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**ADVANCED OIL RECOVERY TECHNOLOGIES FOR IMPROVED  
RECOVERY FROM SLOPE BASIN CLASTIC RESERVOIRS, NASH  
DRAW BRUSHY CANYON POOL, EDDY COUNTY, NEW, MEXICO**

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By  
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February, 1999

Work Performed Under Contract No. DE-FC22-95BC14981

Strata Production Company  
Roswell, New Mexico



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

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Advanced Oil Recovery Technologies for Improved Recovery from Slope Basin Clastic  
Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, New Mexico

By  
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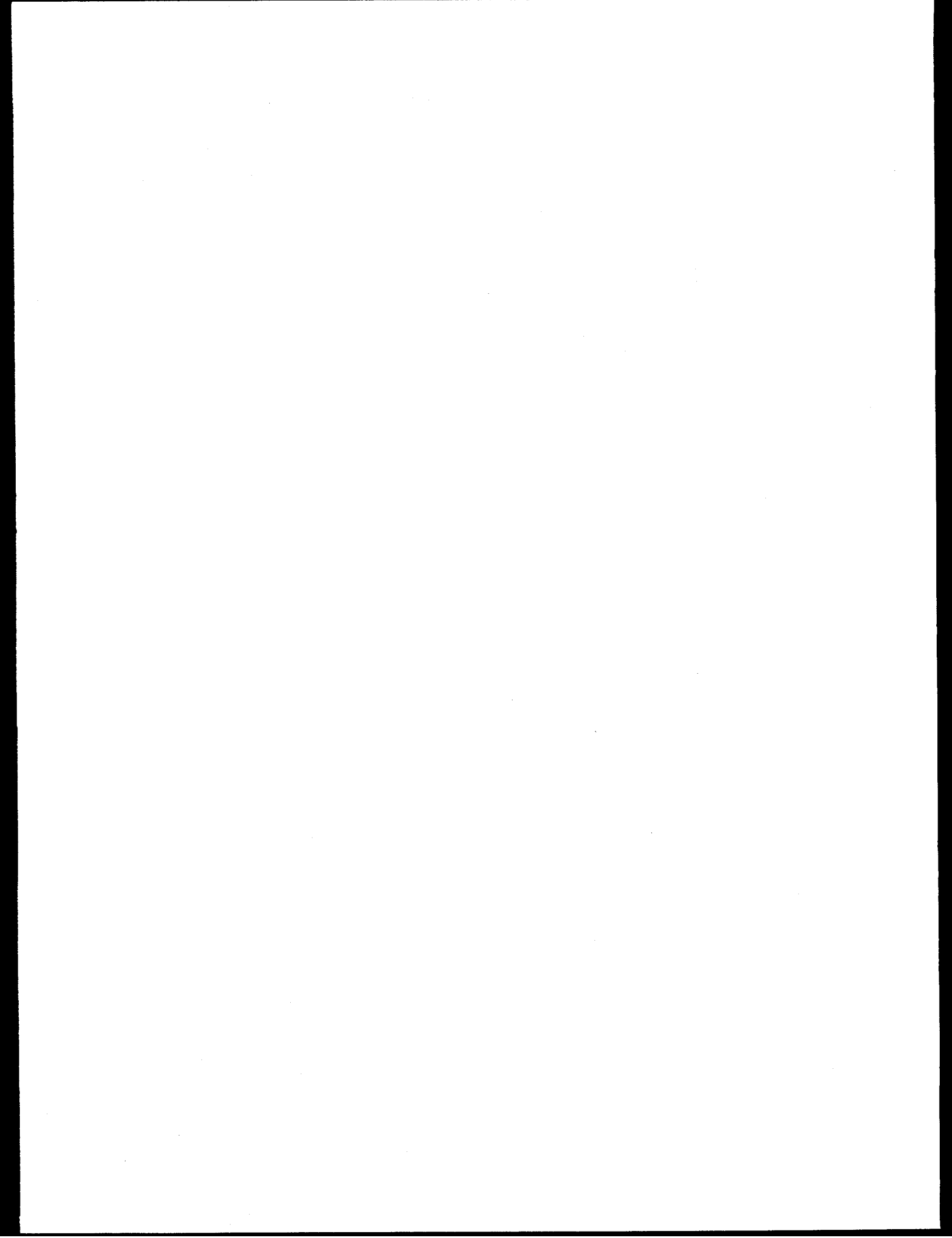
February 1999

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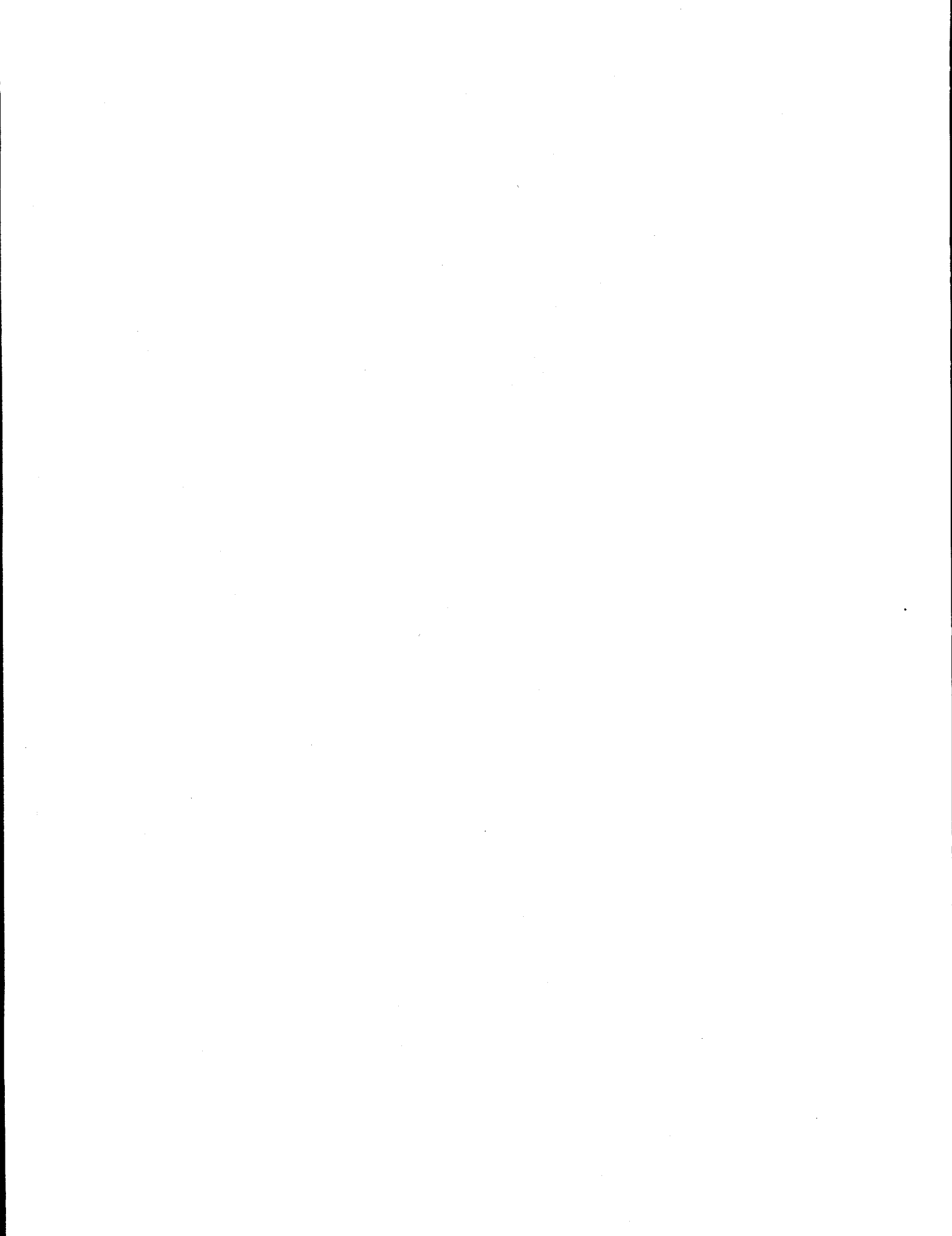
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## ABSTRACT

The Nash Draw Brushy Canyon Pool in Eddy County New Mexico is a cost-shared field demonstration project in the U.S. Department of Energy Class III Program. A major goal of the Class III Program is to stimulate the use of advanced technologies to increase ultimate recovery from slope-basin clastic reservoirs. Advanced characterization techniques are being used at the Nash Draw project to develop reservoir management strategies for optimizing oil recovery from this Delaware reservoir.

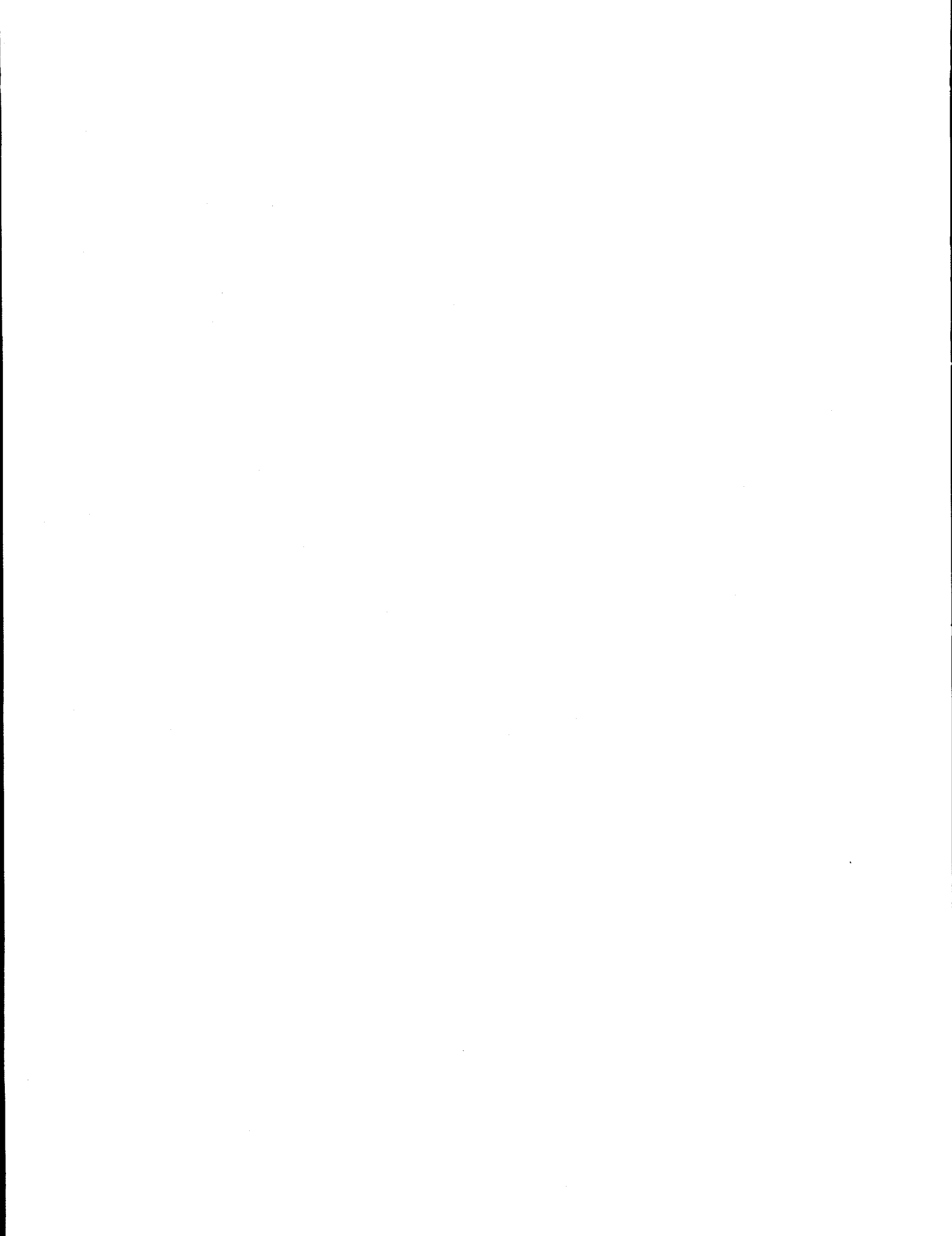
Analysis, interpretation, and integration of recently acquired geological, geophysical, and engineering data revealed that the initial reservoir characterization was too simplistic to capture the critical features of this complex formation. Contrary to the initial characterization, a new reservoir description evolved that provided sufficient detail regarding the complexity of the Brushy Canyon interval at Nash Draw. This new reservoir description is being used as a risk reduction tool to identify "sweet spots" for a development drilling program as well as to evaluate pressure maintenance strategies.

The reservoir characterization, geological modeling, 3-D seismic interpretation, and simulation studies have provided a detailed model of the Brushy Canyon zones. This model was used to predict the success of different reservoir management scenarios and to aid in determining the most favorable combination of targeted drilling, pressure maintenance, well stimulation, and well spacing to improve recovery from this reservoir.

The original Statement of Work included a pressure maintenance pilot project in a developed area of the field. The proposed pressure maintenance injection was not conducted because the pilot area was pressure depleted, and the seismic results suggest the pilot area is compartmentalized. Because reservoir discontinuities would reduce the effectiveness of any injection scheme, the pilot area will be reconsidered in a more continuous part of the reservoir if such areas can be located that have sufficient reservoir pressure.

Results from the project indicate that further development will be under playa lakes and potash areas that will be reached with combinations of deviated/horizontal wells. These areas are beyond the regions covered by well control, but are covered by the 3-D seismic survey that was obtained as part of the project.

This report presents results of the integrated reservoir characterization effort that covers a three-year timeframe in the first phase of this Class III project.



## EXECUTIVE SUMMARY

The Nash Draw Pool (NDP) in Eddy County, New Mexico is one of the project sites in the Department of Energy Class III field demonstration program involving slope-basin clastic reservoirs. Production at the NDP is from the basal Brushy Canyon zones of the Permian (Guadalupian) Delaware Mountain Group. The basic problem at the NDP is the low recovery typically observed in similar Delaware fields. Based on the production response of comparable Delaware fields, pressure maintenance was considered to be a likely requirement at the NDP. By comparing production performance for a control area using standard infill drilling techniques to a pilot area developed using advanced reservoir characterization methods, the goal of the project was to demonstrate that advanced technology can significantly improve oil recovery.

Initially, the proposal was for a 5-year project that had two budget periods; duration of the first budget period was to be two years and duration of the second budget period was to be three years. The first phase of the project was a "Science Phase," in which detailed reservoir characterization and project data, including the acquisition of 3-D seismic data, were to be analyzed to provide the basis for delineating appropriate reservoir management strategies. During Phase I, the feasibility of a pilot project was to be determined and the results of the pilot would be extrapolated to a full field implementation, if technically and economically feasible. Phase II of the project was the "Implementation Phase" in which results of the pilot testing would be considered for expansion to the remainder of the field.

Because of delays in project initiation, evaluating the seismic data and reservoir complexities, and obtaining simulation software, the Phase I period was extended from two years to three years. This was a one-year, no-cost extension granted by the DOE to complete Phase I.

Originally in Phase I, eight (8) wells were planned to gather data, delineate the field, and evaluate completion and production techniques. To date, six (6) wells have been drilled; these wells have evaluated the seismic survey, reservoir characterization, and production characteristics. The current reservoir model indicates the NDP is located at the end of a turbidite fan system with the south half of the field being in an area comprised of small sand accumulations that have been splayed off of the turbidite flow system, and the north half of the field is located at the end of the fan.

Vertical seismic profiles and a 3-D seismic survey were acquired to assist in interwell correlations and facies prediction. By conducting pre-survey VSP wave testing and by careful processing of 3-D seismic data, the thin-bed turbidite reservoirs at the NDP could be imaged, and the individual Brushy Canyon sandstones could be resolved.

The Brushy Canyon reservoir at the NDP was found to be much more complex than initially indicated by conventional geological analysis. While the original concept pictured the NDP as a collection of thin channel sands continuously distributed between wells, the results from the Phase I work show the subzones within the sandstones are lenticular and are not always continuous from well to well.

Although the original evaluation was that both the "K" and "L" sandstones were the major oil producing intervals, the results of this study show the primary oil productive zone at the NDP is the "L" sandstone.

The reservoir characterization, geological modeling, seismic interpretation, and simulation studies obtained in Phase I provided a detailed model of the Brushy Canyon zones. A detailed reservoir model of the pilot area was developed, and enhanced recovery options, including waterflooding, lean gas, and carbon dioxide injection, were considered. Reservoir simulation results suggest that the low permeabilities at the NDP will preclude waterflooding, but immiscible gas injection may be viable if initiated early and if undeveloped regions of the field can be found that have not been pressure depleted. Areas of the field already under production appear to be candidates for CO<sub>2</sub> injection if pressures have not declined too much. However, a low-cost source of CO<sub>2</sub> is currently not available in the immediate vicinity of the NDP.

In the process of determining the feasibility of the pressure maintenance project, several problems were encountered: 1) the relative permeabilities indicate that the permeability to water at the residual oil saturation may be too low to make water injection a practical method of pressure maintenance, 2) the seismic survey indicates that the area around the proposed pilot area is compartmentalized, and the individual zones are not continuous between multiple wells, 3) analysis of the production data indicates that the compartmentalization, shown by the seismic, is real, and 4) the reservoir pressure in the pilot area is very low. These problems indicated the prospect of success from the pilot pressure maintenance project was limited, and a more continuous area of the reservoir with less depletion would yield more favorable results. This resulted in the pressure maintenance pilot project being shifted into Phase II, when new areas of the NDP are drilled.

Restricted surface access at the Nash Draw Pool, caused by proximity of underground potash mining and surface playa lakes, limits field development with conventional drilling. Further development will be under the playa lakes and potash areas that will be reached with combinations of deviated/horizontal wells. The data acquisition and drilling evaluation is complete, and application of the enhanced recovery techniques will be done in Phase II.

The potential value of geostatistical techniques for estimating interwell reservoir properties, with infill drilling as a possible goal, was investigated. However, NDP wells primarily cover the center part of the available seismic survey, so a new technique was developed to extrapolate reservoir properties beyond the area directly constrained by wells.

This new technique utilizes a non-linear multivariable regression using seismic attributes as inputs and porosity, water saturation, and net pay as outputs. The regression equations allow the prediction of these three reservoir properties in areas without direct well control, and the resulting computed maps, such as hydrocarbon pore volume, will be used with other information in Phase II to identify "sweet spots" for an aggressive development drilling program.

A plan for Phase II has been submitted to the DOE, and the DOE has approved the continuation of the project into the next budget period.

## OBJECTIVE

The overall objective of this project is to demonstrate that a development program—based on advanced reservoir management methods—can significantly improve oil recovery at the Nash Draw Pool (NDP). The plan includes developing a control area using standard reservoir management techniques and comparing its performance to an area developed using advanced reservoir management methods. Specific goals are (1) to demonstrate that an advanced development drilling and pressure maintenance program can significantly improve oil recovery compared to existing technology applications and (2) to transfer these advanced methodologies to oil and gas producers in the Permian Basin and elsewhere throughout the U.S. oil and gas industry.

## INTRODUCTION

The Nash Draw Brushy Canyon Pool, operated by Strata Production Company (Strata), is located in Sections 12, 13, and 14 T23S-R29E, and Section 18 T23S-R30E, in Eddy County, New Mexico. Production at the Nash Draw Pool (NDP) is from the basal Brushy Canyon zones of the Delaware Mountain Group of Permian, Guadalupian age.

The primary concerns at the NDP are: (1) the primary oil recovery was initially believed to be in the order of 10% of the OOIP, (2) a steep initial oil production decline rate, and (3) rapidly increasing gas-oil ratios. This low recovery is caused by low reservoir energy, and low permeabilities and porosities. Initial reservoir pressure is just above the bubblepoint pressure and declines to below the bubblepoint around the wellbore after a few months of production. With the solution gas drive reservoir, oil production declines 50% in the first year, and gas/oil ratios increase dramatically. These concerns point out the importance of considering various reservoir management strategies to maximize the economic recovery of oil at the NDP. Production characteristics of similar Delaware fields indicate that pressure maintenance is a likely requirement at the NDP.

Early in the NDP development, Strata identified three basic constraints: (1) limited areal and interwell geologic knowledge, (2) lack of an engineering method to evaluate the various producing strategies, and (3) restricted surface access that prohibits development with conventional drilling. The limited surface access at the NDP is caused by the proximity of underground potash mining and surface playa lakes (**Figure 1**).

## GEOLOGICAL BACKGROUND

### Deposition and Structure

The structural trend at the NDP is North-South to Northeast-Southwest, and there were at least three depositional events. The sandstone reservoirs of the basal Brushy Canyon sequence of the Delaware Mountain Group in this study lie above the Permian Bone Spring Formation. The top of the Bone Spring

Formation is marked by a regionally persistent limestone varying from 15.2 to 30.5 m (50 to 100 ft) in thickness that provides an excellent regional mapping horizon. Regional dip is to the East-Southeast at about 100 ft per mile in the area of the NDP. The structural dip resulted from an overprint of post-depositional tilting that is reflected in reservoir rocks of the Delaware Formation and impacts the trapping mechanism in the sandstones.

The sandstone units of the Brushy Canyon sequence represent the initial phase of detrital basin fill in the Delaware Basin during Guadalupian time. The Delaware sandstones are deep-water marine turbidite deposits. Depositional models<sup>1,2</sup> suggest that the sands were eolian-derived and were transported across an exposed carbonate platform to the basin margin. Interpretations of the associated transport mechanisms<sup>3,4</sup> suggest that the clastic materials were deposited episodically, and were transported into the basin through shelf by-pass systems along an emergent shelf-edge margin.

### **Early Interpretation**

The initial development of the NDP was based on subsurface mapping of key horizons that had mudlog shows in various sands. A typical approach to developing Delaware sand prospects in southeast New Mexico has commonly involved searching the files for mudlogs and core data. This led to either drilling new wells offsetting those with shows or re-entering existing boreholes. In the case of the NDP, both methods were employed in the initial phase of development. The first well, NDP Well #9, was drilled and completed in June, 1992. Subsequent drilling led to mixed results. While no dry holes were drilled, some wells performed better than others. Prediction of better quality reservoir facies remained a big challenge early on in the project.

Production at the NDP comes from a total of 14 different sands within the Brushy Canyon and Cherry Canyon Members of the Delaware Mountain Group. The sands were deposited as part of a submarine fan/channel complex in a 4,000 ft basinal fill sequence. Depositional strike is generally north/northeast-south/southwest with the productive sands apparently draping over subtle structural noses and/or closures. Post depositional compaction may also play a part in the trapping mechanisms. Lateral variations in porosity and permeabilities limit the extent of the individual reservoirs and act as a stratigraphic component of the traps. Porosities range from 12 to 20%, and permeabilities vary from 0.5 to 18 md. The most prolific sands in the field are the basal sands of the Brushy Canyon Member, and average net pay thickness is 90 ft. The Brushy Canyon reservoir consists of thin stacked sandstones; vertical permeability is extremely low, and horizontal permeability is poor to good.

Early subsurface mapping showed the NDP as having more of a blanket sand morphology (see the isopach map in **Fig. 2** based on an early geological interpretation). With continued drilling the interpretation evolved into a more complex reservoir, having two primary sand depocenters trending in a north-south to northeast-southwest direction. Even with more data incorporated, the prediction of high quality reservoir sands was difficult.

Locally, the three intervals of interest are referred to as the "K", "K-2", and "L" sandstones which can be correlated from well to well over large distances. The "K" and "L" sandstones, the main producing

intervals of the Brushy Canyon formation, have multiple lobes, and both sandstones can be divided into four sub-units (see the Type Log in Fig. 3). Initially, the primary productive intervals were believed to be the "K" and "L" sands. A challenge in developing these Delaware reservoirs of marginal quality was to distinguish oil-productive pay intervals from water-saturated, non-pay intervals.

The original reservoir model resulted in the discovery of the NDP; however, the original characterization of the reservoir was not accurate and did not provide a high success ratio of subsequent wells. This resulted in the drilling of one uneconomic well and some marginally economic wells.

## **METHODS EMPLOYED IN PHASE I**

Part of the development program in the NDP Class III project called for a pressure maintenance program for enhancing recoveries from the reservoir. The original concept in the Statement of Work for Phase I was to conduct a pressure maintenance pilot project in a developed area of the field and to expand the pilot to the remainder of the field in Phase II. The proposed pilot area included NDP Wells #1, #5, #6, #9 and #14, which were chosen because of their close proximity to one another. These wells are arranged in a 5-spot pattern (see Fig. 1), and were believed to be in communication.

It was obvious at the start of the Phase I project that a considerable amount of data acquisition and analysis was needed prior to implementation of a pressure maintenance pilot. To refine the characterization of the reservoir at the NDP, many sources of data were used. Some of the sources employed were core and log data from an analog area and Delaware wells in the area, as well as core data, wireline data, mud logs, and seismic surveys from the NDP.

Typical of small independent producers, Strata lacked the in-house expertise to address all of the needs of the Class III project, and, therefore assembled a diverse team of experts to manage and analyze the NDP.

### **Project Team**

The project team demonstrated a virtual company concept involving this small independent oil producer and geographically diverse experts. As lead organization for the Class III project, Strata is responsible for project management and day-to-day operations from its location in Roswell, NM. Territorial Resources, Inc. in Roswell, NM until recently provided geological expertise; and Pecos Petroleum Engineering, Inc. (PPE), also of Roswell, provides reservoir, production, and drilling engineering services. Dr. Bob A. Hardage of the Texas Bureau of Economic Geology (BEG) in Austin, TX provides seismic and geophysical expertise. Dave Martin and Associates, Inc., with virtual employees in Los Alamos and Albuquerque, NM and in Houston, TX, provides reservoir modeling and simulation services. The Petroleum Recovery Research Center (PRRC), located in Socorro, NM, provides reservoir characterization, technical support, and technology transfer functions.

The Nash Draw virtual team demonstrated the benefits of networking and communications technologies with an independent petroleum producer. One challenge to this type of organization is providing communication and coordination between the team members located in five different geographic areas. Reporting and coordinating of five subcontractors used advanced technologies to communicate and coordinate efforts. The Internet, e-mail, and high-capacity data transfer were used successfully to exchange data, interpretations, and conclusions between each group. E-mail was used to coordinate the technical activities of the team, in preference to more conventional communications media like the telephone and fax. Petrophysical and production databases were developed and maintained by Pecos Petroleum Engineering, Inc. in Roswell, NM. These were shared electronically with all other project sites. In this case the file sizes were more appropriate to the file transfer protocol (ftp) than e-mail. Geological interpretations in the form of digitized two-dimensional structures and isopach maps were generated by Territorial Resources, Inc. also located in Roswell, NM. The resulting annotated contour files were exported to Dave Martin & Associates, Inc. in Los Alamos, NM.

This virtual company concept used successfully for the NDP project is described in a recent technical paper.<sup>5</sup>

### **Methodology**

The advanced characterization effort of the NDP team integrated geological, geophysical, petrophysical, geostatistical, production, and reservoir engineering data. The stratigraphic framework was quantified in petrophysical terms using innovative rock-fabric/petrophysical relationships calibrated to wireline logs. Geostatistical techniques coupled with correlations of 3-D seismic attributes were used to extrapolate petrophysical properties into the interwell area. Successively refined geological reservoir models were developed by the interdisciplinary team. Reservoir characterization and simulation studies were used to predict the distribution of remaining oil saturation, to assess the feasibility of a pressure maintenance pilot injection test, and to optimize development drilling programs.

## **RESULTS OBTAINED IN PHASE I**

This report will highlight results obtained in Phase I of the NDP Class III project. Detailed results are contained in the annual project reports<sup>6-8</sup> and in several technical papers.<sup>9-13</sup>

### **Comparison of NDP Data to Nearby Delaware Fields**

Log and core data from wells in the E. Loving Delaware Pool, Texaco wells southeast of the NDP, and from Maralo wells offsetting the NDP were obtained and analyzed. Structure maps and cumulative oil, gas, and water production for the E. Loving Pool, and logs and available core data from all three fields were analyzed and compared to data from the NDP.

To evaluate the recovery techniques used in the Nash Draw DOE Class III project, an analog area was selected and analyzed to determine the recovery efficiency and producing characteristics of a field

completed using standard techniques. An entire 640-acre section in the Loving Brushy Canyon Pool was selected as a typical primary producing model. Section 14, Township 23S, Range 28E was selected because it was fully developed on 40-acre spacing, offered a wide variety of geological conditions, and had sufficient production history to reliably predict recoveries. Sixteen wells in the E. Loving Pool in Section 14, T23S-R28E were selected as an analogy to the NDP. These wells represent varying structural positions and corresponding production characteristics. Logs were obtained from each well, structure maps were constructed, and available core data were obtained for the wells in the study area. Structure and isopach maps were developed in the analog area using the same criteria that were used in the NDP area.

Results obtained in Phase I of the study indicate that core data from all three nearby Delaware fields, the E. Loving Pool, the Texaco, and the Maralo fields offsetting the NDP, correlate very well in the "L" zone, but there is less agreement in the data from the "K" and "K-2" zones (see Fig. 4). Core data from the offset and analog wells were calibrated to characterize the uniformity of the zones over the area. As it turns out, the porosity and permeability relationships for each of the basal Brushy Canyon sands in the study area are very uniform from well to well. Rock characteristics in the analog area are similar enough to those in the NDP to allow accurate comparisons of the production data and characteristics of the two areas.

#### Analog Area

Section 14 contains the typical components of a Delaware pool. It dips from west-northwest to the east, the northwest corner of the section is at -3107 ft at the top of the Bone Spring Formation and the east edge is at -3261 ft. This is a change of 254 ft in the structure across the section. The surface on top of the Bone Spring in Section 14 indicates a bench located west of center with an updip step on the west side and a downdip step on the east side. Located in the middle-west side of the section is a bench which has a lower dip angle than the steps on either side of the bench.

The step-bench sequence is a typical depositional characteristic of the basal Delaware zones in this area. Typical benches are 0.5 to 1.0 mile wide with dip rates of 0.8 to 1.9 ft per 100 ft (0.8% to 1.9%). Typical steps are 0.25 miles to 0.5 mile wide with dip rates of 3.3 to 8 ft per 100 ft (3.3% to 8.0%). Section 14 has a bench that is approximately one-half mile wide, with steeply dipping steps on either side. Wells located on the bench in Section 14 have significantly higher recoveries than wells located on the updip step or the downdip step (see cumulative production totals in Fig. 5). Wells on the bench are estimated to have an average primary recovery of 192,000 BO. The projected production from the wells located on the offsetting western updip step is 122,375 BO. Recoveries from wells on the eastern offsetting downdip step are projected at 139,370 BO, and wells located on the far eastern downdip part of the step are projected at 56,935 BO.

Comparison of data from the NDP and the Loving Field helped confirm that reservoir characteristics were similar between areas. Core data were obtained from the wells in the Loving Field, and the distribution of porosity versus permeability were compared. As shown in the first annual report<sup>6</sup> on the NDP project, the two data sets are very similar. Also, producing characteristics, oil saturations, and rock properties are in close agreement. The single most important difference between the two areas is the

difference in the "K-2" zone. The NDP has a highly developed "K-2" zone that is wet and produces large volumes of water if stimulated. The Loving wells do not have a significant zone in the "K-2" zone and produce only small quantities of water.

To predict the ultimate primary recovery from this section, a production curve was created for each well displaying oil, gas, and water historical production. From this production history, decline curves of each phase were described and projected to the economic limit to calculate the ultimate recovery from each well. The sixteen Brushy Canyon producers have cumulative production ranging from 51,000 to 168,000 bbl of oil. The total primary recovery from the 16 wells in Section 14 is projected at 2,084,013 BO, 10,981,608 MCFG and 976,669 BW.

The estimation of the original-oil-in-place was made by performing a core calibrated log analysis to determine the actual net pay from digitized logs. The use of digitized logs with 0.5 foot sampling provides the resolution to determine productive zone in the highly laminated Delaware Zones. Once the pay zones, saturations, and permeabilities were calculated, a volumetric calculation was performed to determine the oil in place at each wellbore. These values were assigned to a grid with 1,600 cells representing 0.4 acres per cell. A computer was programed to estimate the oil volumes for the remaining cells in the grid. Oil saturations varied from 26,707 BO/acre to 10,327 BO/acre.

By summing the value of each cell in the section a value for the original-oil-in-place was calculated. The OOIP is estimated at 12,473,340 BO and the gas-in-place volume was estimated, using a GOR of 1020 SCFG per BO, to be 12.722 BCFG. To check this estimate, a calculation using the General Material Balance Equation was made. Comparing the two methods of analysis, we find that there is good agreement between the two calculations.

These values will be used to analyze the techniques used at the NDP. Through better stimulation, targeted drilling, pressure maintenance, and reservoir characterization, recoveries should be better than the 16.7% realized at the Loving Pool (see **Table 1**).

#### **Data from Offset Wells**

Texaco has drilled five (5) wells offsetting the NDP to the southeast. The "L" zone is the main pay zone in the Texaco wells, similar to the NDP wells, the "K-2" zone is wet and produces large quantities of water, and the "K" zone is lower structurally and is wet.

The permeability versus porosity relationships between the NDP and the Texaco wells provided in the first annual report<sup>6</sup> showed similar relationships for the "L" zone in both areas. Permeability is slightly lower in the "K-2" zone in the Texaco wells, and the permeability is slightly higher in the "K" zone (see **Fig. 4**).

The wells in the Texaco area are deposited on a bench-step surface on top of the Bone Spring zone, similar to other Delaware fields in the area. The top of the Bone Spring zone on the west edge of Section 19 is at a depth of 6830 ft (common datum), and the east edge is at a depth of 6950 ft. This represents a dip of 120 ft across the north end of the section. The bench is approximately 0.5 miles wide and the steps

are approximately 0.25 miles wide. Wells in Units "A" and "C" are located on benches and wells located in Units "B", "F" and "K" are located on the steps. Wells on the benches exhibit better pay quality and higher OOIP values than the wells located on the steps.

The Texaco wells were completed in the first half of 1996 and sufficient production history is not available for an accurate prediction of ultimate recoveries from decline curve analysis. A volumetric estimate of the OOIP was made by assigning the oil-in-place value for 0.4 acre grid blocks for the 640-acre section. Using this analysis the section contains 2,954,648 BO, with 493,526 recoverable reserves using a recover factor of 16.7%. The recovery for each well was based on drainage areas.

Because of thinner pays, a narrower bench, and only the "L" zone as a pay, the Texaco wells have approximately half of the primary reserves that the NDP wells have. Also, the very wet "K-2" contributes large quantities of water if this zone is fracture stimulated in conjunction with the "L" zone.

### Well Data Acquired at the NDP

Conventional suites of logs (neutron porosity, formation density, gamma ray, caliper, dual lateral log, micro resistivity log) were obtained in all of the NDP wells, and a magnetic resonance tool was run in Well No. 23 for comparison to the core analysis. Multiple sidewall cores were obtained for analysis from each new well, and 61.9 m (203 ft) of full core was cut for laboratory analysis from Well No. 23. The whole core obtained from Well No. 23 was cut from the "J" zone through the "L" zone. Basic core data including porosity, permeability, oil and water saturations, grain density, show description, and lithology description, were measured for each foot of core. Special core analysis included wettability, capillary pressure, relative permeability, thin sections, X-ray diffraction, and Scanning Electron Microscope (SEM) studies. In the scanning electron microscope (SEM) study performed on the full core, detailed petrographic, scanning electron microscopy, and x-ray diffraction analyses were performed on thin-section samples from Well Nos. 15 and 23.

The full core data were used to provide a transform to correct the log crossplot porosity to yield a true porosity based on the whole core porosity. The relationship between crossplot log porosity (logs run on a limestone matrix) and core porosity is presented in Fig. 6, and the equation of the line that fits the data was determined to be:

$$\phi_{\text{CORR}} = (\phi_{\text{x-plot}} - 3.7685) / 0.848294$$

Sidewall core data from each well in the NDP were compiled, and porosity/permeability ( $\phi/k$ ) relationships were determined. These relationships were compared to the whole core data and found to be in good correlation (see Fig. 7). Permeability was plotted against porosity, and a regression analysis was performed to generate equations to fit the data. These relationships were used to predict the permeability of each zone based on the corrected log porosities.

This relationship was used to predict permeability of each zone based on the corrected log porosities, and permeability/porosity distributions were obtained for each zone. These data were used to

calibrate the logs and determine pay distribution in each zone. A detailed core-calibrated log analysis of  $S_{or}$ ,  $S_w$ , and porosity was applied to the digitized logs to determine the productive and the water zones in each interval. The application of porosity/permeability transforms and relative permeability data to each zone yielded flow capacity data for each interval.

By applying the core-calibrated log analysis to the entire basal Delaware section, oil-productive zones could be identified, reserves could be estimated, production rates could be predicted, and water-productive zones can be avoided. This procedure has proven to be an accurate predictive tool for new wells in the NDP. Strata and other members of the project team are refining and testing this analysis technique on other Delaware formation wells throughout southeastern New Mexico and west Texas.

Production, transmissibility, and capillary pressure data were combined with geological interpretations to develop reservoir maps. A detailed correlation of the basal Brushy Canyon sandstones was performed in order to better understand the lateral and vertical distribution of the reservoirs. Detailed correlations also provide a more accurate geological model for use in the reservoir simulation phase of the study. Wireline log and core data were compiled for each of the wells within and directly adjacent to the NDP for the purposes of constructing the maps for the initial structural and stratigraphic model.

#### **Petrophysical Data**

Analysis of whole core and drilled sidewall core data have shown that individual Brushy Canyon micro-reservoirs may be oil-bearing, water-bearing, or transitional in nature.<sup>6</sup> In addition, the sandstones have been found to have little or no vertical permeability from one micro-reservoir to the next.

Mineralogy of the "K" and "L" sandstones are similar. Examination of the whole core showed that the reservoir rock is fine to very fine-grained, massive to very thinly laminated. There is some evidence of high energy turbulence as exhibited by sets of low to medium angle cross bedding within some of the sandstone units. Evidence of bioturbation occurs in some of the shaley and silty zones. There is also carbonate clastic debris present in some intervals within the core. Both zones contain some clays--illite and chlorite. The petrographic analysis of sidewall cores from Well Nos. 15 and 23 described the sands as follows: silty, very fine to fine grained, feldspathic to feldspathic lithic sandstones, angular to subrounded, low to moderate sphericity, and polymictic quartz. Various diagenetic effects are present including quartz and calcite overgrowths, authigenic chlorite, pore-bridging illite, mixed layer illite/smectite, and detrital kaolinite. All of these components work to influence the porosity and permeability of these reservoirs in a negative way. A common concern in Delaware sands has always been the clay content. Fieldwide, consistently higher water saturations are calculated in the "K" sand than in the "L" sand. According to the x-ray diffraction clay analysis, there is a 1 to 2 percent by volume increase of boxwork chlorite filling the pores in the "K" sand than is present in the "L" sand, at least in Well Nos. 15 and 23, that could occlude permeabilities and may have influenced higher initial water saturations. The morphology of the chlorite clays is such that they have a very high surface area upon which to bind water. A higher initial, irreducible, water saturation ( $S_{w,ir}$ ) would have prohibited migration of oil into the already crowded pore spaces. If this relationship exists between the "K" and "L" sands in other wells in the field, then that could explain the low OOIP in the "K" sand.

Examination of the core under ultraviolet light shows the discontinuous character of the hydrocarbon distribution throughout the reservoir. This correlates with the erratic vertical distribution of calculated oil and water saturations seen in the log analysis.

Data used to characterize these zones were capillary pressure data, wettability data, and water-oil relative permeability. These data indicate that the Brushy Canyon sandstones are water-wet zones.

The whole core data were used to calibrate the logs and determine pay distribution in each zone. By performing a detailed core calibrated log analysis of  $S_{xo}$ ,  $S_w$ , and porosity, a detailed analysis was applied to the digitized logs to determine the productive and water zones in each interval. The application of porosity/permeability transforms and relative permeability data to each zone yielded flow capacity data for each interval. These data were summed for each layer and input into the reservoir simulator.

### Permeability ( $k_p$ )/ Porosity Relationships

Porosity/permeability relationships for each interval were developed from the sidewall cores and full core analyses. Flow unit variables  $a$  and  $b$  were determined for the power function:

$$k = 10^{a \phi - b}$$

Values of the flow unit variables are given in **Table 2**. A data file was prepared for each well that included digitized log files, perforations, cement programs, tracer logs, completion information, and frac treatments. These data were used to allocate production, estimate drainage areas, determine productivity, estimate saturations for each interval, and prepare data files for reservoir simulation.

Early in the analysis of the sidewall core data, the full core data, and the digitized logs, it became evident that an accurate method of predicting oil productive zones was necessary. Following the sidewall core methodology used to identify pay zones, a method was devised which identified pay zones using core-calibrated log analysis. This analysis requires the following steps:

1. Obtain an accurate history of the resistivity of the mud filtrate ( $R_{mf}$ ) while drilling the pay zones. Obtain accurate  $R_{mf}$  values for the mud used while logging. Correct the  $R_{mf}$  values to bottomhole temperature using Arp's Equation:

$$R_{mf\text{corr}} = R_{mf@75^\circ F} \times (75^\circ + 7) / (T_{\text{amb}} + 7 + ((\text{depth}/100 \text{ ft}) \times T_{\text{gradient per 100 ft}}))$$

2. Correct porosity values using the cross-plot vs. core porosity transform.
3. Calculate a residual oil saturation ( $S_{xo}$ ) using the  $R_{mf\text{corr}}$  and  $\phi_{\text{corr}}$  values in the equation
 
$$S_{xo} = 1 - ((F_r \times R_{mf\text{corr}}) / R_{xO\text{MSFL}})^{.5} \quad \text{Where } F_r = 0.81 / \phi$$
4. Calculate an  $S_{xo}$  value for each interval in the digitized logs, and sort out the intervals with  $S_{xo}$  values greater than the residual oil values in the cores. Since intervals with low or no residual oil saturation have a low probability of being oil productive and intervals with high residual oil

saturations have a high probability of being oil productive, this is the first sorting step in the process of determining productive zones. These intervals are potentially productive zones and can be processed with other criteria to arrive at an accurate determination of the productive zones.

5. Because of the thin-bed nature of the Delaware formation, the Deep Resistivity Log is influenced by the zones on either side of a productive zone; this averaging of approximately three feet of zone and invasion leads to low  $R_t$  measurements. Low  $R_t$  values yield high  $S_w$  calculations and pessimistic interpretations of potential productive zones. To compensate for the averaging of thinly bedded reservoirs by the deep resistivity tool, an adjustment factor is used to multiply the observed  $R_t$  value by this correction factor to obtain a corrected  $R_t$  value ( $R_{t_{corr}}$ ). This correction factor can be obtained by two methods: (1) by using Tornado Charts for thin-bed reservoirs, or (2) if a known productive zone is available and the  $S_w$  is known, it can be used to calibrate the calculations by finding the correction factor that yields  $S_w$  calculations which match actual production and test data. The most often used correction factor at Nash Draw Pool is 1.1, when this correction is multiplied by the  $R_t$  value, this yields a  $R_t$  value 10% higher than measured. By applying a  $S_w$  cutoff of less than 60% to the prospective intervals, only intervals which have favorable relative permeability values are included in the sample of potentially productive zones.
6. The next sorting criteria is the gamma ray (GR) value from the logging suite. By eliminating intervals with GR values greater than 70 API units, shales and shaley sands are eliminated from consideration as productive zones. Shaley sands have low permeabilities and are seldom productive.
7. The relative permeability data and the permeability/porosity relationships indicate that porosity values less than 11% yield permeabilities below the level that is productive. Therefore, only zones with a corrected porosity of 11% or greater are included in the final set of intervals which are projected to be productive.
8. Using  $S_w$ ,  $\phi_{CORR}$ , and other reservoir parameters, an original-oil-in-place (OOIP) value can be calculated for each interval on the digitized log. The OOIP value cutoff is a value greater than 300 bbl/ac-ft.

An example of the output from the core-calibrated log analysis is shown in **Fig. 8**.

In summary, the sorting guidelines were used on the Nash Draw Pool wells to determine productive zones and water producing zones. We have successfully used this advanced log analysis procedure in other Delaware fields, and we believe that the methodology can be used in other complex sandstone reservoirs.

Using core and log data, each well was calibrated to match production, net pay, and transmissibility. By calculating a  $kh/\mu$  value for each interval, production rates and cumulative production was allocated to each interval. The transmissibility for each layer was used as input into reservoir simulation model along with saturation data to determine the producing characteristics of each layer. Transmissibility values were used to calculate production from the various zones for all of the 16 wells

in the NDP (see Fig. 9). These data show that the bulk of the oil production at the NDP comes from the "L" sandstone, but much of the water is produced from the "K" and "K-2" sandstone, if the latter zone is present.

### **Production Well Characteristics**

A total of six (6) data wells were drilled during Phase I of the project. Four data wells, Nos. 12, 23, 24, and 25, were drilled during the first year of the project. Each of these wells was drilled in different areas of the field to determine the producing characteristics at different field positions.

NDP Well #29 has been production tested since June 1, 1997. Testing has confirmed that the "L" zone is partially pressure-depleted as indicated during the Repeat Formation Test performed on the zone at 6525 ft that indicated a stabilized bottomhole pressure of 1905 psi. The initial gas-oil ratio was over 8 MCFG per barrel of oil. A GOR of this magnitude is typical of a well that has been on production for over a year. By April 1998 the GOR had increased to 11.7 to 1. A typical well achieves a GOR of 11 to 1 after approximately 24 months of production.

The pressure depletion experienced in NDP Well #29 prompted a review of the production data to determine the interference between wells, drainage areas and the effect on ultimate primary recovery. To evaluate the history of the reservoir, 1) the completion sequence was determined, 2) an initial GOR was determined for each well, 3) a Rate vs. Cumulative Production curve for each well was plotted, 4) the ultimate primary production was estimated from the decline curves, 5) primary recovery per acre was estimated from the log analysis, 6) an indicated drainage area was estimated by dividing the ultimate recovery by the recovery per acre value, and 7) a ratio of indicated drainage area vs. allocated acreage was calculated. Plots of rate vs cumulative production for the NDP wells are shown in Fig. 10. These plots were reviewed for evidence of interference resulting from the production from newly completed off-set producing wells.

The pressure depletion evidenced in NDP Well #29 indicates that some of the main producing zones are continuous over large distances. NDP Well #29 is 2,214 ft from the NDP Well #5, 1,617 ft from NDP Well #10, and 2,577 ft from NDP Well #23. At this time it appears that NDP Well #29 has interfered with NDP Well #10 and possibly NDP Well #5, as evidenced by the change in slope of the Cumulative vs. Rate Curve for the affected wells.

By plotting Rate vs. Cumulative Production (log scale), three groups of wells were identified. The first group is characterized by a straight line with a moderate slope. This type of curve is indicative of a well that is in a large reservoir with minor or no interference with other wells. The wells in this group are NDP Wells #5, #14, #15, #19, and #24. These wells are located on the outside of the developed area and have other producing wells on only one or two sides.

The second group of wells is characterized by initial production similar to the first group of wells with a increase in the slope of the curve when interference effects the production rate. The wells in this group are NDP Wells #1, #6, #9, #10, #11, and #13. All of these wells, except NDP Well #13, are inside wells that are offset by two or more producers. NDP Well #13 is offset by three high cumulative

production wells on the south and east sides and is open on the north and west sides. This group of wells is developed on approximately 40-acre spacing.

The third group of wells is characterized by a steep slope of the Rate vs. Cumulative Production curve. This group of wells exhibit high initial GORs associated with partial pressure depletion and low initial oil production rates. The wells in this group are NDP Wells #12, #20, #23, #25, #29, and #38.

An ultimate primary recovery volume was estimated for each well by projecting the decline curve to the economic limit. This volume was then divided by the recovery per acre estimated from the log analysis. The resulting value indicates the number of acres being drained by each well (see **Table 3**). By comparing the indicated drainage area to the allocated area (40- or 80-acre spacing) a drainage ratio can be calculated. The eight wells with initial GORs of less than 2,000 CFG/BO indicate a drainage efficiency of 100% to 60% from the indicated drainage area versus the allocated drainage area. The remaining eight wells with high GORs indicate a decreasing drainage efficiency from 60% to 20%.

A summary from this analysis and the basis for future investigation is: 1) wells drilled on 40-acre spacing exhibit interference, 2) pressure depletion can occur over distances greater than 1,600 ft, 3) some wells exhibit little or no effects of interference (which may be attributed to compartmentalization or a large reservoir volume in relation to the amount of interference), and 4) wells on 40-acre spacing may be recovering less than 60% of the recoverable oil due to the laminated and discontinuous nature of the reservoir.

The NDP Well #38 was spudded on September 12, 1997, drilled to a depth of 7,200 ft with no difficulties, and production casing was set and cemented on October 3, 1997. The surface location of the well is 330 ft FSL & 2450 ft FWL in Section 13, T23S-R29E, approximately 1,777 ft south-southwest of NDP Well #29. This well was drilled on a seismic anomaly that indicated high amplitude values for the "K" interval and high negative amplitude values in the "L" interval.

The results from the NDP Well #38 were disappointing due to the low permeability and porosity in the "L" sands. The "L" zone has 38 ft of pay with 10% or greater porosity, 20 ft of pay with 12% or greater porosity and 5 ft of pay with greater than 14% porosity. The sands were finer grained and had corresponding lower permeabilities and porosity. The highest permeability measured from the sidewall cores cut from the "L" interval was 0.24 md. The average permeability in the "L" zone over the NDP area is greater than 1.0 md.

The seismic interpretation made a fair estimate of gross pay, but small variations in porosity can effect the permeability drastically. Further work on interpretation of seismic attributes is needed to resolve differences in pay quality.

## Seismic Data

Two vertical seismic profiles (VSPs) were recorded in the centrally located Well No. 25, and a 3-D seismic survey was acquired to aid the characterization of the NDP reservoir, especially in providing interwell correlations and facies prediction. There were multiple reasons for shooting the 3-D seismic survey at the NDP. One reason was to develop a more refined geological model that gave better resolution of the structural aspects of the trap. A second reason was to try to determine whether or not the reservoirs in the basal Brushy Canyon sequence could be imaged using thin-bed seismic techniques. Details of the acquisition and interpretation of the seismic results are presented elsewhere.<sup>6,12,13</sup>

### Acquisition of VSP Data

To properly prepare and plan for a 3-D seismic survey, a vertical seismic wavetest was first done in NDP Well #25 to characterize the seismic noise induced by surrounding subsurface mining and to define the optimum vibroseis parameters that should be used to generate 3-D seismic wavefields. Concurrent with this wavetest, two vertical seismic profiles (VSPs) were also recorded to establish a precise depth-to-time conversion function for interpreting the 3-D seismic data and to produce a first-look seismic image of the targeted thin-bed "K" and "L" turbidite reservoirs. One Litton 315 vibrator was positioned 255 ft southeast of the well (127° azimuth) to produce zero-offset VSP data, and a second Litton 315 vibrator was stationed 2,178 ft north of the well (349° azimuth) to create a far-offset VSP. One advantage of VSP data recording is that the image produced can be displayed as either a function of seismic two-way traveltime, so that it can be correlated with surface-recorded 3-D seismic data, or as a function of stratigraphic depth to better correlate with wireline-measured log and core data.

### Interpretation of VSP Data

The VSP calibration data acquired in Well No. 25 established the top of the Bone Spring as a robust reflection peak, the "L" sequence was associated with the first reflection trough immediately above the Bone Spring, and the "K" sequence began just above the first reflection peak above the Bone Spring (see Fig. 11). The reflection character of both the "K" and "L" events changes significantly north of the well which implies variation in the reservoir system and is a direct indication of stratigraphic changes or facies changes, or both.

One important result of this initial VSP imaging effort is that it revealed that smaller stacking bins would have to be created in the 3-D seismic data volume if the 3-D data are to show lateral changes in the reservoir that are of the size seen in the VSP images. Consequently, as a result of the VSP work, the Nash Draw 3-D seismic grid was redesigned to produce acquisition bins measuring 55 x 110 ft. During data processing, a trace interpolation was done in the source line direction to create interpretation bins measuring 55 x 55 ft.

A key conclusion of this vertical wavetest is that high quality seismic data can be recorded at the Nash Draw field. Essentially all of the signal components of each test wavelet survived the downward trip to the targeted stratigraphy at a depth of 7,000 ft.

VSP calibration data acquired in the NDP Well #25 established: (1) the top of the Bone Spring Limestone was a robust reflection peak, (2) the "L" sequence that dominates production at the NDP was

associated with the first reflection trough immediately above this Bone Spring peak, and (3) the "K" sequence began at, or just above, the first reflection peak above the Bone Spring event.

#### Acquisition of 3-D Seismic Data

The VSP data were instrumental in setting the size of the stacking bins used in the subsequent 3-D seismic program. As a result of the VSP work, the 3-D seismic grid at the NDP was redesigned to produce acquisition bins measuring 16.8 m by 33.5 m (55 ft by 110 ft). During data processing, a trace interpolation was done in the source direction to create interpretation bins measuring 16.8 m by 16.8 m (55 ft by 55 ft). For the 3-D survey at the NDP, a total of 917 source points were recorded to create a 3-D coverage across an area of 20.4 km<sup>2</sup> (7.875 sq. mi). The recorded data were quite high quality due to the extensive pre-survey testing and planning, and the rigorous processing sequence that was applied to the 3-D field records.

#### Interpretation of 3-D Seismic Data

Results from the 3-D seismic data were used to generate amplitude maps that show high amplitude areas and the producing trends. The amplitudes of the reflection peak and trough associated with the "K" and "L" sands varied significantly over the NDP, and the most facies-sensitive attribute was reflection amplitude. Inspection of the 3-D data volume showed that the "L" reflection trough had a highly variable amplitude and waveshape, and that it was associated with a number of distinct seismic facies across the image space.

Well productivity appears to be directly correlatable to the amplitude of the dominant "K" reflection peak and "L" reflection trough. A map of maximum negative reflection amplitudes for the "L" sand across the NDP area (see **Fig. 12**) provides a strong visual correlation between the areal distribution of the high-amplitude "L" reflections and the positions of the better producing wells ( NDP Wells #19, 11, 15) documents an important principle that should be considered when siting future NDP well locations: as the amplitude of the "L" reflection trough increases, the productive potential of the "L" sequence increases.

A map of the amplitude of the "K" reflection peak looks much like this "L" reflection trough map, with higher reflection amplitudes again occurring at the better producing locations.<sup>6,12,13</sup> Future wells will be drilled to confirm this analogy and evaluate targeted drilling of the seismic anomalies.

The visual correlation between well performance and the "L" reflection amplitude can be expressed quantitatively and used in reservoir simulators to calculate critical fluid-flow parameters from the 3-D seismic amplitude volume. In particular, statistically significant linear relationships have been established between reflection amplitudes of the "L" sequence and three critical "L" reservoir properties: net pay, porosity-feet, and transmissivity to oil and water.

Crossplots of the relationships among these parameter pairs were used to provide equations to describe the distribution of the respective reservoir-data populations:

$$NP = 12.18 - 0.37 A,$$

$$PF = 1.52 - 0.05 A, \text{ and}$$

$$Tow = 5.98 - 0.24 A,$$

where NP = net pay, PF = porosity feet, Tow = transmissivity to oil plus water, and A = amplitude of the "L" reflection trough.

This suite of equations represents numerical relationships that can be used to convert the "L" reservoir reflection trough amplitudes in the NDP 3-D data volume into estimates of the "L" reservoir net pay, porosity feet, and fluid transmissivity in areally continuous cells measuring 55 ft x 55 ft, which is the smallest spatial sampling provided by the 3-D seismic volume. These trough amplitudes are negative numbers; consequently, the best-fit straight lines slope up to the right, which is the direction that the reflection amplitude increases in these plot formats. In each case, the reservoir parameter (net pay, porosity feet, transmissivity) increases as the magnitude of the reflection trough amplitude increases.

When the 3-D seismic dataset was interpreted, it became apparent that the original conception of the NDP as a collection of thin channel sands continuously distributed between wells was probably not correct. In particular, on the basis of the interpreted seismic amplitude data, the area around the proposed pilot centered at NDP Well #1 was reduced to a "lobe" of approximately 121 hectares (300 acres) containing NDP Wells #1, #5, #6, #10, and #14.<sup>6,12,13</sup> Moreover, analysis of the instantaneous frequency displays, seismic volume, and pressure data indicate that the NDP may be highly compartmentalized (see Fig. 13), and that some of the compartments, for some sand sequences in the "L" zone, may be much smaller than 121 hectares (300 acres).

Anomalous frequencies can be important indicators of stratigraphic discontinuities. Because stratigraphic discontinuities can infer where there are barriers to horizontal fluid flow, then instantaneous frequency displays can be used to infer where reservoir compartment boundaries exist. The confirmation of reservoir boundaries and compartments at the NDP using seismic data, production interference, and pressure testing will be discussed later in this report.

#### **Recent Seismic Interpretation**

In addition to the seismic interpretations of the "K" and "L" pay intervals in the Brushy Canyon formation at the NDP, recent seismic interpretations have been extended to include the Morrow, Bone Spring, and Cherry Canyon formations. The basal Brushy Canyon interval is deposited on the top of Bone Spring depositional surface, which influences the quality of the reservoir and the continuity of the individual sands. To further understand the importance and origin of the depositional surface for the basal Brushy Canyon sandstones at the NDP and enable the extrapolation of this information to other areas, a 10,000-foot interval from the Cherry Canyon to the Morrow formation was investigated.

Several observations can be drawn from this portion of the seismic work.<sup>8</sup>

- Deep, Morrow-related faults (see **Fig. 14**) appear to have a genetic relationship (see **Fig. 15**) to the bench-step model that is being used to describe Brushy Canyon deposition.
- The top of the Bone Spring Carbonate (see **Fig. 16**) reflects the deep structure and provides the depositional surface for the Basal Brushy Canyon interval.
- The bench-step sequence is carried through to the shallow Cherry Canyon interval in the upper Delaware (see **Fig. 17**).
- A north-south bench running through Sections 12 and 13 and a step running north-south through Sections 11 and 14 is evident at each stratigraphic level.<sup>8</sup>

### **Reservoir Compartments and Boundaries**

Analysis of the instantaneous frequency displays, seismic volume, production interference, and pressure data have indicated parts of the "K" and "L" reservoirs are compartmentalized. For the NDP 3-D seismic data, any frequency component calculated from the data that falls outside the range 0 to 120 Hz (the highest frequency created by the vibrators) is, by definition, an anomalous frequency value. When 3-D seismic data volumes are converted into 3-D volumes of instantaneous frequency, there is always a large number of anomalous frequency values.

Instantaneous frequency volumes were calculated from the NDP 3-D data, and the instantaneous frequency behavior was then interpreted across several chronostratigraphic horizons passing through the "K" and "L" reservoir sequences. Using these interpretations, a tentative reservoir compartment model was developed for the "K" sequence across the NDP. This tentative compartment map is realistic in the sense that it indicates there are large compartments around the better producing wells (e.g. NDP Wells 11, 15, and 19) and segmented compartments at the poorer producers (e.g., NDP Wells 5, 6, and 25). Production modeling confirms that the compartment sizes and shapes suggested by this model are realistic and a more detailed compartment model can be developed for both the "K" and "L" sequences in those areas of the Nash Draw Unit where reservoir simulation studies are to be done.

Further work was done in the Brushy Canyon "L" zone to compare the correlation of the boundaries between the observed data, the seismic interpretation and the geostatistics/seismic attribute analysis. A strong correlation is seen between production and testing analysis, seismic interpretation, and the geostatistics/seismic attribute analysis. These data were refined to predict drainage areas and depositional trends.

#### **Drainage Areas**

To estimate drainage areas for each well, decline curves were extrapolated to predict the ultimate oil recovery from each well, and this value was divided by the oil recovery per acre. The calculated drainage area (see **Table 3**) was then adjusted depending on the seismic amplitude in the "L" zone.

The seismic amplitude coincides with areas that are compartmentalized or continuous. Negative amplitudes of 0 to -20 are associated with areas that are compartmentalized, and areas with negative amplitudes from -20 to -60 are in areas where the zones are more continuous. Analysis of the areas that are compartmentalized indicates that approximately 60% to 75% of the pay interval is continuous enough to contribute to production. The drainage areas associated with these wells are multiplied by a factor of 1.33 to adjust for zones that are not continuous and this yields an indicated drainage area.

By comparing the indicated drainage area to the drainage area that the well was predicted to drain, based on governmental proration units or stimulation designs, a drainage ratio "D" can be calculated. If the wells are effectively draining the area they are designed to drain, the drainage ratio should be 1.0. The drainage ratios range from 0.15 to 1.23, with 53% ranging from 0.75 to 1.25.

The other factor influencing oil recovery is interference from offset wells and the resulting depletion. Depletion is evidenced by initial gas-oil-ratios (GORs) that are above 2,000 SCFG/BO. The initial wells and wells drilled away from developed areas had initial GORs of less than 2,000, and wells drilled in developed areas or later in the development of the field had GORs of 2,000-14,000 to 1.

This results in the early wells, such as NDP Wells #1, #11 and #13, recovering more oil than predicted and later wells such as NDP Wells #12, #29 and #38 recovering less oil than predicted. A strong correlation was found between the transmissivity (kh/μ), the number of sacks of sand used in the frac treatment, and the ultimate recovery. The ultimate recovery can be approximated by the following relationship:

$$BO = ((kh/\mu) \times \text{No. Sx. Sand})^5 \times 1,000$$

A closer correlation is obtained by adding the drainage ratio to the equation to obtain:

$$BO = ((kh/\mu) \times \text{No. Sx. Sand})^5 \times \text{Drainage Ratio} \times 1,000$$

This correlation will be explored further to determine the applicability to forecast recoveries from Delaware wells, and as a tool to size fracture treatments.

### **Reservoir Compartments**

The analysis of reservoir, seismic, and production data has led to an interpretation of the major reservoir compartments in the "L" Zone. Using a reservoir simulator model to match GOR history and to estimate the reservoir pressure, bottomhole pressure (BHP) history was developed for each well (see the BHP/GOR model results shown in **Table 4**).

The BHP data were then used in a nearest-neighbor analysis to determine areas of the reservoir with common pressure characteristics. The nearest neighbor analysis coupled with the

cumulative production vs. rate analysis and the geostatistical analysis (described later in this report) have provided an interpretation of the major reservoir compartments in the "L" Zone.

The current interpretation indicates a series of well defined compartments that are identified by production interference, seismic data, and pressure history. These compartments are shown in **Fig. 18** and are summarized in **Table 5**. There is good correlation of the boundaries between the observed data and the seismic interpretation. Boundaries are interpreted to exist where there is a large contrast in amplitudes, from a high negative amplitude area to a low negative amplitude area. This interpretation is supported by the analysis<sup>7</sup> of instantaneous frequencies prepared earlier by Dr. Bob Hardage. His interpretation indicated compartments that were more complex than this interpretation, but may be more accurate in the light of reduced recovery efficiency of wells in areas he described as "highly compartmentalized." This may indicate that some individual sands are continuous from well to well and some sands are very limited in their aerial extent.

This work will continue for the purpose of aiding in the prediction of drilling locations with minimal pressure depletion and compartments that have not been drained. NDP Well #36 will test this theory when a directional/horizontal well is drilled into the seismic anomaly north of NDP Well #15. This pod may be a separate compartment that is defined by a large contrast in seismic amplitudes surrounding this anomaly.

### **Reservoir Modeling**

Each of the primary reservoir sands were mapped using a variety of parameters. The following maps were digitized for each of the five main zones of the NDP reservoir: (1) top of structure, (2) gross isopach, (3) porosity-thickness, and (4) net porosity. Structure and isopach maps were loaded into Landmark's Stratamodel program, and a preliminary 3-D geological layer model was developed. Digitized maps of the interpreted horizons ("J", "K", "K-2", "L", and the top of the Bone Spring formation) were imported into SGM (Stratigraphic Geocellular Model) to create a stratigraphic framework model of the NDP. The structural relationship between the five major producing horizons at the NDP is illustrated in **Fig. 19**.

Initially, both the "K" and "L" sandstones were divided into four sub-units. The sandstones were correlated laterally from well to well in the NDP. Gross isopach, net porosity isopach and log-derived net pay maps were constructed for each of the sub-units of the "K" and "L" sands as well as the "K-2" and "J" sands. The maps were contoured to conform to the overall gross interval isopach maps for the respective pay zones that were used to construct the geological model. Since the producing zones and subzones are relatively thin, great care had to be exercised to prevent intersections of the horizons. It is also critical that the surfaces tie to the well picks of the lithological markers in the well traces. In general, the most successful approach to this problem was based on the use of gross isopach thickness interpretations building from the structural top of the Bone Springs Formation up to the structural top of the "J" sandstone.

The next major step was the development of a well attribute model. This activity was supported by the engineering database. For each of the 17 NDP wells, the following attributes were imported into the well model: neutron porosity and gamma ray, interpreted porosity and permeability, perforated interval and fractured interval, net pay, and water saturation. In some instances, these attributes were available on a foot-by-foot basis for one or more of the producing zones. Not all of the attributes were available for each well. For reservoir simulation, the most important reservoir attributes are fluid conductivity and rock matrix storage capacity. The distribution of these properties throughout the NDP have been based on the well attribute model. Within SGM, these distributions are interpolated deterministically, that is, weighted by the reciprocal of the square of the distance between the location of interest and nearby wells in the reservoir model.

### **Geological Model of the NDP**

As mentioned earlier in the discussion of the Analog area, the step-bench sequence observed in the geological modeling of the NDP is a typical depositional characteristic of the basal Delaware zones in this area. Typical benches are 0.8 to 1.6 km (0.5 to 1.0 mile) wide with dip rates of 0.8% to 1.9%, and typical steps are 0.4 to 0.8 km (0.25 mile to 0.5 mile) wide with dip rates of 3.3% to 8.0%. Better producing wells are located on the benches and poorer producers are located on the steps in the NDP as was observed in nearby Delaware fields.

Initially, it was believed that the NDP was composed of thinly-bedded channel sandstones more or less continuously distributed between wells. The initial geological interpretation suggested that the Brushy Canyon sandstones in the NDP appeared to be blanket type sands. However, data and analyses obtained in the project suggest the sandstones at the NDP are laterally discontinuous and complex in nature. Over the course of the first year of the project, three "generations" of geological models were developed based on evolving interpretations of the structure of the NDP. In the first generation, a full NDP model was developed from the initially-available geological interpretation based on logs and cores. The second generation model was based on these data plus newly-interpreted pressure transient data. The latest version reflects a geological interpretation, based on the 3-D seismic data, that indicated there is considerable compartmentalization within the NDP.

### **Modeling of the Pilot Area**

The integration of the log, core, and pressure transient data led to an interpretation of the NDP with three non-communicating lobes of oil. The proposed pilot injection area is confined to one of these lobes. A detailed reservoir model of the basal Brushy Canyon sandstones in the proposed pilot injection area (which contains the oil lobe supporting the pilot) was developed for reservoir simulation studies. The original proposal called for a pilot area around NDP Well #1, with production response anticipated in NDP Wells #1, 6, 14, 5, 9, and 10. This site was chosen primarily because a five-spot well pattern already existed there. The spacing in this part of the field is very close, and it was hoped that production response could be observed in a relatively short period of time. At the outset of the project, it was envisioned that a field pilot would be implemented in this area to investigate the feasibility of enhanced recovery through pressure maintenance.

Detailed flow unit maps were prepared in the pilot area. Each of the sub-units of the three main

sands previously mentioned were mapped individually. Maps prepared for each sub-unit were isopach maps for log-derived net pay and gross sub-unit isopach maps. These maps were included in the initial geologic model for the simulation study of the pilot area.

Production, transmissibility, capillary pressure data, and geological interpretations were combined to arrive at reservoir maps which honored the available data. It was necessary to perform a detailed correlation of the sands in the basal Brushy Canyon sands in order to better understand the lateral and vertical distribution of the reservoirs. Detailed correlations also facilitate a more accurate geological model for use in the reservoir simulation phase of the study. The data were compiled into a spreadsheet for ease of use between all members for the project team. Well data were compiled for each of the wells within and directly adjacent to the NDP for the purpose of constructing the maps for the initial structural and stratigraphic model.

### The Pilot Model

After the 3-D seismic data acquired at the beginning of the project was interpreted, it became apparent that the original conception of the NDP as a collection of thin channel sands continuously distributed between wells was probably not correct. In particular, on the basis of the interpreted seismic amplitude data, the area around the proposed pilot centered at NDP Well #1 was reduced to a "lobe" of approximately 300 acres containing NDP Wells #1, #5, #6, #10, and #14. Moreover, the interpreted seismic data indicates that the NDP may be highly compartmentalized, and that some of the compartments, for some sand sequences in the "L" zone, may be somewhat smaller than 300 acres. The current geological and simulation models do not reflect this interpretation. Histograms of various petrophysical attributes of the "L" zone do not confirm the conclusion that the NDP is highly compartmentalized, but do confirm the notion that the Brushy Canyon sands are heterogeneous and that reservoir attributes may have short correlation lengths. NDP Wells #9 and #20 are very close to this lobe, but they are not included in the model because they do not appear to be connected to it hydraulically. The present simulation model is based on a geological interpretation of this lobe. Except for reservoir limits, this interpretation is based solely on petrophysical data.

Because approximately 90% of the oil production from the five wells in this lobe comes from the "L" zone, only that zone was modeled in the simulation studies. In order to capture the highly lenticular distribution of oil within the four subzones identified in the "L" zone, a twenty layer simulation model (see Fig. 20) was chosen for the pilot area; that is, five proportional layers for each of the La, Lb, Lc, and Ld subzones. This resolution was the minimum required to capture the nature of the thin beds of the sandstones in the "L" zone. The distributions of porosity and water saturation in the model are shown in Figs. 21 and 22, respectively. These figures illustrate the highly lenticular nature of the Brushy Canyon sandstones in the NDP pilot area. Areal grid spacing in the model was chosen to be 220 ft in both directions, this value being a multiple of the spacing of the seismic lines (x4).

Interpretation of the 3-D seismic data indicated that the pilot area was not a "sweet" spot. It became apparent that a field pilot would not be attempted in the original pilot area, but it was felt that it would be useful to perform a post-mortem on past performance in preparation for the selection of a new pilot site, where it is expected that less field data will be available.

### **Model Validation Criteria**

Our criteria for a "good" match of historical performance were reasonable agreement between simulated values and actual values of drainage-area average pressure for each well (as determined by analytical methods), oil production by well, water production by well, gas production by well and onset of pumping conditions.

Oil production, by well, was used as the driving function for the simulations. Consequently, it would be expected that oil rates were honored exactly by the simulations. However, all five of the Nash Draw wells in the pilot area node reach pumping conditions during the validation step of this project. When a simulated well reaches pumping conditions, the oil rate is not necessarily honored by the simulator, and the oil rate itself becomes a history matching parameter. In this case the bottomhole pressure becomes the driving function.

### **Reservoir Simulation Forecasts**

After the geological model was completed, a reservoir simulation model was generated for the pilot area. Reservoir attributes including porosity, relative permeability, and oil and water saturations were distributed vertically and laterally throughout the layers in the simulation model. The distributions of net pay, porosity, and water saturation obtained from the modeling effort illustrate the highly lenticular nature of the Brushy Canyon sandstones in the NDP pilot area.

A reservoir simulation model for the pilot area envisioned that a single well in the pilot area would be converted to injector status evaluate alternative recovery methods for the field pilot. Reservoir simulation forecasts focused on the efficacy of injecting: (1) water, (2) immiscible lean gas, and (3) CO<sub>2</sub> (immiscible or miscible) to improve oil recovery at the NDP. Eclipse 100 was used for the immiscible hydrocarbon gas cases and VIP-COMP for the CO<sub>2</sub> cases. However, the reservoir description was the same for all forecasts, and was based on the history match obtained with Eclipse 100. The following tasks were required to complete the pilot simulation phase: possible scale-up of lithological units, interpolation of geological attributes on the simulation grid, validation of pilot simulation model, and design and execution of prediction cases. A simulation grid was designed which was centered around the potential injector, but included the net pay of the oil lobe containing the pilot area. The scale-up task was done in Stratamodel. The PVT and rock property data needed for the simulation (not a part of the geological model) was processed, and scripts were written to convert the production data in the Lotus engineering database into simulator input format.

Reservoir simulation results indicate that the permeabilities of the Brushy Canyon sandstones are too low for waterflooding to be effective. Preliminary calculations of water injection rates indicates that the water injection rates would be 150 to 200 barrels of water per day, which would be too low to obtain response in a reasonable length of time (see **Fig. 23**).

Lean gas, carbon dioxide, and nitrogen were studied as possible injection fluids for a pressure maintenance project. From the fluids tested, carbon dioxide exhibits the most favorable characteristics, and separator gas exhibits satisfactory results. Nitrogen has limited solubility in the NDP crude oil and

exhibits only approximately half of the oil viscosity reduction of CO<sub>2</sub> and separator gas. Forecasts were made for two possible enhanced recovery scenarios: immiscible gas (both hydrocarbon and CO<sub>2</sub>) injection and miscible CO<sub>2</sub> injection. Details of the reservoir simulation studies are presented elsewhere.<sup>6,13</sup>

### **Immiscible Lean Gas Injection**

Two cases were investigated for the injection of hydrocarbon gas:

Case 1: Conversion of NDP Well #1 to a gas injector on March 1, 1997 (this corresponded to the date of the most recent production data available at the time of the study),

Case 2: Conversion of NDP Well #1 to a gas injector on October 1, 1993, one year after production in the pilot area started.

An early screening case indicated that water injection would not be feasible.

Case 1. The premise of this forecast was simple: NDP Well #1 was to be converted from an oil producer to a gas injector on October 1, 1996. The forecast was run for two years. NDP Well #1 injected against a fbhp constraint of 3000 psi, the largest pressure entry in our PVT table. As illustrated in Fig. 24, the pressure in the drainage region of NDP Well #1 did respond to gas injection as anticipated. However, the pressure response for the remaining four producers in the pilot area was not very encouraging, as illustrated for NDP Well #14 in Fig. 25. The corresponding oil rate for NDP Well #14 is displayed in Fig. 26. Gas breakthrough occurred in NDP Well #5, the well nearest NDP Well #1, after about a year, and this well was shut in, since the large induced fracture mitigated against a workover.

Case 2. It is apparent that there was very little natural energy left in the pilot node at the inception of Case 1, and that the induced fractures and zones with free gas provide a ready conduit for early breakthrough of injected gas. The premise for Case 2 was the idea that the injection of gas early after the onset of production might avoid the channeling of gas through zones of free gas that existed in Case 1. For this case, NDP Well #1 was converted to gas injection after only one year of production. The average pressure in its drainage region was still around 1700 psi, and above 2500 psi in the drainage areas of the other wells in the pilot node. As in Case 1, the fbhp = 3000 for NDP Well #1. The pressure response of NDP Well #1 is illustrated in Fig. 27. The pressure response for NDP Well #6, unlike Case 1, experiences an increase in pressure during the period of the forecast (see Fig. 28). The oil production rate for NDP Well #6 is illustrated in Fig. 29. The production behavior, typical of the other producers in the pilot node, shows a high plateau of oil production is followed by a gradual decline.

Because the pilot area is the most developed area of the NDP, this area has a greater well density and the wells in this area have been producing for a longer period of time. Consequently, there is very little natural energy left in the pilot node at the inception of injection, and any induced fractures or zones with free gas would provide a ready conduit for early breakthrough of injected gas. The simulation results indicate that implementation of a gas injection pressure maintenance scheme after the drainage area pressures have declined below 3,447 kPa (500 psi) will not be successful in improving oil recovery. Even for higher initial drainage area pressures around 10,342 kPa (1500 psi), the simulation studies indicate that immiscible gas injection will be of marginal value. On the other hand, the implementation of pressure

maintenance, specifically gas injection, early in the development of the pattern could have doubled the recovery of oil in the five spot pattern during the early years of production. Immiscible gas injection at pressures above 17,237 kPa (2500 psi) might lead to the recovery of enough additional oil to merit a look at economics.

Thus, the low permeabilities at the NDP will preclude waterflooding, but immiscible gas injection may be viable if initiated early and if undeveloped regions of the field can be found that have not been pressure depleted.

### **Carbon Dioxide Injection**

Although a different reservoir simulator was required for the carbon dioxide (CO<sub>2</sub>) injection study, the history match in the pilot area for the CO<sub>2</sub> cases was qualitatively the same as that obtained for the hydrocarbon gas study. History match for gas production from the five wells in the pilot area (NDP Wells #1, 5, 6, 10, and 14) show typical solution-gas-drive performance with initial high GORs decreasing as the reservoir is depleted. Since the pilot location for this study is no longer under consideration for the field trial, further history matching was not performed, since it is likely only minor differences in results would follow. Instead, several predictions for CO<sub>2</sub> injection were performed to obtain qualitative results for this recovery process.

Several prediction simulations were performed with CO<sub>2</sub> for both miscible and immiscible CO<sub>2</sub> injection scenarios. For the miscible injection cases, simplifying assumptions were made because no laboratory data were available. In particular, the miscible injectant was assumed to have properties of pure carbon dioxide and to be first-contact miscible with the reservoir oil. To compare the different prediction cases, oil production was calibrated by adjusting the flowing bottomhole pressure at the beginning of the prediction cases so that the oil production rate was similar to the field-observed rates. With the constant bottomhole pressure as a boundary condition, predictions were then made from the end of history for 11 years to March 1, 2008. Injection was assumed to begin immediately after the end of the history match, although in reality a delay of at least two years would be required for project implementation. Injection was based on 120 MSCF/D of gas injectant - either miscible or immiscible. This volume was based on the volume of immiscible gas required to maintain pressure in the reservoir. A water-alternating-gas (WAG) scenario was also simulated. In this case the injection bottomhole pressure was limited to 5000 psi with a WAG ratio of about 4:1 water to carbon dioxide.

Simulations compared a base case of continued operations with no injection to a total of 9 prediction cases for various recovery scenarios: (1) convert NDP # 1 to injector - 120 MSCF/D CO<sub>2</sub> miscible, (2) convert NDP # 5 to injector - 120 MSCF/D CO<sub>2</sub> miscible, (3) convert NDP # 6 to injector - 120 MSCF/D CO<sub>2</sub> miscible, (4) convert NDP # 10 to injector - 120 MSCF/D CO<sub>2</sub> miscible, (5) convert NDP # 14 to injector - 120 MSCF/D CO<sub>2</sub> miscible, (6) infill injector - 120 MSCF/D CO<sub>2</sub> miscible, (7) infill injector - 4:1 WAG, (8) infill injector - 60 MSCF/D CO<sub>2</sub> miscible, and (9) infill injector - 120 MSCF/D immiscible injection. The infill injector was located at the center of the pilot area between wells NDP # 1, 6, 10, and 14.

Simulation results for miscible injection in the NDP pilot area indicate that carbon dioxide injection may be a viable alternative for improved oil recovery for this field, if an economical source of CO<sub>2</sub> was available. For the eight different CO<sub>2</sub> miscible scenarios, incremental oil recovery was observed (see **Table 6**). Compared to a continued operations case, increased oil recoveries ranged from a low of 40 MSTB to a high of 110 MSTB or an increase in recovery in the range of 2-5% of OOIP for several different CO<sub>2</sub> miscible scenarios during the ten years of the forecast. These results coupled with a reasonable recovery per MCF of CO<sub>2</sub> injected indicate that further investigations should be made into CO<sub>2</sub> miscible injection. However, immiscible CO<sub>2</sub> injection did not produce significant oil production in the simulation forecasts.

Based on these preliminary results, CO<sub>2</sub> breakthrough should occur in less than one year even in the most optimistic situation. This indicates that a well-designed and simulated pilot could provide timely information for use in a full-field implementation. Better characterization of the reservoir in the vicinity of the new pilot area should be obtained to assess the practicality of initiating an injection test.

Simulation results for miscible injection in the NDP pilot area indicate that carbon dioxide injection may be a viable alternative for improved oil recovery for this field. CO<sub>2</sub> injection, if implemented before the pressure has declined below about 10,342 kPa (1500 psi), might be successful but economics of the process would need to be evaluated. Areas of the field already under production may be candidates for CO<sub>2</sub> injection if pressures have not declined too much.

## **Geostatistics and Reservoir Mapping**

The second annual report<sup>7</sup> discussed the results of the L-zone amplitude-porosity correlation used to locate NDP Well #29. Because the porosity encountered in Well #29 was 40% less than that predicted from correlation, two different approaches were investigated to forecast spacial reservoir properties. A production interference analysis was conducted to define flow units, and several mapping techniques were used to describe the static reservoir properties.

### **Well Interference and Flow Units**

Oil rate versus cumulative production curves were reviewed for evidence of interference resulting from the production from newly completed off-set producing wells. The wells were assigned to the flow units based on the a slope change and the initial GOR. A high initial GOR with a constant slope indicates that pressure depletion had occurred at the time of completion. In this case flow units are defined as areas exempt from interference from off-set wells.

### **Statistical Analysis of Flow Units**

Several mapping techniques were used to describe the spatial distribution of the L-zone static reservoir properties. Since the objective is to optimize the placement of drilling locations, the hydrocarbon pore volume ( $h\phi S_o$ ) was the reservoir mapping parameter. The  $h\phi S_o$  parameter was developed from log information and was mapped with a conventional, nearest neighbor ( $1/r^2$ ) technique, with a kriging technique based on a spherical variogram model, and with a fractal model. The maps resulting from the three different methods are similar,<sup>8</sup> and only the fractal map is presented in this report (see **Fig. 30**).

In addition to the static reservoir properties, a "drill here" map requires an estimate of bottomhole pressure to be complete. Estimates of the distribution of dynamic reservoir properties such as pressure are best obtained by matching the past reservoir history with a simulator which was reported in the second annual report.<sup>7</sup> Bottomhole pressure was estimated based on the current producing GOR data and PVT data. These estimates were normalized with the 2950 psi discovery pressure and then used to calculate  $h\phi_s p/p_i$ . These values were used to generate the fractal map in Fig. 31. The delineation of the flow units coupled with the hydrocarbon pore volume/BHP map suggests that future primary development should be towards the northwest under the playa lakes.

### **Geostatistics and Interwell Properties**

Targeted infill drilling is a development option at the NDP. In an effort to better define interwell properties and to understand the reservoir northwest of the current producing wells, two geostatistical analyses were conducted. The first focused on extrapolating with the variogram developed from well data to an area northwest of NDP Well #13. The second was a scoping study applying ordinary kriging to slices from the 3-D seismic survey to estimate the density of 2-D lines required to capture the features apparent in the 3-D grid. The study provides insight to the number of 2-D lines required to characterize the reservoir under the playa lake.

### **Geostatistical Extrapolation**

Interwell reservoir properties were estimated with three different mapping techniques: a conventional nearest neighbor ( $1/r^2$ ) method, a kriging method, and a fractal algorithm. The net thickness, porosity, and oil saturation arithmetic average values for the K-zone and the L-zone were determined by well log analysis. The interpolated porosity values between the wells show that the basic pattern provided by the three mapping methods is similar for the L-zone while the K-zone is less similar.

A 16% correlation coefficient for interwell properties provides little help in selecting future vertical well locations based on HCPV maps. If the correlation coefficient was better than 16%, these mapping techniques could be used as a method to select vertical well drilling locations with some confidence. The unknown effect of free gas saturation (pressure) on estimating oil saturation could be a cause of the poor correlation coefficient. Multivariate analytical tools, described later in this report, were investigated as a means of correlating 3-D seismic attributes with the same well properties as used in this geostatistical study.

### **2-D Seismic Analysis**

The purpose of this geostatistical research is to gain insight into the density of 2-D seismic lines required to identify reservoir features that are present in the 3-D data set. An experimental 2-D data set was constructed from the NDP K-zone 3-D survey. A 3-D attribute map, showing the spatial distribution of the average reflective strength across the K-zone, served as a reference for identifying reservoir features that result from combining increasing numbers of 2-D slices. A geostatistical algorithm, ordinary kriging, was used to merge the one-dimensional 2-D lines into a two-dimensional presentation.

Landmark's SuperSeisWorks, software was used to cut the 2-D slices from the 3-D survey. The Landmark documentation states that in sandstone reservoirs the average reflective strength is thought

to be related to spatial changes in lithology or is evidence of channels. Gviz, a geostatistical mapping program was used to integrate the 2-D lines.

The density of the 2-D slices was increased in order to capture many of the original features. All of the major features in the reference map are captured with the kriged map using 10 equally-spaced 2-D slices. Thus, in this example, a network of 2-D lines spaced about 1050 ft apart were used to generate kriged maps that capture the major features seen in the 3-D data set with 55 ft bin resolution. The example visually demonstrates the potential to identify reservoir features with multiple 2-D datasets. Details of this analysis can be found in the Third Annual Report to DOE.<sup>8</sup>

### **Seismic Attribute Analysis**

In the prior section, the potential value of geostatistical techniques for estimating interwell reservoir properties, with infill drilling as a possible goal, was discussed. However, NDP wells primarily cover the center part of the available seismic survey, so a methodology was tested for relating reservoir properties at the wellbore to sets of seismic attributes in order to extrapolate reservoir properties beyond the area directly constrained by wells and to predict reservoir properties across the whole field. Seismic attributes have recently been the focus of renewed interest for evaluating reservoir properties. Well data gives very precise information on the reservoir properties at specific field locations with a high degree of vertical resolution, while 3-D seismic surveys can cover large areas of the field, yet reservoir properties are not directly observable, in part due to relatively poor vertical resolution.

A new technique was developed that utilizes a non-linear multivariable regression to correlate statistically selected seismic attributes to reservoir properties ( $\phi$ ,  $S_w$ , and net pay). The new technique uses seismic attributes as inputs with porosity, water saturation, and net pay as outputs. The regression equations allow a prediction of these three reservoir properties in areas without direct well control. When mathematical relationships between the attributes and wellbore parameters from wireline logs are established, maps of reservoir properties were computed for the location of each seismic bin (every 110 ft) across the NDP for the "K" and "L" intervals.

#### **Data**

The two primary sources of data required for this method are well data and seismic attribute data. Over 80 seismic attributes were extracted from the NDP seismic data volume for the two horizons using the PostStack and Pal tools of the Landmark Graphics seismic interpretation suite. Extracted attributes were averaged across the entire interval of both the "K" and "L" horizons, respectively, and the well data from each of the 19 wells used in the study were also averaged across the respective intervals. Thus the output maps presented later in this report represent interval-averaged values for the respective reservoir properties.

#### **Attribute Selection**

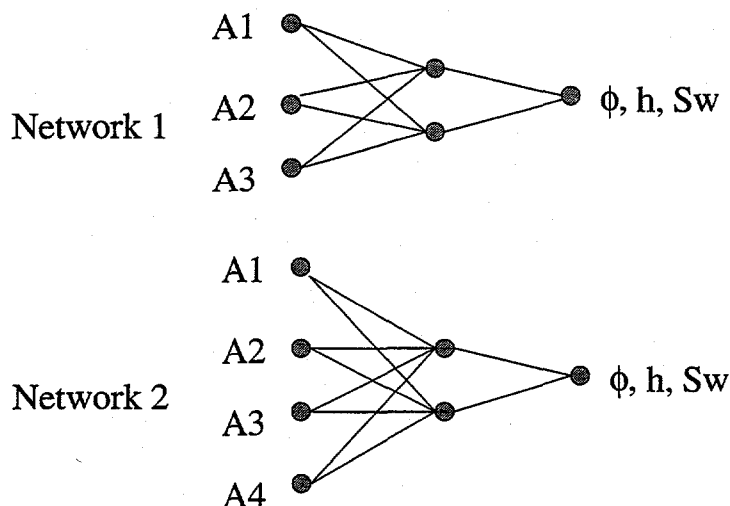
It is computationally infeasible to use all of the extracted attributes in individual non-linear regressions for reservoir properties, therefore a fuzzy-ranking algorithm<sup>14</sup> was used to select attributes best

suiting for predicting individual reservoir properties. The algorithm statistically determines how well a particular input (seismic attribute) could resolve a particular output (reservoir property at the wellbore) with respect to any number of other inputs. Each attribute is assigned a rank, which allows a direct estimation of which attributes would contribute the most to a particular regression.

The fuzzy ranking algorithm was applied to select the optimal inputs (attributes) for six output cases: "K" porosity, "K" net pay, "K" water saturation, "L" porosity, "L" net pay, and "L" water saturation.

### Multivariable Nonlinear Regression

Linear regression for reservoir properties was not feasible for this study, as the relationships between input and outputs were poorly defined by individual attributes. We elected to use a non-linear regression using the fast-converging, feed-forward, back-propagation conjugate gradient algorithm (neural network) implemented in-house at the PRRC. Two neural network architectures were used in the study, both of which were minimized in order to maintain a satisfactory ratio of training data to weights (coefficients of the regression equation). The two networks are graphically illustrated below.



In these architectures, circles represent "neurons" or locations of non-linear functions, while each line represents a coefficient applied to these equations. A back-propagation feed-forward algorithm such as the conjugate gradient algorithm used, is "trained" using known inputs and outputs. For this study, reservoir properties are known at the locations of the wellbore intersections with the interval of interest. Seismic attribute data from the same seismic bin that contains the well is correlated to wellbore values of porosity, net pay, or water saturation in an iterative process using the neural network.

### Training and Testing

It is customary to test the robustness of a solution by holding some data out for testing. Since only 19 control points were available, the networks were trained using all 19 points, and then tested by removing sets of three wells, retraining the network with 16 control points, and then using that network to predict the three withheld points. This exercise was applied three times for each property and interval, withholding differing sets of three points for each test. Results of the training with all 19 points, and three

test sets for the "L" interval porosity regression, show that the network resolved porosity in a robust fashion, and that the tool may be used to predict porosity in other areas of the field (see Fig. 32). Figure 33 shows the 19 point networks for the other reservoir properties of the "L" and the "K" intervals. These regressions were also tested in the same manner, and had similar results.

From the Fuzzy Ranking and non-linear multivariable regression evaluation of seismic attributes, key reservoir properties were estimated. The porosity evaluation used the isochron, instantaneous frequency, and energy half-time attributes as inputs, and the resulting neural network trained to a correlation coefficient (cc) of 0.88. The water saturation evaluation trained to a cc of 0.84 and used the instantaneous phase, average trough amplitude, and energy half-time attributes. The net pay evaluation used the maximum peak amplitude, RMS amplitude, and peak amplitude attributes and trained to a cc of 0.80. In each case, the output data used for training was a reservoir property,  $\phi$ ,  $S_w$ , or net pay, from 19 wells in and adjacent to the NDP.

### **Predicting Fieldwide Reservoir Properties**

The regression relationships (architecture and weights) were used to compute maps of fieldwide porosity, net pay, and water saturation, which were displayed in Landmark's SuperSeisworks Map view. In general these maps fit expectations based on other geostatistical techniques and reservoir understanding. Net pay,  $\phi$ , and  $S_w$  maps were generated using the regression relationships and seismic attributes at each seismic bin location. Maps of  $\phi h$  and  $h\phi S_o$  computed from those reservoir property maps provided a detailed estimate of interwell and field-wide oil pore volume at the NDP. The techniques that were developed maximize both the well control and seismic data and generated useful maps for targeted drilling programs in the field.

From the "K" and "L" interval porosity maps, predicted using the regression relationships, both the "K" and "L" horizons show patterns of distinct, or isolated porosity, and the "L" porosity map compares favorably with compartment maps produced independently. From the "K" and "L" interval net pay maps, the "K" horizon shows much more variation in pay than the "L" zone, which is reasonable considering that the "K" interval is discontinuous and may pinch out, while the "L" interval is considered to be reasonably continuous across the study area. Lineations in the NW corner of the "L" net pay map may indicate facies changes, or onlap deposition and subsequent compartmentalization. From the "K" and "L" interval water saturation maps, the "K" interval appears to very water wet, except in distinct pods, which may represent possible drilling targets. The "L" interval is wet, in a more uniform fashion, though an area of high water saturation in the NW corner, which is up-dip, may be due to compartmentalization.

The  $\phi h$  maps were useful as an indicator of where sufficient pay porosity exists within the field. The "K" horizon shows a good deal of variability, with relatively lower  $\phi h$  in areas where the "K" zone is interpreted to pinch out. The "L" interval  $\phi h$  shows a more uniform distribution of pay porosity, though some thinner and thicker areas do exist. Fine detail across the middle portion of the map may assist in determining compartmentalization of porosity, as net pay is relatively uniform across that region. The hydrocarbon pore volume maps for the "K" and "L" intervals include information on oil saturation ( $1-S_w$ ) and essentially illustrates where the oil is located in the field. The water wet "K" interval shows

only isolated pods of good production potential, while the less wet "L" interval (see Fig. 34) shows strong undrilled potential production in the SE quadrant of Section 11, the SW and NW quadrants of Section 7, and the west half of Section 14. Areas to avoid drilling for the "L" interval might include the east half of Sections 7 and 18, the SW quadrant of Section 13, and the SE quadrant of Section 14.

### DEVIATION FROM ORIGINAL PLAN

The original Statement of Work included a pressure maintenance pilot project in the developed area of the field. In the process of determining the feasibility of the pressure maintenance project, several problems were encountered. Some of the problems that have been identified are: 1) the relative permeabilities indicate that the permeability to water at the residual oil saturation may be too low to make water injection a practical method of pressure maintenance, 2) the seismic survey indicates that the area around the proposed pilot area is compartmentalized and the individual zones are not continuous between multiple wells, 3) analysis of the production data indicates that the compartmentalization, shown by the seismic, is real, and 4) the reservoir pressure in the pilot area is very low. These problems indicated the prospect of success from the pilot pressure maintenance project was limited, and a more continuous area of the reservoir with less depletion would yield more favorable results. This resulted in the pressure maintenance pilot project being shifted into Phase II, when new areas of the NDP are drilled.

Since the pilot pressure maintenance project was delayed and will be evaluated in another part of the field, the associated components of this part of the project were delayed. Unitization of interest in the pilot area was partially competed by the consolidation of minor interests, and other interests were evaluated in preparation of unitization. Associated testing and evaluation such as interference testing, tracer surveys, and continuity testing were discontinued when the pilot area was determined to be highly compartmentalized. This testing will be completed if an alternate pilot area is defined.

A second full core was originally planned, but good recovery and data from the first full core were representative of the reservoir, so that a second core was not necessary. A modification to the statement of work was made to eliminate the second core and substitute additional fluid swelling tests to determine the effectiveness of gas injection for pressure maintenance.

Eight (8) wells were planned to gather data, delineate the field, and evaluate completion and production techniques. To date six (6) have been drilled; these wells have evaluated the seismic survey, reservoir characterization, and production. The current reservoir model indicates the NDP is located at the end of a turbidite fan system with the south half of the field being in an area comprised of small sand accumulations that have been splayed off of the turbidite flow system, and the north half of the field is located at the end of the fan. Further development will be under the playa lakes and potash areas that will be reached with combinations of deviated/horizontal wells. The data acquisition and drilling evaluation is complete, and application of the enhanced recovery techniques will be done in Phase II.

Due to delays in project initiation, evaluating the seismic data and reservoir complexities, and obtaining simulation software, the Phase I period was extended from two (2) years to three (3) years. This was a one year no-cost extension granted by the DOE to complete Phase I.

## **TECHNOLOGY TRANSFER**

The technology and data from the NDP have been transferred to industry in many forms. Following is a chronological listing by category of the major technology transfer activities:

### **Meetings**

#### **NDP Partners Meeting - February 1996 - Roswell, NM**

A meeting of the partners in the Nash Draw Pool was held with twenty (20) participants in attendance. The project status was discussed, and plans for the remainder of the year were outlined.

#### **DOE Outreach Meeting - July 1996 - Roswell, NM**

A poster was presented at a DOE Outreach Program meeting. Several area producers attended the meeting, and there was considerable interest in the activities being conducted at the Nash Draw Pool.

#### **Liaison & Technical Committee - August 1996 - Albuquerque, NM**

A liaison and technical committee meeting was held with fourteen (14) participants including Nash Draw Pool partners, BLM representatives, OCD representatives and industry group representatives. The status of the project was discussed and findings to date were reviewed.

#### **Technology Transfer Meeting - December 1996 - Roswell, NM**

A liaison committee meeting was held for the purpose of updating Mr. William J. Lemay, Director of the New Mexico Oil Conservation Division, as to the status of the project and findings to date.

#### **Informal DOE Meeting - April 1997 - Bartlesville, OK**

Several members of the Nash Draw team discussed results obtained in the NDP project with BPO field office personnel.

#### **Technical Team Meeting - May 1998 - Albuquerque, NM**

Each subcontractor presented a summary of conclusions to date, with an emphasis on activities since September 1997. Requirements for concluding Budget Period I were discussed, and a plan for Budget Period II was discussed.

### **Workshops**

#### **Characterization Workshop - August 1996 - Roswell, NM**

A workshop titled "Integration of Advanced Reservoir Characterization Techniques" was sponsored by the Petroleum Recovery Research Center (PRRC) at New Mexico Tech. Strata Production Company

presented an update of the status and findings at the Nash Draw Pool project.

**FRAC Design Workshop - September 1996 - Hobbs, NM**

A conference titled: "Stimulation Design and Monitoring - Delaware Mountain Group Formations" was held at the New Mexico Junior College. Sponsors of the Conference included the PRRC and the Petroleum Technology Transfer Council. Strata presented the results and conclusions of the fracture stimulation design and evaluation scenario used to determine effectiveness of the stimulation program.

**Logging Workshop - September 1997 - Midland, TX**

The Department of Energy and BDM Oklahoma held a workshop entitled "Advanced Applications of Wireline Logging for Improved Recovery." Strata's project was a participant in the workshop.

**Reservoir Characterization Workshop - September 1997 - Hobbs, NM**

A workshop including results from the Nash Draw project was held in conjunction with a reservoir characterization symposium coordinated by the PRRC. The geological interpretation, integration of the seismic and reservoir data, and a discussion of the reservoir petrography and composition as it relates to log analysis and reservoir productivity were covered. The full core from NDP Well #23 was also be available for inspection by attendees at the presentation and workshop.

**Core Workshop - February 1998 - Midland, TX**

The Nash Draw core and associated materials were exhibited at a core workshop sponsored by the Permian Basin Section/SEPM for cores from DOE projects in the Permian Basin.

**Technical Papers & Presentations**

**DOE/CEED Poster Session - May 1996 - Midland, TX**

A poster was presented at the session titled "Improving Production from Shallow Shelf Carbonate (Class II) Reservoirs" at the Center for Energy & Economic Diversification.

**Fourth International Reservoir Characterization Technical Conference - March 1997 - Houston, TX**

A paper entitled "Advanced Reservoir Characterization for Improved Oil Recovery in a New Mexico Delaware Basin Project" was given at the 4th International Reservoir Characterization Technical Conference.

**Poster at the AAPG Annual Convention - April 1997 - Dallas, TX**

A poster at the AAPG Annual Convention updated the status and findings at the NDP.

**IEA Paper - September, 1997 - Copenhagen, Denmark**

A paper "Optimizing Oil Recovery from a Complex, Low Permeability Turbidite Reservoir" was presented at the 18<sup>th</sup> International Energy Agency Workshop and Symposium on Enhanced Oil Recovery.

**SPE Paper 38916 - October 1997 - San Antonio, TX**

A paper titled "Reservoir Characterization as a Risk Reduction Tool at the Nash Draw Pool" was presented at the 1997 SPE Annual Technical Conference and Exhibition.

**SPE Paper 38868 - October 1997 - San Antonio, TX**

A paper entitled "Implementation of a Virtual Enterprise for Reservoir Management Applications" provided results obtained by the Nash Draw virtual team and described the Web technologies approach and virtual enterprises.

**SPE Paper 39775 - March 1998 - Midland, TX**

A paper entitled "Using Reservoir Characterization Results at the Nash Draw Pool to Improve Completion Design and Stimulation Treatments" was presented at the 1998 Permian Basin Oil and Gas Recovery Conference.

**SPE Paper 38916 - March 1998 - Midland, TX**

The Program Committee of the Permian Basin Oil and Gas Recovery Conference requested this paper also be presented at their meeting.

**Other**

**DOE Oil Technology Project Review - June 1997 - Houston, TX**

Results obtained in the NDP Class III project were presented at the DOE Oil Technology Project Review Meeting.

**Geophysics Papers Accepted - 1998**

Two papers, "3-D Seismic Imaging and Interpretation of Brushy Canyon Thin-Bed Turbidite Reservoirs, Northwest Delaware Basin" and "3-D Instantaneous Frequency Used as a Coherency/Continuity Parameter to Interpret Reservoir Compartment Boundaries Across an Area of Complex Turbidite Deposition," have been published in September-October 1998 edition of *Geophysics*.

**AAPG Paper Accepted - 1998**

The paper entitled "Advanced Reservoir Characterization for Improved Oil Recovery in a New Mexico Delaware Basin Project" that was presented at the Fourth International Reservoir Characterization Technical Conference in Houston, TX was peer-reviewed. The revised manuscript was submitted for a book on the conference that will be published by the AAPG.

**Internet Homepage:** <http://baervan.nmt.edu/REACT/Links/nash/strata.html> This site includes an interactive map of logs and production data for the Nash Draw project and the most recent annual (second annual) report including graphics.

## SUMMARY OF PHASE I RESULTS

Following is a summary of the results of the studies conducted in Phase I:

### **Geological Analysis**

The faults and depositional character of the deeper structures (Morrow and Bone Spring) provide the depositional surface for the shallower sequences and creates the bench-step surface being used to describe the Brushy Canyon reservoir.

The Brushy Canyon reservoir at the NDP is much more complex than initially indicated by conventional geological analysis. While the original concept pictured the NDP as a collection of thin channel sands continuously distributed between wells, the results from Phase I show the subzones within the sandstones are lenticular and are not always continuous from well to well which can affect flow paths between wells.

The interpretations of the advanced reservoir analysis show the oil accumulation in Brushy Canyon interval exists areally as pods or fairways and vertically as stacked micro-reservoirs.

Examination of the core under ultraviolet light revealed the discontinuous character of the hydrocarbon distribution mixed with water zones throughout the pay interval. This correlates with the erratic vertical distribution of oil and water saturations calculated from the log analysis.

### **Advanced Core-Calibrated Log Analysis**

To evaluate the highly laminated micro-reservoirs that make up the pay zones in the Brushy Canyon interval, a log evaluation technique was developed to identify pay that is laminated with wet zones. The methodology for identifying net pay in complex reservoirs can be applied in other sandstone formations, and the technique is being evaluated to be programmed in a stand-alone program for use by industry in the development of other highly laminated reservoirs.

By properly identifying productive pay intervals, oil recovery from the Brushy Canyon reservoir at the NDP is calculated to be 16.6%, rather than the 10% as initially estimated.

Although the original evaluation suggested that both the "K" and "L" sandstones were the major oil producing intervals, the results of Phase I show the primary oil productive zone at the NDP is the "L" sandstone.

Using transmissibility values to calculate production from the various zones for all 16 wells in the NDP, results show that while the bulk of the oil production at the NDP comes from the "L" sandstone, much of the water is produced from the "K" and "K-2" sandstone, if the latter zone is present.

## **Well Completion and Stimulation**

A detailed characterization of the reservoir provides a accurate model to predict completion and development scenarios: only zones with commercial quantities of hydrocarbons can be completed, fracture heights can be predicted, and well spacing and completions can be optimized.

The design and implementation of fracture stimulation treatments was aided by running Dual Spaced Sonic Logs to determine reservoir properties including Poisson's Ratio, Young's Modulus and fracture gradients. These data were used to predict fracture height and improve fracture geometry.

Combinations of deviated and horizontal wells combined with selective zone completions are being evaluated to improve production performance.

## **Geophysical Results**

By conducting pre-survey VSP wave testing and by careful processing of 3-D seismic data, the thin-bed turbidite reservoirs at the NDP could be imaged, and the individual Brushy Canyon sandstones could be resolved.

The interpreted seismic data indicates that the NDP may be highly compartmentalized, and that some of the compartments, for some sand sequences in the "L" zone, may be much smaller than 300 acres.

Results of seismic data and other interpretations are being used for targeted drilling in high-grade areas of the Pool.

## **Reservoir Simulation**

Immiscible gas injection for pressure maintenance in the proposed pilot area at the NDP was ruled out because of low reservoir pressure and compartmentalization of productive intervals.

The low permeabilities and relative permeability effects precludes waterflooding at the NDP.

Miscible CO<sub>2</sub> flooding appears to be a viable method at the NDP, and areas of the field already under production may be candidates for miscible CO<sub>2</sub> injection, but a low-cost source of the gas is currently not available in the vicinity of the NDP.

Injection of immiscible hydrocarbon gas for pressure maintenance appears to be viable in undeveloped regions if those areas are not pressure depleted or compartmentalized and if injection is initiated early.

## **Geostatistics and Seismic Attribute Analysis**

Fuzzy Ranking can help decide which seismic attributes are most useful for evaluating reservoir properties.

Multivariable nonlinear regression (Neural Networks) were used at the NDP project to correlate well and seismic data with the goal of predicting interwell reservoir properties and extrapolating to regions beyond well control.

Predictions of interwell and fieldwide reservoir properties are possible.

## **Risk Reduction**

Results of the integrated reservoir characterization efforts are being used at the NDP as a risk reduction tool. Reservoir characterization has identified additional drilling locations at the NDP and will reduce the risk of drilling marginal wells in the future. Drilling dollars can be expended to develop "sweet spots" with higher reserve volumes and better economics. Results of seismic data and other interpretations are being used for targeted drilling in high-grade areas of the Pool.

Completion procedures and fracture stimulation treatments can be designed more efficiently when the reservoir is understood in detail. Zones that would be marginal or non-economic are not completed which results in more emphasis being applied to the zones which represent the most potential. This saves perforating, acidizing and fracturing a zone that will not produce enough reserves to return the cost of completion.

An extensive database of new geological, geophysical, and engineering data for the Delaware formation, a new play in New Mexico where limited data are available, has been compiled that can be of interest to companies operating in similar reservoirs. Producing companies and consultants working in the area can extend the data and interpretations to other Delaware reservoirs. Because of the complex distribution of the Delaware sands, the principles learned at the NDP can be applied to other Delaware Pools to help reduce the lead time and shorten the learning curve associated with implementing reservoir management strategies to maximize recoveries.

## **Project Management**

The concept of the Virtual Company was successfully used in Phase I. This concept used experts and consultants in geographically diverse areas. Also, a novel approach to software sharing, by the transfer of a license token over the Internet, was developed.

## **Technology Transfer**

The technology transfer component of this project was expanded to include authoring three (3) SPE papers, an AAPG paper and poster session, two (2) papers presented for publication in Geophysics,

a fracture stimulation workshop and a logging workshop, and various meetings and technical sessions where the NDP project was discussed.

## PROJECT STATUS

The reservoir characterization, geological modeling, seismic interpretation, and simulation studies provided a detailed model of the Brushy Canyon zones. This model is being used to predict the success of different reservoir management scenarios and to aid in determining the most favorable combination of targeted drilling, pressure maintenance, well stimulation, and well spacing to improve recovery from the NDP.

The proposed pressure maintenance injection was not conducted because the pilot area was pressure depleted, and the seismic results suggest the pilot area is compartmentalized. Because reservoir discontinuities would reduce the effectiveness of any injection scheme, the pilot area will be reconsidered in a more continuous part of the reservoir if such areas can be located that have sufficient reservoir pressure.

## CONCLUSIONS

Advanced reservoir characterization techniques were used at the Nash Draw Brushy Canyon Pool project to develop reservoir management strategies for optimizing oil recovery from this Delaware reservoir. The reservoir characterization, geological modeling, 3-D seismic interpretation, and simulation studies have provided a detailed model of the Brushy Canyon zones. This model was used to predict the success of different reservoir management scenarios and to aid in determining the most favorable combination of targeted drilling, pressure maintenance, well stimulation, and well spacing to improve recovery from this reservoir.

The original Statement of Work included a pressure maintenance pilot project in a developed area of the field. The proposed pressure maintenance injection was not conducted because the pilot area was pressure depleted, and the seismic results suggest the pilot area is compartmentalized. Because reservoir discontinuities would reduce the effectiveness of any injection scheme, the pilot area will be reconsidered in a more continuous part of the reservoir if such areas can be located that have sufficient reservoir pressure.

Miscible CO<sub>2</sub> flooding may be viable in areas of the NDP if reservoir pressure has not declined too much; however, a low-cost source of the gas is not available in the vicinity of the field. A more viable option would be pressure maintenance with injection of lean hydrocarbon gas. Maximization of recovery will be a combination of targeted drilling, selective completions, and pressure maintenance designed to drain reservoir compartments.

Results from the project indicate that further development will be under playa lakes and potash areas that will be reached with combinations of deviated/horizontal wells. These areas are beyond the

regions covered by well control, but are covered by the 3-D seismic survey that was obtained as part of the project.

## RECOMMENDATIONS

To develop better areas of the field located under the playa lakes and the potash area, the drilling of deviated/horizontal wells will be necessary. The technology of drilling and completing deviated/horizontal wells and targeting seismic defined targets will be refined. The initial part of Phase II will involve the drilling of three (3) deviated/horizontal wells to evaluate drilling and completion techniques and the ability of the seismic to identify high quality targets. Upon the successful completion of the three (3) initial wells the remaining reservoir will be developed with four (4) additional deviated/horizontal wells.

To extend the original 3-D seismic survey to areas under the playa lakes and to the north end of the NDP a series of 2-D seismic lines will be run. These lines will be used to predict deposition to the north and predict drilling targets.

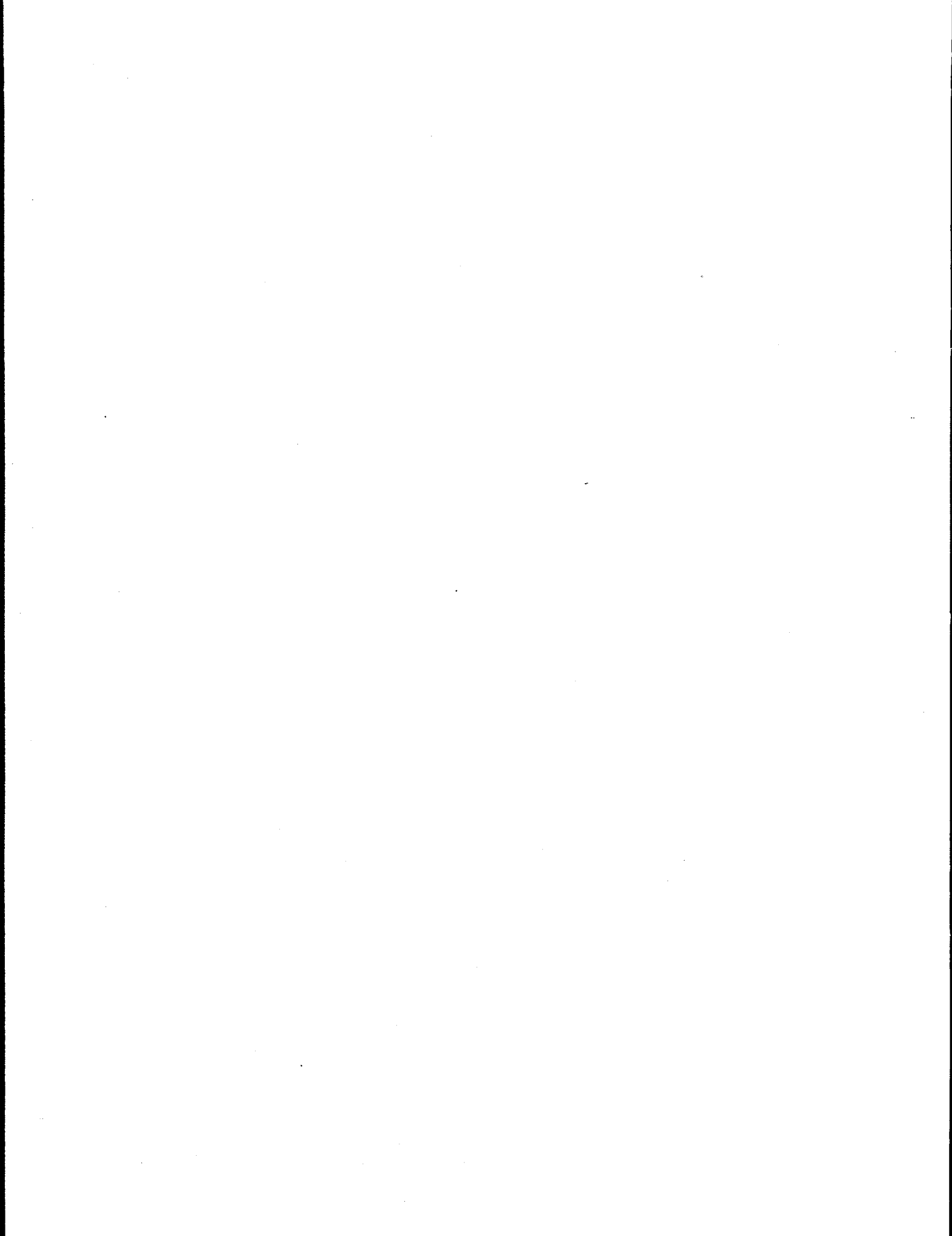
Since the early implementation of pressure maintenance is desirable, a plan will be developed to implement pressure maintenance in more continuous and less depleted area of the reservoir within one year of drilling. It is anticipated that two (2) of the deviated/horizontal wells would be converted to injection and lean hydrocarbon gas would be injected.

The reservoir simulation would be expanded to a full field simulation to predict reservoir pressures, volumes and oil saturations throughout the NDP. Geostatistics and multiple seismic attribute analysis will be used to predict  $S_w$ ,  $S_o$ , porosity, thickness, and compartmentalization to drive the reservoir simulation model. This interpretation will predict areas to be drilled and effectiveness of the pressure maintenance pilot project.

To tie the original 3-D seismic survey to the 2-D lines to be shot across the north end of the NDP, geostatistics and multiple seismic attribute analysis will be used to project reservoir parameters in areas under the playa lakes.

The Virtual Company concept will be expanded and refined in Phase II by continuing to use experts and consultants in geographically diverse areas and to use improved data transfer media including the Internet and fiber optic systems.

Technology Transfer of the data and results from the NDP project have been a major component of the project. Interest in this project has been high and the application of results from the project have been useful in other Delaware fields. The transfer of technology from Phase II will continue to be a major component of the project.



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Table 1. Analog Area Recovery Factor

	<b>Volumetric Analysis</b>	<b>Material Balance Calculation</b>
<b>OOIP</b>	12,473,340	12,467,072
<b>Oil Recovery</b>	16.71%	16.77%
<b>OGIP</b>	12,722,807	12,716,413
<b>Gas Recovery</b>	88.04%	

Table 2. Permeability/Porosity Correlations

<b>Flow Unit</b>	<b>Sidewall</b>	<b>Core</b>	<b>Full</b>	<b>Core</b>
<b>Variable</b>	a	b	a	b
"K"	0.164915	2.25338	0.207675	2.8858
"K-2"	0.186535	2.06872	0.315038	3.69966
"L"	0.179787	2.45666	0.231250	3.06330

Table 3. Drainage Areas

WELL #	1-1-98	CALCULATED			SEISMIC CONTINUITY INDEX	INDICATED DRAINAGE ACRES	DESIGNED DRAINAGE ACRES	"D"	"P"	"S"	P-S-D INDEX	INITIAL GOR SCFG/BO
	ULTIMATE RECOVERY BBLs	RECOVERY BO/ACRE	DRAINAGE AREA ACRES	AREA ACRES				DRAINAGE RATIO	TOTAL TRANSMISSIVITY (OIL AND WATER)	SAND SX		
1	61,776	2,758	22.40	1.33	29.90	40	0.7475	11.620	357	48,146	2,000	
5	71,722	2,926	24.51	1.33	32.72	40	0.8180	12.826	410	59,322	1,200	
6	57,525	2,627	21.90	1.33	29.23	40	0.7308	13.772	410	54,914	1,400	
9	58,822	1,545	38.07	1.33	50.82	60	0.8471	4.687	1,150	62,189	1,600	
10	48,162	1,613	29.86	1.33	39.86	40	0.9965	6.374	358	47,601	1,800	
11	142,173	2,896	49.09	1.00	49.09	40	1.2273	14.050	410	93,151	1,200	
12	34,580	2,957	11.69	1.00	11.69	60	0.1949	14.699	1,900	24,429	14,000	
13	87,644	5,325	16.46	1.33	21.97	40	0.5493	22.460	540	60,493	1,500	
14	89,832	3,085	29.12	1.33	38.87	40	0.9718	15.235	479	83,016	2,600	
15	124,598	2,964	42.04	1.00	42.04	60	0.7006	20.890	1,860	138,104	2,700	
19	134,171	2,205	60.85	1.00	60.85	60	1.0141	9.380	1,192	107,217	1,500	
20	55,240	1,937	28.52	1.33	38.07	40	0.9518	7.721	410	53,549	5,900	
23	41,315	1,710	24.16	1.17	28.15	60	0.4691	4.338	2,239	46,232	5,700	
24	128,583	3,338	38.52	1.33	51.42	60	0.8570	10.746	1,894	122,276	2,500	
25	9,721	1,178	8.25	1.33	11.02	60	0.1836	0.975	1,650	7,364	4,700	
29	23,335	2,640	8.84	1.00	8.84	60	0.1473	19.609	2,169	22,785	8,100	
38	27,504	1,389	19.81	1.00	19.81	60	0.3301	10.477	1,798	33,982	6,200	
TOTAL	1,196,703		474.09		564.35	860.00				1,064,773		

Table 4. Bottomhole Pressure vs. Gas-Oil Ratio

WELL #	GOR 1993	BHP PSI	GOR 1994	BHP PSI	GOR 1995	BHP PSI	GOR 1996	BHP PSI	GOR 1997	BHP PSI	GOR 1998	BHP pSI
1	2.85	2100	8.54	1100	10.95	800	9.56	150	8.35	100	4.37	50
5	1.28	2800	6.38	1250	8.81	950	6.29	1275	8.47	950	9.01	900
6	1.45	2800	6.10	1280	7.64	1050	6.61	1225	6.66	1250	8.57	950
9	1.68	2800	3.01	1950	3.82	1750	12.06	400	11.60	300	8.59	200
10	0.77	2900	4.72	1550	7.23	1100	6.90	1200	13.52	500	14.06	400
11	0.96	2900	1.40	2700	4.82	1525	4.08	1800	5.26	1400	4.81	1500
12									13.03	800	15.98	500
13	1.07	2900	1.94	2400	4.96	1500	5.71	1400	6.16	1300	8.40	960
14	1.05	2900	5.79	1470	7.91	1050	12.69	400	10.81	300	9.34	200
15			1.92	2400	3.91	1725	5.74	1400	10.20	800	13.39	600
19			1.54	2600	6.87	1200	8.23	1000	5.94	1330	6.31	1250
20			2.96	2000	6.09	1300	3.80	1525	6.21	1300	7.59	1100
23					5.10	1480	7.10	1120	18.56	500	20.77	400
24					1.71	2500	3.85	1750	4.64	1550	4.26	1620
25							3.75	1760	4.45	1600	7.17	1125
29									7.00	1150	9.38	860
38									3.71	1750	5.59	1400

Table 5. Reservoir Compartments

Wells in Common Compartments	Comments
1, 6, 9, 10, 12, 14, 19, 20, 23, 25, 29 & 38	This area exhibits communication between wells, and later wells such as #12, 29, & 38 exhibited partial pressure depletion and high initial GORs.
5	This well does not exhibit major communication with neighboring wells.
11 & 13	These wells do not exhibit major communication with neighboring wells.
15	May have minor communication with #23, which would indicate a trend through #15, 23, 29, & 38.
24	This well does not exhibit communication with neighboring wells.

Table 6. Reservoir Simulation Forecasts for CO<sub>2</sub> Injection

**Continued Operation**

*Predicted Oil Recovery, MSTB*

No CO<sub>2</sub> Injection

267.6

**Miscible CO<sub>2</sub> Injection, 120 mscf/D**

<i>Injection Well</i>	<i>Predicted Oil Recovery, MSTB</i>
1	325.1
5	318.1
6	377.6
10	366.5
14	341.1
Infill	365.1
Infill (4:1 WAG)	311.2
Infill*	320.0
Infill (Immiscible)	280.0

\*60 mscf/D

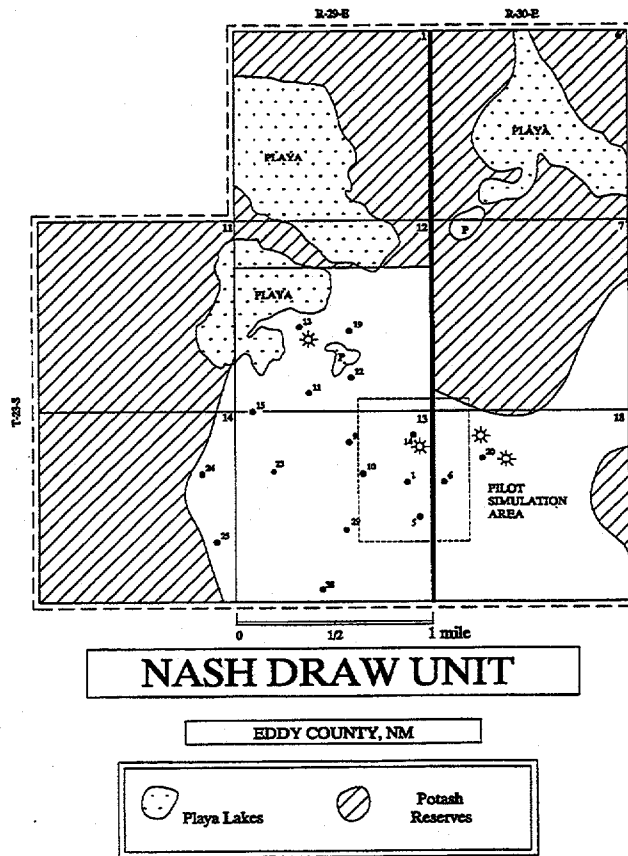


Fig. 1. Map of Nash Draw Pool.

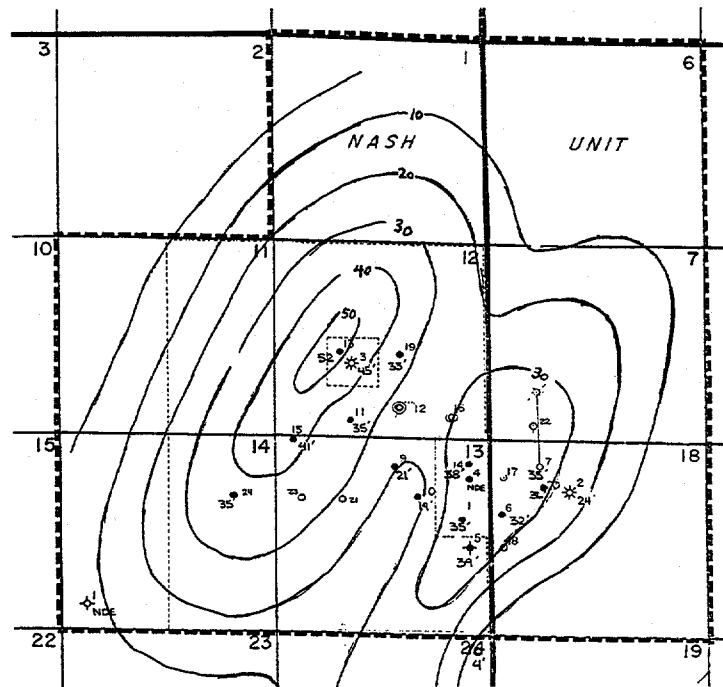


Fig. 2. Early isopach map of Nash Draw Pool.

**TYPE LOG**  
**STRATA PRODUCTION COMPANY**  
**NASH UNIT #15**

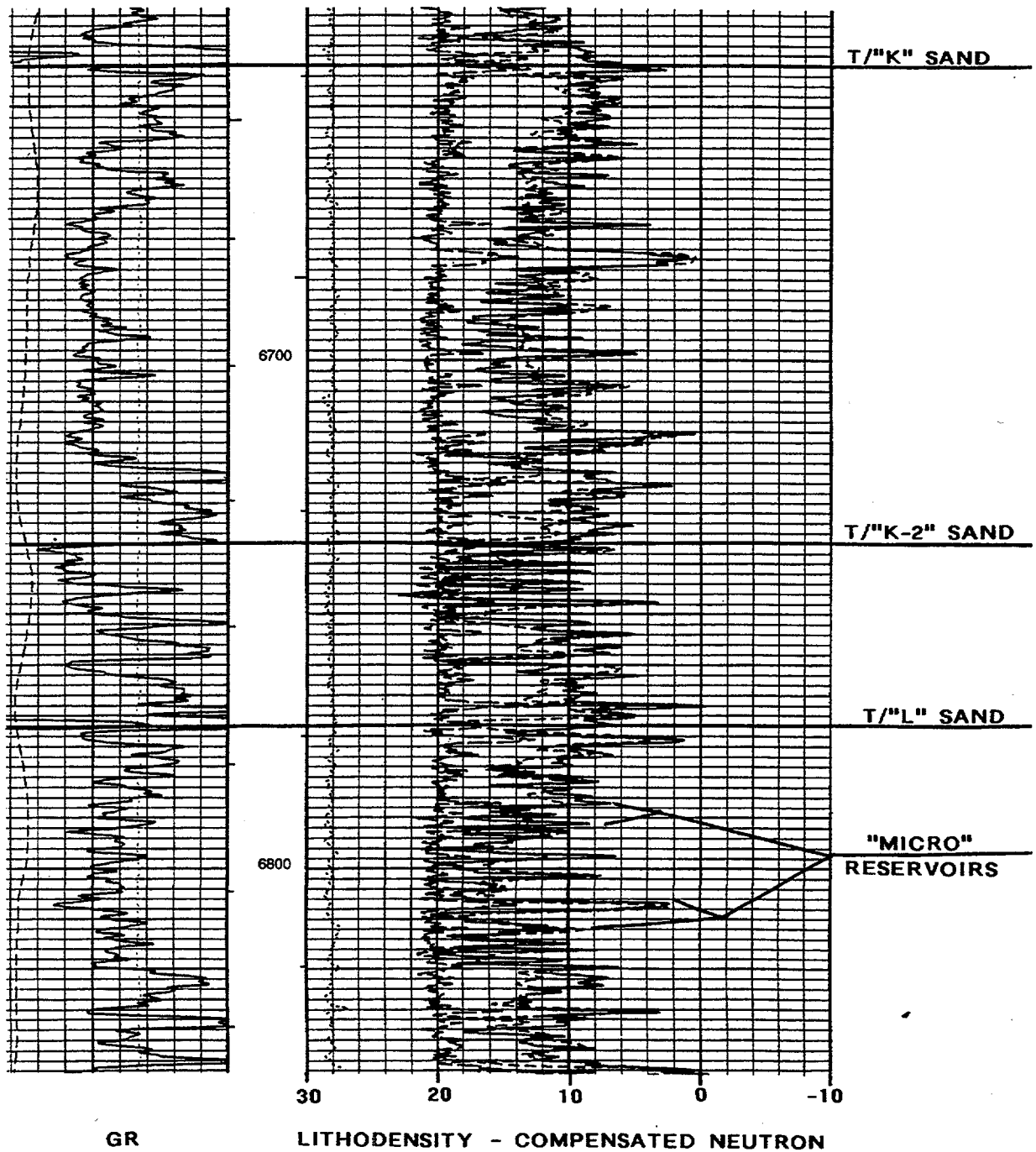


Fig. 3. Typelog showing stacking of thin, multiple reservoir packages.

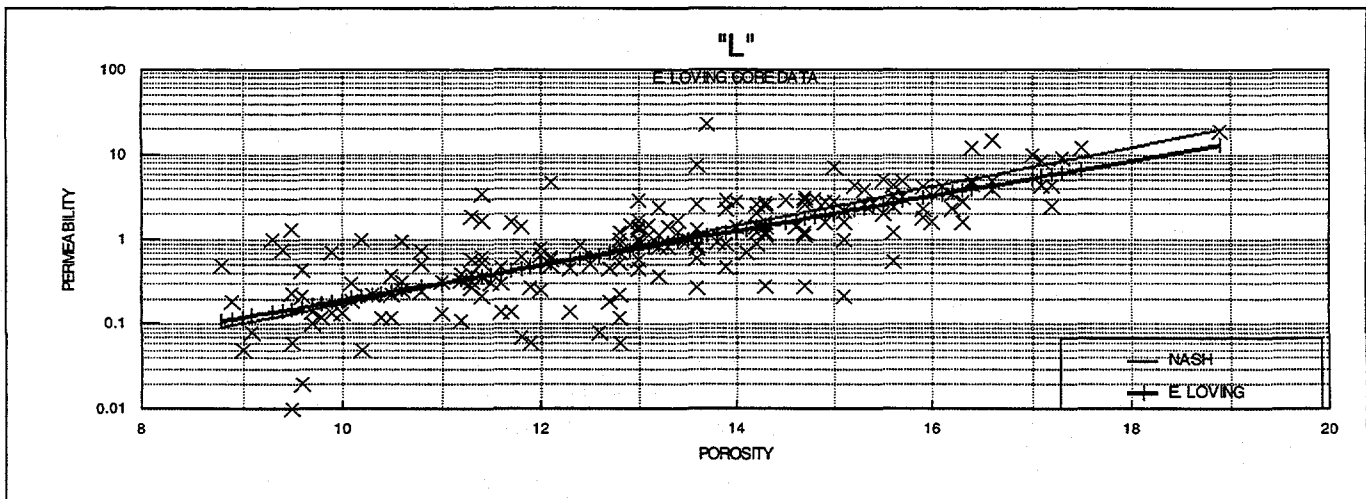
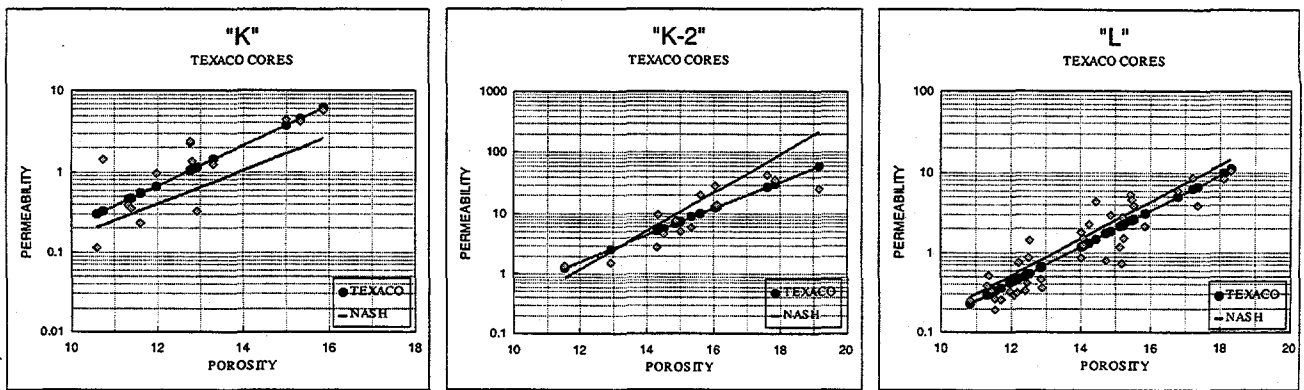
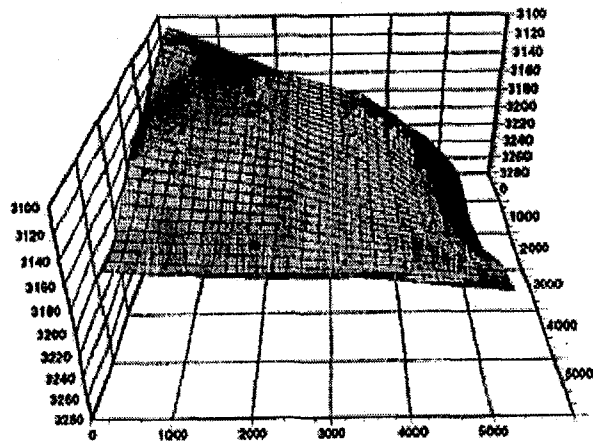
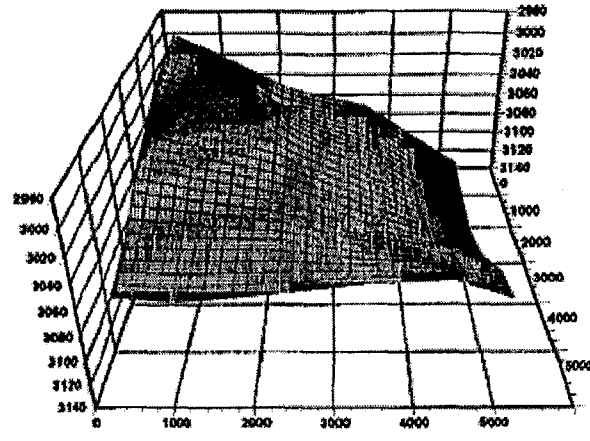


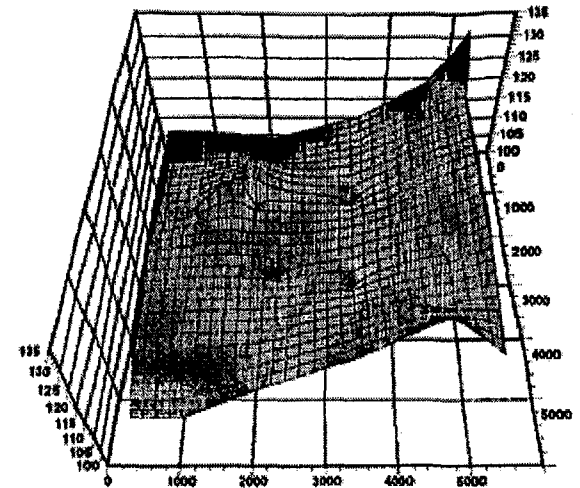
Fig. 4. Porosity vs. permeability correlations of nearby Delaware fields.



TOP OF BONE SPRINGS

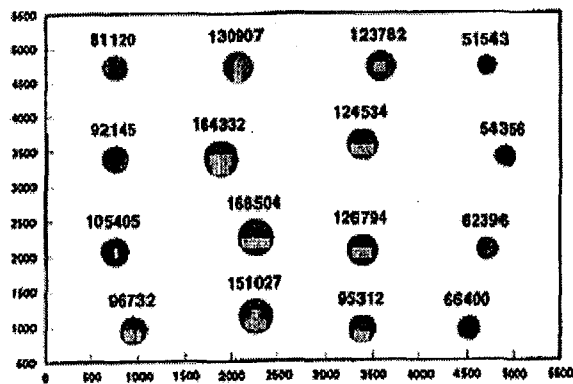


TOP OF "L" SAND

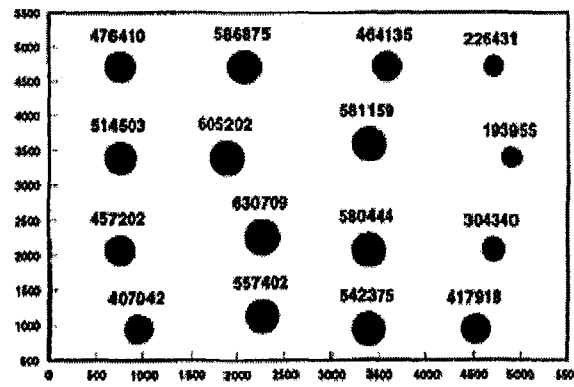


"L" GROSS THICKNESS

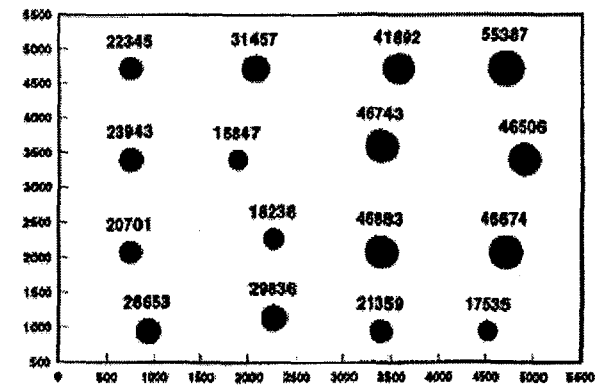
48



CUMULATIVE OIL PRODUCTION



CUMULATIVE GAS PRODUCTION

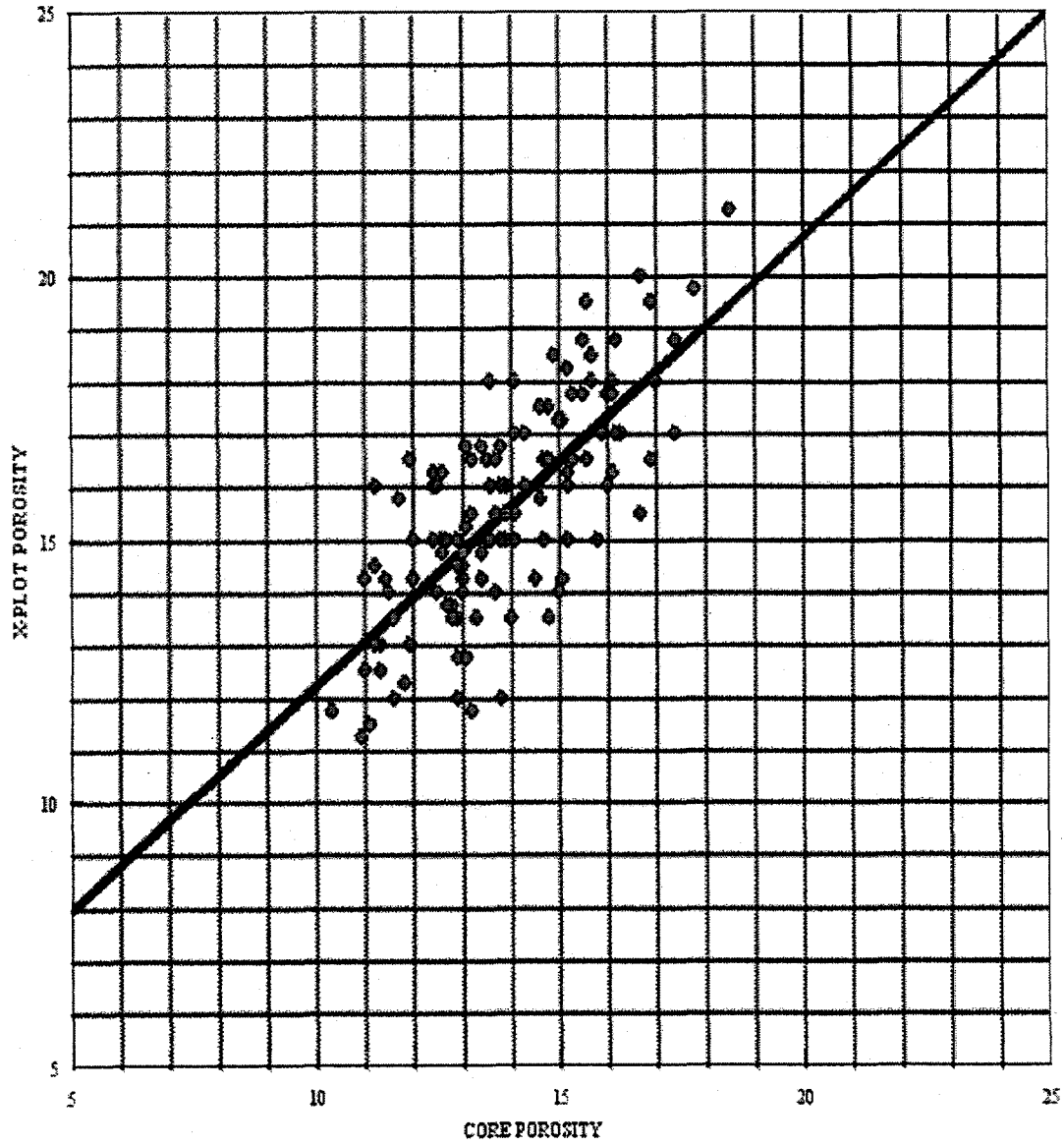


CUMULATIVE WATER PRODUCTION

Fig. 5. Analog area cumulative production.

# POROSITY CALIBRATION

CROSS-PLOT POROSITY vs. CORE POROSITY



CORE CORRECTED CROSS-PLOT POROSITY =  
(X-PLOT POROSITY - 3.7685) / 0.848294

■ REGRESSION ANALYSIS

Fig. 6. Crossplot porosity vs. full core porosity.

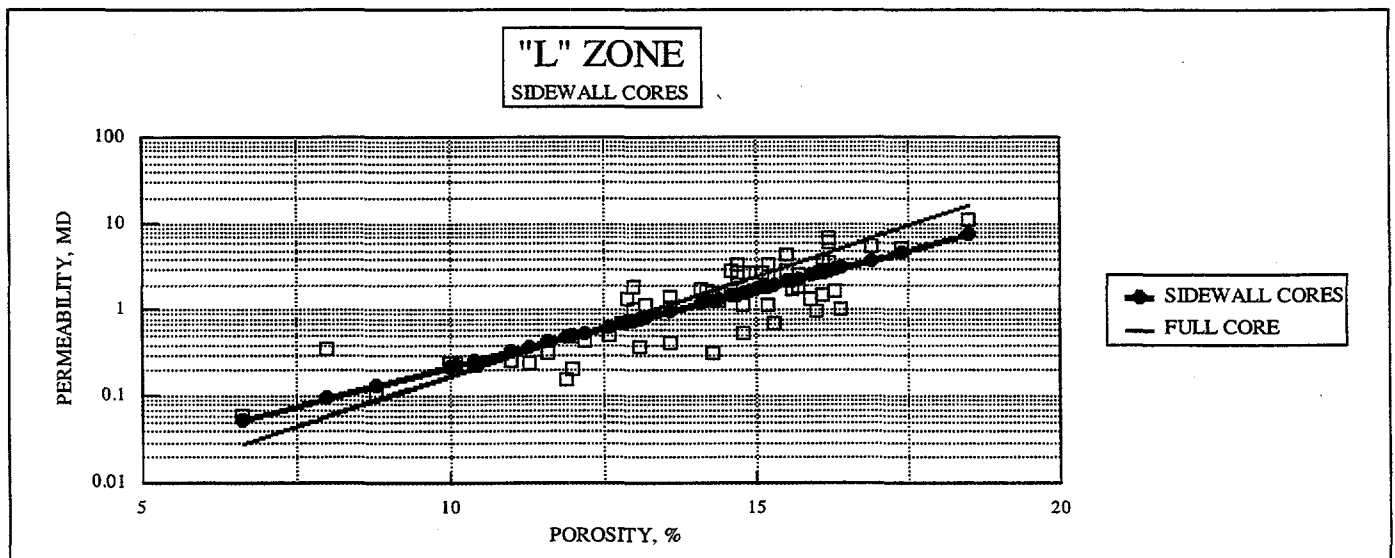
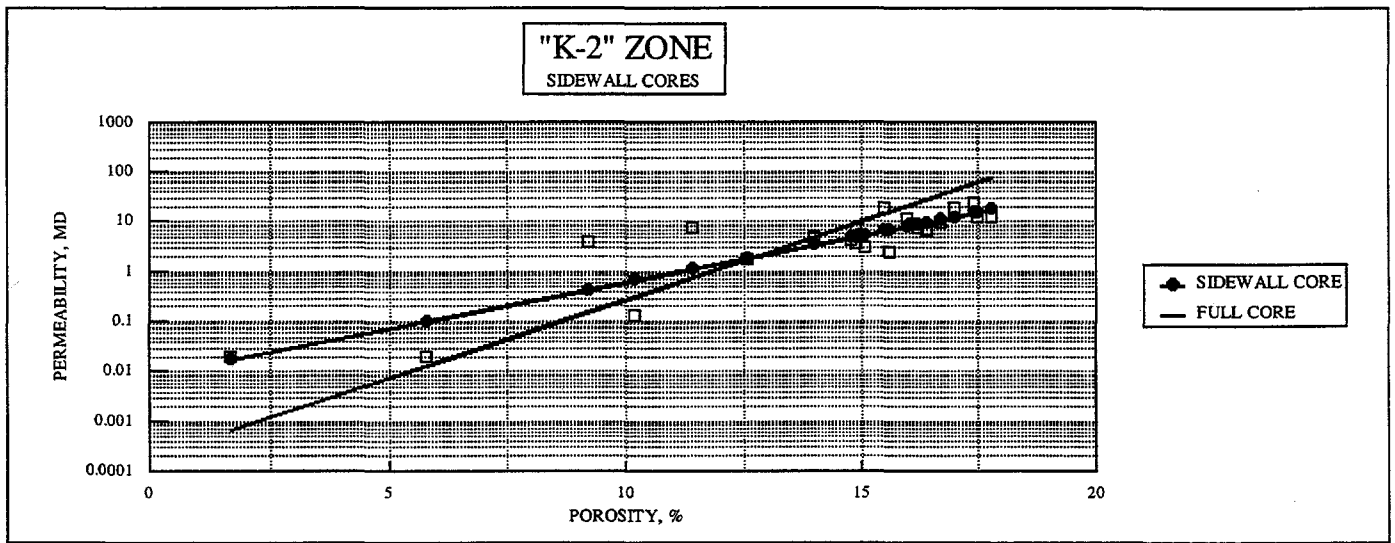
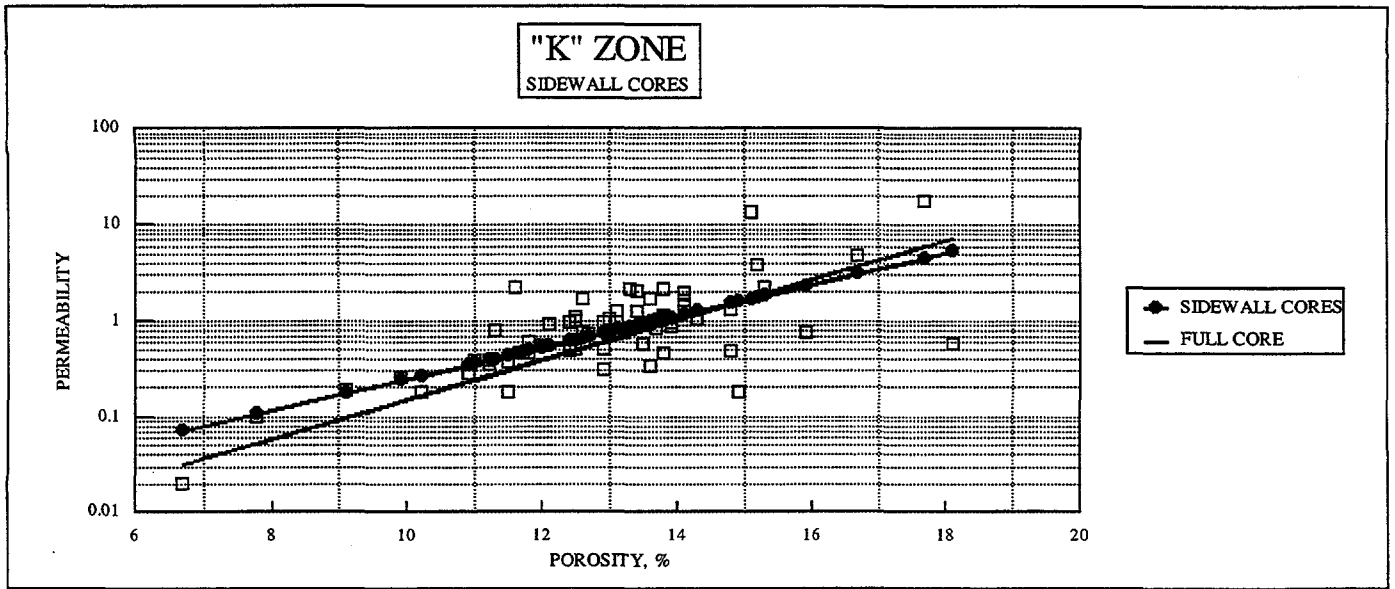


Fig. 7. Whole core data vs. sidewall core data.

WELL INFORMATION		INPUT	MEASURED BHT=	126	F
OPERATOR:	Strata Production Company		BHT DEPTH=	7245	FT.
WELL NO.:	Nash Unit #29		AMBIENT TEMPERATURE=	60	F
FORMATION:	Nash Draw Delaware		INTERVAL TO BE CALCULATED=	6650	TO 6900
LOCATION:	1980' FSL & 2310' FEL SECTION 13-T23S-R29E		TEMPERATURE GRADIENT=	0.9110	F/100 FEET
COUNTY:	Eddy	VISCOSITY OF RESERVOIR FLUIDS OIL, cp =	0.6		WATER, cp = 0.8
STATE:	New Mexico	ESTIMATED RILs=	0.0340		
DATE:	15-MAR-1997	DELAWARE Rw=	0.047	@ 70 F	
		DELAWARE Rw=	0.045	@ 75 F	
		PERMEABILITY TYPE=	3		TITE=1, HIGH=2, MED.=3, MANUAL=4
		CORE CALIBRATED PERMEABILITY FACTOR=	1.00		
		MEASURED Rmf=	0.103	@ 75 F	
		CALCULATED @ 75 F	0.055	@ 75 F	
		CORE CALIBRATED POROSITY FACTOR=	1.00		
		Bg, OIL FORMATION VOLUME FACTOR=	1.51	RES. BBL./STB	
		DRAINAGE AREA=	60	ACRES	
		Rt-corr CORRECTION FACTOR =	1.10		
		CUTOFF RESIDUAL OIL SATURATION =	20.00%		
		ESTIMATED RECOVERY FACTOR=	16.70%		
		ORIGINAL GOR=	1,109	SCFG/BO	
CALIBRATIC INPUT		CUTOFF VALUES		MAXIMUM Sw VALUE =	55.00%
Rt-corr=	1.10	POROSITY=	14.10%	MINIMUM POROSITY - OIL ZONES =	10.00%
DEPTH =	6844	Sw =	31.32%	MINIMUM POROSITY - WATER ZONES =	8.00%
ENTER DEPTH OF A KNOWN PRODUCING ZONE, THEN ADJUST RT CORRECTION FACTOR TO ACHIEVE CORRECT Sw VALUE:				MAXIMUM GAMMA RAY VALUE =	75
					API UNITS

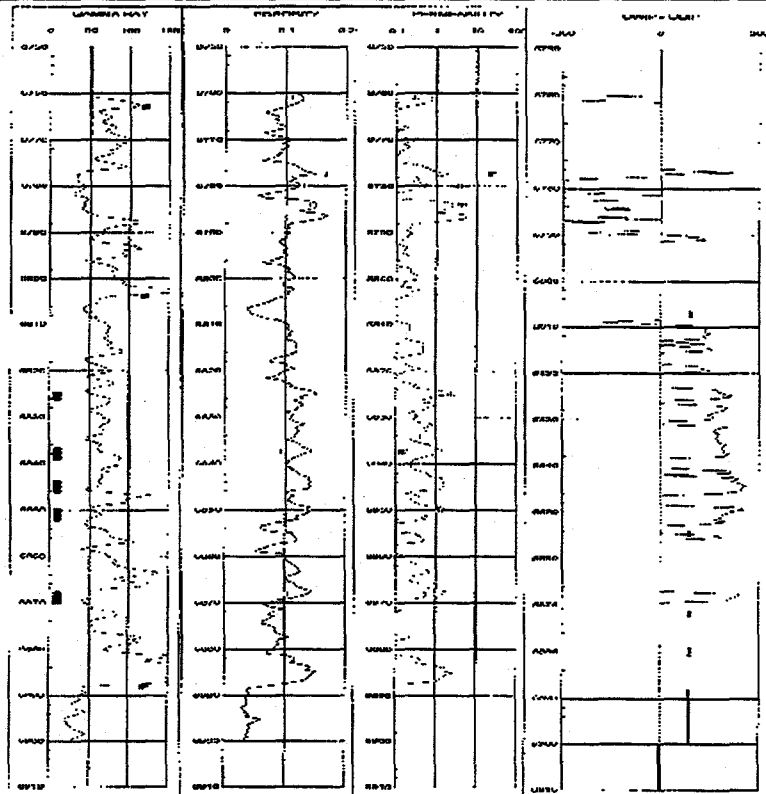
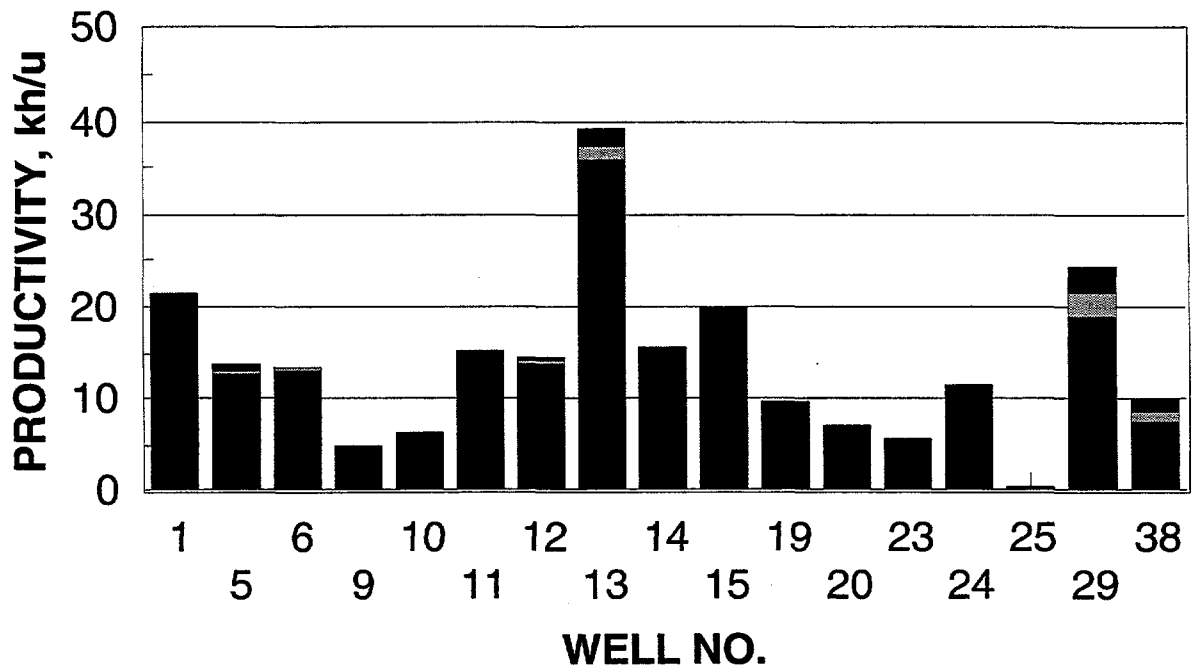


Fig. 8. Advanced log analysis output.

## OIL PRODUCTIVITY



## WATER PRODUCTIVITY

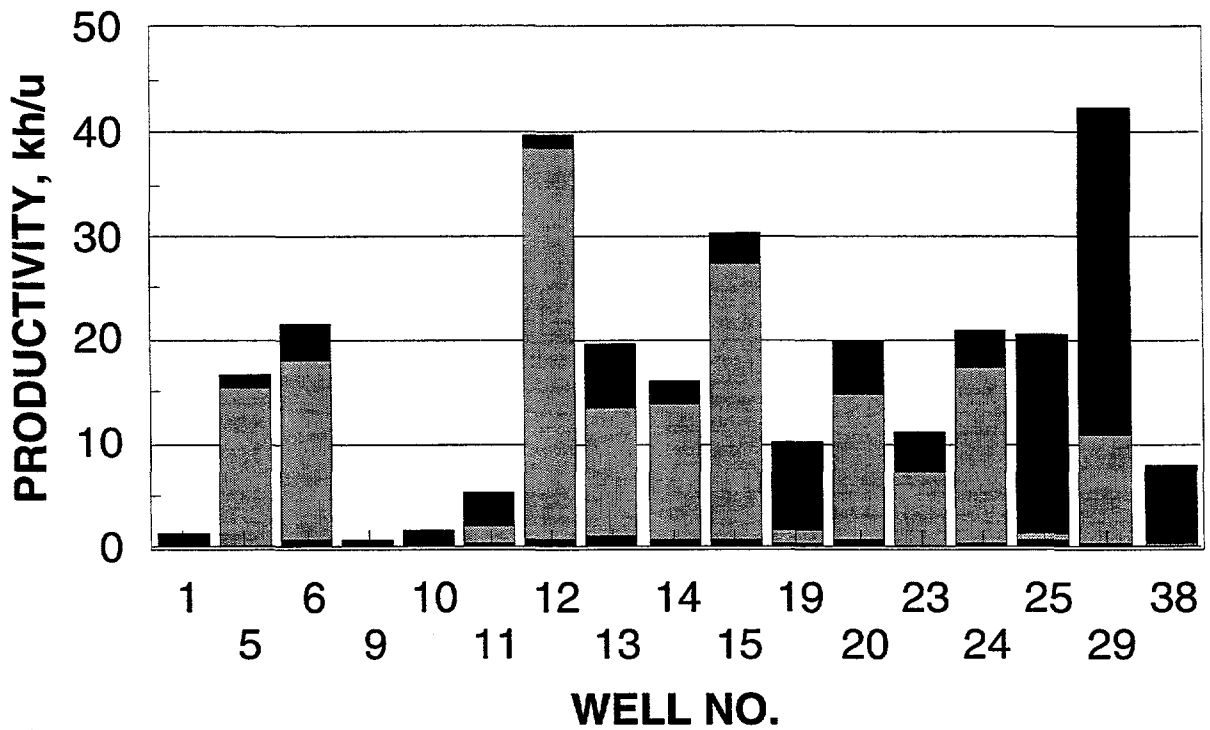


Fig. 9. Productivity of oil and water by well.

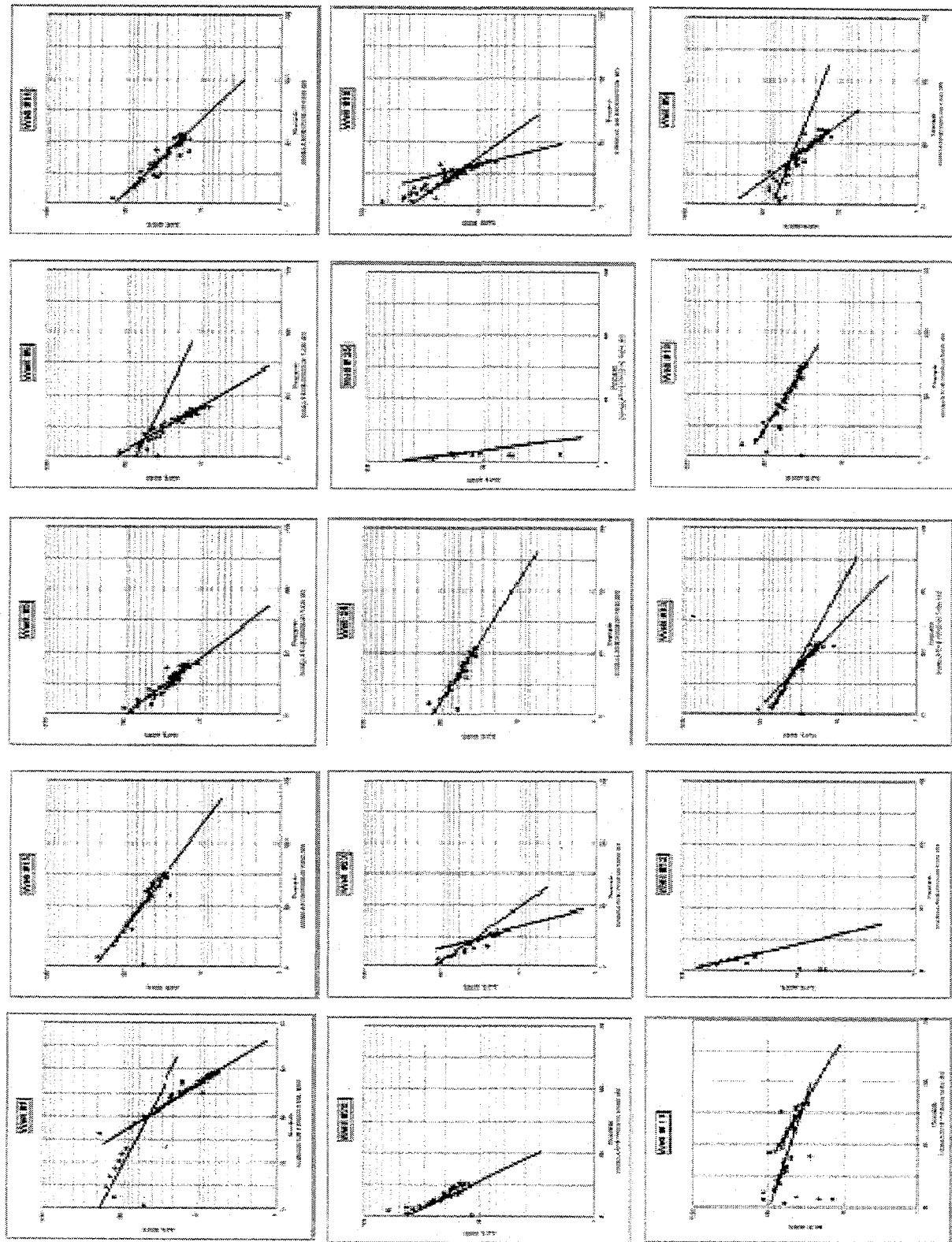


Fig. 10. Oil rate vs. cumulative production.

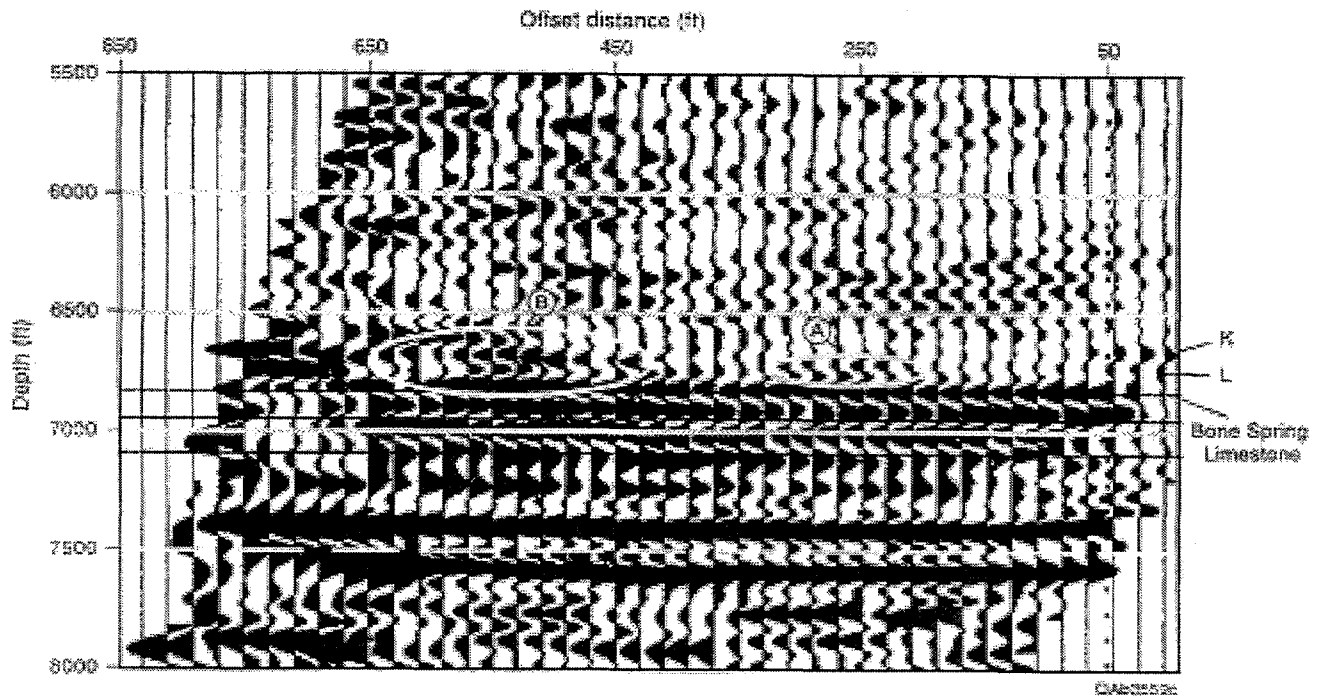


Fig. 11. VSP image.

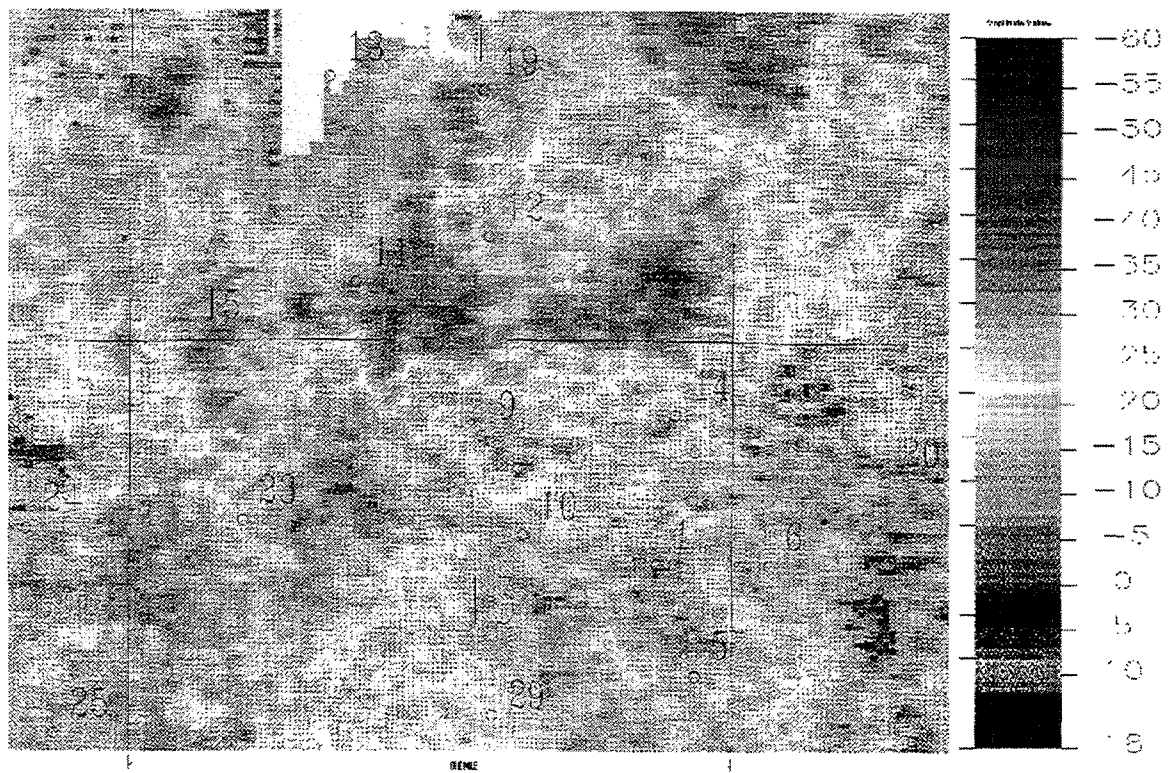
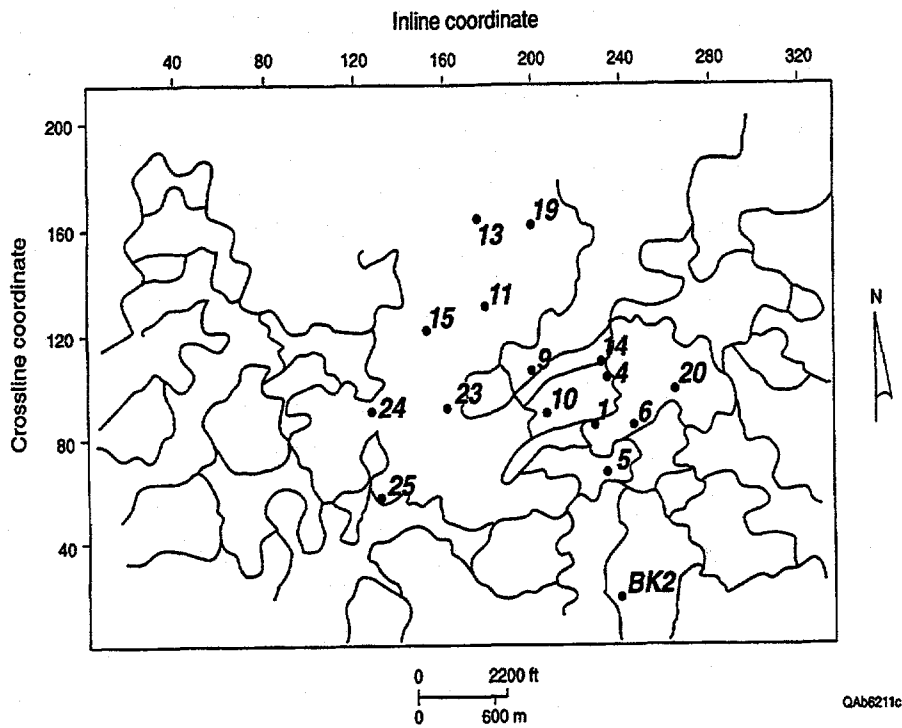


Fig. 12. "L" zone seismic amplitude.

RESERVOIR COMPARTMENTS: K SEQUENCE (TOP K + 10ms)



RESERVOIR COMPARTMENTS: L SEQUENCE (BONE SPRING - 14ms)

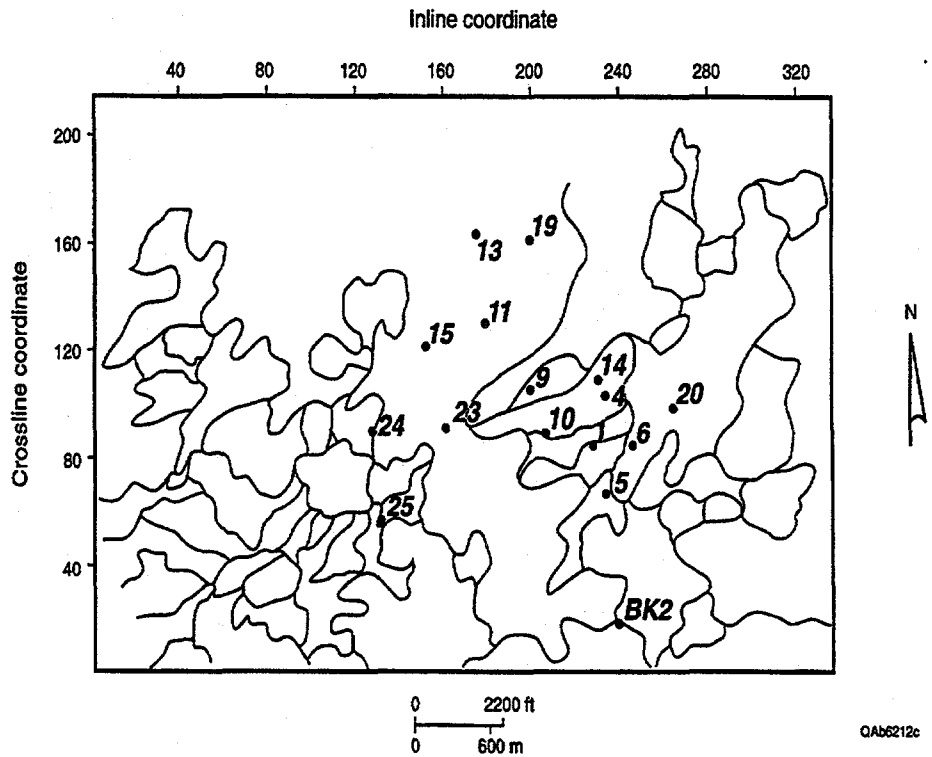


Fig. 13. Reservoir compartmentalization.

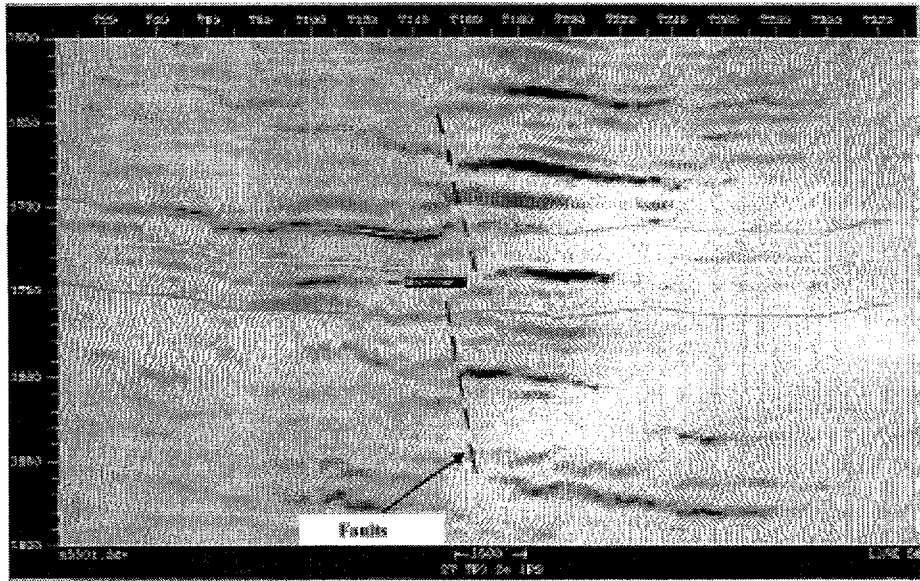


Fig. 14. Morrow level faults.

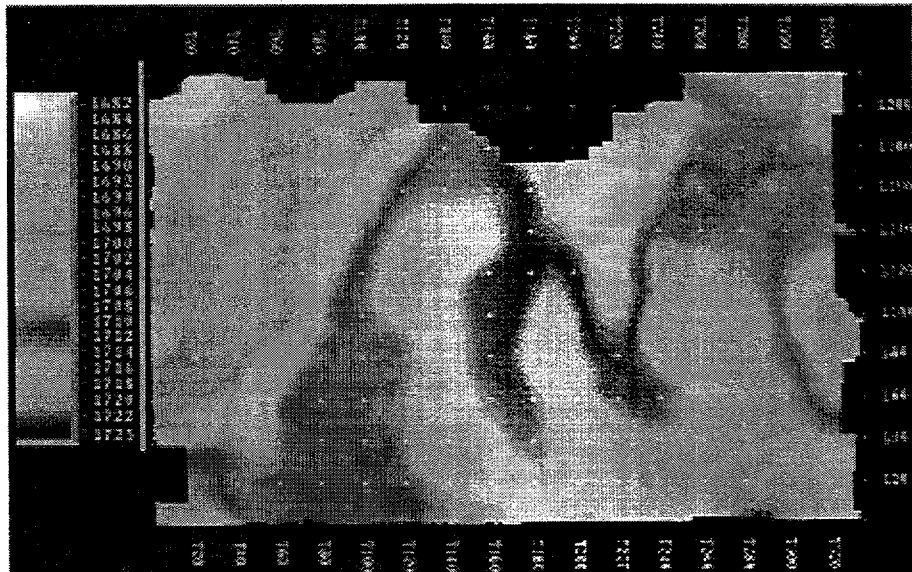


Fig. 15. Morrow time structure map.

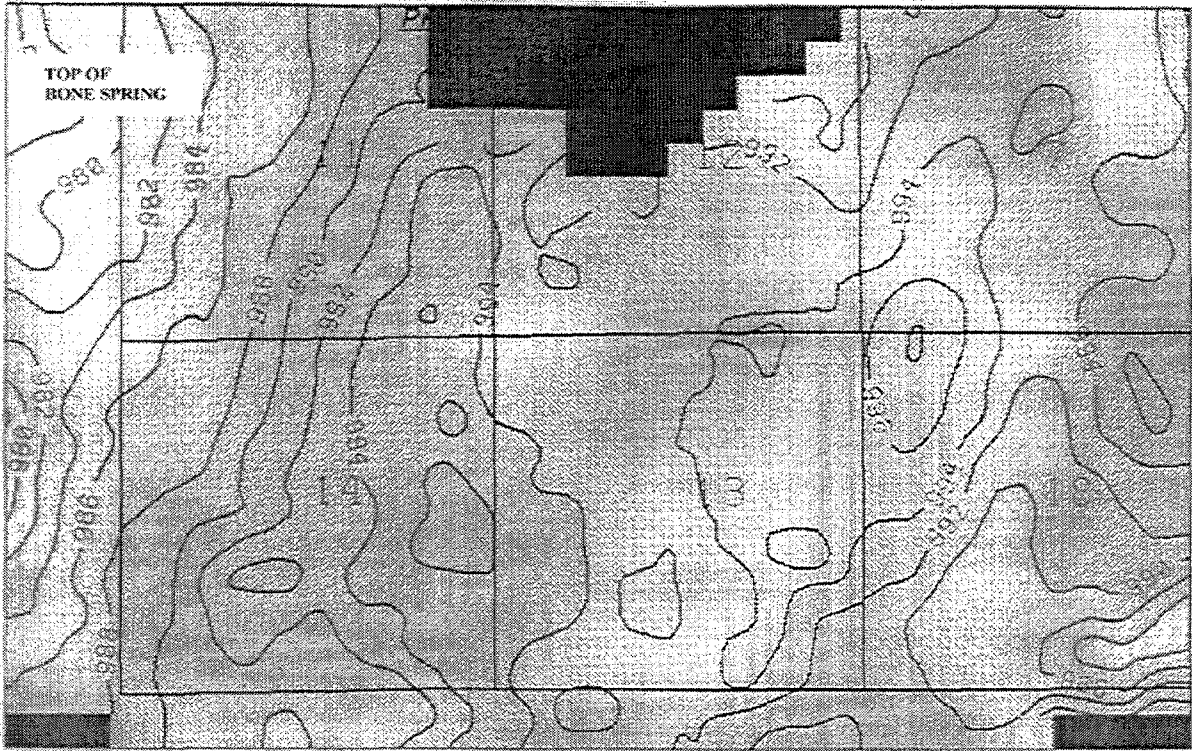


Fig. 16. Bone Spring amplitude.

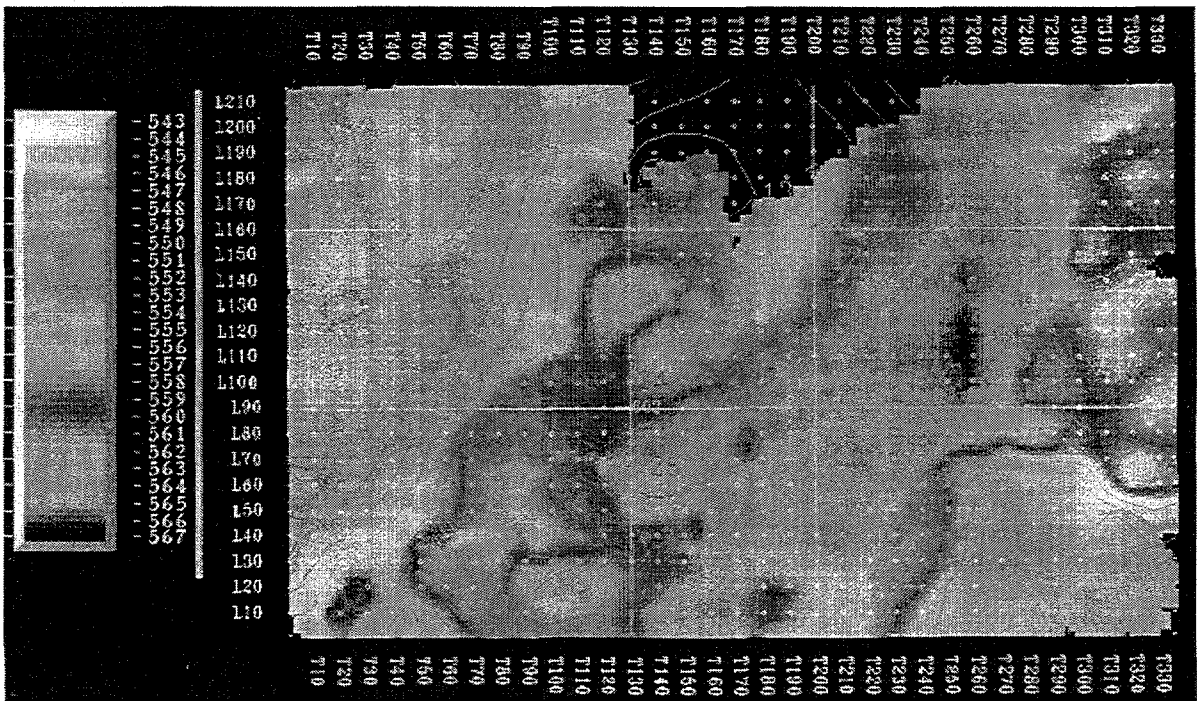


Fig. 17. Cherry Canyon time structure.

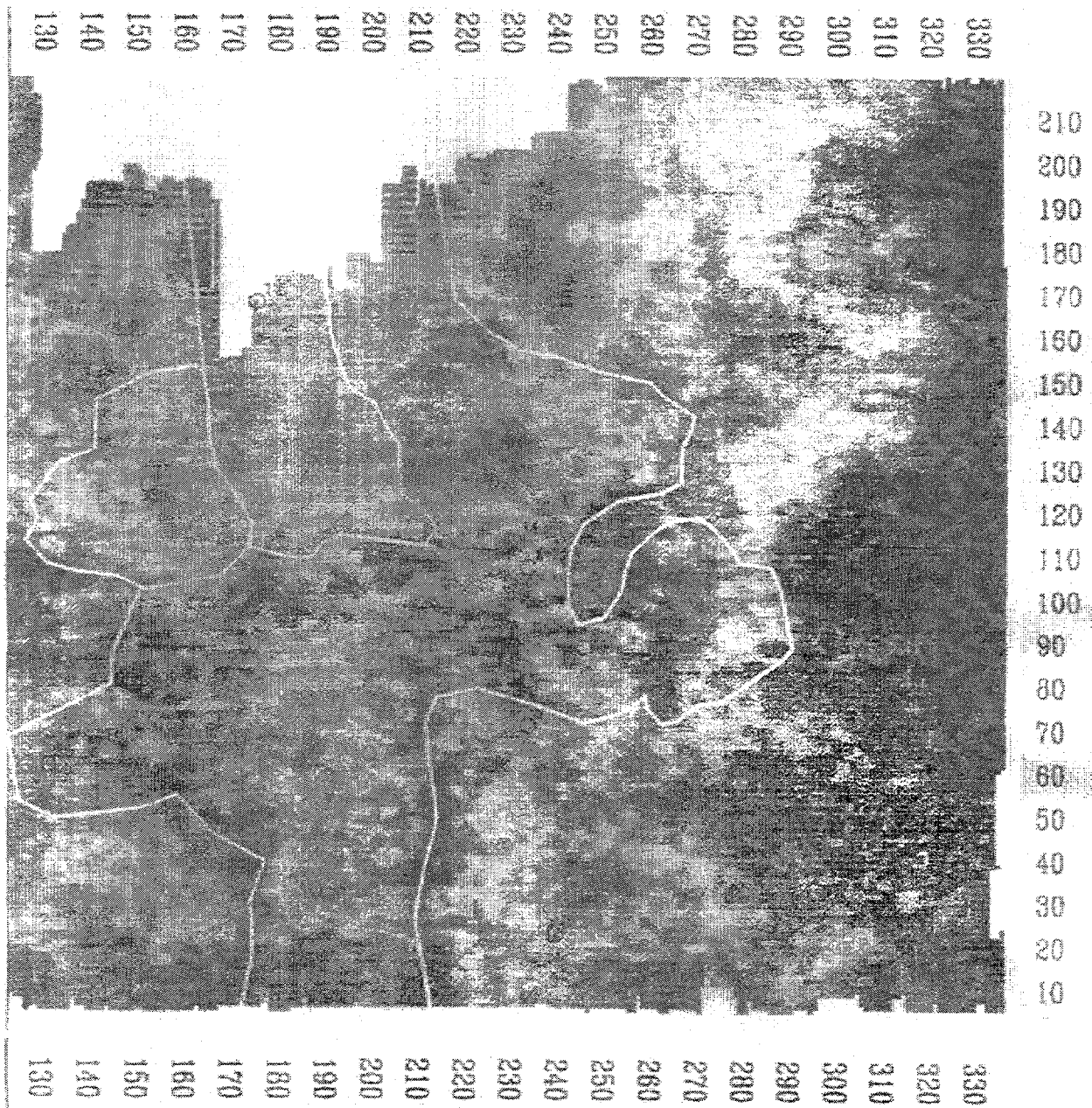


Fig. 18. Major reservoir compartments.

# Nash Draw Brushy Canyon Class III Project

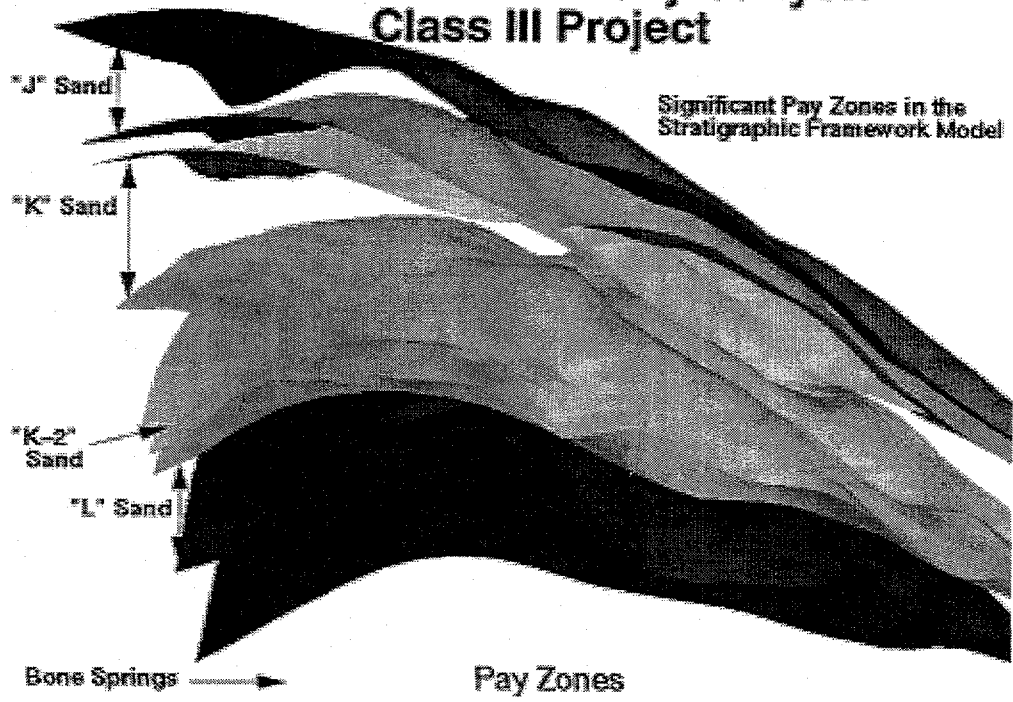


Fig. 19. Stratigraphic framework model.

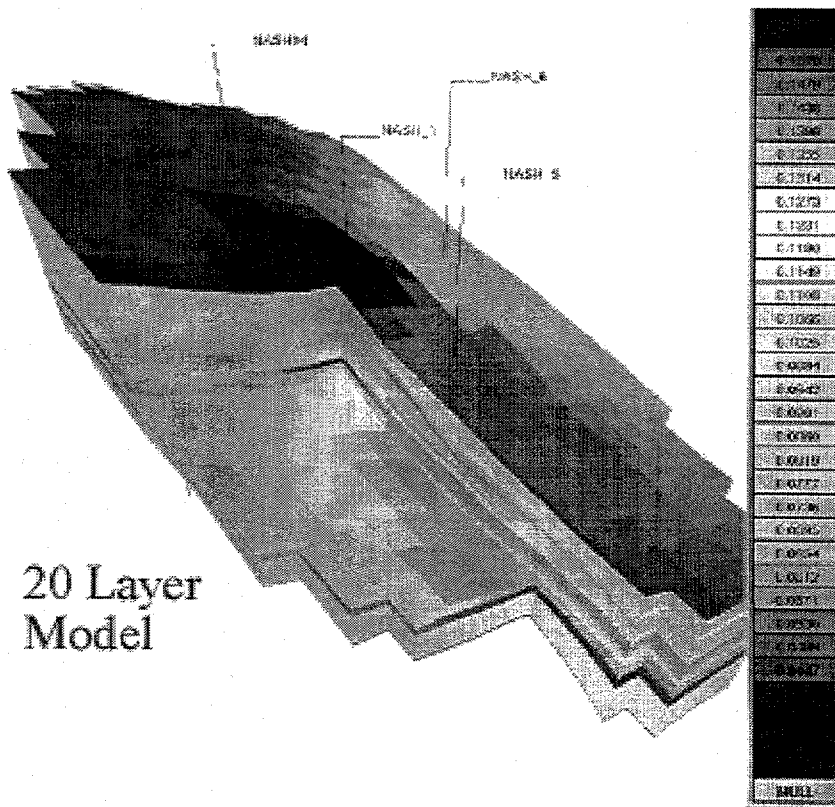


Fig. 20. 20-layer model.

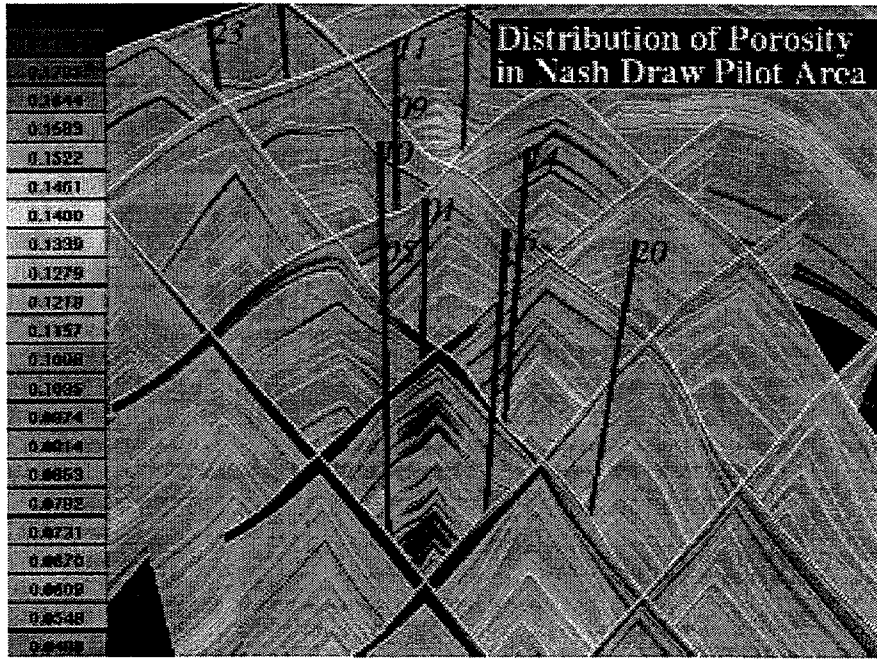


Fig. 21. Porosity distribution in model.

**Fence Diagram of Water Saturation**  
 (Stratigraphic Geocellular Model)

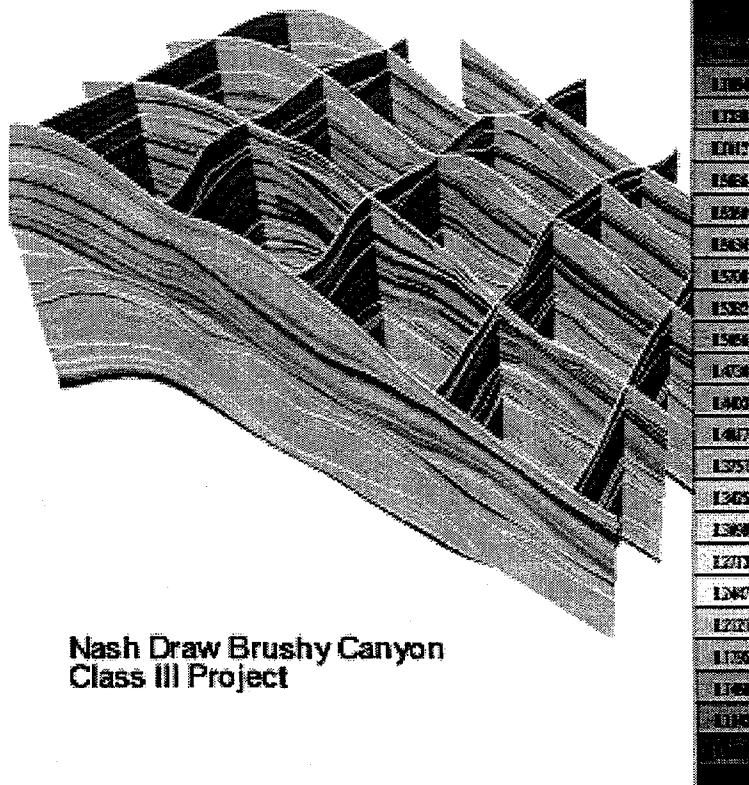


Fig. 22. Water saturation distribution in model.

# INJECTION RATE

# WATER

NASH DRAW #1

## OIL ZONE ONLY

$k = 1.1320755$  md, ABSOLUTE PERMEABILITY  
 $k_{rw} = 0.22$  %, RELATIVE PERMEABILITY TO WATER, FRACTION ("L" @ 70%  $S_w$ )  
 $h = 53$  FT., HEIGHT  
 $P_{iwf} = 5000$  PSI, INJECTION WELL BOTTOM-HOLE PRESSURE  
 $P_e = 1000$  PSI, PRESSURE AT EXTERNAL BOUNDARY  
 $U_w = 1.00$  CP, WATER VISCOSITY PRODUCED WATER @ 120 F  
 $r_{wo} = 100$  FT., RADIUS OF THE LEADING EDGE OF THE WATER BANK, AT THE WATER-OIL INTERFACE  
 $r'_{w} = 37.755063$  EFFECTIVE WELL RADIUS, FT.  
 $M = 0.4088889$  MOBILITY RATIO  
 $r_e = 1144$  FT., EXTERNAL BOUNDARY RADIUS  
 $S = -4$  SKIN  
 $r_w = 0.7$  WELL RADIUS, FT.  
 **$i_w = 189.44$  BWPD**

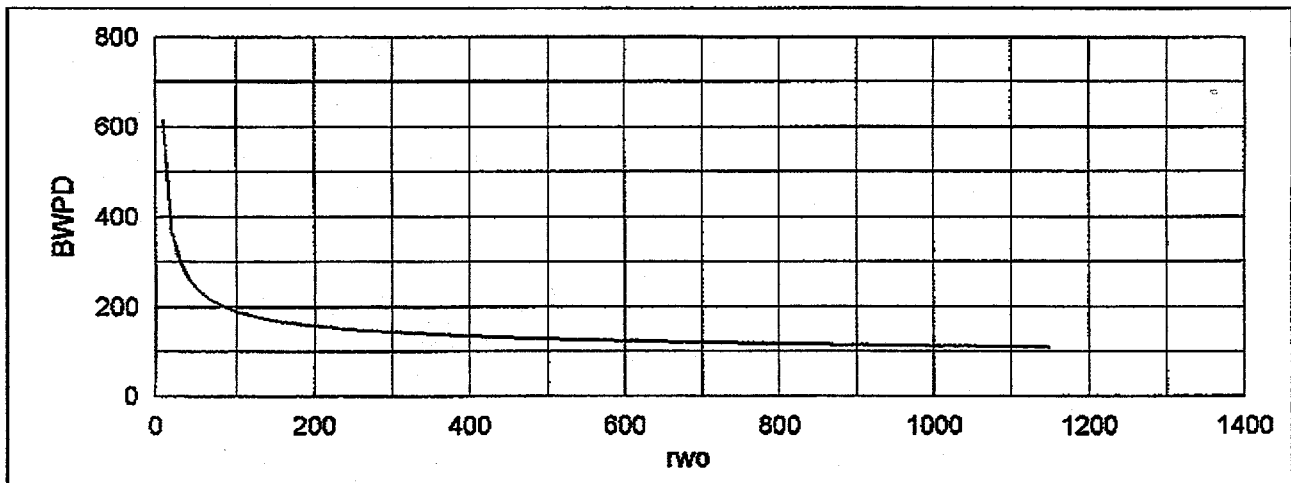


Fig. 23. Water injection in NDP Well #1.

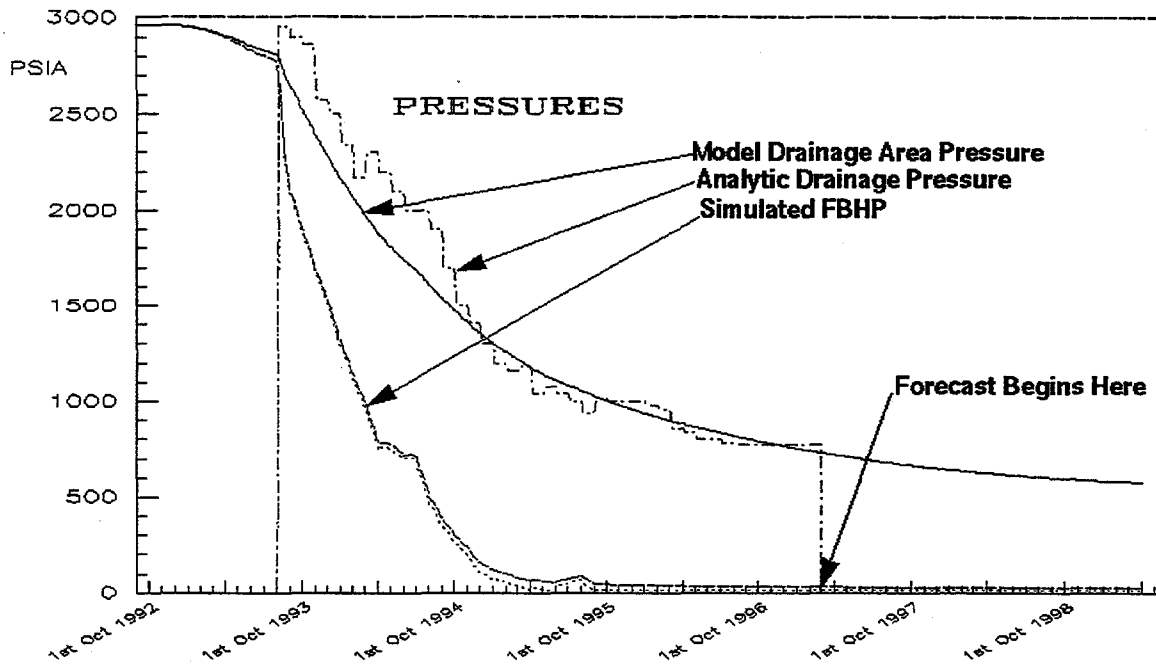


Fig. 24. Pressure response for Case 1, NDP Well #1.

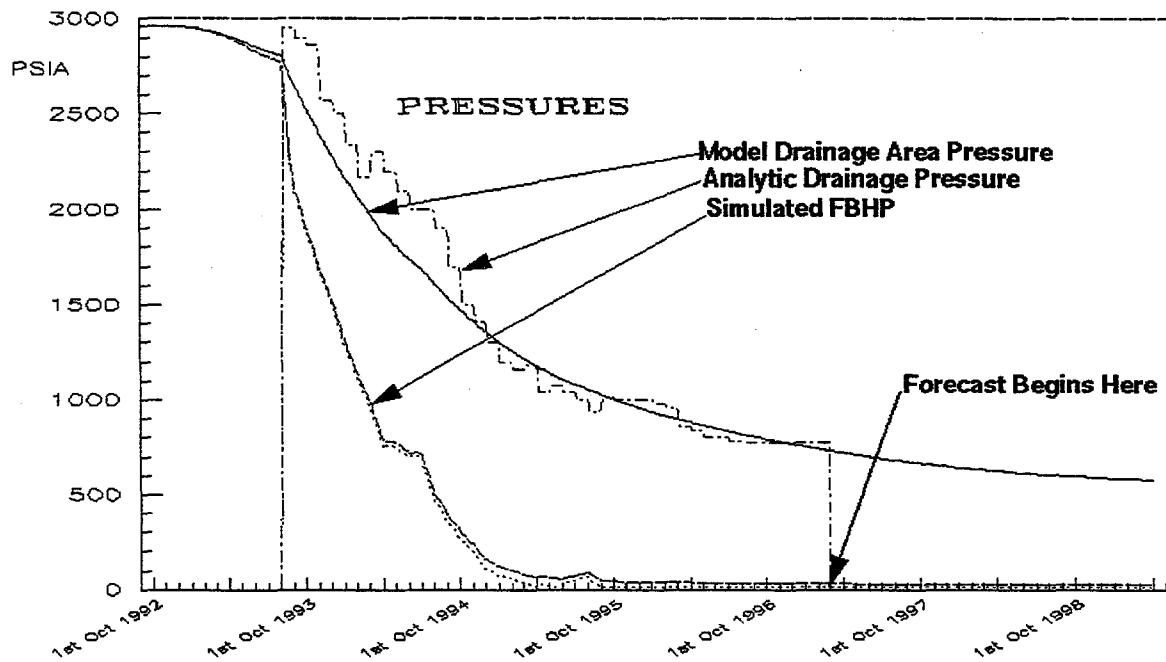


Fig. 25. Pressure response for Case 1, NDP Well #14.

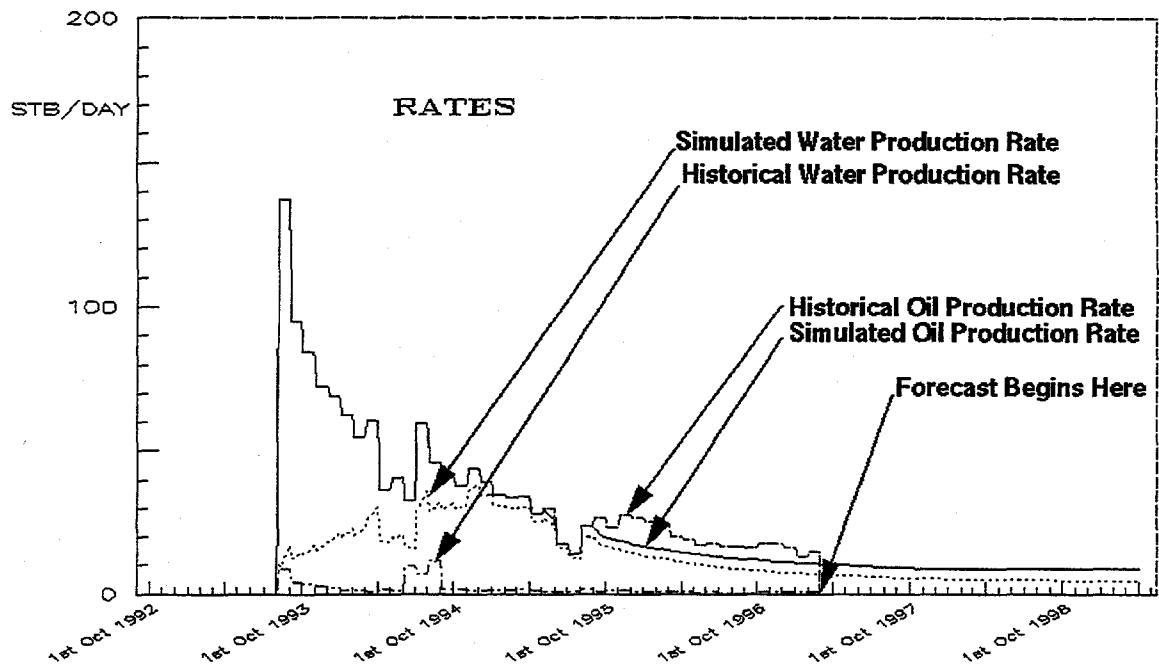


Fig. 26. Rate response for Case 1, NDP Well #14.

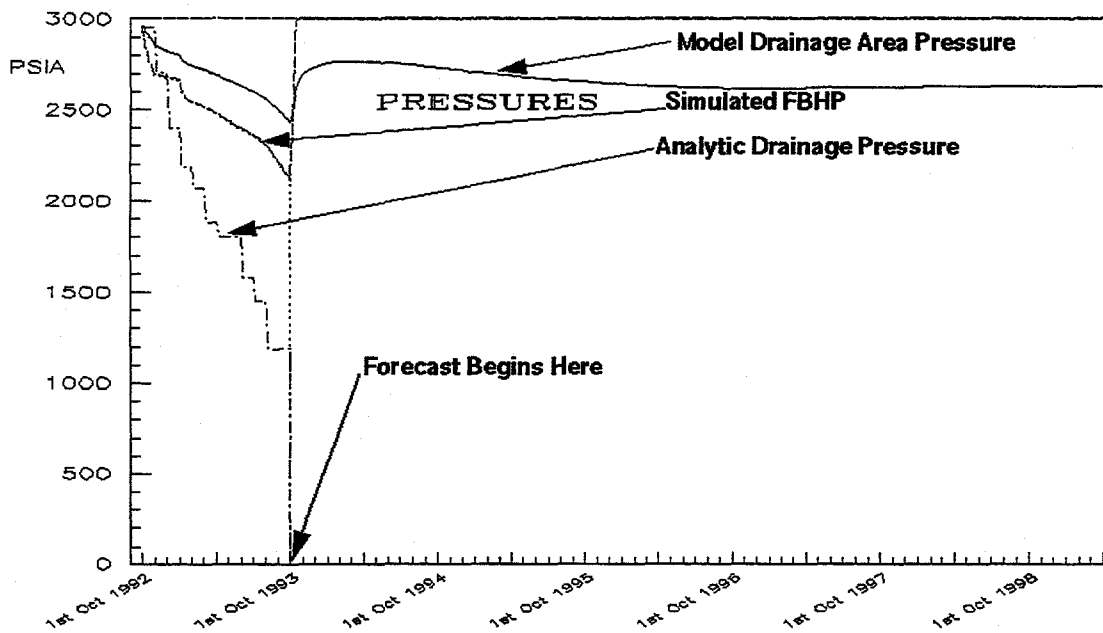


Fig. 27. Pressure response for Case 2, NDP Well #1.

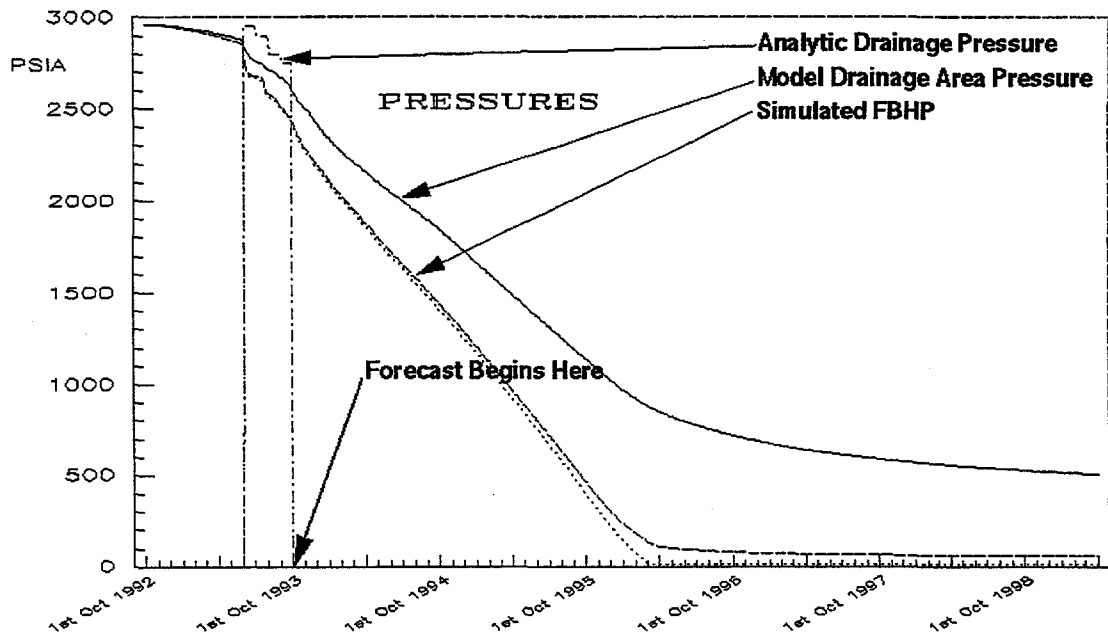


Fig. 28. Pressure response for Case 2, NDP Well #6.

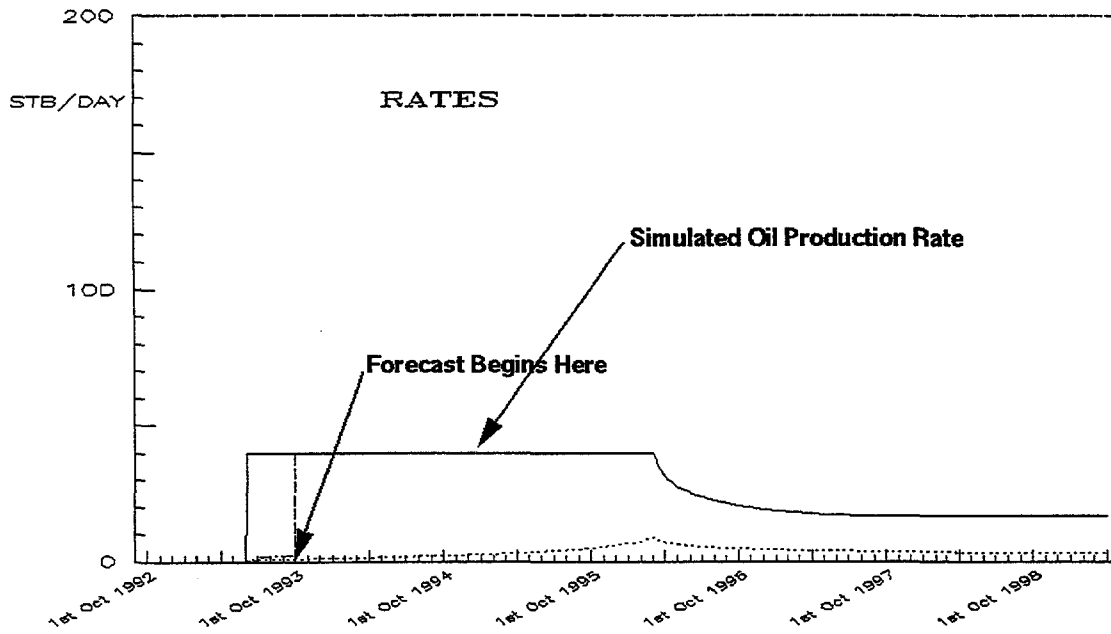
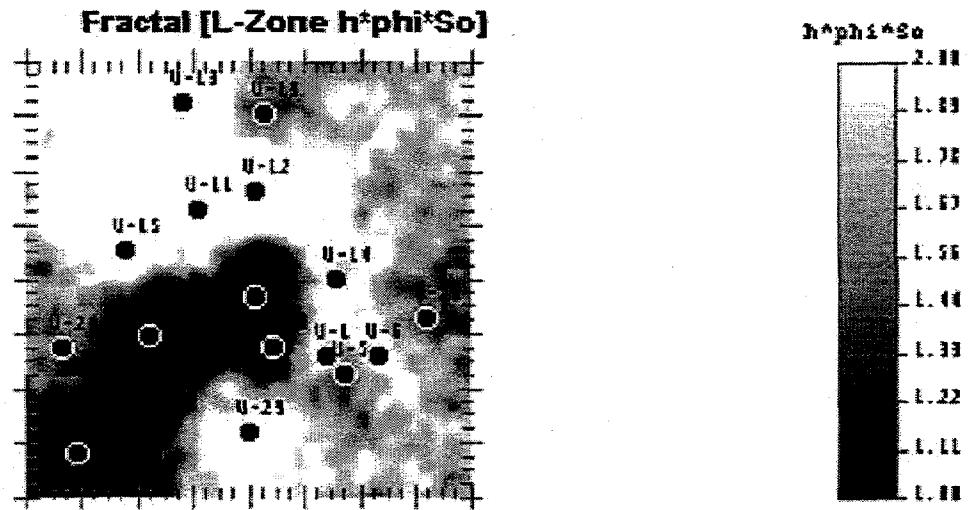
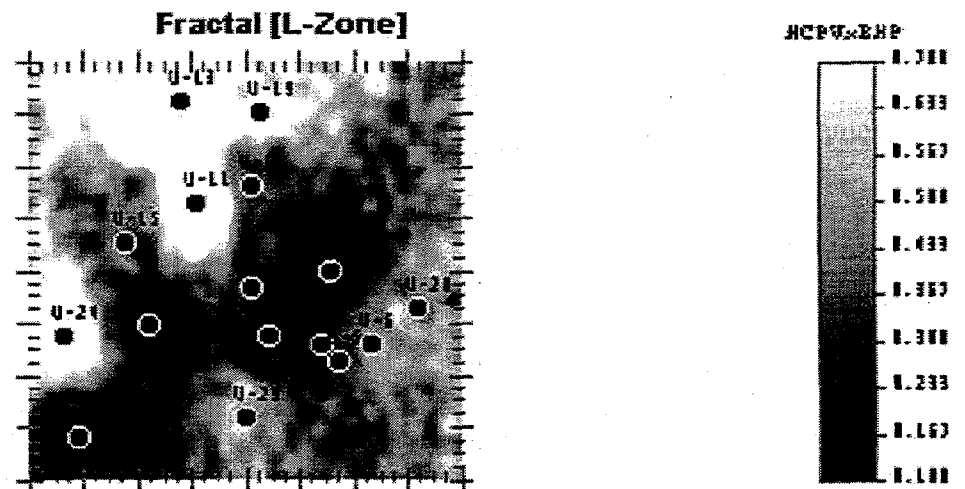


Fig. 29. Oil production for Case 2, NDP Well #6.



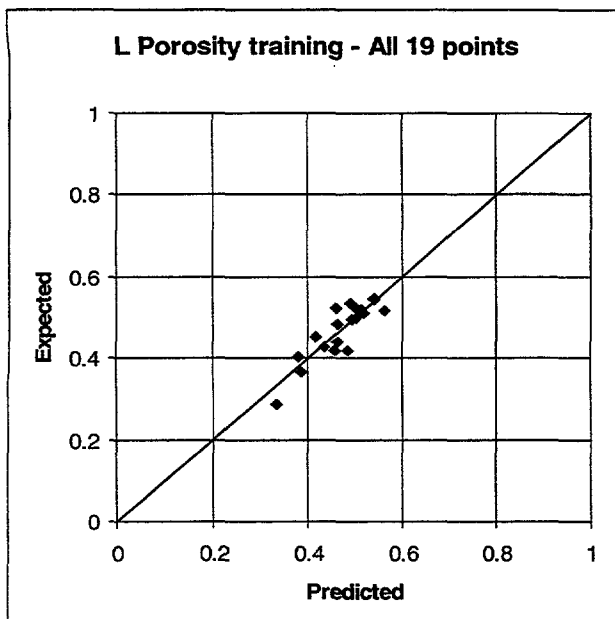
Layer 0

Fig. 30. Fractal hydrocarbon pore volume map

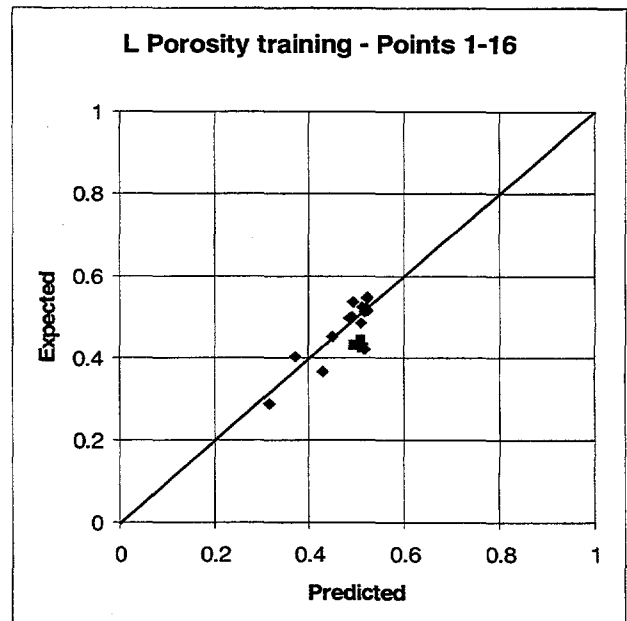


Layer 0

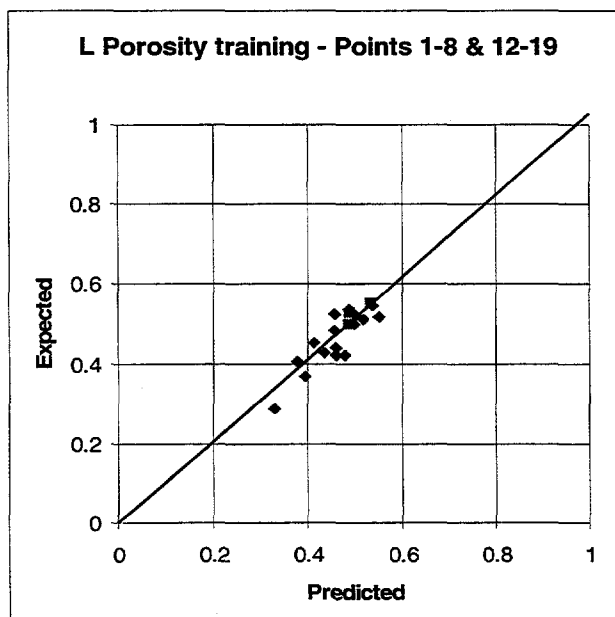
Fig. 31. Fractal hydrocarbon pore volume map conditioned with normalized bottomhole pressure.



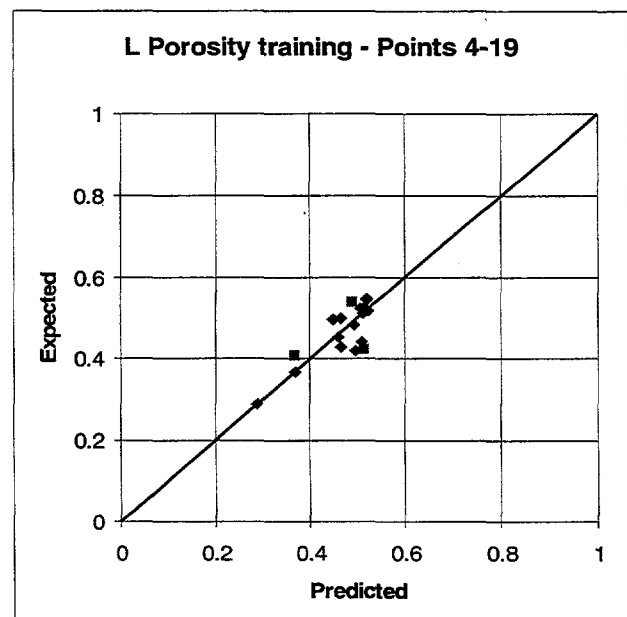
32a.



32b.



32c.



32d.

Fig. 32. Crossplots for the L-zone porosity, final and test regressions. 1a) Shows the crossplot for training with all 19 well control points. 1b) The network was retrained excluding points 17-19, which were then predicted using the network (purple points). 1c) The network was retrained excluding points 9-10, which were then predicted using the network (purple points). 1d) The network was retrained excluding points 1-3, which were then predicted by the network (purple points).

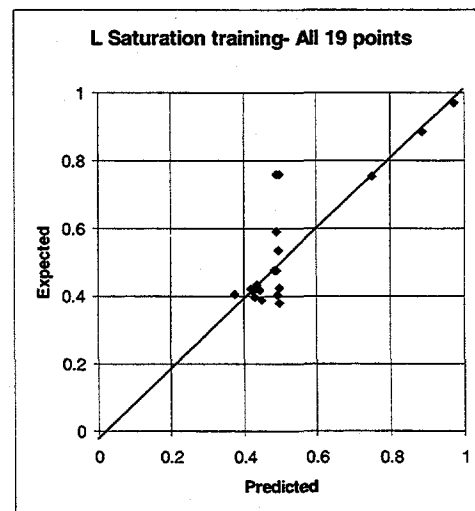
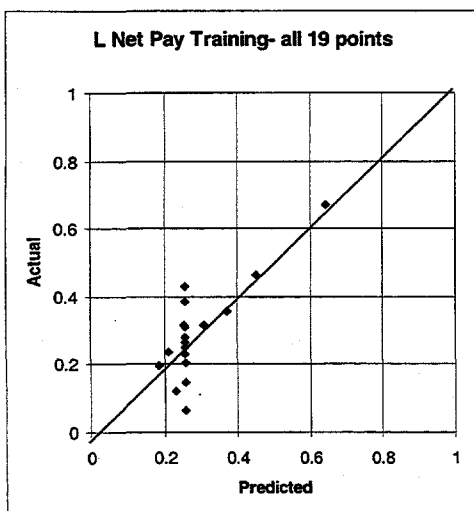
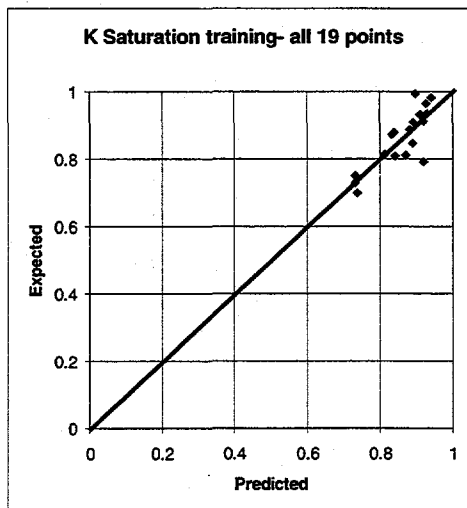
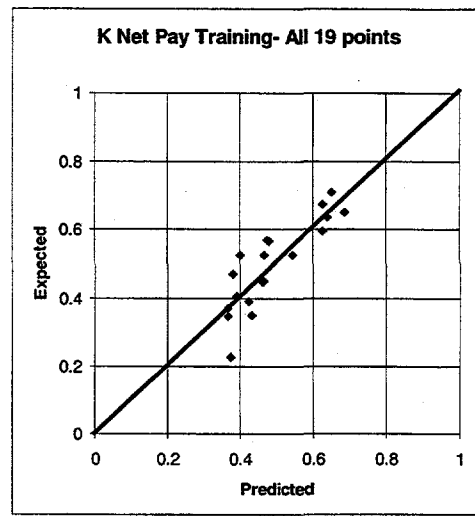
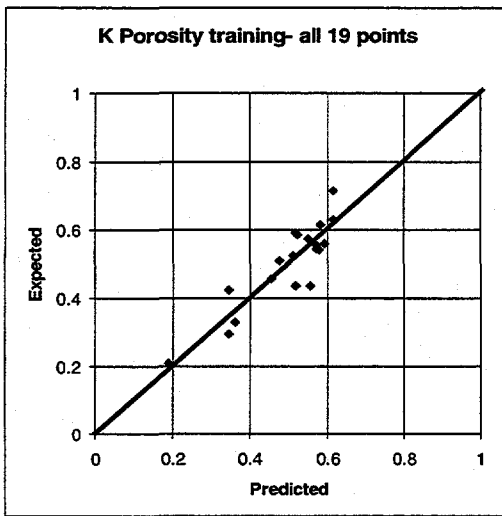


Fig 33. Crossplots for training the K-interval porosity, net pay, and water saturation; L-interval net pay and water saturation.

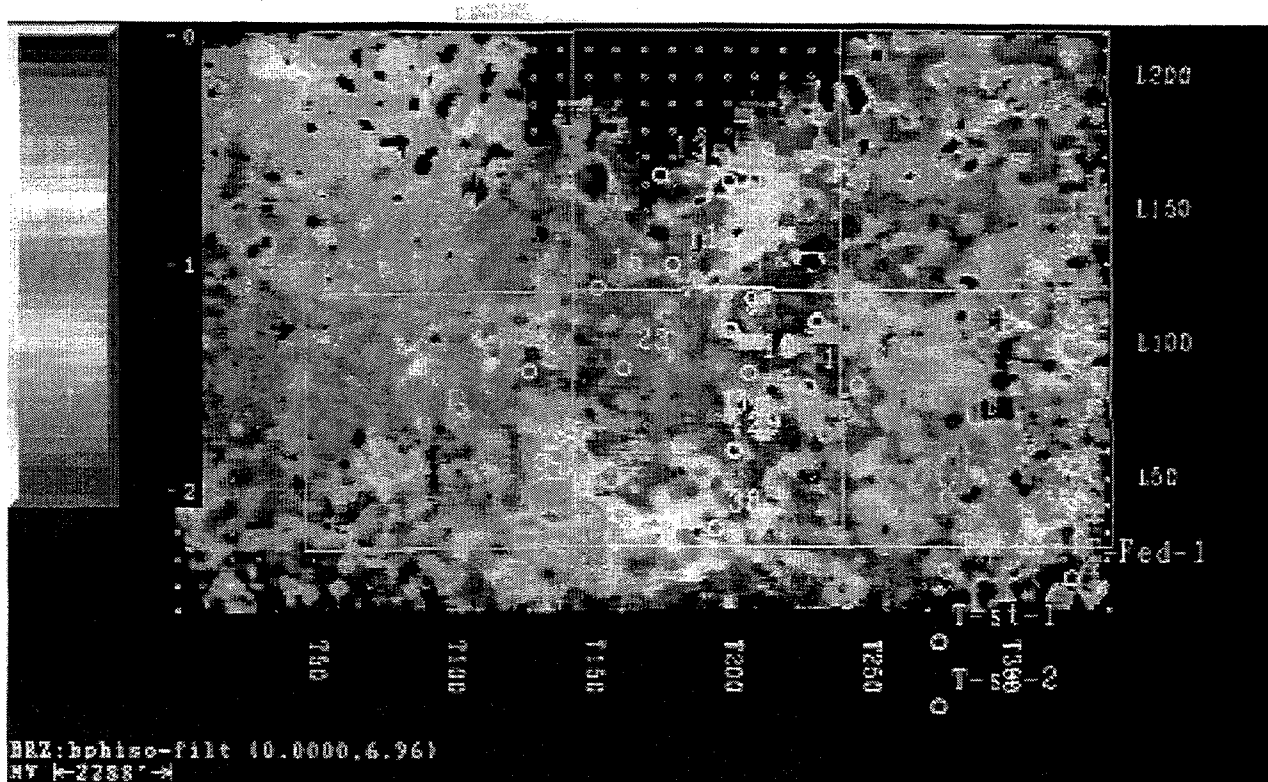


Fig. 34. Predicted hydrocarbon pore volume from neural network.