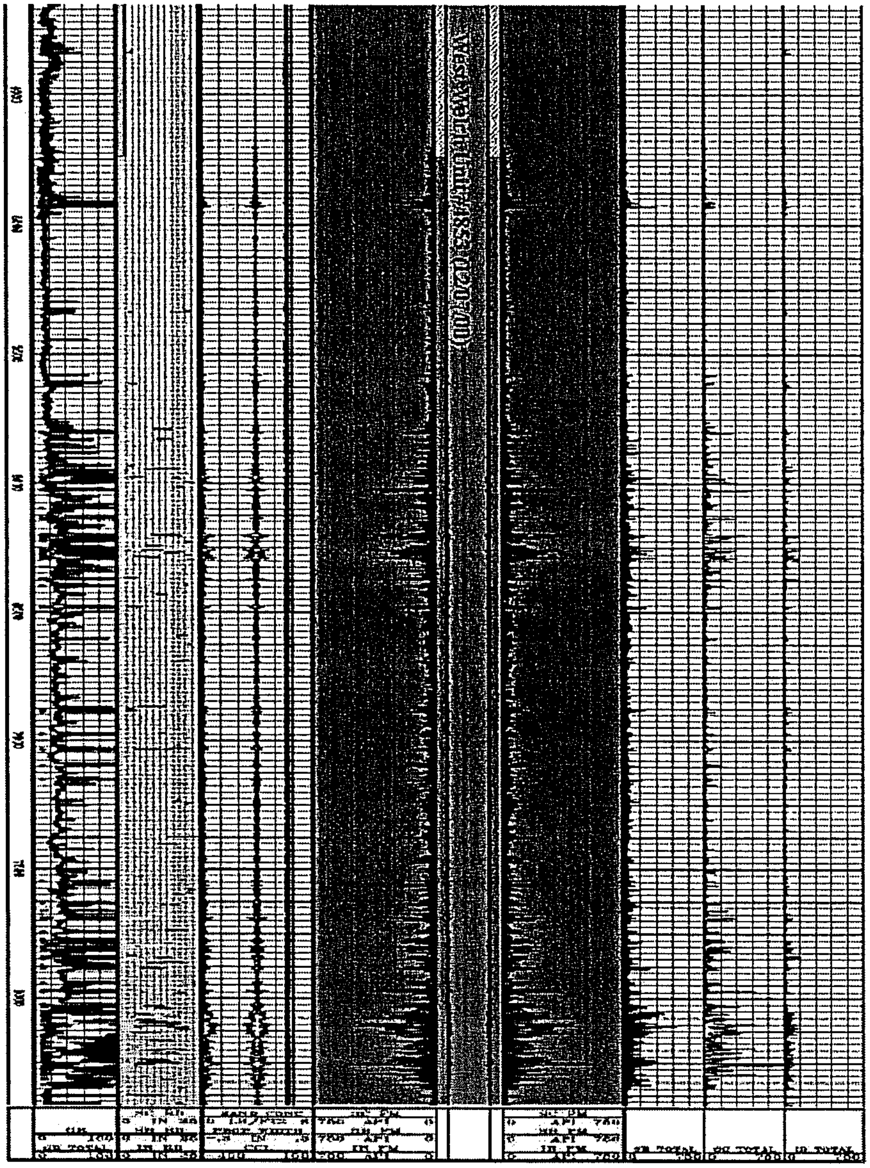


Fig. 11 - Radioactive Tracer Log - WWU 4853 Lateral - Run 12/07/00
After Initial Completion Attempt

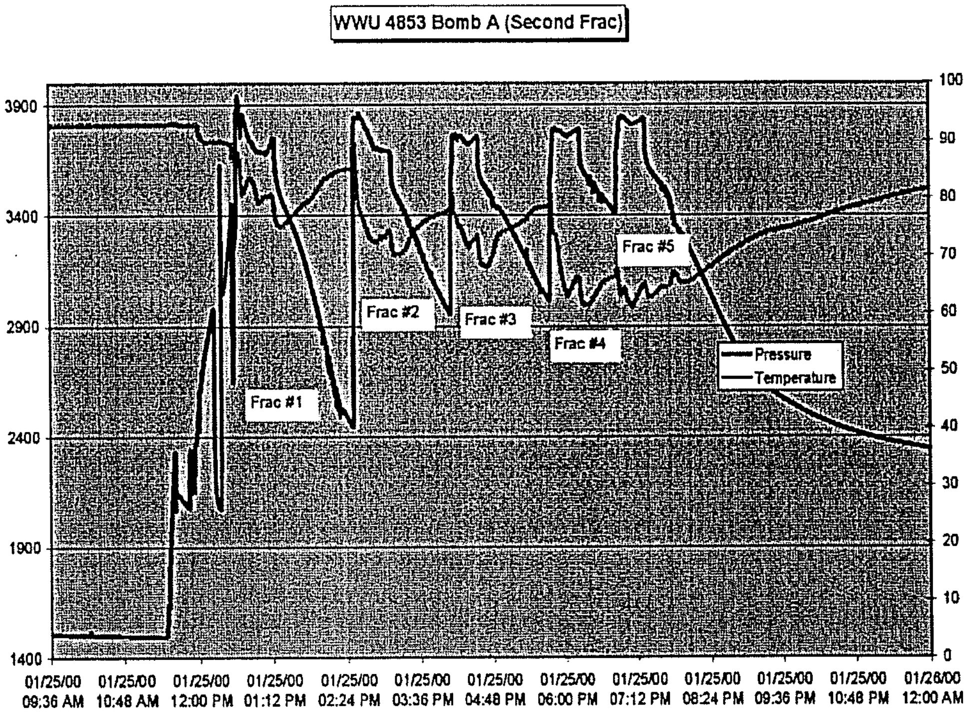


Fig.12 - BHP & Temp Chart - WWU 4853 Lateral - Second Surgi-frac Completion Attempt 1/25/01

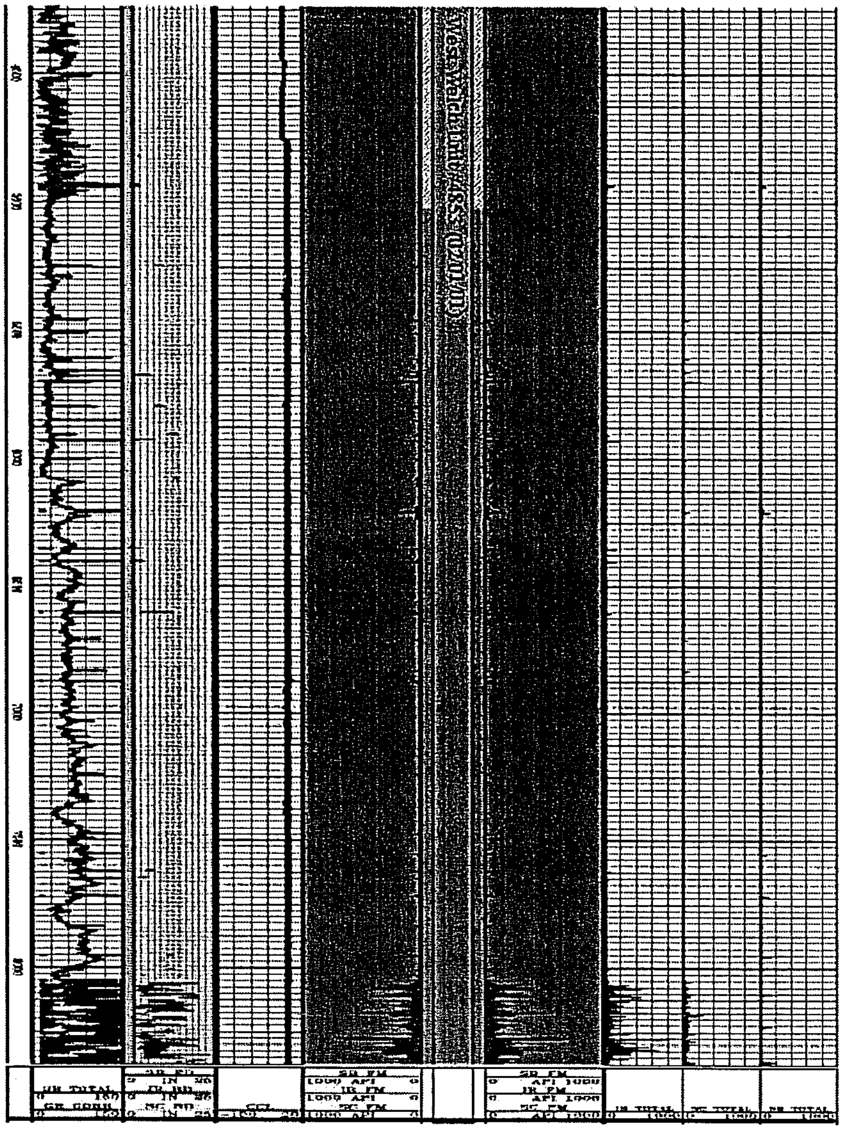
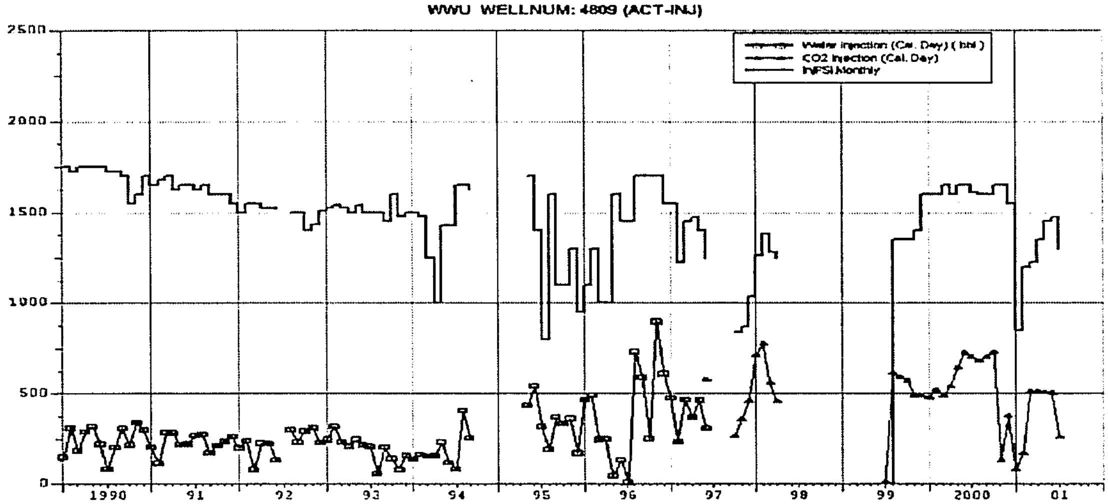


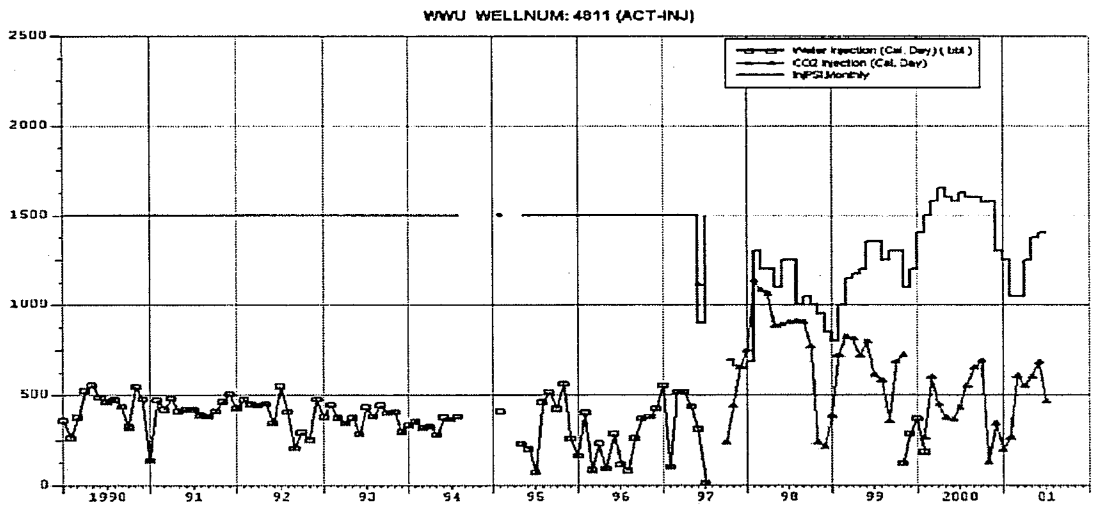
Fig. 13 - Radioactive Tracer Log - WWU 4853 Lateral - Run 2/01/01
After Second Completion Attempt



WWU #4809 CO2 Injector

47

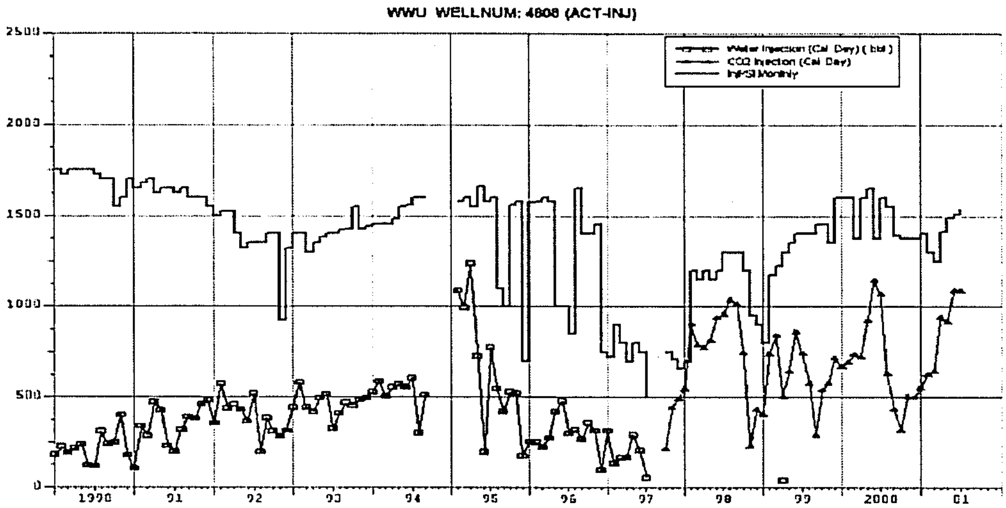
Figure 15



WWU #4811 CO2 Injector

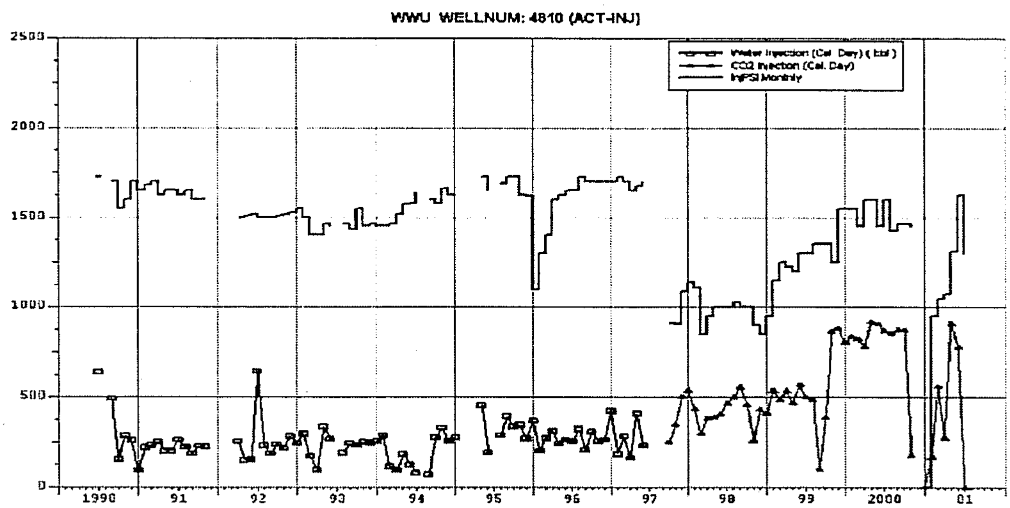
48

Figure 16



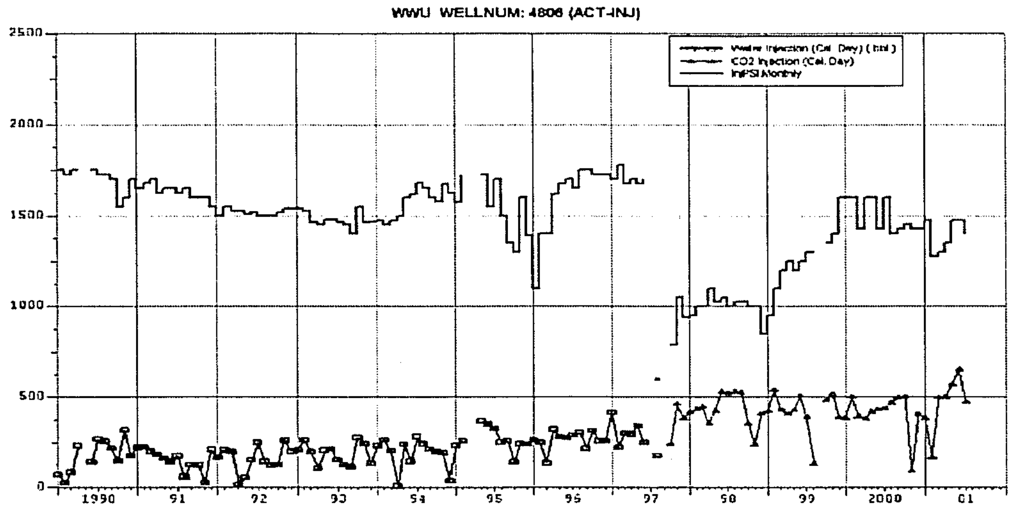
WWU #4808 CO2 Injector 49

Figure 17



WWU #4810 CO2 Injector 60

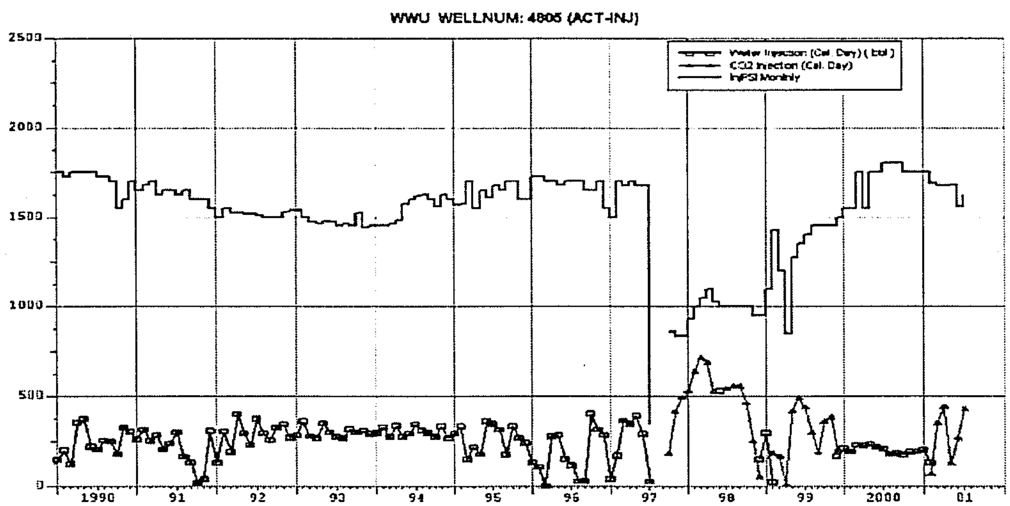
Figure 18



WWU #4806 CO2 Injector

61

Figure 19



WWU #4805 CO2 Injector

62

Figure 20

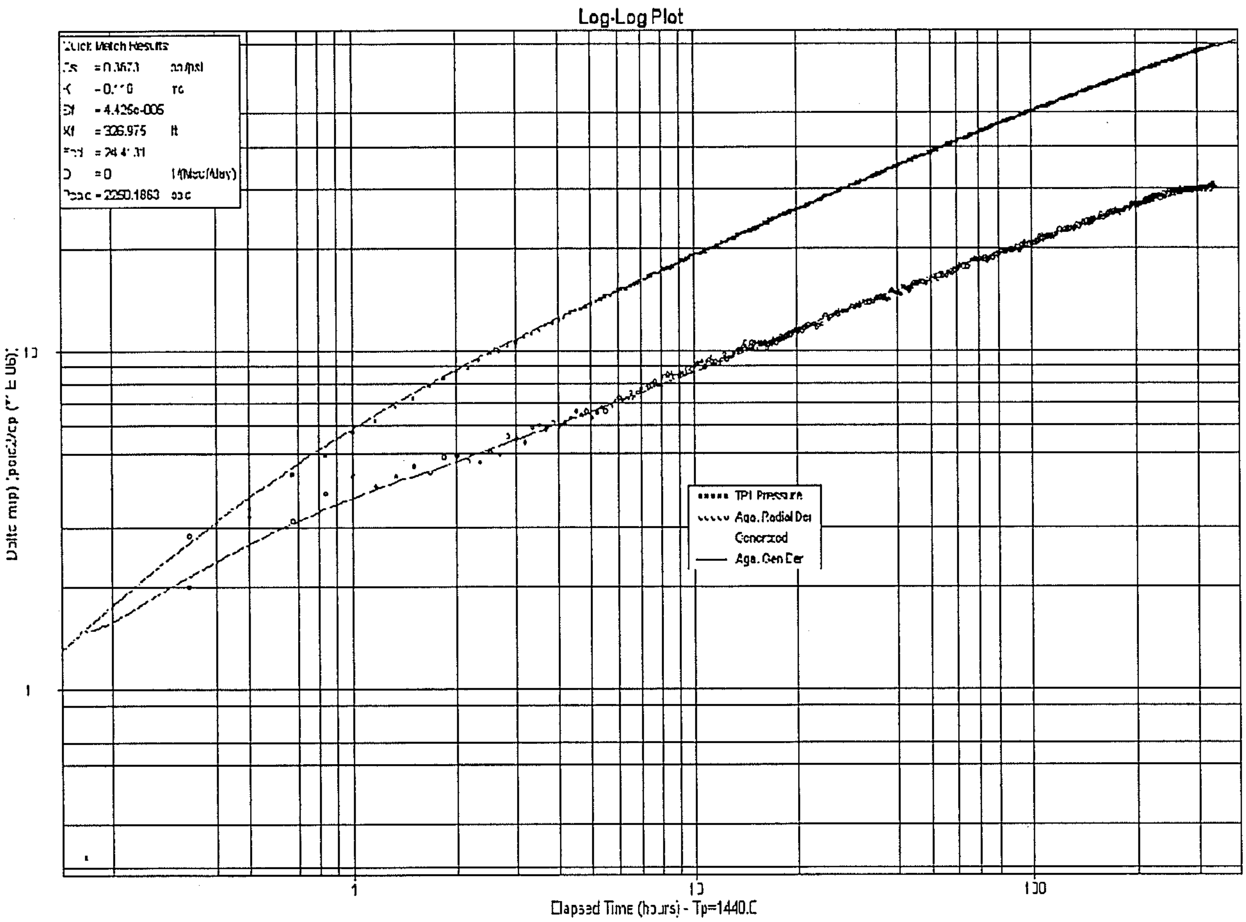
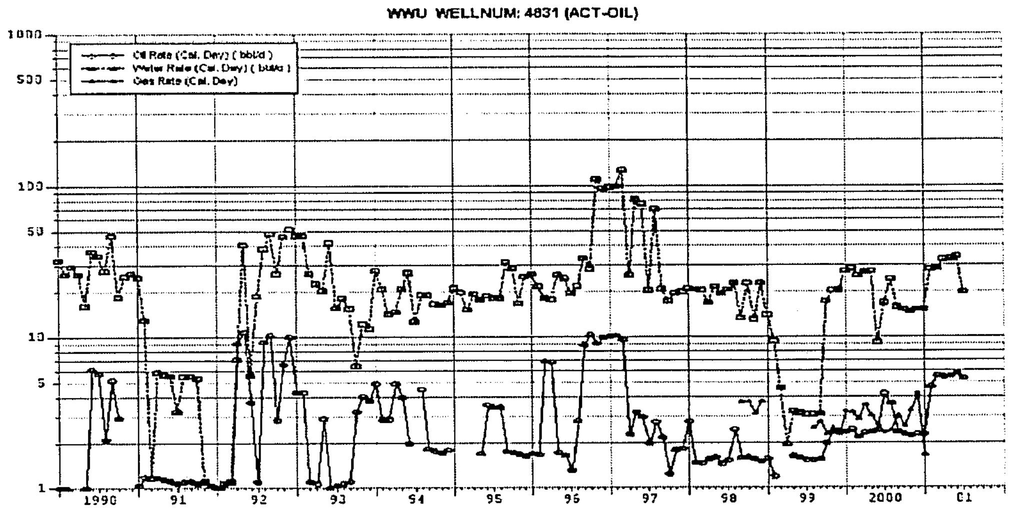


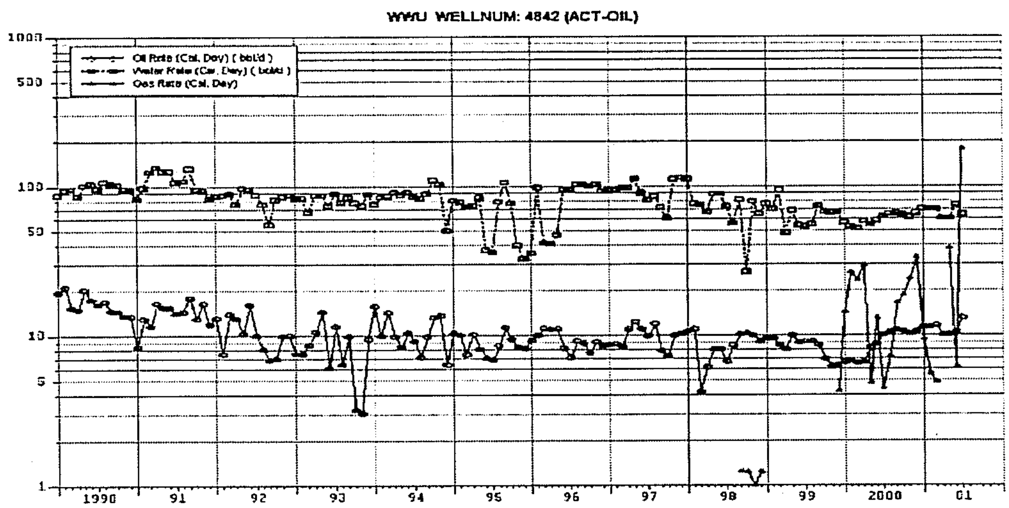
Fig. 21 - Injector 4810 - Pressure Transient Analysis of Pressure Falloff Test



WWU #4831

38

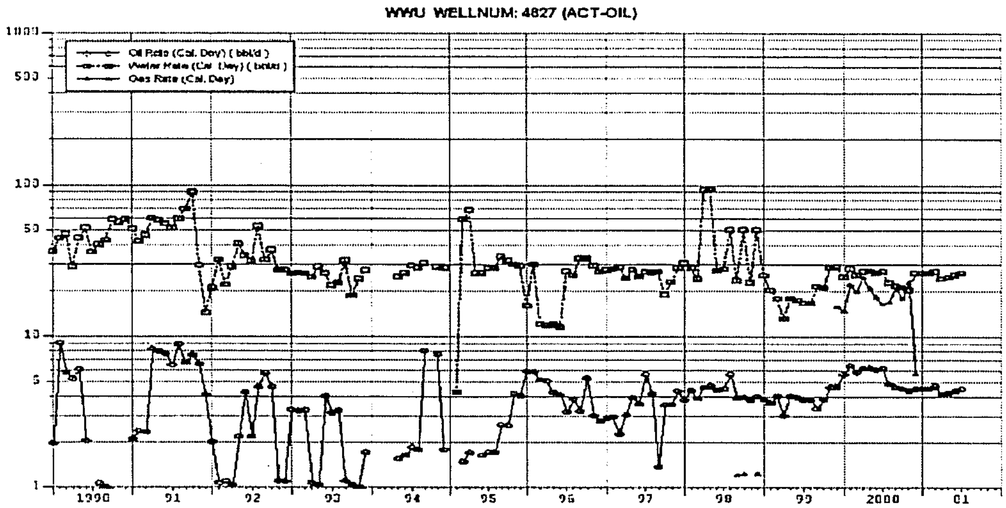
Figure 22



WWU #4842

39

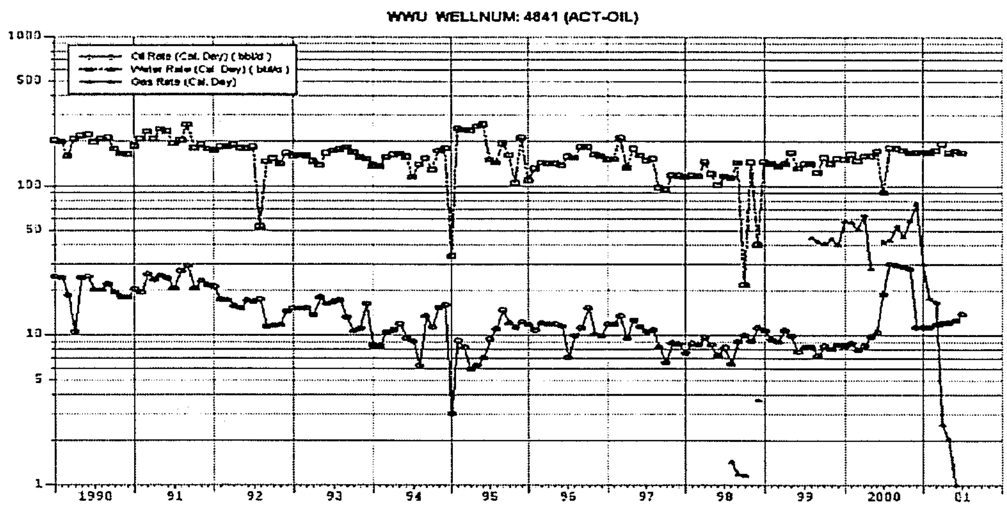
Figure 23



WWU #4827

40

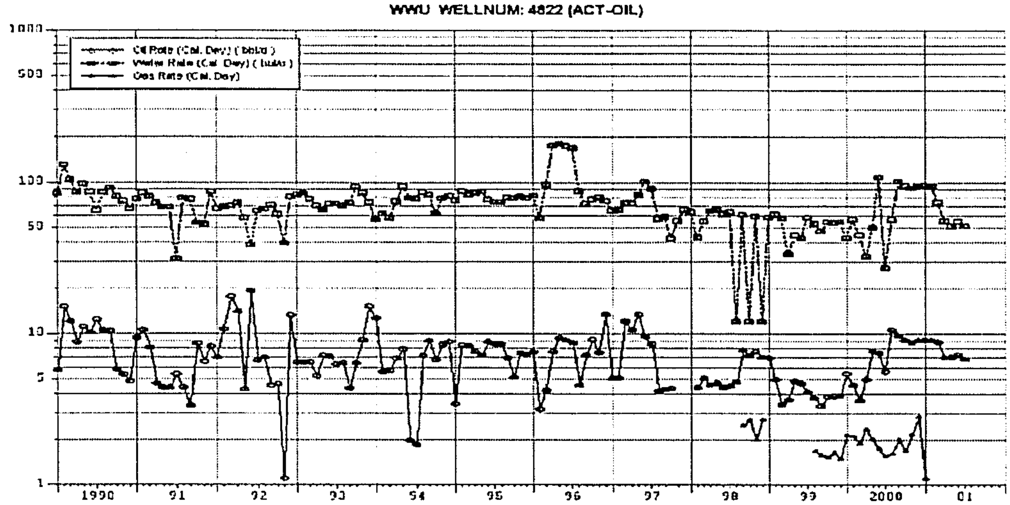
Figure 24



WWU #4841

41

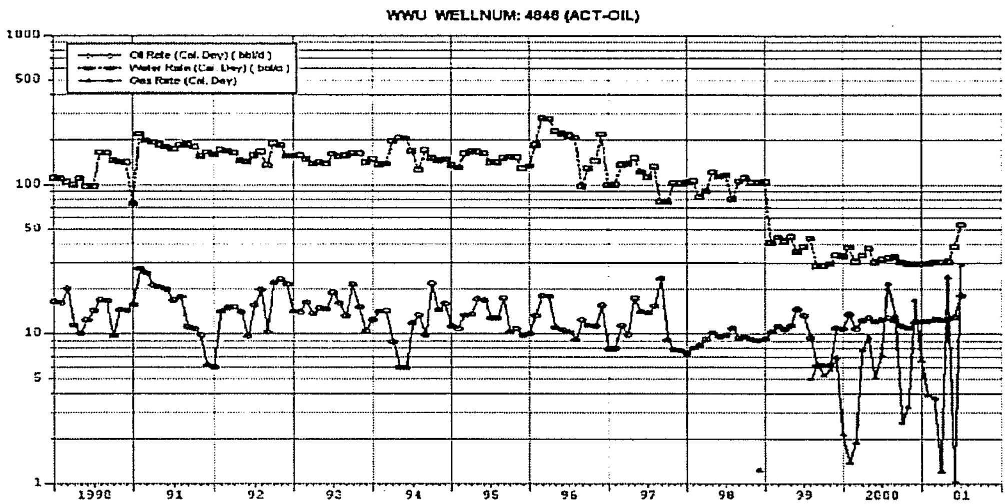
Figure 25



WWU #4822

42

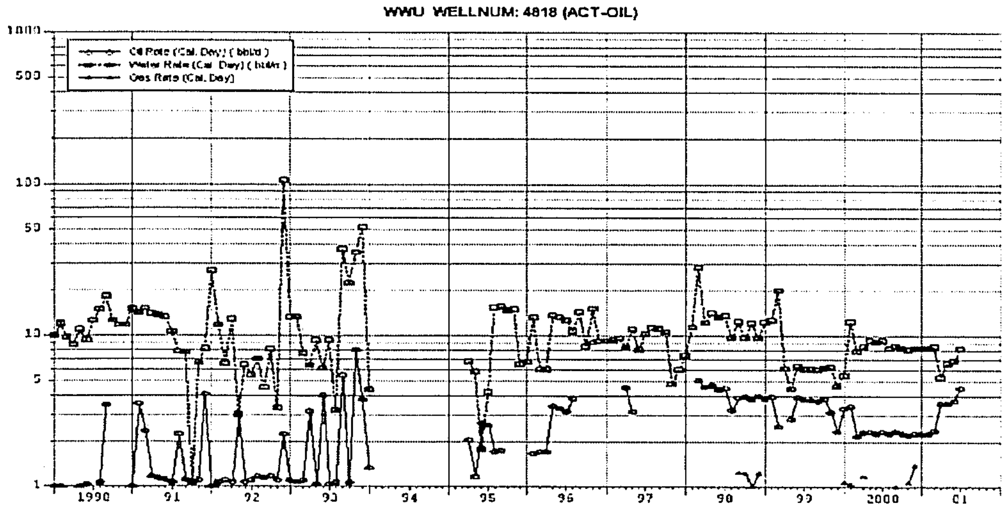
Figure 26



WWU #4846

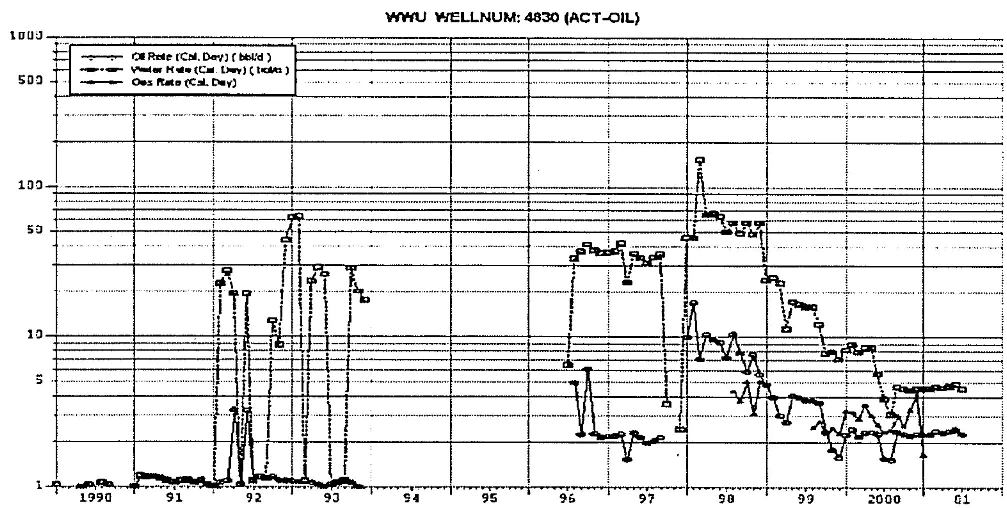
43

Figure 27



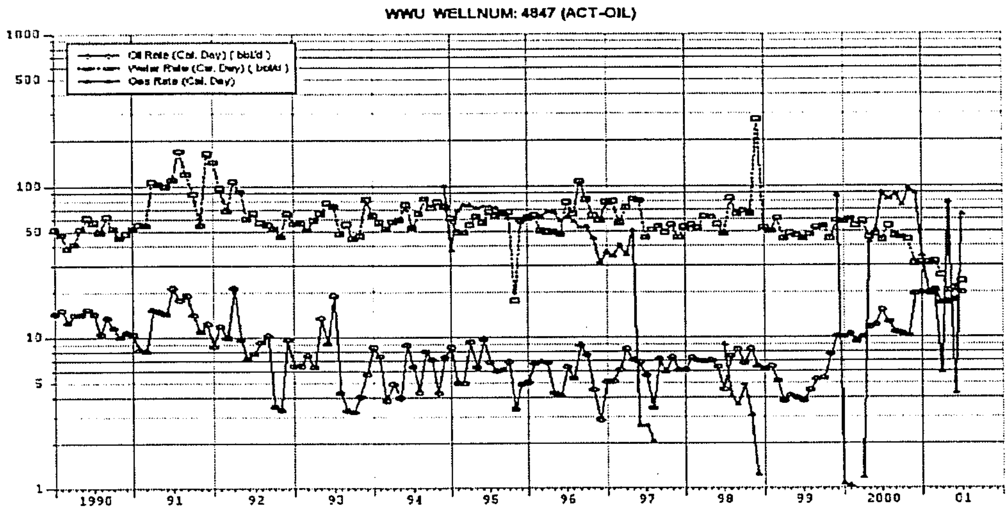
WWU #4818 44

Figure 28



WWU #4830 51

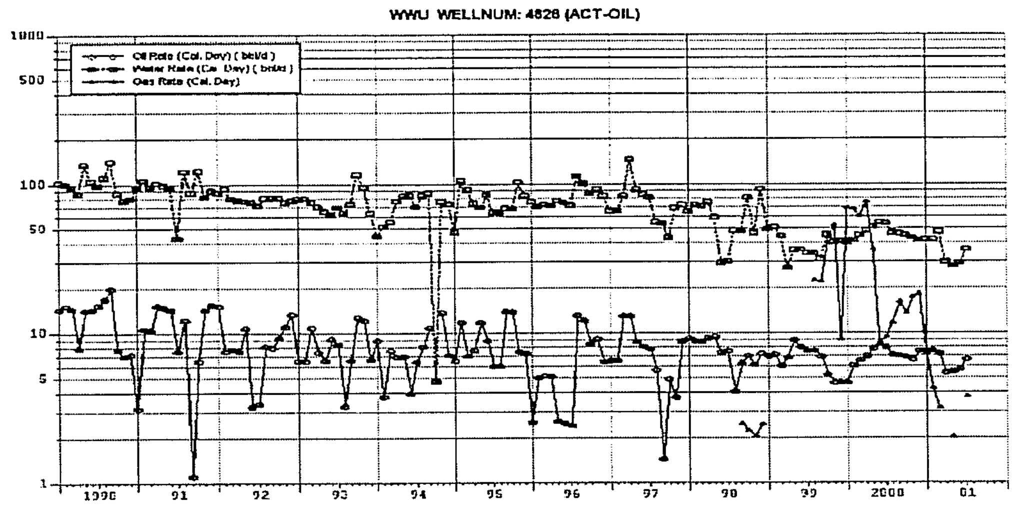
Figure 29



WWU #4847

52

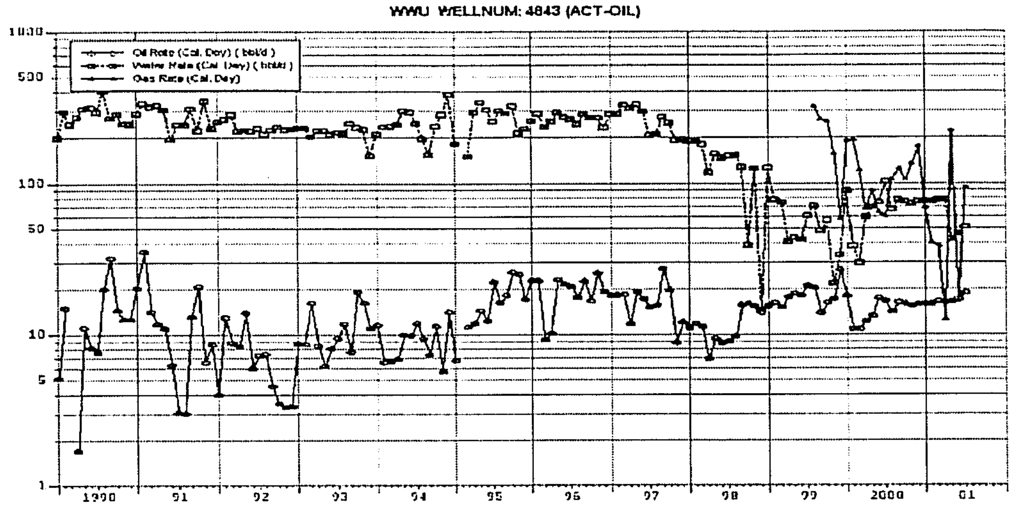
Figure 30



WWU #4828

53

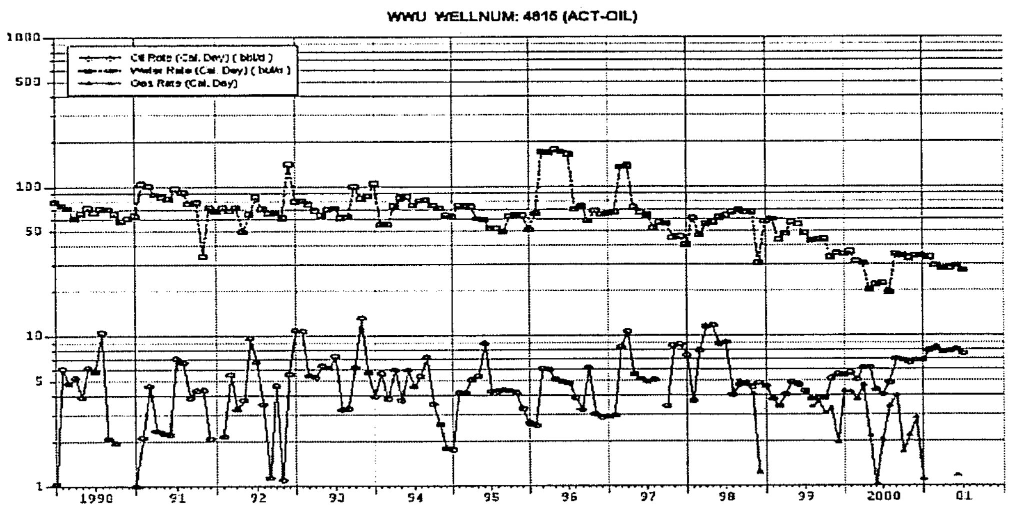
Figure 31



WWU #4843

54

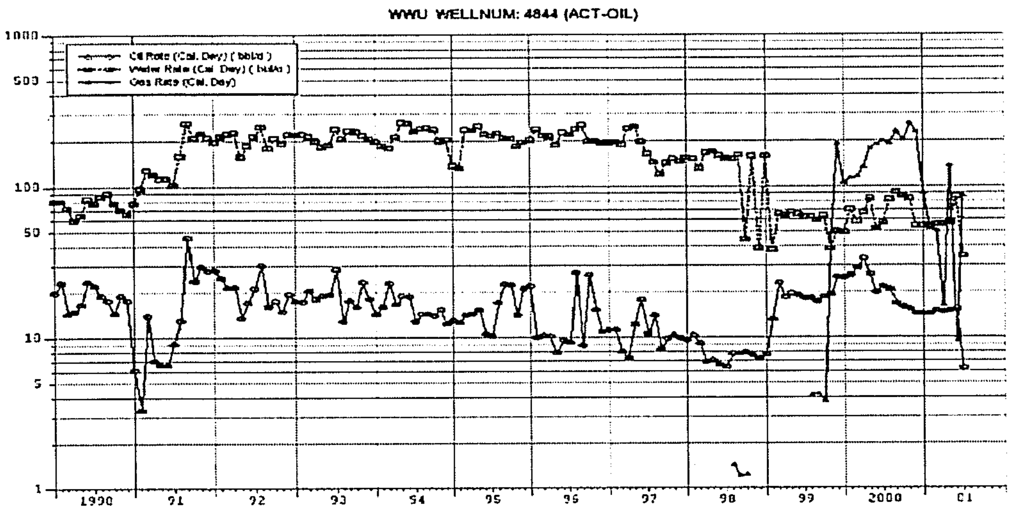
Figure 32



WWU #4815

55

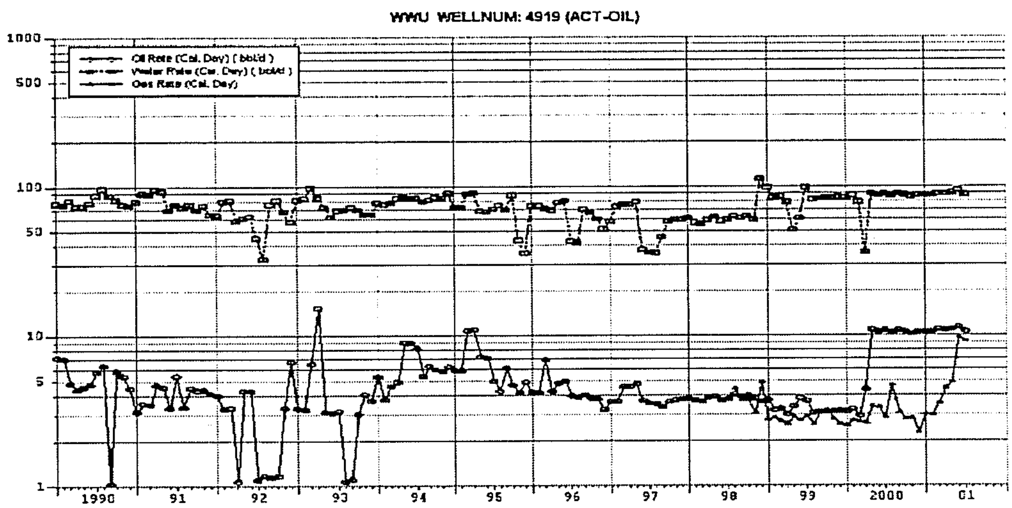
Figure 33



WWU #4844

56

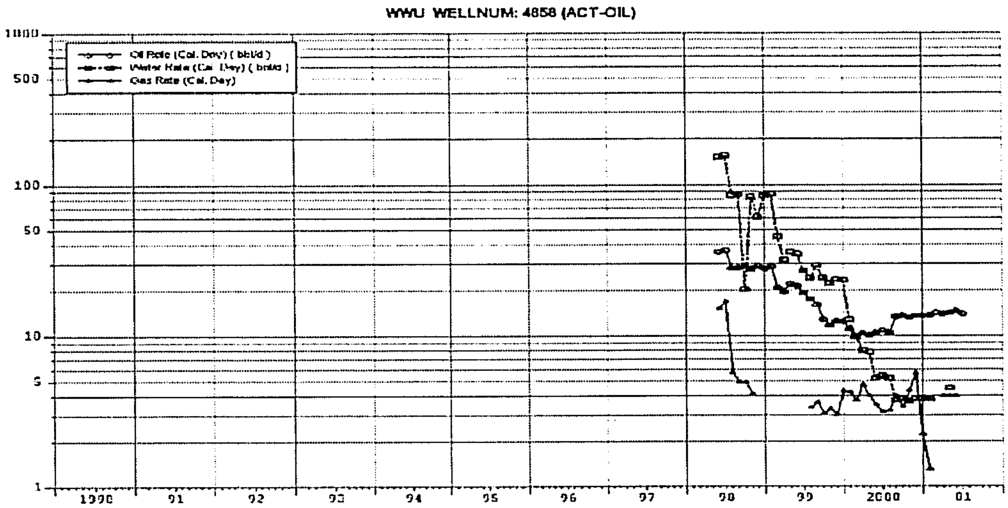
Figure 34



WWU #4919

59

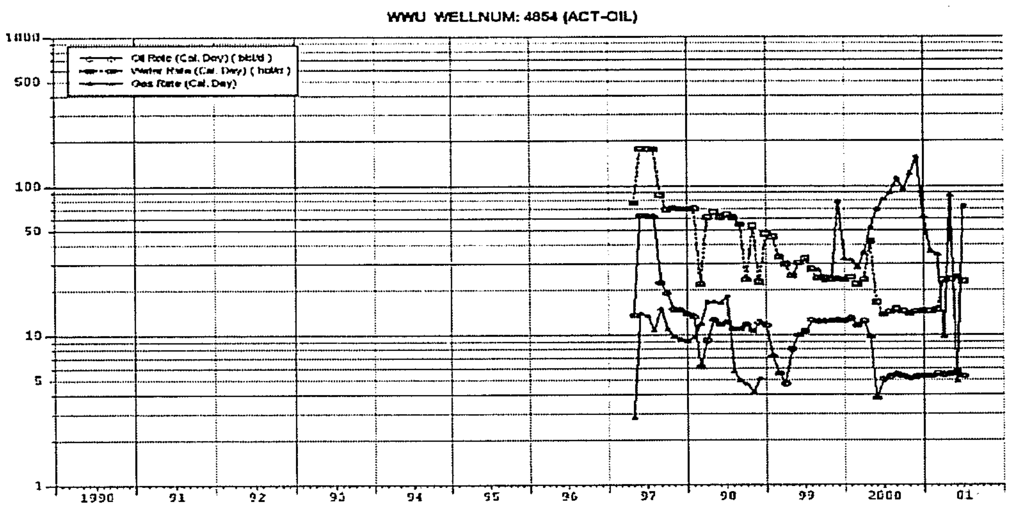
Figure 35



WWU #4858

64

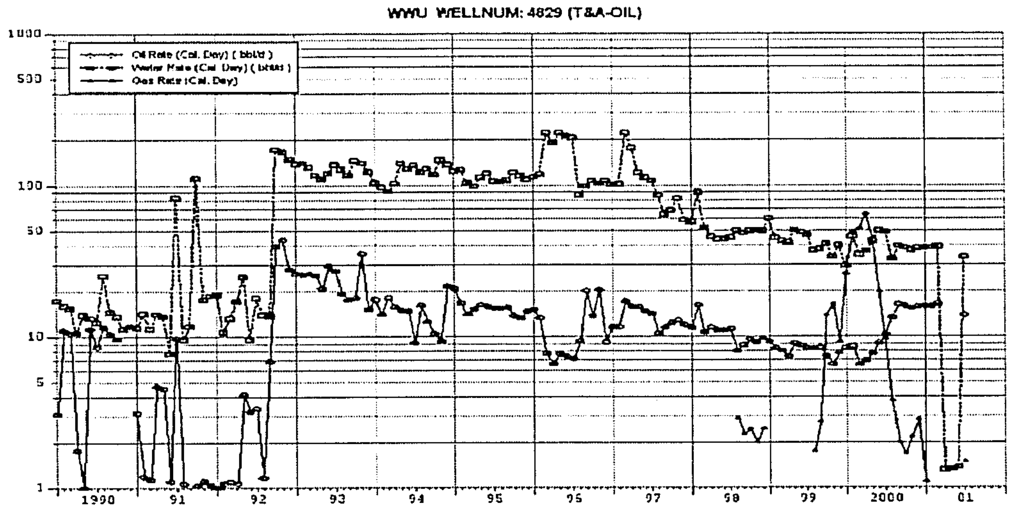
Figure 36



WWU #4854

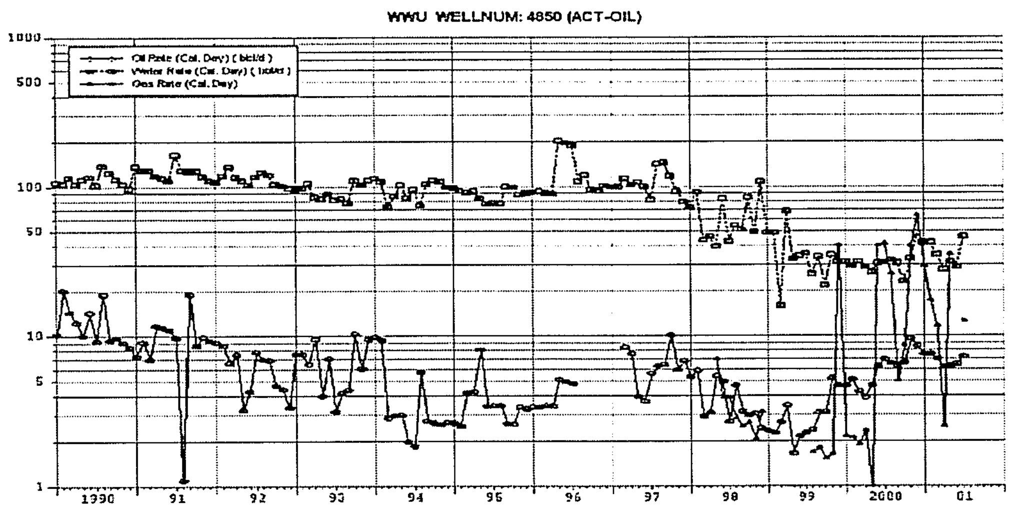
65

Figure 37



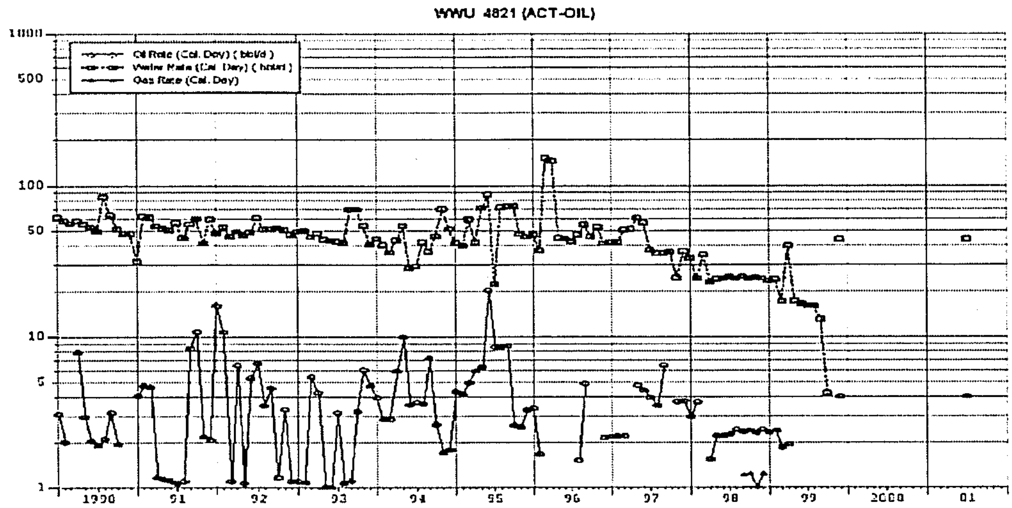
WWU #4829 66

Figure 38



WWU #4850 67

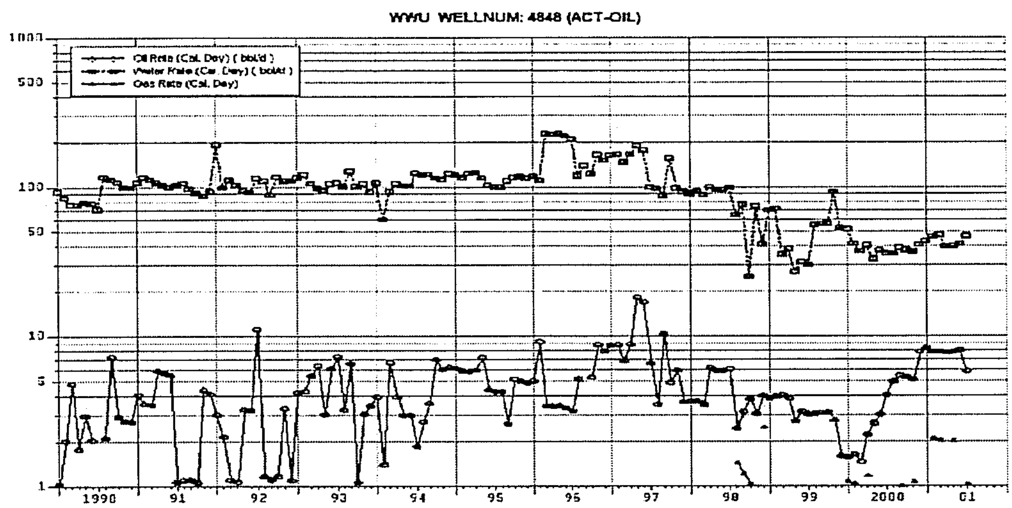
Figure 39



WWU #4821

68

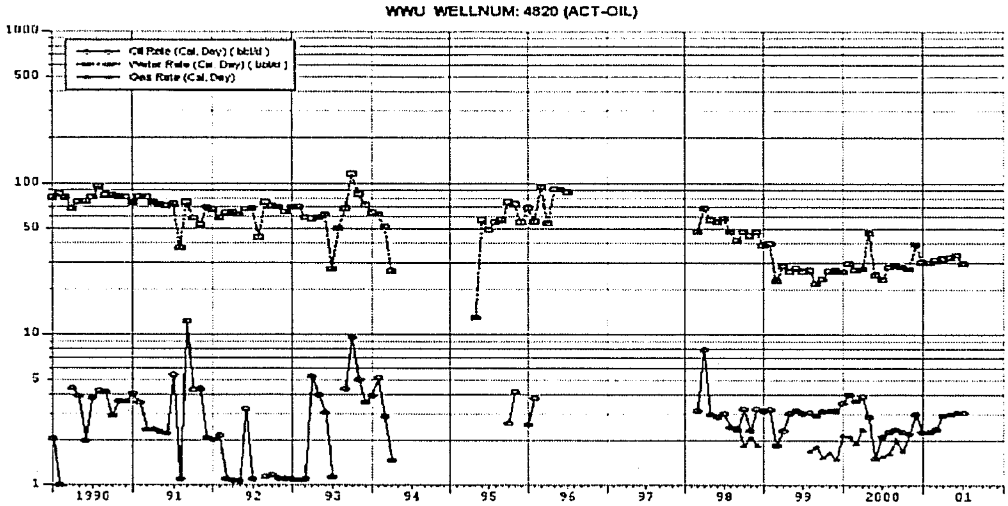
Figure 40



WWU #4848

69

Figure 41



WWU #4820

70

Figure 42

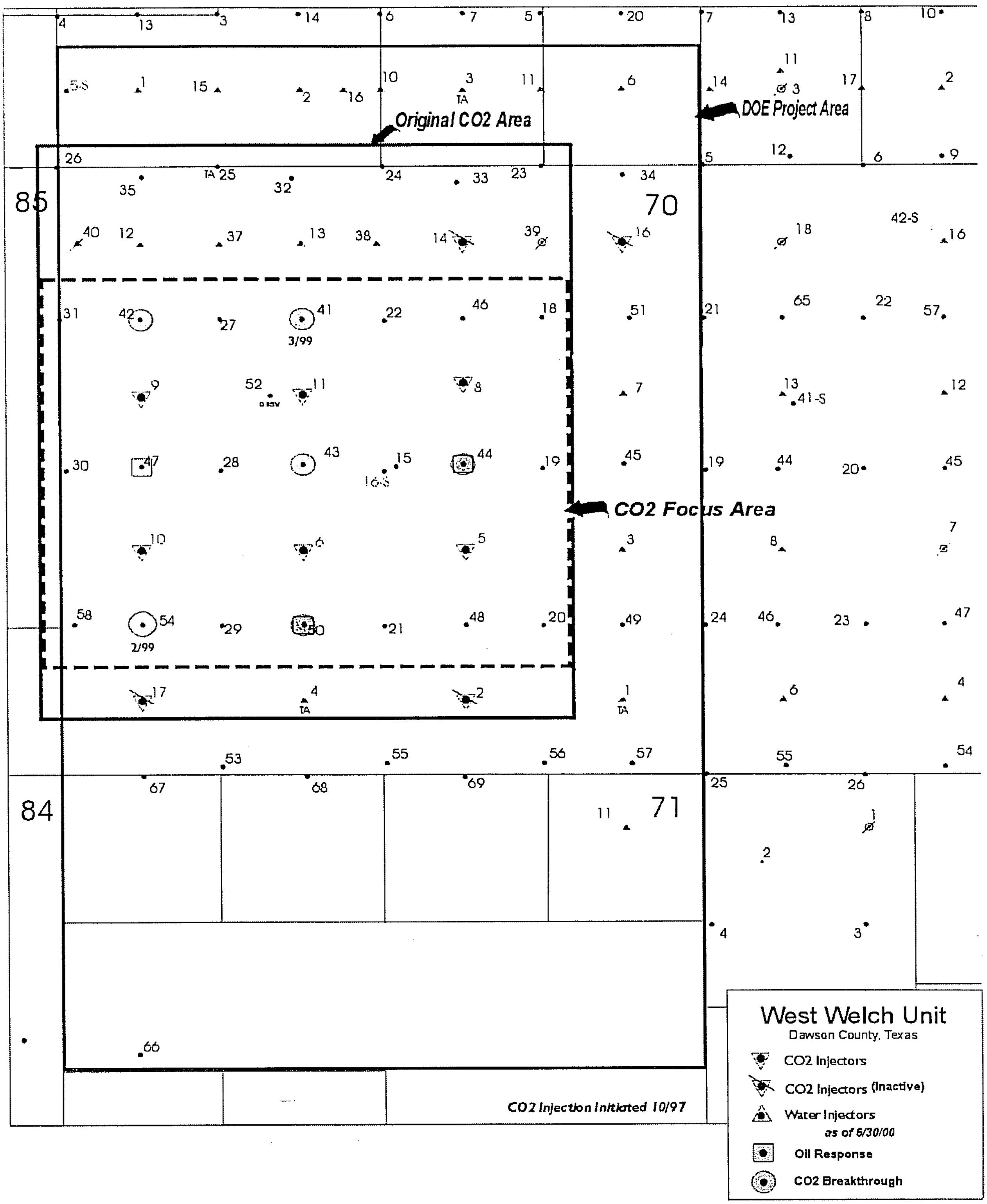


Fig. 43 - Response to CO2 Injection As Of 6/30/01