FOSSIL ENERGY

DOE/BC/14941-12
(DE98000532)

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

SECOND ANNUAL TECHNICAL PROGRESS REPORT

Annual Report
October 1, 1996 - September 30, 1997

By
Strata Production Company

September 1998

Performed Under Contract No. DE-FC22-95BC14941

Strata Production Company
Roswell, NM

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

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Distribution Category UC-122

Advanced Oil Recovery Technologies For Improved Recovery From Slope Basin Clastic Reservoirs, Nash Draw Brushy Canyon Pool, Eddy County, NM

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ABSTRACT

The Nash Draw Brushy Canyon Pool in Eddy County New Mexico is a field demonstration in the U.S. Department of Energy Class III Program. Advanced reservoir 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 description was too simplistic to capture the critical features of this complex formation. As a result of the analysis, a proposed pilot area was reconsidered. Comparison of seismic data and engineering data have shown evidence of discontinuities in the area surrounding the proposed injector. Analysis of the 3-D seismic has shown that wells in the proposed pilot are in an area of poor quality amplitude development. The implication is that since amplitude attenuation is a function of porosity, then this is not the best area to be attempting a pilot pressure maintenance project. Because the original pilot area appears to be compartmentalized, the lateral continuity between the pilot wells could be reduced. The 3-D seismic interpretation indicates other areas may be better suited for the initial pilot area. Therefore, the current focus has shifted more to targeted drilling, and the pilot injection will be considered in a more continuous area of the NDP in the future.

Results of reservoir simulation studies indicate that pressure maintenance should be started early when reservoir pressure is still high.

INTRODUCTION

The Nash Draw Pool (NDP) in southeast New Mexico is one of the nine projects selected in 1995 by the U.S. Department of Energy (DOE) for participation in the Class III Reservoir Field Demonstration Program. Production at the NDP is from the Brushy Canyon formation, a low-permeability turbidite reservoir in the Delaware Mountain Group of Permian, Guadalupian age. Reservoir and fluid data were provided in the first annual report and in recent publications.[1-3]

A challenge in developing these Delaware reservoirs of marginal quality is to distinguish oil-productive pay intervals from water-saturated, non-pay intervals. Additionally, because initial reservoir pressure is only slightly above bubble-point pressure, rapid oil decline rates and high gas/oil ratios are typically observed in the first year of primary production. Further, limited surface access, caused by underground potash mining and surface playa lakes at the NDP (see **Fig. 1**), prohibits development with conventional drilling in some parts of the reservoir.

Various combinations of vertical and horizontal wells combined with selective completions are being considered for optimizing production performance. Based on the production constraints due to high gas-oil ratios observed in similar Delaware Basin fields, pressure maintenance is a likely requirement at the NDP.

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. The demonstration plan includes developing a control area using standard reservoir management techniques and comparing the performance of the control area with an area developed using advanced reservoir management methods. Specific goals to attain the objective are: (1) to demonstrate that a development drilling program and pressure maintenance program, based on advanced reservoir management methods, can significantly improve oil recovery compared with existing technology applications, and (2) to transfer the advanced methodologies to oil and gas producers in the Permian Basin and elsewhere in the U.S. oil and gas industry.

DISCUSSION OF RESULTS

This is the second annual progress report on the project. Results obtained to date are summarized.

MANAGEMENT AND PROJECT PLANNING

Project Management Concept

The project involved the demonstration of a virtual company concept involving a small independent oil producer and geographically diverse experts. 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 analyze and implement the Nash Draw project. The organization of the Nash Draw virtual team is presented in **Fig. 2.** 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 provides 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 uses advanced technologies to communicate and coordinate efforts. The Internet, e-mail, and high-capacity data transfer are used successfully to exchange data, interpretations, and conclusions between each group. E-mail is 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 are developed and maintained by Pecos Petroleum Engineering, Inc. in Roswell, NM. These are shared electronically with all other project sites. In this case the file sizes are 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 is described in a recent technical paper.[4]

Initial Development Plan

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.

Early subsurface mapping showed the NDP as having more of a blanket sand morphology. 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.[1] Even with more data incorporated, the prediction of high quality reservoir sands was difficult.

Part of the development program in the NDP called for a pressure maintenance program for enhancing recoveries from these reservoirs. The area chosen 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, and production tests and pressure buildup tests indicated that they were in communication.

RESERVOIR SANDS

The sandstone units of the basal Brushy Canyon sequence of the Delaware Mountain Group in this study represent the initial phase of detrital basin fill in the Delaware Basin during Guadalupian time. The Delaware sands are deep-water marine turbidite deposits. Depositional models[5,6] 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[7,8] 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.

The Brushy Canyon sequence lies above the Bone Spring formation. The top of the Bone Spring is marked by a regionally persistent limestone varying from 50 to 100 feet in thickness. This surface 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, and this overprint is reflected in the reservoir rocks of the Delaware formation and impacts the trapping mechanism in the sands.

Locally, the three sands of interest are referred to as the "K", "K-2", and "L" sands (Fig. 3). These sands can be easily correlated from well to well over many square miles. Each of the sands is a composite of a series of stacked micro-reservoirs (Fig. 3) that vary from one to six feet in thickness.[1] Lateral extent of reservoir quality facies may only be a quarter of a mile or less in some areas. Analysis of whole core and drilled sidewall core data[1] have shown that individual micro-reservoirs may be oil-bearing, water-bearing, or transitional in nature. In addition, the sands have been found to have little or no vertical permeability from one micro-reservoir to the next.

By all accounts even the best of these sands would be considered "dirty" reservoirs. Petrographic and scanning electron microscope (SEM) studies[1] show that the sands have a very complex composition and pore structure. In general they can be described as subarkose, calcitic, very slightly dolomitic, slightly clayey, very fine to fine grained, silty, and poorly sorted. Grains are subangular to subrounded, there is evidence of framework grain dissolution, and some secondary porosity occurs by grain dissolution. Clay that is present coats some of the grains and fills some of the pores. Mineral composition of a typical reservoir sand in the NDP study area has been provided previously.[1,3] Productive reservoirs have porosity values ranging from 11 to 18 percent and permeability values ranging from 0.5 to 4 md.

Generally, the rock is fine-grained to very fine-grained, massive to very-thinly laminated. There is some evidence of turbulence as exhibited by sets of low-to-medium angle crossbedding within some of the sand units. Evidence of bioturbation occurs in some of the shaley and silty zones. Carbonate clastic debris is also present in some intervals within the core. Examination of the core under ultraviolet light shows the discontinuous character of the hydrocarbon distribution throughout the pay interval. This correlates with the erratic vertical distribution of oil and water saturations calculated from the log analysis.

The overall compositional character and discontinuity of the sands in these reservoirs has made log analysis, well completions and predictability (i.e., where to drill next) difficult for many years. These laminated sands with fine-grain to very-fine grain size and clay content typically yield "wet' saturation calculations, even in productive sands. Clays and migrating fines have always required that special consideration be given to drilling and completion fluids. Operators are always looking for the "water-free" Delaware sand completion. Given the nature of the sands at the NDP, water-free completions are not possible.

EARLY PROJECT RESULTS

By the end of 1995, fifteen wells had been drilled at the NDP and the results were still mixed. The first 13 wells were drilled using conventional geological interpretations, and estimates indicate that ultimate recoveries per well will range from 40,000 bbl oil to 150,000 bbl oil and the average oil recovery per well will be 90,000 bbl oil. Well quality could not be accurately predicted using subsurface geology and conventional data interpretation.

A third geological picture evolved in which there were possibly three depocenters. This interpretation was substantiated with bottomhole pressure data and capillary pressure data. Using this new, more detailed interpretation, NDP Well #25 was drilled in early 1996 at a location that was thought to be in the middle of a prolific sand depocenter. Log and core data showed that the primary reservoir, the "L" sand, had just four feet of net pay. The subsurface maps had predicted in excess of 30 feet of net pay in this zone. Thus, the reservoir characterization activities focused on providing a better understanding of the NDP.

EARLY RESERVOIR CHARACTERIZATION RESULTS

The initial geological interpretation suggested that the Brushy Canyon sands at the NDP appear to be blanket type sands. However, data and analyses obtained in the DOE Class III project suggest the sands at the NDP are laterally discontinuous and complex in nature. The focus of the reservoir characterization activities was to understand the nature of the complexities.

Stratigraphic Framework/Geological Model

Structure and isopach maps based on successive interpretations of the main NDP geobody were imported into Landmark's Stratigraphic Geocellular Model (SGM) to create a stratigraphic framework model. These interpretations were based on well data from wells within and directly adjacent to the NDP. After a preliminary 3-D stratigraphic model was developed, all surface intersections in the multilayered model were eliminated by fine-tuning the relationships among the different structural surfaces using isopach maps. These surface intersections occurred due to the sparse well control in some areas and relatively thin sand sub-units within the pool itself. The final model was constructed from the bottom up using the Bone Spring surface as the basal surface.

Production, petrophysically-derived storage and transmissibility distributions at the wells, special core analysis data, and geological interpretations were combined to arrive at a reservoir description that honored all of 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 facilitated 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.

Log and Core Analyses

A major problem in evaluating potentially productive zones in the Delaware sands is that wireline logs do not provide a definitive answer regarding what zones are productive and, most importantly, the amount of reserves recoverable from a particular well. This is primarily due to the highly laminated nature of the Delaware oil zones that are mixed with water zones. The resolution of the wireline logs is not good enough to arrive at accurate measurements for zones less than one foot in thickness.

To compensate for the lack of wireline log data, full cores and sidewall cores were used to confirm the presence of productive zones by measuring fluid permeabilities and residual oil saturations. A core-calibrated log analysis procedure was developed to give accurate data with a minimum number of sidewall cores. This is a PC-based computer analysis system that is easily adapted to most sandstone reservoirs. Details of the procedure are given in the first annual project report as well as in a recent publication.[1,3]

Identification of Net Pay

The core 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 (See **Fig.** 4).

By applying the core-calibrated log analysis to the entire basal Delaware section, oil-productive zones can be identified, reserves can be estimated, production rates can 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 and in other Delaware reservoirs in the region.

The application of the core-calibrated advanced log analysis procedure to two other Delaware wells in southeast New Mexico was performed with good results. The first application was a standard analysis similar to the NDP. The second application in a new rock type required a major correction in log values (14%) to accurately predict pay intervals. The wells have been completed, and one well agreed closely with predictions while the other well has higher water cuts than predicted. The higher water cuts are believed to be the result of down-dip water and possible scaling in the oil productive zones. A remedial treatment is being planned for this well.

COMPARISON OF NDP TO NEARBY FIELDS

Loving Analogy

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.

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 the bench located west of center and 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 miles 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. This is exhibited in Table 1, wells in units

"C", "F", "K" and "N" are on the bench. These wells 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 was obtained from the wells in the Loving Field and the distribution of porosity versus permeability were compared. As shown in the first annual report[1] on the NDP project, the comparison of the two data sets is 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 Nash 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" and produce 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 projected primary recovery from each well is presented in **Table 1A.** 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 log. 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. As shown in **Table 1B**, 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 (see details in Appendix A). Comparing the two methods of analysis, we find that there is good agreement between the two calculations, as seen in **Table 2.**

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.

Delaware Data

Texaco has drilled five (5) wells offsetting the NDP. Log and core data were obtained from

Texaco for analysis and inclusion into the NDP data base. The "L" zone is the main pay zone in the Texaco wells, similar to the NDU 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[1] 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.

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' (common datum) and the east edge is at a depth of 6950'. This represents a dip of 120' across the north end of the section. The bench is approximately 0.5 miles wide and the steps are approximately 0.25 miles wide.

The net pay associated with these depositional areas is presented in **Table 3**. 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 high 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. Production from thee wells is presented in **Table 4a**. 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 based on drainage areas, is shown in **Table 4b**.

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 NDU 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.

GEOPHYSICAL PROGRAM

Considerable geophysical activity occurred in year one of the project to aid the characterization of the NDP reservoir system. The critical component of the geophysical database necessary for the reservoir characterization effort was a high-quality 3-D seismic survey over the NDP. Details of the interpretations are presented elsewhere.[1,9,10]

Vertical Seismic Profiles

To properly prepare and plan for this 3-D seismic effort, a vertical seismic wavetest was first done in the centrally located 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, vertical seismic profile (VSP) data 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. These VSP data were instrumental in setting the size of the stacking bins used in the subsequent 3-D seismic program.

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.

3-D Seismic Data Acquisition and Interpretation

Using the information provided by the vertical wavetest and VSP, a 3-D seismic survey was designed and implemented. 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. A total of 917 source points were recorded to create a 3-D coverage across an area of 7.875 sq. mi.

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. Regardless of what type of depositional facies was exhibited (concordant, downlap, mounded, or chaotic), the L reflection trough never rose higher than 16 ms or 18 ms above the Bone Spring. Because of this approximate conformability between the L reflection trough and the robust Bone Spring reflection peak, the amplitude of the L reflection trough was defined in every bin of the 3-D volume by determining the maximum negative amplitude value in a data window that was bounded at the base by the Bone Spring reference surface and at the top by an arbitrary surface defined as Bone Spring-18 ms.

A map of maximum negative reflection amplitudes for the "L" sand across the NDP area is displayed as **Fig. 5**. The 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 (not included) looks much like this "L" reflection trough map, with higher reflection amplitudes again occurring at the better producing locations.[1,8,9]

The visual correlation between well performance and the "L" reflection amplitude exhibited in **Fig. 5** 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 (Fig. 6).

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, and

Tow = 5.98 - 0.24 A,

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

Interpreters now know that these 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.

Reservoir Compartments

Analysis of the instantaneous frequency displays, seismic volume, and pressure data have indicated parts of the "K" and "L" reservoirs are compartmentalized. For the Nash Draw 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 value.

Instantaneous frequency volumes were calculated from the Nash Draw 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 shown in **Fig. 7** was developed for the "K" sequence across the Nash Draw Unit. This tentative compartment map is realistic in the sense that it indicates there are large compartments around the better producing wells (e.g, 11, 15, and 19) and segmented compartments at the poorer producers (e.g., 5, 6, and 25). If production modeling confirms that the compartment sizes and shapes suggested by this model are realistic, 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.

New Data Acquisition Wells

Subsequent to the drilling of the NDP Well #25, two wells (NDP Wells #12 and #29) were drilled using targets selected on the basis of amplitude anomalies in the "K" and "L" sands. The first well based on the seismic data was drilled in March 1997, and a second well was drilled in September 1997. Both wells were successful, and the ability to use thin-bed seismic data in the NDP has re-directed the approach taken to locate new wells. Locations for all of the wells in the NDP are shown in **Fig. 8.**

NDP Well #12, located at 918ft FSL and 2153 ft FEL of Section 12-T23S-R29E, was completed, and initial production tests show daily production rates of 75 BO, 250 MCFG and 240 BW. The well is flowing up the annulus and is capable of higher production rates. The majority of the water production is coming from the high permeability wet "K-2" zone.

This well exhibited good "L" zone development and exhibited fair "K" zone development. The correlation of porosity in the "K" and "L" sands with the high intensity seismic reflection amplitudes for the respective intervals in the 3-D seismic data volume, presents positive information that seismic attributes correlate to the best quality reservoir rocks in the NDP.

NDP Well #29 was drilled in March 1997. The location for the well was picked using the seismic anomaly associated with the "L" Sand reflection amplitudes. The "L" Sand was encountered in the anticipated structural position relative to the other wells in the field. The porosity and sand development was not of the quality of similar reflection amplitudes in other parts of the field. The well resulted in an "L" Zone with 5.24 m (16.0 ft) of net pay (NP) with a weighted average porosity of 12.52 percent, for a total of 0.6572 porosity-meters [(2.0032 porosity-feet (PF)]. The expected values from the seismic amplitude calculations indicated a well with 0.9508 porosity-meters (2.898 PF) and 7.3430 m NP (22.38153 ft NP). The predicted values varied by approximately 40 percent from the actual values seen in the well It is possible the sand characteristics in this area have given similar amplitude attenuation, but for reasons other than thick porosity. The sand is more highly interbedded with shales than are other wells in the field.

Further investigation revealed the location of the well was approximately two to three bins northeast of the area of maximum amplitude. Negative amplitudes associated with the bin where the NDP Well #29 was drilled has a value of -20 and the maximum amplitude associated with the sand pod is -30 to -35. If this is the case, we should still have relatively good connectivity to better quality sands. A digital array sonic log was run in the well. The data will facilitate calibration of the seismic velocities and may help us understand the amplitude variations in these sands.

During the logging of the NDP Well #29, a continuity test was performed with a Repeat Formation Testing Tool (RFT) to determine zones showing pressure changes due to offset well production. Two zones indicated lower reservoir pressures and one higher reservoir pressures than were previously known. A good test of the top sand in the "L_a" interval indicated a pressure of 13,126.2 kPa (1,904 psi), which is approximately 7,238.7 kPa (1,050 psi) lower than the original reservoir pressure. This indicates communication with other wells in the field. Another zone in the "L_d" at 2,253.12 m (6867.5 ft.), indicated lower pressure by differentially "sticking" the tool, but a good seat was not obtained for gathering pressure data. Other zones in the "K", "K-2" and "L" indicated original pressure and no communication with other producers. Problems were encountered in getting good seats for the tool pad, and only 20 percent of the tests were successful. The data are presented in **Fig. 9**.

Completion of the NDP Well #29 began in May 1997. Log analysis indicated the "L" zone contained most of the oil productive zones in the Brushy Canyon interval. Therefore, only the "L" zone was selectively perforated from 2,080 m to 2,094 m (6,825 ft to 6,870 ft) with twenty-three (23) 1.07-cm (0.42") diameter perforations. The perforations were acidized with 7.5% NEFE hydrochloric acid with 50 rubber coated nylon ball sealers. The perforations were "balled out" to ensure all perforations were open and taking fluid. Results after the acid treatment indicated good fluid entry with a 30% oil cut and a good show of gas.

To facilitate the design of the fracturing treatment, a Digital Array Sonic Log was run, and a Frac Log with mechanical rock properties was derived. Rock properties included Young's Modulus, Poisson's Ratio, and frac gradient. A frac pressure was calculated for each half-foot interval and plotted against depth. Barriers were indicated at the shale-lime sequence on top of the Bone Spring at 2,100 m (6,890 ft) and in the upper "K" zone at 2,054 m or 2,039 m (6,740 ft or 6,690 ft). This indicated a gross frac height of 43 m to 61 m (140 ft to 200 ft).

The fracture stimulation treatment was designed for 66 m (216.5 ft) of height and 110 m (360.5 ft) of propped fracture half-length. If the height was only 43 m (140 ft), the length would be approximately 122 m (400 ft). The zone was fractured with 246 m^3 (65,000 gallons) of 4.2 kg/m^3 (35 lb./1000 gals.) crosslinked gelled water carrying 98,376 kg (216,880 lbs) 16/30 sand at an average rate of 0.055 m^3/s (21 BPM).

A temperature log was run at three, four, and six hours after the fracturing treatment to determine fluid entry. The temperature log indicated the majority of the fracturing treatment was contained from 2,056 m to 2,096 m (6,745 ft to 6,875 ft). There is an indication of greater cooling and that larger volumes of fluid entered from 2,057 m to 2,076 m (6750 ft to 6810 ft) and 2,086 m to 2,091 (6,845 ft to 6,860 ft). The temperature log confirmed that the lower "K", "K-2"and "L" zones were stimulated by the fracturing treatment.

Log analysis of this interval, with core-calibrated calculations using "L" zone porosity-permeability relationships for the oil productive zones and "K-2" zone porosity-permeability relationships for the water productive zones, indicates the well should produce 26.7 m^3/day oil (168 BOPD) and 189 m^3/day water (1,187 BWPD). After cleanup and stabilization the well averaged 11.9 m^3/day (74.8 BOPD) and 86.8 m^3/day (546 BWPD) from June 14th through June 19th. A fluid level obtained on June 24th indicated a fluid level at 771 m (2,529 ft) from the surface, which indicates there is 1,311 m (4,300 ft) of gas-cut fluid above the perforations. This high fluid level indicates that higher production rates are possible if sufficient lift equipment were available to produce the available fluid. The actual oil cut of 13.7% is close to the predicted oil cut of 14.2% .

A 912 pumping unit installation was designed to move in excess of 95.4 m^3/day (600 barrels of fluid per day). The installation of this larger unit occurred during the first part of August 1997.

Reduction of the fluid level and additional testing will be required to fully evaluate this well.

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 bottom hole 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 October 1, 1997 the GOR has increased to 10.7 to 1. A typical well achieves a GOR of 10 to 1 after approximately 20 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 the completion sequence was determined, an initial GOR was determined for each well, a Rate vs. Cumulative Production curve for each well was plotted, the ultimate primary production was estimated from the decline curves, primary recovery per acre was estimated from the log analysis, a indicated drainage area was estimated by dividing the ultimate recovery by the recovery per acre value, and a ratio of indicated Drainage Area vs. Allocated Acreage was calculated. A summary of this data is presented in **Table 5**.

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 is not known which wells are in communication with NDP Well #29, but there should be a change in slope of the Cumulative vs. Rate Curve for the effected wells after NDP Well #29 has produced for a few months.

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, and #29.

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. By comparing the indicated drainage area to the allocated area (40- or 80-acre spacing) a drainage ratio can be calculated. The 8 wells with initial GORs of less than 2 MCFG/BO indicate a 60% ratio from the indicated drainage area to the allocated drainage area. The remaining 8 wells with high GORs indicate a decreasing drainage ratio from 60% to 20% (see **Fig. 10**).

A summary from this analysis and the basis for future investigation is:

- Wells drilled on 40-acre spacing exhibit interference.
- Pressure depletion can occur over distances greater than 1,600 ft.
- Some wells exhibit little or no effects of interference. This may be attributed to compartmentalization or a large reservoir volume in relation to the amount of interference.
- 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 the 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. A complete analysis of this well will be included in the next quarterly report.

Production and decline curves have been updated through September 1, 1997. Production for the month of August 1997 averaged 301 BOPD, 2,925 MCFGD and 1,168 BWPD.

CURRENT RESERVOIR DESCRIPTION

Detailed mapping of the reservoir engineering data along with the geological data revealed the complex nature of these Brushy Canyon sands. Each of the three primary reservoir sands in the study were mapped using a variety of parameters. In the NDP, there appears to be three primary depositional fairways in the "L" sand in which the better reservoir quality rock has been developed. Net porosity maps combined with log-derived net pay and capillary pressure data have been integrated and support this interpretation. Isopressure maps suggest a correlation between pressure and the distribution of sand in the lobes of the "L" sand. If these sands were more uniform or laterally continuous, then we would expect to see a more gradational and uniform change in pressure following the east-to-west change in structural dip. The pressure distribution along with the geological interpretation suggests that these reservoirs are more compartmentalized than initially believed. The "K" sand has been laterally segregated into two primary depositional lobes in the same manner as the "L" sand.

There were multiple reasons for shooting the 3-D seismic survey. 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. The distribution of the seismic reflection amplitudes in both the "K" and "L" sands showed that the sands could be imaged using thin-bed techniques. The data presented a new picture of the distribution of the reservoir quality rocks in the NDP. Subsequent to the drilling of the NDP Well #25, two wells (NDP Wells #12 and #29) were drilled using targets selected on the basis of amplitude anomalies in the "K" and "L" sands. Both wells were successful, and the ability to use thin-bed seismic data in the NDP has re-directed the approach taken to locate new wells.

Analysis of the instantaneous frequency displays, seismic volume, and pressure data have indicated parts of the "K" and "L" reservoirs are compartmentalized (see **Fig. 7**). Instantaneous frequency volumes were calculated from the Nash Draw 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 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).

Each of the reservoirs in the study is a series of stacked micro-reservoirs forming an amalgamated composite reservoir. The "L" sand appears to have a "primary" depositional area and a fringing "secondary" depositional area as exhibited by the seismic results. The secondary depositional composites are more disjointed and isolated, forming an apron in front of the primary area. While the original subsurface mapping interpretations suggested a stricter, more linear channel morphology, the geological model derived from the 3-D seismic data volume suggests a less linear morphology. The reservoir sand distribution, as a function of the composite porosity of the thin-bed turbidite reservoirs, has a lobate morphology that trends in a north - south direction. This morphology is clearly seen in "L" sand reflection amplitude plot. The NDP is within the mid- to distal portion of the lobe.

The Brushy Canyon sands, part of a lowstand systems tract, are of eolian origin and were transported basin-ward through shelf by-pass systems. They may fit into what would be a mid-slope turbidite sequence of shingled turbidites, part of a prograding complex scheme. Shingled turbidites are comprised of amalgamated sands that appear to be continuous. The sands seem to fit the seismic criteria as well. The internal seismic architecture is discontinuous and chaotic, within localized sequence boundaries. The seismic expression is an overall tabular unit with subparallel to basinal thinning reflections.

The unit extends across the 3-D volume indicating a widespread sheet of amalgamated turbidites. From log to log, the "L" sand appears to be continuous throughout the unit as well. This is a preliminary interpretation of a geological model for the NDP.

Further study of the NDP Well #23 core and case studies in the literature will be undertaken to more clearly define the geologic model that best fits the basal Brushy Canyon sands in the NDP. High resolution sequence stratigraphic analysis from the well logs will be incorporated and integrated with the seismic data as well.

RESERVOIR MODELING AND RESERVOIR SIMULATION

During the first half of FY 1997, the activities of the Reservoir Characterization/Simulation Team were focused on the development of a geological model for an area of the pool centered at NDP Well #1. This site was chosen primarily because a five-spot well pattern already existed there. At the outset of this project, it was envisioned that a field pilot would be implemented in this area to investigate the feasibility of enhanced recovery through pressure maintenance. An interpretation of 3-D seismic data acquired during the current project year indicated that this area is not a "sweet" spot. Moreover, early simulations also confirmed that a field pilot was not likely to have been very successful if implemented after most of the reservoir energy had been depleted, as was the case at the beginning of 1997.

During the last half of the project year, the team turned its attention to (1) validation of a simulation model developed for the Eclipse 100 reservoir simulator for the proposed pilot area, and (2) investigation of the probable impact on oil recovery of the early implementation of pressure maintenance options. It was apparent by this time that a field pilot would not be attempted here, 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 to be expected that less field data will be available.

The Pilot Model

After the 3-D seismic data acquired at the beginning of this project year 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. Recently generated 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. Moreover, since approximately 95% of the oil produced from the five wells in this lobe can be traced back to the "L" zone, only this zone is included in the model. Due to the highly lenticular distribution of oil within the four subzones identified in the "L" zone, a twenty layer simulation model (see **Fig. 11**) was chosen for the pilot area; that is, five proportional layers for each of the L_a, L_b, L_c, and L_d subzones. The distribution of mobile oil saturation for this choice of layering is depicted in **Fig. 12.** Areal grid spacing was chosen to be 220 ft in both directions, this value being a multiple of the spacing of the seismic lines (x4).

Other Model Attributes

The wells in the NDP flow through induced fractures. These trend in a north-south direction and extend some 400 ft from each well. We chose to model these fractures through the enhancement of the vertical transmissibility of the columns of grid blocks where the fractures are located, and the enhancement of y-direction transmissibilities (y being the north-south direction of the model) of neighboring columns of cells. This approach is referred to as the equivalent continuum technique. Each fracture was represented by the transmissibility enhancement of the well column and its two y-direction neighbor columns on either side. The effect of the vertical enhancement of transmissibility is to reduce the pressure drop in the perforated zone of the wells. The presence of the fractures is also modeled in two other ways: (1) well skin effects and (2) well completion effects. The observed well skins and well indices are described in **Table 6**.

Each model well was completed throughout the vertical column of cells where it is located. In Eclipse 100, these skin factors could not all be realized because of the possibility of cancellation with the "pressure equivalent radius" in the denominator of the well transmissibility equation, $\ln(r_o/r_w) + S$, where r_o is the pressure equivalent radius, r_w the well radius and S the skin factor. The possibility of catastrophic cancellation prevented any model skin factor from being more negative than –4.85.

Drainage areas were defined around the model wells. These are based on log calculations to obtain a value of B_o per acre coupled with an estimate of the drainage area for each well. The initial oil volumes of these drainage areas correspond to a recovery factor of 16.6% and are given in **Table 7**.

Figure 13 depicts the model drainage areas assigned to each well in the simulation model. The log-derived saturations of water and gas at each well were interpolated to create initial distributions. Since these logs were taken at different times, it was to be expected that a simulation initialized in such a manner would not be at equilibrium. The use of interpolation and extrapolation could also have this result. To determine the possible effects of this approach, the simulator was allowed to re-equilibrate with no well production for a period of five years. During this period the fluids readjusted themselves into an equilibrium state. The maximum change in the oil phase pressure at any location was less than 5 psi; the maximum change in fluid saturation was less than 0.05%. The simulation grid itself was designed to accommodate the reservoir volume associated with a recovery factor of 12%, that is, approximately 3.6M STB; hence the "border" of unused cells. These cells would have been needed to accommodate the larger drainage areas for this case.

Model Validation Strategy

Since the exact oil volume of the pilot area node was not known and only one pressure buildup test had been performed for a well in the pilot area, NDP Well #5, model validation was necessarily confined to qualitative, rather than quantitative, behavior.

Model Validation Criteria

As described in previous quarterly reports, our criteria for a "good" match of historical performance were reasonable agreement between simulated values and actual values of the following:

- drainage-area average pressure for each well (as determined by analytical methods)
- oil production by well
- water production by well
- gas production by well
- 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.

The absence of buildup test data meant that only a qualitative pressure match could be expected. We attempted to match the average pressure in the drainage area of each well with the values calculated by classical reservoir engineering methods, assuming that the drainage area volumes were those described in **Table 7**. We also made model adjustment to bring the wells onto pumping conditions (zero bottomhole pressure) at the times summarized in **Table 8**.

Model Uncertainty

The first step in the model validation process is to identify the major sources of uncertainty in the reservoir and fluid descriptions. In the NDP, we confront the usual limitations attributable to sparse well control. The distribution of permeability and porosity in our model were based on interpreted petrophysical data (mainly derived from logs calibrated with side-wall cores). Data at well locations were interpolated using inverse distance weighting to provide values at other model locations.

The relative permeability and capillary pressure data were obtained from a special core analysis performed on a sample from NDP Well #23. This well is not near the pilot node. As we have already noted, there were no pressure transient data for wells in the pilot area, except for a single test of NDP Well #5. Consequently, the exact hydrocarbon volume of the lobe is unknown, and the drainage area volumes are approximate. The list of uncertain variables used in the validation step include (in rough order of decreasing uncertainty):

- fracture transmissibility
- grid block transmissibility (by drainage area)
- grid block porosity (by drainage area)
- end-point saturations, especially S_{gc}
- two phase relative permeabilities, k_{rw}, k_{rg}, and k_{rog}
- well index

The Current "Best" Match

There are always many ways to match the well behavior actually observed in the field—simulation models are always underconstrained. This is especially true in this case, since there are so few production measurements to tie down the model. Our guiding principle has been to try to make the smallest excursions possible from the measurements that do exist.

Fracture Transmissibilities

The fracture treatment was described in an earlier paragraph of this section of the report. The effective fracture transmissibility, for which we had no welltest data, has a strong effect on the behavior of the flowing bottomhole presure (fbhp), as would be expected. We adjusted the effective fracture transmissibility until the dates of the onset of pumping (equivalent to fbhp=0) were matched as closely as possible. Of course, fracture transmissibility is not the only factor which influences the fbhp behavior of a well. However, after relative permeabilities, it was the dominant factor. As described below, the relative permeabilities were adjusted to match water and gas production. The values of effective transmissibility which yielded the best match of the onset of pumping are tabulated in **Table 9**.

The effect of this parameter on the behavior of the flowing bottomhole pressure is illustrated in **Figs. 14** and **15**. For an effective fracture transmissibility of 2.0 Darcy-ft per cp, the flowing bottomhole pressure of NDP Well #14 declined more rapidly and reached the condition fbhp=0 in December, 1996, about two months late, as is illustrated in **Fig. 14**. When the effective transmissibility of the fracture at NDP Well #14 is only 0.5 Darcy-ft per cp, the decline of the flowing buttonhole pressure is more gradual, as is illustrated in **Fig. 15**.

A comparison of **Figs. 14** and **15** reveals that the 0.5 Darcy-ft per cp case exhibits a slightly better match to the material balance drainage area pressure than the former. This is due to the fact that the fbhp for the case of **Fig. 15** skims above zero and the simulated well produces more fluid than its counterpart for the case represented by **Fig. 14**, a fracture transmissibility of 2.0 Darcy-ft per cp. To some extent this is an artifact of the simulation. In the perfect run, the simulated NDP Well #1 would have produced the correct volume of fluid while operating under the constraint fbhp = 0. A final point to make about this is that the effective transmissibilities in **Table 9** are probably too high. This is due to the fact that the well skins had to be truncated at a value of S= –4.86.

Relative Permeabilities

As noted above, we made the produced oil rate the driving function for the simulations. Under this scenario water and gas rates depend on the mobility of these two phases. The availability of the measured water and gas production rates provides the opportunity to adjust the relative permeabilities to match this field data. The initial values of the water phase relative permeability for the "L" zone, k_{rw}, and the "best fit" (to historical water rate) values are plotted in **Fig. 16**. The initial values were obtained from a special core analysis on a sample from NDP Well #23. This well is not in the pilot area. It lies near the western edge of Section 13.

The simulated water production profile for the original values of water relative permeability for NDP Well #1 is exhibited in **Fig. 17**. If the initial water saturation distribution is assumed to be credible, then the initial k_{rw} distribution, derived from a special core analysis on a sample from NDP Well #23, is too favorable to the movement of water. Moreover, because the simulated NDP Well #1 produces too much total fluid, the fbhp drops too quickly and reaches pumping conditions about five months early as depicted in **Fig. 18.** The initial water distribution is not beyond question. For example, NDP Well #5 produces no water in the field, but has water production in the model even for the severe k_{rw} curves of the best fit. The log-interpreted initial water saturations were not altered during the validation step because (1) they were based on data from actual pilot area wells, and (2) the distribution was too complex to be altered in a simple way.

Gas Relative Permeabilities

For the original values of k_{rg}, the drainage area pressure is in poor agreement with the analytical value for NDP Well #1, and the flowing bottomhole does not reach pumping conditions, as can be seen in **Fig. 19**. Here the effective fracture transmissibility is 10 Darcy-ft per cp. This is primarily due to the fact that gas production is too low, as can be seen in **Fig. 20**.

Adjustments to the k_{rg} curve, which enhanced the mobility of gas at higher gas saturations, did not improve the result. Upon closer examination of **Fig. 19**, it is apparent that NDP Well #1 was only producing solution gas in the model, whereas, the field data supports the notion that NDP Well #1 also produces free gas. This lead us to question the drainage area volume assumed in the model in addition to the gas mobility. Adjustments of both drainage area volume and k_{rg} brought the simulated performance of NDP Well #1 into better agreement with the actual production data (see **Fig. 21**). This is the worst match of gas production for any of the pilot wells.

The envelope of k_{rg} curves investigated during this match is displayed in **Fig. 22.** In Run 40 the flowing buttonhole pressures for each of the pilot area wells drop precipitously and the wells go onto pumping status too early with the consequence that the produced gas and oil volumes are too low. In Run 51 the behavior of the flowing bottomhole pressure is better, but the model wells still produce too little oil or gas. This would seem to say that there is insufficient data to calibrate the k_{rg} curves at higher gas saturations because at higher gas saturations the k_{rg} curves of Run 40 and Run 51 diverge.

Permeabilities (Transmissibilities)

The rock matrix in the "L" zone is fairly tight--permeabilities range from fractions of a millidarcy to a few millidarcies. We adjusted these slightly to improve the match. The largest adjustment was in the region that supports NDP Well #14. **Figures 23** and **24** contrast the pressure behavior for the original case with the best match case. **Table 10** summarizes the transmissibility adjustments made to the original data to reach the "best match" state.

Porosities

The drainage area boundaries were chosen to best approximate the drainage area volumes for each well listed in **Table 7.** In turn, these volumes were based on the initial saturation values inherited from the geological model, which, in turn, was based on interpolated saturation distributions at the wells. Because rigorous fluids in-place values were not available, the drainage area oil volume itself became a matching parameter. We chose to modify the porosity in each of the well drainage areas to improve the match instead of modifying any of the log-derived saturation distributions. However, the porosity was altered only as a last resort. The modification took the form of a single porosity multiplier for each drainage area.

The adjusted oil volumes for the "drainage areas" for each of the model wells is specified in **Table 11.**

Well Index

The observed well indices are described in **Table 6**. Model results were not very sensitive to these values. The principal impact is on the behavior of the well fbhp, as was to be expected. This parameter influences results when the wells reach pumping conditions. This parameter was used to lift model wells off of pumping conditions, that is, elevate the fbhp of a well slightly above zero.

A Brief Look at the Best Match

The pressure behavior, fluid (water and oil) production rates, and gas production rates for the five wells in the pilot appear in **Figs. 25, 26,** and **27**, respectively. Except for NDP Well #6, the drainage area pressures are a little high; that is, a little greater than the material balance pressure calculated for each region. This is probably due to compressibility effects engendered by the presence of free gas.

The treatment of fbhp was a not straightforward. On the one hand, we sought to match the onset of pumping conditions, that is, fbhp = 0. On the other hand, we wanted to match oil rate of each well throughout the history of production. The best compromise is illustrated in **Fig. 24** for NDP Well #1: the fbhp hovers above zero but never attains that value. With this approach, that is, using the inflection point in the fbhp curve as an estimate for the onset of pumping conditions, we can see that the match for NDP Wells #1, #5, #6, and #14 are close (i.e., one or two months from the actual date). We were unable to find adjustments which would match NDP Well #10, which reaches pumping conditions very quickly after the onset of production.

The water match is reasonable, given the uncertainty in the initial water distribution. It is clear that there are no mobile water saturations in the immediate vicinity of NDP Well #5, since this well produces no water. However, the simulated well produced water even for the extreme "best fit" k_{rw} curve illustrated in **Fig. 16.**

Except for NDP Well #1, gas production was matched very well in all other wells for the initial reservoir description and k_{rg} curve and with a high fracture transmissibility, 10 Darcy-ft per cp. The difficulty was that the match of the onset of pumping conditions was very poor, with most wells never reaching this condition during the history match period. Attempts to obtain a better match for the onset of pumping greatly degraded the gas production match. We were never able to identify the parameters which would yield a good match for gas production of NDP Well #1, but suspect that the high average pressure is the main source of the problem.

The problem well for this validation exercise has been NDP Well #10. The model well could not be coaxed onto pumping conditions early with the kinds of model adjustments that were successful with other pilot area wells. Moreover, the behavior of the fbhp for NDP Well #10 was extremely sensitive to perturbations of fracture transmissibility and matrix transmissibility. In **Fig. 25**, the material balance pressure is bracketed between two model pressures. The higher curve represents the drainage area pressure; the lower one the average of the nine blocks surrounding (and including) the well block where NDP Well #10 resides. The match presented in **Fig. 25** represents the best compromise between honoring the oil production rate and the date at which pumping conditions were reached.

Forecasts

Two cases were investigated:

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. The pressure in the drainage region of NDP Well #1 did respond to gas injection as anticipated. This is illustrated in **Fig. 28**. However, the pressure response for the remaining four producers in the pilot area was not very encouraging. This is illustrated for NDP Well #14 in **Fig. 29**. The corresponding oil rate for NDP Well #14 is displayed in **Fig. 30**. 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 fracture mitigated against a workover.

Case 2

It is apparent that there is very little natural energy left in the pilot node at the inception of Case 1, and that the 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. 31**. The pressure response for NDP Well #6 is depicted in **Fig. 32**; unlike Case 1, NDP Well #6 experiences an increase in pressure during the period of the forecast. The oil production rate for NDP Well #6 is illustrated in **Fig. 33**. The behavior is typical of the other producers in the pilot node. A high plateau of oil production is followed by a gradual decline.

Summary of the Simulation Results

This simulation study has fostered three main findings:

(1) In any future wells, the single most important piece of data that could be acquired would be pressure buildup data. This would provide insight into the correct treatment of fracture transmissibility.

(2) The implementation of a pressure maintenance scheme after well drainage area pressures have declined below 500 psi probably will not improve oil recovery.

(3) The implementation of pressure maintenance, specifically gas injection, early in the development of the pattern would help. In Case 2, evidence was presented that this step might have doubled the early oil production of the five spot.

SIGNIFICANCE OF RESULTS IN REDUCING RISK

Reservoir characterization conducted as part of the Class III project has identified 17 additional locations at the NDP. Compared to the initial development plan, this is an increase of 45% in the number of locations and an additional 3 million bbl of oil reserves. The reservoir characterization will reduce the risk of drilling marginal wells, such as the NDP Well #25. Drilling dollars can be expended to develop "sweet spots" with higher reserve volumes and better economics.

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. For example, the NDP Well #29 is only completed in the "L" zone because the "K" zone in this area is marginal. This saves perforating, acidizing and fracturing a zone that will not produce enough reserves to return the $100,000 cost of completion.

Because the reservoir is now better understood, the feasibility of pressure maintenance or other enhanced recovery mechanisms can be evaluated. If a pressure maintenance project had been attempted in the wells surrounding NDP Well #1, it would have resulted in economic failure of the pilot project which would have delayed or terminated expansion to the remaining part of the field.

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.

TECHNOLOGY TRANSFER

The transfer of technical information generated during the course of this project is one of the prime objectives of the project. Toward this objective, Strata has participated in several meetings and workshops to promote the dissemination of information generated during this quarter of the project. A summary of these activities in the second year of the project is outlined as follows:

Technology Transfer Meeting - December 1996
A liaison committee meeting was held on December 18, 1996. The purpose of this meeting was to update Mr. William J. Lemay Director of the New Mexico Oil Conservation Division as to the status of the project and findings to date.

Fourth International Reservoir Characterization Technical Conference - March 1997
A paper[2] entitled "Advanced Reservoir Characterization for Improved Oil Recovery in a New Mexico Delaware Basin Project" was delivered at the Fourth International Reservoir Characterization Technical Conference to be held in Houston, Texas on March 2-4, 1997.

AAPG Annual Convention - April 1997
A poster session at the AAPG Annual Convention held in Dallas, Texas on April 7-10 updated the status and findings at the Nash Draw Project.

Informal DOE Meeting - In April 1997, several members of the Nash Draw team discussed results obtained in the NDP project with BPO field office personnel during a half-day meeting in Bartlesville, Oklahoma.

DOE Oil Technology Project Review - In June 1997, results obtained in the NDP Class III project were presented at the DOE Oil Technology Project Review Meeting in Houston, Texas.

IEA Paper - A paper entitled "Optimizing Oil Recovery from a Complex, Low Permeability Turbidite Reservoir" was presented at the 1997 18th International Energy Agency Workshop and Symposium on Enhanced Oil Recovery held in Copenhagen, Denmark in September, 1997.

SPE Paper - A paper[3] entitled "Reservoir Characterization as a Risk Reduction Tool at the Nash Draw Pool," was selected and prepared for presentation at the SPE Annual Technical Conference and Exhibition to be held in San Antonio, Texas in October, 1997.

SPE Paper - A second paper[4] entitled "Implementation of a Virtual Enterprise for Reservoir Management Applications," was also selected and prepared for presentation at the SPE Annual Technical Conference and Exhibition to be held in San Antonio, Texas in October, 1997.

Geophysics Papers Submitted - Two papers[9,10] have been submitted to Geophysics for peer review and publication. The paper titles are "3-D Seismic Imaging and Interpretation of Brushy Canyon Thin-Bed Turbidite Reservoirs, Northwest Delaware Basin" and "3-D Seismic Imaging of Reservoir Compartment Boundaries Across an Area of Complex Turbidite Deposition."

CONCLUSIONS

1. The Brushy Canyon reservoir is much more complex than initially indicated by conventional geological analysis. The interpretations of the advanced reservoir analyses show the oil accumulation in Brushy Canyon interval exists areally as pods or fairways and vertically as stacked micro-reservoirs.

2. An advanced log analysis and interpretation program was developed that can be used to identify net pay in a complex reservoir. The methodology for identifying net pay can be applied in other sandstone formations.

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

4. Pre-survey VSP wave testing and careful processing of 3-D seismic data allowed imaging of the thin-bed turbidite reservoirs at the NDP, and the individual Brushy Canyon sands could be individually resolved.

5. A proposed pilot pressure maintenance area was found to be compartmentalized. Because reservoir discontinuities would reduce the effectiveness of any injection scheme, the pilot area will be moved to a more continuous part of the reservoir.

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

Nomenclature

GR	=	Gamma ray log
msfl	=	Microspherically focused log
OOIP	=	Original-oil-in-place, barrels
R_{mf}	=	Mud filtrate resistivity, ohm-m
R_{mfcorr}	=	Temperature corrected R_{mf} value, ohm-m.
R_t	=	Uninvaded formation resistivity, ohm-m
R_{tcorr}	=	Corrected uninvaded formation resistivity, ohm-m
R_w	=	Formation water resistivity, ohm-m
R_{xomsfl}	=	Flushed zone resistivity from msfl log, ohm-m
S_{or}	=	Residual oil saturation, %
S_w	=	Water saturation of noninvaded zone, %
S_{xo}	=	Water saturation of flushed zone, %
T_{amb}	=	Ambient temperature, °F
$T_{gradient\ per\ 100\ ft.}$	=	Temperature gradient, °F per 100 ft of depth
f	=	Porosity, %
f_{corr}	=	Corrected porosity, %
$f_{x\text{-}plot}$	=	Crossplot porosity, %

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SI Metric Conversion Factors

acre	×	4.046 873	E+03	=	m^2
acre-ft	×	1.233 489	E+03	=	m^3
bbl	×	1.589 874	E-01	=	m^3
ft	×	3.048*	E-01	=	m
°F		(°F - 32)/1.8		=	°C
mile	×	1.609 344*	E+00	=	km
md	×	9.869 233	E-04	=	mm^2
psi	×	6.894 757	E+00	=	kpa
sq mi	×	2.589 988	E+00	=	km^2

Table 1A
Analog Area Primary Recoveries

	SECTION 14 -T23S-28E LOCATION		DECLINE CURVE PROJECTED ULTIMATE RECOVERY		
WELL	FWL	FNL	OIL	GAS	WATER
"A"	4620	660	58,384	289,205	70,143
"B"	3540	660	141,377	742,714	73,480
"C"	1980	660	195,362	1,167,770	122,208
"D"	660	660	101,204	595,764	40,210
"E"	660	1980	150,460	960,436	106,511
"F"	1880	1980	182,346	834,401	35,287
"G"	3267	1806	138,859	648,146	57,317
"H"	4720	1980	64,929	219,978	60,052
"I"	4658	3336	68,143	385,348	67,041
"J"	3248	3558	151,371	659,036	65,668
"K"	2180	3200	201,938	953,587	36,849
"L"	660	3300	119,702	651,236	46,828
"M"	760	4520	118,125	638,523	42,226
"N"	2080	4290	188,363	913,264	77,269
"O"	3300	4400	125,862	796,261	45,078
"P"	4355	4392	77,588	525,939	30,502
		TOTAL	2,084,013	10,981,608	976,669

Table 1B
Analog Area Original Oil In Place

WELL	FWL	FNL	OOIP/ACRE	OOIP/GRID BLOCK x 1000
"A"	4620	660	19,704	7.88
"B"	3540	660	20,097	8.04
"C"	1980	660	20,358	8.14
"D"	660	660	18,240	7.30
"E"	660	1980	21,789	8.72
"F"	1880	1980	23,564	9.43
"G"	3267	1806	19,191	7.68
"H"	4720	1980	12,616	5.05

"I"	4658	3336	10,323	4.13
"J"	3248	3558	23,713	9.49
"K"	2180	3200	26,707	10.68
"L"	660	3300	15,772	6.31
"M"	760	4520	22,163	8.87
"N"	2080	4290	19,626	7.85
"O"	3300	4400	22,843	9.14
"P"	4355	4392	15,188	6.08

Table 2
Analog Area Recovery Efficiency

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

Table 3
Texaco Wells Original Oil In Place

Unit #	FWL	FNL	NET PAY	OOIP/ACRE
"A"	4620	660	30.50	12,040
"B"	3700	510	21.00	6,602
"C"	2130	510	19.50	8,259
"F"	1980	1980	18.00	6,089
"K"	1980	3300	15.00	5,545

Table 4a
Production History of Texaco wells

"C" **REMUDA BASIN "19" FEE #1**

	OIL	GAS	WATER	GOR
4/96	2,884	5,724	5,760	1,985
5/96	3,167	8,034	6,200	2,537
6/96	521	2,187	1,400	4,198
7/96	1,167	31	3,864	27

"K" **REMUDA BASIN STATE #2**

	OIL	GAS	WATER	GOR
4/96	4,885	16,241	7,170	3,325
5/96	3,599	13,031	3,224	3,621
6/96	2,607	15,204	3,120	5,832
7/96	4,223	20,415	3,224	4,834

"N" **REMUDA BASIN STATE #4**

	OIL	GAS	WATER	GOR
2/96	2,377	7,016	3,059	2,952
3/96	0	0	0	0
4/96	2,002	10,962	2,820	5,476
5/96	1,650	6,955	3,410	4,215
6/96	887	5,411	2,200	6,100
7/96	1,522	9,932	3,286	6,526

"F" **REMUDA BASIN STATE #1**

	OIL	GAS	WATER	GOR
4/96	3,937	12,470	6,540	3,167
5/96	2,889	9,223	4,619	3,192
6/96	2,092	10,762	4,470	5,144
7/96	2,614	10,898	5,394	4,169

"B" **REMUDA BASIN FED. #2**

	OIL	GAS	WATER	GOR
5/96	1,684	2,019	7,175	1,199
6/96	1,702	2,638	8,610	1,550
7/96	2,224	3,198	7,175	1,438

"A" **REMUDA BASIN FED. #1**

	OIL	GAS	WATER	GOR
5/96	1,684	2,019	7,175	1,199
6/96	1,702	2.638	8.610	1.550
7/96	2,224	3.198	7.175	1.438

Table 4b
Estimated recoveries, based on drainage areas

Unit	PRIMARY RECOVERIES, BO	ACRES
"A"	92,151	72.0
"B"	59,182	64.0
"C"	49,942	57.6
"F"	53,152	70.4
"K"	50.209	83.2
TOTAL	305,636	347.2

Table 5
Summary of Production Data for NDP Wells #1-14

Well No. & Order	Initial GOR MCFG/BO	Rate vs.Cum. Plot	Ultimate Primary Recovery	Recovery BO/Acre	Indicated Drainage Area, Ac.	Acreage Allocation Acres	Indicated/ Allocated Ratio
1-2	1.98	Multiple slopes	63,346	2,758	22.97	40	0.5742
5-8	1.17	Straight	73,846	2,926	25.24	40	0.6309
6-5	1.37	Multiple slopes	50,980	2,627	19.41	30	0.6469
9-1	1.59	Multiple slopes	52,785	1,545	34.16	60	0.5694
10-3	1.82	Multiple slopes	44,516	1,613	27.60	60	0.4600
11-6	1.19	Multiple slopes	143,196	2,896	49.45	80	0.6181
12-14	14.03	Steep slope	76,883	2,957	26.00	60	0.4333
13-4	1.48	Multiple slopes	89,698	2,613	34.33	80	0.4291
14-7	2.59	Straight	91,147	3,085	29.55	60	0.4924
15-10	2.73	Straight	117,895	2.964	39.78	80	0.4972
19-11	1.47	Straight	145.086	2.205	65.80	80	0.8225

20-9	5.93	Steep slope	45,620	1,937	23.55	60	0.3925
23-13	5.72	Steep slope	49,204	1,710	28.77	60	0.4796
24-12	2.54	Straight	138,031	3,338	41.35	80	0.5169
25-14	4.69	Steep slope	8,415	1,178	7.14	40	0.1786
29-16	8.06	Steep slope	52,204	2,640	19.77	60	0.3296

Table 6
Pilot Area Well Performance Parameters

Well Name	Skin Factor(psi_{-1})	Well Index(bbl/psi)
Nash #1	-5.0	0.064
Nash #5	-5.17	0.052
Nash #6	-4.5	0.0334
Nash #10	-6.24	0.03655
Nash #14	-5.0	0.04632

Table 7
Drainage Area Oil Volumes

Well Name	B_o/Acre	Drainage Area Oil Volume, STB(2)
Nash #1	16,516	391, 653
Nash #5	9,656	428, 132
Nash #6	18,471	248, 695
Nash #10	17,523	312, 246
Nash #14	15,731	530, 916

Total Pilot Oil Volume , STB1,911,642

Table 8
Date of Onset of Well Pumping

Well Name	**Date Pumping Began**
Nash #1	7/29/93
Nash #5	7/23/94
Nash #6	3/17/94
Nash #10	2/24/93
Nash #14	9/16/94

Table 9
Effective Fracture Transmissibility

Well Name	**Effective Fracture Transmissibility, Darcy-ft per cp**
Nash #1	0.5
Nash #5	0.5
Nash #6	15.0
Nash #10	15.0
Nash #14	2.0

Table 10
Transmissibility Multipliers for Best Match

Drainage Region	Adjustment Factor (multiplicative)
Nash #1	2.5
Nash #5	1.25
Nash #6	3.5
Nash #10	4.5
Nash #14	3.5

Table 11
Adjusted Drainage Area Oil Volumes of the Best Match

Well Name	Oil Volume of Match, STB	% Deviation
Nash #1	392,817	-29
Nash #5	428,224	nil
Nash #6	247,341	+11
Nash #10	313,028	-8
Nash #14	536,892	nil

APPENDIX A

To estimate the OOIP in the analog area, attributes from the well logs were used to verify the volumetric analysis.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, at 12.722 BCFG.

To check this estimate, a calculation using the General Material Balance Equation was made.

$$N = \frac{NpBo + (Gp-NpRs)\,Bg + (Wp-Wi-We)\,Bw - Gi\,Bg}{(Bo-Boi) + (Rsi-Rs)\,Bg + mBoi[Bg-Bgi/Bgi] + Boi/1-Sw\,(1+m)\,(Sw\,cw+cf)\,(pir-pr)}$$

		Nash Unit PVT Data
Bg=	Gas formation volume factor	@ 100 psi = .13867
Bgi=	Initial GFVF	.0047
Bo=	Oil formation volume factor	@ 100 psi = 1.147
Boi=	Initial OFVF	1.542
Bw=	Water formation volume factor	
cf=	Formation compressibility	
cw=	Water compressibility	
Gi=	Cumulative gas injection	
Gp=	Cumulative gas produced	10,981,608 MCFG
m=	PV of gas cap/PV of oil zone	
N=	Initial oil-in-place	
Np=	Cumulative oil production	2,084,013 BO
pir=	Initial reservoir pressure	2950 psi
pr=	Reservoir pressure	100 psi *
r=	Recovery, %	
Rp=	Produced GOR	10,981,608/2,084,013 = 5269.5
Rs=	Solution GOR	162
Rsi=	Initial GOR	1020
Sw=	Water saturation	
We=	Cumulative water injection	
Wi=	Cumulative water influx	
Wp=	Cumulative water produced	

* Abandonment pressure = 100 psi.

Since there is no injection, water drive, gas cap, and the effects of compressibility are negligible the equation reduces to:

$$N = \frac{NpBo + (Gp-NpRs)\,Bg}{(Bo-Boi) + (Rsi-Rs)\,Bg} \cong 12{,}467{,}072 \text{ BO}$$

Rewriting this equation to arrive at r, fractional recovery of oil-in-place, yields:

$$r = \frac{Np}{N} = \frac{(Bo-Boi) + (Rsi-Rs)\,Bg}{Bo - (Rp-Rs)\,Bg} = 16.77\%$$

Comparing the two methods of analysis, we find that there is good agreement between the two calculations, as seen in Table 2.

Appendix B

Eclipse 100 Input File for History Match Sequence

```
RUNSPEC ==============================================
TITLE
    NASH DRAW PILOT EVALUATION MODEL:  ZONE "L"
--
--  ------------------------------------------------------------------------
----
--  PROJECT TITLE:
-- "ADVANCED OIL RECOVERY TECHNOLOGIES FOR IMPROVED OIL
-- RECOVERY FROM SLOPE BASIN CLASTIC RESERVOIRS, NASH DRAW
-- BRUSHY CANYON POOL, EDDY COUNTY, NM"
--
-- THREE HUNDRED + ACRE MODEL WHICH INCLUDES NASH#1, NASH#5,
--  NASH#6, NASH#10, AND NASH#14
--
-- DOE COOPERATIVE AGREEMENT # DE-FC-95BC14941
--
-- DAVE MARTIN & ASSOCIATES, INC.
-- RICHARD KENDALL AND EARL WHITNEY, SIMULATION ENGINEERS
-- NOVEMBER, 1996
--
-- REVISION 1 JANUARY 20, 1996
-- MODEL CHANGED FROM 12 TO 20 VERTICAL LAYERS
-- X,Y INTERVAL IS 220X220 FEET, CORRESPONDING TO SEISMIC GRID
-- REVISION 2 JANUARY 26, 1996
-- Match01: Reduce volume in REGION 3 (Well #5) 1.1 to 1.05*PORO
--          Increase volume in REGION 4 (Well #6) 1.1 to 1.2*PORO
--          Increase volume in REGION 5 (Well #10) 1.2 to 1.25*PORO
-- Match02: Run113 is the base-case history match, and is now also
--          referred to as Match01.  Match02 is a perturbation run
--          on the character of the fractures.  Transmissibility is
--          increased from 100 to 1000 (See MULTY keywords).
-- Match03: Match03 is a perturbation run on the character of the
--          fractures.  Transmissibility is increased to 10000*, and
--          fracture lengths from Wells #1 and #5 are extended toward
--          each other by an additional block.
-- Match04: Examine the tightening of fractures from all wells, by
--          changing transmissibilities from 10000 to 10.
-- Match05: Other changes to transmissibity multipliers have had no
--          effect - so use EQUALS to set all fracture block TRANY
--          values to 10000mD.
-- Match06: Use EQUALS to set all fracture block TRANY
--          values to 5000mD.
-- Match07: Use EQUALS to set all fracture block TRANY
--          values to 4000mD.
-- Match08: Reset all matrix values to 1.0*TRANS, and open Fractures
--          to 10000mD
-- Match09: Set all matrix values to 2.0*TRANS, and open Fractures
--          to 10000mD
-- Match10: Set all matrix values to 1.0*TRANS, and open Fractures
--          to 1000mD
-- Match11: Set all matrix values to 5.0*TRANS, and open Fractures
--          to 10000mD
-- Match12: Set all matrix values to 2.0*TRANS, and open Fractures
--          to 20000mD
-- Match13: Set all matrix values to 1.0*TRANS, and open Fractures
--          to 20000mD
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```
-- Match14: Set all matrix values to 2.0*TRANS, and open Fractures
--          to 20000mD, and multiply POROs by 1.5, 1.15, 1.3, 1.35, and
1.2
-- Match15: Set all matrix values to 2.0*TRANS, and open Fractures
--          to 30000mD, and multiply POROs by 1.5, 1.15, 1.3, 1.35, and
1.2
-- Match16: Set       Poro. Mult.  Fracture Trans. Mult. Matrix Trans.
Mult.
--                     PORO             TRANY              MULTX,MULTY
--        Region2      1.30             20000                 2.0
--        Region3      1.05             20000                 2.5
--        Region4      1.20             20000                 2.5
--        Region5      1.25             20000                 5.0
--        Region6      1.10             20000                 5.0
-- Match17: Same as Match16, but adjust oil/water relative permeability
--          tables to favor oil
-- Match18: Same as Match17, but reduce water relative permeability
--          tables across all saturations
-- Match19: Same as Match18, but reduce water relative permeability
--          at high water saturations, and increase oil relative
--          permeability at low oil saturations.  Also, increase gas
--          relative permeability at high gas saturations.
-- Match20: Same as Match19, but again reduce water relative permeabil-
ity
--          at high water saturations, and increase oil relative
--          permeability at low oil saturations.
-- Match21: Same as Match19 (use it as a starting point, rather than
Match20,
--          as Match20 was a very poor match), but reduce water relative
--          permeability at high water saturations, and increase oil
relative
--          permeability at low oil saturations (but not as much as
run20).
-- Match22: From Match21, adjust overall perm multipliers by region, to
--          bring down region average pressures, yet still meet rates on
--          water and oil
-- Match23: From Match22, adjust overall perm multipliers by region
-- Match24: From Match23, adjust overall perm multipliers by region
--           reduce Region 2 from 1.5 to 1.0, Region 5 from 4.0 to 3.0
--           and Region 6 from 4.0 to 3.0
-- Match25: From Match24, adjust water relative permeability curve to
--           reduce water permeability at higher water saturations
-- Match26: From Match25, adjust PORO multipliers for regions:
--           Region 2:  Unchanged
--           Region 3:  from 1.05 to 1.10
--           Region 4:  from 1.20 to 1.00
--           Region 5:  Unchanged
--           Region 6:  from 1.10 to 1.00
-- Match27: From Match26, Reduce PORO multiplier in Region 2 from 1.3 to
1.2
--           Adjust transmissibility multiplier for Region 6 from 3.0 to
4.0
-- Match28: From Match27, Restore PORO multiplier in Region 2 from 1.2
to 1.3
--           Also, adjust connate water on rel perm curve to 0.25 from
0.131
-- Match29: From Match28, adjust connate water on rel perm curve from
0.25 to
--           0.639
-- Match30: From Match29, adjust connate water on rel perm curve from
0.639
--           to 0.617
-- Match31: From Match30, adjust connate water on rel perm curve from
```

```
0.617
--             to 0.53
-- Match32: From Match31, adjust connate water on rel perm curve from
0.530
--             to 0.40
-- Match33: From Match32, adjust connate water on rel perm curve from
0.400
--             to 0.35
-- Match34: Replace SWFN table with "L" zone relperm table, (vary the
end
--           point).  Also Change the SOF3 table to match "L" zone
properties
-- Match35: Adjust end point for water relative permeability from 0.25
to 0.5
-- Match36: Use "K" zone water relperm, cutoff at 0.5
-- Match37: Adjust "L" zone oil relperm, interpolate between oil
saturations
--             of 0.2 and 0.361  (0.0 and 0.012)
-- Match38: Return to Match32, but adjust the penultimate point in SWFN
--             table from 0.25 to 0.5
-- Match39: Adjust Gas relperm table values from
--          .470                .420000        13.9
--          .5                     1*            1*
--          .6                  .638600        27.0
--           to
--          .470                .520000        13.9
--          .5                     1*            1*
--          .6                  .738600        27.0
-- Match40: Adjust Gas relperm table values from
--         0.0                0.0               0.0
--          .1                .003758           7.5
--          .2                .028040           8.5
--          .292              .087800          10.0
--          .341              .126800          1*
--          .361              .146800          1*
--          .383                 1*            1*
--          .409                 1*           12.0
--          .425                 1*            1*
--          .447                 1*            1*
--          .465                 1*            1*
--          .470              .520000        13.9
--          .5                   1*            1*
--          .6                .738600        27.0
--          .75                  1*            1*
--          .869             1.0            278.0
--
--         to
--
--         0.0               0.0               0.0
--          .1                .01              7.5
--          .2                .07              8.5
--          .292              .18             10.0
--          .341              .26              1*
--          .361              .30              1*
--          .383              1*               1*
--          .409              1*             12.0
--          .425              1*               1*
--          .447              1*               1*
--          .465              1*               1*
--          .470              .50             13.9
--          .5                1*               1*
--          .6                .75             27.0
--          .70              1.0               1*
```

```
--        .869                  1.0              278.0
-- Match41: Complete description of NULLBOXES and adjust gas rel perms
to
--       0.0                    0.0               0.0
--        .1                    .003758           7.5
--        .2                    .028040           8.5
--        .292                  .087800          10.0
--        .341                  .126800            1*
--        .361                  .146800            1*
--        .383                     1*              1*
--        .409                     1*            12.0
--        .425                     1*              1*
--        .447                     1*              1*
--        .465                     1*              1*
--        .470                  .270000          13.9
--        .5                       1*              1*
--        .6                    .500000          27.0
--        .75                      1*              1*
--        .869                 1.000            278.0
-- Match42: Adjust gas rel perms to allow more gas mobility at low gas
--          saturations:
--       0.0                    0.0               0.0
--        .1                    .010000           7.5
--        .2                    .050000           8.5
--        .292                  .120000          10.0
--        .341                  .150000            1*
--        .361                  .170000            1*
--        .383                     1*              1*
--        .409                     1*            12.0
--        .425                     1*              1*
--        .447                     1*              1*
--        .465                     1*              1*
--        .470                  .270000          13.9
--        .5                       1*              1*
--        .6                    .500000          27.0
--        .75                      1*              1*
--        .869                 1.000            278.0
-- Match43: Adjust gas rel perms to restrict gas mobility at low gas
--          saturations:
--       0.0                    0.0               0.0
--        .1                    .003758           7.5
--        .2                    .018000           8.5
--        .292                  .030000          10.0
--        .341                  .037700            1*
--        .361                  .040000            1*
--        .383                     1*              1*
--        .409                     1*            12.0
--        .425                     1*              1*
--        .447                     1*              1*
--        .465                     1*              1*
--        .470                  .050000          13.9
--        .5                       1*              1*
--        .6                    .200000          27.0
--        .75                      1*              1*
--        .869                 1.000            278.0
-- Match44: Adjust gas rel perms to permit more gas mobility at about
50%
--          gas saturation (0.1 at Sg=0.47)
--        .470                  .100000          13.9
-- Match45: Adjust gas rel perms to permit more gas mobility between 30%
--          and 60% gas saturation
--        .292                  .050000          10.0
--        .341                  .070000            1*
```

```
--        .361                .080000        1*
--        .383                   1*          1*
--        .409                   1*         12.0
--        .425                   1*          1*
--        .447                   1*          1*
--        .465                   1*          1*
--        .470                .170000       13.9
--        .5                     1*          1*
--        .6                  .300000       27.0
-- Match46: Adjust gas rel perms to permit more gas mobility between 20%
--          and 30% gas saturation
--        .2                  .030000        8.5
--        .292                .055000       10.0
-- Match47: Multiply absolute permeability in REGION 2 by 2.0
-- Match48: Multiply absolute permeability in REGION 2 by 1.0
--          Adjust WELPI for Well #1 from 0.03 to 0.01 and for
--                           Well #5 from 0.052 to 0.015
--                           Well #6 from 0.05 to 0.015
--                           Well #10 from 0.04 to 0.01
--                           Well #14 from 0.04632 to 0.015
-- Match49: Adjust WELPI for Well #6 from 0.015 to 0.0075
--                           Well #10 from 0.01 to 0.005
--                           Well #14 from 0.015 to 0.0075
--          Multiply porosity in REGION 2 by 1.5 (add volume so that
--          more solution gas is available for late production), and
--          tighten transmissibility in REGION 2 (MULTX,MULTY x 0.75),
--          to lower regional pressure.
-- Match50: Original Well PI For Well#1 (.064) , REGION 2 volume to
match
--          material balance decline analysis (PORO *1.5), original perm
--          distribution (MULTX,MULTY x 1.0), and original krg
-- Match51: Original Well PI For all Wells, original perm
--          distribution (MULTX,MULTY x 1.0), volumes to match material
--          balance decline analysis for 16.7% case (PORO *1.56, *1.1,
--          *0.86, *1.17, *1.0 for wells 1,5,6,10,14 respectively),
--          Gas Relative Permeability Curve:
--       0.0                0.0             0.0
--        .1                .003758         7.5
--        .2                .030000         8.5
--        .292              .055000        10.0
--        .341              .070000         1*
--        .361              .080000         1*
--        .383                 1*           1*
--        .409                 1*          12.0
--        .425                 1*           1*
--        .447                 1*           1*
--        .465                 1*           1*
--        .470              .170000        13.9
--        .5                   1*           1*
--        .6                .400000        27.0
--        .75                  1*           1*
--        .869              1.000         278.0
-- Match52: Same as Match 51, but adjust gas relative permeability
curve:
--       0.0                0.0             0.0
--        .1                .01             7.5
--        .2                .04             8.5
--        .292              .09            10.0
--        .341              .13             1*
--        .361              .15             1*
--        .383                 1*           1*
--        .409                 1*          12.0
--        .425                 1*           1*
```

```
--        .447                    1*           1*
--        .465                    1*           1*
--        .470                  .30          13.9
--        .5                      1*           1*
--        .6                    .50          27.0
--        .7                    .70            1*
--        .75                     1*           1*
--        .869                 1.000         278.0
-- Match53: Begin with Match 51, but adjust gas relative permeability
curve:
--       0.0                   0.0             0.0
--        .1                    .01            7.5
--        .2                    .03            8.5
--        .292                  .055          10.0
--        .341                  .10            1*
--        .361                  .12            1*
--        .383                    1*           1*
--        .409                    1*          12.0
--        .425                    1*           1*
--        .447                    1*           1*
--        .465                    1*           1*
--        .470                  .30           13.9
--        .5                      1*           1*
--        .6                    .50           27.0
--        .7                    .70            1*
--        .75                     1*           1*
--        .869                 1.000         278.0
-- Match54: Begin with Match 53, and increase transmissibility in
--          Region 6 x 2, Increase WELPI for Well #10 x 2
-- Match55: Begin with Match 54, decrease WELPI for Well#10 x 0.25
--          Adjust Gas relative permeability to be like Match43 at
--          low gas saturations:
--       0.0                   0.0             0.0
--        .1                    .003758        7.5
--        .2                    .018000        8.5
--        .292                  .030000       10.0
--        .341                  .037700        1*
--        .361                  .040000        1*
-- Match56: Open up transmissibility in REGION 3 (MULTX,MULTY x 1.5)
--          Also, Begin with Match 55, adjust gas relative permeability
--          to increase gas mobility above 30% thus:
--       0.0                   0.0             0.0
--        .1                    .003758        7.5
--        .2                    .018000        8.5
--        .292                  .030000       10.0
--        .341                  .060000        1*
--        .361                  .080000        1*
--        .383                    1*           1*
--        .409                    1*          12.0
--        .425                    1*           1*
--        .447                    1*           1*
--        .465                    1*           1*
--        .470                  .250000       13.9
--        .5                      1*           1*
--        .6                    .500000       27.0
--        .75                     1*           1*
--        .869                 1.000         278.0
-- Match57: Adjust KROW to reduce oil perm like that of Run95
-- Match58: Adjust KRG to increase gas perm at higher gas saturation
-- Match59: Adjust KRG to decrease gas perm at lower gas saturation
--          Open up permeability in all regions REGION #2=1.25,#3=1.5,
--          #4=1.25,#5=1.25,#6=2.5
-- Match60: Adjust Trans Multipliers
```

```
--          REGION 5 TRANS * 3.0
--          Adjust Storage Multipliers
--          REGION 2 PORO * 1.4
-- Match61: Adjust Trans Multipliers for REGION 4 (TRANS*3.0)
--          Adjust Trans Multipliers for REGION 6 (TRANS*4.0)
--          Adjust WELPI on Well #10 from 0.07310 to 0.03655
--          Reduce volume multiplier for REGION 2 (from PORO*1.40 to
--          PORO*1.25)
-- Match62: Reduce volume multiplier for REGION 2 (from PORO*1.25 to
--          PORO*1.10), and increase volume for REGION 4 (from PORO*0.86
--          to PORO*0.96), also decrease TRANS in REGION 5 from 3.0* to
2.0*
-- Match63: Increase TRANS in REGION 2 from (MULTX,MULTY*1.25 to *2.5))
--          Reduce WELPI on Well #10 from 0.03655 to 0.018225, and
increase
--          TRANS in REGION 5 back to 3.0 from 2.0
-- Match64: Adjust Permeability and Porosity for Well 5 to
--          values like those in Match59, Perm 1.5, PORO 1.10
--          Adjust Permeability for Well 6 to 1.25
-- Match65: Reduce oil permeability in the presence of gas at low oil
--          saturation (KROG in SOF3) thus:
--     0.0                    0.0                    0.0
--     0.1                    0.0                    0.0
--     0.119                  0.0                    0.0002
--     0.269                  0.0                    0.0045
--     0.292                  0.0006                 1*
--     0.4                    0.034                  0.03
--     0.46                   0.086                  0.075
-- Match66: Return to Match63 and raise vertical permeability in
--          fracture blocks, so that layers communicate vertically
--          in the fractures
-- Fracture Treatments
-- EQUALS
--     'TRANZ' 10000.    9  9  15  18  1  20 /
--     'TRANZ' 10000.   10 10  18  21  1  20 /
--     'TRANZ' 10000.   14 14  14  17  1  20 /
--     'TRANZ' 10000.    4  4  12  15  1  20 /
--     'TRANZ' 10000.   10 10   8  11  1  20 /
--
-- Match67: Same as match66, but double the vertical transmissibilities
--          in fracture blocks, to 15000
-- Match68: Cut vertical transmissibilities in fracture blocks and in
--          well blocks, to 1000
-- Match69: Cut vertical transmissibilities in well blocks and fractures
--          to 2000
-- Match70: Adjust vertical transmissibilities in fracture blocks
--EQUALS
--          'TRANZ'  2000.    9  9  15  18  1  20 /
--          'TRANZ'   500.   10 10  18  21  1  20 /
--          'TRANZ' 15000.   14 14  14  17  1  20 /
--          'TRANZ' 15000.    4  4  12  15  1  20 /
--          'TRANZ'  2000.   10 10   8  11  1  20 /
--          and adjust transmissibilities in REGIONS:
--          REGION 4*3.5
--          REGION 5*3.5
--          REGION 6*4.5
--          Reduce storage in REGION 5 (PORO*1.17 to PORO*1.07)
-- Match71: Examine low vertical transmissibility in the fracture case
--          'TRANZ'   500.    9  9  15  18  1  20 /
--          'TRANZ'   500.   10 10  18  21  1  20 /
--          'TRANZ'   500.   14 14  14  17  1  20 /
--          'TRANZ'   500.    4  4  12  15  1  20 /
--          'TRANZ'   500.   10 10   8  11  1  20 /
```

```
-- Match72: Begin again with Match70, and adjust vertical
--           transmissibility inthe fracture of REGION 2
--           'TRANZ'   500.   9  9  15  18  1  20 /
--           Also, increase X,Y transmissibilities in REGION 5
--           from 3.5 to 4.5
-- Match73: Begin with Match72, and adjust vertical
--           transmissibility inthe fracture of REGION 2
--           'TRANZ'   100.   9  9  15  18  1  20 /
--           Also, increase X,Y transmissibilities in REGION 5
--           from 4.5 to 5.0
--
-- ----------------------------------------------------------------------
----
DIMENS
  16  30  20  /

OIL

WATER

GAS

DISGAS

FIELD

EQLDIMS
--   NTEQUL
       1  /
TABDIMS
--   NTSFUN     NTPVT      NSSFUN      NPPVT
          1         1         20          20          /
WELLDIMS
--   NWMAXZ     NCWMAX      NGMAXZ      NWGMAX
          6         20           3          10          /
REGDIMS
--   NTFIP
       7 /
NSTACK
  50 /
START
  1 'OCT' 1987    /

GRID    ==============================================

INCLUDE
   'NASHGRID'  /

-- Transmissibility multipliers for Nash1 well nearest neighbors
BOX
   8   9  16  18  1 20 /
MULTX
   120*1.0 /

BOX
   8  10  16  17  1 20 /
MULTY
   120*1.0  /

-- Transmissibility multipliers for Nash5 well nearest neighbors
BOX
   9  10  19  21  1 20 /
```

```
MULTX
   120*1.0 /

BOX
   9  11  19  20  1 20 /
MULTY
   120*1.0  /

-- Transmissibility multipliers for Nash6 well nearest neighbors
BOX
   13  14  15  17  1 20 /
MULTX
   120*1.0 /

BOX
   13  15  15  16  1 20 /
MULTY
   120*1.0  /

-- Transmissibility multipliers for Nash10 well nearest neighbors
BOX
   3  4  13  15  1 20 /
MULTX
   120*1.0 /

BOX
   3  5  13  14  1 20 /
MULTY
   120*1.0  /

-- Transmissibility multipliers for Nash14 well nearest neighbors
BOX
   9  10  9  11  1 20 /
MULTX
   120*1.0 /

BOX
   9  11   9  10  1 20 /
MULTY
   120*1.0  /

-- Transmissibility multipliers for ENTIRE RESERVOIR
BOX
   1 15   1 30  1 20 /
MULTX
   9000*1.0 /

BOX
   1 16   1 29  1 20 /
MULTY
   9280*1.0 /

-- Transmissibility multipliers for REGION 2
BOX
   7   11  15  18  1 20 /
MULTX
   400*2.5/

BOX
   7  12  15  17  1 20 /
MULTY
   360*2.5/
```

```
-- Transmissibility multipliers for REGION 3
BOX
   8   11  19  24  1 20 /
MULTX
   480*1.75 /

BOX
   8  12  19  23  1 20 /
MULTY
   500*1.75    /

-- Transmissibility multipliers for REGION 4
BOX
   13  15  14  18  1 20 /
MULTX
   300*3.50 /

BOX
   13  16  14  17  1 20 /
MULTY
   320*3.50  /

-- Transmissibility multipliers for REGION 5
BOX
   3   5   11  18  1 20 /
MULTX
   480*5.0/

BOX
   3   6   11  17  1 20 /
MULTY
   560*5.0 /

-- Transmissibility multipliers for REGION 6
BOX
   7   11  6  13  1 20 /
MULTX
   800*4.5 /

BOX
   7   12  6  12  1 20 /
MULTY
   840*4.5  /
-- Transmissibility multiplier to DISCONNECT REGIONs 2 & 3
-- BOX
--    7   12  18  18  1 20 /
-- MULTY
--    120*0.0  /

-- Multiply porosity values in a box that corresponds to REGION 2
--   (Well #1).
MULTIPLY
    'PORO'  1.10     7 12   15 18  1 20 /
/
-- Multiply porosity values in a box that corresponds to REGION 3
--   (Well #5).
MULTIPLY
    'PORO'  1.10   8 12   19 24  1 20 /
/
-- Multiply porosity values in a box that corresponds to REGION 4
--   (Well #6).
MULTIPLY
```

```
    'PORO'  0.96    13 16  14 18  1 20 /
/
-- Multiply porosity values in a box that corresponds to REGION 5
--    (Well #10).
MULTIPLY
    'PORO'  1.07     3  6   11 18  1 20 /
/
-- Multiply porosity values in a box that corresponds to REGION 6
--    (Well #14).
MULTIPLY
    'PORO'  1.00     7 12    6 13  1 20 /
/
-- Multiply porosity values in a box that corresponds to NULLBOX 1
MULTIPLY
    'PORO'  0.0      5  6    7 10  1 20 /
/
-- Multiply porosity values in a box that corresponds to NULLBOX 2
MULTIPLY
    'PORO'  0.0      8 12    4  5  1 20 /
/
-- Multiply porosity values in a box that corresponds to NULLBOX 3
MULTIPLY
    'PORO'  0.0     13 16    3 13  1 20 /
/
-- Multiply porosity values in a box that corresponds to NULLBOX 4
MULTIPLY
    'PORO'  0.0      3  6    3 10  1 20 /
/
-- Multiply porosity values in a box that corresponds to NULLBOX 5
MULTIPLY
    'PORO'  0.0      7 12    3  5  1 20 /
/
-- Multiply porosity values in a box that corresponds to NULLBOX 6
MULTIPLY
   'PORO'  0.0     3  7   26 29  1 20 /
/
-- Multiply porosity values in a box that corresponds to NULLBOX 7
MULTIPLY
    'PORO'  0.0      3  7   19 25  1 20 /
/
-- Multiply porosity values in a box that corresponds to NULLBOX 8
MULTIPLY
    'PORO'  0.0      8 12   25 29  1 20 /
/
-- Multiply porosity values in a box that corresponds to NULLBOX 9
MULTIPLY
    'PORO'  0.0     13 16   19 29  1 20 /
/

-- Output from Grid Section

GRIDFILE
  2  /

RPTGRID
   'COORD=1'
   'DX'
   'DY'
   'DZ'
   'PERMX'
   'PERMY'
   'PERMZ'
   'TRANX'
```

```
    'TRANY'
    'TRANZ'
/

EDIT      ===================================================

-- Fracture Treatments
EQUALS
   'TRANY' 20000.    9  9  15  18  1  20 /
   'TRANY' 20000.   10 10  18  21  1  20 /
   'TRANY' 20000.   14 14  14  17  1  20 /
   'TRANY' 20000.    4  4  12  15  1  20 /
   'TRANY' 20000.   10 10   8  11  1  20 /
/

EQUALS
-- Multiply vertical transmissibility by zero in all cells in
-- Layers 5,10, and 15 (La,Lb,and bottom Layer of Lc) to
-- prevent vertical communication between zones 5 and 6, 10 and 11,
-- and 15 and 16, respectively.
   'TRANZ'  0.0  1 16 1 30 5 5 /
   'TRANZ'  0.0  1 16 1 30 10 10 /
   'TRANZ'  0.0  1 16 1 30 15 15 /
/
-- MULTIPLY
--     'TRANX'  1.0  1 16 1 30 1 20 /
--     'TRANY'  1.0  1 16 1 30 1 20 /
--     'TRANZ'  1.0  1 16 1 30 1 20 /
-- /

EQUALS
-- Well #1 Vertical Transmissibilities are large for wellblocks
'TRANZ'  2000.0  9   9 17 17 1 20 /
-- Well #10 Vertical Transmissibilities are large for wellblocks
'TRANZ'  2000.0  4   4 14 14 1 20 /
-- Well #6 Vertical Transmissibilities are large for wellblocks
'TRANZ'  2000.0  14  14 16 16 1 20 /
-- Well #5 Vertical Transmissibilities are large for wellblocks
'TRANZ'  2000.0  10  10 20 20 1 20 /
-- Well #14 Vertical Transmissibilities are large for wellblocks
'TRANZ'  2000.0  10  10 10 10 1 20 /
/

-- Fracture Treatments
EQUALS
         'TRANZ'   100.    9  9  15  18  1  20 /
         'TRANZ'   500.   10 10  18  21  1  20 /
         'TRANZ' 15000.   14 14  14  17  1  20 /
         'TRANZ' 15000.    4  4  12  15  1  20 /
         'TRANZ'  2000.   10 10   8  11  1  20 /
/

PROPS     ===========================================
--
--   *********************************************
--       WATER PROPERTIES FOR ZONE "L"
--   *********************************************
SWFN
--         SW                 KRW                 PCOW
-- ---------------          --------            -----------
           .131               0.0                 139
           .25                0.0                  35
```

```
          .40            0.002          14
          .53            0.005          7
          .553           1*             1*
          .575           1*             1*
          .591           0.007          6
          .617           0.009          1*
          .639           .012           1*
          .659           .015           1*
          .673           .020           1*
          .682           1*             1*
          .691           1*             1*
          .708           .025           5
          .80            .075           4.5
          .9             .15            1*
          .975           .50            0.69
          .980           1*             1*
          .995           1*             1*
         1.0            1.0             0.0
--Match30 Relperms
--         .53            0.0             7
--         .553           1*              1*
--         .575           1*              1*
--         .591           0.0             6
--         .617           0.005           1*
--         .639           .010            1*
--         .659           .015            1*
--Match28 Relperms
--         .40            .005            14
--         .53            .006            7
--         .553           1*              1*
--         .575           1*              1*
--         .591           1*              6
--         .617           .008            1*
--Match27 Relperms
--         .25            .0005           35
--Match24 Relperms
--         .9             .20             1*
--         .975           .30             0.69
--         .980           1*              1*
--         .995           1*              1*
--         1.0            1.0             0.0
--Match19 Relperms
--         .131           0.0             139
--         .25            .0005           35
--         .40            .005            14
--         .53            .006            7
--         .535           1*              1*
--         .553           1*              1*
--         .575           1*              1*
--         .591           1*              6
--         .617           .008            1*
--         .639           .010            1*
--         .659           .015            1*
--         .673           .020            1*
--         .682           1*              1*
--         .691           1*              1*
--         .708           .030            5
--         .80            .10             4.5
--         .9             .25             1*
--         .975           .35             0.69
--         .995           1*              1*
/
--    *********************************
```

```
--      GAS TABLE FOR ZONE "L"
--   ***********************************
SGFN
--            SG                       KRG           PCOG
--   -------------                  ---------      ------------
           0.0                      0.0              0.0
            .1                        .003758        7.5
            .2                        .010000        8.5
            .292                      .025000       10.0
            .341                      .075000        1*
            .361                      .110000        1*
            .383                         1*          1*
            .409                         1*         12.0
            .425                         1*          1*
            .447                         1*          1*
            .465                         1*          1*
            .470                      .300000       13.9
            .5                           1*          1*
            .6                        .538600       27.0
            .75                          1*          1*
            .869                    1.000          278.0
/
--   *******************************************
--        OIL PROPERTIES FOR ZONE "L"
--   *******************************************
SOF3
--      SO                          KROW                           KROG
--   ------------                ------------                  ------------
        0.0                        0.0                        0.0
        0.1                        0.0                        0.0
        0.119                      0.0                        0.000352
        0.269                      0.00                       0.009182
        0.292                      0.0006                     1*
        0.4                        0.034                      0.044444
        0.46                       0.086                      0.07852
        0.577                      1*                         0.140
        0.6                        0.27                       1*
        0.669                      1*                         0.3000
        0.75                       0.60                       1*
        0.769                      1*                         0.580
        0.869                      1.0                        1.0
/
--
--   *******************************************
--       PVT PROPERTIES FOR WATER
--   *******************************************
PVTW
--   REF PRES    FVF            COMP               VISC              VISC-
BILITY
--   ---------   ---           ------            --------          --------
---
         3000    1.0100         2.9D-6             .8294              0.0
/
--   ****************************************
--       ROCK COMPRESSIBILITY
--   ****************************************
ROCK
--       REF PRES       COMPRESSIBILITY
-- ---------------------  ------------------------------
           3000               3.0D-6                             /
--   ***********************************************************
--       SURFACE DENSITIES OF RESERVOIR FLUIDS
--   ***********************************************************
```

```
GRAVITY
--          OIL                        WATER                     GAS
--          (API)                    (SPECIFIC)              (REL. TO AIR)
--   ------------          ----------------          -------------------
--
           42.4                     1.212                    .828
/
--   *********************************************
--          PVT PROPERTIES OF DRY GAS
--   *********************************************
PVDG
--          P                       BG                  VISG
--   ------------             -----------           --------------
100                   13.867               .00998
         201                      7.224                 .0106
         450                      3.221                 .0117
         700                      2.026                 .0125
         950                      1.459                 .0133
         1200                     1.130                 .0142
         1450                     0.916                 .0152
         1700                     0.767                 .0163
         1950                     0.658                 .0177
         2200                     0.575                 .0193
         2450                     0.511                 .0213
/
--
--   ************************************************
--              PVT PROPERTIES OF LIVE OIL
--   ************************************************
PVTO
--          RS                 PO                 FVFO              VISO
--   -------------        -----------         -----------        -----------
       0.162                100                1.147             .9760   /
       0.217                201                1.1790            .8760   /
       0.317                450                1.2290            .7430   /
       0.407                700                1.2670            .6590   /
       0.492                950                1.3020            .5970   /
       0.575               1200                1.3370            .547    /
       0.659               1450                1.3720            .5070   /
       0.746               1700                1.4080            .4720   /
       0.834               1950                1.4460            .4400   /
       0.926               2200                1.4860            .4200   /
       1.020               2450                1.5280            .4000   /
       1.109               2677                1.5680            .3720
                           2700                1.5420            .373
                           2800                1.5400            .375
                           2900                1.5380            .377
                           3000                1.5350            .380    /
/
RPTPROPS
        'SOF3','SWFN','SGFN','PVTO',
        'PVTW','PVDG','DENSITY','ROCK',
/

REGIONS    ==================================================
-- ARRAY                       VALUE                 ------ BOX ------------
--                          (REGION NO.)             1  NX  1  NY  1  NZ
-- DRAINAGE RADIUS FOR WELL 1 = 33 ACRES
EQUALS
'FIPNUM'                         2                   7  12   15 18  1  20
/
/
```

```
-- DRAINAGE RADIUS FOR WELL 5 = 34 ACRES
EQUALS
'FIPNUM'                    3                    8  12  19  24  1  20
/
/

-- DRAINAGE RADIUS FOR WELL 6 = 22 ACRES
EQUALS
'FIPNUM'                    4                    13 16  14 18  1  20
/
/

-- DRAINAGE RADIUS FOR WELL 10= 45 ACRES
EQUALS
'FIPNUM'                    5                     3  6  11  18 1  20
/
/

-- DRAINAGE RADIUS FOR WELL 14= 40 ACRES
EQUALS
'FIPNUM'                    6                     7 12   6 13  1  20
/
/

--   EQUILIBRIUM TABLE---NOT USED
--
--   DATUM   DATUM    OWC      GOC      GOC    RSVD    RVVD   TABLE
--   DEPTH   PRESS    DEPTH    DEPTH    PCOG   TABLE   TABLE
--
--   -----------------------------------------------------------------
----
--   NON-EQUILIBRIUM INITIALIZATION

SOLUTION      ================================================

INCLUDE
  'SWAT.DAT'  /
INCLUDE
  'PRESSURE.DAT'  /
INCLUDE
  'PBUB.DAT'  /
INCLUDE
  'SGAS.DAT'  /
--
--EQUALS
--'PRESSURE'   2963.0  1 16 1 30 1 20 /
--'PBUB   '    2677.0  1 16 1 30 1 20 /
--'SGAS   '       0.0  1 16 1 30 1 20 /
--/
--
--

-- RESTART
--   'NASH07' 31 /

SUMMARY      ================================================
ALL
FOPTH
FWPTH
FLPRH
WPI
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
WBP
```

```
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
WBHP
    'NASH1'  'NASH5'  'NASH5'  'NASH10'   'NASH14'  /
WBP4
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
WBP5
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
WBP9
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
WBHPH
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
WWPRH
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
WGPR
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
WGPRH
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
WOPR
    'NASH1'  'NASH5'  'NASH5'  'NASH10'   'NASH14'  /
WOPRH
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
WOPP
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
--  FIELD OIL PRODUCTION
FOPR
--  FIELD WATER CUT
FWCT
--  GAS-OIL RATIO FOR WELL
WGOR
    'NASH1'   'NASH5'  'NASH6'  'NASH10'  'NASH14'  /
--  BHP FOR WELL
WBHP
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
RPR
  1  2  3  4  5  6 /

--  FIELD OIL PRODUCTION
FOPR
--  FIELD WATER CUT
FWCT
--  GAS-OIL RATIO FOR WELL
WGOR
    'NASH1'   'NASH5'  'NASH6'  'NASH10'  'NASH14'  /
--  BHP FOR WELL
WBHP
    'NASH1'  'NASH5'  'NASH6'  'NASH10'   'NASH14'  /
RPR
  1  2  3  4  5  6 /
--  SWITCH ON REPORT OF WHAT IS TO GO ON SUMMARY FILES

RPTSMRY
  1   /
SCHEDULE    ==================================================
WPAVE
  1* 0.0  /

RPTSCHED
-- 'SWAT'
-- 'SGAS'
   'RESTART=4'
   'PRES'
   'SOIL'
   'SWAT'
```

```
    'SGAS'
    'FIP=2'
    'WELLS'
    'SUMMARY'
    'CPU'
    'WELSPECS'
    'NEWTON'   /

--   ********************************
--   WELL SPECIFICATION DATA
--   ********************************
--    WELL           GROUP     LOCATION    BHP      PREF     DRAIN
--    NAME           NAME      I       J   DATUM    PHASE    RADIUS
--    ----------     -----     ----------- -----    -------  -------
WELSPECS
     'NASH1'       'PILOT'   9      17   3850.    'OIL'        1053.   /
     'NASH5'       'PILOT'  10      20   3850.    'OIL'         745.   /
     'NASH6'       'PILOT'  14      16   3850.    'OIL'        1053.   /
     'NASH10'      'PILOT'   4      14   3850.    'OIL'        1053.   /
     'NASH14'      'PILOT'  10      10   3850.    'OIL'        1053.   /
/
--   ******************************
--   WELL COMPLETION DATA
--   ******************************
--   WELL        LOCATION          OPEN/   SAT   WELL      WELL    EFF
--   NAME       I    J    K1   K2  SHUT    TAB   TRANS     DIAM    KH       SKIN
D DIR
--   ----       ---------------    -----   ---   -----     ----    -----    -----
- ---
COMPDAT
     'NASH1'    9   17    1    20  'OPEN'   0      0       .6667   7.987     -
4.85 /
     'NASH5'   10   20    1    20  'OPEN'   0      0       .6667   5.105     -
4.85 /
     'NASH6'   14   16    1    20  'OPEN'   0      0       .6667   5.053     -
4.85 /
     'NASH10'   4   14    1    20  'OPEN'   0      0       .6667   2.378     -
4.85 /
     'NASH14'  10   10    1    20  'OPEN'   0      0       .6667   5.794     -
4.85 /
/
--   **********************************
--   WELL PRODUCTIVITY INDICES
--   **********************************
--     'NASH6'    .0334     /
--     'NASH10'   .03955     /
--    'NASH1'     .064       /
--    'NASH10'    .0500      /
-- From Match47
--    'NASH1'     .030       /
--    'NASH5'     .052       /
--    'NASH6'     .0500      /
--    'NASH10'    0.040      /
--    'NASH14'   .04632      /
-- From Match53
--    'NASH10'    .03655    /
WELPI
   'NASH1'    .064       /
   'NASH5'    .052       /
   'NASH6'    .0334      /
   'NASH10'   .018225    /
   'NASH14'   .04632     /
```

```
/
--   ********************************************************
--   PRODUCTION CONTROLS
--      PRODUCTION IN PILOT STARTS    1 OCT, 1992
--   ********************************************************
--   SPECIFY UPPER LIMIT FOR NEXT TIMESTEP
--   EQUILIBRIUM SOAK
--   WELL    OPEN/   CNTL      OIL       WAT    GAS    VFP     ALQ       OBS
 OBS
--   NAME    SHUT    MODE      RATE      RATE   RATE   TAB               THP
 BHP
--   ----    ----    -----     -----     ----   ----   ----    ---       ----
 ----
WCONHIST
    'NASH1'   'SHUT' 'ORAT'    /
    'NASH5'   'SHUT' 'ORAT'    /
    'NASH6'   'SHUT' 'ORAT'    /
    'NASH10'  'SHUT' 'ORAT'    /
    'NASH14'  'SHUT' 'ORAT'    /
/
TUNING
       1      365.25    /
/
       12     1       50   /
TSTEP
      1.0    5.0    10.0   14.4375 30.4375 30.4375 30.4375 30.4375
      30.4375 30.4375 30.4375 30.4375 30.4375 30.4375 30.4375
      91.3125 91.3125 91.3125 91.3125
      91.3125 91.3125 91.3125 91.3125
      91.3125 91.3125 91.3125 91.3125
      91.3125 91.3125 91.3125 91.3125
/
--   1 OCT, 1992

TUNING
       0.1      5.0 -  /
/
       12     1       50   /

WCONHIST
   'NASH1'   'OPEN' 'ORAT'   0.0       0.      0.       3*   2950.0  /
   'NASH5'   'SHUT' 'ORAT'   /
   'NASH6'   'SHUT' 'ORAT'   /
   'NASH10'  'SHUT' 'ORAT'   /
   'NASH14'  'SHUT' 'ORAT'   /
/
TSTEP
   30.4375
/
--   1 NOV, 1992
/
WCONHIST
   'NASH1'   'OPEN' 'ORAT'   50.5    3.78    0.0  3*    2710.0    /
   'NASH5'   'SHUT' 'ORAT'    /
   'NASH6'   'SHUT' 'ORAT'    /
   'NASH10'  'SHUT' 'ORAT'    /
   'NASH14'  'SHUT' 'ORAT'    /
/
TSTEP
    30.4375
/
--   1  DEC, 1992
WCONHIST
```

```
  'NASH1'   'OPEN' 'ORAT'   118.      3.78   0.0   3*    2400.0     /
  'NASH5'   'SHUT' 'ORAT'   /
  'NASH6'   'SHUT' 'ORAT'   /
  'NASH10'  'SHUT' 'ORAT'   /
  'NASH14'  'SHUT' 'ORAT'   /
/
TSTEP
    30.4375
/
--  1 JAN, 1993
WCONHIST
  'NASH1'   'OPEN' 'ORAT'  148.8  6.41  68.6  3*       2185.0   /
  'NASH5'   'SHUT' 'ORAT'  /
  'NASH6'   'SHUT' 'ORAT'  /
  'NASH10'  'OPEN' 'ORAT'   32.69  5.22  50.56 3*      2950.0  /
  'NASH14'  'SHUT' 'ORAT'  /
/
TSTEP
    30.4375
/
--  1 FEB, 1993
WCONHIST
  'NASH1'   'OPEN' 'ORAT'  134.8  10.0  384.5     3*   2075.0   /
  'NASH5'   'SHUT' 'ORAT'  /
  'NASH6'   'SHUT' 'ORAT'  /
  'NASH10'  'OPEN' 'ORAT'  36.43  5.13   78.16    3*   2450.0   /
  'NASH14'  'SHUT' 'ORAT'  /
/
TSTEP
    30.4375
/
--  1 MAR, 1993
WCONHIST
  'NASH1'   'OPEN' 'ORAT'  114.6  8.67  343.16    3*   1880.0   /
  'NASH5'   'SHUT' 'ORAT'  /
  'NASH6'   'SHUT' 'ORAT'  /
  'NASH10'  'OPEN' 'ORAT'  43.14  1.28  110.20    3*   2400.0  /
  'NASH14'  'SHUT' 'ORAT'  /
/
TSTEP
    30.4375
/
--  1 APR, 1993
WCONHIST
  'NASH1'      'OPEN'     'ORAT'    101.8    6.24   147.61  3*    1800.0   /
  'NASH5'      'SHUT'     'ORAT'     /
  'NASH6'      'SHUT'     'ORAT'     /
  'NASH10'     'OPEN'     'ORAT'    22.34    2.96   82.3    3*    2300.0  /
  'NASH14'     'SHUT'     'ORAT'    /
/
TSTEP
    30.4375
/
--  1 MAY, 1993
WCONHIST
  'NASH1'      'OPEN'     'ORAT'  94.85    5.82   225.61    3*   1800.0    /
  'NASH5'      'SHUT'     'ORAT'  /
  'NASH6'      'SHUT'     'ORAT'  /
  'NASH10'     'OPEN'     'ORAT'   41.89   8.41   178.96    3*   2200.0    /
  'NASH14'     'SHUT'     'ORAT'  /
/
TSTEP
    30.4375
```

```
/
--  1 JUN, 1993
WCONHIST
  'NASH1'     'OPEN'    'ORAT'   82.83  6.18  113.41   3*    1575.0   /
  'NASH5'     'SHUT'    'ORAT'   /
  'NASH6'     'OPEN'    'ORAT'   80.09   0.46   21.32  3*    2950.0   /
  'NASH10'    'OPEN'    'ORAT'   37.62  7.43  140.16   3*    2100.0   /
  'NASH14'    'SHUT'    'ORAT'   /
/
TSTEP
    30.4375
/
--  1  JUL, 1993
WCONHIST
  'NASH1'     'OPEN'    'ORAT'  103.30    1.54    31.9  3*  1450.0  /
  'NASH5'     'SHUT'    'ORAT'  /
  'NASH6'     'OPEN'    'ORAT'   63.22    1.84   164:87 3*  2900.0  /
  'NASH10'    'OPEN'    'ORAT'   32.82   7.16   81.91   3*  1900.0  /
  'NASH14'    'SHUT'    'ORAT'  /
/
TSTEP
    30.4375
/
--  1 AUG, 1993
WCONHIST
  'NASH1'   'OPEN'   'ORAT' 103.30  42.05  121.63  3*  1180.0  /
  'NASH5'   'OPEN'   'ORAT'  68.0  0.0 85.59        3*  2950.0  /
  'NASH6'   'OPEN'   'ORAT'  48.20  2.0  50.56      3*  2800.0  /
  'NASH10'  'OPEN'   'ORAT'  36.40  5.91  44.94     3*  1700.0  /
  'NASH14'  'OPEN'   'ORAT'  137.3   8.77  18.27    3*  2950.0  /
/
TSTEP
    30.4375
/
--  1 SEP, 1993
WCONHIST
  'NASH1'   'OPEN'   'ORAT'  74.09  5.75  242.0     3*  1190.0  /
  'NASH5'   'OPEN'   'ORAT'  92.0  0. 76.55         3*  2900.0  /
  'NASH6'   'OPEN'   'ORAT'  61.0  2.33  97.4       3*  2750.0  /
  'NASH10'  'OPEN'   'ORAT'   24.67  5.78  107.53   3*  1500.0  /
  'NASH14'  'OPEN'   'ORAT'  94.81  4.0  99.8       3*  2900.0  /
/
TSTEP
    30.4375
/
--  1  OCT, 1993
WCONHIST
  'NASH1'   'OPEN'   'ORAT'  66.04  5.59  131.65    3*   980.0 /
  'NASH5'   'OPEN'   'ORAT'  59.43  0.  83.81       3*  2800.0 /
  'NASH6'   'OPEN'   'ORAT'  62.09  2.14  158.3     3*  2700.0 /
  'NASH10'  'OPEN'   'ORAT'   26.68  4.8  203.8     3*  1400.0 /
  'NASH14'  'OPEN'   'ORAT'  84.67  3.68  228.67    3*  2860.0 /
/
TSTEP
    30.4375
/
--  1 NOV, 1993
WCONHIST
  'NASH1'   'OPEN'   'ORAT'  49.30  5.39  239.67    3*   910.0  /
  'NASH5'   'OPEN'   'ORAT'  39.23  0.  112.4       3*  2700.0  /
  'NASH6'   'OPEN'   'ORAT'  57.92  2.3  234.05     3*  2500.0  /
  'NASH10'  'OPEN'   'ORAT'   29.83  1.81 85.49     3*  1300.0  /
  'NASH14'  'OPEN'   'ORAT'  72.35  2.86  290.79    3*  2570.0  /
```

```
/
TSTEP
    30.4375
/
-- 1 DEC, 1993
WCONHIST
  'NASH1'   'OPEN'   'ORAT'  50.14  4.37 361.17    3*    940.0  /
  'NASH5'   'OPEN'   'ORAT'  57.36  0. 206.7       3*   2500.0  /
  'NASH6'   'OPEN'   'ORAT'  46.16  1.28 281.07    3*   2400.0  /
  'NASH10'  'OPEN'   'ORAT'  34.27  1.38  131.71   3*   1290.0  /
  'NASH14'  'OPEN'   'ORAT'  69.19  2.17 360.94    3*   2500.0  /
/
TSTEP
    30.4375
/
-- 1  JAN, 1994
WCONHIST
  'NASH1'   'OPEN'   'ORAT'  39.83   3.94  314.74  3*    855.0  /
  'NASH5'   'OPEN'   'ORAT'  57.99  0.   370.14    3*   2300.0  /
  'NASH6'   'OPEN'   'ORAT'  42.74   0.82  260.9   3*   2300.0  /
  'NASH10'  'OPEN'   'ORAT'  28.35   2.56  133.95  3*   1133.0  /
  'NASH14'  'OPEN'   'ORAT'  62.32  1.45   361.1   3*   2340.0  /
/
TSTEP
    30.4375
/
-- 1  FEB, 1994
WCONHIST
  'NASH1'   'OPEN'   'ORAT'  32.66   4.21  269.47  3*    810.0  /
  'NASH5'   'OPEN'   'ORAT'  36.21  0.   351.51    3*   2100.0  /
  'NASH6'   'OPEN'   'ORAT'  37.36   0.56  226.6   3*   2200.0  /
  'NASH10'  'OPEN'   'ORAT'  21.39   1.87  124.42  3*   1120.0  /
  'NASH14'  'OPEN'   'ORAT'  54.93  1.15   329.4   3*   2170.0  /
/
TSTEP
    30.4375
/
-- 1  MAR, 1994
WCONHIST
  'NASH1'   'OPEN'   'ORAT'  34.37   5.26  269.21  3*    755.0  /
  'NASH5'   'OPEN'   'ORAT'  42.12  0.   336.85    3*   2000.0  /
  'NASH6'   'OPEN'   'ORAT'  32.99   1.64  139.24  3*   2100.0  /
  'NASH10'  'OPEN'   'ORAT'  27.47   1.544  119.33 3*   1110.0  /
  'NASH14'  'OPEN'   'ORAT'  60.45  1.05   349.8   3*   2300.0  /
/
TSTEP
    30.4375
/
-- 1  APR, 1994
WCONHIST
  'NASH1'   'OPEN'   'ORAT'  29.04   4.57  213.26  3*    740.0  /
  'NASH5'   'OPEN'   'ORAT'  35.32   0.   283.83   3*   1800.0  /
  'NASH6'   'OPEN'   'ORAT'  52.24   1.12  228.21  3*   2000.0  /
  'NASH10'  'OPEN'   'ORAT'  21.78   4.40  100.14  3*    960.0  /
  'NASH14'  'OPEN'   'ORAT'  36.63  1.84   330.68  3*   2200.0  /
/
TSTEP
    30.4375
/
-- 1  MAY, 1994
WCONHIST
  'NASH1'   'OPEN'   'ORAT'  26.35   4.50  204.88  3*    710.0  /
  'NASH5'   'OPEN'   'ORAT'  29.90   0.   240.69   3*   1600.0  /
```

```
   'NASH6'   'OPEN'   'ORAT'  36.53   0.92  201.46  3*    1550.0  /
   'NASH10'  'OPEN'   'ORAT'  19.29   4.6   104.31  3*     900.0  /
   'NASH14'  'OPEN'   'ORAT'  40.97   1.41  235.93  3*    2100.0  /
/
TSTEP
     30.4375
/
-- 1  JUN, 1994
WCONHIST
   'NASH1'   'OPEN'   'ORAT'  22.77   3.65  281.92   3*     695.0  /
   'NASH5'   'OPEN'   'ORAT'  27.86   0.    319.61   3*    1500.0  /
   'NASH6'   'OPEN'   'ORAT'  30.82   0.69  131.6    3*    1350.0  /
   'NASH10'  'OPEN'   'ORAT'  17.81   16.43  30.49   3*     855.0  /
   'NASH14'  'OPEN'   'ORAT'  32.89   9.72   16.36   3*    2000.0  /
/
TSTEP
     30.4375
/
-- 1  JUL, 1994
WCONHIST
   'NASH1'   'OPEN'   'ORAT'  22.04   4.14  259.42   3*     735.0  /
   'NASH5'   'OPEN'   'ORAT'  36.34   0.   192.36    3*    1400.0  /
   'NASH6'   'OPEN'   'ORAT'  42.55   0.95  110.85   3*    1700.0  /
   'NASH10'  'OPEN'   'ORAT'  18.4    20.27  22.24   3*     870.0  /
   'NASH14'  'OPEN'   'ORAT'  59.43   6.77  66.66    3*    2000.0  /
/
TSTEP
     30.4375
/
-- 1  AUG, 1994
WCONHIST
   'NASH1'   'OPEN'   'ORAT'  20.11   3.81  276.6    3*     650.0  /
   'NASH5'   'OPEN'   'ORAT'  41.63   0.   243.19    3*    1300.0  /
   'NASH6'   'OPEN'   'ORAT'  39.56   0.986  149.35  3*    1610.0  /
   'NASH10'  'OPEN'   'ORAT'  17.12    23.82  18.63  3*     840.0  /
   'NASH14'  'OPEN'   'ORAT'  46.16   11.73  64.39   3*    1900.0  /
/
TSTEP
     30.4375
/
-- 1  SEP, 1994
WCONHIST
   'NASH1'   'OPEN'   'ORAT'    19.20 3.38 230.11    3*     715.0  /
   'NASH5'   'OPEN'   'ORAT'    26.05 0.   210.5     3*    1050.0  /
   'NASH6'   'OPEN'   'ORAT'    30.36 0.53 187.2     3*    1330.0  /
   'NASH10'  'OPEN'   'ORAT'    18.46 1.58 161.8     3*     875.0  /
   'NASH14'  'OPEN'   'ORAT'    41.16 1.84 271.2     3*    1700.0  /
/
TSTEP
     30.4375
/
-- 1  OCT, 1994
WCONHIST
   'NASH1'   'OPEN'   'ORAT'    21.78  3.68   194.4    3*     625.0  /
   'NASH5'   'OPEN'   'ORAT'    30.32  0.0    211.3    3*    1010.0  /
   'NASH6'   'OPEN'   'ORAT'    32.16  0.43   258.6    3*    1380.0  /
   'NASH10'  'OPEN'   'ORAT'    18.50  1.12   161.08   3*     875.0  /
   'NASH14'  'OPEN'   'ORAT'    37.82  1.58   278.3    3*    1500.0  /
/
TSTEP
     30.4375
/
-- 1  NOV, 1994
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WCONHIST
   'NASH1'    'OPEN'   'ORAT'     16.26  3.75   213.75   3*      600.0  /
   'NASH5'    'OPEN'   'ORAT'     23.60  0.00   221.1    3*      900.0  /
   'NASH6'    'OPEN'   'ORAT'     24.84  0.62   297.9    3*     1160.0  /
   'NASH10'   'OPEN'   'ORAT'     17.68  1.81   166.7    3*      830.0  /
   'NASH14'   'OPEN'   'ORAT'     44.22  1.51   367.2    3*     1410.0  /
/
TSTEP
     30.4375
/
--   1  DEC, 1994
WCONHIST
   'NASH1'    'OPEN'   'ORAT'     20.47   4.4    230.0    3*      600.0  /
   'NASH5'    'OPEN'   'ORAT'     22.74   0.0    213.06   3*      855.0  /
   'NASH6'    'OPEN'   'ORAT'     24.44   0.624  279.88   3*     1145.0  /
   'NASH10'   'OPEN'   'ORAT'     16.13   1.70   160.5    3*      813.0  /
   'NASH14'   'OPEN'   'ORAT'     39.50   1.15   294.8    3*     1300.0  /
/
TSTEP
     30.4375
/
--
--   1 JAN, 1995
WCONHIST
   'NASH1'    'OPEN'   'ORAT'     14.65  3.81   160.5    3*      600.0  /
   'NASH5'    'OPEN'   'ORAT'     20.30  0.0    178.8    3*      805.0  /
   'NASH6'    'OPEN'   'ORAT'     29.00  0.59   221.76   3*     1290.0  /
   'NASH10'   'OPEN'   'ORAT'     18.90  17.5   136.6    3*      880.0  /
   'NASH14'   'OPEN'   'ORAT'     34.76   1.31  275.05   3*     1200.0  /
/
TSTEP
     30.4375
/
--   1  FEB, 1995
WCONHIST
   'NASH1'    'OPEN'   'ORAT'   8.27   2.46   109.27      3*      600.0  /
   'NASH5'    'OPEN'   'ORAT'  20.20   0.00   154.9       3*      802.0  /
   'NASH6'    'OPEN'   'ORAT'  16.95   0.6    183.85      3*      920.0  /
   'NASH10'   'OPEN'   'ORAT'  14.70   1.3    128.2       3*      875.0  /
   'NASH14'   'OPEN'   'ORAT'  33.5    1.25   231.23      3*     1165.0  /
/
TSTEP
     30.4375
/
--   1 MAR, 1995
WCONHIST
   'NASH1'    'OPEN'   'ORAT'     16.50  26.8   179.50   3*      595.0  /
   'NASH5'    'OPEN'   'ORAT'     20.93   0.0   167.0    3*      840.0  /
   'NASH6'    'OPEN'   'ORAT'     20.6    0.46 212.5    3*     1025.0  /
   'NASH10'   'OPEN'   'ORAT'     18.6    1.41 119.1    3*      875.0  /
   'NASH14'   'OPEN'   'ORAT'     34.3    1.64 262.3    3*     1180.0  /
/
TSTEP
     30.4375
/
--   1 APR, 1995
WCONHIST
   'NASH1'    'OPEN'   'ORAT'   14.03  7.03   172.7      3*      595.0  /
   'NASH5'    'OPEN'   'ORAT'   21.95  0.0    153.3      3*      840.0  /
   'NASH6'    'OPEN'   'ORAT'   20.70  0.46   162.6      3*     1029.0  /
   'NASH10'   'OPEN'   'ORAT'   16.00  1.74   112.4      3*      810.0  /
   'NASH14'   'OPEN'   'ORAT'   28.25  1.28   220.3      3*     1045.0  /
/
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TSTEP
    30.4375
/
-- 1 MAY, 1995
WCONHIST
  'NASH1'   'OPEN'   'ORAT'   12.9    7.59   172.9    3*    590.0  /
  'NASH5'   'OPEN'   'ORAT'   20.86   0.0    214.87   3*    815.0  /
  'NASH6'   'OPEN'   'ORAT'   19.06   0.56   233.7    3*    980.0  /
  'NASH10'  'OPEN'   'ORAT'   16.30   1.90   161.2    3*    820.0  /
  'NASH14'  'OPEN'   'ORAT'   29.90   0.85   276.96   3*   1080.0  /
/
TSTEP
    30.4375
/
-- 1 JUN, 1995
WCONHIST
  'NASH1'   'OPEN'   'ORAT'   12.52   6.97   204.5    3*    575.0  /
  'NASH5'   'OPEN'   'ORAT'   17.50   0.     182.9    3*    750.0  /
  'NASH6'   'OPEN'   'ORAT'   23.1    0.49   215.4    3*   1100.0  /
  'NASH10'  'OPEN'   'ORAT'   14.9    1.31   146.8    3*    780.0  /
  'NASH14'  'OPEN'   'ORAT'   17.9    0.59   237.9    3*   1040.0  /
/
TSTEP
    30.4375
/
-- 1 JUL, 1995
WCONHIST
  'NASH1'   'OPEN'   'ORAT'   11.60   6.7    180.8    3*    565.0  /
  'NASH5'   'OPEN'   'ORAT'   18.60   0.0    190.9    3*    770.0  /
  'NASH6'   'OPEN'   'ORAT'   20.24   0.46   214.3    3*   1015.0  /
  'NASH10'  'OPEN'   'ORAT'   14.90   1.31   146.8    3*    785.0  /
  'NASH14'  'OPEN'   'ORAT'   13.90   0.59   237.9    3*   1000.0  /
/
TSTEP
    30.4375
/
-- 1 AUG, 1995
WCONHIST
  'NASH1'   'OPEN'   'ORAT'   11.07   9.03   201.7    3*    555.0  /
  'NASH5'   'OPEN'   'ORAT'   13.7    0.0    202.6    3*    755.0  /
  'NASH6'   'OPEN'   'ORAT'   13.7    0.36   207.08   3*    945.0  /
  'NASH10'  'OPEN'   'ORAT'   14.2    1.51   153.66   3*    762.0  /
  'NASH14'  'OPEN'   'ORAT'   23.66   1.64   267.76   3*    940.0  /
/
TSTEP
    30.4375
/
-- 1 SEP, 1995
WCONHIST
  'NASH1'   'OPEN'   'ORAT'   10.25   5.71   185.6    3*    550.0  /
  'NASH5'   'OPEN'   'ORAT'   17.14   0.0    180.3    3*    740.0  /
  'NASH6'   'OPEN'   'ORAT'   16.0    0.29   149.97   3*    885.0  /
  'NASH10'  'OPEN'   'ORAT'   13.7    1.45   118.34   3*    750.0  /
  'NASH14'  'OPEN'   'ORAT'   26.71   1.02   187.10   3*   1010.0  /
/
TSTEP
    30.4375
/
-- 1 OCT, 1995
WCONHIST
  'NASH1'   'OPEN'   'ORAT'   10.08   4.96   193.3    3*    545.0  /
  'NASH5'   'OPEN'   'ORAT'   23.03   0.     202.7    3*    860.0  /
  'NASH6'   'OPEN'   'ORAT'   15.5    0.59    63.13   3*    860.0  /
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  'NASH10'  'OPEN'   'ORAT'   12.7   1.48  132.8     3*   725.0  /
  'NASH14'  'OPEN'   'ORAT'   23.44  1.11   78.68    3*  1000.0  /
/
TSTEP
   30.4375
/
--  1 NOV, 1995
WCONHIST
  'NASH1'   'OPEN'   'ORAT'   9.79  4.6    166.6     3*   540.0  /
  'NASH5'   'OPEN'   'ORAT'  18.8   0.     124.8     3*   775.0  /
  'NASH6'   'OPEN'   'ORAT'  13.3   0.2    100.0     3*   800.0  /
  'NASH10'  'OPEN'   'ORAT'  13.5   1.08    99.52    3*   745.0  /
  'NASH14'  'OPEN'   'ORAT'  27.58  1.41   338.14    3*  1000.0  /
/
TSTEP
   30.4375
/
--  1 DEC, 1995
WCONHIST
  'NASH1'   'OPEN'   'ORAT'  9.3   5.48    155.5     3*   537.0  /
  'NASH5'   'OPEN'   'ORAT' 21.4   0.      121.7     3*   830.0  /
  'NASH6'   'OPEN'   'ORAT' 16.06  0.39    102.7     3*   885.0  /
  'NASH10'  'OPEN'   'ORAT' 14.1   1.05     97.77    3*   759.0  /
  'NASH14'  'OPEN'   'ORAT' 26.6   0.92    344.0     3*  1000.0  /
/
TSTEP
   30.4375
/
--
--  1 JAN, 1996
WCONHIST
  'NASH1'   'OPEN'   'ORAT' 15.3   3.74    146.0     3*   633.0  /
  'NASH5'   'OPEN'   'ORAT' 17.7   0.      111.5     3*   752.0  /
  'NASH6'   'OPEN'   'ORAT' 14.4   0.24     95.0     3*   835.0  /
  'NASH10'  'OPEN'   'ORAT' 19.2   1.41     89.3     3*   890.0  /
  'NASH14'  'OPEN'   'ORAT' 25.3   0.74    321.3     3*   975.0  /
/
TSTEP
   30.4375
/
--  1 FEB, 1996
WCONHIST
  'NASH1'   'OPEN'   'ORAT'  8.41  4.01    138.9     3*   525.0  /
  'NASH5'   'OPEN'   'ORAT' 19.4   0.      109.2     3*   787.0  /
  'NASH6'   'OPEN'   'ORAT' 11.04  0.15     86.7     3*   730.0  /
  'NASH10'  'OPEN'   'ORAT' 16.36  1.12     87.3     3*   820.0  /
  'NASH14'  'OPEN'   'ORAT' 24.5   0.75    281.7     3*   957.0  /
/
TSTEP
   30.4375
/
--  1 MAR, 1996
WCONHIST
  'NASH1'   'OPEN'   'ORAT'  8.21  3.94    146.23    3*   520.0  /
  'NASH5'   'OPEN'   'ORAT' 18.4   0.      110.72    3*   765.0  /
  'NASH6'   'OPEN'   'ORAT' 14.16  0.27     96.92    3*   825.0  /
  'NASH10'  'OPEN'   'ORAT' 12.9   0.87     88.2     3*   730.0  /
  'NASH14'  'OPEN'   'ORAT' 20.2   0.82    327.5     3*   860.0  /
/
TSTEP
   30.4375
/
--  1 APR, 1996
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WCONHIST
   'NASH1'    'OPEN'    'ORAT' 7.98   3.42   130.7      3*   516.0  /
   'NASH5'    'OPEN'    'ORAT' 19.55  0.     111.05     3*   790.0  /
   'NASH6'    'OPEN'    'ORAT' 13.4   0.15    90.12     3*   803.0  /
   'NASH10'   'OPEN'    'ORAT' 11.0   0.67    88.77     3*   680.0  /
   'NASH14'   'OPEN'    'ORAT' 19.4   0.75   313.0      3*   840.0  /
/
TSTEP
     30.4375
/
--  1 MAY, 1996
WCONHIST
   'NASH1'    'OPEN'    'ORAT'  7.88  3.52   125.3      3*   515.0  /
   'NASH5'    'OPEN'    'ORAT' 16.6   0.     114.1      3*   730.0  /
   'NASH6'    'OPEN'    'ORAT' 12.1   0.19    79.64     3*   765.0  /
   'NASH10'   'OPEN'    'ORAT' 11.37  0.68    91.4      3*   690.0  /
   'NASH14'   'OPEN'    'ORAT' 17.5   0.52   287.5     -3*   800.0  /
/
TSTEP
     30.4375
/
--  1 JUN, 1996
WCONHIST
   'NASH1'    'OPEN'    'ORAT'  6.93  3.11   111.8      3*   500.0  /
   'NASH5'    'OPEN'    'ORAT' 15.3   0.     107.56     3*   705.0  /
   'NASH6'    'OPEN'    'ORAT' 15.2   0.44    83.45     3*   860.0  /
   'NASH10'   'OPEN'    'ORAT' 10.84  0.89    85.75     3*   675.0  /
   'NASH14'   'OPEN'    'ORAT' 17.67  0.80   282.3      3*   800.0  /
/
TSTEP
     30.4375
/
--  1 JUL, 1996
WCONHIST
   'NASH1'    'OPEN'    'ORAT'  7.49  3.03   116.3      3*   510.0  /
   'NASH5'    'OPEN'    'ORAT' 16.6   0.     110.06     3*   730.0  /
   'NASH6'    'OPEN'    'ORAT' 12.12  0.41   138.08     3*   765.0  /
   'NASH10'   'OPEN'    'ORAT' 10.4   1.19    88.05     3*   663.0  /
   'NASH14'   'OPEN'    'ORAT' 17.0   0.41   182.9      3*   780.0  /
/
TSTEP
     30.4375
/
--  1 AUG, 1996
WCONHIST
   'NASH1'    'OPEN'    'ORAT'  7.0   2.88   112.1      3*   501.0  /
   'NASH5'    'OPEN'    'ORAT' 15.7   0.     110.9      3*   712.0  /
   'NASH6'    'OPEN'    'ORAT' 11.99  0.45   120.54     3*   760.0  /
   'NASH10'   'OPEN'    'ORAT' 12.42  0.74    89.49     3*   715.0  /
   'NASH14'   'OPEN'    'ORAT' 16.8   0.45   161.1      3*   775.0  /
/
TSTEP
     30.4375
/
--  1 SEP, 1996
WCONHIST
   'NASH1'    'OPEN'    'ORAT'  6.47  2.71    95.01     3*   493.0  /
   'NASH5'    'OPEN'    'ORAT' 15.6   0.     107.4      3*   710.0  /
   'NASH6'    'OPEN'    'ORAT' 11.6   0.45   126.3      3*   750.0  /
   'NASH10'   'OPEN'    'ORAT' 11.0   1.85    85.72     3*   680.0  /
   'NASH14'   'OPEN'    'ORAT' 16.4   0.48   168.0      3*   770.0  /
/
TSTEP
```

```
    30.4375
/
-- 1 OCT, 1996
WCONHIST
  'NASH1'    'OPEN'    'ORAT'  6.52  2.74    78.42      3*   490.0  /
  'NASH5'    'OPEN'    'ORAT' 15.32  0.0    137.4       3*   700.0  /
  'NASH6'    'OPEN'    'ORAT' 12.0   0.30   127.2       3*   750.0  /
  'NASH10'   'OPEN'    'ORAT'  9.85  1.02   118.20      3*   680.0  /
  'NASH14'   'OPEN'    'ORAT' 17.91  0.96   133.1       3*   770.0  /
/
TSTEP
    30.4375
/
-- 1 NOV, 1996
WCONHIST
  'NASH1'    'OPEN'    'ORAT'  6.37  3.08    44.56      3*   490.0  /
  'NASH5'    'OPEN'    'ORAT' 14.74  0.0     99.36      3*   700.0  /
  'NASH6'    'OPEN'    'ORAT' 11.58  0.25    97.87      3*   750.0  /
  'NASH10'   'OPEN'    'ORAT' 11.37  1.65    85.44      3*   680.0  /
  'NASH14'   'OPEN'    'ORAT' 17.85  0.83   133.13      3*   770.0  /
/
TSTEP
    30.4375
/
-- 1 DEC, 1996
WCONHIST
  'NASH1'    'OPEN'    'ORAT'  7.20  3.07    61.18      3*   490.0  /
  'NASH5'    'OPEN'    'ORAT' 24.93  0.0    166.62      3*   700.0  /
  'NASH6'    'OPEN'    'ORAT' 12.82  0.28   111.86      3*   750.0  /
  'NASH10'   'OPEN'    'ORAT' 20.50  1.87   143.85      3*   680.0  /
  'NASH14'   'OPEN'    'ORAT' 16.50  0.58   150.88      3*   770.0  /
/
TSTEP
    30.4375
/
-- 1 JAN, 1997
WCONHIST
  'NASH1'    'OPEN'    'ORAT'  6.94  3.22    57.29      3*   490.0  /
  'NASH5'    'OPEN'    'ORAT' 15.50  0.0    205.16      3*   700.0  /
  'NASH6'    'OPEN'    'ORAT' 13.36  0.23   104.00      3*   750.0  /
  'NASH10'   'OPEN'    'ORAT' 10.00  0.98   176.90      3*   680.0  /
  'NASH14'   'OPEN'    'ORAT' 13.10  0.69   141.70      3*   770.0  /
/
TSTEP
    30.4375
/
-- 1 FEB, 1997
WCONHIST
  'NASH1'    'OPEN'    'ORAT'  5.85  3.21    50.96      3*   490.0  /
  'NASH5'    'OPEN'    'ORAT' 12.74  0.0    120.30      3*   700.0  /
  'NASH6'    'OPEN'    'ORAT' 10.50  0.37    67.82      3*   750.0  /
  'NASH10'   'OPEN'    'ORAT'  9.00  1.09   123.69      3*   680.0  /
  'NASH14'   'OPEN'    'ORAT' 15.10  0.91   140.40      3*   770.0  /
/
TSTEP
    30.4375
/
END      ===========================================================
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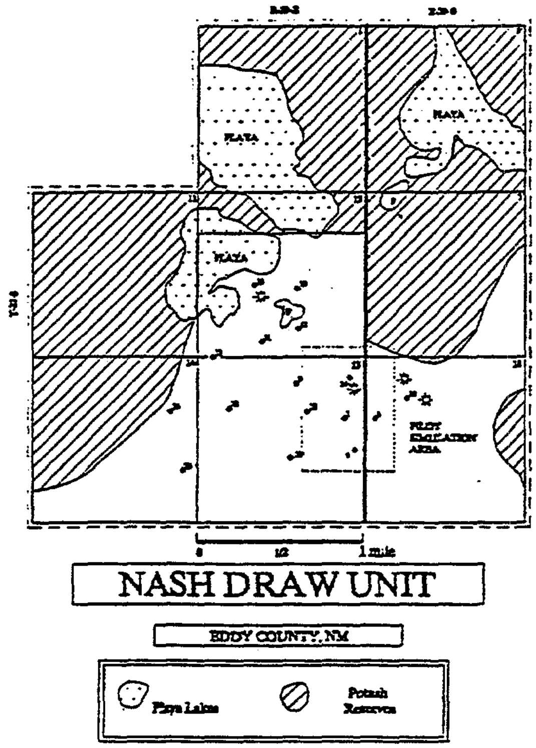


Fig. 1. Well locations with potash area and playa lakes.

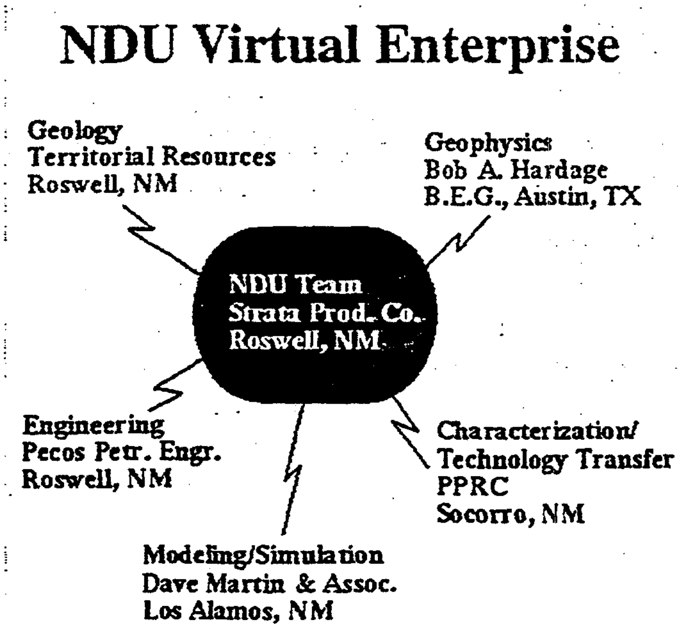


Fig. 2. Virtual Enterprise concept for reservoir management applications.

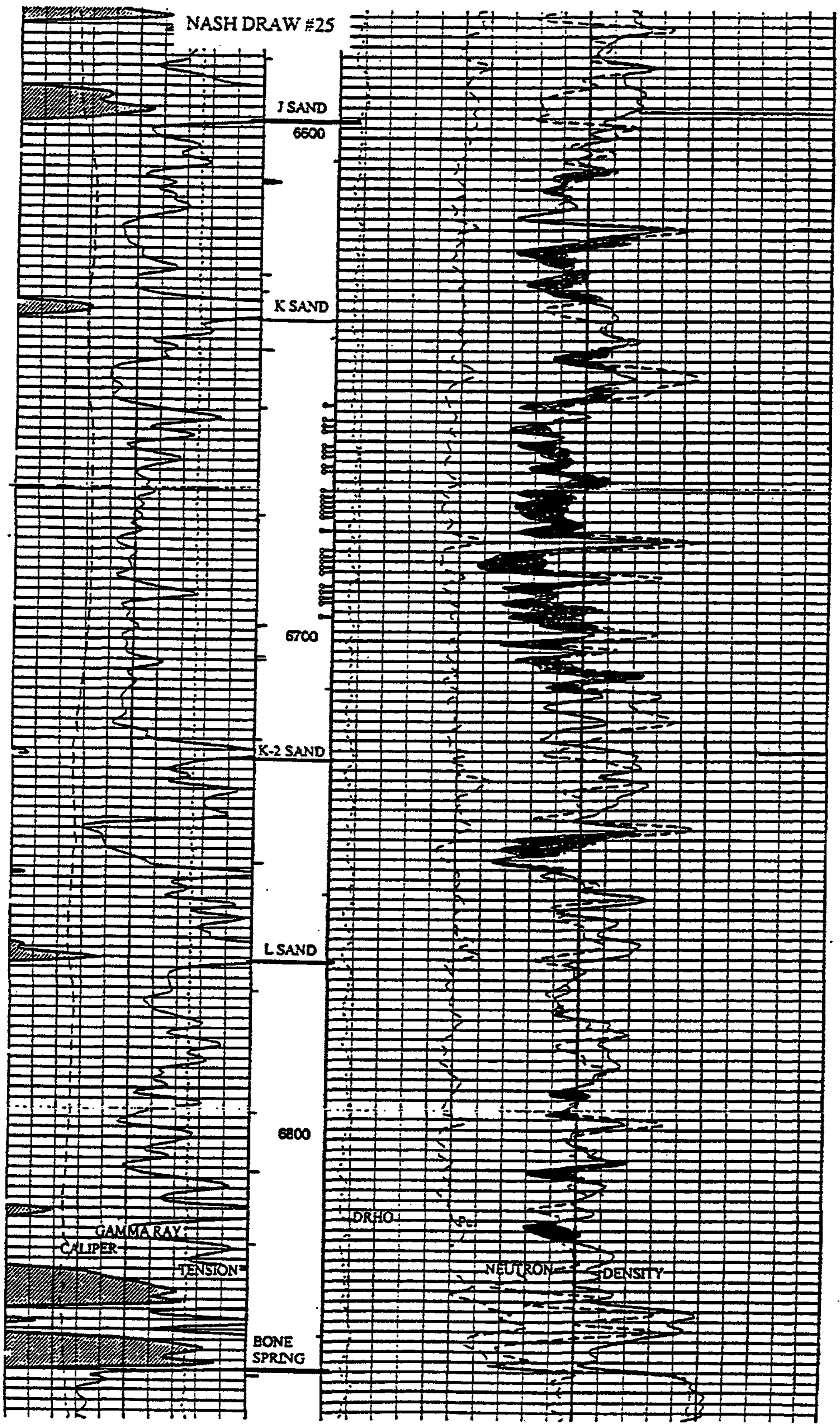


Fig. 3. Log from Well 25 showing poor pay quality.

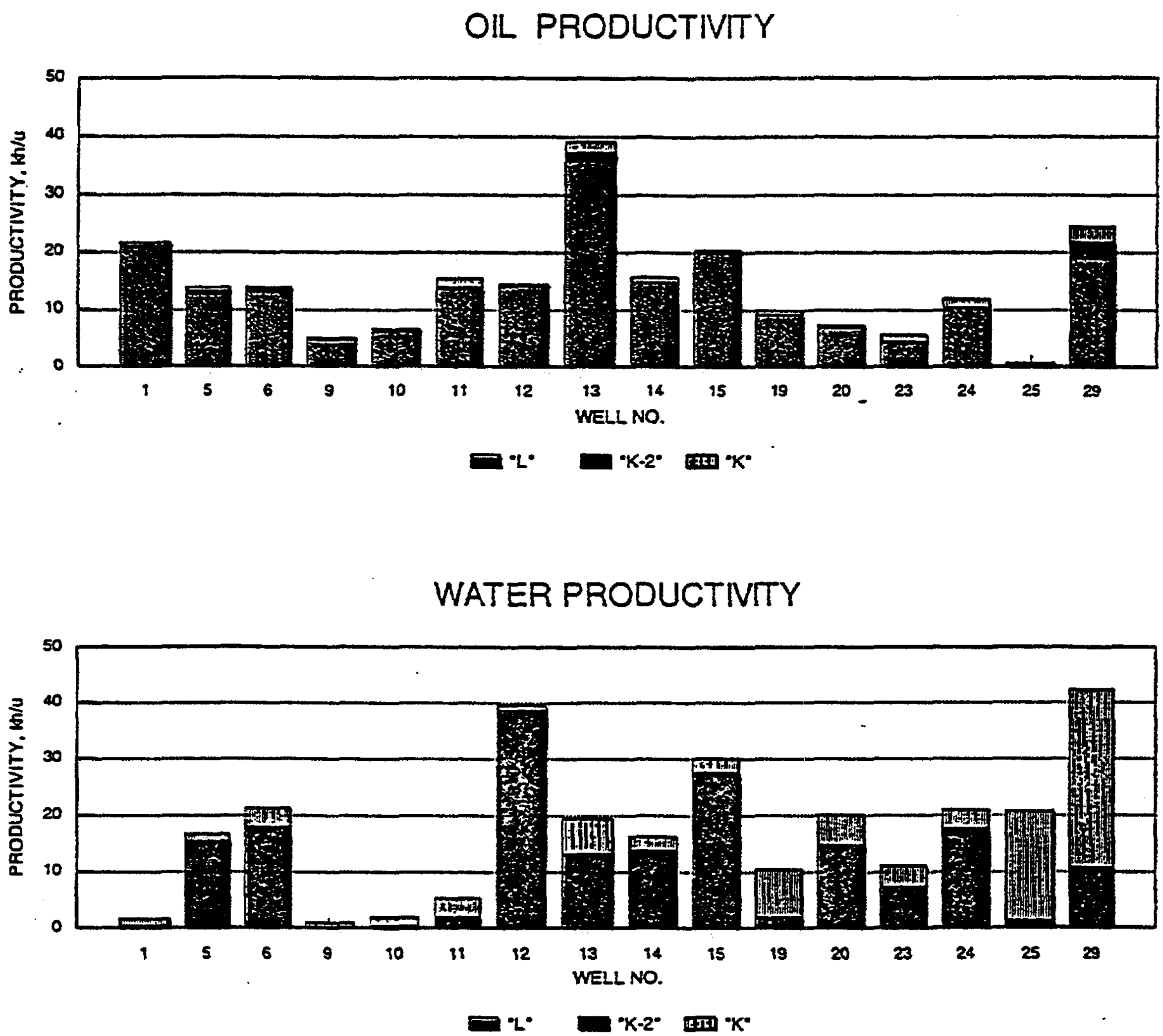


Fig. 4. Productivity of oil and water by well.

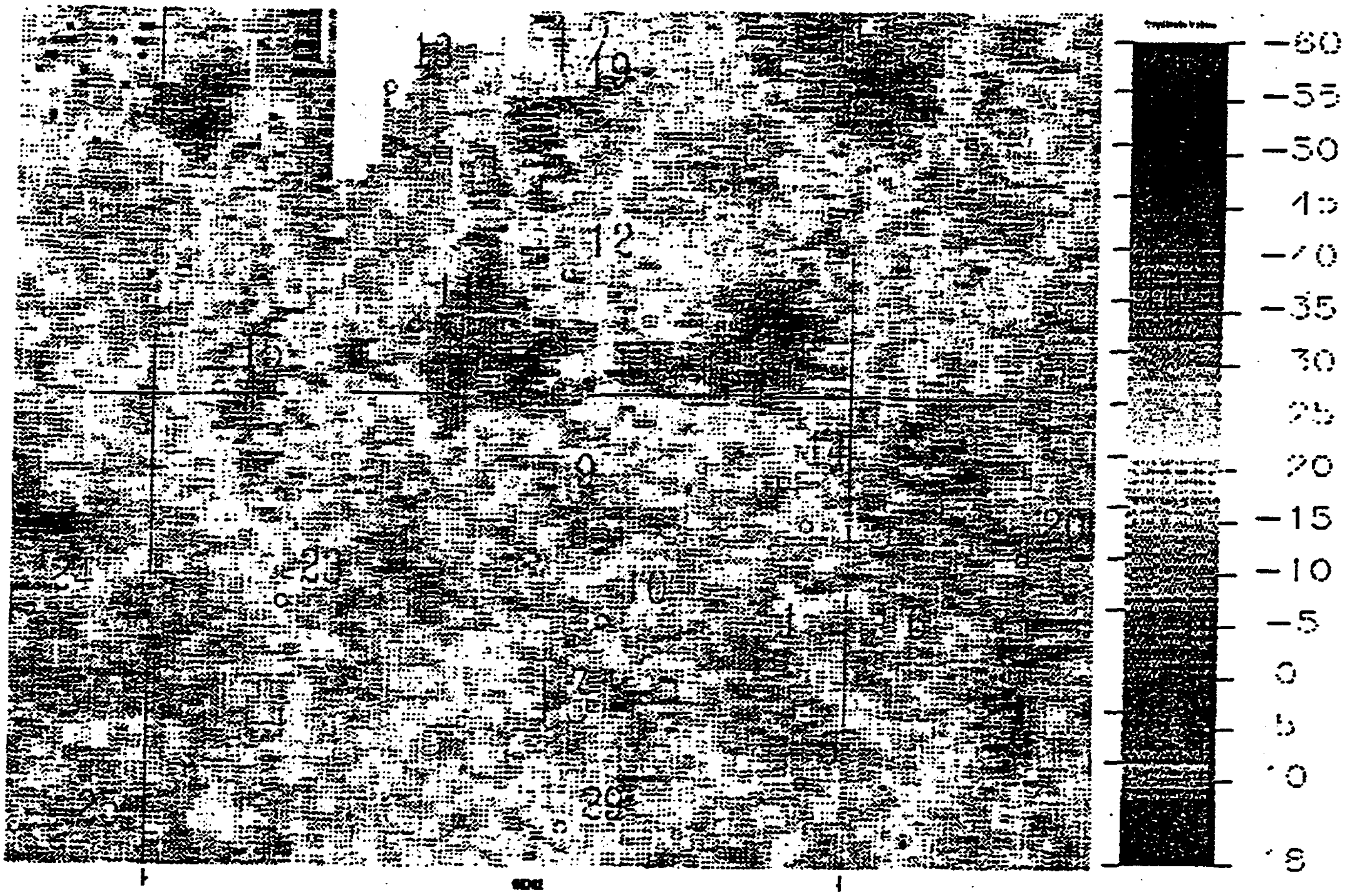


Fig. 5. "L" zone seismic amplitude.

WELL NO.:	REFLECTION AMPLITUDE	NET PAY (ft)	TOTAL TRANSMISSIVITY (OIL AND WATER)
5	-11.20	21.5	12.835
6	-19.20	25.0	13.772
9	-6.33	12.5	4.687
10	-8.73	13.5	6.374
11	-35.86	28.0	14.050
12	-31.02	37.0	14.699
14	-14.10	26.0	15.235
15	-24.98	28.0	20.890
19	-37.26	19.5	9.380
20	-12.23	20.5	7.721
23	-17.78	6.5	4.338
24	-10.74	20.0	10.746
25	-10.55	2.5	0.975
29	-32.50	31.0	19.609

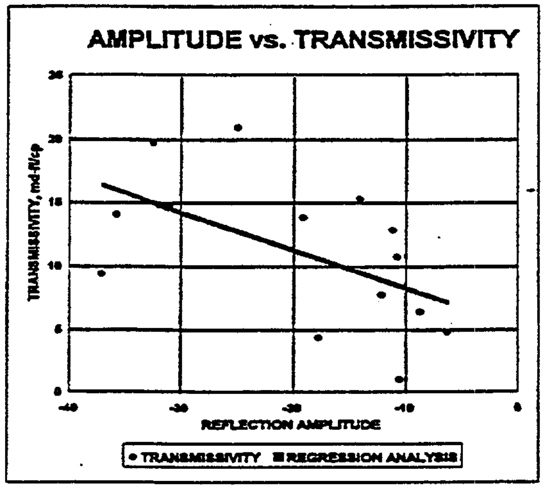
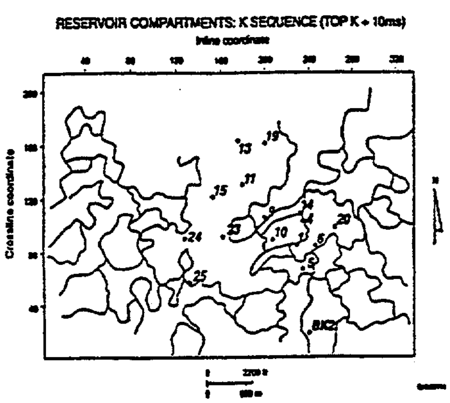


Fig. 6. "L" Zone seismic amplitude vs. transmissivity.



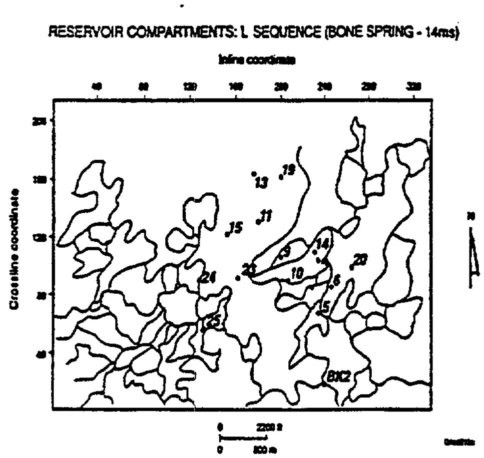


Fig. 7. Reservoir compartmentalization.

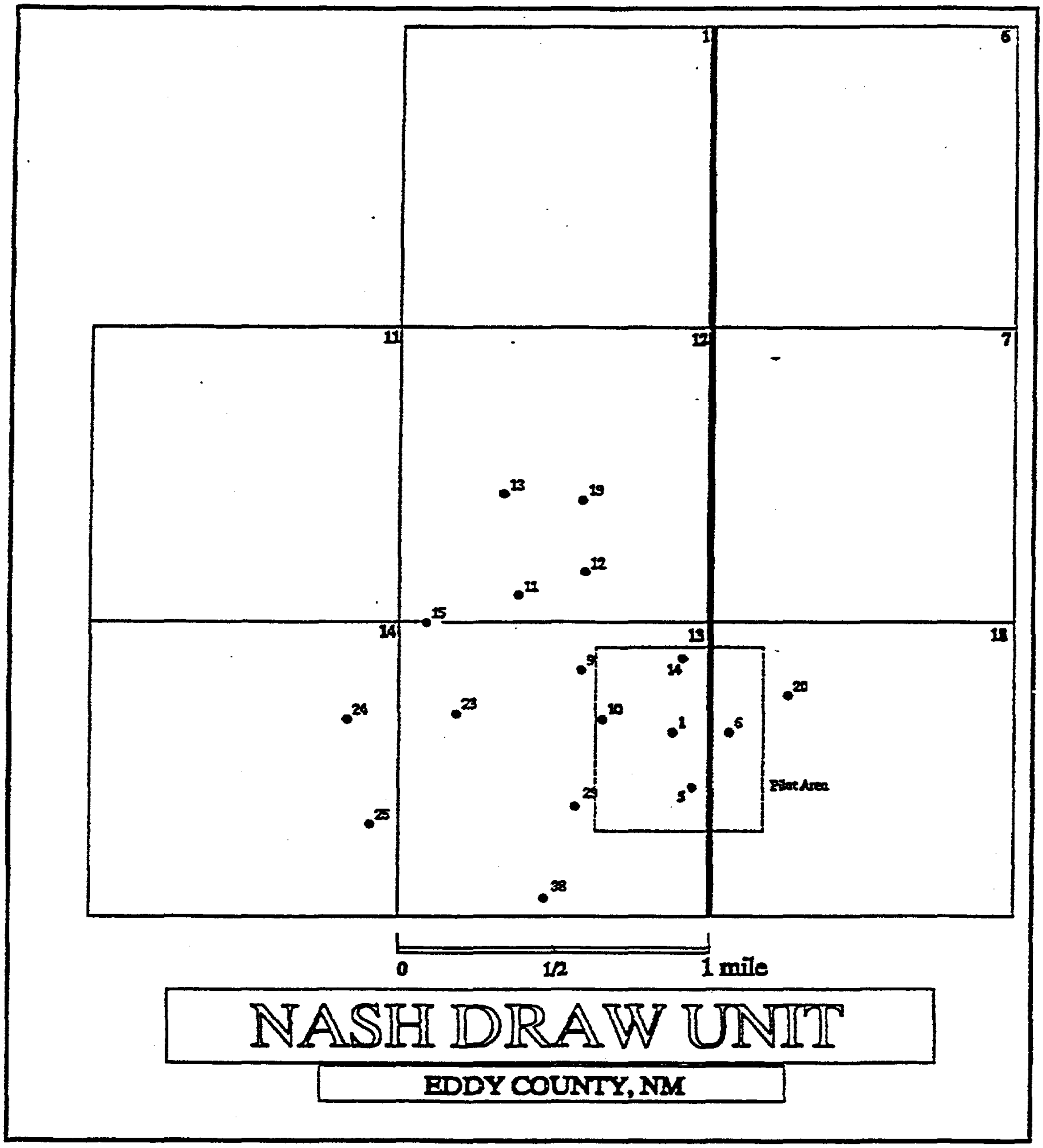


Fig. 8. Well locations at the Nash Draw Pool.

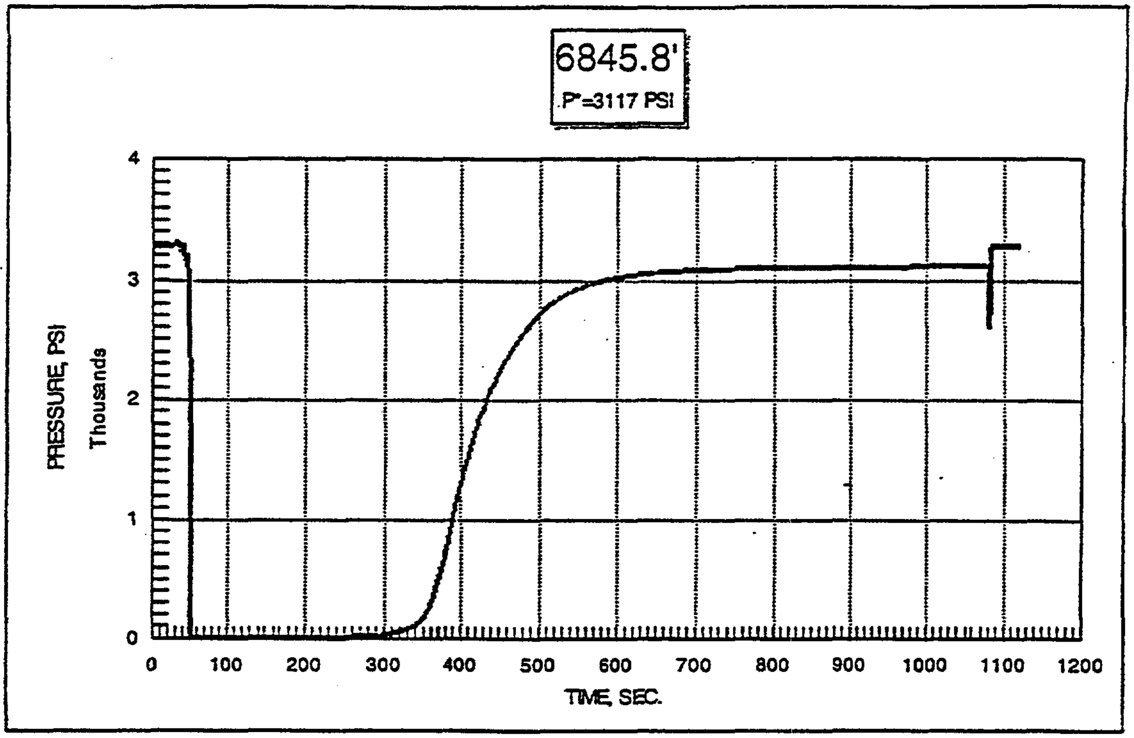


Fig. 9. Continuity test with RFT tool.

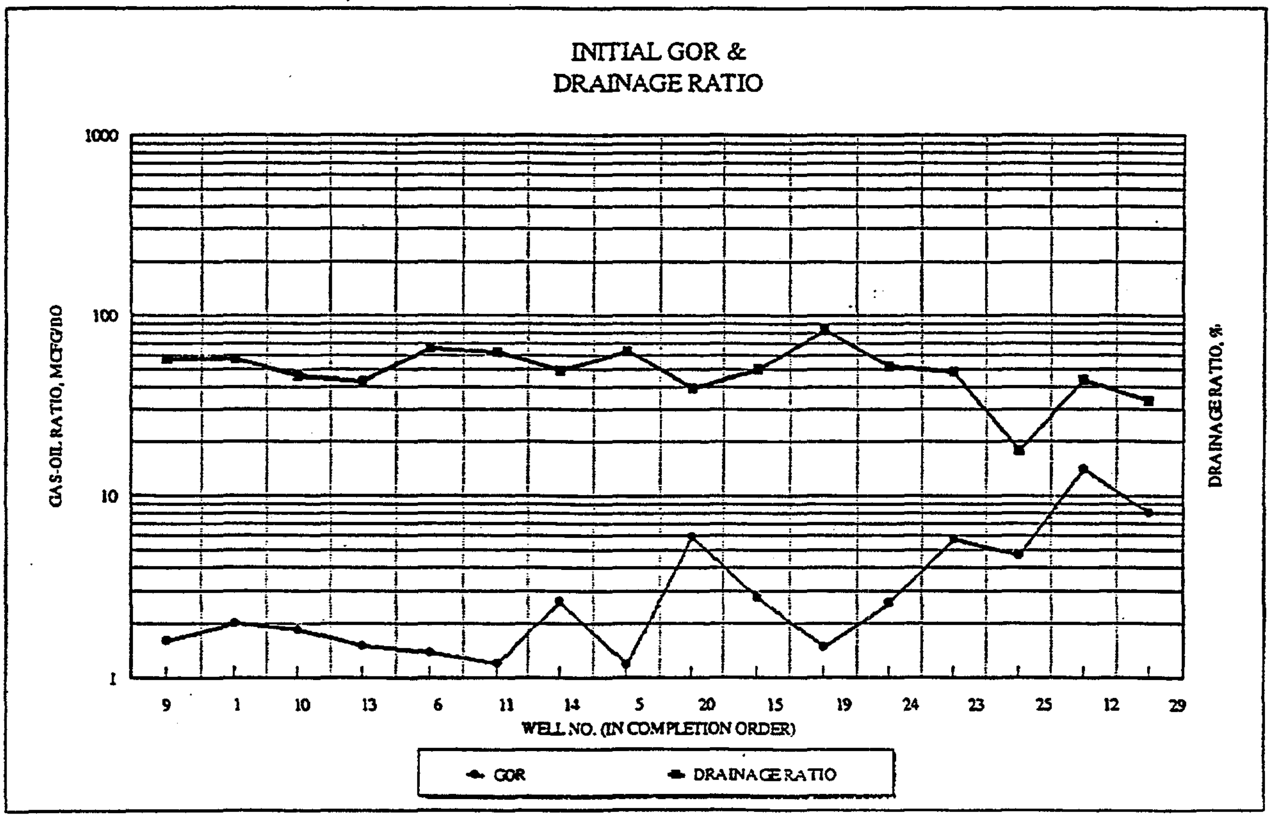


Fig. 10. Initial gas-oil ratio and drainage ratio.

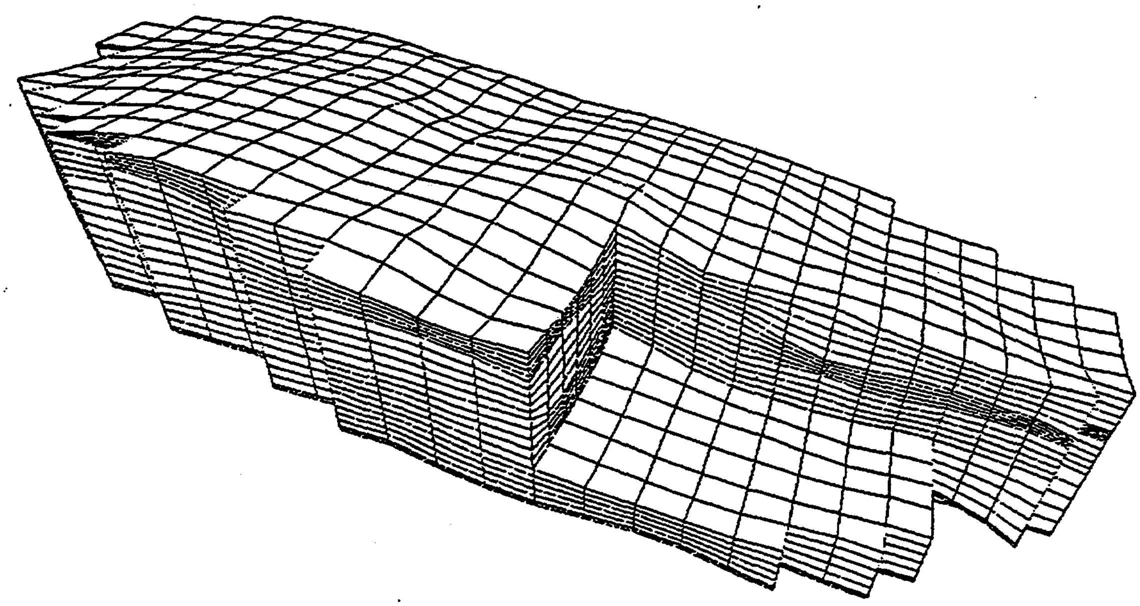


Fig. 11. "L" Zone model grid illustrating proportional layering.

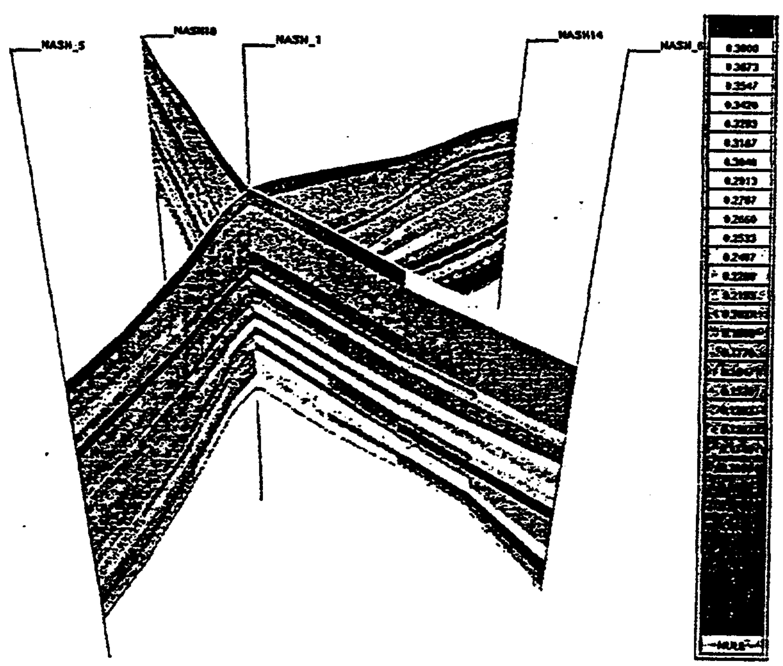


Fig. 12. Initial distribution of mobile oil in the "L" Zone.

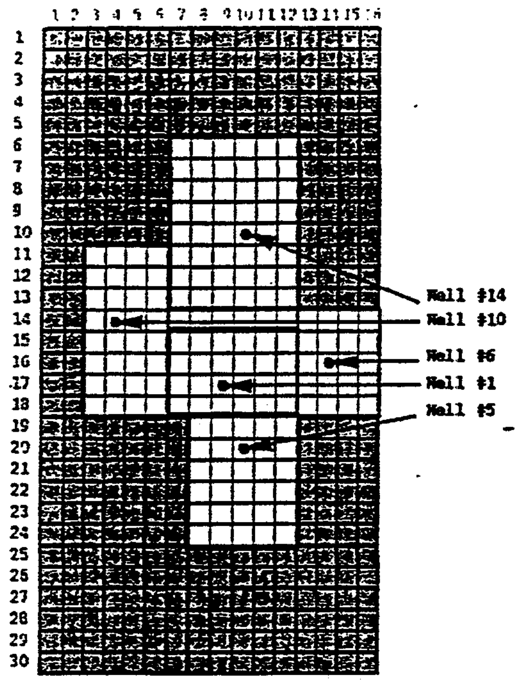


Fig. 13. Well drainage areas in the simulation model. (Each cell occupies an area of approximately one acre).

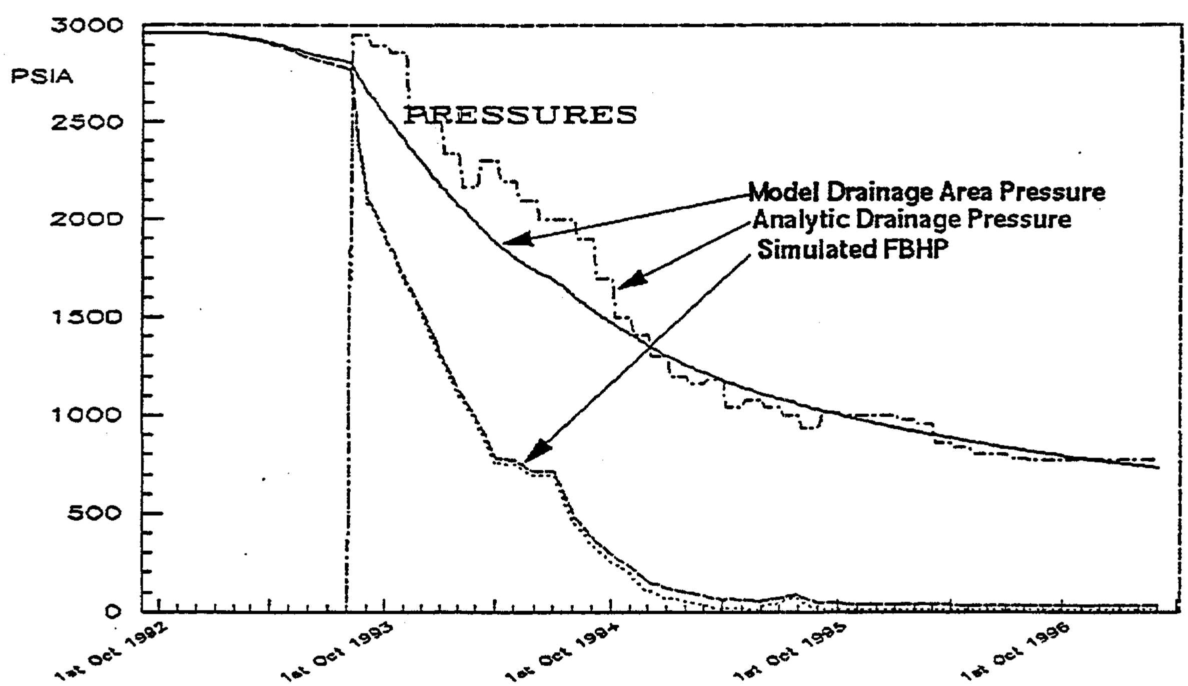


Fig. 14. Pressure response for $trans_{fracture}$ = 2.0 darcy-ft per cp. NDP Well #14.

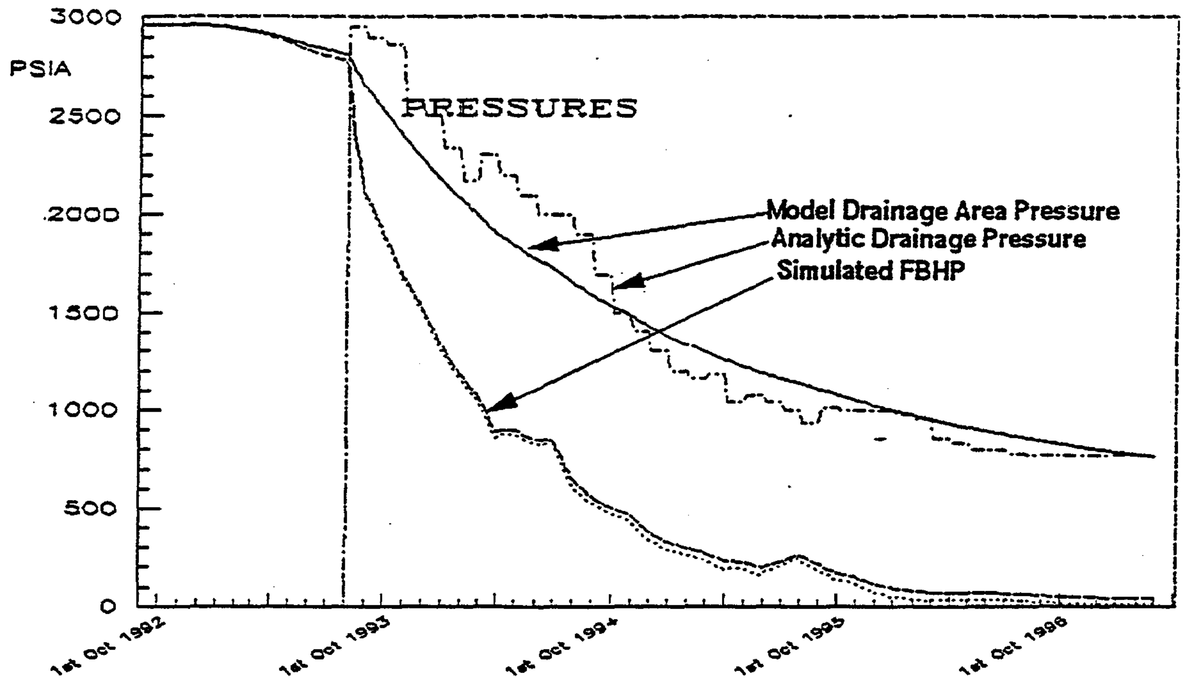


Fig. 15. Pressure response for $trans_{fracture}$ = 0.5 darcy-ft per cp, NDP Well #1.

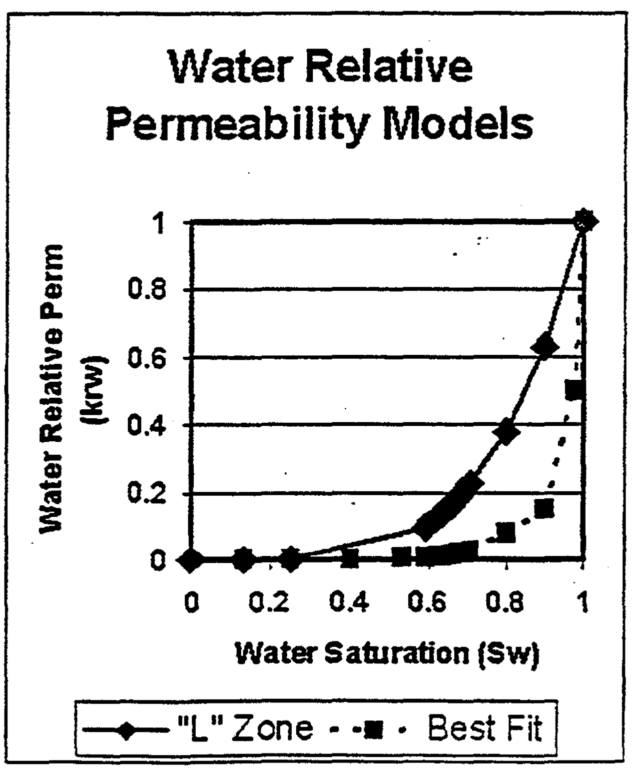


Fig. 16. Initial and "best fit" values of k_{rw}.

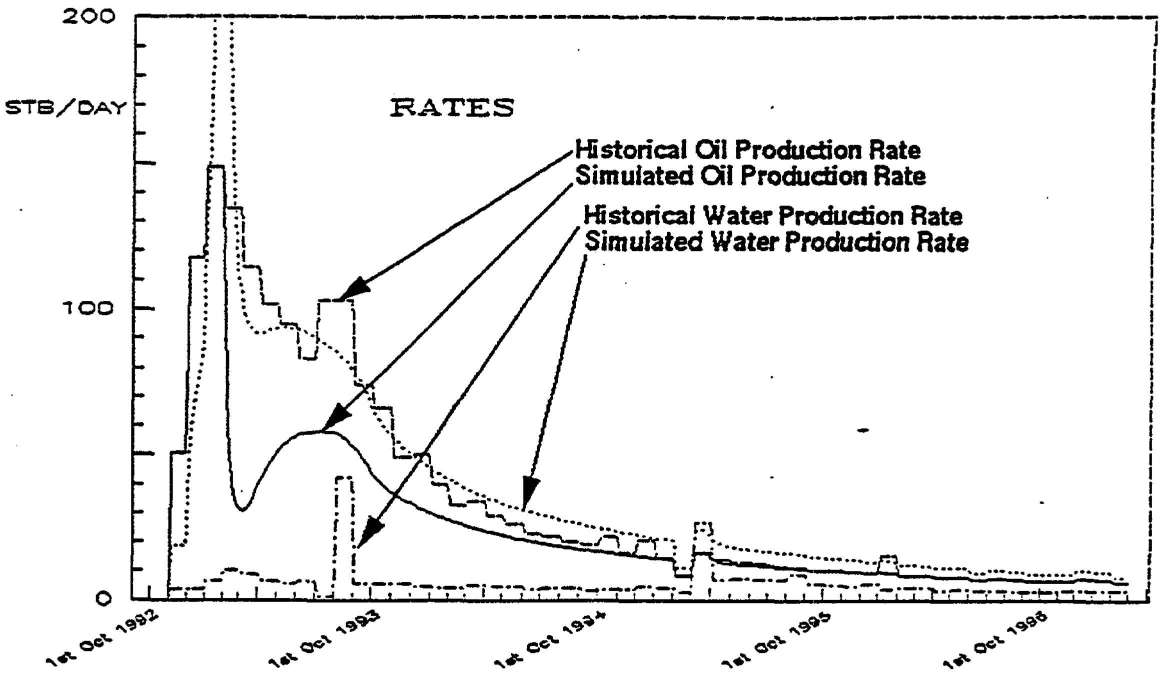


Fig. 17. Liquid production profiles, NDP Well #1.

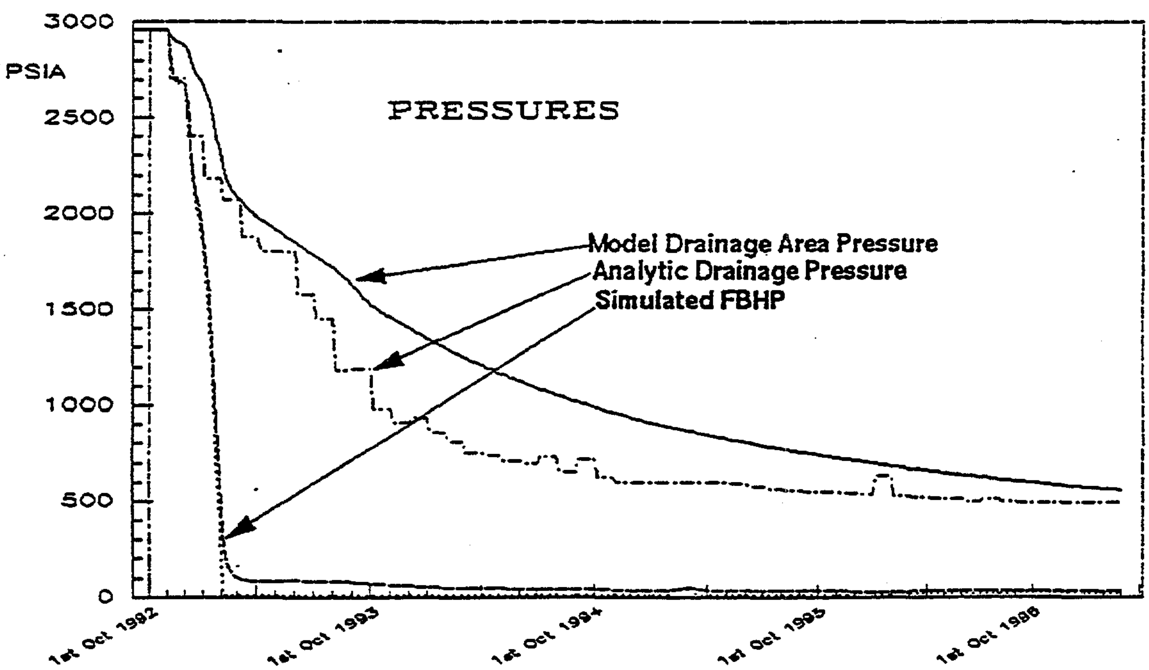


Fig. 18. Simulated pressure response with original data. NDP Well #1.

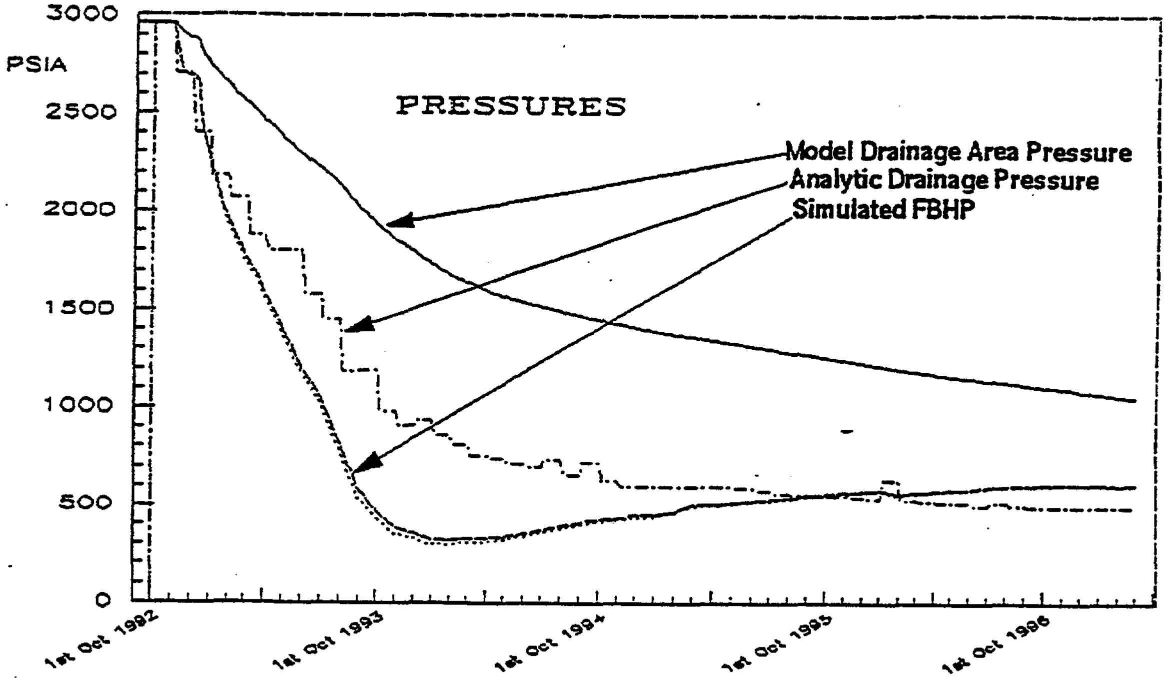


Fig. 19. Analytical vs. simulated pressure response for initial k_{rg}, NDP Well #1.

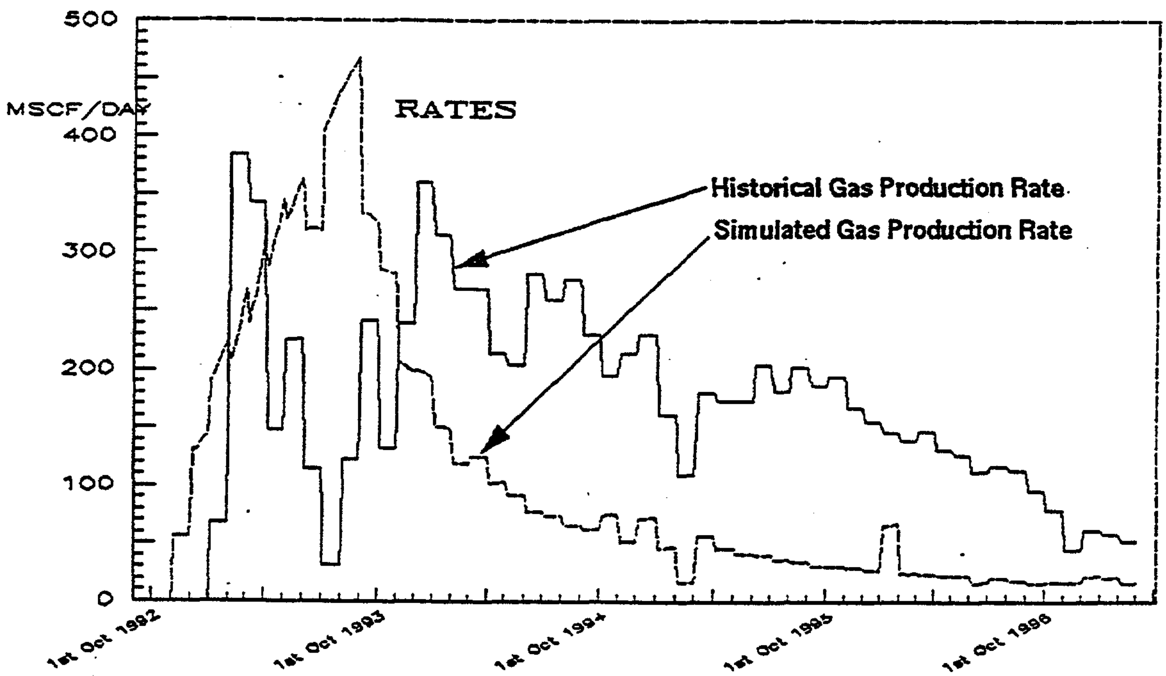


Fig. 20. Gas production for initial k_{rg}. NDP Well #1.

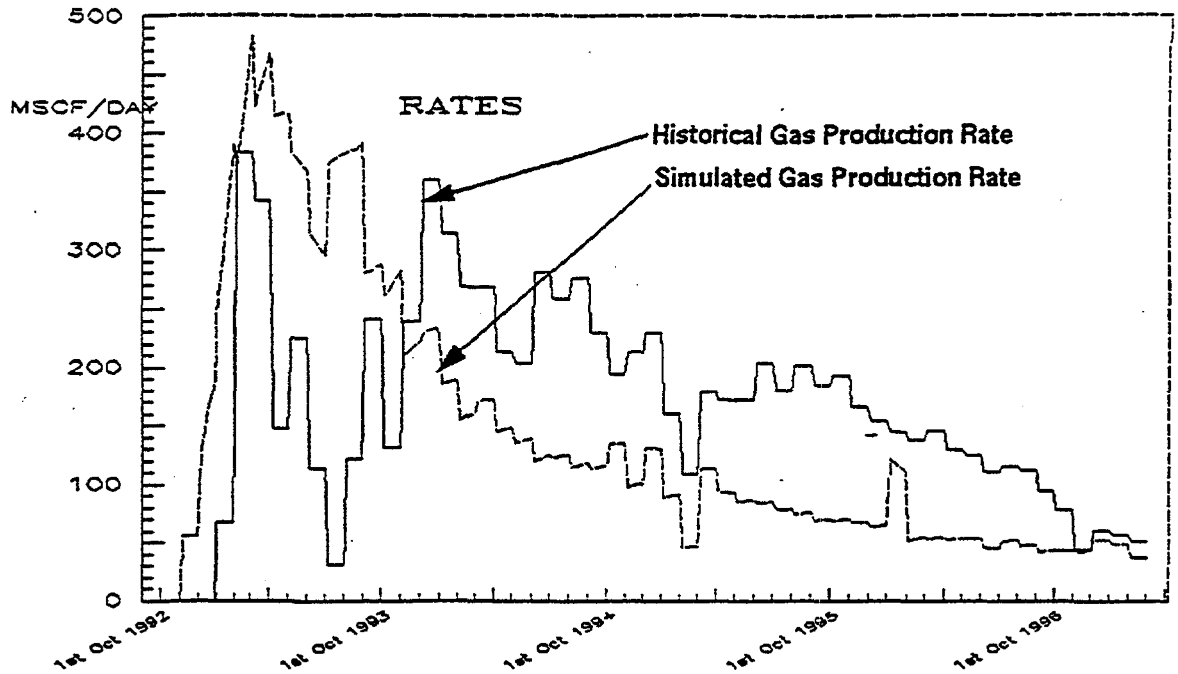


Fig. 21. Gas production after history matching adjustments, NDP Well #1.

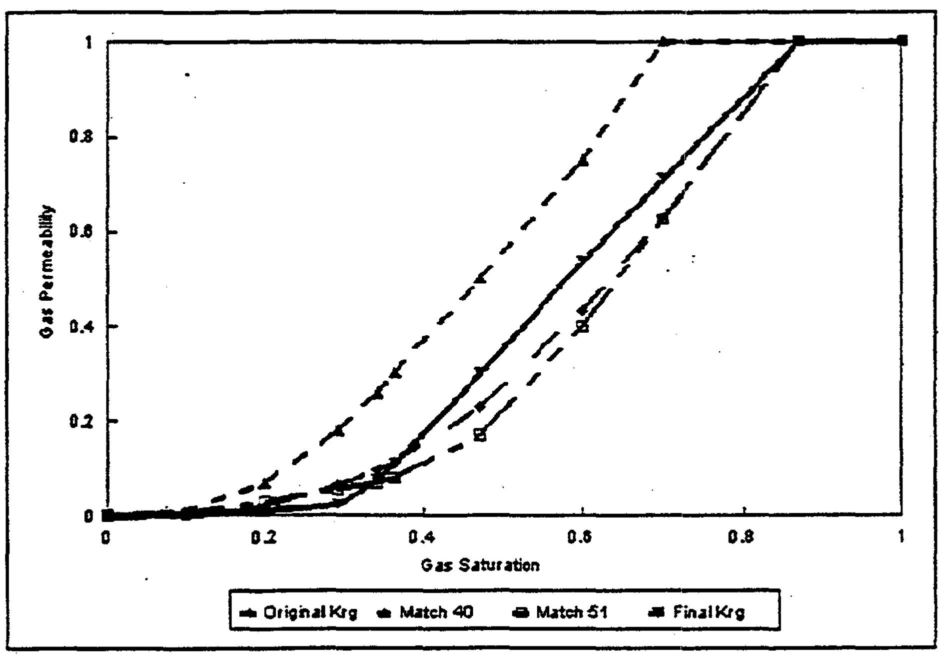


Fig. 22. The envelope of k_{rg} curves investigated during model validation.

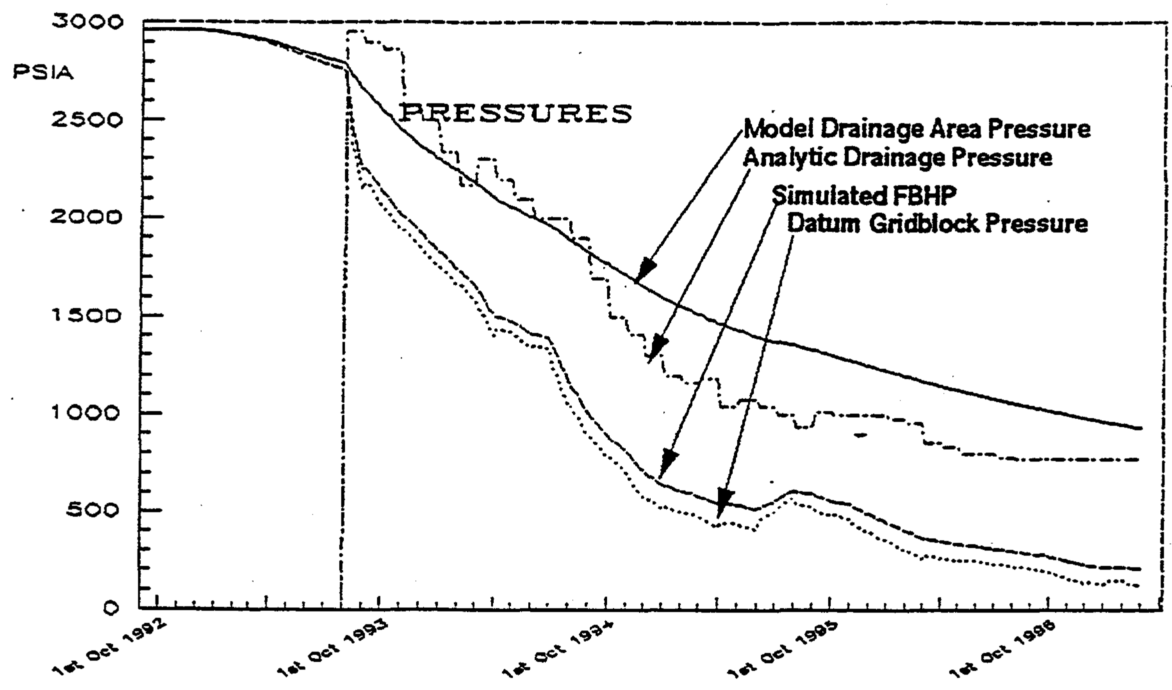


Fig. 23. Pressure response with original reservoir description, NDP Well #14.

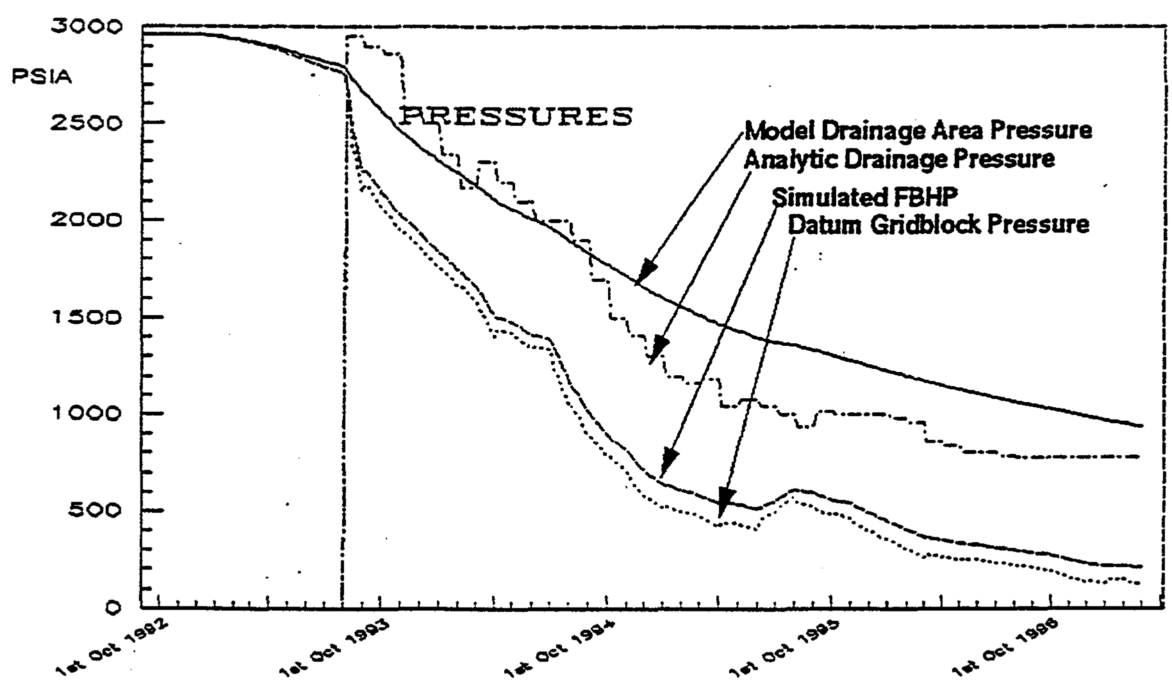


Fig. 24. Pressure response with enhanced matrix transmissibility, NDP Well #14.

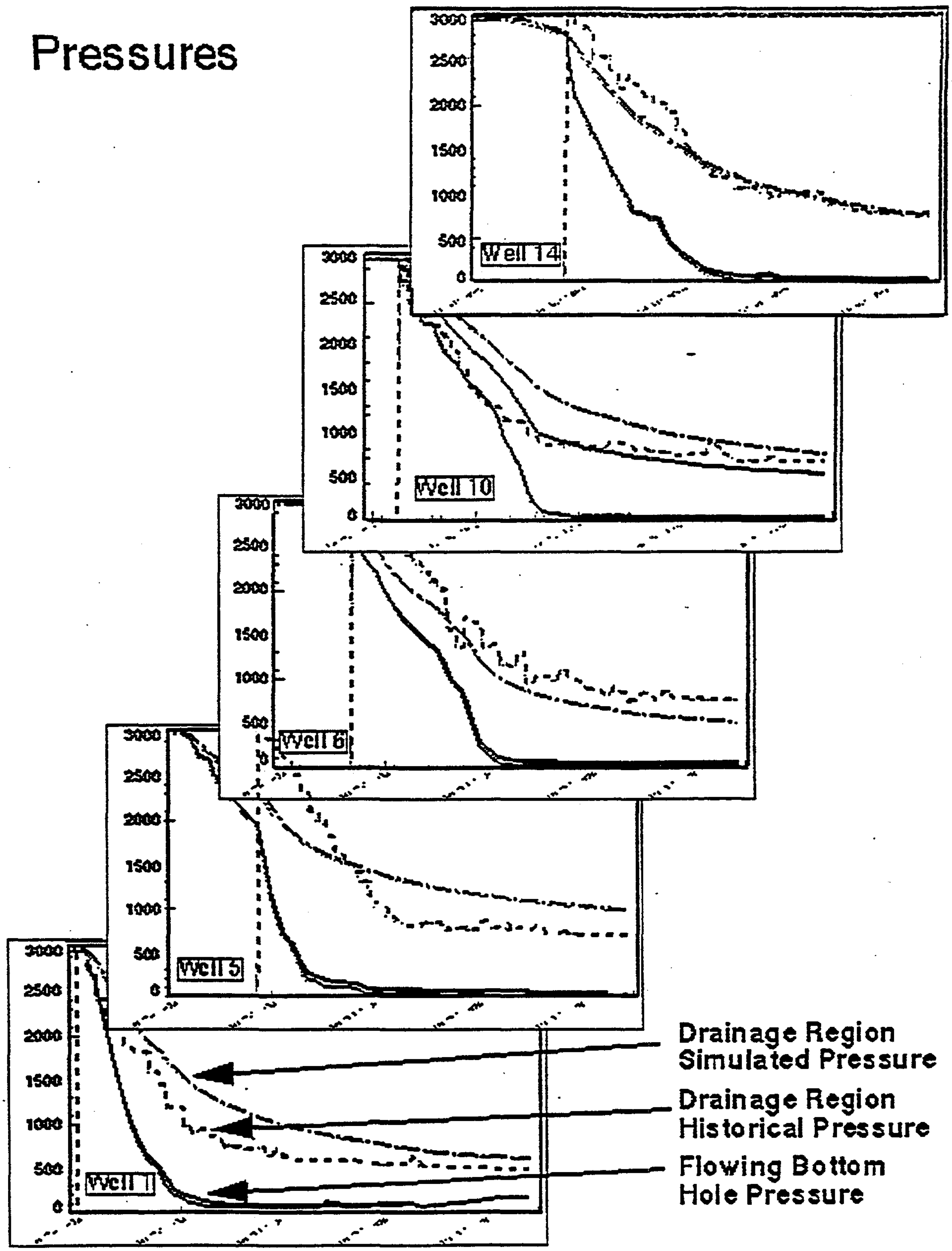


Fig. 25. Pressure match for Nash Draw pilot area wells.

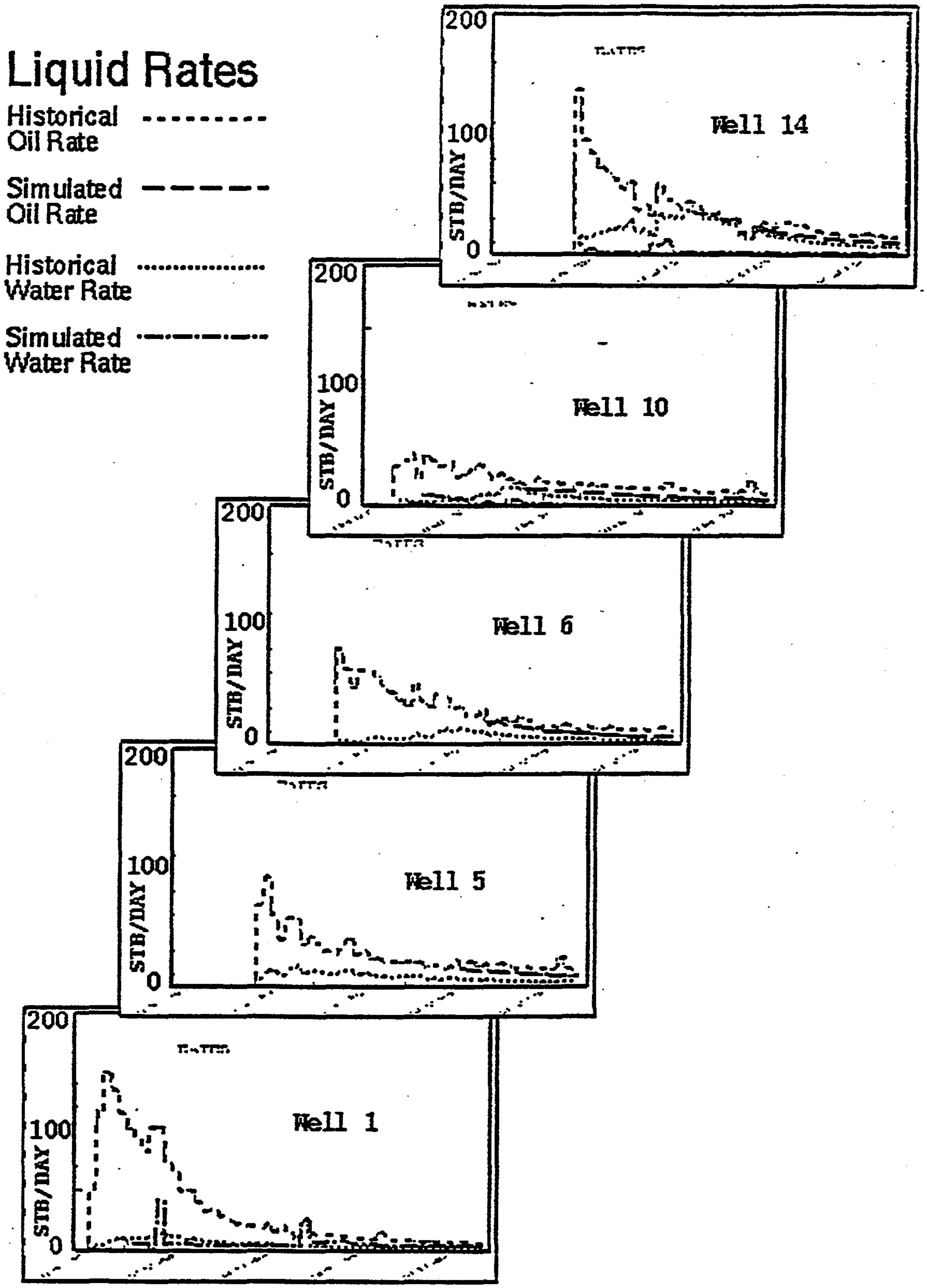


Fig. 26. Liquid production rate match for Nash Draw pilot area wells.

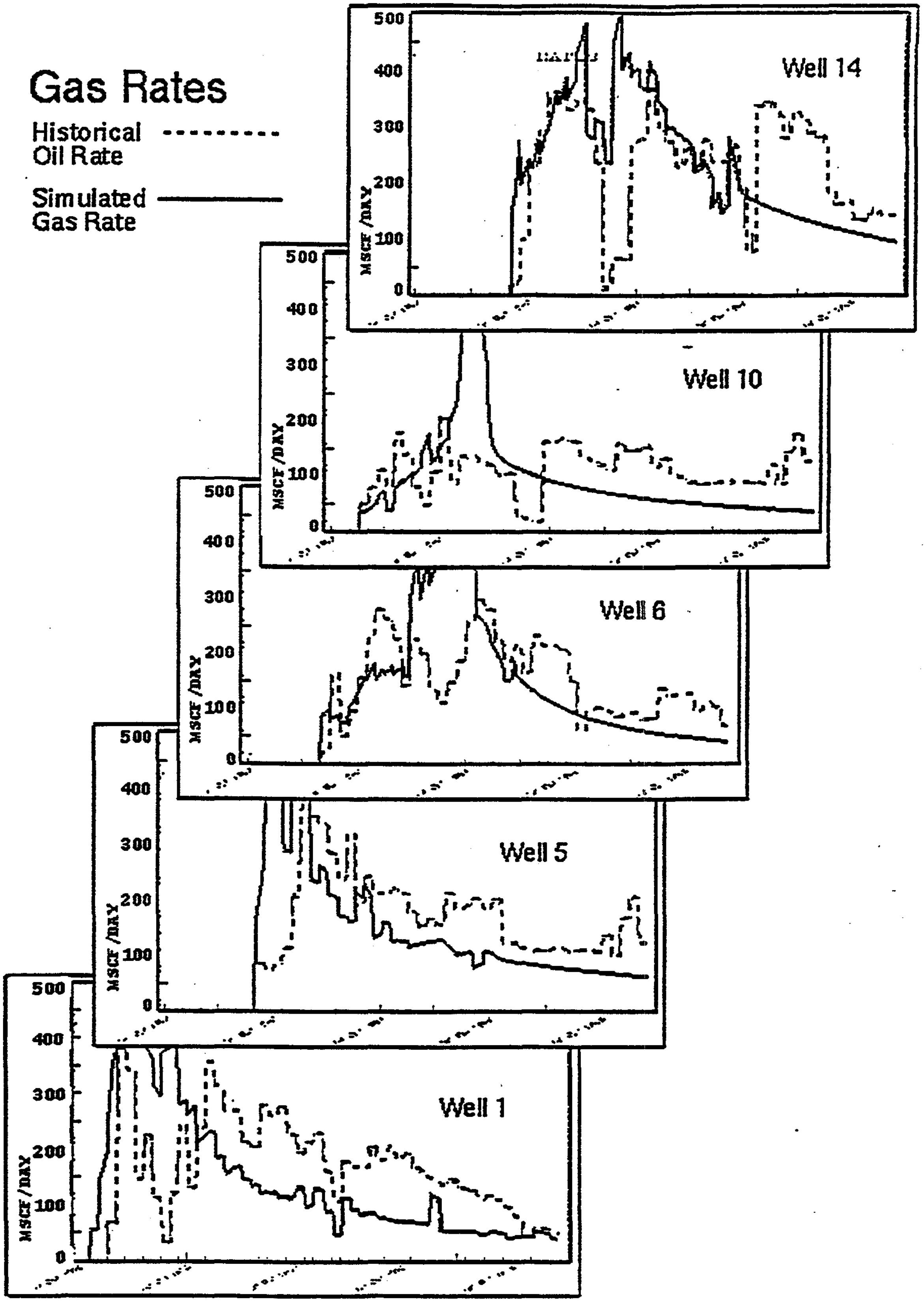


Fig. 27. Gas production rate match for Nash Draw pilot area wells.

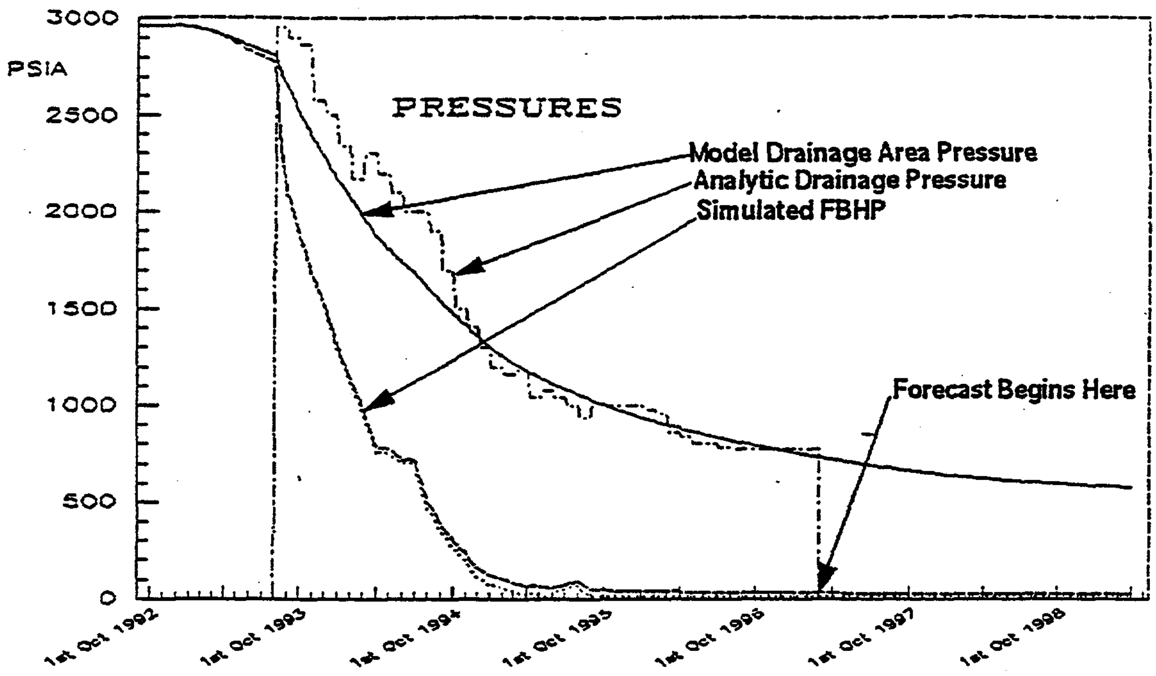


Fig. 28. Pressure response for case 1, NDP Well #1.

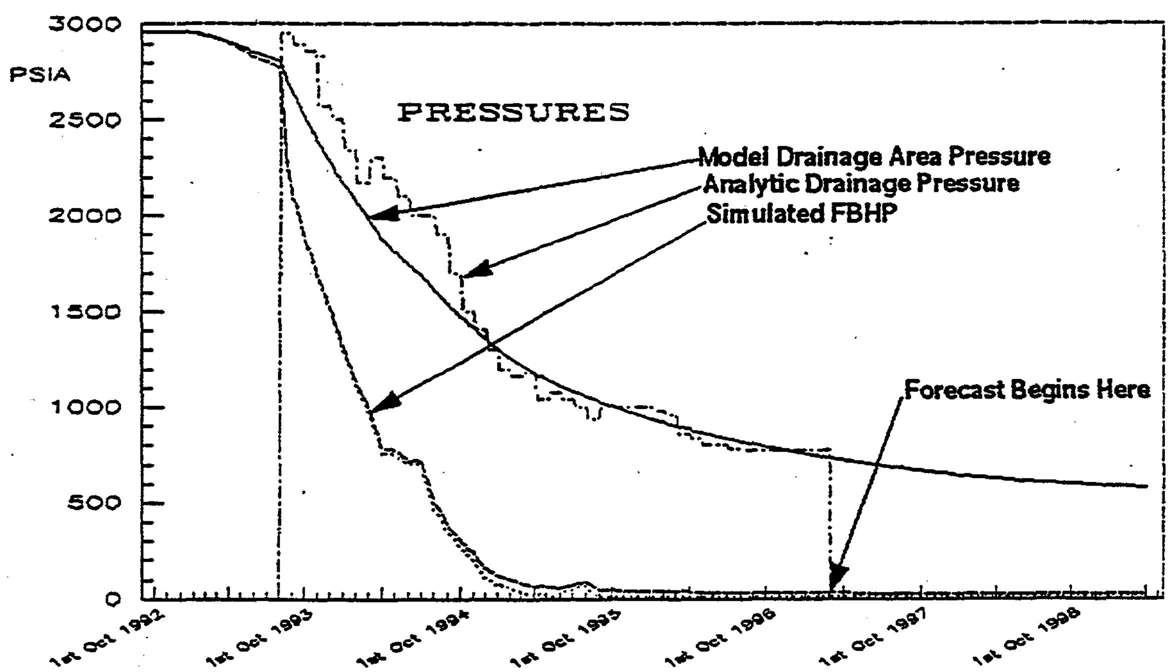


Fig. 29. Pressure response for case 1, NDP Well #14.

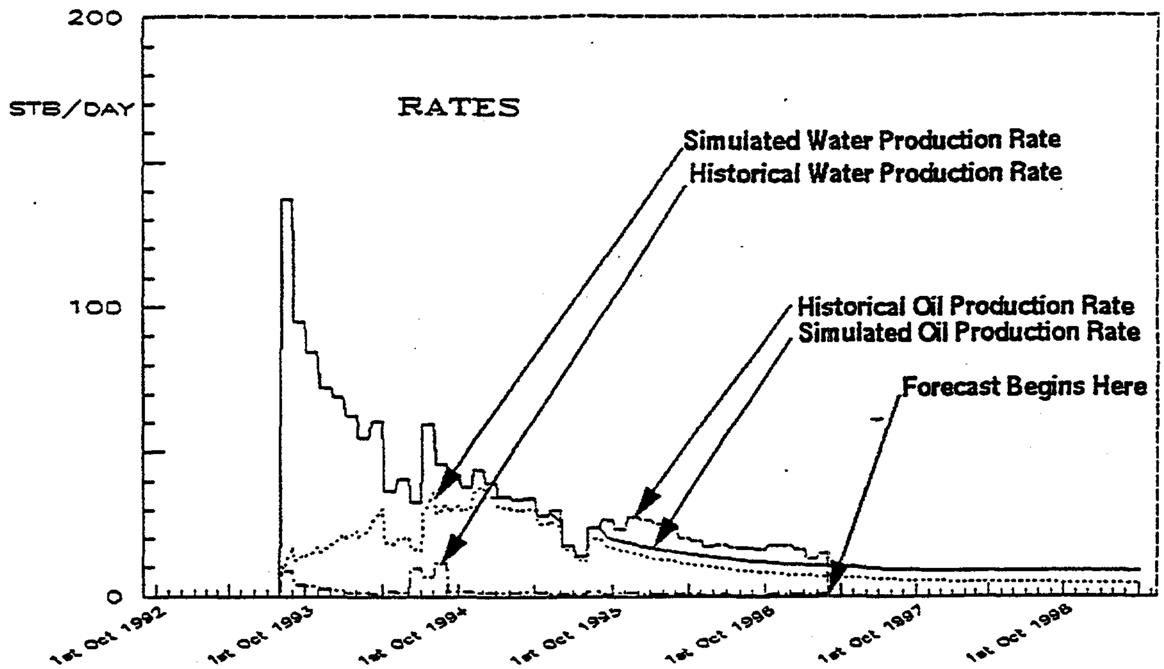


Fig. 30. Rate response for case 1, NDP Well #14.

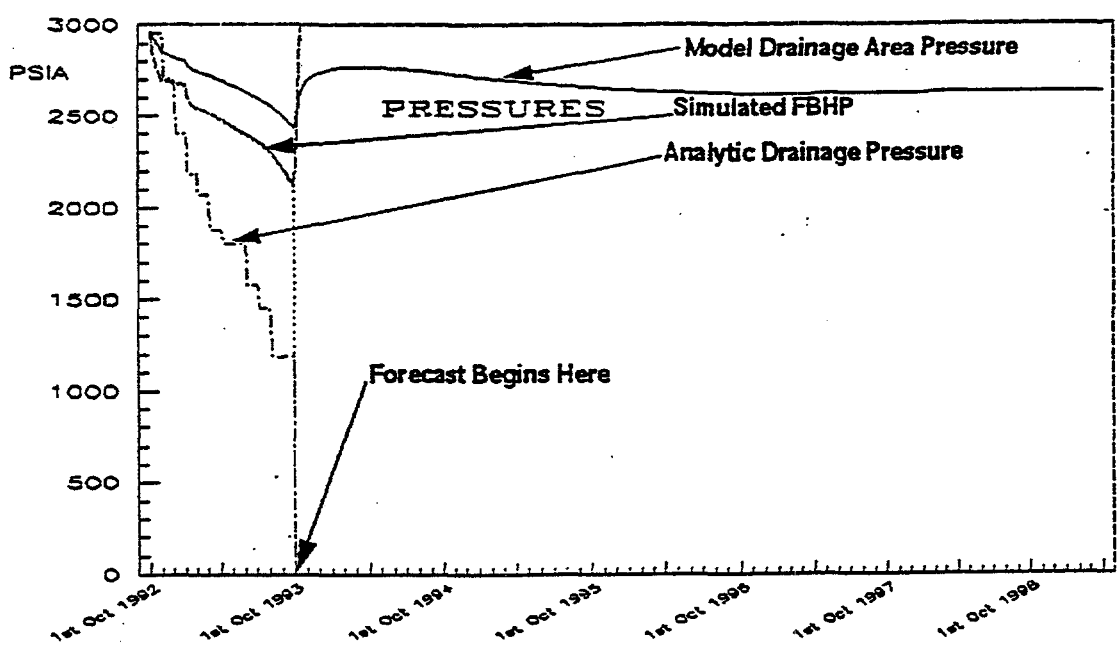


Fig. 31. Pressure response for case 2. NDP Well #1.

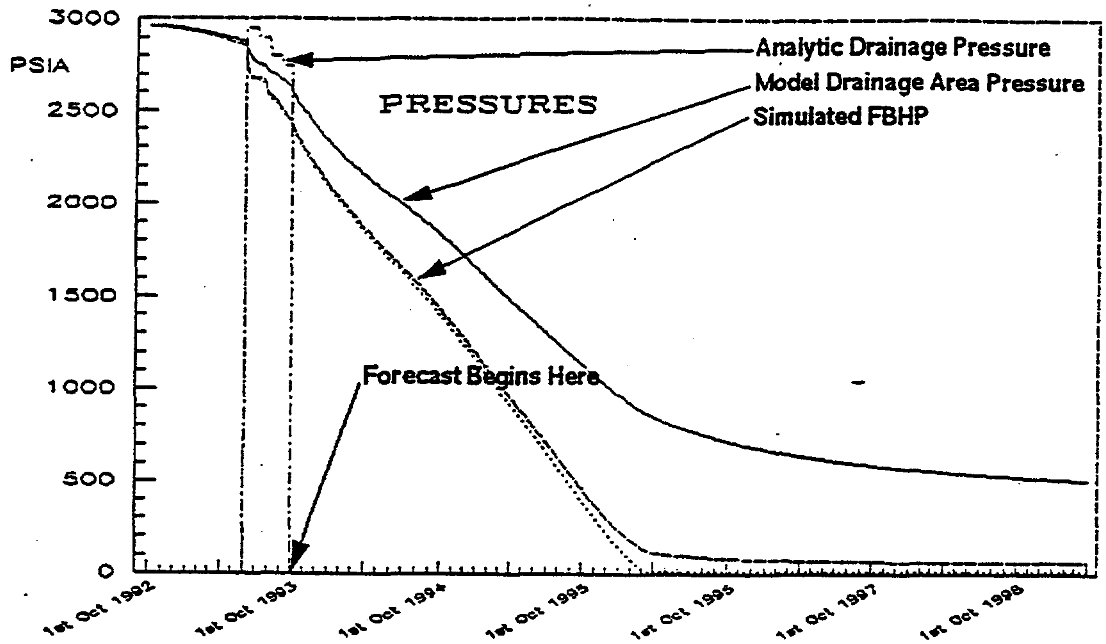


Fig. 32. Pressure response for case 2, NDP Well #6.

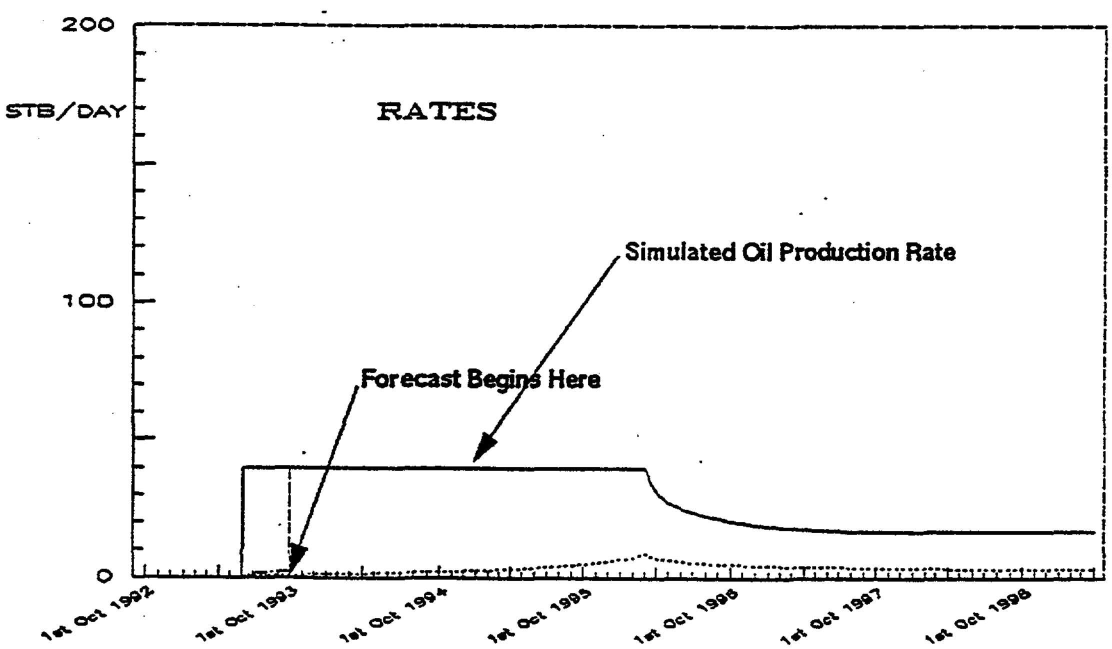


Fig. 33. Oil production for case 2, NDP Well #6.