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Application Of Integrated Reservoir Management And Reservoir Characterization To Optimize Infill Drilling

Topical Report

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APPLICATION OF INTEGRATED RESERVOIR MANAGEMENT AND RESERVOIR CHARACTERIZATION TO OPTIMIZE INFILL DRILLING

TOPICAL REPORT

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TOPICAL REPORT

EXECUTIVE SUMMARY

PROJECT EVALUATION REPORT

Project Status: This project has used a multi-disciplinary approach employing geology, geophysics, and engineering to conduct advanced reservoir characterization and management activities to design and implement an optimized infill drilling program at the North Robertson (Clearfork) Unit in Gaines County, Texas. The activities during the first Budget Period consisted of developing an integrated reservoir description from geological, engineering, and geostatistical studies, and using this description for reservoir flow simulation. Specific reservoir management activities were identified and tested. The geologically targeted infill drilling program currently being implemented is a result of this work.

A significant contribution of this project is to demonstrate the use of cost-effective reservoir characterization and management tools that will be helpful to both independent and major operators for the optimal development of heterogeneous, low permeability shallow-shelf carbonate (SSC) reservoirs. The techniques that are outlined for the formulation of an integrated reservoir description apply to all oil and gas reservoirs, but are specifically tailored for use in the heterogeneous, low permeability carbonate reservoirs of West Texas.

The overall thrust of this project has been Geologically Targeted Infill Drilling. Specifically, in Budget Period I we have demonstrated that it is possible to optimize economics for each and every new well in an infill drilling program. We have demonstrated that strategic drilling is an important advanced recovery technology necessary to satisfy the objectives of the National Energy Strategy. Blanket drilling in shallow-shelf carbonate (SSC) reservoirs is neither prudent nor warranted with the modern reservoir characterization tools and techniques available to operators. The key is reservoir characterization. Operators need to recognize its importance and how it can help in optimizing and maximizing recovery economics. The project's comprehensive technology transfer activities have helped in promoting this awareness. The cost/benefits of the technologies and evaluation schemes employed in this project will be an important topic for the technology transfer workshops. The validation work during Budget Period II will also be important in establishing these cost/benefit relationships.

Summary of Project Results: In the case of North Robertson, the economics are significantly better for a geologically targeted infill drilling pattern which employs a direct line-drive where new producers and injectors are drilled, rather than utilizing a five-spot pattern where existing producers are converted to injectors and new wells are drilled as producers only. Development costs are nearly 25% less for equivalent or improved recoveries with the direct line-drive configuration than for the five spot pattern. In addition, the development risk in realizing the expected reserves are significantly reduced with the line-drive pattern due to suspected directional fracture and flow trends within the reservoir. An additional reason for this is that good existing producing wells are retained in the line-drive development configuration. With the five spot pattern, the risks in realizing the expected reserves are higher due to the inherent unpredictable nature of the "small scale" heterogeneity in the Glorieta/Clearfork. Good geologically targeted infill drilling at North Robertson is expected to reduce development costs by nearly 50% over blanket drilling.

Finally, without reservoir characterization, it is impossible to identify all areas which have extremely poor development potential. Some of these poor areas can be identified with relative ease, such as those lacking sufficient quantity and quality of pay rock. The difficulty arises in assessing potential of poor development areas which have performed well in the past. Such areas in North Robertson are thought to be characterized by good continuity in which the waterflood sweep efficiency has been fairly high. Some of these areas were effectively drained on 40- or 20-acre nominal spacing. The future development for these areas, however, is relatively poor because most of the incremental recovery is accelerated oil rather than additional or incremental recovery. Only through reservoir characterization and studies can these areas be identified and avoided.

Project Continuation: We plan to drill and complete 18 new infill wells comprised of producers and injectors during Budget Period II in areas of the Unit which appear to have good 10-acre infill potential (Sections 362, 329, and 327) as shown in **Fig. 1**.

Phased Program

The drilling of the eighteen wells in the Field Demonstration will be implemented in a two phase program which consists of eleven wells in Phase I followed by seven wells in Phase II. The phased implementation will allow flexibility in geologically targeting the final seven wells in the Field Demonstration based on the performance and data obtained from the first eleven wells. The specific areas in which the Phase I wells will be drilled are shown in **Figs. 2, 3**. The flexibility and options available to drill the final seven wells in Sections 329 and 327 are shown in **Fig. 3**. The development in Section 362 consists of only one well to be drilled during Phase I.

Maintaining some flexibility in the final configuration of the well placement for the Field Demonstration is important because we recognize that there are uncertainties in our evaluation tools and methodologies such as reservoir modelling and interpretative geology. We feel that independent producers, who are one of the key targets in the DOE Class II Program for transferring the technologies and approaches used in the project and Field Demonstration, would also want to maintain flexibility when drilling a relatively large infill drilling program such as North Robertson which consists of eighteen wells. All of the options available to us for the second phase of the Field Demonstration have been studied with reservoir simulation models. Early performance data from the first 10 wells to be drilled in Phase I in Sections 329 and 327 will allow for an early first pass validation of the models and reservoir description projected for these areas. Core and other data will also be taken in Phase I. This will be useful for confirming the results of our reservoir quality studies, and to better define interwell continuity within the Unit. Final selection of the seven Phase 2 well locations which are directly adjacent to the Phase I areas will then be made.

Reserves

Our analysis indicates that this project will recover approximately 2.2 Million Barrels of additional oil over a 20-year period. These reserves and associated economics are sufficient to warrant implementation of the Field Demonstration during Budget Period II. We believe that other operators which utilize the advanced recovery technologies employed in this project would follow a similar course of action.

The reserves expected in each of the areas of the Field Demonstration are as follows:

Area	Total No. Wells, Phase I & II	Estimated Reserves, (MBO) Per Well	Estimated Reserves, (MBO) For Area
High Potential Areas:			
Section 362	1	150	150
Section 329	9	130	1,140
Moderate Potential Area:			
Section 327	8	115	920
Total/Average	18	123	2,210

Specific Locations

The locations for the Phase I and II wells in each of the Field Demonstration areas are described below:

Section 362: A single producing well will be drilled in an undrained, approximately 20-acre well location area surrounded by expected banked oil from 3 injectors as shown in **Fig. 4.** By drilling this well we expect to demonstrate how to increase production in areas where there has been incomplete pattern development in the past. Geologically targeted infill drilling opportunities on a single well basis such as this exist in many shallow-shelf carbonate reservoirs in the Permian Basin. These opportunities can be identified by other operators by utilizing historical performance studies, pattern balance analyses, or by applying advanced characterization tools such as material balance decline type curve analysis. We identified this location for the Field Demonstration by using these specific technologies. The geological reservoir characterization and other performance analyses also supported this development approach for the Section 362 well location.

Section 329: The Phase I program in this area consists of drilling a line-drive pattern where one injector and 4 producers are drilled (See **Figs. 5-8**). Both geostatistical and deterministic reservoir simulation models (encompassing 320 surface acres) were completed in this area of Section 329. These results, along with performance analysis and geological knowledge support the Phase I area as one of relatively low risk and high reward.

There are many options available for drilling three additional wells in Phase II drilling for the Section 329 area. Some of these outcomes are shown in **Figs. 5-8** and discussed below.

<u>Scenario A</u> is shown in **Fig. 5** and entails extension of the Phase I line-drive to the central section of Section 329. This is a relatively low risk approach which completes another pattern in the direct line-drive development scheme by drilling an additional injector and two producers. The advantage of this approach is that "smaller", lower risk reserves in the Section 329 areas can be captured. The disadvantage is that implementing this scenario in Phase II will not allow us to evaluate the higher risk, higher reward possibilities which exist directly to the east of the Phase I wells as shown in **Fig. 6** and discussed next as Scenario B.

<u>Scenario B</u> **(Fig. 6)** entails drilling one injector, one conversion of an existing producer to injection, and drilling three new producers. The simulation results and other analyses indicate potential for higher reward than Scenario A but the geological risks are expected to be greater due to the lack of abundant data on the edge of the Unit. The conversion is necessary to add needed injection support in the northeast area of Section 329 in which sweep efficiency is felt to be rather low in the existing waterflood configuration since it is lacking injection support because of its proximity to the lease line. Recognizing that injection support could also be beneficial in other areas of Section 329 led to development of two additional development scenarios for Phase II (Scenarios C and D).

<u>Scenarios C and D</u>, shown in **Fig. 7 and 8** respectively, focus on adding anticipated needed injection in various areas of Section 329. These areas are adjacent to the Phase I development area. Core obtained during the Phase I drilling will be analyzed and the resulting interwell continuity study will allow us to make a more informed decision on whether or not we should pursue the development schemes shown in these infill drilling scenarios.

Additional infill drilling scenarios which are variations of the ones described above, or ones which entail some other locations near the Phase I wells, are possible and will continue to be evaluated for Phase II drilling as we obtain results from the Phase I performance and data. acquisition programs. An informed choice, weighing the risks and rewards for the Phase II wells in the Section 329 area will then be made. Refinements will continue to be made to the models and to other characterization tools available to us when picking one of the scenarios or variations thereof for the final selection of Phase II wells.

Section 326/327: It is important that areas other than just the high potential areas be included in the Field Demonstration so that the characterization completed in Budget Period I can be validated in parts of the reservoir where different factors are at play in the subsurface geology and areas where different dynamic forces impacting the waterflood performance exist. It is for these reasons that this area of moderate potential for geologically targeted infill drilling was selected.

We recognize that this is not the very best area of the Unit available to us with regard to geologically driven reservoir quality estimates, however, reducing nominal well spacing to 20-acres during the previous infill program resulted in a substantial reserves addition in this area due to previously uncontacted oil. Future operations in this area of the Unit have been considered more on the basis of historical performance, decline curve analysis, and reservoir surveillance activities. The reservoir rock in this area is of lower quality compared to that found in Section 329, but is more homogeneous. It is important to note that this area of moderate potential is economic at North Robertson and would also be economic in fields for other operators including independents. In addition, not all operators will have geologically-driven targets which are characterized as high potential areas. In this case, operators would be left to evaluate and pursue opportunities on the basis of previous production performance and engineering calculations.

Fig. 9 shows the detail of the Phase I and available Phase II development areas for Section 327 area wells in the Field Demonstration. As in Section 329, Phase I entails drilling of one injector and four producers in a direct line-drive configuration. All of the three potential Phase II areas involve extending the line-drive pattern either in a north/south direction or directly west of the Phase I wells. The model results indicate some quantifiable differences in the three different options for Phase II. Our judgment, however, is that the simulation reservoir description may not capture all of the heterogeneity and compartmentalization present in this complex reservoir. For this reason, we do not want to rely on simulation alone in prematurely selecting all the locations for the Section 327 area. It is prudent to leave flexibility in selection of some locations and base these locations on results from the first five wells. Thus, a phased development plan was developed for Section 327. The options for Phase II drilling in Section 327 are somewhat simpler than Section 329 since we are not on the periphery of the Unit, and do not need to consider the need for injection support on "boundary wells."

Summary on Selection of Well Locations

We have used all the information from the geological, engineering, and reservoir performance areas to geologically target the Field Demonstration well locations. We recognize that simulation is a good tool for targeting wells but like any tool its limitations, as well as strong points, must be considered. Constructive discussion of the simulation studies and their input parameters was a high priority for the project team. Significant judgment using all the collective knowledge was applied to the final decisions for the Field Demonstration plan.

For SSC reservoirs, reservoir heterogeneity and compartmentalization is a day to day reality which impacts operators' field operations and subsequent well performance, and may result in "untapped" oil. We have focused on utilizing reservoir characterization tools and techniques which allow us to better deal with this producibility problem. With respect to reservoir simulation, especially deterministic modelling which cannot capture this heterogeneity and compartmentalization, -- we recognize that results from these conventional simulations predict more acceleration rather than the additional recovery which may actually exist and be closer to "reality." We believe our efforts in geostatistical reservoir description and flow simulation can improve on the shortcomings of conventional simulation. The validation exercise in Budget Period II will allow us to determine the value of geostatistics in quantifying future reservoir performance.

<u>Details of Budget Period I Activities</u>:

These details are included in the remaining sections of this Topical Report. The activities include reservoir analysis and characterization (geological analysis, cross-borehole tomography, fluid properties validation, and reservoir performance analysis), integrated reservoir description, integrated reservoir management, geostatistical analysis, reservoir simulation, economic evaluation, and technology transfer.

Technology Transfer Workshops: The first Technology Transfer workshop is scheduled to be held in Midland, Texas on April 25-26, 1996. Another workshop will be scheduled during 2nd Quarter, 1996 in Houston, Texas. It is expected that based on the experience of these first two workshops, at least one more workshop will be held at a yet undecided location during Budget Period II. The "technology transfer packages" are designed to describe the results and methodologies of the project and will be distributed as part of the workshops.

The workshop agenda is a one and one half day format. The first day will cover an introduction to the project, historical perspective, geology, and geophysics. This will be followed by detailed discussions of reservoir performance analysis and reservoir surveillance and monitoring activities in the previously defined reservoir management areas. The second day would focus on geostatistics and reservoir flow simulation. Information on resource requirements and lessons learned would be emphasized. A panel discussion format will be utilized where appropriate to retain audience enthusiasm and encourage audience participation.

The target audience for the workshops are independent and major operators. The workshop planning will be coordinated with the University of Tulsa Continuing Education Department.

Workplan Deviations, Budget Period I

Deviations from the Statement of Work (SOW) workplan during Budget Period I have been minimal. The reservoir characterization and management analysis and approach was extended to the entire Unit. After consultation with the DOE, only one cross-borehole tomography survey was conducted. These aspects as well as other (minor) deviations are discussed below.

Analysis Expanded to Include Entire Unit: The original intent of the project was to do detailed analysis in three defined Pre-Demonstration Reservoir Management Study Areas (PDSAs) which encompassed about 60% of the Unit. These areas were ultimately expanded to include the entire Unit as it provided much more meaningful interpretations of the geologic models and data, reservoir performance analysis, and geostatistical or deterministic reservoir simulations. We have provided information on a unitwide basis during Budget Period I and will continue to do so during the Field Demonstration.

Cross-Borehole Tomography: A change of scope in the Statement of Work was approved by the DOE in early 1995 for this reservoir characterization task. Originally, three surveys had been planned. Only one survey was conducted due to operational difficulties, excessive costs, and poor cost/benefit ratio. Further, for the technology to be effective, several surveys would have been needed. Due to high costs, we felt that additional work would have resulted in substantial cost overruns with minimal benefit to the project.

Project Management and Administration: Technical Committee meetings have been held on approximately a 6-9 month basis to review progress with DOE and Fina management. We have found that this is about the right frequency versus the planned quarterly frequency. Work meetings with team members have been very frequent, on anywhere from a 2-6 week basis. Management Committee Meetings have not been held on a formal basis. Issues and questions have been addressed on an as needed basis due to close, effective, and open communication between team members, project personnel, and groups within Fina. Accounting procedures implemented at Fina have been extremely effective for monitoring the financial aspects of the project.

Integrated Reservoir Management: Pressure fall off tests on injection wells were planned for all injectors within the PDSAs. To date only 12 have been run. Due to the low permeability of the reservoir it was found that excessive falloff periods were required to fully consider major portions of the reservoir surrounding individual injection wells (i.e., boundary effects). Additional pressure falloff tests will be conducted on injectors as workovers are performed. Additional data has been obtained with the pressure buildup test program for monitoring reservoir performance. A good "baseline" data set has been acquired across the Unit to be used for monitoring reservoir pressure maintenance and injection/production efficiency with future surveillance work. These activities are detailed in the "Reservoir Surveillance" section of this document.

Budget Period II Workplan

During the second Budget Period, the recommendations for geologically targeted infill drilling will be implemented, new data collected, and reservoir performance monitored. The new data and observed performance will be critically evaluated to determine the validity of the predictions and conclusions of the first Budget Period. Technology transfer is also a critical component of the second Budget Period.

Specific activities during the Field Demonstration, Budget Period II are included below. The second Budget Period is scheduled to last 39 months beginning March 13, 1996 and ending June 12, 1999. A summary of the specific activities are:

- **Implement the Field Demonstration:** Drill a total of 18 infill wells and convert up to 16 wells to injection. Obtain 3,600 feet of core, well log, pressure transient, and additional well test data in the new infill wells. Make all tie-ins to gathering and injection system for all new and converted wells.

- **Integrated Reservoir Management Program, Field Operations and Surveillance:** Performance of all wells in the Field Demonstration areas will be closely monitored. Reservoir surveillance and data acquisition programs will continue with follow up surveys recorded on new wells and in the areas of the previous surveillance surveys. Specific focus on analysis will include considering injection volumes and pressures, production volumes, fluid sampling, production logging, and pressure transient testing. The effectiveness of the waterflood in the infill areas will be evaluated.

- **Integration and Validation:** The validation activities are a very important aspect of Budget Period II. All of the data acquired during the Field Demonstration, along with the data and analysis from the first Budget Period, will be integrated and analyzed. One goal of this effort is to evaluate the validity of the analyses performed during Budget Period I. This effort will first involve validation of the reservoir characterization. A large part of this effort will be integration of the analyses from the newly acquired core and from the special core analysis. Another important aspect of this effort will be validation of the reservoir management and reservoir performance analysis activities such as material balance decline type curve analysis. As during Budget Period I, geostatistics and reservoir simulation will also complement the geological and reservoir performance analysis efforts. The geostatistical and deterministic reservoir simulation models will be revised and continually updated to monitor performance. One goal will be to use reservoir simulation as an operational tool so that we can be proactive to operational and reservoir issues as they arise in the field.

- **Technology Transfer:** For Budget Period II, we will build upon our knowledge from the first Budget Period. This knowledge in the areas of reservoir characterization and reservoir management for shallow-shelf carbonates (SSC) reservoirs, with the Clearfork in particular, will be refined. The experience of the Field Demonstration will validate this knowledge. More insight into the cost/benefit relationship of various approaches and technologies will be developed. This information will be extremely helpful to the industry and will be conveyed using the same technology transfer components used during Budget Period I. These components include technology transfer workshops, publications, newsletters, and report writing.

PROJECT REVIEW

INTRODUCTION

In this project, we are demonstrating that infill drilling of wells on a uniform spacing, without regard to reservoir performance and characterization, must become a process of the past. Such efforts do not optimize reservoir development as they fail to account for the complex nature of reservoir heterogeneities present in many low permeability reservoirs, and carbonate reservoirs in particular. These reservoirs are typically characterized by:

- Large, discontinuous pay intervals
- Vertical and lateral changes in reservoir properties
- Low reservoir energy
- High residual oil saturation
- Low recovery efficiency

The operational problems we encounter in these types of reservoirs include:

- Poor or inadequate completions and stimulations
- Early water breakthrough
- Poor reservoir sweep efficiency in contacting oil throughout the reservoir as well as in the near-well regions
- Channeling of injected fluids due to preferential fracturing caused by excessive injection rates
- Limited data availability and poor data quality

Infill drilling operations only need target areas of the reservoir which will be economically successful. If the most productive areas of a reservoir can be accurately identified by combining the results of geological, petrophysical, reservoir performance, and pressure transient analyses, then this "integrated" approach can be used to optimize reservoir performance during secondary and tertiary recovery operations without resorting to "blanket" infill drilling methods.

New and emerging technologies such as cross-borehole tomography, geostatistical modelling, and rigorous decline type curve analysis have been used in an attempt to quantify reservoir quality and the degree of interwell communication. These results were used to develop 3-D simulation models for prediction of infill locations. The application of reservoir surveillance techniques to identify additional reservoir "pay" zones, and to monitor pressure and preferential fluid movement in the reservoir is demonstrated. These techniques are: long-term production and injection data analysis, pressure transient analysis, and advanced open- and cased-hole well log analysis.

A significant contribution of this project is to demonstrate the use of cost effective reservoir characterization and management tools that will be helpful to both independent and major operators for the optimal development of heterogeneous, low permeability carbonate reservoirs such as the North Robertson (Clearfork) Unit. The techniques that are outlined for the formulation of an integrated reservoir description apply to all oil and gas reservoirs, but are specifically tailored for use in the heterogeneous, low permeability carbonate reservoirs of West Texas.

Conclusions and observations which can be drawn from the project to date are:

<u>Geological Reservoir Characterization, Importance of Core</u>: It is possible to perform a detailed characterization of the reservoir, even with a limited quantity of core data. Elements of a successful characterization include: 1) development of competent environments of deposition and a sequence stratigraphic model; 2) rock type constrained core-measured porosity versus permeability relationships; 3) sufficient modern wireline log data; and 4) adequate historical production data. *It is important to emphasize that core data and observations are the key* to calibrating the wireline log data, thereby allowing one to generate and then test a "rock-log" model. The model can be used to calculate permeability values from wireline log calculated porosities in areas of the reservoir with insufficient core measured permeability values.

<u>Relative Permeability Measurements & Special Core Analysis (SCAL)</u>: Due to the importance of special core data for reservoir flow simulation, the acquisition of additional data during the infill drilling process is of paramount importance. These data are required for reservoir description as well as for predicting the future performance of an infill drilling program. Core imaging technologies will play an important role in the program so that the section of core upon which costly SCAL tests are to be performed can be appropriately screened. To ensure that quality data are obtained, a quality control program will need to be an integral part of the SCAL program.

<u>Cross-Borehole Tomography</u>: Due to the problems associated with the utilization of older boreholes for recording interwell surveys, the level of heterogeneity in the Glorieta/Clearfork section, and low benefit-cost ratio for this particular Unit, it was determined that the use of cross-

borehole tomography as a reservoir characterization tool is not a cost-effective technology at the NRU. Improvements made to new generations of downhole tools currently being developed by tomographic service companies may offer future opportunities to obtain data of sufficient resolution for integrated reservoir description.

<u>Material Balance Decline Type Curve Techniques</u>: This approach gives excellent estimates of contacted reservoir volumes (total and movable), and reasonable estimates of formation flow characteristics. Using this method to analyze and interpret long-term production data is relatively straightforward and can provide the same information as conventional pressure transient tests, without the associated cost of data acquisition, or loss of production. The results have been used together with the geologic analysis to identify the optimum locations for 10-acre infill wells, and to calibrate the reservoir simulation models with respect to contacted oil-in-place.

<u>Waterflood Type Curve Analysis</u>: Type curve techniques similar to those currently used in decline type curve and pressure transient analysis are currently being used to provide additional tools for the diagnosis of individual injection well problems and for monitoring long-term waterflood efficiency.

<u>Producibility Problems</u>: Problems at North Robertson are similar to those associated with the majority of heterogeneous, low permeability carbonate reservoirs -- a lack of reservoir continuity, and low waterflood sweep efficiency due to early water breakthrough, water channeling, poor injector-producer conformance, and scaling and pore plugging problems. Many of these problems may be remediated through the use of conformance studies and vigilant injection water quality and reservoir surveillance programs.

<u>Reservoir Surveillance</u>: Surface pressure acquisition during pressure falloff tests yields data of sufficient quality for interpretation, even when low precision pressure gauges are utilized. This is an efficient and cost-effective waterflood surveillance tool. Pressure buildup surveys have been combined with the results of the pressure falloffs and the cased-hole logging program to build a "baseline" data set for future reservoir surveillance programs.

<u>Fracture Direction, Communication, and Quality</u>: The results of the previous hydraulic fracture treatments on producing wells at the NRU have been relatively poor, resulting in extremely short, low conductivity fractures. New completion and stimulations designs will be implemented to improve completion efficiency and optimize the hydraulic fracturing procedures. New injection wells will be completed and stimulated differently than producing wells in order to by-pass high permeability zones that may become "thief" zones. Several of the current injection wells are in communication via hydraulically induced fractures resulting from long-term injection at pressures well above the fracture pressure of the reservoir.

<u>Water Quality Monitoring</u>: Injection water quality is one of the critical components in the implementation of a successful waterflood. Unfortunately, a surveillance program set up to continuously monitor injection water quality is still not considered a major part of many operator's waterflood surveillance programs. A cost-effective surveillance program was initiated

at the NRU to identify and resolve potential water quality problems. At the same time, an injection well workover program was implemented to remediate the scaling problems in individual wells.

Geostatistics: Geostatistics proved to be a valuable tool in developing a reservoir description which is consistent with the underlying geology, petrophysical data, and oil-in-place calculations based on material balance techniques. We were able to generate detailed reservoir descriptions which can be qualitatively evaluated in order to understand the relative continuity of point data (well logs) across the reservoir. The validation work performed during Budget Period II will provide valuable insights on the value of geostatistical techniques in predicting future reservoir performance. The development of a geostatistical reservoir description is both time and computationally intensive. These factors must be considered when assessing the cost/benefit relationship for a geostatistically based approach.

Reservoir Flow Simulation: Using both conventional and geostatistical 3-D reservoir simulation models for history matching, defining infill drilling locations, and developing production forecasts provided valuable insights into the geologic targeting of infill wells. Conventional reservoir description methods for flow simulation, have limitations in that the true heterogeneity present in many SSC reservoirs will not be captured. This "layer cake" treatment of the reservoir may result in future projections which show reserves acceleration rather than the additional recovery of bypassed incremental reserves. It is important to understand the limitations of conventional simulation when analyzing the results of this approach, however, it should also be noted that conventional simulation can be accomplished in a more time-efficient manner, which is a major concern for most operators. By comparing the results of the two simulation approaches we can better quantify the uncertainties in predicting future performance, and by comparing the results of these two simulation methods we can target infill well locations with more certainty.

Infill Well Economics: Geologically targeted drilling can capture reserves for nearly half the cost of a blanket drilling program. For SSC reservoirs which are relatively deep, such as North Robertson (7,200 feet), blanket drilling would not generate acceptable economics for most, if not all operators. The geologic targeting process offers tremendous promise in realizing the goals of the National Energy Strategy by offering an economic alternative that will aid the development of the nation's oil resources.

Data Acquisition and Analysis: The analyses performed to date have reinforced the requirement for early and in-depth data acquisition programs. The lack of complete and accurate early reservoir data will obviously make a rigorous reservoir characterization project much more difficult. During Budget Period II, data acquisition programs are in place to gather information for the verification and optimization of the geological and rock-log models, special core measurements, degree of interwell continuity, reservoir directional flow and pressure trends, and completion and stimulation treatments.

HISTORICAL BACKGROUND

The North Robertson (Clearfork) Unit (NRU) is located in Gaines County, Texas on the northern edge of the Central Basin Platform of the Permian Basin (**Fig. 10**). The producing horizons are the Glorieta and Clearfork Formations (referred to as the upper, middle, and lower Clearfork), which are Permian Age, Leonardian Series carbonates. The hydrocarbon bearing interval extends from the top of the Glorieta to the base of the lower Clearfork, between the correlative depths of approximately 5,870-7,440 feet. The NRU project area of 5,633 acres contained a total of 252 wells as of March, 1996. This included 142 active producing wells, 109 active injection wells, and 1 water supply well.

Development and Production History

Production from the North Robertson field area began in the early 1950s with 40-acre primary well development. This 40-acre primary development resulted in 141 producing wells by 1965. The NRU was formed effective March, 1987 for the purpose of implementing waterflood and infill drilling operations to reduce nominal well spacing from 40 acres to 20 acres. At the time of unitization, oil production from the Unit area was approximately 670 STBO/D, with a GOR of 1,550 scf/STB, and water production of 500 BW/D. Secondary recovery operations were initiated after unitization and in conjunction with infill drilling. Most of the 20-acre infill drilling was completed between unitization and the end of 1991.

The cumulative produced and injected fluid volumes are summarized below. **Fig. 11** shows the production and injection history of the Unit from development in 1956 through March, 1996.

	Cumulative Oil Produced (MMSTB)	***Cumulative Water Produced*** (MMBW)	***Cumulative Water Injected*** (MMBW)
As of 1987	17.52	8.22	0.00
1987-1996	9.14	27.38	62.98

At the time of unitization, the estimated ultimate recovery (EUR) for primary production was 20.5 MMSTBO, and the secondary to primary recovery ratio was estimated to be approximately 1:1. The current waterflood utilizes a 40-acre 5-spot pattern type with 20-acre nominal well spacing. Current Unit production rates are approximately 2,850 STBO/D, 1,080 MCF/D, and 12,900 BW/D. The total water injection volume is approximately 18,000 BWI/D, with injection water comprised of both produced water and fresh water from the Ogallala aquifer obtained from a water supply well within the Unit.

GEOLOGICAL/PETROPHYSICAL STUDY

Summary

Depositional, environmental, and sequence stratigraphic models[1,2] were constructed for the Glorieta and Clearfork Formations on the basis of both macroscopic (visual) and microscopic (petrographic thin section and scanning electron microscope) data obtained from observations and analyses of available whole core within the Unit. Ten distinct lithofacies were defined, assigned an environment of deposition, and incorporated into 3-D sequence stratigraphic models.

The diagenetic history of the Glorieta and Clearfork reservoirs was determined using thin sections and scanning electron microscope (SEM) data. This work indicates that pore geometry and, thus, reservoir quality variations within these rocks are largely the result of diagenetic overprinting (post-depositional alteration) of the original rock fabric. The most important diagenetic factors affecting these rocks include: 1) the nature and extent of cementation (primarily by calcite in limestones and by secondary anhydrite in dolostones); 2) post-depositional leaching of chemically unstable grains, resulting in varying amounts of secondary dissolution porosity; and 3) the timing and duration of dolomitization (largely controlling crystal size in dolostones and, thus, intercrystalline pore size -- an important characteristic controlling matrix permeability).

Quantitative analyses of pore structures were performed primarily by computer image processing of polished thin sections, and augmented with point count analysis of thin sections and epoxy pore casts with a SEM. This analysis led to the definition of seven different pore types. Rock types were then defined on the basis of characteristic pore type distributions.

Porosity-permeability relationships for each wireline log calculated rock type were established and used to identify the intervals with acceptable reservoir quality. The distribution of rock types in individual wells has been calculated and was used to generate a variety of interwell reservoir quality maps such as, but not limited to, interval *kh*, interval *Øh*, and interval percent rock type.

A GPS (Global Positioning System) survey was performed by Land Topographic Surveyors of Midland, Texas to verify the position of all surface well locations relative to one another. The survey was low cost, rapid (two days survey time), and accurate (guaranteed to ±1.5 meters). The survey verified that most of the surface locations as represented on the "old" base maps were correct. However, approximately 10% of the surface locations were incorrectly spotted with errors ranging from 50-500 feet in magnitude. Very few of these errors (none of the significant errors) are within the proposed infill drilling areas. Corrected surface well locations have been revised on the computer-generated version of the Unit base map.

A water injection-to-oil production conformance analysis was recently performed by constructing interval perforation, temperature survey, and injection profile survey maps across the entire Unit. Additionally, selected cross-sections were constructed to clarify conformance improvement opportunities.

Information and insight gained from <u>all</u> aspects of the above mentioned geological study were used to check the correctness of the rock-log model generated *kh*, *Øh*, and rock type values. These geologically generated *kh*, *Øh*, and rock type values were then entered into both the deterministic and geostatistical 3-D reservoir simulation models.

Depositional Environments and Sequence Stratigraphy

The interpretations for depositional environments and sequence stratigraphy have been derived primarily from qualitative descriptions and thin-section studies of the whole core samples. The results for the Clearfork and Glorieta formations are as follows:

- Highstand Lithofacies Tracts
  - supratidal exposed
  - small isolated vegetation covered nearshore islands
  - intertidal and channelized tidal flats
  - lagoons
  - shoal water banks / sand belts
  - forebank

- Transgressive Lithofacies Tracts
  - forebank
  - reef
  - shallow basinal

- Low Stand Lithofacies Tracts
  - continental deposits

The lower Clearfork, which is defined as the portion of the Clearfork Formation directly overlain by the Tubb Formation (silty dolostone interval), was deposited primarily in open marine-shelfal conditions and is dominated by grainstones that are thought to have developed in shallow water shoaling environments. The shoaling areas may have coalesced and interfingered with one another thereby resulting in more or less continuous belts (current and wave-dominated) of grainstone deposits with allochems composed primarily of fusulinids, ooids, oncoids, skeletals, and peloids. Intershoal regions exist laterally to grainstone shoals, and rocks from these intershoal areas contain greater amounts of muddy carbonate material and correspondingly less amounts of allochem material. Only minor amounts of shallow subtidal algal mat rocks were observed in the lower Clearfork. A study of historical production data using contour maps of reservoir performance suggests that many of the outer shelf grainstone reservoirs are in communication with one another and the amount of compartmentalization and heterogeneity may not be as pronounced as in the middle Clearfork, upper Clearfork, and Glorieta (which overly the Tubb Marker).

The upper/middle Clearfork and Glorieta sequences are typified by highstand lithofacies characterized by highly cyclic depositional environments consisting of inner shelfal subtidal flats, small isolated vegetation that covered nearshore islands, restricted and open lagoons, and tidal flats which are channelized, intertidal or supratidal. The lower portion of the middle Clearfork, which immediately overlies the Tubb marker, is an exception in that it is characterized by a transgressive lithofacies tract (approximately 150 to 250 feet thick). Within this interval, there is evidence of reef development represented in the core as non-porous, mottled boundstones that contain sponge, algae, coral, and bryozoan fragments. Analysis of historical well performance data suggests that most of the dolostone rocks that characterize these reef depositional environments have generally poorer reservoir parameters. Porosity and permeability are reduced because these dolostones tend to be mud rich and anhydritic. However, the debris apron surrounding these reefs can have good reservoir quality, such as may be the case in the southwestern region of the Unit. Open lagoon rocks occur as widespread, thick areas of burrowed, porous and permeable deposits. They are a significant portion of the reservoir in selected locations within the NRU. Although not as prevalent and well developed in the upper/middle Clearfork and Glorieta, grainstone shoals also comprise a significant portion of the reservoir quality rock. In general, the middle/upper Clearfork and Glorieta were deposited in more cyclical environments, and as a result the rocks display a high degree of compartmentalization, heterogeneity, and numerous variations in petrophysical properties both vertically and laterally. This degree of heterogeneity generally increases upward within the entire stratigraphic section and within each major carbonate cycle, reflecting the overall west to east progradational nature of the upper/middle Clearfork and Glorieta.

The best quality reservoir rocks are generally dolomitized ooid or skeletal grainstones that were deposited in shoaling depositional environments. These rocks contain abundant and uniformly distributed omoldic, biomoldic, and intercrystalline porosity with good to excellent permeability. Open lagoonal dolostones also make up an important portion of the reservoir interval. They have moderate porosity and permeability values, are thick and widespread, and represent a significant portion of the total rock volume.

Diagenesis

The most probable diagenetic history for the Glorieta/Clearfork formations[2] and the diagenetic processes affecting the formation of the different rock types are shown in **Figs. 12-13.** Moldic porosity has been attributed to skeletal and grain dissolution by post-depositional leaching. This has taken place during periods of subaerial exposure. Dolomite crystals have also been leached resulting in the development of intercrystalline porosity. Periods of leaching and dissolution are probably related to sea level fluctuations and predate diagenetic dolomitization.

Most of the dolomitization may be explained by neomorphozation of syndepositional aragonite (high-magnesium calcite) cement which lined fenestral pores. The fenestral fabric is representative of supratidal and intertidal facies. The calcite cement was subsequently dolomitized. Reflux dolomitization probably played a significant role in the dolomitizing process of converting the shelf edge wackestones to grainstones.

Pore Geometry

Reservoir quality and continuity are dominated by variations in pore geometry.[3] Reservoir rocks having equal values of total porosity may have significantly different permeability, relative permeability, and irreducible fluid saturation characteristics. These discrepancies are a result of changes in pore structure caused by variations in pore type, size, and throat size.[4] Extreme variation in pore geometry is characteristic of heterogeneous, low permeability carbonate formations such as the Clearfork/Glorieta sequence.

Pore types were quantitatively defined[1,2] from the available core using pore cast studies and scanning electron microscope (SEM) image analysis on the basis of:

- Pore body size and shape measurement
  - Pore size
  - Pore shape factor = [perimeter^2/(4π*Area)]
  - Length to width ratio
- Pore throat measurement
  - Coordination number = [# pore throats/pore]
  - Aspect ratio = [pore size/pore throat size]

- Matrix/pore arrangement and interconnection in two and three dimensions

Pore geometries are classified by shape as triangular, irregular, polyhedral, and tetrahedral. Primary interparticle porosity has triangular pores, and the vuggy porosity is described as being irregular (and sometimes elongated). The triangular pores are generally well interconnected and are typical of the grainstone reservoir facies. The irregular pores are typical of dissolution porosity and although porosity values may be high, relative to triangular pores, interconnectivity is usually relatively poor resulting in lower reservoir rock quality.

On the basis of these analyses, seven unique pore types were identified for use in rock typing. Their characteristics are summarized in **Table 1.**

Core Based Rock Typing

A total of eight rock types have been identified from core examination and core measured data, of which four have reservoir potential (one being limestone and water bearing), and four have barrier potential. Rock types have been identified on the basis of volume proportions of pore types and unique lithological characteristics. The relative volume proportions of each of the seven pore types in each rock type are shown in **Fig. 14.** Median core values for porosity, permeability, and estimated recovery efficiency are presented for each of the eight rock types in **Table 2.** Recovery efficiency was estimated using methods outlined by Wardlaw and Cassan[5] on the basis of the pore arrangement, coordination number, and aspect ratio. Low aspect ratios and high coordination numbers typically result in good reservoir sweep efficiency. Rock types 1 and 2 make up the primary reservoir "pay" intervals at the NRU. These rock types consist of coarsely crystalline dolostones that differ in terms of their pore size and geometries. These rocks generally correspond to subtidal sandflats, grainstone shoals, and open shelf depositional environments. Rock types 3 and 4 may be productive in certain areas, but for the most part, they are considered non-reservoir rock. These rocks are finely crystalline dolostones that have different pore geometries and usually correspond to supratidal, tidal flat, and restricted lagoon depositional environments. Rock type 5 is limestone and water-bearing.

The highest quality reservoir rocks are typically associated with rock type 1, which consists primarily of grainstones. The coordination numbers and aspect ratios for rock type 1 are less favorable than for the other reservoir quality rock types (2, 3, and 5), however, pore interconnectibility is much more favorable, resulting in good fluid flow potential. The less favorable reservoir rock types have generally low coordination numbers and high aspect ratios reflecting relatively poor fluid flow potential.

The non-reservoir rock types (rock types 6, 7, and 8) are essentially impermeable and can be considered to be vertical flow barriers. The presence of these rock types is a significant factor in the level of reservoir heterogeneity and compartmentalization. Knowledge of the distribution of these non-reservoir rock types is essential to the successful implementation and operation of secondary and tertiary recovery programs.

Irregular porosity and permeability distribution in the Glorieta/Clearfork results in poor reservoir continuity and, therefore, poor sweep efficiency during waterflooding operations. These same characteristics suggest that infill drilling on a reduced spacing and a vigilant reservoir surveillance program are required to optimally deplete this reservoir.

Wireline Log Based Rock-Log Model

In a very general sense the wireline log based rock-log model is a series of crossplots that calculate permeability values from wireline log calculated porosity values. These crossplots are calibrated to core observed rock types and core measured porosity versus permeability relationships. It is essential to generate such a wireline log based rock-log model, because only a limited number of wells in the NRU have core measured permeability values for the Glorieta/Clearfork Formations.

The rock-log model was formulated to take advantage of the large amount of modern well log data (120 wells) that was available due to the completion of a 20-acre post-unitization infill drilling program between 1987 and 1991. These modern well log suites allow for a more comprehensive evaluation of formation properties than would be possible using older porosity and resistivity well log suites.

This rock-log model[1,2] requires the following modern wireline logs:

- Gamma ray (GR)
- Photoelectric capture cross-section (PE)
- Compensated neutron (CNL ϕ)
- Compensated formation density (ρ_b)
- Dual Laterolog (LLD and LLS - deep/shallow resistivities)
- Borehole caliper

The wireline log data has been corrected for wellbore environment, normalized to the core porosity and the mean porosity across the interval of interest (when required), and depth shifted. Sonic and Micro-laterologs would have been extremely useful in isolating the highest quality reservoir rock types, however, these well logs were run with insufficient frequency to be used in the analysis. We will attempt to improve upon the existing rock-log model during Budget Period II by recording these additional surveys in a cost-effective manner on the 10-acre infill wells.

The wells drilled prior to unitization do not have the requisite well log suites required to use the rock-log model. However, since there is usually an abundance of older wireline log data for many older properties, such as the North Robertson Unit, it is noted that these well logs would be sufficient to formulate a competent rock-log model if the well log data are properly interpreted.

There is no simple, direct relationship between core porosity and core permeability (**Fig. 15**). However, when the data were segregated by core observed rock types, the relationship between porosity and permeability became fairly unique. Linear relations were utilized to define these core measured permeability versus core measured porosity relationships for individual core observed rock types, as shown in **Fig. 16**.

It was necessary to develop a process for estimating core observed rock types from petrophysical (wireline log) parameters. This task was accomplished by first crossplotting apparent matrix grain density, ρ_{maa}, versus the apparent matrix volumetric cross section, U_{maa}, which adequately segregated petrophysical rock types 5, 6, 7, and 8 (**Fig. 17**). The lithology of petrophysical rock types 5-8 closely matches the lithology of core observed rock types 5-8. To segregate the remaining four rock types, Pickett plots of deep resistivity versus crossplot dolomite porosity were utilized, as shown in **Fig. 18**. Rock types 3 and 4 were segregated on the basis of their shallow resistivity response. There is a reasonable match between the lithology of petrophysical rock types 1-4 and the core observed rock types 1-4. We conclude that the wireline log based rock typing process reasonably reflects the rock types observed in the cores.

Foot-by-foot permeability values were estimated from wireline log calculated porosity values utilizing the core based porosity versus permeability relationships for the applicable rock type. We tested the accuracy of the model by crossplotting calculated permeabilities versus core measured permeabilities. Results were mixed (correlation coefficients between 0.6 and 0.8), but we deem the model results acceptable. The model reflects the general trend of permeability values from core (where core measured permeabilities are high, the rock-log model predicts high values of permeability, etc.). The model worked best for rock type 1, which is the best quality reservoir rock type. Also in a very general sense, the model did a better job of predicting areas of high permeability than it did for areas of low permeability. We will work on improving the model's error rate during Budget Period II by utilizing the additional core data obtained from the Field Demonstration phase of the project.

The intrawell rock type, porosity, and permeability data were then extended on an interwell basis using geostatistical simulation, and reservoir quality maps (*kh*, *Øh*, and rock type) were generated.

Special Core Analysis

Representative rock-fluid interaction data are required to accurately model reservoir flow conditions. The available capillary pressure and relative permeability data sets will be augmented with additional data from proposed infill wells during Budget Period II. The initial analyses have helped identify which rock types will be important with regard to reservoir producing mechanisms, as well as the rock types that will act as barriers to fluid flow. This data was used as initial input data for reservoir simulation, as well as being a guide for future data acquisition.

Relative Permeability Measurements

Oil-water relative permeability data were available on twelve core samples from a single well in the Unit (NRU 3522). These data also confirm that rock types 1 and 2 are the primary pay rocks in the reservoir. From the limited data available, rock type 1 has a comparatively lower irreducible water saturation, however, the residual oil saturation appears to be extremely high. The planned acquisition and analysis of additional data during the 10-acre infill drilling program during Budget Period II will give us the opportunity to further study the wettability and relative permeability characteristics of the various rock types, and to refine our flow simulation work.

Capillary Pressure Measurements

A total of twenty-four core plugs from two wells (NRU 207 and 3522) were used to generate mercury-air capillary pressure curves. These data clearly show significant differences in the displacement characteristics of the reservoir rock types. Although these data are from wells in areas of the Unit with the highest degree of reservoir continuity, we can make some qualitative interpretations regarding reservoir quality and production/injection potential as a function of rock type. Additional capillary pressure measurements will be made on core from the 10-acre infill program to validate currently available data.

Using the methods presented by Thomeer,[6] the data have been interpreted as hyperbolic functions in order to estimate composite averages of pore throat radius, minimum entry pressure, and the relative amount of ineffective porosity (porosity occupied by mercury at injection pressures exceeding 500 psia) for each rock type. The results are summarized in **Table 3**. Rock type 1 is the primary reservoir rock with the largest pore throat radius, the lowest entry pressure, and the least amount of ineffective porosity. Rock types 2 and 5 are moderate quality reservoir rocks, and rock types 3 and 4 appear to have limited reservoir potential due to their smaller pore throat radii and large percentage of ineffective porosity. Rock types 6, 7, and 8 can be characterized as flow barriers in the reservoir.

Flow Unit Delineation

The formulation of a rock-log model provided us with a mechanism to identify particular flow units, which may consist of one or more rock types, and which may be related to their respective depositional environments. It is worth noting that rock types are usually not unique to a particular depositional environment. Flow units are discontinuous and reflect a high degree of reservoir compartmentalization and heterogeneity both laterally and vertically.

The methodology used in the determination of flow units involved the following studies:

- Sedimentologic descriptions of approximately 6,700 feet of whole rock cores from nine wells
- Log analysis to correlate markers, porosity, and other features from all wells
- X-ray diffraction of core samples for mineralogy and quantification of clay mineralogy
- Pore geometry analysis by SEM and pore cast studies

- Special core analysis for the determination of relative permeability and capillary pressure characteristics for each rock type
- Development of a rock-log model to determine porosity and permeability relationships unique to each rock type

The Glorieta/Clearfork Formations (approximately 1,200 feet gross thickness) have been layered into 21 individual "flow" units. Nearly all of these flow units are bounded by potential crossflow barriers that are representative of a supratidal depositional environment (the culmination of a shoaling upward, fifth order cycle ranging from approximately 50 feet to 200 feet in total thickness). These cycles have been identified within the whole cores and in some instances have gamma ray well log responses that are characteristic of various rock types.

These units have an origin related to rapid and frequent eustatic (sea level) changes on a carbonate shelf or platform that was essentially featureless or without any significant topography. Therefore, small sea level changes produced highly cyclic sequences. These parasequences are carbonate dominated with insignificant clastic influences.

There is correspondence between the sediment accommodation indicated by the respective stratigraphic unit isopachs and the distribution(s) of the various reservoir rock types. There is also correspondence between the occurrence of the reservoir rock types and the areas of the Unit exhibiting good historical production and interconnectivity as per the reservoir performance maps (in particular, the distribution of reservoir rock type 1, the most favorable reservoir rock).

Additionally, based on the rock-log model, kh and ϕh maps have been constructed for each stratigraphic unit.[2] There is correspondence between the distribution of the reservoir rocks types, porosity and permeability distribution(s) within the interval isopachs, and the reservoir performance maps.

The results of this work were incorporated within the geostatistical analysis of the reservoir. Areas that have been qualitatively evaluated as very favorable, favorable, and unfavorable for infill drilling have been quantified with flow simulation. This process involved assessing the merits of respective areas of the reservoir for infill drilling on the basis of the relative probability of success: i.e., the qualitative geologic evaluation for relative success of infill drilling was quantified and uneconomic blanket drilling in the less favorable areas of the reservoir will hopefully be eliminated.

Pay Continuity Analysis

The quantification of pay continuity based on 20-acre well log data is in progress. Although reservoir continuity will vary for individual wells depending upon the direction in which the correlations are made, this is still an effective tool for the evaluation of pay continuity, as well as locating the best areas for infill drilling. Three infill 10-acre wells will be cored offset to existing 20-acre cored wells in order to quantify the degree of continuity between wells. By performing these studies we will hopefully eliminate the requirement of estimating how individual rock "packages" may thicken or thin laterally between wells. Prior case studies[7,8] indicate that analysis of the existing 20-acre, and future 10-acre well data will show that the actual reservoir continuity is less than that predicted from 40-acre well analysis, and that by reducing well spacing to 10 acres, a much larger volume of the reservoir will be contacted.

CROSS-BOREHOLE TOMOGRAPHY

The objective of the cross-borehole tomography work was to obtain interwell data concerning the spatial variability of formation properties, reservoir structure, and reservoir heterogeneity. The cross-borehole seismic technique has promise since it provides a mechanism for understanding the physical scale of the interwell vertical and lateral continuity. This geophysical information can be used with geostatistical studies to formulate an integrated reservoir description, and provides an additional method for choosing optimum infill drilling locations, as well as a method for monitoring flood fronts during secondary and tertiary recovery operations.[9]

Reservoir analysis utilizing data from cores and well logs is incomplete since it does not include enough information concerning properties between individual wells. Pressure transient testing only considers portions of the reservoir that are in communication with the wellbore, but will not adequately delineate reservoir heterogeneities and flow barriers.

Cross-borehole seismic data is acquired by physically lowering seismic source and receiver arrays down wellbores via electric wireline and recording waves reflected off reservoir interwell facies that possess varying acoustical impedance properties. The use of cross-borehole seismic results in higher resolution images than are possible using surface seismic since the distances over which the acoustic waves must travel are shorter, resulting in less wave attenuation and allowing for the use of a broader range of bandwidths for interpretation.[10]

Completed Tomography

A cross-well tomography survey using NRU wells 207 and 403 was completed during July, 1994. This particular area was chosen because a fully cored well was available as a control point for data analysis (NRU 207).

Survey parameters used for the completed survey on NRU 207 (Receiver Array) and NRU 403 (Source) were:

- 80 X 80 survey (80 source and 80 receiver positions)
- 800 Hertz, 32 Golay
- Receiver and source spacing of 4 meters (13.1 feet), 1,048 feet vertical distance surveyed
- Interwell spacing of approximately 1,040 feet

Operational Considerations

Approximately half the expenditures on the survey pertained to pre- and post-survey well preparation and repair costs. The planning required to use producing wells for tomographic surveys is much more straightforward (and economic) than for injection wells. In waterfloods such as the NRU, where the producing wells are pumping wells, flowback is generally not a concern. The preparatory work required for producers typically involves just removing the pump, rods, and tubing. Injection wells generally have to be "killed" with mud or salt water to achieve static wellbore conditions for the survey. Post-survey restimulation using acid or other chemicals may be required in order to restore injectivity. This stimulation work on the injector adds significantly to post-survey costs.

In the Permian Basin, typically sour gas (H_2S) conditions exist in reservoirs for which tomographic data would be of interest. Operators contemplating surveys should work with the service company to carefully consider the ability of the tools to withstand sour wellbore conditions. The materials used in the tools must be able to survive normal "live" wellbore conditions, in which gas is likely to be present in wellbore fluids.

Receiver arrays are generally more time consuming to move from well to well than the source tool. For this reason, consideration should be given to minimize well-to-well moves of the receiver array whenever possible in multiple well surveys. In addition, consideration should be given to the amount of wellbore "rathole". In order to perform both tomography and reflection profiling work, there needs to be sufficient rathole so that tool strings can be positioned below the zones of interest to generate seismic waves uphole, as well as downhole.

Service companies offering tomographic services are becoming more aware of the need of operators to minimize pre- and post-survey operational costs. Efforts to reduce tool size and minimize the possibility of tool sticking are also in progress. Service companies have also recognized the need to reduce operational downtime of tools. Only if a significant number of surveys are recorded with the prototype tools to ensure reliability and provide benefits to the operator will survey costs be reduced to the point where tomographic services can become a part of standard reservoir characterization and surveillance operations.

Cross-Borehole Tomography Status

No additional surveys will be conducted at North Robertson. The primary reasons for this are:

Operational Aspects

Operational difficulties have been outlined above. The sour gas environment at NRU is extremely corrosive to the current tomography tools available and destruction of tools is costly. There are also problems with the integrity of the wells to be used in the surveys due to their age, and there is significant potential for permanent damage to the wellbores.

Poor Cost/Benefit

The cost of the survey was approximately ten times higher than anticipated due to the problems encountered. This results in a very poor cost/benefit ratio for the technology.

Applicability For Reservoir Description

The technology relies on more than one survey per area to be effective and give confidence to the data for use in integrated reservoir description with geostatistics. We believe that by recording a much greater number of traces (order of magnitude increase), and by utilizing a downhole tool with a higher operating frequency that better survey results may have been obtained in this Glorieta/Clearfork reservoir. However, due to the number of operational problems that were encountered, both with the tools and the wellbores, it is doubtful that such changes would have resulted in a successful survey in this case. It is economically and operationally impossible to support several surveys in each area of the Unit at present.

RESERVOIR PERFORMANCE

The NRU was developed using an east-west line-drive configuration (1:1 injector/producer ratio) for optimum injectivity and pressure support. Sweep efficiency is difficult to quantify due to differences in depositional environments throughout the Unit (**Fig. 1**). As an example, Sections 5 and 329 appear to have fairly high overall reservoir quality, and are in areas of the reservoir dominated by the formation of grainstone shoals. In these areas, secondary production appears to be dominated by the movement of the injected water (i.e., sweep), however, there are problems with injection efficiency related to the presence of high permeability streaks which reduce sweep efficiency.

In areas such as Sections 326 and 327, the reservoir quality appears to be relatively lower, and is dominated by the deposition of a lagoonal-type facies, which although possessing relatively lower permeability and porosity characteristics, appear to be much more homogeneous in structure, and perhaps more continuous than the supposed higher quality reservoir rocks. Due to the fact that there is less variation in permeability across this region, the secondary recovery process has been very effective in contacting undrained oil. Average reservoir pressure is much higher in these areas, apparently due to the structure of reservoir, and the recovery process appears to be one involving pressure maintenance rather than reservoir sweep.

In order to best define the factors affecting reservoir producing mechanisms, we will analyze all available long-term production and injection data using the following reservoir performance tools:

- Material Balance Decline Type Curve Analysis of Long Term Production Data
- Material Balance Decline Type Curve Analysis of Long Term Injection Data

Material Balance Decline Type Curve Analysis

In order to verify the results of the rock-log modelling, the analysis of long-term production data was performed using a rigorous material balance decline type curve method.[11] An initial study of both the 40- and 20-acre producers was completed utilizing the Fetkovich/McCray Type Curve.[12-14] (**Fig. 19**). A step-by-step procedure for the use of this technique is given in **Ref. 11**.

This method yields excellent results for both variable rate and variable bottomhole flowing pressure cases, without regard to the structure of the reservoir (shape and size), or the reservoir drive mechanisms. The use of three different type curve plotting functions (rate, rate integral, and rate integral derivative) allows for the analysis and interpretation of typical "noisy" field production data. In addition, the integral functions provide better type curve matches than could be obtained using existing decline type curve matching techniques and increases confidence in our interpretations. These analysis techniques have been verified by evaluation of a number of simulated and actual field data cases, with outstanding results.

Results of these analyses include the following:

- In-place fluid volumes:
  - Contacted original oil-in-place, N
  - Movable oil at current conditions, $N_{p,\,mov}$
  - Reservoir drainage area, A

- Reservoir properties:
  - Skin factor for near well damage or stimulation, s
  - Formation flow capacity based on production performance, kh

One benefit of this technique is that analysis can be performed using data that operators acquire as part of normal field operations (e.g., production rates from sales tickets and pressures from permanent surface and/or bottomhole gauges). In most cases, these will be the only data available in any significant quantity, especially for older wells and marginally economic wells, where both the quantity and quality of <u>any</u> types of data are limited. This approach also eliminates the loss of production that occurs when wells are shut in for pressure transient testing, and provides analysis and interpretation of well and field performance at little or no cost to the operator. This technique allows properties to be evaluated quickly and easily, provides an additional method for locating the most productive areas of the reservoir, and allows for the possible identification of any preferential flow paths that may exist.

Reservoir performance maps (contacted OOIP, producing *kh*, and EUR) have been utilized in conjunction with the geologic model to identify the areas of the Unit to be considered for the targeted infill drilling program. The results for the analysis of production data from the 20- and 40-acre producing wells are shown in **Figs. 20-25**. Results of these analyses have been utilized in the following manner:

- Estimates of contacted original oil-in-place for the 40-acre producing wells has been used to calibrate the reservoir flow simulation models.
- In-place fluid volumes and reservoir flow properties obtained from decline curve analysis have been used in conjunction with reservoir surveillance studies to identify areas of the Unit which have lower reservoir quality from a geologic standpoint, but appear to have extremely good 10-acre potential.

- Material balance decline type curve analyses have been performed on some offset Clearfork properties in an attempt to quantify expected 10-acre infill well performance at NRU.

Section 362 Analysis

A single producing well will be drilled in an undrained, approximately 20-acre well location area in the southernmost part of Section 362 as shown in **Fig. 4**. This proposed well location is in a section of the Unit which had an incomplete pattern development. This area is not geologically attractive with regard to reservoir quality, however, this area has historically performed extremely well. Decline curve analysis shows the location to be in an excellent region with respect to estimates of contacted oil-in-place and producing *kh* from the analysis of 20-acre well performance (**Figs. 26-27**). The map of EUR shown in **Fig. 28** also indicates that the well is in an area in which it can be produced economically. Injection support in this region is fairly good, and additional 10-acre infill wells should be cost-effective. Maps of current daily oil production and water injection are shown in **Figs. 29-30**.

Offset Analogy - Estimated 10-acre Well Performance

Material balance decline curve analysis was performed on some offset Glorieta/Clearfork properties containing wells on 10-acre spacing in order to obtain an estimate of infill potential at NRU. On average, 10-acre producing wells have made approximately 80% as much as the 20-acre producers. Using these offset producing trends, histograms have been constructed to show the expected recoveries for 10-acre blanket drilling (**Fig. 31**). A blanket drilling strategy would most likely result in an average 10-acre well recovery of 77 MSTBO/well. If only Sections 327, 329, and 362 are considered, average estimated recoveries improve to approximately 107 MSTBO/well as shown in **Fig. 32**. With the aid of our geologic and performance data analyses, we can target certain areas within these quality areas of the Unit and hopefully drill the wells at the high end of the statistical distribution (110 to 180 MSTBO/well). It is worth noting that the estimated 10-acre infill well recoveries from reservoir flow simulation in these targeted areas averaged 123 MSTBO/well, which agrees very well with our offset analogies.

<u>Waterflood Performance Analysis</u>

There are many simple graphical waterflood performance evaluation techniques that can be applied in order to identify the problems that affect flood efficiency. Some of these methods are outlined in the "Reservoir Surveillance" section below. Most of the previous efforts for decline type curve analysis have focused on the analysis of primary, rather than secondary depletion. In an effort to improve upon these analysis techniques, we propose the use of type curve methods, similar to those utilized above, for the analysis of waterflood efficiency and to be used as diagnostic tools for individual injection well remediation. Most techniques available for the evaluation of injection well performance treat the remediation of a physical problem (pore plugging, scaling, or channeling), or yield extremely qualitative results for the evaluation of waterflood performance. These methods can produce results that are often misleading or difficult to interpret. We propose the use of type curve methods for: 1) Evaluation of the degree of pressure support that is felt at the producing well, and 2) Evaluation of individual injection well performance and reservoir flow characteristics using long-term injection rate and pressure data.

Evaluation of Waterflood Support Using Type Curves

In order to analyze the level of injection support at individual producing wells, we developed type curves for the analytical solution of the case involving a well producing at a constant bottomhole pressure in the center of a bounded circular reservoir which was influenced by an external source of pressure support (i.e., water influx/injection).[15] A single phase displacement process was considered in the solution for simplicity. The resulting type curves can be used for the analysis of production data from reservoir systems experiencing natural water influx or pressure support due to water injection. We successfully compared the analytical results with numerical simulation results and field performance data. Unfortunately, this particular method only allows for a qualitative analysis to be performed on the secondary (waterflood) recovery portion of the field production data. The technique accounts for the timing and strength of the injection/influx support, but does not consider multiphase displacement effects. We hope to continue working on this concept during Budget Period II.

An example type curve match for NRU well 4202 is shown in **Fig. 33**. The dimensionless decline rate integral function, q_{Ddi}, is plotted versus dimensionless decline cumulative production, N_{pDd}. The well appears to be well supported by water injection, as the secondary production trend appears to be going down either the 0.875 or the 0.95 decline stem. This indicates that the well is receiving between 87.5% and 95% of the pressure support it would have for the case of an ideal 1:1 injection-to-production scenario (steady-state). Due to the definition of the abscissa (x-axis) for this analysis method, a large quantity of secondary production data is required to simply perform a *qualitative* analysis. For this reason, we have chosen to concentrate on the use of material balance decline type curve techniques for the analysis of long-term injection data from individual wells using methods similar to those described above for oil wells.

Evaluation of Injection Well Performance Using Material Balance Decline Type Curves

As previously stated, we can use the same analysis techniques applied to long-term oil production data for the analysis of long-term injection data.[16] Our goal is to accurately predict the efficiency of the injection process as well as the pressure influence of individual injection wells. We developed a decline type curve for the evaluation of injection wells having an infinite-conductivity vertical fracture in a bounded reservoir. This case was considered since most of the wells we are considering (and most injection wells in SSC reservoirs) have been hydraulically-fractured during completion, or fracturing has resulted due to the effect of long-term water injection at pressures near or above the parting pressure of the reservoir.

We hope to use this technique to evaluate the entire injection history of individual wells, and not just consider the steady-state or pseudosteady-state flow periods as existing analysis techniques (such as the Hall plot[17]). This technique will be used for injection well surveillance during Budget Period II.

RESERVOIR SURVEILLANCE

One of the major goals of this project was to identify cost-effective technologies for reservoir surveillance in shallow-shelf carbonate reservoirs. Reservoir surveillance is often overlooked in less prolific producing areas such as the Permian Basin due to economic constraints, however, we wish to show that a cost-effective program can be maintained if it is properly implemented. A Unit map showing the status of the reservoir surveillance program for 1995 is shown in **Fig. 34.** Our goals for reservoir surveillance at the NRU include:

- Allowing for a maximum pressure differential to exist between the producing and injecting wells without exceeding the formation parting pressure
- Performing regularly scheduled pressure buildup and falloff tests using surface data acquisition to detect formation damage and monitor reservoir pressure
- Utilize step-rate and injection profile data along with completion/stimulation optimization to improve interwell conformance sweep efficiency
- Combine the results of pressure falloff test analyses with the results of waterflood diagnostic plots and regular step-rate testing to improve injection efficiency
- Utilize cased-hole water saturation logs on a periodic basis to monitor the movement of reservoir fluids in the near-wellbore regions of the producing wells
- To utilize all pertinent surveillance data as input data for reservoir flow simulations
- Optimize well conformance by injecting only into zones which are continuous between injectors and producers
- Continuously monitor injection water quality to increase injection efficiency

Pressure Transient Analysis

A unit-wide pressure transient data acquisition program was initiated in the last quarter of 1994 to provide further data for simulation history matching, to estimate completion and stimulation efficiency, to identify the best areas of the reservoir with regard to pressure support, and to identify any other major problems related to waterflood sweep efficiency.

We have used both pressure and pressure integral data (data noise removed by integration) to perform conventional semilog analysis, and log-log analysis using type curves developed for radial fluid flow in both unfractured and fractured wells, that also consider wellbore storage effects. The results of these analyses were then used to match simulated results (generated by optimizing permeability, skin factor, wellbore storage coefficient, and fracture half-length) to the pressure and pressure integral data. Average reservoir pressure was estimated for each test by fitting the data with the equation of a rectangular hyperbola and extrapolating to the appropriate pressure.[18-20]

The majority of the tests will be pressure falloffs on injection wells, so as to minimize the loss of oil production. At present, the plan is to run approximately twenty falloff tests, and ten to fifteen pressure buildup tests in order to set up a "baseline" data set for future data acquisition. Initially, pressure buildups will be performed using downhole shut-ins to reduce wellbore storage effects and obtain better quality data for interpretation. The cost/benefit factor for performing buildups using surface versus downhole data acquisition can then be compared after the baseline data set has been compiled. Many of the producing wells contain significant amounts of wellbore fill that must be cleaned out prior to testing in order to obtain a representative test. If a regular workover program is in place, future pressure buildups will be recorded using surface data acquisition since it is obviously more cost-effective.

Obviously, if we are recording pressures at surface or cannot isolate individual zones downhole, then we are sampling the entire producing interval at once, which may lead to some misleading results with regard to estimates of completion efficiency. We cannot currently isolate zones during the buildup and falloff tests due to the fact that we cannot run sealing packers downhole through perforated intervals without major operational problems, and individual zones are probably in fracture communication with one another even if we could isolate them at the wellbore. Some of the new 10-acre infill wells will be tested on an interval basis to determine specific interval flow properties and pressures in the lower, middle, and upper Clearfork and Glorieta. Individual layer or flow unit pressures will also be obtained using formation test tools during the open-hole logging program. In this way we can identify the relative contributions of individual zones within the producing interval, and determine how it will affect our pressure transient data acquisition program.

Pressure Buildup Test Analysis

1988 Pressure Buildups

At the time of unitization, a wide range of fluid bubble points existed in the reservoir. This differential pressure depletion is indicative of poor pressure continuity and is supported by the bottomhole pressure data collected just prior to unitization and during reservoir fill-up. Pressure buildup data recorded in October and November of 1988 was available for seventeen producing wells. At that time, the wells had received limited pressure support as the water injection program was only initiated in the last half of 1987. Fifteen of these wells were new 20-acre producing wells, and two were original 40-acre producers which were subsequently converted to injection.

These surveys were recorded by measuring the shut-in surface pressure while simultaneously making a fluid column height measurement using an echometer (automated well sounder) device. The overall data quality was not good, and the tests were not recorded for a sufficient length of time to identify any boundary effects, however, fifteen of the tests were of sufficient quality to estimate formation flow characteristics. The results are summarized below:

Average test duration	8 days
Average reservoir pressure	1,013 psia
Average absolute formation permeability	2.1 md
Average skin factor	-3.4
Average fracture half-length	27.5 feet

Even though the majority of these wells were newly drilled, completed, and stimulated at the time of the surveys, the success of the hydraulic fracture treatments appears questionable. These jobs were designed to produce fracture half-lengths of 120 feet, however, the calculated average half-length is only 27.5 feet, and no fractures reached the designed length. The results indicated that several wells had no propped fracture length at all. As stated above, this result may be an artifact of the large sampling interval, however, the optimization of completion and stimulation practices is one of our major goals during the 10-acre infill drilling program during Budget Period II. The average skin factor of -3.4 indicates that although the calculated fracture half-lengths were low, the wells were well stimulated. A reservoir pressure map for the 1988 tests is shown in **Fig. 35**.

1995 Pressure Buildups

At this time, eight pressure buildup tests have been completed on 20-acre producing wells during 1995. The well locations for these tests are distributed throughout the Unit in order to obtain a representative sampling for our baseline data set. These surveys were recorded with high resolution downhole gauges, and the wells have been shut in downhole using packers at the top of the producing interval. Several buildup tests will be run using surface pressure acquisition utilizing the "echometer-type" survey described above for a comparison of relative data quality. We prefer to run most future tests from surface to avoid costs associated with pulling rods and tubing. This will be feasible if a regular producing well workover program is in place to keep the wells cleaned out.

The data quality for this set of pressure buildups has been extremely good, and all the tests have been interpretable. An example log-log type curve match using a commercial software package[21] is shown in **Fig. 36**, and a match using our own optimization software (available as part of the Technology Transfer package) is shown in **Fig. 37**. The estimated formation flow characteristics for these tests are very similar to those from the 1988 buildup tests. The major difference is the reservoir pressure response due to eight years of continuous water injection. A reservoir pressure map for the 1995 tests (buildups and falloffs) is shown in **Fig. 38**.

As we would expect from examining our geologic model, the regions of the reservoir with the highest reservoir quality are at a relatively lower pressure due to increased voidage due to greater continuity and higher permeability. The areas of the Unit with relatively higher reservoir quality appear to be dominated by a water injection sweep mechanism, while the south-central area of the Unit, in which a less continuous lagoonal facies dominates, appears to be producing under a pressure maintenance mechanism in which the oil is being "squeezed" out rather than swept out. It is worth noting that the current average reservoir pressure is above the original reservoir pressure.

Results from the recent buildup tests are shown below:

Average test duration	20 days
Average reservoir pressure	2,850 psia
Average absolute formation permeability	1.46 md
Average skin factor	-3.5
Average fracture half-length	10.0 feet

Once again, the small fracture half-length may be an artifact of the large sampling interval, and the average skin factor of -3.5 indicates that although the calculated fracture half-lengths were low, the wells were well stimulated.

Pressure Transient Data Acquisition Using Real Time Electromagnetic Telemetry

In an attempt to introduce new, cost-effective technologies, we have also recorded several pressure buildup tests with a downhole tool that transmits real time pressure and temperature data to surface via the wellbore tubulars and the formation.[22,23] These surveys can be performed for approximately the same cost as those utilizing memory gauge data collection techniques. This system has been used for some time to monitor bottomhole pressure and temperature during hydraulic fracturing and drill-stem testing operations. The technology offers a distinct advantage over running "blind" downhole gauges which cannot be accessed until they are pulled from the well. Using this telemetry acquisition system, we are able to analyze data in real time as the survey is being recorded, and we can terminate the test in a time-efficient manner if there is a downhole problem or the data quality is poor. This instantaneous feedback allows us to return wells to production faster and reduce the associated loss of production. Real time data acquisition has only been available in the past for short-term pressure transient tests run using electric wireline, which is obviously not economically feasible for the long-term tests that we conduct.

The analyses performed on both the real time surface data and the downhole memory data are shown in **Fig. 39**. Although the early-time data (which is the most critical) is adversely affected by the downhole-to-surface transmission rate, the analyses produced exactly the same results. An increased transmission rate will be a major consideration in the design of the next generation tool so that the early data can be obtained at surface at a much higher sampling rate.

This technology may also be extremely useful for long-term bottomhole pressure monitoring in active producing or injection wells. Daily bottomhole pressure data would greatly increase confidence in our material balance decline curve analyses which are adversely affected by the assumption of a constant bottomhole pressure. In most older, less prolific producing areas such as the Permian Basin, this data is not available. The acquisition of this data would also be extremely useful when performing reservoir flow simulation, as it would provide an additional (extremely important) parameter for history matching. The use of this technology will be explored further during Budget Period II.

Pressure Falloff Test Analysis

Pressure falloff data has been acquired at surface in an effort to reduce costs and demonstrate that these tests can be recorded at little or no cost to the operator. It has been shown that surface pressure acquisition yields data of sufficient quality for interpretation, even when low precision pressure gauges (± 1 psi) are utilized.[24] Results to date have been excellent, and have helped to explain some of the major problems associated with waterflooding a low permeability carbonate reservoir.

In an effort to identify interference/boundary effects on the injection well falloff tests, an effort has been made to let the tests run as long as possible. This is especially important in identifying the problems that may affect reservoir sweep efficiency. The extremely long falloff times we have witnessed to date indicate that the wells may be receiving a great deal of pressure support from offset injectors. These long falloff periods may also be due to the presence of formation scale plugging or wellbore fill which can be identified from waterflood diagnostic plots.[17,24]

The results of the recent pressure falloff tests are shown below:

Average test duration	50 days
Average injection rate	276 BWI/D
Average surface injection pressure	1,650 psia
Average bottomhole injection pressure	4,700 psia
Average reservoir pressure	3,400 psia
Average absolute formation permeability	0.63 md
Average skin factor	-5.8
Average fracture half-length	233.0 feet

The estimate of absolute formation permeability is lower than that obtained from the pressure buildup tests. The assumption was made that only a single phase (water) exists in the injection wells for the purpose of computing a bottomhole pressure in a straightforward fashion. If oil or gas are present, even in relatively small volumes, we are most probably underestimating permeability and slightly overestimating bottomhole pressure.

The bottomhole injection pressures are above the initial parting pressure of the reservoir (approximately 4,250 psia in the lower Clearfork), therefore, it should not be surprising that many of the injection wells are in fracture communication with one another. Step-rate tests are recorded to set surface injection pressure limits, however, they are difficult to interpret after reservoir fill-up has occurred. An effort will be made to devise an improved method for setting individual injection well injection pressure limits during Budget Period II.

Comparison of the pressure buildup and falloff tests on NRU 3510 shows how severe a problem this can be. Pressure buildup tests run after the well had been hydraulically fractured (1987), and prior to conversion to water injection (1989), indicated that the well had no effective fracture length. The well was reperforated and acid-stimulated during conversion, but was not refractured. Recent falloff results indicate the well has an estimated fracture half-length of 614 feet, which must be the result of hydraulically-induced fracturing due to continuous water injection. A falloff test run on NRU 301 shows that direct communication exists with an offset injection well to the west (NRU 2601). A 200 psi injection pressure increase at NRU 2601 caused an almost instantaneous pressure increase at NRU 301, which was on falloff (**Fig. 40**). The water injection wells at NRU run along east-west lines, which also appears to be the preferential fracture direction for the Clearfork in this area,[25] therefore it is not surprising that the injection wells appear to be in communication -- this may actually help improve sweep efficiency. This only becomes a major problem when considering areas of the Unit with incomplete patterns. Around the edges of the Unit, several injection and producing wells are on the same east-west rows. In most cases, this has resulted in poor producer performance involving rapid increases in water cut and tubular corrosion problems.

By utilizing the results of the reservoir quality studies, interwell conformance/continuity analyses, and performing further tests to identify the preferential flow directions in the Unit, we will attempt to decrease bottomhole injection pressures, avoid excessive fracture propagation, and increase sweep efficiency.

Cased-Hole Surveys

Water Saturation Logging

While the cost associated with recording a great number of thermal decay time logs (TDT) may be cost prohibitive for most operators, the periodic utilization of TDT logs in specific wells is an extremely useful tool for monitoring the preferential fluid movement in the near-wellbore regions of producing wells. Approximately ten to fifteen surveys (equally spaced across the Unit) are being run to get updated fluid saturation values for some of the 20-acre producing wells drilled between 1987 and 1991. This data will primarily be collected to form a "baseline" data set for future TDT logging surveys to monitor fluid saturation changes. It will also be used in the history matching segment of reservoir simulation, and for the possible identification of any bypassed production.

It will be much easier to compare results of subsequent surveys to a base set of TDT logs than it is to compare this saturation data with the original open-hole log-derived water saturation data. There does not appear to be an accurate, widely recognized method for determining water saturation from open-hole logs in the Glorieta/Clearfork formation. The general saturation trends (high versus low) appear correct, however, Archie's equation does not work well due to changes in formation water salinity and rock fabric (cementation factor). If possible, one of our goals during Budget Period II is to formulate an acceptable method for estimating water saturation from open-hole surveys.

Previous reservoir surveillance in Clearfork waterfloods has not included the use of TDT logs because they did not perform well in the low porosity, low salinity conditions that exist at the NRU. Advances in tool design over the past five years have produced tools that work well for both fairly fresh formation water and low porosity formations. If positive results are achieved using this new generation tool, it may become a part of the reservoir surveillance and monitoring program at the NRU. **Fig. 41** shows the increase in formation water saturation for NRU 3527 between 1987 and 1995.

Production Logging

If it could be obtained in a cost-efficient manner, the zonal contribution of each individual pay section would be some of the most important data that we could obtain. It could be correlated with the results of the rock-log model data to determine its validity, and it could be used as a guide for our interwell conformance and completion/stimulation optimization programs. Unfortunately, the producing wells at NRU, and many other SSC reservoirs do not flow naturally. In addition, the contributing interval in this reservoir is approximately 1,200 to 1,500 feet, making it very difficult to identify individual zone production rates. The downhole pumps are set at the bottom of the producing interval, and since fluid influx from the formation is at a very low rate, they are kept "pumped off" using pump-off controllers that measure the time it takes the pumping unit to complete an entire stroke (which is directly related to the amount of fluid above the pump).

Natural production can be induced by injecting a low density gas (Nitrogen) to create an artificially low pressure head above a particular producing interval. This must be done using a coiled-tubing unit, and the operation must be performed at each successive depth interval. This is neither cost- nor time-efficient, and the production that results will probably not be representative of the normal producing characteristics of the well.

A radioactive tracer tool can be placed downhole in the tubing-casing annulus and can be used to monitor flow rate while the well is pumping. Obviously, this tool must be in fluid to operate, and requires the downhole pump (and fluid level) to be above the completed interval to get a representative rate sample. Since the downhole pumps are below the completed intervals in NRU producing wells, fluid would have to be added to the well and the tubing/pump assembly would have to be moved to the top of each individual perforated section. At NRU, there are often as many as 10-15 small perforated intervals over the entire section making such a test very difficult and time consuming. Also, the additional fluid added to the well in order to keep fluid over the tool would once again result in survey results that are not representative of the actual producing characteristics of the well.

During the infill drilling program, we will attempt to test individual intervals as they are completed in order to determine the relative contribution of each interval. It has been noted previously that the relative contribution of these intervals appears to change in different areas of the Unit.

Step-Rate Testing

The analysis of step-rate data collected between 1988 and 1993 for eighty-five NRU injection wells indicates that the estimated formation parting pressure has been steadily increasing from year to year due to increased pore pressure resulting from continuous water injection (**Fig. 42**). The results of these tests are used primarily to set surface injection pressure limits for individual injection wells, however, after reservoir fill-up has occurred their utility is limited since the reservoir pore pressure has been increased to the point where it is difficult to accurately estimate the true parting pressure of the formation.

Because bottomhole injection pressures at the NRU are near or above the parting pressure of the reservoir, step rate tests should be used together with injection profiles, material balance decline type curve analysis of injection well data, Hall diagnostic plots, and pressure falloff test analyses to determine not only the optimum injection pressure for individual wells, but also to identify problems affecting injection well efficiency.

Injection Profiles and Tracer Surveys

Water injection-to-oil production well conformance is achieved when the open (unplugged) perforations for injection wells matches the open (unplugged) perforations for offset producing wells for all "pay" intervals. To test the conformance at NRU in a cursory manner, we loaded current perforations, injection profile and temperature survey information into a commercial software analysis package[26] and generated interval perforation, percent injection, and temperature survey maps for all intervals. Selected cross-sections were generated to examine the details of probable conformance improvement opportunities. All information indicates that a number of individual wells, and in some cases significant areas within the field, are not in conformance for selected flow unit intervals. Obviously, using production and injection data to infer reservoir continuity on the basis of individual flow units can be misleading as the analysis of this type of data should not be restricted to a particular flow unit interval. However, when larger intervals, consisting of multiple flow units are considered, we see that there are numerous opportunities to improve water injection support and injection-to-production well conformance at NRU. Additional detailed work will be performed during Budget Period II to develop a list of specific opportunities.

In the areas of the Unit in which the nominal well spacing has been reduced to 10 acres, we will attempt to perform some interwell tracer surveys to determine the directional flow trends and the degree of anisotropy at NRU. Tracer breakthrough times for wells on 20-acre spacing was estimated to be approximately one year, therefore, we determined that this work should be delayed until the infill program was completed so that the breakthrough time could be reduced and we could hopefully obtain more representative results.

Water Injection Well Diagnostic Plots

Hall Plot

Hall[17] provided a straightforward graphical technique for the analysis of long-term injection well performance data. The Hall coefficient, which is defined as the cumulative total of the product of the average monthly injection pressure and the number of days per month the well is on injection, can be plotted versus cumulative water injected to produce a diagnostic plot for monitoring the behavior of injection wells. This is presently the most utilized tool in decisions regarding water injection well workovers at the NRU.

From a plot borrowed from the work of Thakur[27] (**Fig. 43**), it is noted that linear trends which fall above the "normal" line (D) indicate pore plugging and a possible water quality problem. Data plotting below the "normal" line (B and C) indicate water channeling or injection at pressures greater than the formation parting pressure. An example of possible water injection at pressures above the parting pressure of the formation and water channeling is shown in **Fig. 44.** The Hall plot for NRU 301 shows a decrease in slope that is characteristic of these phenomena. Verification is provided in the form of a recent pressure falloff test that indicates the well is in fracture communication with an offset injector (**Fig. 40**). The well's injection rate has declined drastically, and the injection pressure has gradually increased over the past year as it receives pressure support from the offset injector.

Water Quality Program

Injection water quality is one of the critical components in the implementation of a successful waterflood. Unfortunately, the continuous monitoring of water quality is still not considered part of many operator's reservoir surveillance plans. This often results in poor waterflood efficiency and numerous operational problems.

The total daily injection rate for the NRU had decreased from 30,000 BWI/D in 1989 to 16,000 BWI/D in 1992. A cost-effective surveillance program was initiated to identify and resolve potential water quality problems. At the same time, an injection well workover program was implemented to remediate the scaling problems in individual wells.

Due to the fact that both fresh (Ogallala aquifer) and produced water are used for injection at the Unit, both waters had to be tested separately for their plugging and scaling tendencies. In addition, both waters were tested together to determine if any compatibility problems existed. The following tests were conducted:

- Physical properties
  - Total dissolved solids
  - pH
  - Particle size distribution
- Filtration
  - Suspended solids
  - Acid solubles
  - Hydrocarbon solubles
- Dissolved Gases
  - Oxygen
  - Carbon dioxide
  - Hydrogen sulfide
- Bacteria
  - Anaerobes
  - Aerobes
  - Dissolved iron

Although the injection waters were found to be compatible, both the produced and fresh waters were found to have substantial plugging and scaling tendencies. The water handling facilities were redesigned and programs were implemented to: 1) prevent the formation of solids; and 2) remove all remaining solids from the system. The entire NRU water quality program is outlined in detail in **Ref. 28.** The Unit's daily injection rate subsequently increased to 26,000 BWI/D, and is currently between 20,000 and 22,000 BWI/D. At present, quarterly tests are conducted on individual wells, and field-wide tests are conducted biannually.

OPTIMIZATION OF COMPLETION/STIMULATION PROCEDURES

Well Conformance

Previous completion techniques opened all intervals without regard to rock quality. By utilizing the integrated reservoir description results, more emphasis can be placed on maintaining conformance between producers and injectors only over intervals of the reservoir which effectively contribute to oil production. In addition, efforts can be concentrated on maintaining injection over the intervals that can achieve and maintain high injectivity, instead of randomly injecting fluids into intervals with high porosity that may, or may not be effectively connected. Additional completion and stimulation designs can be optimized and costs can be reduced.

Pay Delineation

The NRU was developed using an aggressive 20-acre infill drilling program between the time of unitization (March 1987) and early 1991. During this time period, 116 new 20-acre producing wells were added, and 107 of the 141 original 40-acre producers were converted to water injectors.

Prior to implementation of the infill drilling program in 1987, parameters were established to identify the "pay" quality intervals in each well. These parameters included porosity, water saturation, and bulk water volume. Any interval having a combination of porosity greater than 3.6 percent (dolomite matrix) and water saturation less than 65 percent qualified as potential pay rock. These parameters were used with only slight variations throughout the 20-acre infill program. There may be additional uncontacted pay within the reservoir since these simple pay cutoffs do not identify pay rock on the basis of reservoir rock quality or continuity. We hope to identify the characteristics of these bypassed intervals utilizing the results of our open-hole logging program during the 10-acre infill program, and by updating and improving our existing rock-log model. In addition, many of the producing and injection wells were not drilled to a sufficient depth to access the entire producing interval, or were not completed so that conformance could be maintained between injectors and producers.

Fracture Design

Prior To Unitization

A major concern with regard to well completion work during each phase of Unit development was the need for a limited-entry type fracture job to ensure that the entire productive section was being treated equally. The gross completion interval extends from the top of the Glorieta to the base of the lower Clearfork (1,200-1,500 feet). This interval was completed and stimulated in two or three separate stages, depending on the location of the well within the Unit.

Optimization of the fracture treatment program has been an ongoing process during Unit development. Results of the fracture treatments on the original 40-acre primary producers were poor due to the fact that the bottomhole treating pressure could not be maintained at a sufficiently high level for fracture propagation due to burst limitations on the casing.

At the time of unitization, the average fracture job was approximately 1,000 barrels of fluid with 100,000 pounds of sand (1-8 pounds/gallon). Since there are no effective large-scale barriers to fracture propagation, sufficient non-perforated intervals had to be maintained to prevent communication between successive completion stages. Over the development history of the Unit, the number of perforations per stage has been reduced in order to maintain a limited-entry type of fracture. During the 20-acre infill program, the optimum number of perforations per stage was determined to be one perforation for each barrel per minute (BPM) injection rate using a 2-D Perkins/Kern (PKN) fracture model.[29] The average pump rate was between 35 and 40 BPM down 5.5" casing. Fracture jobs were designed to create fracture half-lengths of 120 feet.

As shown from the analyses performed on pressure buildup data from some of the 20-acre producing wells drilled in 1987 and 1988, it appears these optimized stimulation treatments did not result in fracture half-lengths anywhere near the design length, although it appears that almost all the wells were effectively stimulated, and effective pressure sinks were created at the wellbore. Future fracture jobs must be designed to create vertically contained, fairly short, high conductivity (thick) fractures. Previous production history has shown that regardless of the degree of reservoir continuity, long fractures are not necessary, and are in fact harmful to completion efficiency. If completion and stimulation of only the most continuous layers of the reservoir are accomplished, then long hydraulic fractures are not required.

Current Plans

A major problem at NRU with respect to interwell conformance is that most of the current injection wells were originally completed as producers utilizing large, high volume frac jobs over large intervals which have opened the most permeable intervals between wells. During the infill drilling program in Budget Period II, producing well fracture treatments will be optimized to preferentially stimulate only the intervals that contribute significantly to production and receive effective pressure support from offset injection wells. Future injection well fracture treatments will target the moderate and lower permeability intervals and frac job sizes will be reduced to avoid opening up high permeability streaks that act as thief zones.

We hope to optimize the hydraulic fracturing treatments to prevent vertical fracture propagation outside the interval of interest and to evenly distribute the injected proppant. Downward fracture propagation is a major concern in the lower Clearfork at the NRU due to the presence of the water-filled Clearfork Lime at the base of the producing interval. New fracturing techniques will be used to confine vertical propagation and produce higher conductivity fractures, resulting in more efficient removal of fluids from the formation. Budget Period I studies indicate that the reservoir is most probably oil-wet. This would seem to explain why some operators in the area have had great success using CO_2 foam fracs in the Clearfork. This is obviously an option we wish to try.

During the initial infill drilling program and throughout Budget Period II, we will investigate the affects of perforation density, pre-fracture acid jobs, fracture fluids, fracture proppants, injection volumes, and pump rates on initial well potential (IP). A statistical study is currently being performed on data available from previous completion and stimulation work at NRU. Preliminary findings seem to show that reservoir quality plays the largest role in determining individual well IPs, however, with the additional petrophysical data that will be available from the drilling program, we should be able to target smaller, more confined completion intervals and identify an optimum, cost-effective completion and stimulation procedure for the Glorieta/Clearfork.

DEEPENING CANDIDATES

Twenty-two deepening candidates (10 producers, 12 injectors) were previously identified based on geological and engineering reservoir characterization of the North Robertson Unit. All these wells appeared to have recompletion potential by adding additional perforations in the lower Clearfork, although all the wells are along the shelf-edge on the northern side of the Unit in an area where there was little data for interpretation, i.e., no modern logs and no rock-type solutions. The majority of these wells were in the northwest area of the Unit (Section 329) as shown in **Fig. 45.**

The deepening candidates were identified and ranked on the basis of their relative *kh* potentials from extrapolation of the rock-log model *kh* data to unsampled locations on the edges of the Unit. All of the wells were original 40-acre producers, so that wellbore integrity was a major concern. Past experiences indicated that these lower Clearfork intervals may have been water producers in Section 329, therefore, a well to the southeast in Section 324 (NRU 3603) was chosen as the first deepening candidate. Subsequent decisions regarding whether to proceed northwest or southeast along the shelf-edge were based on the success of this first deepening.

Well NRU 3603 Results

NRU 3603 was deepened approximately 100 feet during July, 1995. Whole core was obtained across the entire interval, and a comprehensive suite of open-hole log surveys were recorded, including:

- **Fluid Saturation Determination**
  - Dual Laterolog
  - Compensated Neutron Log
  - Compensated Density/PE/Caliper Log
  - 200 MHz Dielectric Log
- **Rock Mechanical Properties (Fracture Design)**
  - Digital Array Sonic Log
- **Borehole Imaging Log**

The log and core analysis both indicated potential pay over approximately 40% of the deepened section. The well was producing 7 STBO/D and 1 BW/D prior to the deepening. It currently produces approximately 13 STBO/D and 150 BW/D. Early production after the deepening was intermittent due to problems caused by repeated pump failure due to the presence of frac sand in the wellbore and various other mechanical problems. The well has been on fairly continuous production since the beginning of December 1995. It is encouraging that the total fluid rate has been increased significantly, however, early results indicate that further deepening potential may be limited.

Future Deepenings

The results of this well deepening appear to confirm our suspicions about the lower Clearfork section in the northwest region of the Unit. Subsequent reservoir simulation studies in Section 329 have shown that this interval is a major water producer. Further well deepening activities will most likely be limited to wells southeast of NRU 3603, as shown in **Fig. 46**. The petrophysical data analyses, the results of which were utilized to design this well completion, have provided us with valuable information for our future data acquisition and analysis programs during Budget Period II.

GEOSTATISTICAL ANALYSIS

Geostatistics is being utilized in this project to develop spatial relationships of reservoir description variables of interest at unsampled (interwell) locations across the Unit. Geostatistics was originally developed for applications in mining engineering,[30] and has been used increasingly in reservoir engineering to characterize reservoir properties.[31]

In this section, we describe the application of geostatistical procedures utilized for generating reservoir petrophysical properties descriptions. First, we will discuss the generation of petrophysical properties which are consistent with the underlying geology. By using a combination of indicator and Gaussian simulation methods, a procedure was established which allowed us to simultaneously generate distributions of each rock type and distributions of petrophysical properties. Next, we describe a procedure used to integrate oil-in-place estimates based on material balance analysis. A connectivity procedure was established by which a threshold permeability was defined based on the known connected volume. We assume that the connected volume is related to the oil-in-place estimates which were obtained by evaluating production data. Finally, we provide the upscaling procedure to estimate the grid block properties for flow simulation. The original geostatistical description developed is very detailed so that we can understand the geological heterogeneity and continuity. Such a detailed description cannot be used in a flow simulator due to computational limitations. As a result, an appropriate upscaling procedure is applied to generate grid block level porosity and permeability values.

Generation of Rock Types and Petrophysical Properties Distribution

Conditional Simulation Methods

Conditional simulation is a geostatistical method applied to generate reservoir descriptions using available quantitative and qualitative data. The method is a stochastic approach since reservoir properties are represented by random variables. The description of the properties generated are conditional since the available data are honored at the sampled locations. The method simulates or predicts several equiprobable descriptions of the actual distribution of a property in the reservoir. In constructing the possible reservoir descriptions, the constraints imposed on the simulation process may include prior distribution of the simulated variables, spatial relationships in various directions, and geometry of geological shapes and sizes. The equiprobable images generated in a conditional simulation process will appear more similar as more constraints are incorporated.

Conditional simulation techniques differ from conventional techniques in several ways:

- ***Sample Distribution Data Honored:*** Unlike simple interpolation or extrapolation, conditional simulation honors the entire sample data distribution rather than reducing the spread of the data distribution. This is important for retaining extreme values (outliers) in the sample data set, which form a very small part of the overall sample, but which may greatly influence the flow performance of the reservoir. An example would be a small streak of high permeability, which can have significant influence on waterflood performance, and still constitute a very small part of the entire productive intervals.

- ***Data Spatial Relationships Honored:*** The second advantage of the conditional technique is that it honors the spatial relationships developed from the sample data. Many conventional interpolation methods generate smooth distributions which do not satisfy the spatial relationships established using the sample data.

- ***Reservoir Description Uncertainties Quantified:*** The last advantage of the conditional simulation method is its ability to quantify uncertainties in the reservoir description through multiple, equiprobable images of the reservoir. Conditional simulations allows construction of multiple pictures of the reservoir, all observing the same constraint(s).

Several conditional simulation techniques have been proposed in the literature. The method used to generate the rock type and petrophysical properties in this project is a combination of indicator and Gaussian simulation methods described next.

Co-Simulation of Rock Type and Petrophysical Properties

A common method for generating a reservoir description consistent with both geological and petrophysical constraints is known as the "two stage approach". In the first stage the rock types or the geological facies are simulated. During the second stage, the petrophysical properties are simulated. The second stage requires significant computation time and computer memory to hold the interim results which are discarded after combining these results with the first stage through a filtering process. By combining the two processes, an efficient simulation can be obtained.

A co-simulation program to combine the two stage processes has been developed. The program is a modification of the Gaussian truncated simulation of lithofacies, (GTSIM).[32] The basic principle of GTSIM is to truncate a Gaussian field using threshold values to generate a conditional simulation of the lithofacies. The Gaussian field can be modelled from the variance-weighted or some other weighted average of the pdf-type (probability distribution function) indicator covariances. Meanwhile, the threshold can be determined either from the local lithofacies proportions, also called the proportion curve. This input can be specified by the user or calculated from a pdf-type indicator kriging.

The idea of integrating porosity simulation into the GTSIM program is based on the fact that the porosity field can also be simulated using Gaussian simulation technique which is available while the rock type/facies is being simulated. Once the rock type/facies of each grid block is known after the truncation process, the porosity can be assigned immediately based on the correlation of the sampled porosity value with each corresponding rock type/facies. That is, the assigned grid block porosity value is conditioned to the rock type of that grid block. Further extension can also be made to accommodate the permeability simulation by applying the conditional distribution technique after the rock type and porosity value of each grid block is known.

The steps involved in the co-simulation program are described below:

- ***Determination of the Proportion Curves:*** In this program, the user inputs the cumulative distribution function (cdf) values for each rock type as a function of vertical depth. These cdf values will be used in either one of the following two conditions. In cases when the user does not want to perform the indicator kriging in generating the proportion curves, then these cdf values will be used as the proportion curves and consequently they are a function of vertical depth only. On the other hand, if the user does want to perform indicator kriging to create proportion curves for each grid block, then these cdf values will be used only if a singularity problem occurs during the kriging process. The proportion curves are then transformed into threshold curves which will be used later to truncate the Gaussian field.

- ***Transformation of the Original Data Into Pseudo Gaussian y-Data:*** This transformation is conducted for both the rock type and the porosity data.

- ***Simulation of Gaussian Data:*** Rock type and porosity data are simulated using sequential Gaussian simulation that produces the Gaussian field, y(u), where u is a particular location (grid block). The samples used in the porosity simulation are the same as the samples used in the rock type simulation. Therefore, a significant amount of computation time is reduced in searching the neighborhood. Instead of searching the neighborhoods twice for two different variables, the neighborhood is searched only once.

- ***Truncation of the Simulated Gaussian Field, y(u):*** Truncation is performed using the threshold curves and the back transform Gaussian porosity field. This process yields simulated rock type and porosity values at each simulation grid block (u).

- ***Permeability Assignment:*** Permeability is conditioned to both rock type and porosity values at each grid block. The appropriate permeability distribution is sampled depending on the rock type and the porosity value at that particular grid block.

Simulation for Section 329 and Section 5

The implementation of the co-simulation (COSIM) program in generating the reservoir description of Section 329 and Section 5 uses the procedure detailed below. During Budget Period II, the process will be extended to other areas of the Unit for validation with the Field Demonstration.

Data Preparation: The data used in the co-simulation program are the geologist's interpretation of the rock type at the well location, well log porosity, and the porosity-permeability correlation for each rock type from core measurement. Based on the geologist's interpretation, eight rock types exist in the reservoir, namely rock types 1 through 8. Rock types 1, 2, 3, and 5 are reservoir rock, whereas rock types 4, 6, 7, and 8 are non-reservoir rock. For simulation purposes, all non-reservoir rocks are combined and renamed as rock type 4. Therefore, there are only 5 categorical variables used in the simulation.

In order to have detailed reservoir description, the grid block size needs to be made as small as possible. This requirement will be constrained by the computer facility. As the geology indicates that the reservoir varies more rapidly in the vertical direction than the horizontal direction, the grid block would be sized differently for each direction. The grid block size used was 1 foot in the vertical (z) direction and 55 feet in the horizontal (x and y) directions. With this configuration, the number of grid blocks required to cover Section 329 is 8,088,498 grid blocks, and to cover Section 5 is 14,505,580 grid blocks. These huge numbers of grid blocks are difficult to simulate at once. Therefore, the reservoir is divided into several sub-sections. To avoid the discontinuity in the horizontal direction, the reservoir divisions are performed primarily in the vertical direction, that is, the reservoir is divided into several layers. There are 11 geostatistical layers defined for these geostatistical simulations as shown in **Fig. 47**. Each layer may consist of several flow units and cross-flow barriers.

For each simulation layer, the rock type and porosity data are arranged in the GEOEAS format. In addition, the categorical data of the rock type and the Gaussian data of the porosity are also prepared for variogram calculation using the same format.

Spatial Relationship/Variogram Determination: One of the inputs required in conducting the conditional simulation is the spatial relationship or variogram of the variable being simulated. The variogram calculation is one of the most difficult and time consuming tasks in the whole process of generating reservoir descriptions. Due to the nature of the data, the spatial relationship in the vertical direction is relatively easy to obtain since the data are available at the resolution of 1 foot. **Fig. 48** shows an example of a vertical variogram for rock types 1 to 4 for model layer 6.

In the horizontal direction, the variogram modelling is difficult since the data are available only at the well location. Therefore, the resolution of the data is dictated by the closest distance between two wells. This creates problems in modelling the horizontal variogram, where if we use vertical data on a foot by foot basis, we can only obtain random distribution or pure nugget effect that does not tell us anything about spatial relationship of that variable in the horizontal direction.

To overcome this difficulty, a new technique was developed and used. Instead of directly calculating the variogram of point values, the thickness of the rock type and the average of porosity at each well was used in the variogram calculation. Using this technique, we can obtain the range of the variogram in the horizontal direction. The sill value of the variogram is assumed to be the same as the sill of the vertical variogram. **Figs. 49-50** show examples of the horizontal variogram calculated using this technique.

Simulation of Several Realizations: Several simulation runs were made for Section 329 and Section 5. The images of some of these realizations are presented next. **Fig. 51** shows the comparison of the histogram of the conditioning data and simulation results for the porosity of layer 9 - Section 329. We can see clearly that the simulation result honors the distribution of the conditioning data very well.

An important aspect that must be produced by the program is the consistency of the generated petro-physical properties with its underlying rock type. **Figs. 52-55** are shown here to demonstrate this aspect. **Fig. 52** is the cross section of porosity and rock type at the depth of 150 feet below the top of layer 1 - Section 329, whereas **Figs. 53-55** present the 3-D view of rock type, porosity, and permeability of layer 1 - Section 5. It can be observed that the porosity and permeability values are influenced by the underlying rock type.

Other observations which can be made by observing the simulated results of the rock type is the continuity in the horizontal direction and the discontinuity in the vertical direction as shown in **Figs. 56-57. Fig. 56** is the 3-D view of layer 9 - Section 5, whereas **Fig. 57** is the 3-D view of layer 11 - Section 5. The degree of continuity and discontinuity is a function of the range of the variogram modelling.

The generation of several realizations is required to quantify the uncertainty in the estimation process. For this purpose, several realizations have been generated. **Fig. 58** presents the cross-sections of the rock type at 50 feet below the top of layer 5 - Section 5. It can be observed that very similar images are obtained.

Connectivity Function

Introduction

Connectivity is used to describe whether a portion of a reservoir is connected to a well by a continuous permeable path, so that fluid can flow from the reservoir element to the well or vice versa. To determine whether cells in a three-dimensional fine grid reservoir description are connected, the cells are first tested by comparing the permeability value in the grid with a threshold value. If the permeability of the cell exceeds a given permeability threshold value then the cell is permeable, otherwise it is impermeable. Next, all possible paths from the well completions through the permeable cells are tested. All permeable cells which have at least one permeable path to a well completion are connected. This is illustrated in **Fig. 59**.

Connectivity Calculations for Detailed Description

The procedure for calculation of connectivity starts with a fine grid array of permeability from the geostatistical reservoir description. The cell permeabilities are compared to the threshold permeability value, and an array of binary permeability indicator values is generated. A list of starting locations which corresponds to individual well perforations is provided. Starting from each perforation in turn, a pointer moves from cell to cell, trying each direction, and moving as far as possible through permeable cells only. Each cell that the pointer passes through is marked as connected and an array of binary connectivity indicator values is generated.

Results

The connectivity function was used to filter the geostatistical reservoir description to force the connected pore volume to agree with estimates of pore volume and original oil-in-place determined by material balance analysis of production data.

The material balance analysis estimate for OOIP was performed on the primary production data, so only the primary perforations in the original 40-acre wells were used as starting points. For varying permeability threshold values, the connected cells and the resulting connected pore volume were calculated. The process was repeated iteratively until the pore volume converged to the desired value. For the Section 329 model a threshold of 0.351 md resulted in a connected pore volume of 49.4 MMRB.

Since this pore volume corresponded only to the reservoir connected during the primary production period, the connectivity calculation was performed again using the same permeability threshold but with more starting locations corresponding to all existing wells and perforations. This increased the connected pore volume by 16% to 57.3 MMRB. This was the pore volume which was subsequently scaled up for the flow simulator. Another calculation of connected pore volume was made as a check using additional starting locations representing hypothetical infill wells on 10-acre spacing and uniformly perforated with one shot per foot. This did not result in a significant pore volume increase.

Views of the resulting grid showing impermeable, permeable-disconnected, and permeable-connected cells are shown on **Figs. 60-61.**

<u>Upscaling of Petrophysical Properties</u>

Upscaling of Porosity

Petrophysical properties must be upscaled from the fine grid of the geostatistical reservoir description for use with the coarser grid of the reservoir flow simulator. Porosity is scaled up as a volumetric average, and weighted by the connectivity indicator. In other words, impermeable and disconnected cells are assigned zero porosity, and then the porosities of all the fine grid cells contained within a coarse grid block are arithmetically averaged.

Upscaling of Permeability

Permeability is more complicated to upscale because of its directional nature. The incomplete layers method was used to upscale the permeability values. Along the direction of each grid axis in each coarse grid block, two different average permeabilities are calculated, and then averaged together. The first average assumes no crossflow. The permeability of the fine grid cells in series along the flow direction are averaged harmonically. Then those averages for parallel strings of cells are averaged arithmetically.

The second average assumes "vertical" equilibrium, that is actually equilibrium in the layer cells perpendicular to the flow direction. The permeability of the fine grid cells parallel to the flow direction are averaged arithmetically, then those averages for layers of cells in series are averaged harmonically.

The final permeability is calculated as the geometric average of the no-crossflow and vertical equilibrium averages. This is repeated for each coarse grid along each axis.

The procedure is shown in **Fig. 62** for y-direction permeability in a 3x3x3 block of cells. Using this procedure, the detailed permeability values generated using the COSIM program are upscaled in all three directions. The upscaled values are used for flow simulation.

RESERVOIR SIMULATION

An important objective of this project has been to perform 3-D reservoir simulation for history matching, infill drilling development forecasting, and validation. The results of conventional deterministic simulation runs have been compared to the results of runs using the geostatistical reservoir description. A black oil, three-phase simulator has been utilized. Objectives of the reservoir simulation include:

- Selection of optimum infill drilling sites within the North Robertson Unit
- Prediction of future reservoir performance
- Validation or comparison of predicted and actual reservoir performance during the Field Demonstration phase of the project (Budget Period II)

Full-Unit vs. Partial-Unit Models

The types of models which have been constructed are partial-unit models. The areas for these partial-unit models have been selected based primarily on an understanding of the reservoir performance factors discussed below. In addition, the locations of the partial-unit models have been verified by considering the geologic model and the results of decline type curve analyses.

A full-unit model was not constructed due to the large number of wells in the Unit (252 wells), and the need to focus on detailed flow simulation in areas with the best potential for infill drilling. A full-unit simulation would result in a cumbersome model with a large number of grid blocks primarily due to the large vertical section in the Glorieta/Clearfork and the large number of layers required to adequately model this vertically heterogeneous reservoir. By using partial unit models, the resulting smaller grid block sizes have allowed for more detailed flow simulation in the model areas. .

Reservoir Performance Criteria

In order to identify the partial-unit model areas, reservoir performance factors have been considered to identify the regions which possess good potential for infill drilling from those with little or no potential for infill drilling. These performance attributes for selecting simulation areas at NRU are:

Potential Desirable Areas for Infill Drilling

- *Areas of high productivity*
  - High primary and secondary recovery

- Presence of pay rock types (rock types 1 and 2)
- Good porosity and permeability characteristics

- ***Areas of poor reservoir continuity***

  - Good primary recovery but poor secondary recovery
  - Poor waterflood pattern balance of water injected to fluids produced
  - Current production with high oil cut and relatively low secondary production (indicative of compartmentalization)

Potential Undesirable Areas for Infill Drilling

- Good pattern balance of water injected to fluids produced
- Flat or increasing oil cut (may be indicative of good waterflood sweep efficiency)
- High ratio of secondary estimated ultimate recovery (EUR) to primary EUR
- Uniform increase in pressure in surrounding areas indicating good reservoir continuity

<u>Selection of Modelling Areas</u>

A selection or scoring criteria was devised to identify the desirable locations for infill drilling based on the following readily available reservoir performance parameters:

- Cumulative primary to secondary recovery ratio (PSR)
- Cumulative replacement ratio (CRR)
- Water/oil ratio (WOR)

The cumulative replacement ratio (CRR) is defined as ratio between the cumulative volume of water injected and the cumulative volume of total produced fluids.

Production and injection data was allocated to 5-spot waterflood cells, and the reservoir performance parameters were calculated for each cell. Average Unit values for each of the scoring criteria were calculated, and each cell was assigned one scoring point for having a higher than average CPP, PSR, or CRR, and a lower than average WOR.

The results of the selection process are shown in **Fig. 63**, which was generated using a statistical analysis software package.[33] The areas which are shaded lighter (higher score on 0-4 scale) represent the desirable areas for infill drilling. The darker regions represent areas which may be undesirable for infill drilling. For the most part, these desirable areas coincide with those identified by reservoir performance maps generated from decline type curve analysis on the 20- and 40-acre producing wells (**Figs. 20-25**).

Several areas in the Unit were selected for detailed reservoir simulation. The lighter shaded areas in **Fig. 63** have good infill drilling potential. The darker shaded areas have relatively poorer infill potential. The total number of wells in the modelling areas range between approximately 20 and 40 wells.

Injectors served as boundary wells for all the simulation areas. This configuration was chosen since it is more practical to allocate injection rather than production for the boundary wells. Also for allocation purposes, the injection rate data are more reliable than the oil production data since water injection commenced more recently and is under the control of a single operator.

Reservoir surveillance activities, which consisted primarily of pressure transient tests recorded to monitor reservoir pressure and formation flow characteristics, and TDT logs run to monitor fluid movement in the reservoir, were obtained in and around the modelling areas to obtain additional information for history matching and development forecasting.

<u>Models Developed</u>

The simulation models which have been developed at North Robertson are shown in **Fig. 64**. Three models have been completed so far. These models are the Section 329/324 model, Section 327/326 model, and Section 5 model. The model in the Section 325 area has been initialized and further work will be performed during Budget Period II. Reservoir performance analyses indicate that Section 325 is a poor area for infill drilling. Completing this model during the second Budget Period will validate this concept with numerical modelling.

Also shown in **Fig. 64** are two more models to be constructed in the Section 326 and Section 362 areas of the Unit. The Section 326 area model has some modelling area in common with the Sections 327/326 and Section 5 area models. This model design configuration for the Section 326 area is intentional as it will help validate the role of flux in this multi-patterned waterflood. We have made a simplifying assumption in all the models that flux across the Unit is not a significant performance or producing mechanism. On the other hand, it is possible that this simplifying no-flow boundary assumption is invalid due to interwell fracture communication observed from pressure falloff test results. This assumption will be reconsidered during Budget Period II on a case-by-case basis for each of the model areas. Completing the Section 326 area model will help determine the validity of the boundary flux premise.

The Section 362 area model will be completed during Budget Period II as this area is included in the Field Demonstration. Completing this model will be useful in determining whether reservoir performance and geologic analyses can be used as stand-alone tools for selecting well locations. The single well to be drilled in Section 362 during the Field Demonstration has been selected on this basis.

Models on well over half of the Unit have already been completed. Nearly the entire Unit will be modelled after the completion of the remaining models during Budget Period II. The very first area modelled during the project was Section 329. This simulation model is about half the size of the other models which encompass approximately 640 surface acres and about 21,000 simulation grid blocks. We were able to develop and test techniques for effective partial-unit model studies by first modelling the smaller area in Section 329. The models in Sections 327/326 and Section 5 were developed subsequent to development of the Section 329 model. The Section 325 model was also initialized after we had experience modelling the Section 329 area.

Simulation Initialization

The layering for the deterministic simulation consists of 39 layers (19 flow units, 19 flow barriers, and 1 water layer). The Tubb horizon/marker is treated as a true cross-flow barrier. The Clearfork lime has been included as a potential water source. It is believed that some of the new 20-acre producing wells were hydraulically fractured into this water source.

There are two PVT regions, one for the upper Clearfork and one for the lower Clearfork. The models were initialized to known initial pressures. Water saturations were obtained from the rock/log solutions.

Model volumetrics were calibrated to the material balance decline type curve original contacted oil-in-place volumes. The intrinsic grid properties for permeabilities and porosities were obtained from the rock-log solutions. Relative permeabilities were a history match parameter.

PVT Data for Initialization

The analysis of available fluid data has conclusively established that the fluid properties of the upper and lower Clearfork reservoir fluids are different and need to be treated as two separate PVT regions during simulation to properly represent the phase behavior interactions in the reservoir.

Some of the differences between upper and lower Clearfork reservoir fluid are illustrated in **Table 4.** The data are based on black oil PVT laboratory studies conducted on fluid samples obtained from NRU 3522 and 3013 during 1991.

The feasibility of using the original PVT data from bottomhole samples acquired on offset leases in 1947 (lower Clearfork) and 1958 (upper Clearfork) was considered. The utilization of this data was considered by using a phase behavior simulator to match the original and recently acquired (1991) PVT data. The validation results indicate that the "original" data may be used to represent PVT properties since the data were found to be consistent with laboratory fluid tests conducted on the surface recombined samples collected in 1991.

The accurate representation of the initial fluid data, along with the integrated reservoir characterization undertaken, have allowed the physical processes occurring in the reservoir to be accurately modelled. By using the original data, the simulator automatically adjusted original properties to fluid properties at any subsequent time in the history match or forecast. The fluid properties for the wide range of depletion and repressurization paths have been properly represented.

Rock-Fluid Interaction Data for Initialization

Existing special core data which has been used for the simulation studies are primarily relative permeability data. A total of thirteen steady-state displacements for two cored wells (NRU wells 207 and 3522) were conducted. The displacements include data from the upper, middle, and lower Clearfork. Additional special core work will be completed when new wells are drilled during the Field Demonstration.

Model Gridding

The size of the grid cells used for the modelling are 165 feet x 165 feet. These are the DX and DY dimensions. The vertical, or DZ dimension, will vary depending on the geologic layering scheme for the specific area in the model. The grid block size is approximately equal to the lateral extent of the hydraulic fractures on the producing wells. **Fig 65** shows an example of the grid configuration for the Section 329 area model.

Adjustments to grid block pore volumes on the boundary of the models have been made to account for geometry. This generally requires cutting back pore volumes on the periphery to account for factors like half or quarter boundary wells.

A sufficient number of grid blocks have been included between wells to properly model flow behavior.

History Match Criteria and Procedure

Allocated production data (oil, water, gas) were the primary history match criteria. More weight was put on the oil match than water and gas, which were not measured as accurately as the oil. Pressure data are not available for the primary depletion phase of the history match (1956-1987). The initial reservoir pressure is known (2800 psia), and a limited amount of pressure data for the period prior to water injection and during reservoir fill-up are available.

Another important history match criteria used in the modelling was matching the arrival of fluids (water). Early water production in the field was matched as well as the water production from the 20-acre infill drilling program and waterflood response. The increase in GOR during waterflood fill-up, and then its subsequent decrease to a solution gas GOR level was also matched.

The general procedure followed during the match was to first assemble the performance data. This has been happening throughout Budget Period I. The quality of the performance data was screened and evaluated for use in the match. Match results were compared with actual history and the results analyzed. At this stage any potential adjustments were evaluated to determine if they would be consistent with reality. Adjustments which could be physically supported were then incorporated into the model and the process described above was repeated until an adequate match was obtained.

History Match Techniques

One of the overall goals in this project was to try different evaluation techniques and determine which are most appropriate for application in this work. An important aspect of reservoir simulation involves determining how to ensure a smooth transition to future reservoir forecasts. Three separate techniques were investigated for ensuring a smooth transition from history to forecast. These techniques included a "forced oil match with productivity index (PI) tuning", a "predictive history match with no PI tuning", and a hybrid method, using aspects from the two previous techniques, and were all tested and used. Details on these techniques are now discussed.

First we discuss the forced oil match with PI tuning. In this method there is a "forced" oil match since it is the best known volume parameter during history. This process is widely used in industry and well accepted. PI tuning is generally necessary at the end of history to ensure a smooth transition to the forecast phase of the simulation.

An alternative technique is conducting what is known as a predictive history match with no PI tuning. In this method, the PI tuning parameters are set at the beginning of the match. The match is generally based on the total volumes of all the produced fluids. No adjustments to the PI of the existing wells are made at the end of history. With this technique the emphasis is on a good overall match of the trends, however, sometimes it may be difficult to obtain a good match on a desired fluid over the entire history match period. Emphasis is therefore towards a good overall match on the cumulative fluid production.

As the modelling progressed at North Robertson, a hybrid technique was developed for use in the models. This technique initially involves the use of a forced oil match with PI tuning. PI tuning changes at the end of history are kept to a minimum since adjustments were made at the beginning of the history, during history, and with recompletions or other significant well activity. Thus, as the match progresses, elements of the predictive history match technique are incorporated.

Modelling Enhancements During Budget Period I

As with reservoir management and surveillance, modelling is an activity which deserves ongoing attention. Improvements are always possible. Enhancements were made to the North Robertson models by improving the existing models several times. This process of adding enhancements improved our ability to use this simulation for selecting the Field Demonstration well locations. Improvements which were made to the models included many items, some of which are described below.

In the early models, the focus was on a good overall match. This was improved by obtaining good well-by-well matches with subsequent models. An "outside" source of water was added to the model to match the early and late water breakthrough. A potential aquifer function was added to match early water production. Hydraulic fracs on producing wells were extended to an aquifer to match late water breakthrough. This water source is physically supported by the geology of the lower Clearfork.

Another enhancement involved constructing a model to represent the "real" pay at North Robertson. This was accomplished by making adjustments consistent with the findings from the material balance decline type curve analysis. Vertical communication with layers other than the Tubb was another enhancement necessary to obtain a good match and to be consistent with the vertical flow realities in the Clearfork. As mentioned earlier, modelling enhancements also included calibration of PIs on wells during the match instead of just at the end of the match.

Modelling Enhancements During Budget Period II

Our simulation models will be updated and improved during Budget Period II as new data are obtained from the Field Demonstration. More work will be done in the pseudoization of reservoir properties especially relative permeabilities. These enhancements may result in better representation of water breakthrough.

The number of model layers may be reduced as we gain a better understanding of reservoir flow mechanisms from data acquired during the Field Demonstration phase of the project. We will also investigate the use of a dual-porosity simulation model to better capture the behavior of a reservoir with high permeability productive streaks surrounded by large intervals of low permeability rocks that may act as a hydrocarbon source for those high-perm productive intervals. We also expect to obtain more insight into the reservoir directional permeabilities with additional geological and surveillance data.

Simulation Results

In the remaining sections, we describe summary results from the various models which were used in the assessment of geologically targeted infill drilling at the North Robertson Unit. A wealth of information is obtained in the course of a reservoir simulation study. Results can be analyzed using many different post-processing techniques. To provide a flavor of some of the possibilities, these summary results are presented in a range of formats for different models. The objective here is to provide some perspective of how other operators may go about assessing results from such a study for geologically targeted wells. With the results, some additional perspective is provided on the history match process where appropriate. Much of this additional perspective on the match pertains to the Section 329 model, as it was the first area modelled. The experiences gained and processes developed from the match were then applied to the models in the other areas.

Section 329 Reservoir Simulation Results

Two approaches were used for modelling Section 329: one based on a deterministic reservoir description, and the other based on the geostatistical reservoir description.

History Match

Matching the water production data was the key issue. The initial log-derived water saturation, relative permeability, and water production history were not completely consistent with each other and had to be modified. The water saturation was increased above the log-derived average in the lower layers of the model by adjusting the capillary equilibrium parameters and water oil contact.

A single set of relative permeability curves was used for each model. The initial set was averaged by simulation of a grid with regions for each of the laboratory measured curves in parallel. Water and gas production rates were adjusted by scaling the relative permeability curves. Water relative permeability was increased and gas relative permeability was decreased. The saturations at the relative permeability endpoints were not changed from the averages derived from the laboratory data.

The initial pore volume in the deterministic model based on log-derived parameters was too large and was reduced by a factor of 0.67. This brought the original oil-in-place into agreement with the material balance derived estimate, when only the part of the reservoir open to producing wells was considered.

The water production behavior just before and after the beginning of the waterflood was especially difficult to match. In general, an attempt was made to avoid arbitrary local changes in the grid properties other than changes in well productivity indices, however, some local adjustments were made in trying to match this part of the history.

The specific problem was the high water production of the infill wells completed before water injection began in the model area, which increased after water injection began but then decreased before starting a more normal appearing response to the waterflood. This behavior did not appear to be explained by anything in the reservoir model, or by changes in wells outside of the model area. A less than satisfactory match was obtained in the deterministic model by increasing the permeability and well productivity indices in the lowest layer of the model with the highest water saturation.

Later, a much improved match was obtained in the geostatistical model by adding another water productive layer at the bottom of the model. This was assumed to be isolated from the rest of the reservoir until the infill wells were drilled and inadvertently fractured into the underlying layer, which produced water for a while but eventually depleted with no injection support.

Skin factors were adjusted in the history match to keep the flowing bottomhole pressures within reasonable bounds. During the last year of the history match the skin was adjusted to match the bottomhole pressure specified for the forecast.

Plots comparing the oil rate and water cut from the models to the observed data are shown on **Fig 66-69** for the deterministic and geostatistical models. The geostatistical model improved the speed of the history match by requiring fewer changes than were required for the deterministic model history match. The match with the observed water cut using the geostatistical model was much better than the deterministic model.

Future Performance Prediction

After the models were calibrated by history matching, they were ready to be used for forecasting. Bottomhole pressures were specified as 300 psig in producing wells and 3,500 psig in injection wells. The maximum water cut in producing wells was limited to 97.5%, above which the wells were shut in. In general, the completions of existing wells were not changed. Skin factors were held constant after the end of the history match. Prediction cases were run through the year 2025. None of the cases completely watered out before then.

The base forecast case was the continued operation of the current wells. Additional cases were run to investigate the effect of well deepenings and other reservoir management strategies. The key forecast cases compared uniform infill drilling on line-drive and 5-spot well patterns. In these cases the line-drive consistently produced more oil than the 5-spot.

Early forecasts were made with new wells completed in the same intervals as the current wells which had been history matched. Additional cases investigated the impact of completing new wells in the Glorieta interval, which had not been produced historically in this area of the Unit, but which appeared to have a high flow capacity according to the geologic reservoir description.

Final forecasts were made with both the deterministic and geostatistical models. These include: continuation of the current operation, uniform infill drilling on a line-drive pattern, and several options for selected infill drilling on a line-drive pattern. An example of a geologically targeted forecast scenario representing the Phase I drilling program for Section 329 with a line-drive pattern is shown in **Fig. 70.**

The geostatistical model forecasts of oil rate and cumulative oil versus time for the full line-drive and continuation cases are shown in **Figs. 71-72**. The plot shown in **Fig. 73** summarizes the forecasts of cumulative oil, incremental oil, and incremental oil per well versus the number of new infill wells for the deterministic and geostatistical models.

Section 327 Reservoir Simulation Results

We now describe the results from the Section 327 deterministic reservoir modelling. **Fig. 74** is a location map of the existing wells in this model area.

History Match

The overall match is excellent and is a "forced oil" match as shown in **Fig 75**. The matches on historical water cut trends and GOR are very good. The late water cut response due to the 20-acre infill drilling program and waterflood response are also matched well. The match on the cumulative production volumes of oil, gas, and water are shown in **Fig 76**. We also meet the target rate for water injection during the waterflood as shown in **Fig 77**.

Extremely good well-by-well matches were obtained on each and every well in the model. Here, we will show two examples, one for a 40-acre well and one for a 20-acre well. The rate and cumulative production matches for 40-acre well NRU 502 are shown in **Figs. 78-79**, respectively. These same plots are shown for 20-acre well NRU 1505 in **Figs. 80-81**. Again, as with the full model results, matches for rates, trends, fluid arrivals, and cumulatives on these and other individual wells were excellent.

An important tool which can be used in geologically targeting wells is considering oil saturations at the end of history. **Fig. 82** shows the oil saturation at the end of history in 1995 for the lower Clearfork. The saturations shown are pore volume weighted. These oil saturations are lower than in the upper layers. This result is expected as the geologic analysis indicated that this interval is the most continuous, and possesses a relatively high absolute permeability, resulting in more efficient sweep.

Future Performance Prediction

We now discuss some forecast cases run with this model. A line-drive infill prediction case in which new injectors and producers are drilled is shown in **Fig. 83**. The estimated ultimate recoveries for drilling new wells is shown. A similar plot is shown for the five-spot infill case in **Fig 84**, where only new producers are drilled. In this scenario, all existing producers are converted to injection. The results from these development scenarios were used to form the framework for model runs to geologically target infill wells in Section 327. Examples of some of the overall scenarios, as well as geologically targeted scenarios run are shown in **Tables 5-6**. These results were subsequently used to develop the framework for the specific Field Demonstration locations in Section 327 and the economic analysis.

Section 5 Reservoir Simulation Results

History Match

With no bottomhole pressure data available during primary production, it was decided to perform a "predictive history match" whereby bottomhole flowing pressure, p_{wf}, was constrained and projected fluid rates were matched to the field observed rates. This technique is especially applicable for reservoirs produced by artificial lift where the actual p_{wf} is constant or near constant.

Simulation tuning was achieved by global adjustments to permeability, water saturation, and pore volume. Tuning was performed on three distinct vertical sections which correspond to a three-stage completion procedure that was used extensively during field development. Typical completions involved selectively perforating, stimulating, and testing the lower Clearfork followed by setting a bridge plug and proceeding to the middle Clearfork. The bridge plug was then retrieved, drilled out or pushed to the bottom allowing these two zones to produce commingled. Completions in the upper Clearfork and Glorieta zones were subsequently added.

Results of the performance history match, including monthly volumes and cumulative production, is shown in **Fig. 85**. The actual and model injection volumes are shown in **Fig. 86**.

Future Performance Prediction

Simulation cases for continued operations and pattern 10-acre infill drilling with both line-drive and 5-spot patterns were performed. Line-drive and 5-spot recoveries were comparable. In order to determine what region within the Section 5 area would be best suited for geologically targeted infill drilling, cases were run in which an individual well was drilled at a 10-acre location and incremental reserves were calculated. Results of the study indicated incremental reserves ranging from 17 MSTB to 62 MSTB per well, with an average of 40 MSTB. These reserves were significantly lower than the Section 329 and 327 areas. Therefore, the focus of the Field Demonstration plan was not in the Section 5 area.

DATA ACQUISITION - INFILL DRILLING

Statement on Data Quality and Quantity

During the infill drilling phase of this project in Budget Period II, the acquisition of as much new data as is economically feasible will be carried out to verify the results of our previous geologic and engineering studies. This includes:

- Production data
  - Verification of simulation results
- Additional whole core for analysis
  - Verification of geologic model
  - Verification of rock-log model
  - Special core analysis
- New generation open-hole well logs
  - Use of the fracture identification tools to locate intervals with substantial secondary porosity that may have been previously ignored
  - Use of the formation test tool to record pressure data in each of the reservoir flow unit layers to determine if they are in communication
  - Use of borehole imaging tools to confirm the preferential fracture direction in the reservoir
- Pressure transient data acquisition
- Use of all available data to optimize completion/stimulation treatments

ECONOMIC EVALUATION AND FIELD DEMONSTRATION RECOMMENDATION

Summary

The recommendations made for the Field Demonstration outlined in the Executive Summary section of this document have been based on evaluating economic as well as other technical factors like geology and engineering. The tools and techniques developed in this project allow operators to geologically target well locations for infill drilling. This process results in infill drilling development which has more favorable economics than blanket drilling.

North Robertson Field Demonstration Implementation

For this project, rate-time projections have been developed from the reservoir flow simulation, reservoir performance analyses, and other technical work. These rate-time projections will serve as the basis for benchmarking our reservoir validation exercise during Budget Period II. We will be using this final projection to answer the following questions: 1) Will we achieve the expected reserves from a geologically targeted drilling program?; 2) Are the projections for initial rate and early decline rates good?; and 3) How much uncertainty will be acceptable when we try to predict the future performance of an extremely heterogeneous and compartmentalized SSC reservoir? These and other issues will be of interest to the industry now and during Budget Period II. These issues form the basis for addressing the economic status or success of a project.

Another measure of the economic viability of this project is to consider $/barrel reserve development cost. An extension of this concept which we have used is to determine the relative value of a geologically targeted program versus one in which the conventional approach of the past, blanket drilling, is used. This approach is illustrated below for consideration of various development options in the Section 327 area. The methodology was also applied in considering the development options for Section 329 development which is also part of the Field Demonstration.

Section 327 Development Options, Economic Indicators:

Development Case	Number of Producers (P), Injectors (I) & Ratio	Development Cost $/Barrel	Relative Value
Simulation Case 2 (Blanket Drilling)	16P, 16I, 1:1	9.72	1.00
Simulation Cases 2J, 2K	4P, 1I, 4:1	5.25-6.51	0.54-0.67
Simulation Case 2E, 2I	6P, 2I, 3:1	5.83-6.32	0.60-0.65
Simulation Case 2F	6P, 6I, 1:1	8.55	0.88

As illustrated above for some of the Section 327 development options considered, it is possible to identify target wells which will provide a much better economic result than blanket drilling alone. North Robertson, is a relatively deep SSC reservoir in the Permian Basin as our target well depths will be approximately 7,300 feet. For shallower, SSC reservoirs, like the San Andres formation, the $/Barrel development costs will be significantly less as many of these formations are under 4,000 feet deep and will have significantly lower drilling costs. At North Robertson, it is projected that a new producing well will cost approximately $510M. If the same reserves could be realized in a San Andres reservoir the wells could be drilled for about half the cost and would result in development costs well under $3 per barrel.

The relative costs and benefits of implementing geologically targeted will be illustrated in examples such as these in the technology transfer workshops. The costs and resource requirements needed to utilize the tools and techniques to geologically target wells will also be emphasized in these workshops as this will be of significant interest to the industry. In this project we hope to demonstrate that geologically targeted drilling will generate much better economics than blanket drilling. In the Section 327 area, blanket infill drilling in the example shown above would not result in an economically viable project.

TECHNOLOGY TRANSFER

Summary

A significant knowledge base has been developed in the reservoir management and reservoir characterization areas for Clearfork SSC reservoirs throughout Budget Period I. An important goal of the DOE, Fina, and the project team has been to disseminate this technology and information through the technology transfer mechanisms in place for the project. These mechanisms include report writing, the project newsletter, publications and presentations, and technical workshops with technology transfer packages.. All of the technology transfer activities have been well received by the industry personnel we have encountered as well as academic institutions, other organizations, and the DOE. Plans for the technology transfer workshops and packages have been discussed in the Executive Summary section of this document. We will continue these activities with a high degree of enthusiasm during Budget Period II.

Report Writing

The target audience for written reports is government officials, academic institutions, state geological societies, and hydrocarbon producing companies. Another important audience for these written reports include the Working Interest Owners at North Robertson, which comprise a range of operating companies from majors to large and small independents to small "individual" operators. These reports have served to effectively transfer key portions of the technology to the appropriate audience.

Newsletters

The first project newsletter was completed and distributed during November, 1995 which was fairly late in Budget Period I. The material had been prepared well ahead of schedule and the original plans were to develop and distribute these newsletters on a more regular basis. However, the quality of the completed newsletter was superb. Extremely favorable feedback was received from industry and the DOE. The difficulty associated with completing the newsletter by an earlier date was due to the fact that it was developed entirely "in-house". New desktop publishing software had to be installed. There was a steep learning curve for software utilization. Hardware issues with respect to the memory requirements needed to complete the newsletter had to be handled. Fortunately, the systems are in place, and future newsletters will be developed and completed in a more time-efficient manner during Budget Period II. Approximately 1,000 copies of the first newsletter have been distributed to industry. Based on the feedback received from the first newsletter, we need to continue using this tool for technology transfer.

Publications and Presentations

The primary audience for this effort is independent and major oil companies, service companies, academic and research institutions, state geological agencies, and geological societies. A large number of publications and presentations have been made in different technical and professional society forums during Budget Period I. These activities are ongoing and many more presentations and publications by the project team are scheduled during the next few months. A current list of technology transfer activities performed to date include:

- **Published Papers and Professional Meeting Presentations:**
  - SPE International Petroleum Conference and Exhibition of Mexico, October 10-13, 1994, Veracruz, Mexico:

    SPE 28688, "Decline Curve Analysis Using Type Curves - Analysis of Oil Well Production Data Using Material Balance Time: Application to Field Cases."

- West Texas Geological Society Symposium, October 31 - November 1, 1994, Midland, Texas:

  SPE 27760, "Data Acquisition Design and Implementation: Opportunities and Challenges For Effective Programs In Mature Reservoirs."

- AAPG Annual Convention, March 5-8, 1995, Houston, Texas:

  "Flow Unit Modelling of a Heterogeneous Shallow Shelf Carbonate Reservoir (Clear Fork/Glorieta), North Robertson Unit, Gaines County, Texas."

- SPE Rocky Mountain Regional Meeting and Low Permeability Reservoirs Symposium, March 20-22, 1995, Denver, Colorado:

  SPE 29594, "An Integrated Geologic and Engineering Reservoir Characterization of the North Robertson (Clearfork) Unit, Permian Basin, West Texas - A Case Study."

- Southwestern Petroleum Short Course, April 19-20, 1995, Lubbock, Texas:

  "An Integrated Geologic and Engineering Reservoir Characterization of the North Robertson (Clearfork) Unit, Permian Basin, West Texas - A Case Study."

- SPE Annual Technical Conference and Exhibition, October 22-25, 1995, Dallas, Texas:

  SPE 30774, "Decline Curve Analysis Using Type Curves: Water Influx/Waterflood Cases."

- SPE Permian Basin Oil and Gas Recovery Conference, March 27-29, 1996, Midland, Texas:

  SPE 29594, "An Integrated Geologic and Engineering Reservoir Characterization of the North Robertson (Clearfork) Unit, Permian Basin, West Texas - A Case Study."

  SPE 35161, "Pressure Transient Data Acquisition and Analysis Using Real Time Electromagnetic Telemetry."

  SPE 35183, "Identification and Distribution of Hydraulic Flow Units in a Heterogeneous Carbonate Reservoir: North Robertson Unit, West Texas."

  SPE 35205, "Evaluation of Injection Well Performance Using Decline Type Curves."

- **Poster Sessions/Public Presentation of Project:**

  - West Texas Geological Society Symposium, October 31 - November 1, 1994, Midland, Texas:

    SPE 27657, "Application of Integrated Reservoir Management and Reservoir Characterization To Optimize Infill Drilling."

- Permian Basin SPE Section Presentation, February 21, 1996, Midland, Texas:

  "Reservoir Characterization and Management - A Synergistic Approach To Development Optimization and Enhancing Value."

- **Conference Program and Technical Committee Contributions:**

  - SEG Development and Production Forum - "Cooperative Projects to Improve Reservoir Management," June 11-16, 1995, Snowmass, Colorado (oral presentation of project)

  - DOE Contractor Review Conference, coordinated by Bartlesville Project Office, June 25-29, 1995

  - SPE Forum Series in North America - "Risk and Confidence in Reserves Evaluation," July 30 - August 4, 1995, Snowmass, Colorado

  - SPE Forum Series in North America - "Multidisciplined Analysis and Solutions to Rejuvenating Old or Marginal Fields," August 6-11, 1995, Snowmass, Colorado (oral presentation and poster session on project)

  - 1996 SPE/SEG Forum on Application of Geophysics to Reservoir Development and Production

<u>Technology Transfer Workshops and Packages</u>

Technology transfer plans have been highlighted in the Executive Summary in a section detailing additional work to be performed during Budget Period I. These workshops and the associated tech transfer packages will be important aspects of the project's technology transfer program to ensure that the developed technology is communicated to the industry. The project team is taking this task very seriously as it is important to communicate the results, successes, failures, and other issues which have resulted from the project. We will do all we can to ensure that is a useful product. Reviews of the workshops will be requested from the participants to obtain the feedback necessary to improve future workshops.

NOMENCLATURE

FIELD VARIABLES:

Formation and Fluid Parameters:

RB	=	reservoir barrel
STB	=	stock tank barrel = 5.615 ft^3
scf	=	standard cubic foot
GOR	=	gas-oil ratio, scf/STB
BWI	=	barrel of injected water
BW	=	barrel of produced water
A	=	reservoir drainage or injection area, ft^2
ϕ	=	porosity, fraction
h	=	formation thickness, ft
k	=	formation permeability, md
B	=	formation volume factor, RB/STB
μ	=	viscosity, cp
c_t	=	total compressibility, $psia^{-1}$
GR	=	gamma ray log
PE	=	photoelectric capture cross-section, barns/electron
U_{maa}	=	apparent matrix volumetric cross-section, $barns/cm^3$
ρ_b	=	formation bulk density, $grams/cm^3$
ρ_b	=	apparent matrix grain density, $grams/cm^3$
SW	=	water saturation, decimal
P1RX	=	effective porosity used in rock-log model calculations
I88	=	tracer intensity from 1988 survey
V90	=	tracer velocity from 1990 survey
FT90	=	flowing temperature from 1990 survey
n_x	=	number of layers for permeability scale-up

Pressure/Rate/Time Parameters:

b	=	Fetkovich/Arps[12] decline curve exponent
b_{pss}	=	constant in the pseudosteady-state equation for liquid flow
q	=	flow rate, STB/D, BW/D, or BWI/D
N	=	original oil in place, STB
N_p	=	cumulative oil production, STB
$N_{p,mov}$	=	movable oil, STB
W_{tot}	=	total system volume for water injection, STB
W_i	=	cumulative water injection, STB
W_{mov}	=	total injectable water, STB
p	=	pressure, psia

p_i	=	initial reservoir pressure, psia
p_{wf}	=	flowing bottomhole pressure, psia
p_{ws}	=	shut-in bottomhole pressure, psia
Δp	=	p - p_{wf}, pressure drop, psi
$\Delta p'$	=	pressure drop derivative, psi
Δp_i	=	integral pressure drop, psi
$\Delta p_i'$	=	integral pressure drop derivative, psi
r_e	=	reservoir drainage radius, ft
r_w	=	wellbore radius, ft
r_{wa}	=	r_w exp($-s$), equivalent wellbore radius, ft
x_f	=	fracture half-length, ft
t	=	time, days
Δt	=	shut-in time, hours
t_{bar}	=	N_p/q, material balance time, days (oil production), and W_i/q_{wi}, material balance time, days (water injection)

DIMENSIONLESS VARIABLES: REAL DOMAIN

b_{Dpss}	=	pseudosteady-state correlating parameter defined by Blasingame[15]
q_{Dd}	=	dimensionless decline rate function as defined by Fetkovich[12]
q_{Ddi}	=	dimensionless decline rate integral as defined by McCray[13]
q_{Ddid}	=	dimensionless decline rate integral derivative function as defined by McCray[13]
r_{eD}	=	dimensionless drainage radius of reservoir
s	=	skin factor for near well damage or stimulation
t_{Dd}	=	dimensionless decline time as defined by Fetkovich[12]
p_D	=	dimensionless wellbore pressure function
p_D'	=	dimensionless wellbore pressure function derivative
C_{Df}	=	dimensionless wellbore storage coefficient based on fracture half-length
C_{fD}	=	dimensionless fracture conductivity
t_{LfD}	=	dimensionless time based on the fracture half-length
N_{pDd}	=	dimensionless decline cumulative production as defined by Blasingame[15]
$t_{Dd,Start}$	=	dimensionless start time for external boundary flux as defined by Blasingame[15]
$q_{Dext,\_}$	=	dimensionless strength term for external boundary flux as defined by Blasingame[15]

SPECIAL SUBSCRIPTS:

Dd	=	dimensionless decline variable
MP	=	match point
pss	=	pseudosteady-state
i	=	integral or initial
id	=	integral derivative
o	=	oil

w	=	water
wi	=	water injection
abs	=	absolute

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TABLE 1 - Pore Types Identified From Core Thin-sections, XRD, and SEM Analysis, after Davies (Ref. 1).

Pore Type	Size (μm)	Shape	Coordination Number	Aspect Ratio	Arrangement	Geologic Description
A	30 to 100	Triangular (Interparticle)	3 to 6 (Moderate)	> 50 - 100:1 (Moderate)	Interconnected	Primary Interparticle
B	60 to 120	Irregular (Generally elongate)	< 3 (Low)	up to 200:1 (High)	Isolated	Shell Molds - Dissolution Vugs
C	30 to 60	Irregular (Generally elongate)	< 3 (Low)	up to 100:1 (High)	Isolated	Shell Molds - Dissolution Vugs
D	15 to 30	Polyhedral	≈ 6 High	< 50:1 (Low)	Interconnected	Intercrystalline
E	5 to 15	Polyhedral	≈ 6 High	< 30:1 (Low)	Interconnected	Intercrystalline
F	3 to 5	Tetrahedral	≈ 6 High	< 20:1 (Low)	Interconnected	Intercrystalline
G	< 3	Sheet/Slot	1 (Intercrystalline Pore Throats)	1:1 (Intercrystalline Pore Throats)	Interconnected	Interboundary Sheet pores - Interconnect Intercrystalline Pores

TABLE 2 - Rock Types Defined for the Clearfork and Glorieta Formations, after Davies (Ref. 2).

Rock Type	Lithology	Dominant Pore Type	Secondary Pore Types	Median Core Porosity (%)	Median Core Permeability (md)	Recovery Efficiency (%)	Reservoir Quality	Crossflow Barrier Quality
1	Dolostone	A	B,C,D	4.0	0.70	35 - 45	Excellent	Poor
2	Dolostone	B,C	D,E	5.6	0.15	30 -35	Good	Poor
3	Dolostone	C	D,E	3.5	0.39	20 - 30	Poor	Moderate
4	Dolostone	B	F	7.5	0.01	35	Poor	Moderate
5	Limestone	C	A,D,E,F	5.8	0.40	30 - 35 (Water Bearing)	Good (Water Bearing)	Poor
6	Anhydritic Dolostone	C,D	F	1.0	0.01	0	None	Good
7	Silty Dolostone	E,F	---	2.3	0.01	0	None	Good
8	Shale	G	---	---	0.01	0	None	Good

TABLE 3 - Quantitative Analysis of Mercury-Air Capillary Pressure Data, after Davies (Ref. 1).

Rock Type	Throat Radius (μm)	Displacement Pressure (psia)	Ineffective Porosity at 500 psia injection pressure (%)
1	7.61 - 53.30	2 - 10	8.2 - 29.6
2	2.67 - 3.55	30 - 40	23.1 - 49.5
3	0.36 - 1.33	80 - 300	61.6 - 72.3
4	1.77	60	88.0
5	1.07 - 1.78	60 - 150	21.7 - 57.2
6	0.133	800	100
7	---	---	---
8	---	---	---

TABLE 4 - Results of PVT Analysis on 1991 Surface Fluid Samples (Upper & Lower Clearfork)

Fluid Properties	NRU 3522 (Section 329)	NRU 3013 (Section 327)
Zone	Upper Clearfork	Lower Clearfork
Sampling Date	February 7, 1991	February 11, 1991
Recombination Bubble Point	1,330 psia	1,305 psia
Oil Viscosity at Bubble Point	2.67 cp	1.32 cp
Oil Formation Volume Factor at Bubble Point	1.132 RB/STB	1.280 RB/STB
Oil Density at Bubble Point	0.848 gm/cc	0.762 gm/cc
Stock Tank Oil API Gravity at 60°F	30.5°	33.5°

Table 5

CASE DESCRIPTIONS - AREAL MODEL SIMULATIONS
CLEARFORK RESERVOIR, NORTH ROBERTSON UNIT, SECTION 327

<u>CASE 1</u> Continued historical production / injection scheme.
Sixteen production wells - with calibrated productivity indices. Pumps: min. BHFP = 80. psia.
Twenty-five water injection wells (one shutin). Rates assigned based on historical potential.
Production wells shutin at WOR = 49. (WCUT = 98. percent) No workovers.
Simulation terminated at 31/12/15 or mininum area oil production rate of 10. STB/day.
Water injection rates adjusted to maintain constant average reservoir pressure.

<u>CASE 2</u> Line - drive water injection with infill drilling. Same as CASE 1 except:
Twenty new production wells and twenty new water injection wells completed from 07/96 to 09/97.
Calibrated productivity indices of new production wells derived from values at offset wells.
Injection rates for new water injection wells derived from values at offset wells.
All new production and injection wells completed in all nineteen layers.
Water injection rates adjusted to maintain constant average reservoir pressure.

<u>CASE 4</u> Five - spot water injection with infill drilling. Same as CASE 1 except:
Forty new production wells drilled from 07/96 to 09/97.
Sixteen existing production wells converted to water injection from 07/96 to 06/97.
All new production wells completed in all nineteen layers.
All existing production and injection wells completed as in history period.
Water injection rates adjusted to maintain constant average reservoir pressure.

Table 6

CASE DESCRIPTIONS - AREAL MODEL SIMULATIONS
CLEARFORK RESERVOIR, NORTH ROBERTSON UNIT, SECTION 327

CASE 2A Same as Case 2 except:
Only six new producers drilled (NRLD03, NRLD04, NRLD08, NRLD09, NRLD13, NRLD14)
Only two new injectors drilled (NLD07W, NLD11W)

CASE 2B Same as Case 2 except:
Only two new producers drilled (NRLD11, NRLD12)
Only two new injectors drilled (NLD09W, NLD13W)

CASE 2C Same as Case 2 except:
Only two new producers drilled (NRLD11, NRLD12)
Only one new injector drilled (NLD09W)

CASE 2D Same as Case 2 except:
Only two new producers drilled (NRLD11, NRLD12)
Only one new injector drilled (NLD13W)

CASE 2E Same as Case 2 except:
Only six new producers drilled (NRLD07, NRLD08, NRLD09, NRLD12, NRLD13, NRLD14)
Only two new injectors drilled (NLD10W, NLD11W)

CASE 2F Same as Case 2 except:
Only six new producers drilled (NRLD07, NRLD08, NRLD09, NRLD12, NRLD13, NRLD14)
Only six new injectors drilled (NLD06W, NLD07W, NLD10W, NLD11W, NLD14W, NLD15W

CASE 2G Same as Case 2 except:
No new injectors drilled

CASE 2H Same as Case 2 except:
No new producers drilled

CASE 2I Same as Case 2 except:
Only six new producers drilled (NRLD08, NRLD09, NRLD13, NRLD14, NRLD18, NRLD19)
Only two new injectors drilled (NLD11W, NLD15W)

CASE 2J Same as Case 2 except:
Only four new producers drilled (NRLD08, NRLD09, NRLD13, NRLD14)
Only one new injector drilled (NLD11W)

CASE 2K Same as Case 2 except:
Only four new producers drilled (NRLD07, NRLD08, NRLD12, NRLD13)
Only one new injector drilled (NLD10W)

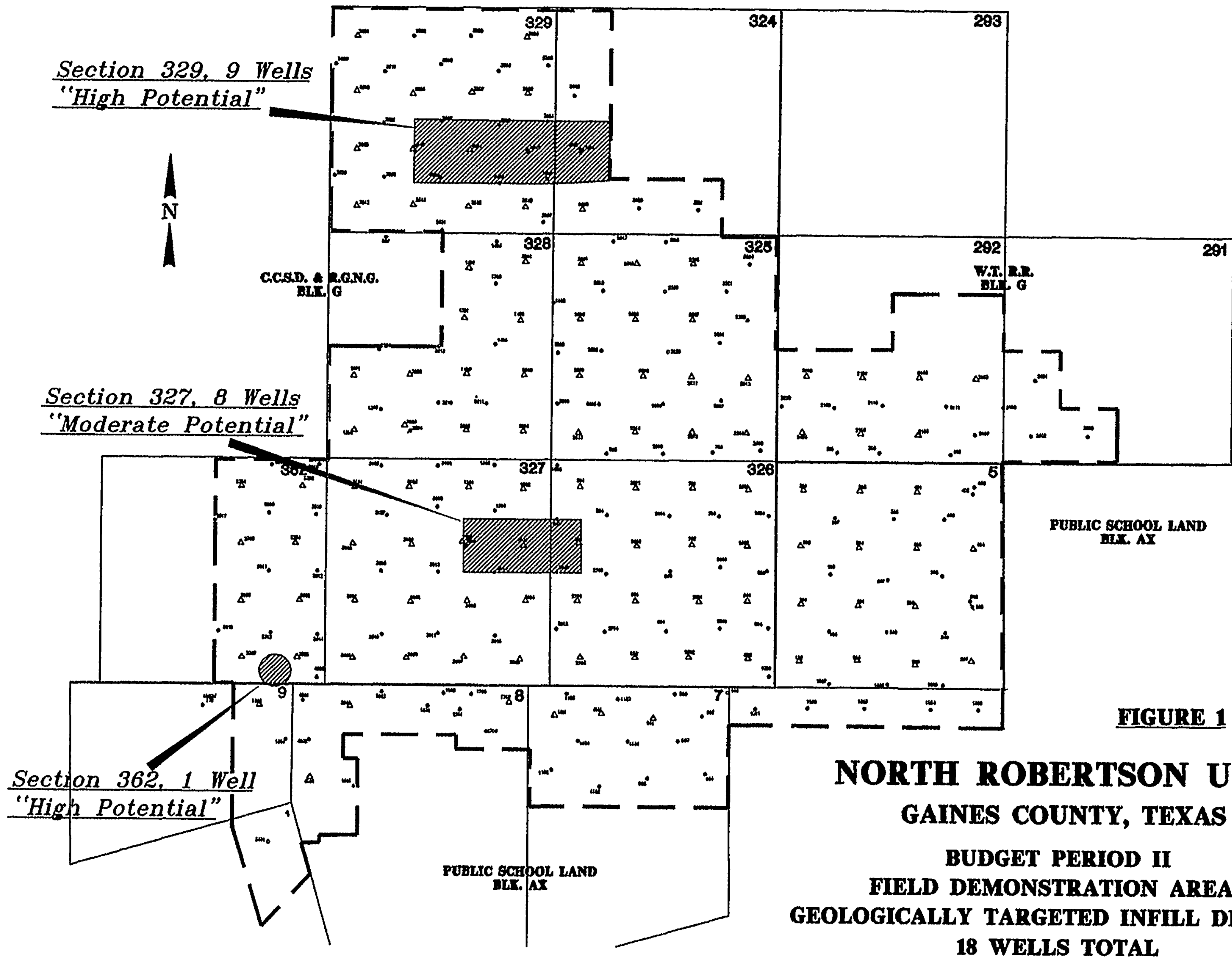


FIGURE 1

NORTH ROBERTSON UNIT

GAINES COUNTY, TEXAS

BUDGET PERIOD II
FIELD DEMONSTRATION AREAS
GEOLOGICALLY TARGETED INFILL DRILLING
18 WELLS TOTAL

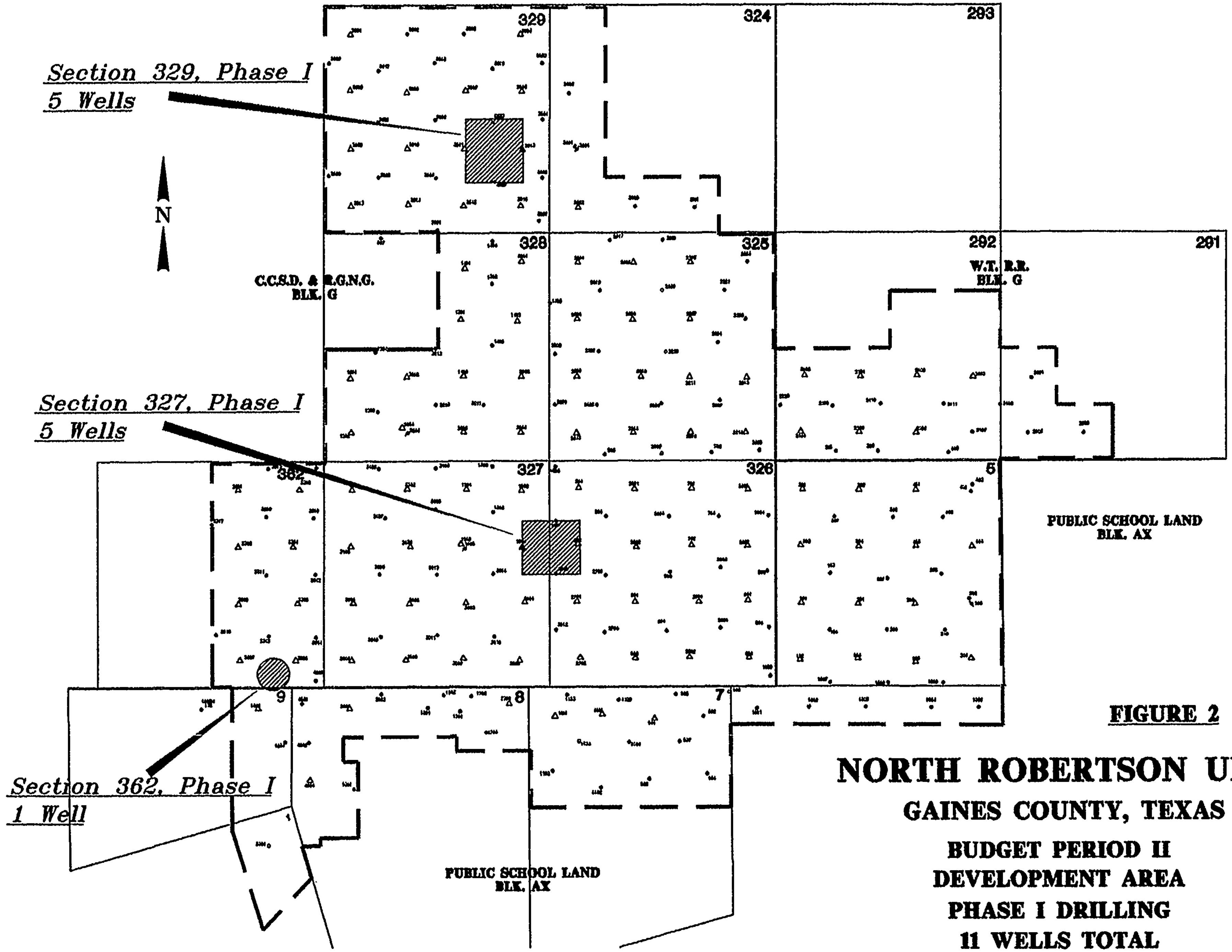


FIGURE 2

NORTH ROBERTSON UNIT

GAINES COUNTY, TEXAS

BUDGET PERIOD II
DEVELOPMENT AREA
PHASE I DRILLING
11 WELLS TOTAL

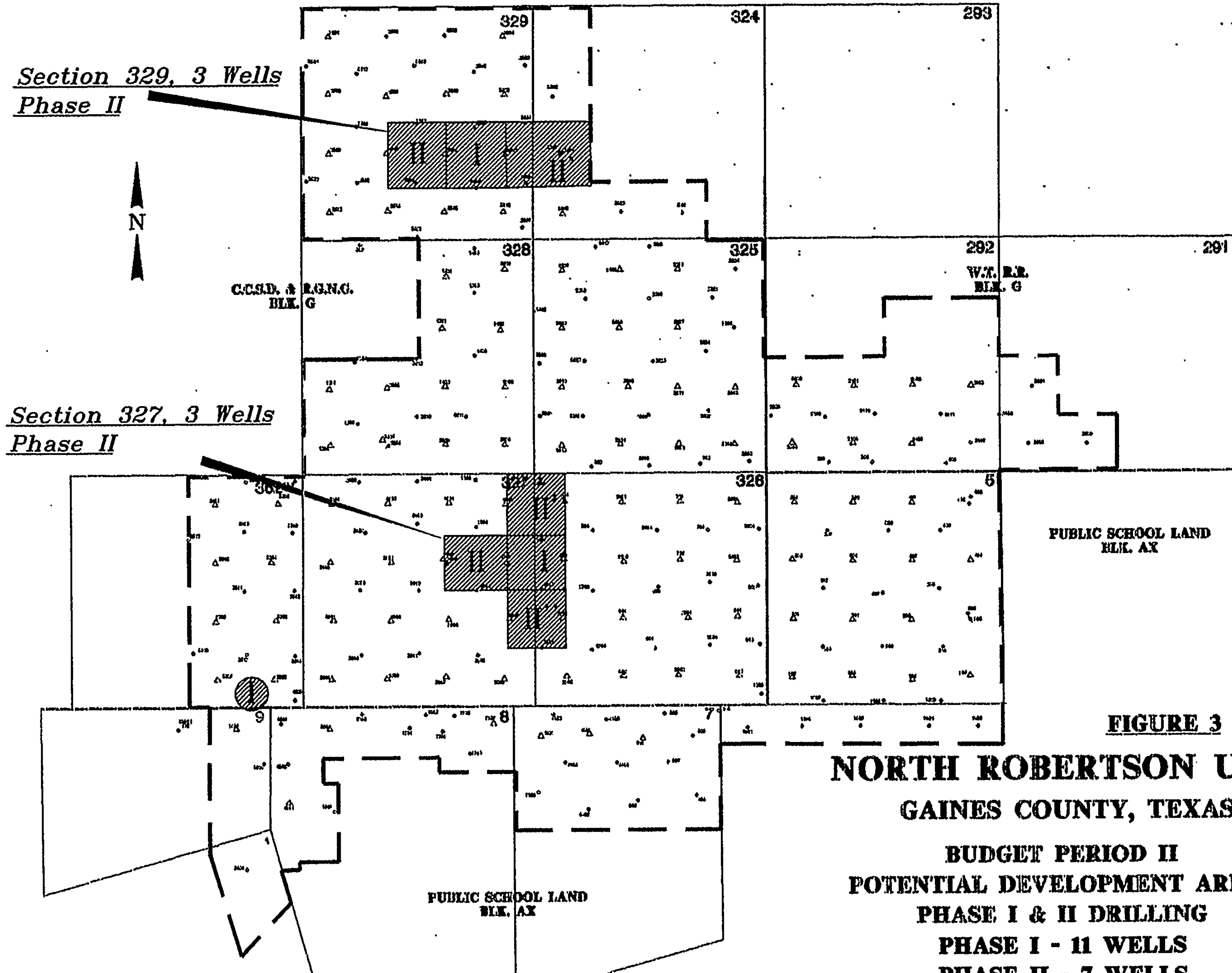


FIGURE 3

NORTH ROBERTSON UNIT

GAINES COUNTY, TEXAS

BUDGET PERIOD II
POTENTIAL DEVELOPMENT AREAS
PHASE I & II DRILLING
PHASE I - 11 WELLS
PHASE II - 7 WELLS

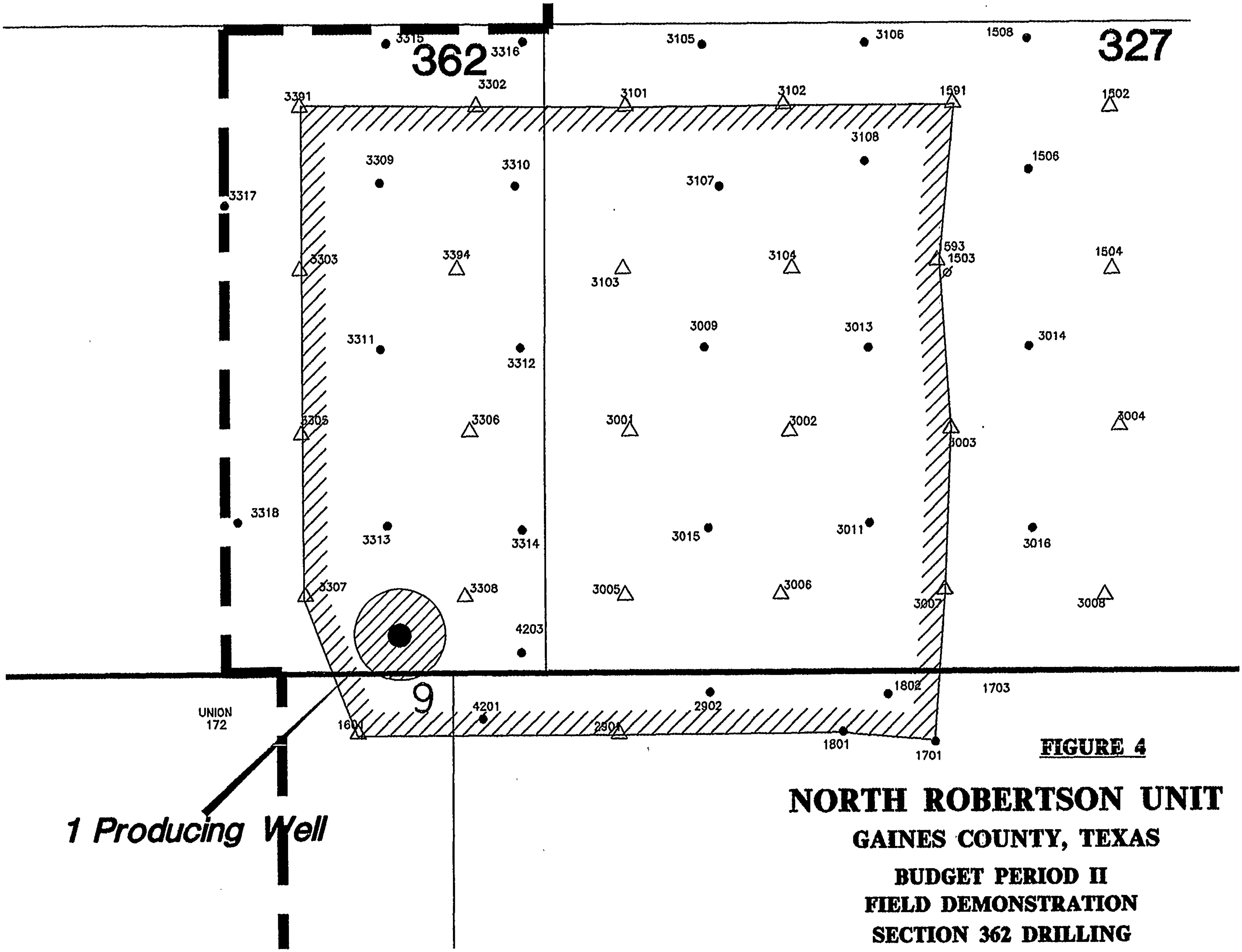


FIGURE 4

NORTH ROBERTSON UNIT
GAINES COUNTY, TEXAS
BUDGET PERIOD II
FIELD DEMONSTRATION
SECTION 362 DRILLING

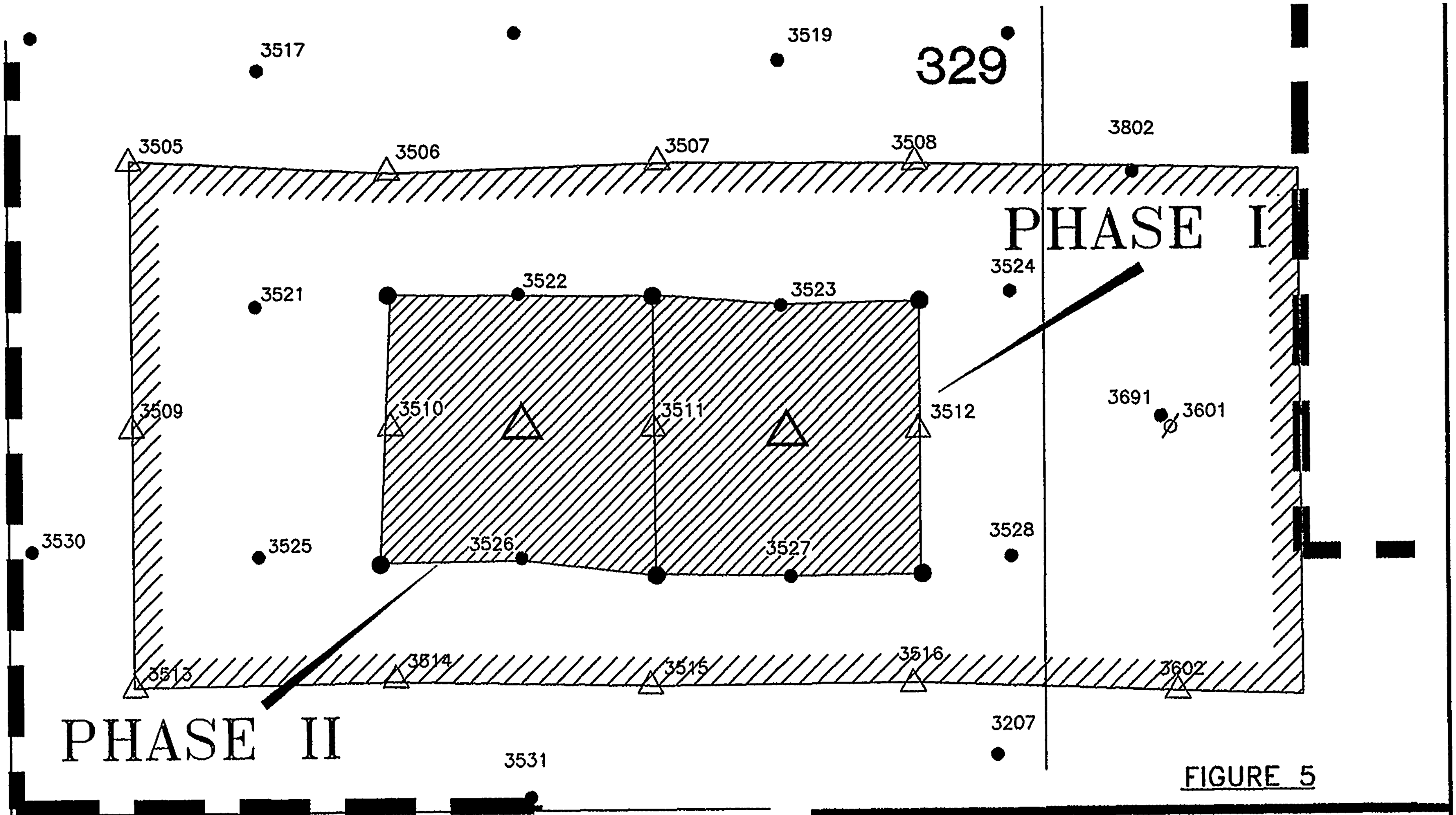


FIGURE 5

PHASE I: 5 Wells (4 Producers, 1 Injector)

PHASE II: 3 Wells (2 Producers, 1 Injector)

LEGEND

● NEW PRODUCER

△ NEW INJECTOR

FINA OIL & CHEMICAL CO.
WEST TEXAS DIVISION

NORTH ROBERTSON UNIT
GAINES COUNTY, TEXAS

BUDGET PERIOD II
FIELD DEMONSTRATION
SECTION 329 DRILLING
DEVELOPMENT SCENARIO A

Geology by:	DWG.: NRUSCENA Scale: NONE	Date: 1-96	Revised:	Drafted by: J.V.A.

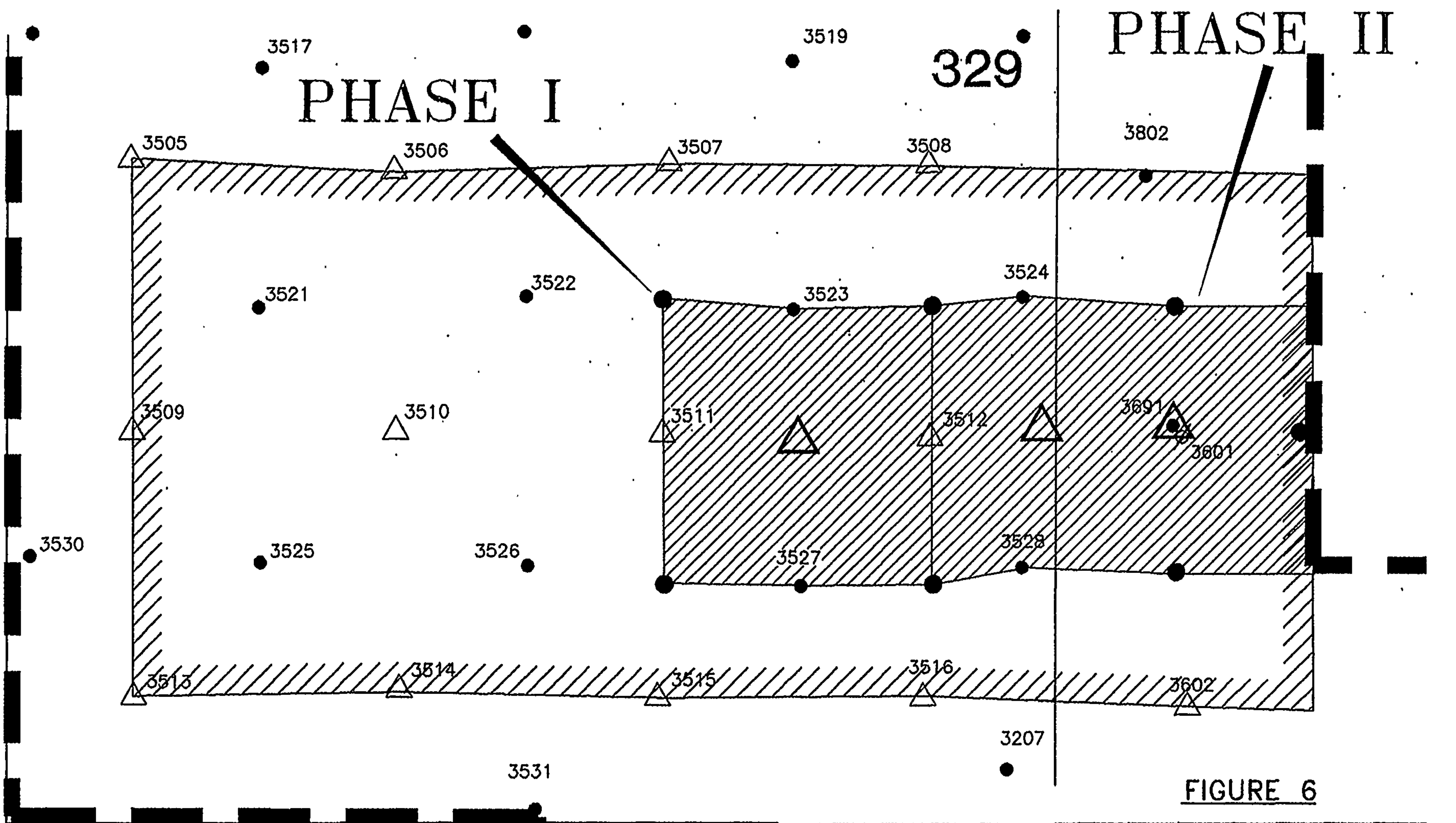


FIGURE 6

PHASE I: 5 Wells (4 Producers, 1 Injector)

PHASE II: 4 Wells (3 Producers, 1 Injector, 1 Conv.)

LEGEND

● NEW PRODUCER

△ NEW INJECTOR

FINA OIL & CHEMICAL CO. WEST TEXAS DIVISION				
NORTH ROBERTSON UNIT GAINES COUNTY, TEXAS BUDGET PERIOD II FIELD DEMONSTRATION SECTION 329 DRILLING DEVELOPMENT SCENARIO B				
Geology by:	DWG. : NRUSCENB Scale: NONE	Date: 1–96	Revised:	Drafted by: J.V.A.

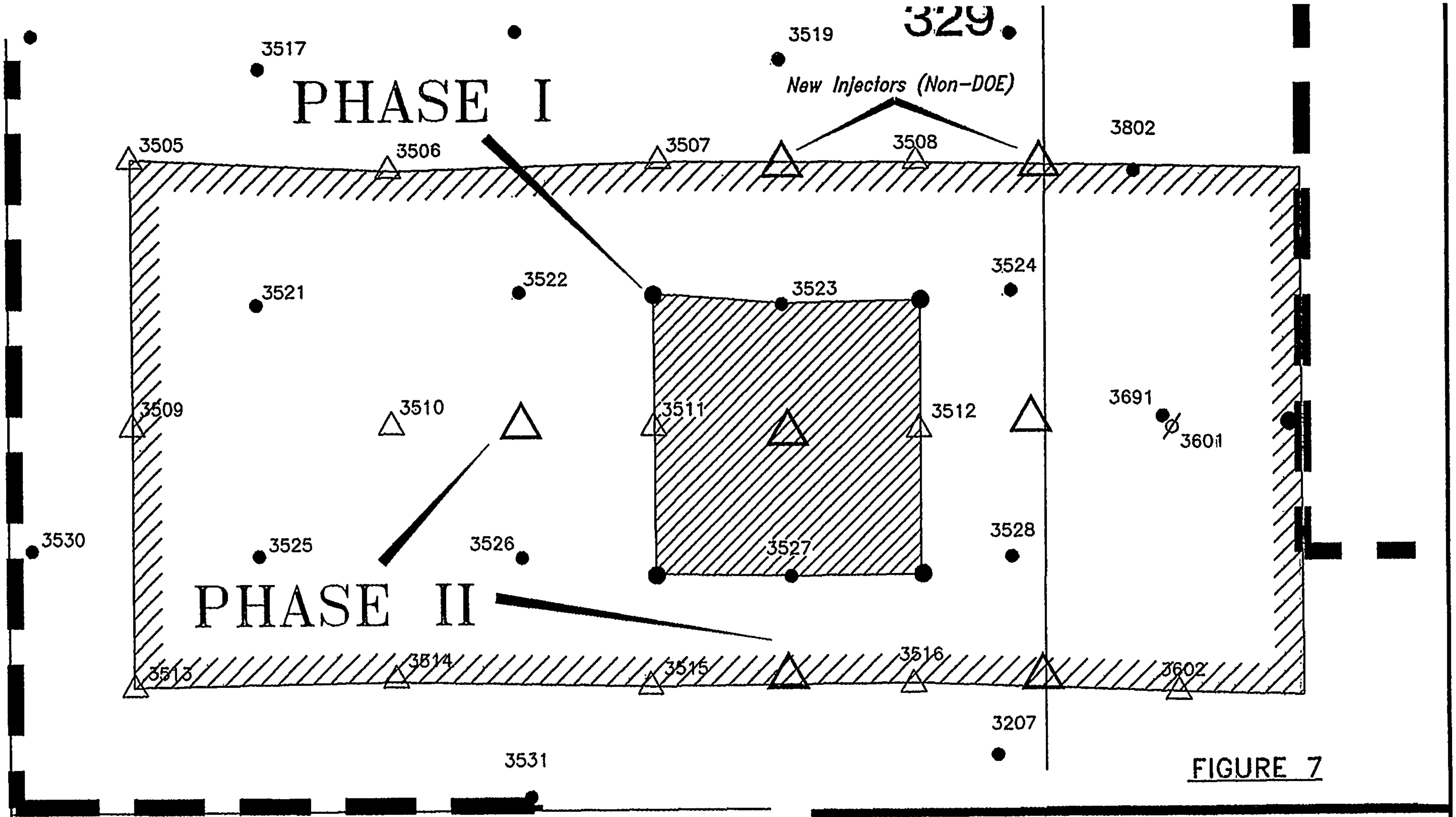


FIGURE 7

PHASE I: 5 Wells (4 Producers, 1 Injector)

PHASE II: 4 Wells (4 Injectors)

LEGEND

● NEW PRODUCER

△ NEW INJECTOR

FINA OIL & CHEMICAL CO.
WEST TEXAS DIVISION

NORTH ROBERTSON UNIT
GAINES COUNTY, TEXAS

BUDGET PERIOD II
FIELD DEMONSTRATION
SECTION 329 DRILLING
DEVELOPMENT SCENARIO C

Geology by:	DWG.: NRUSCENC Scale: NONE	Date: 1-96	Revised:	Drafted by: J.V.A.

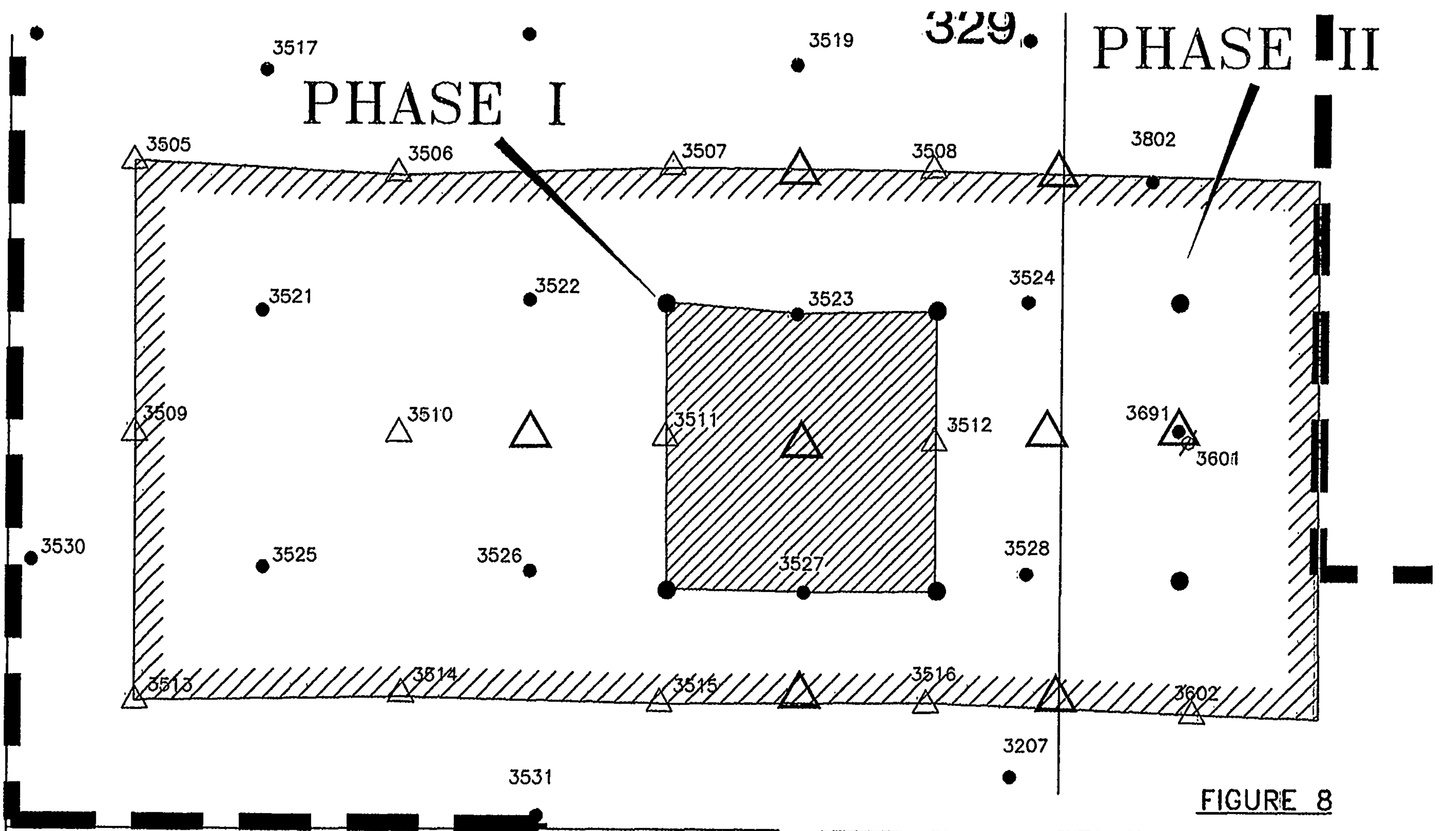


FIGURE 8

PHASE I: 5 Wells (4 Producers, 1 Injector)

PHASE II: 4 Wells (2 Producers, 2 Injectors, 1 Conv.)

LEGEND

● NEW PRODUCER

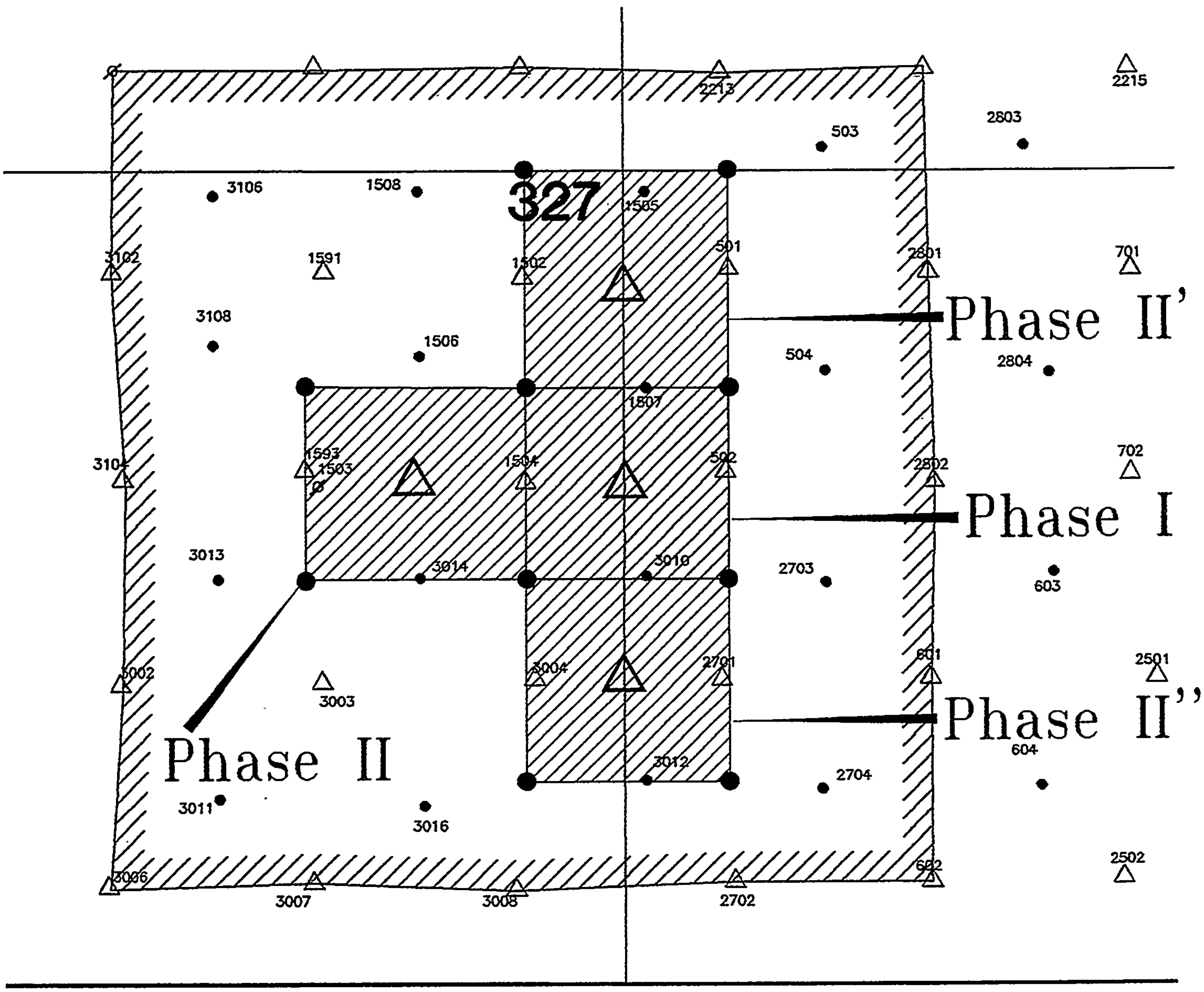
△ NEW INJECTOR

FINA OIL & CHEMICAL CO.
WEST TEXAS DIVISION

NORTH ROBERTSON UNIT
GAINES COUNTY, TEXAS

BUDGET PERIOD II
FIELD DEMONSTRATION
SECTION 329 DRILLING
DEVELOPMENT SCENARIO D

Geology by:	DWG. : NRUSCEND Scale: NONE	Date: 1-96	Revised:	Drafted by: JVA.



PHASE I: 5 Wells (4 Producers, 1 Injector)

PHASE II: 3 Wells (2 Producers, 1 Injector)

FIGURE 9

LEGEND

● NEW PRODUCER

△ NEW INJECTOR

FINA OIL & CHEMICAL CO.
WEST TEXAS DIVISION

NORTH ROBERTSON UNIT
GAINES COUNTY, TEXAS

BUDGET PERIOD II
FIELD DEMONSTRATION
SECTION 327 DRILLING

Geology by:	DWG. : NRU–PK–A Scale: NONE	Date: 1–96	Revised:	Drafted by: J.V.A.

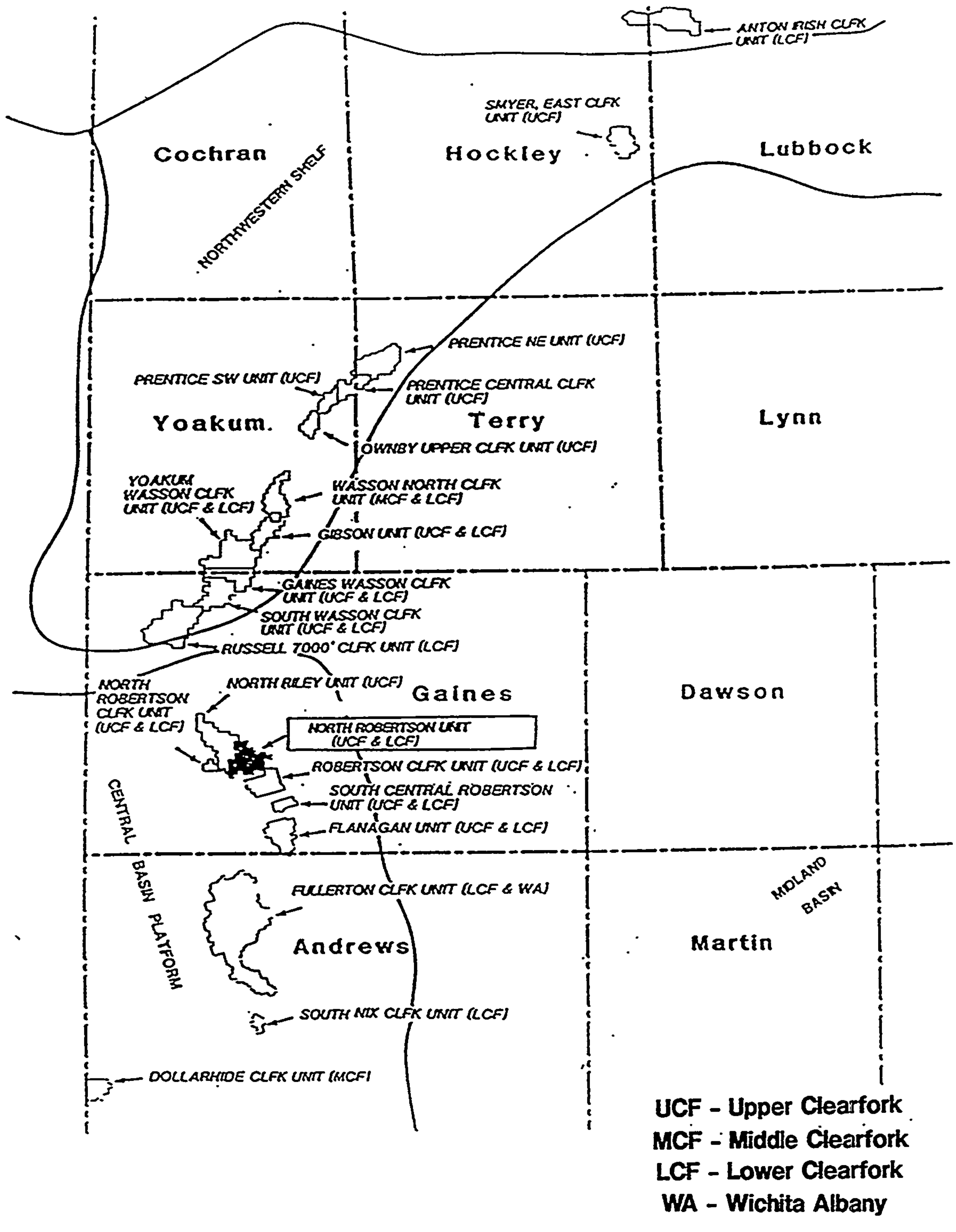


Figure 10 - Clearfork Waterflood Projects in the Permian Basin

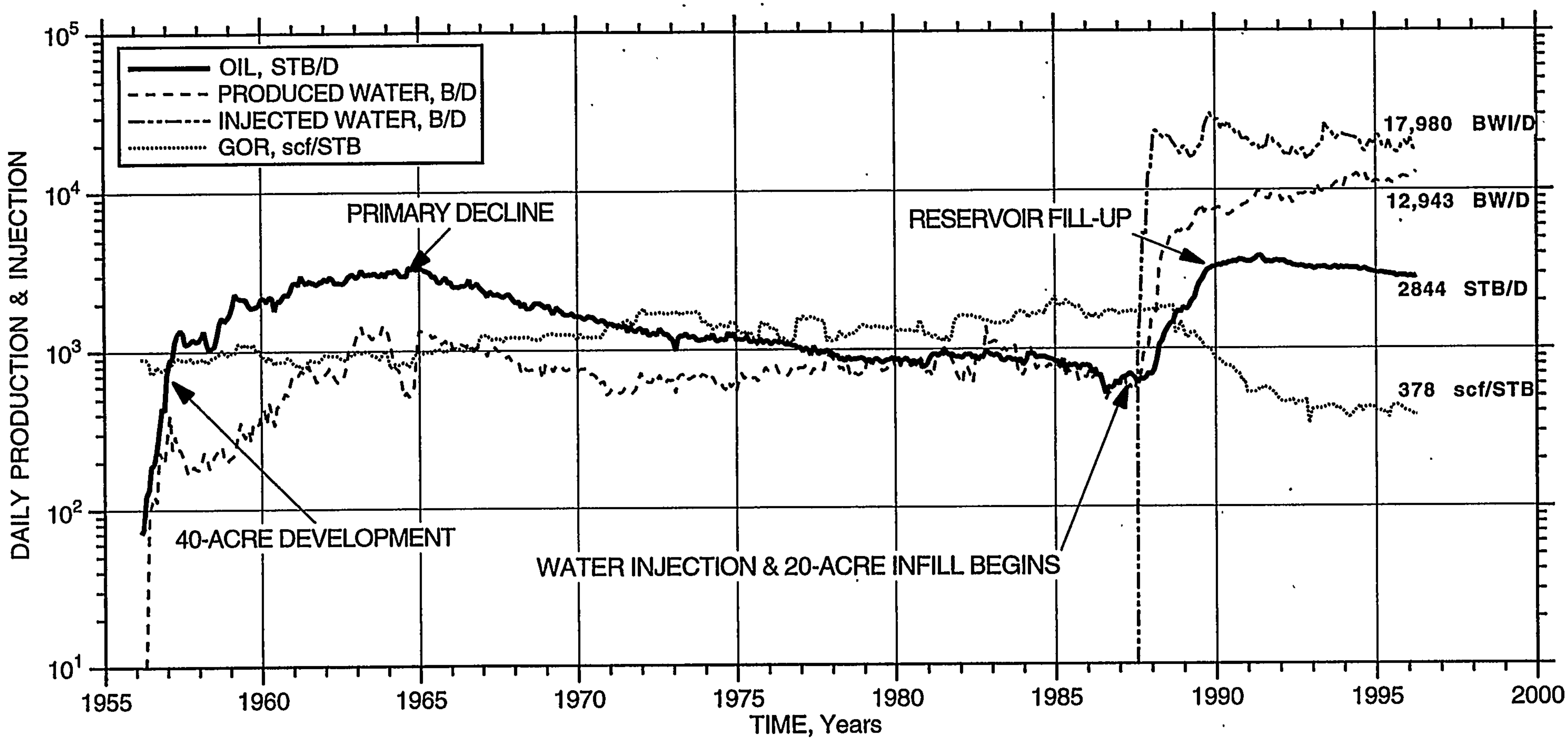


Figure 11 - Production and Injection History for the North Robertson (Clearfork) Unit

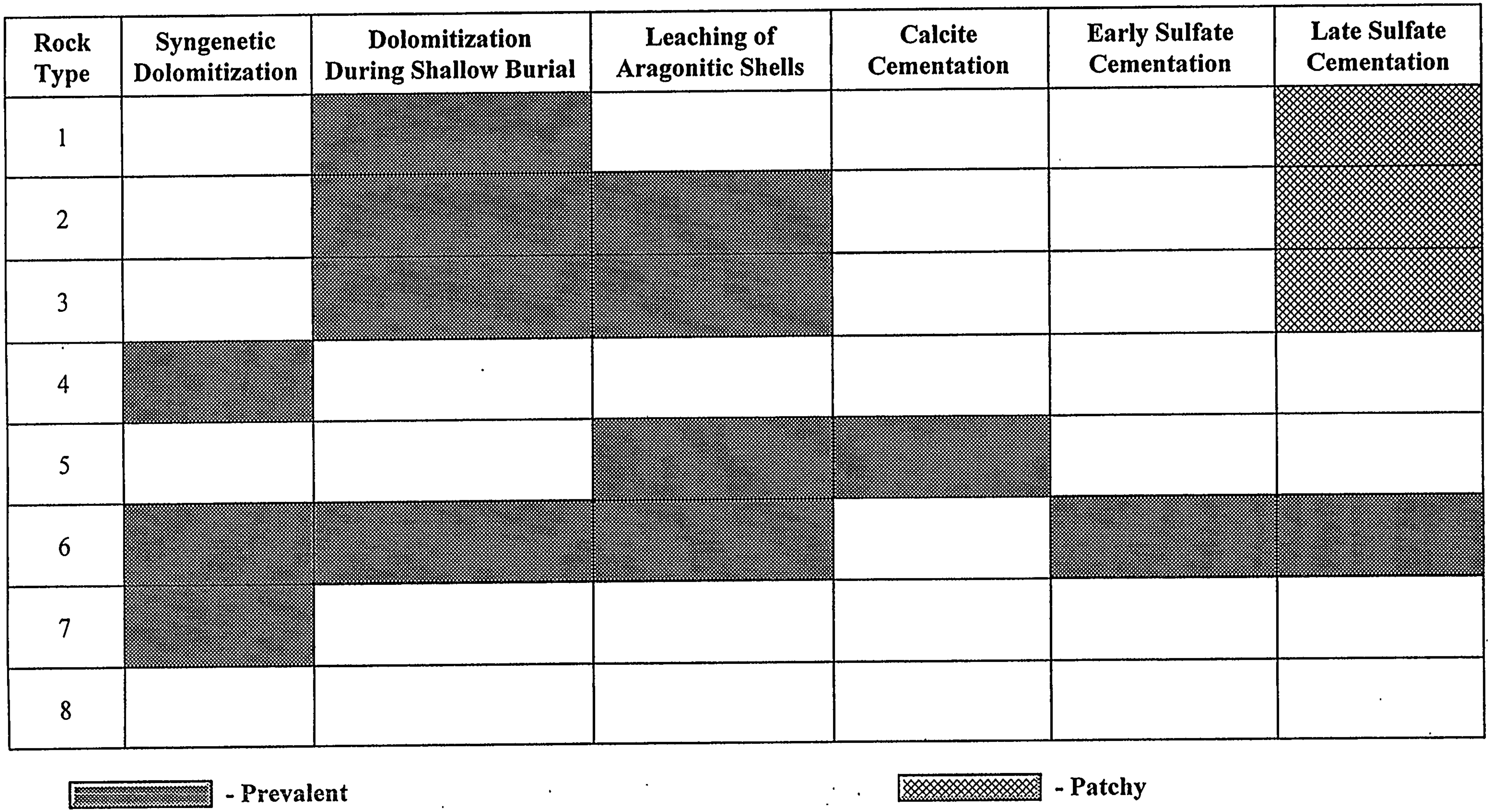


Figure 12 - Diagenetic History of Glorieta and Clearfork Carbonates, after Davies (Ref. 2).

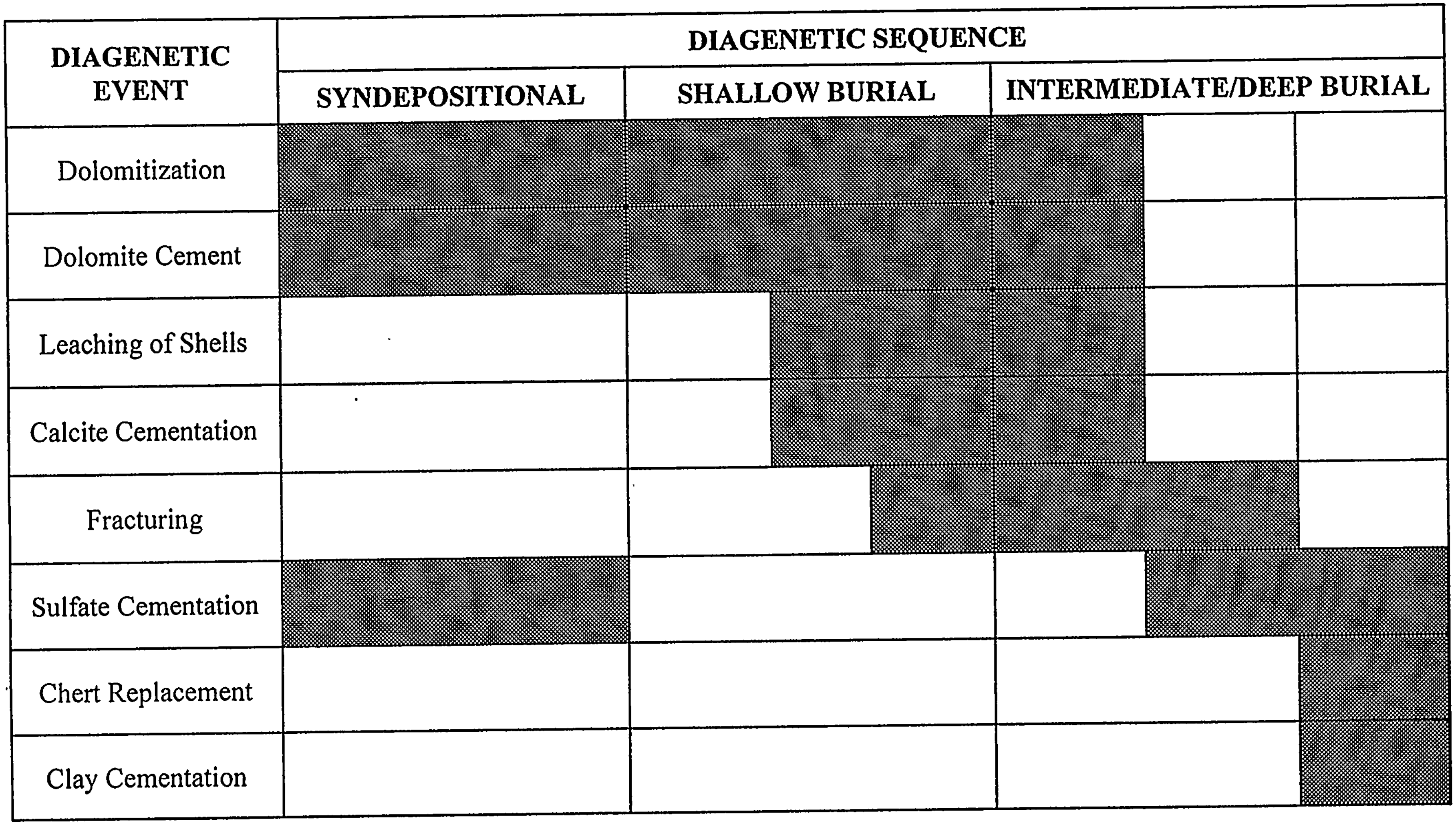


Figure 13 - Diagenetic Processes Affecting Glorieta and Clearfork Carbonates, after Davies (Ref. 2).

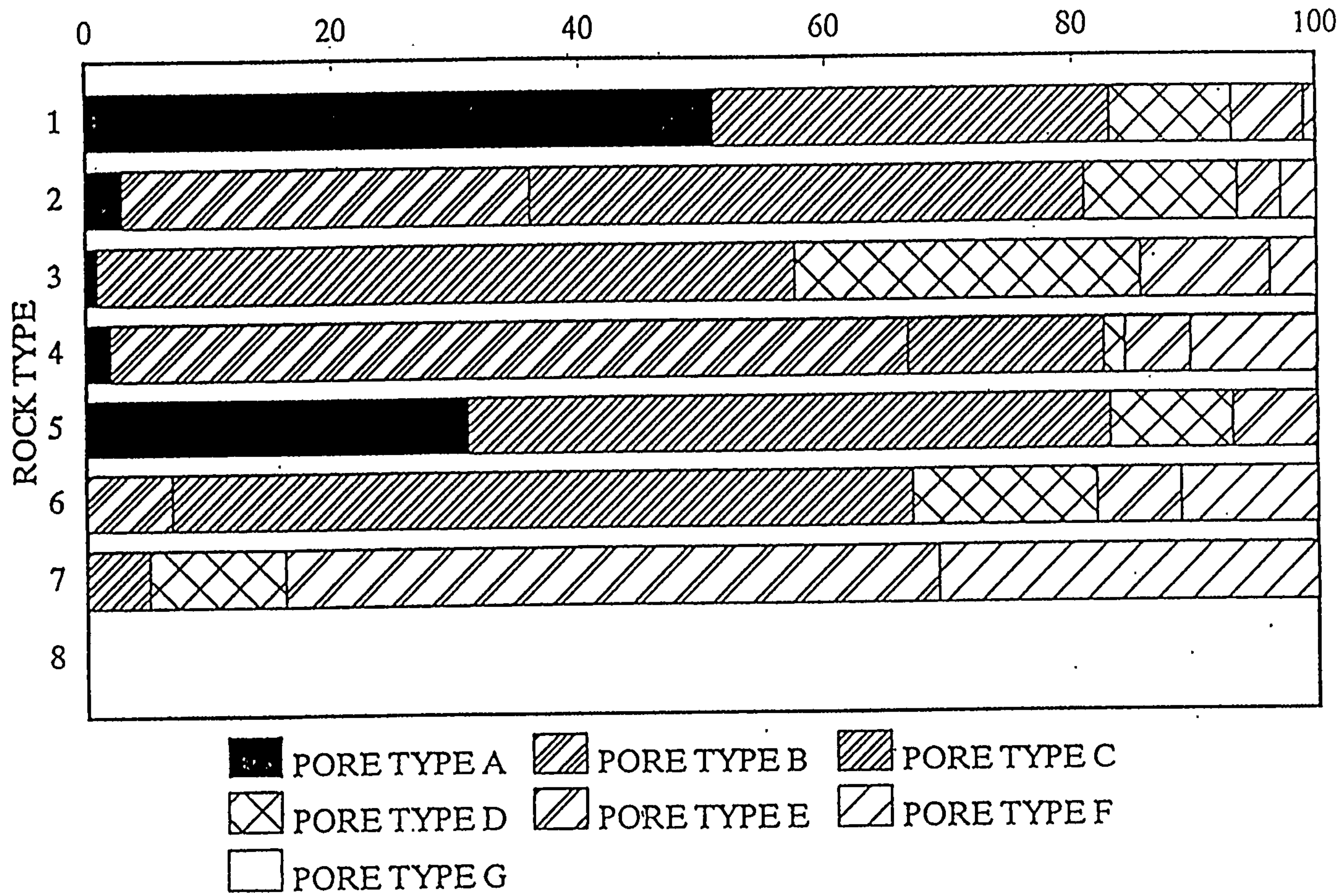


Figure 14 - Relative Volume Proportions of Pore Types (A-G) in Each Rock Type (1-8), after Davies (Ref. 1).

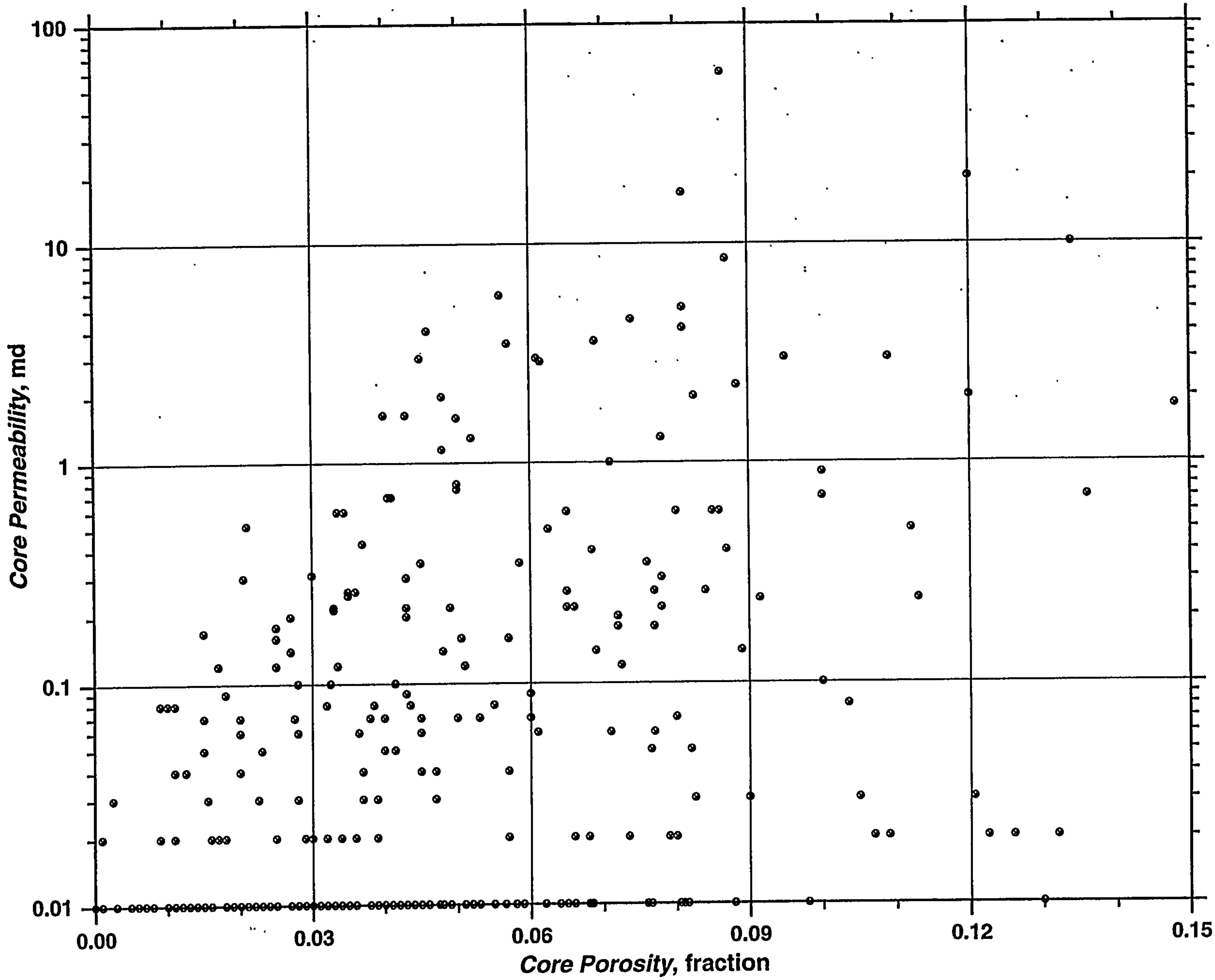


Figure 15 - Porosity-Permeability Crossplot For All Rock Types, after Davies (Ref. 2).

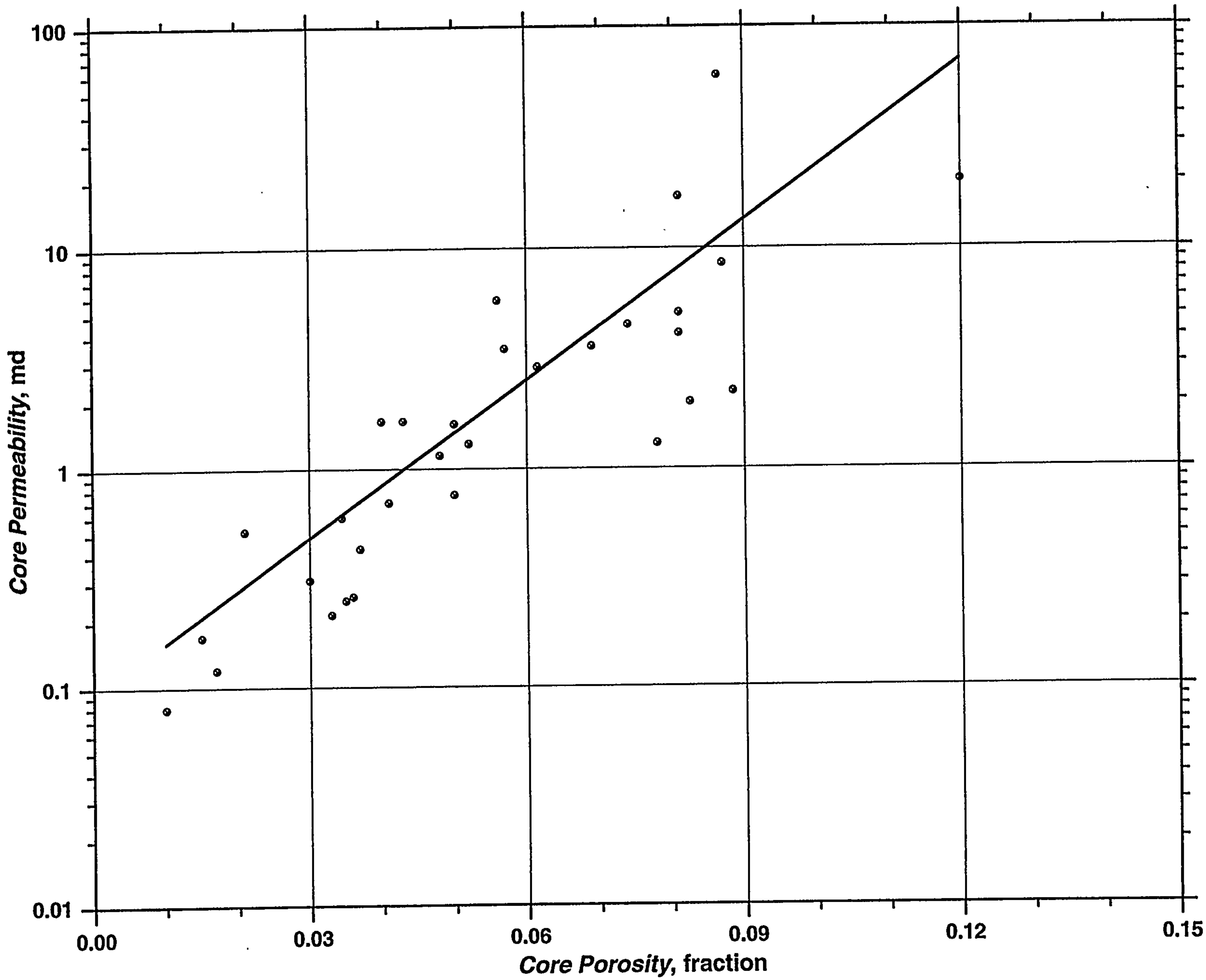


Figure 16 - Porosity-Permeability Crossplot For Rock Type 1, after Davies (Ref. 2).

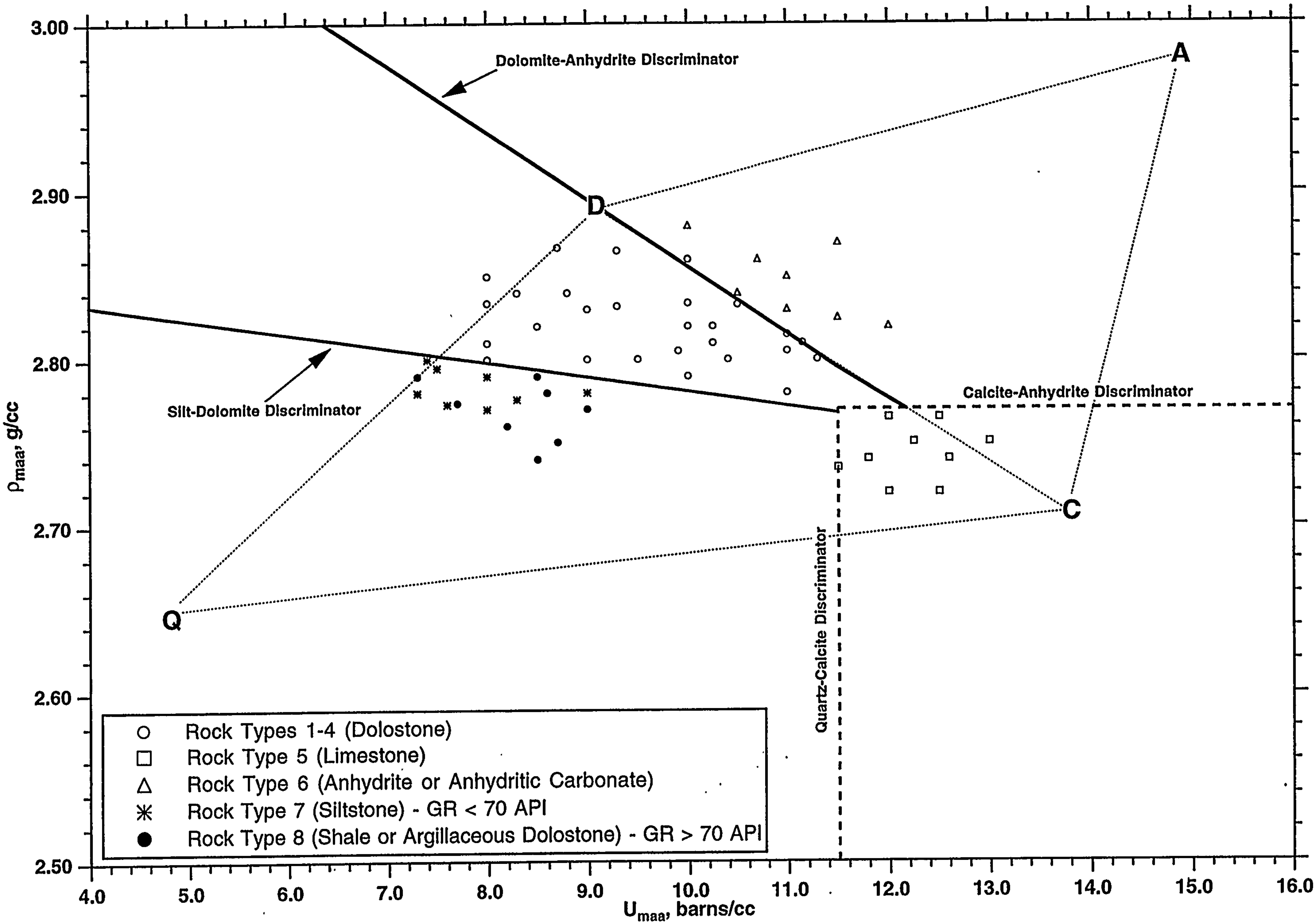


Figure 17 - Differentiating "Pay" from "Non-Pay" Reservoir Rock Types

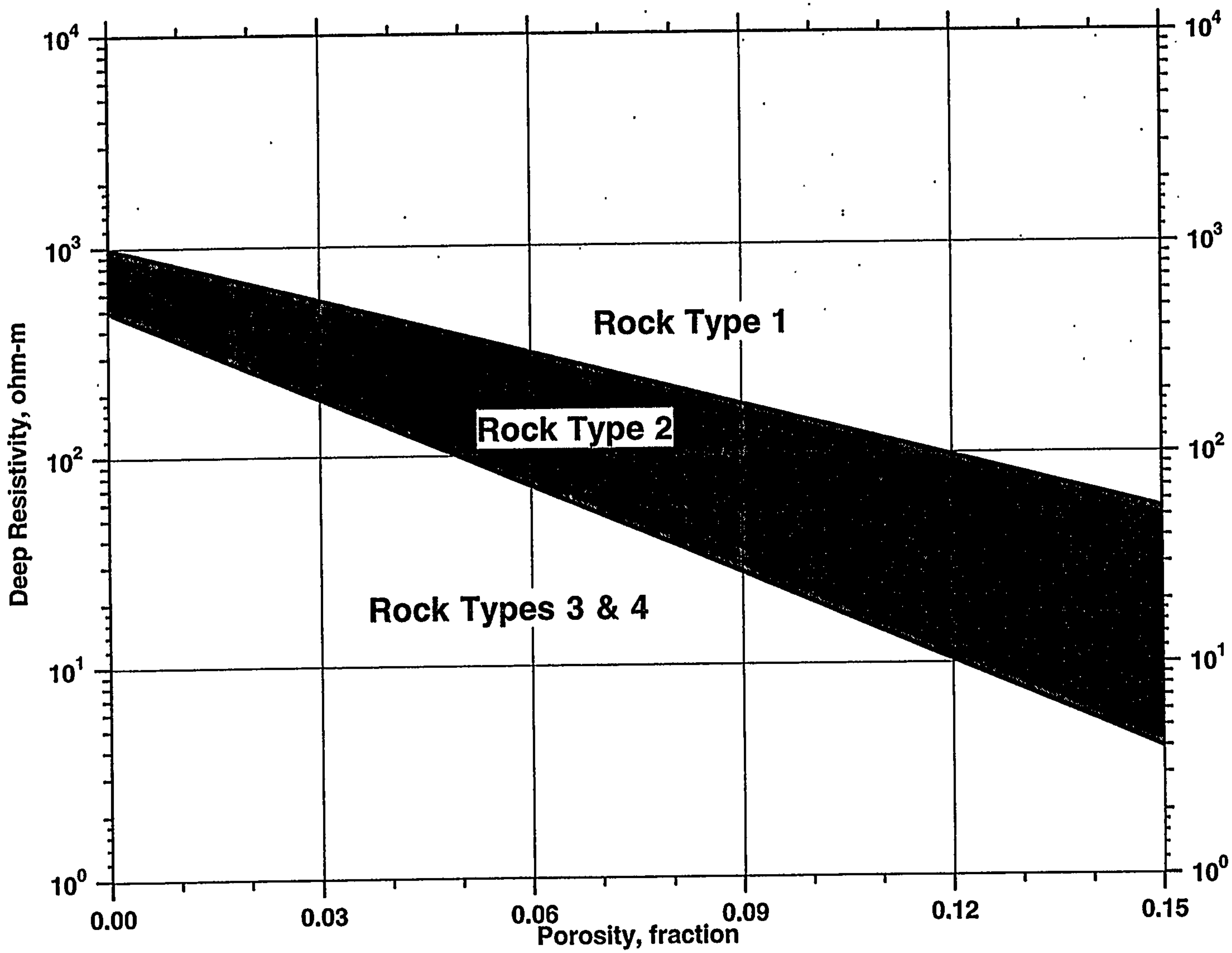


Figure 18 - Differentiating "Pay" Reservoir Rock Types

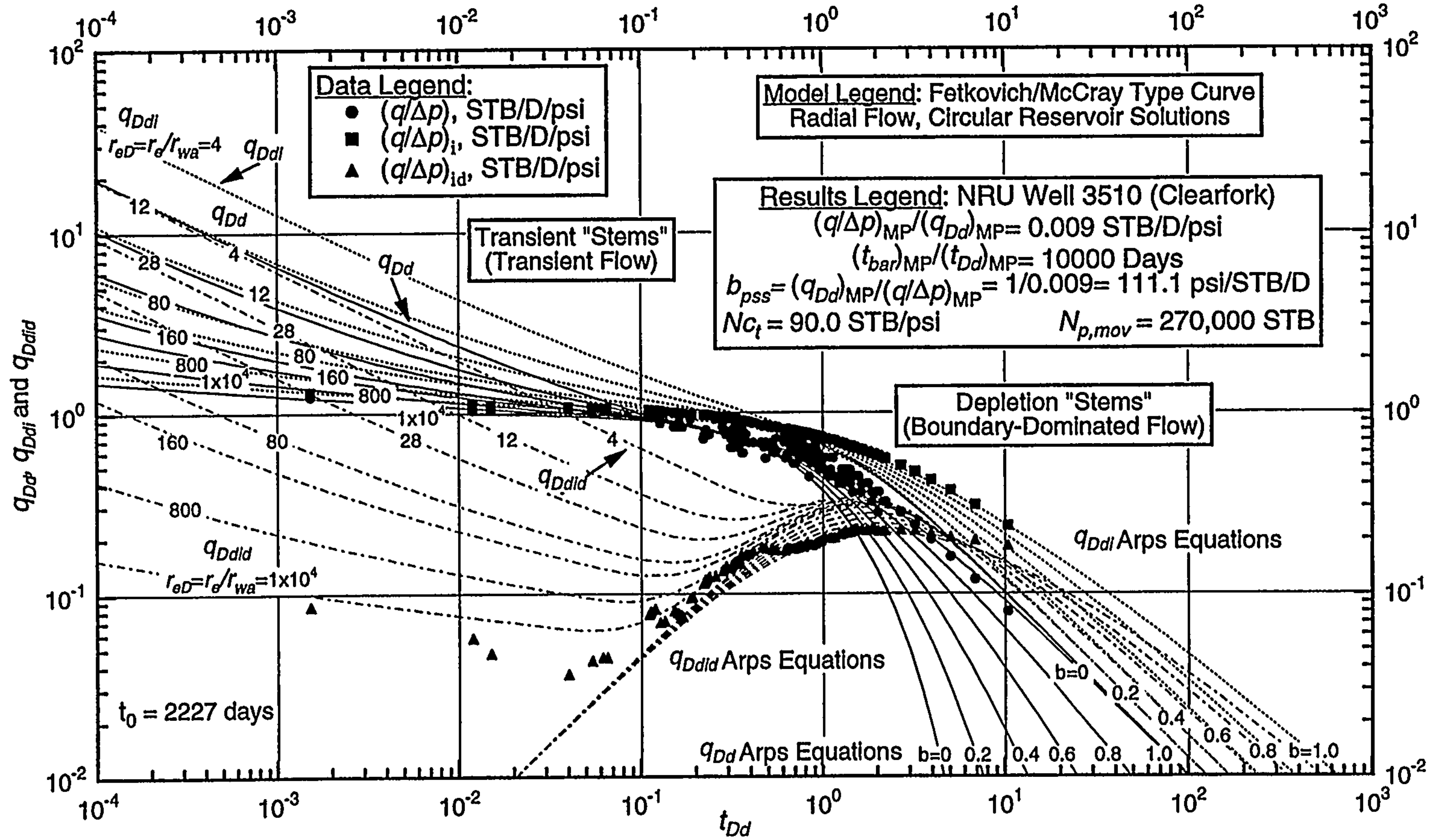


Figure 19 - Match of Production Data for NRU Well 3510 - Clearfork (Radial Flow Type Curve).

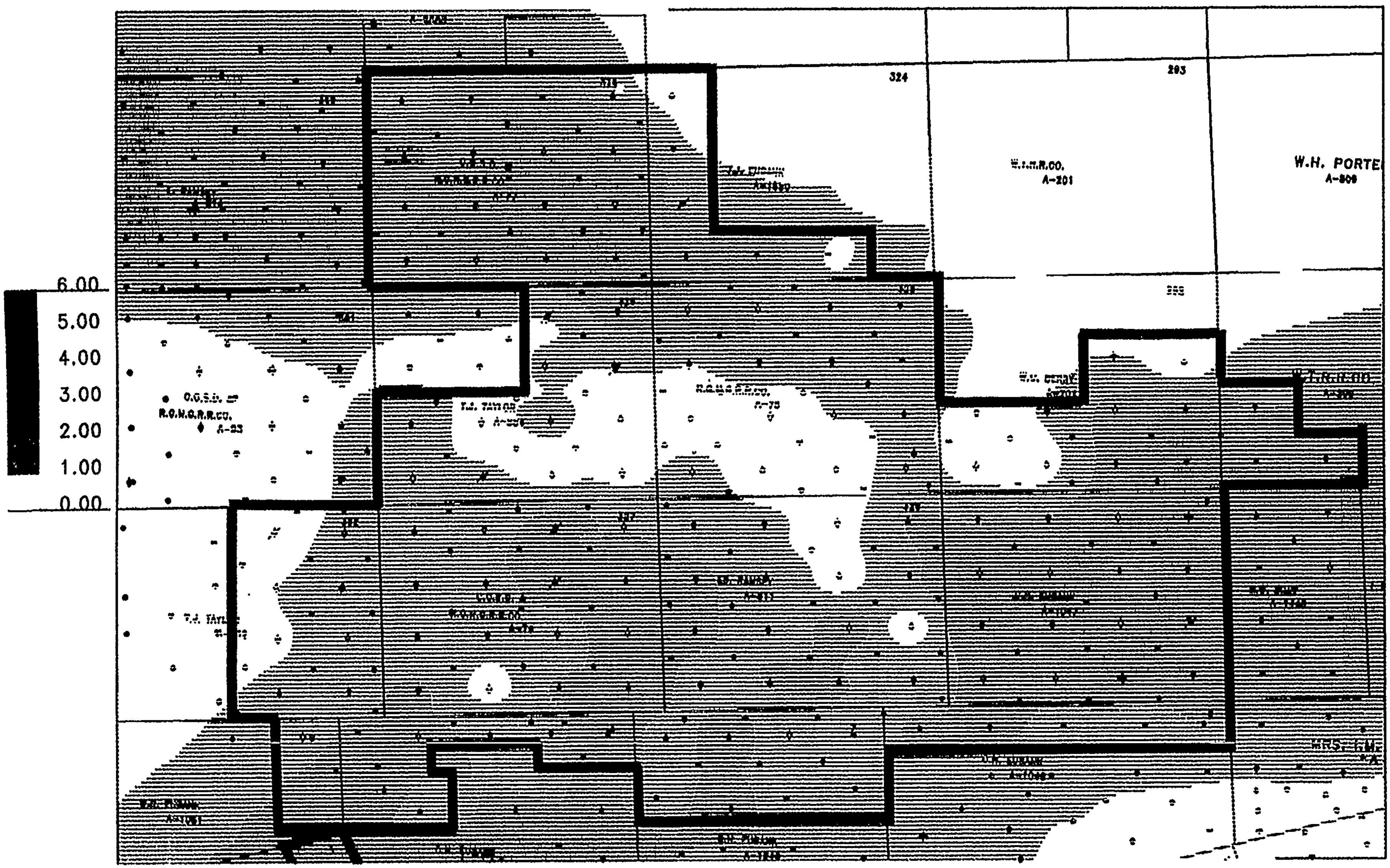


Figure 20 - Material Balance Decline Type Curve Analysis - Map of Contacted Original Oil-In-Place (CI = 1.0 MMSTB)

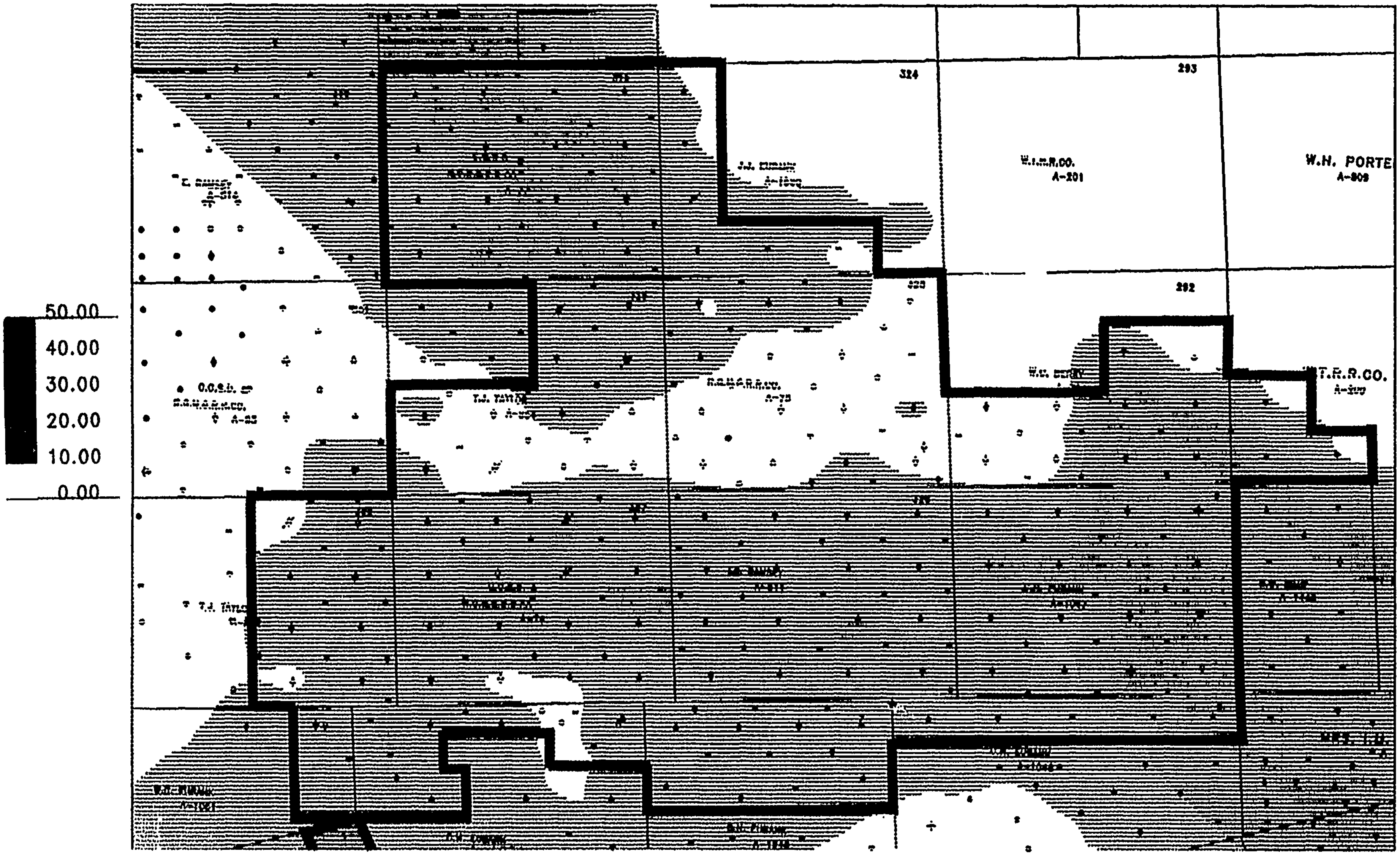


Figure 21 - Material Balance Decline Type Curve Analysis - Map of 40-acre Flow Capacity, kh (CI = 10 md-ft).

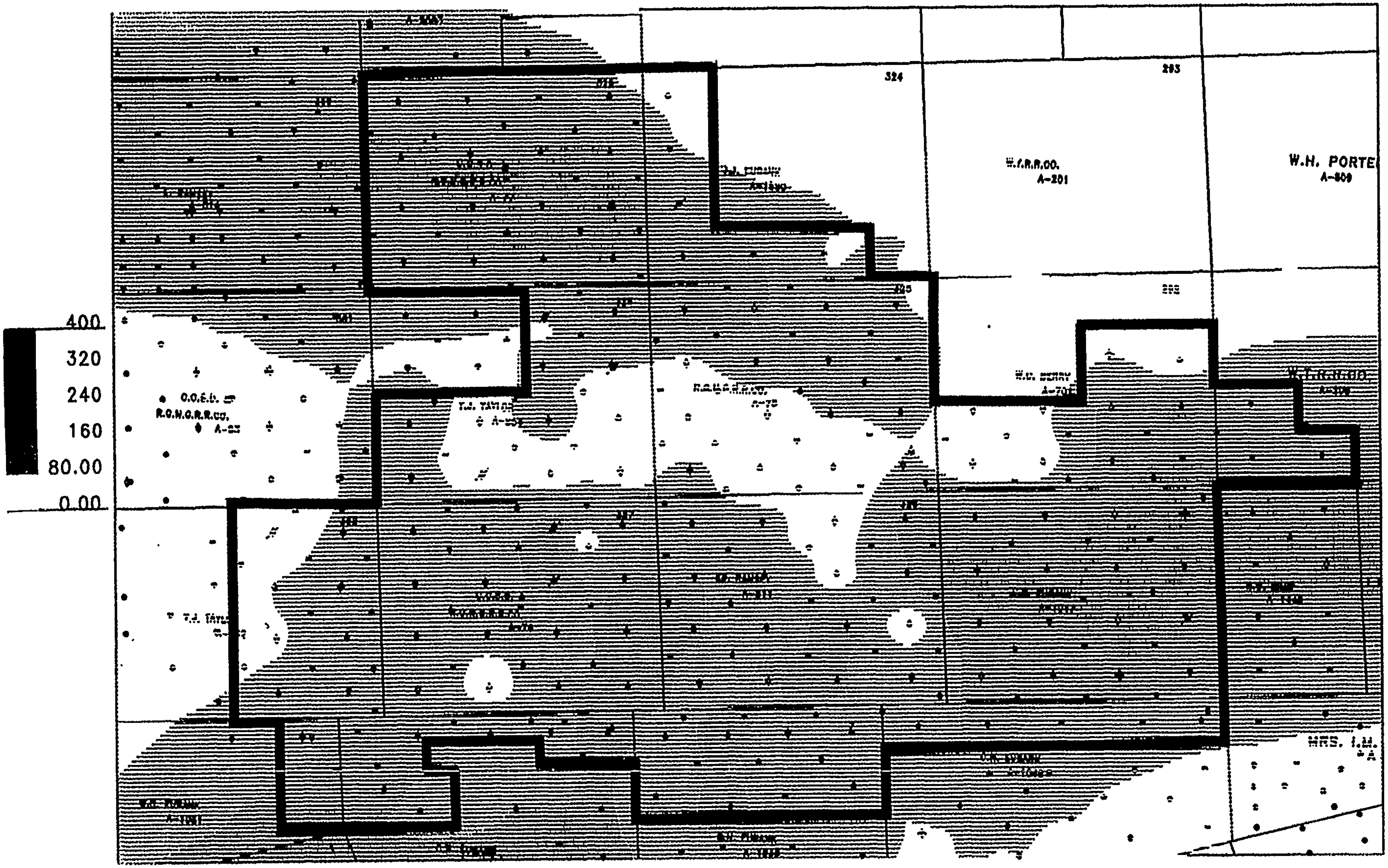


Figure 22 - Material Balance Decline Type Curve Analysis - Map of 40-acre EUR (CI = 80 MSTB).

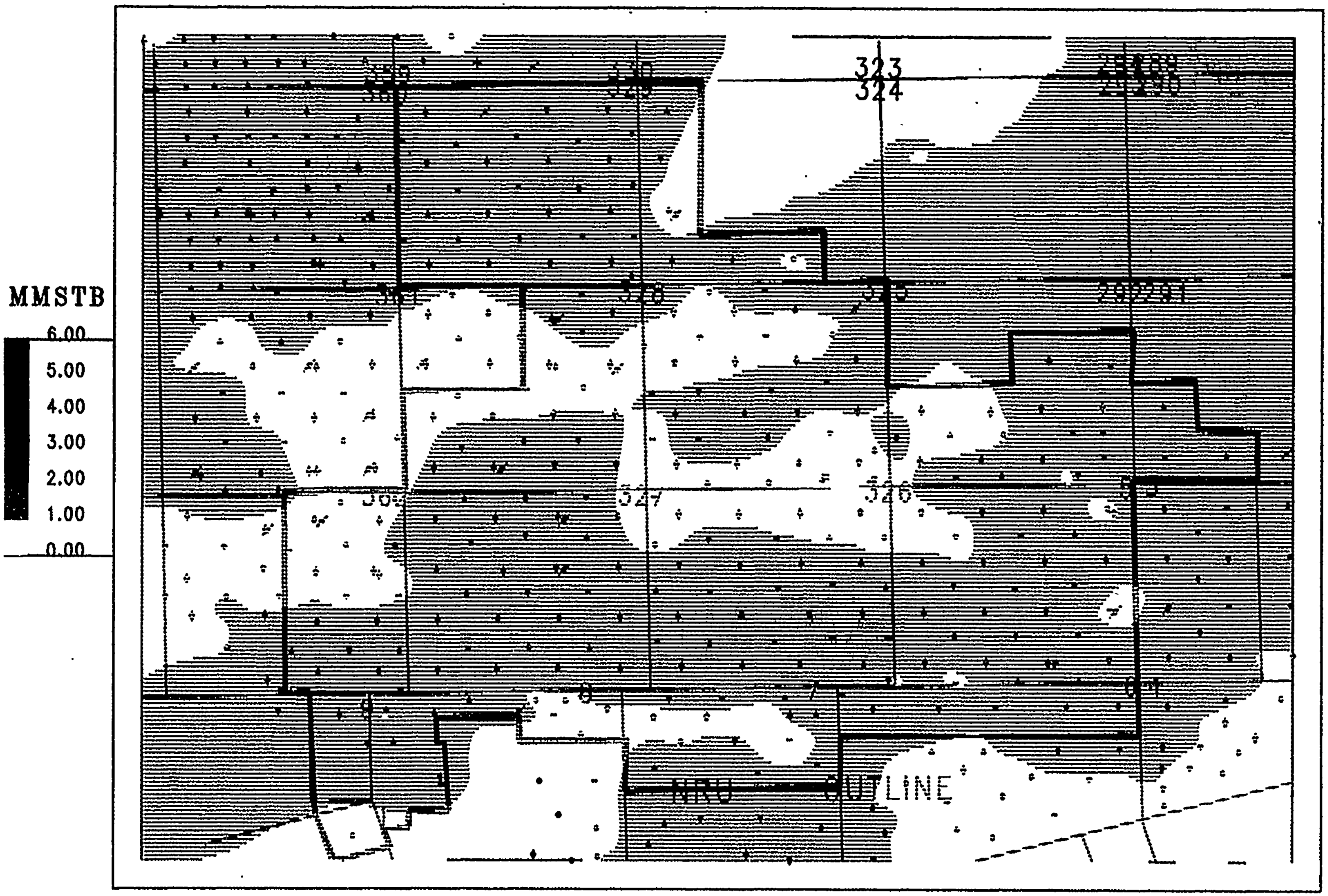


Figure 23 - Material Balance Decline Type Curve Analysis - Map of 20-acre Contacted Oil-In-Place (CI = 1.0 MMSTB)

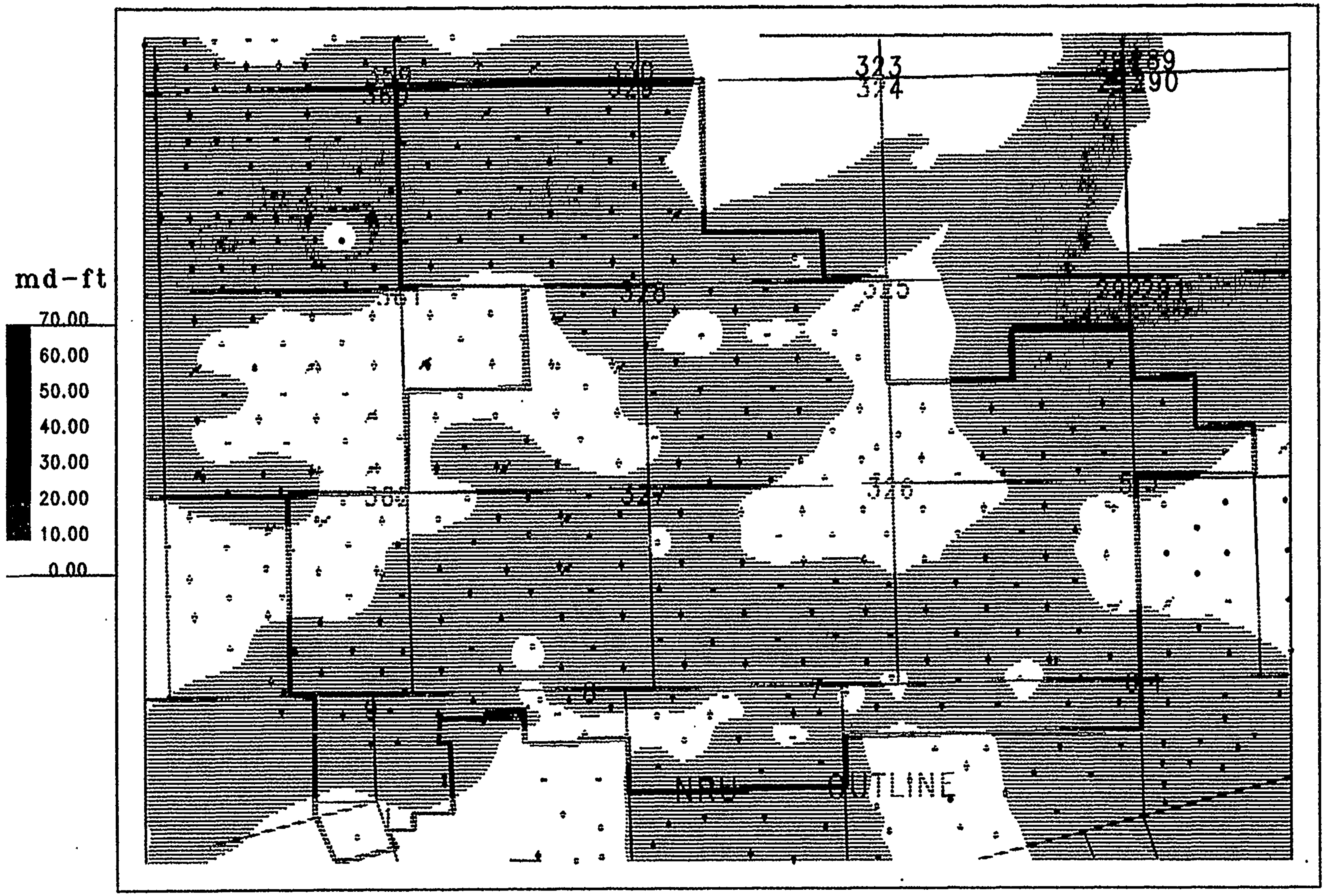


Figure 24 - Material Balance Decline Type Curve Analysis - Map of 20-acre Flow Capacity, kh (CI = 10 md-ft)

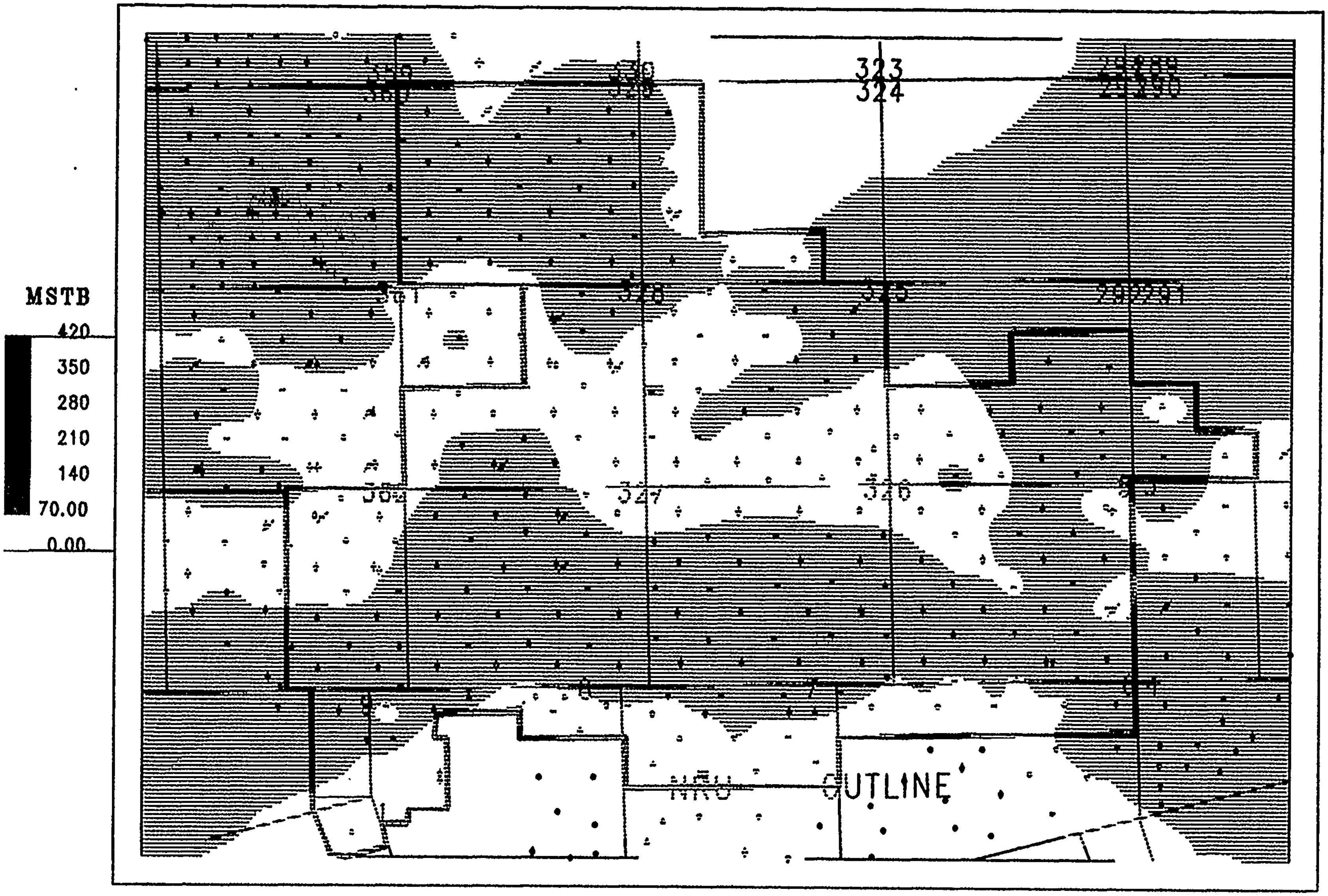


Figure 25 - Material Balance Decline Type Curve Analysis - Map of 20-acre EUR (CI = 70 MSTB).

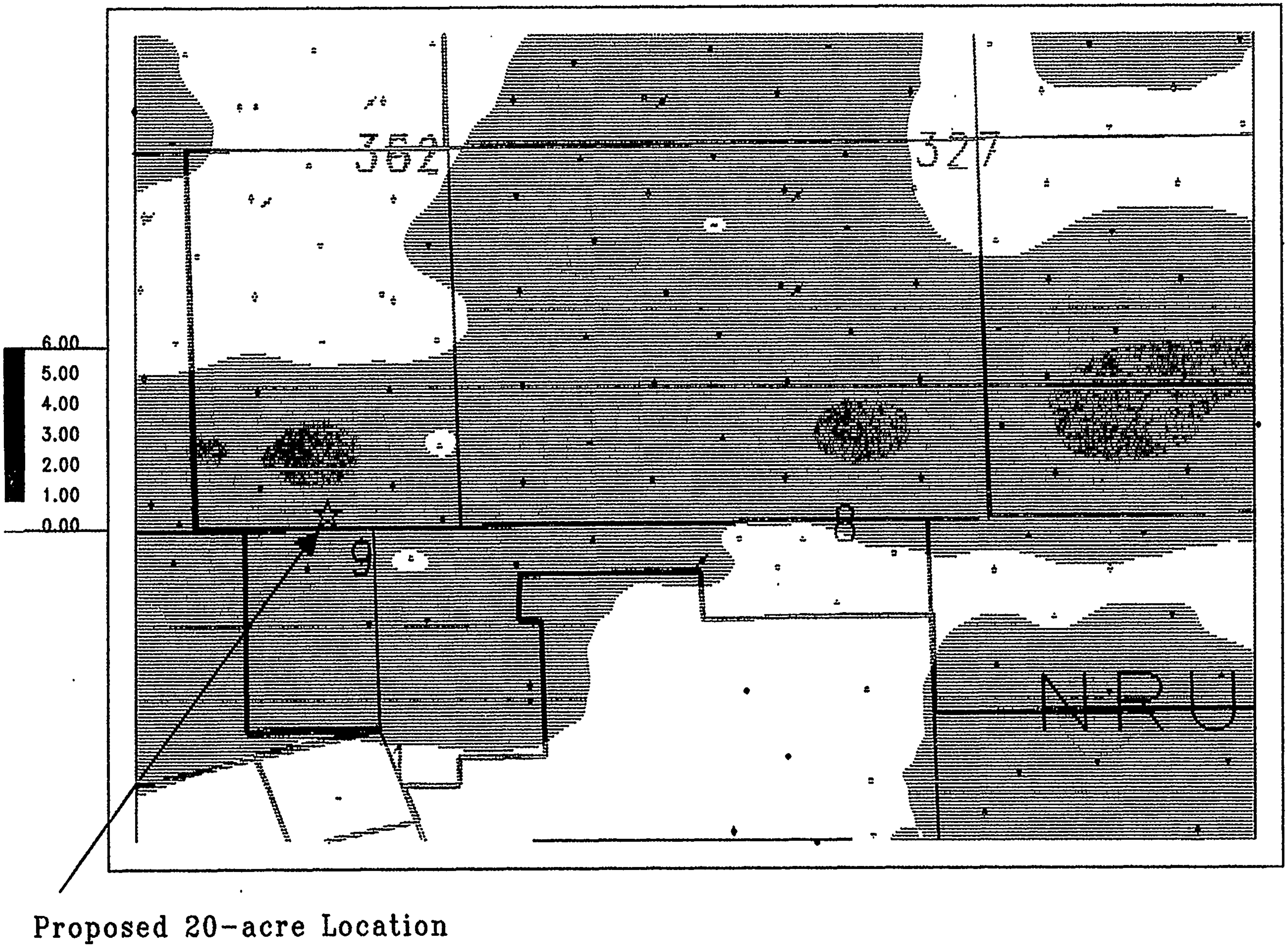


Figure 26 - NRU Section 362 Infill Location - Map of 20-acre Contacted Oil-In-Place (CI = 1.0 MMSTB).

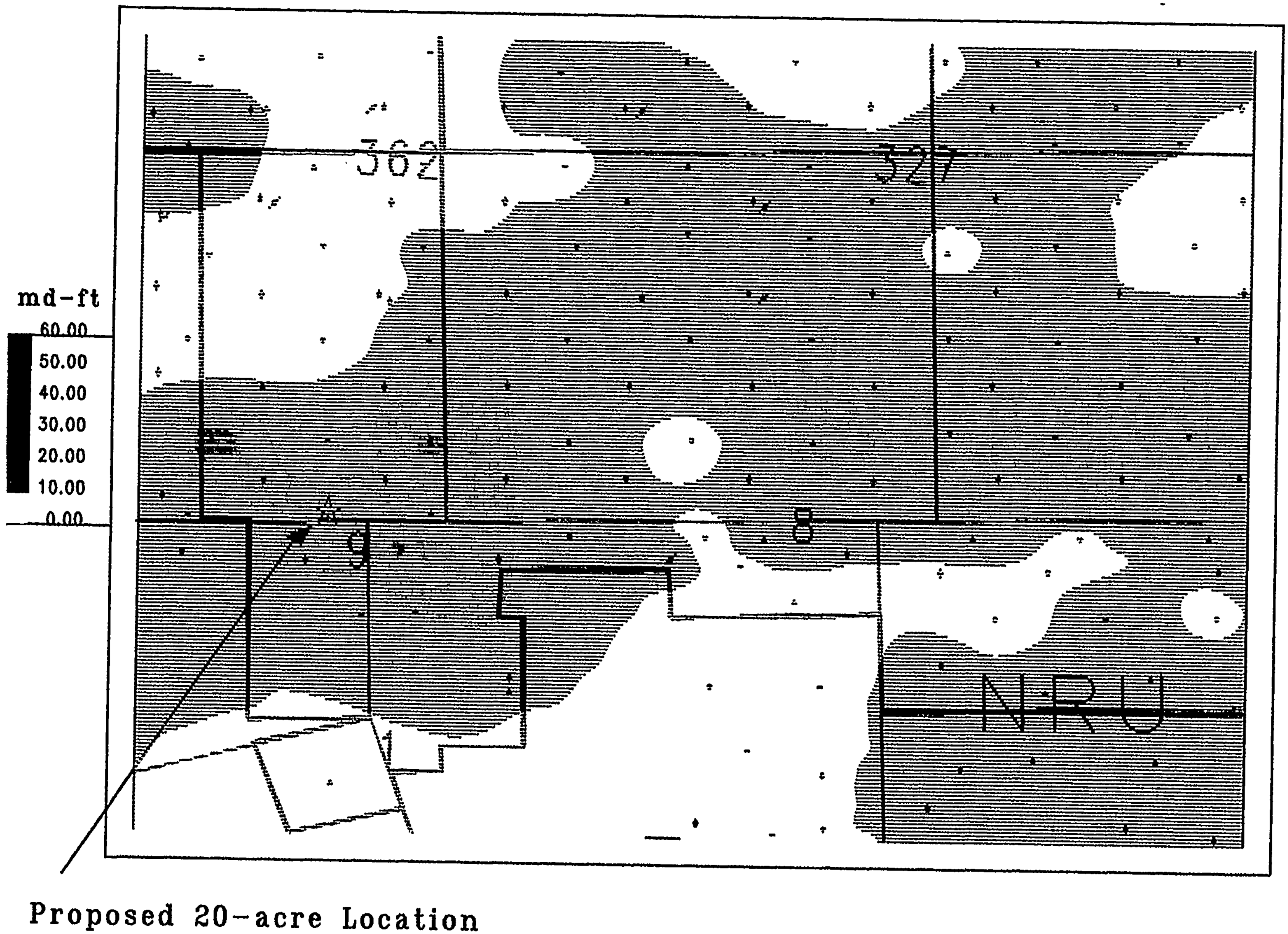


Figure 27 - NRU Section 362 Infill Location - Map of 20-acre Flow Capacity, kh (CI = 10 md-ft).

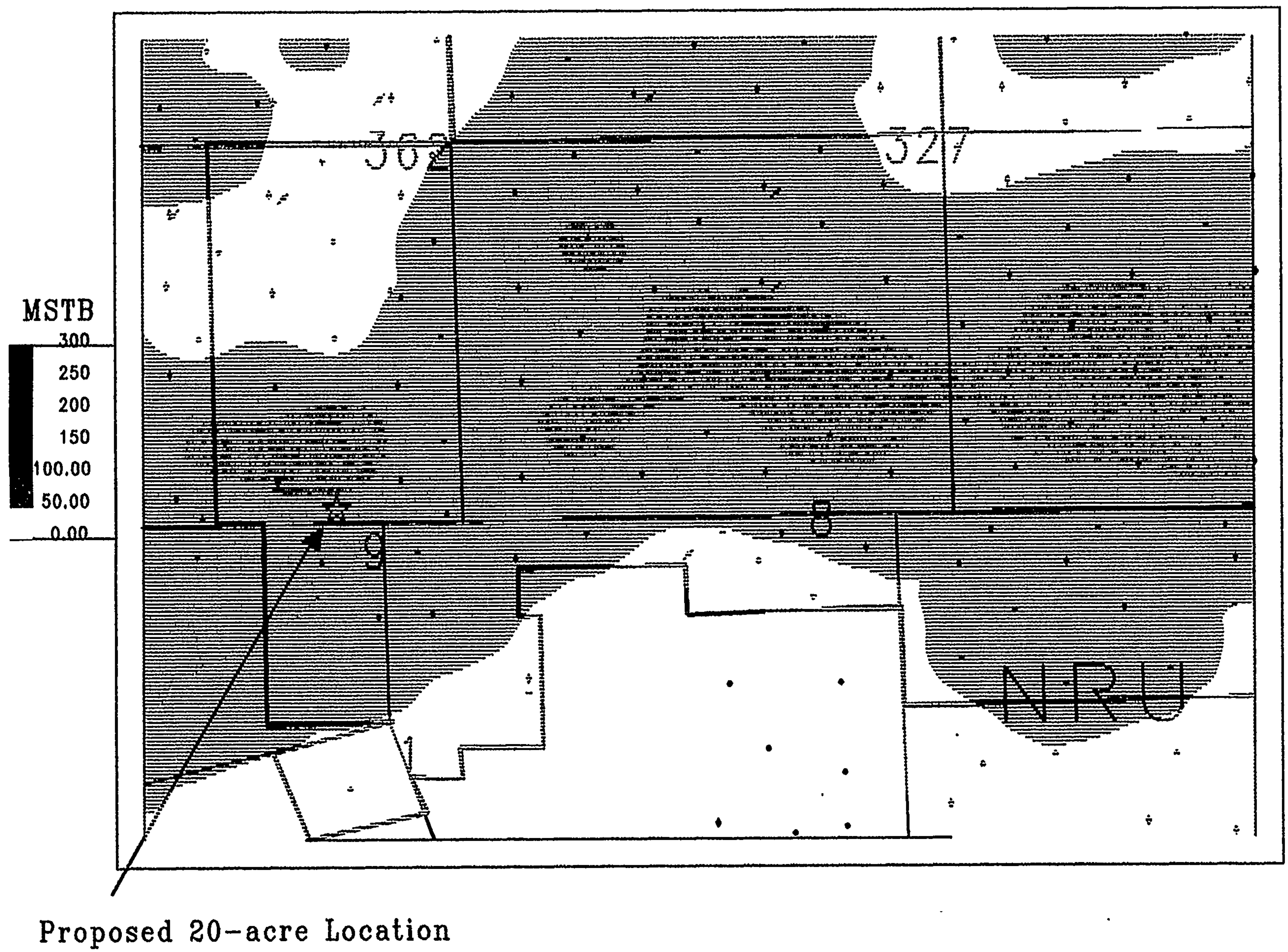


Figure 28 - NRU Section 362 Infill Location - Map of 20-acre EUR (CI = 50 MSTB).

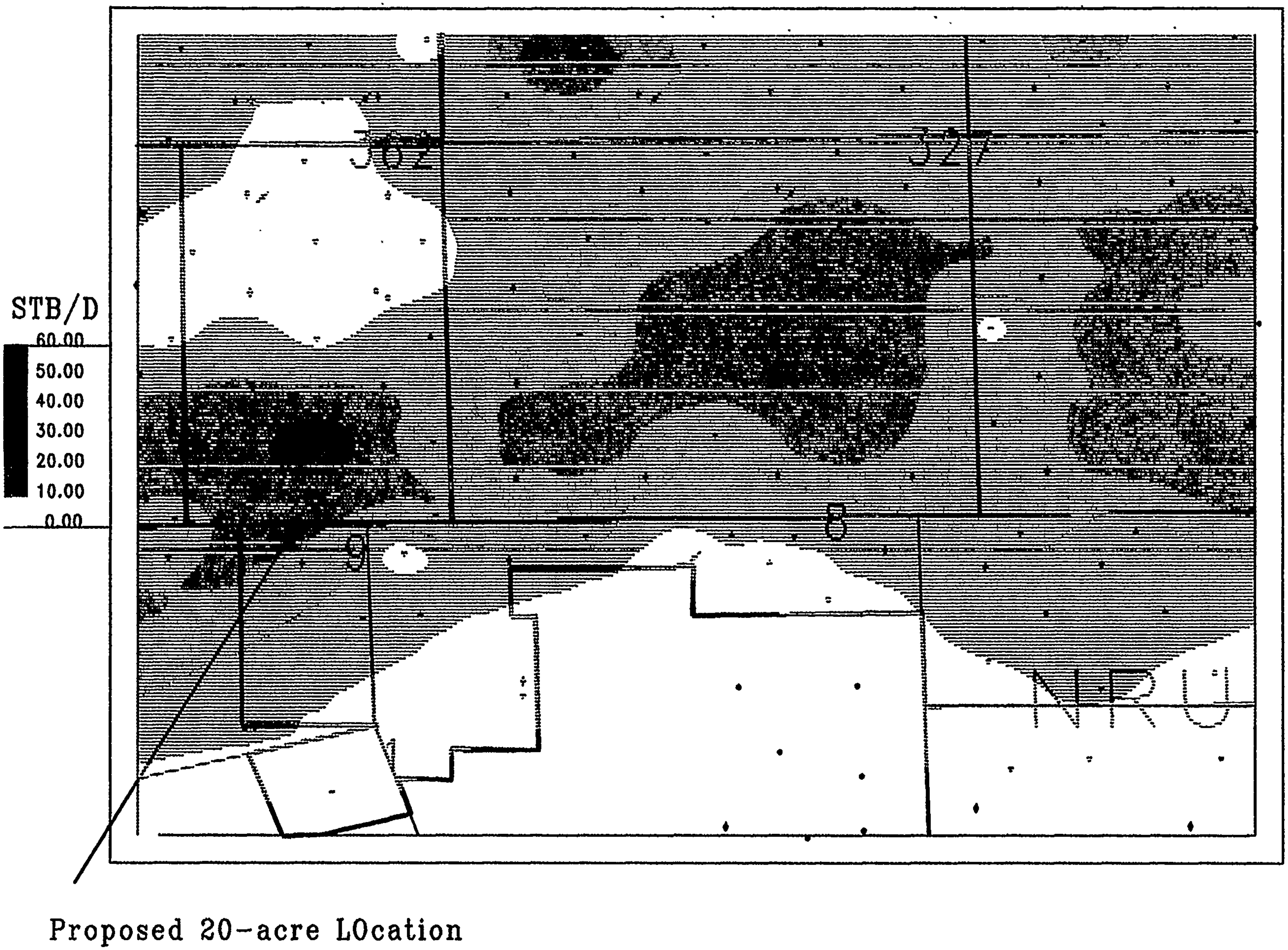


Figure 29 - NRU Section 362 Infill Location - Map of Daily Oil Rates (CI = 10 STB/D).

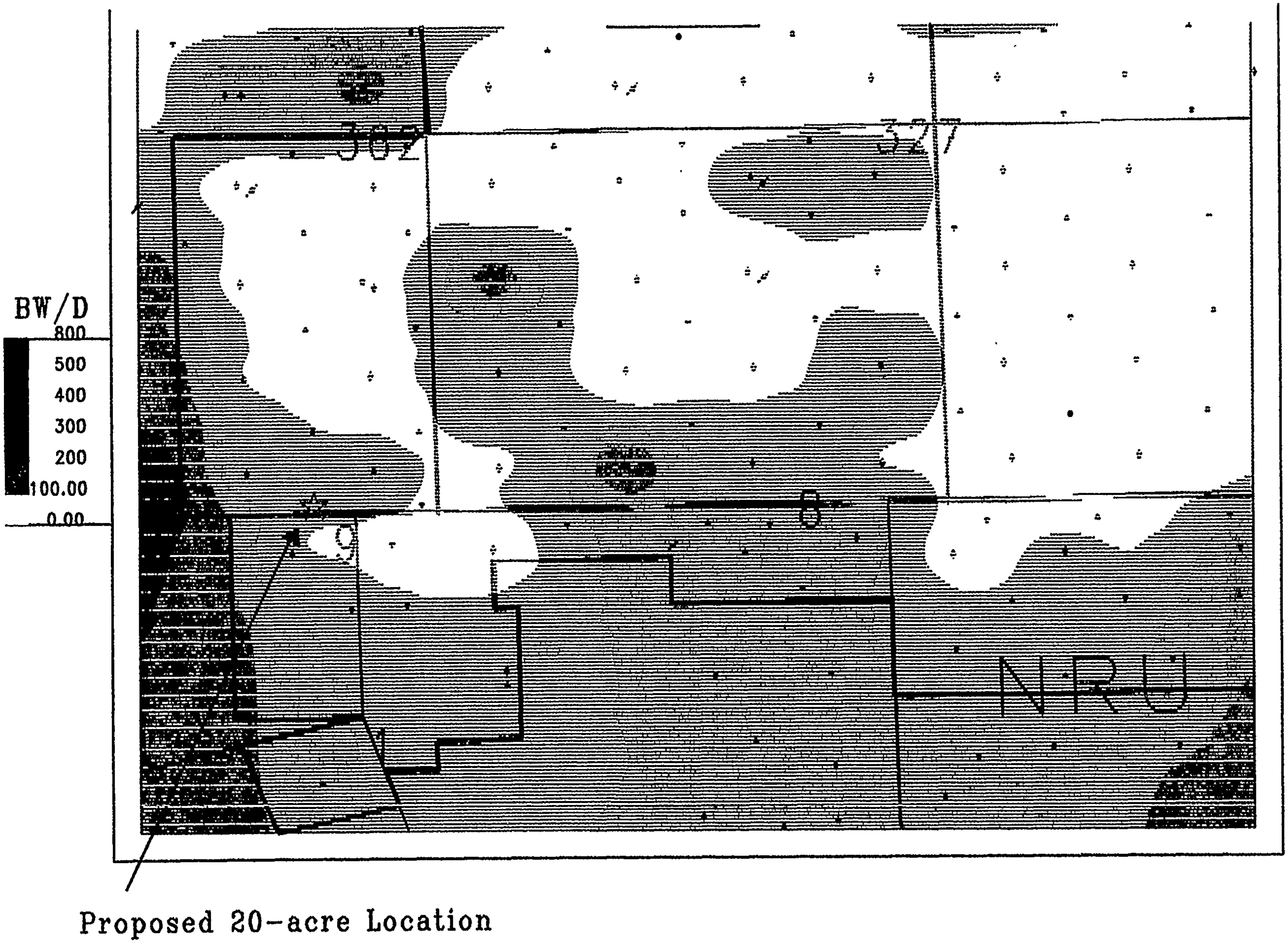


Figure 30 - NRU Section 362 Infill Location - Map of Daily Water Injection Rates (CI = 100 BWI/D).

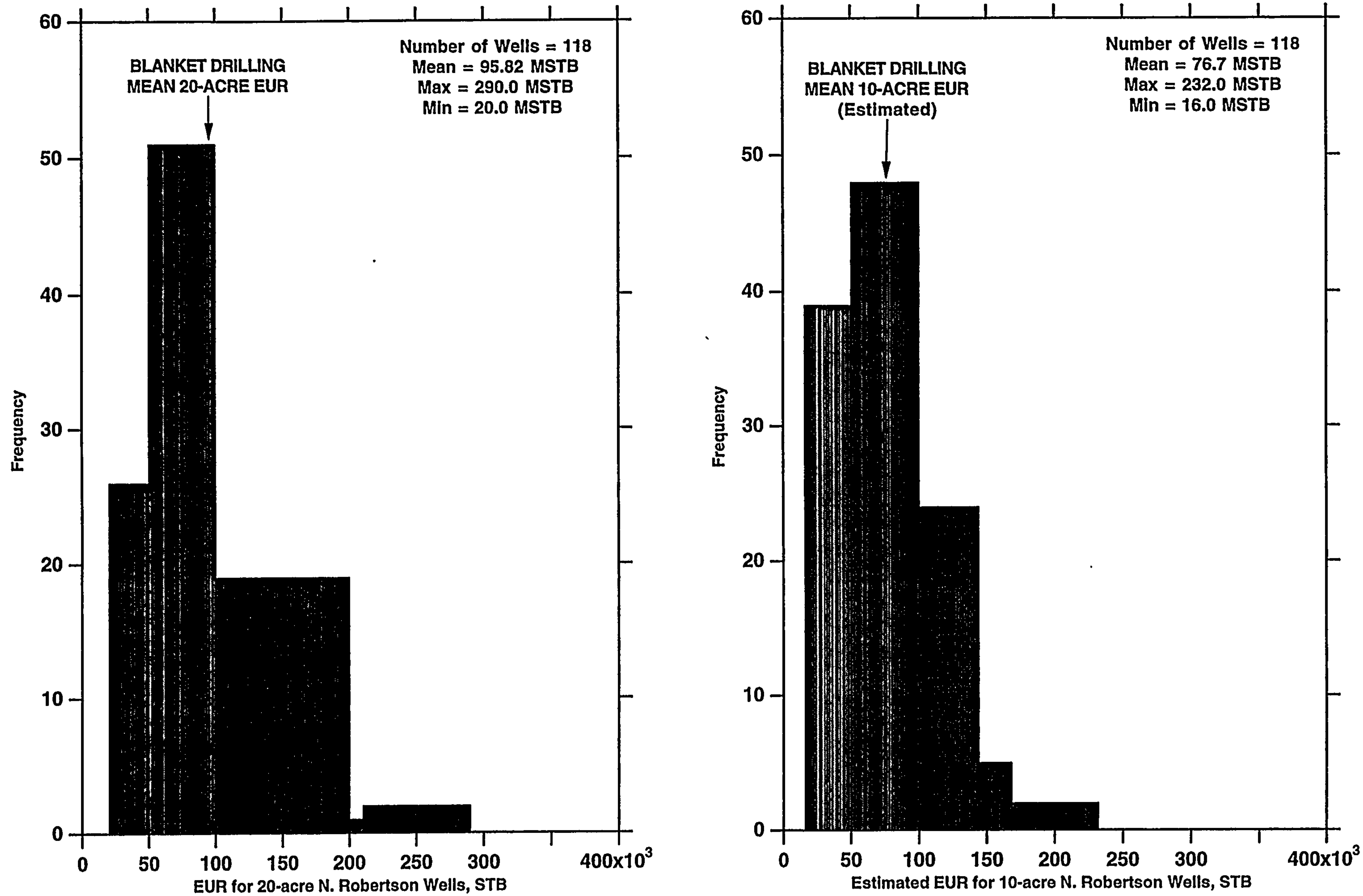


Figure 31 - N. Robertson Unit - Comparison Between Actual 20-acre and Estimated 10-acre Well Performance.

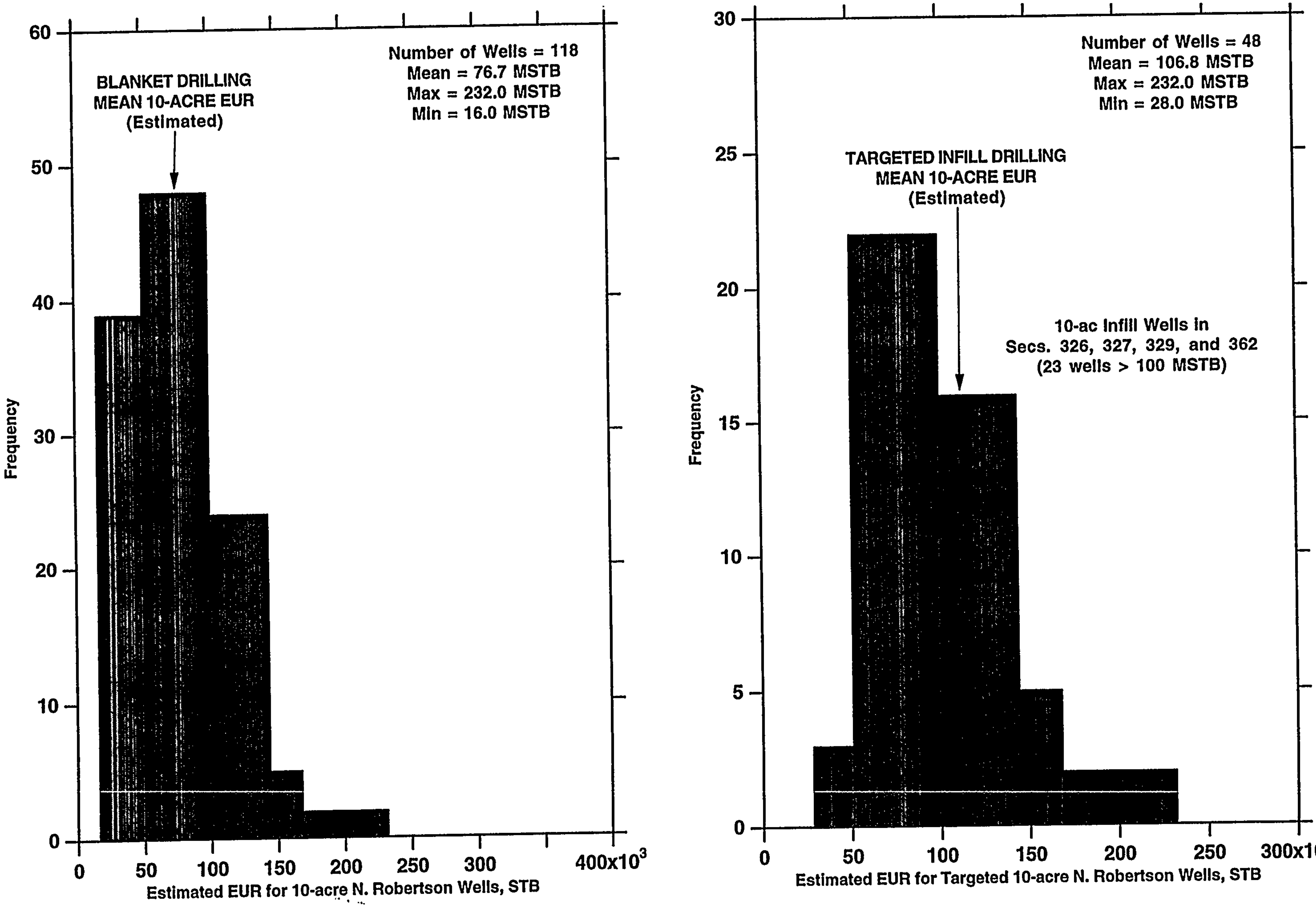


Figure 32 - N. Robertson Unit -Improvement of Estimated 10-acre EUR Using Targeted Infill Drilling.

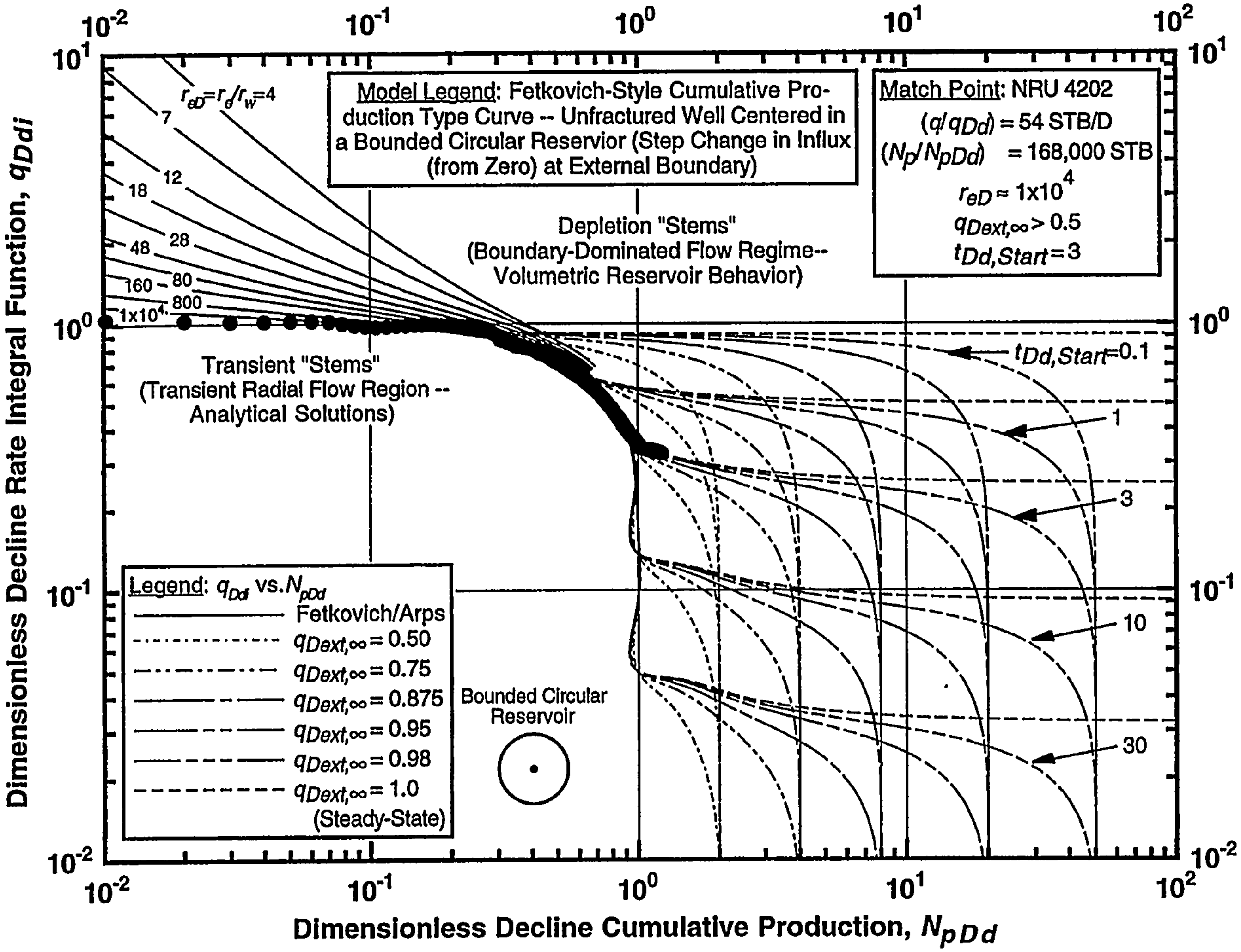


Figure 33- Match of Rate Integral versus Cumulative Production Data for NRU Well 4202 on the Fetkovich/McCray-Style "Waterflood" Type Curves for an Unfractured Well Centered in a Bounded Circular Reservoir (Constant Production Pressure and "Step" Rate Boundary Flux).

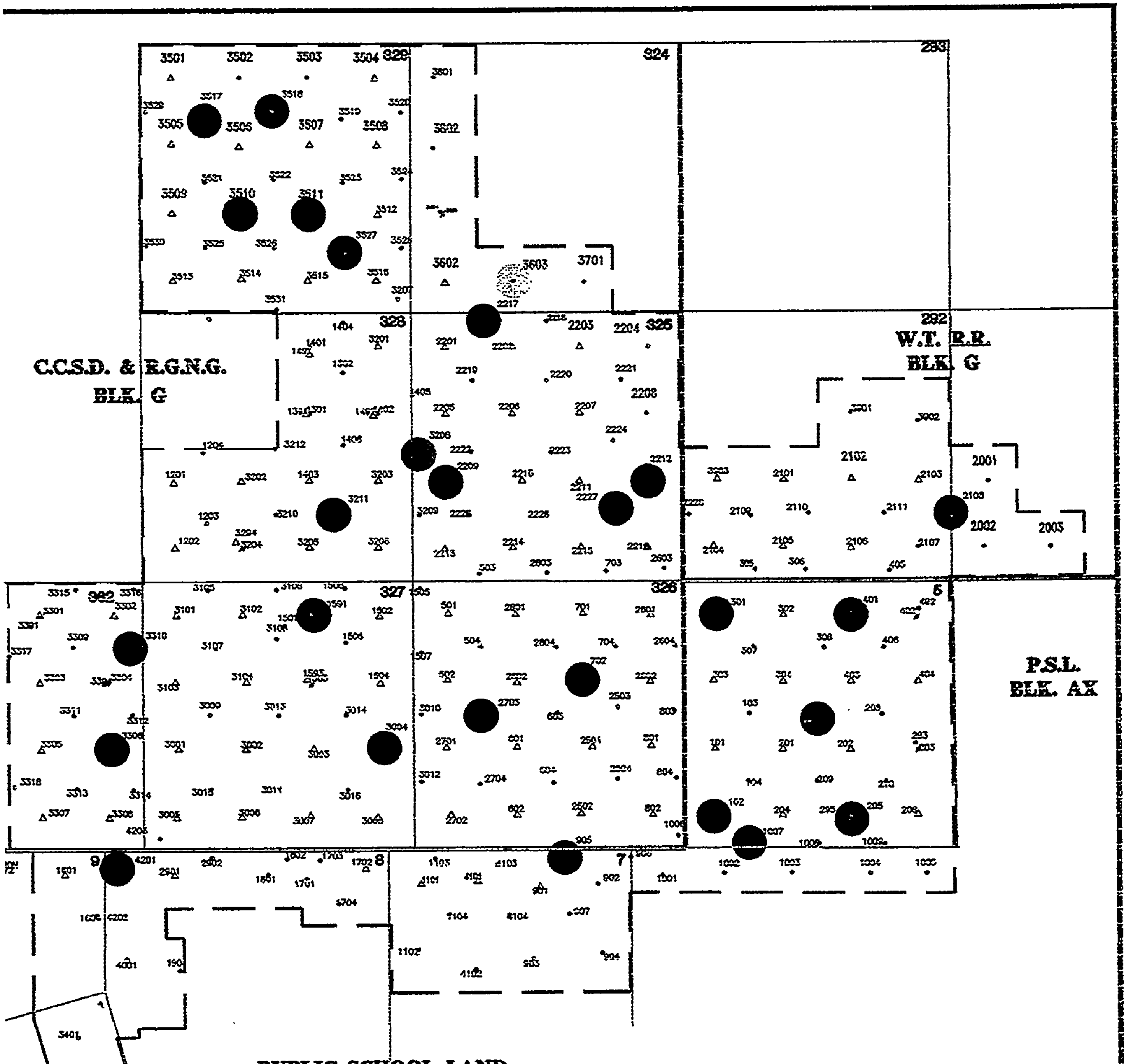


Figure 34

- TDT Logs and PBU Tests
- PFO Tests
- Future TDT/PBU Tests
- Attempted Production Log
- Dipole Sonic Log
- Deepening

FINA OIL & CHEMICAL CO.
WEST TEXAS DIVISION

NORTH ROBERTSON UNIT
GAINES COUNTY, TEXAS

RESERVOIR SURVEILLANCE

PRESSURE TRANSIENT AND CASED HOLE LOGGING SURVEY LOCATIONS

Geology by:	Drawing : NRU-WTR Scale: NONE	Date: 1-96	Revised:	Drafted by: J.V.A.

NRU - Ave. Reservoir Pressure from 1988 PBU Tests

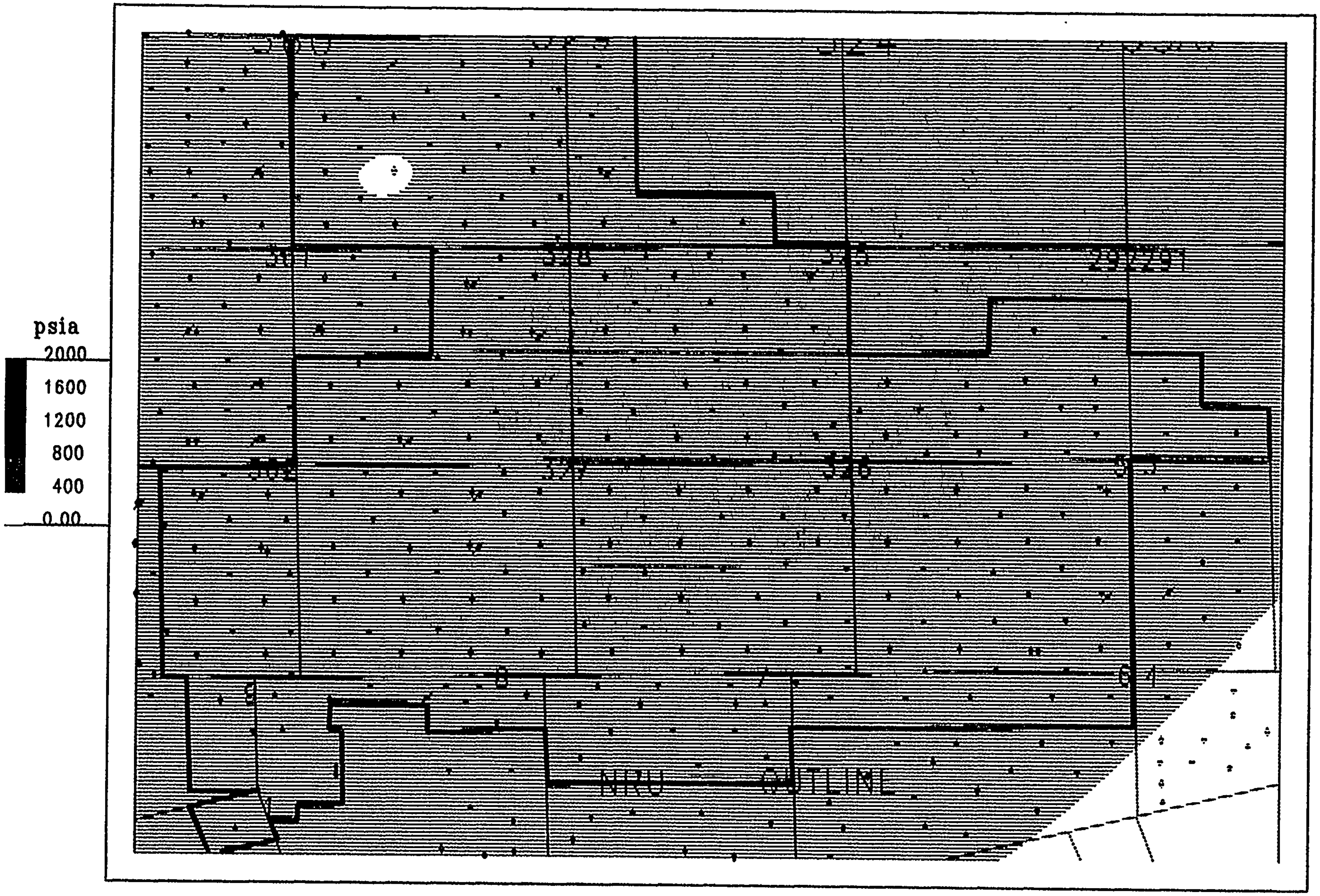


Figure 35 - Estimated Average Reservoir Pressure Distribution Prior to Waterflood Response (1988)

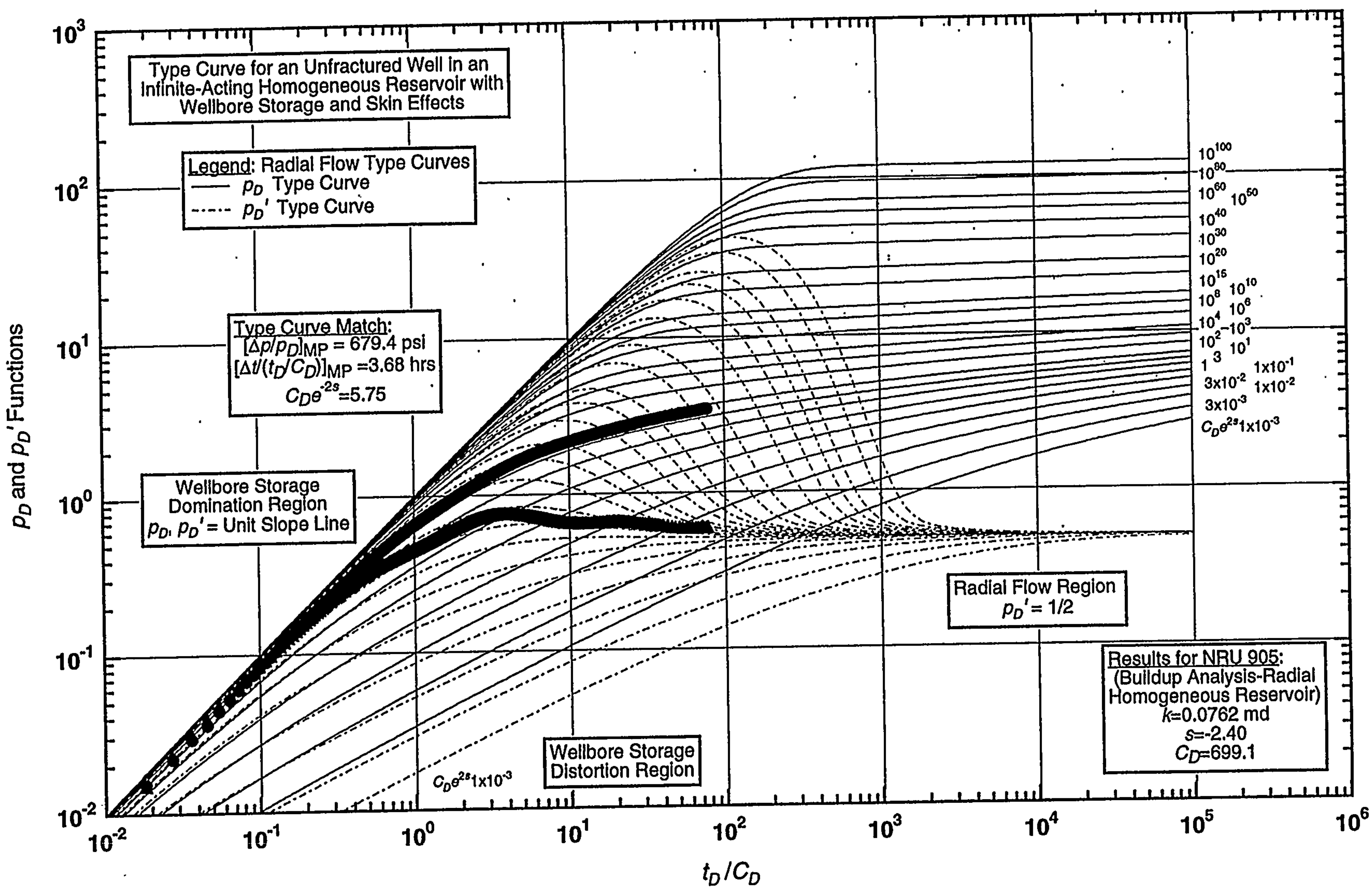


Figure 36 - Match of Buildup Test Data for Well NRU 905 on the Type Curve for an Unfractured Well in an Infinite-Acting Homogeneous Reservoir.

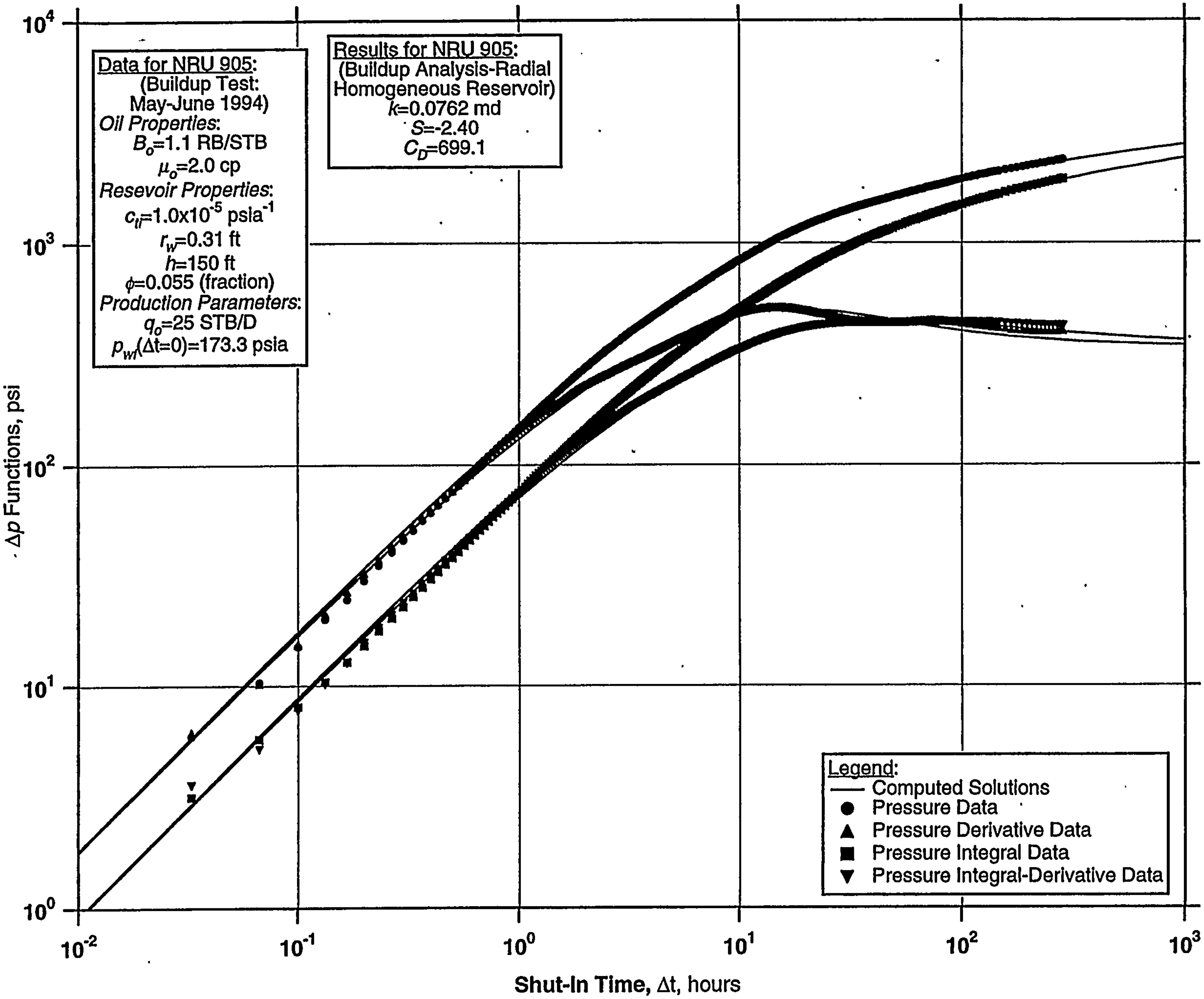


Figure 37 - Data Match on Log-Log Plot for Well NRU 905 Buildup Test (May-June 1995). Match Optimized Using the Infinite-Acting Homogeneous Reservoir Model.

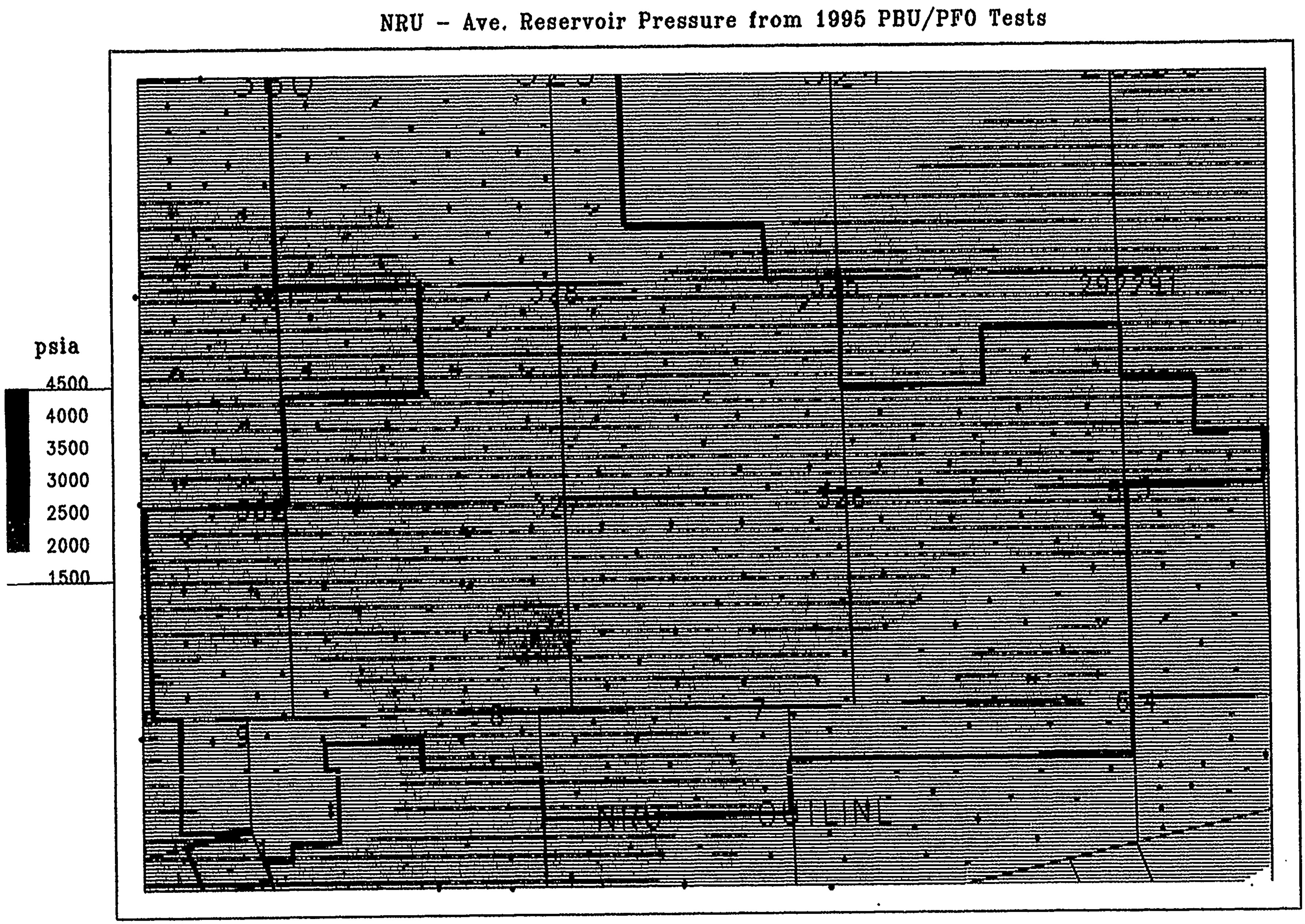


Figure 38 - Estimated Current Average Reservoir Pressure Distribution (1995)

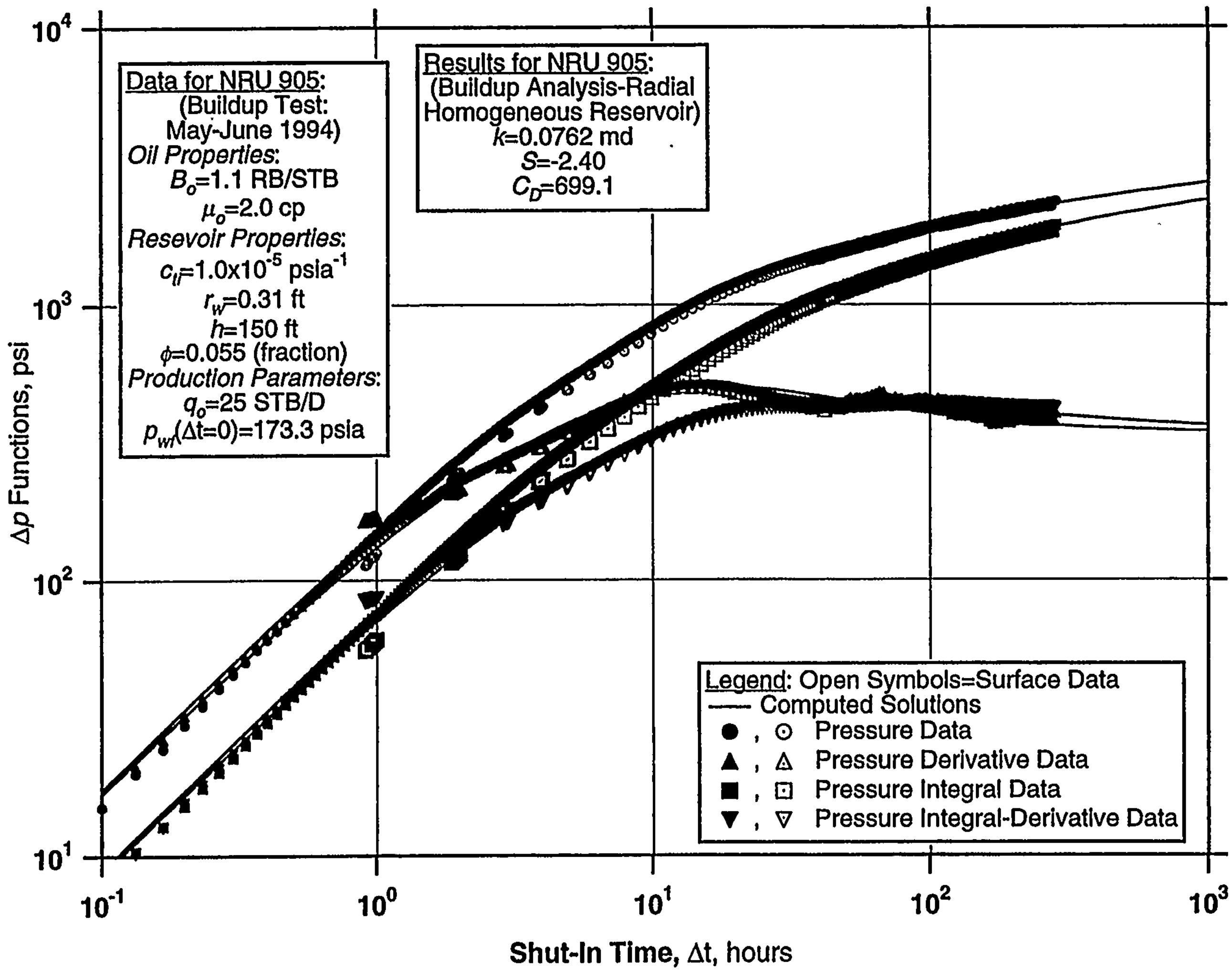


Figure 39 - Data Match on Log-Log Plot for Well NRU 905 Buildup Test (May-June 1995). Match Optimized Using the Infinite-Acting Homogeneous Reservoir Model. Comparison of Surface and Bottomhole Pressure Data.

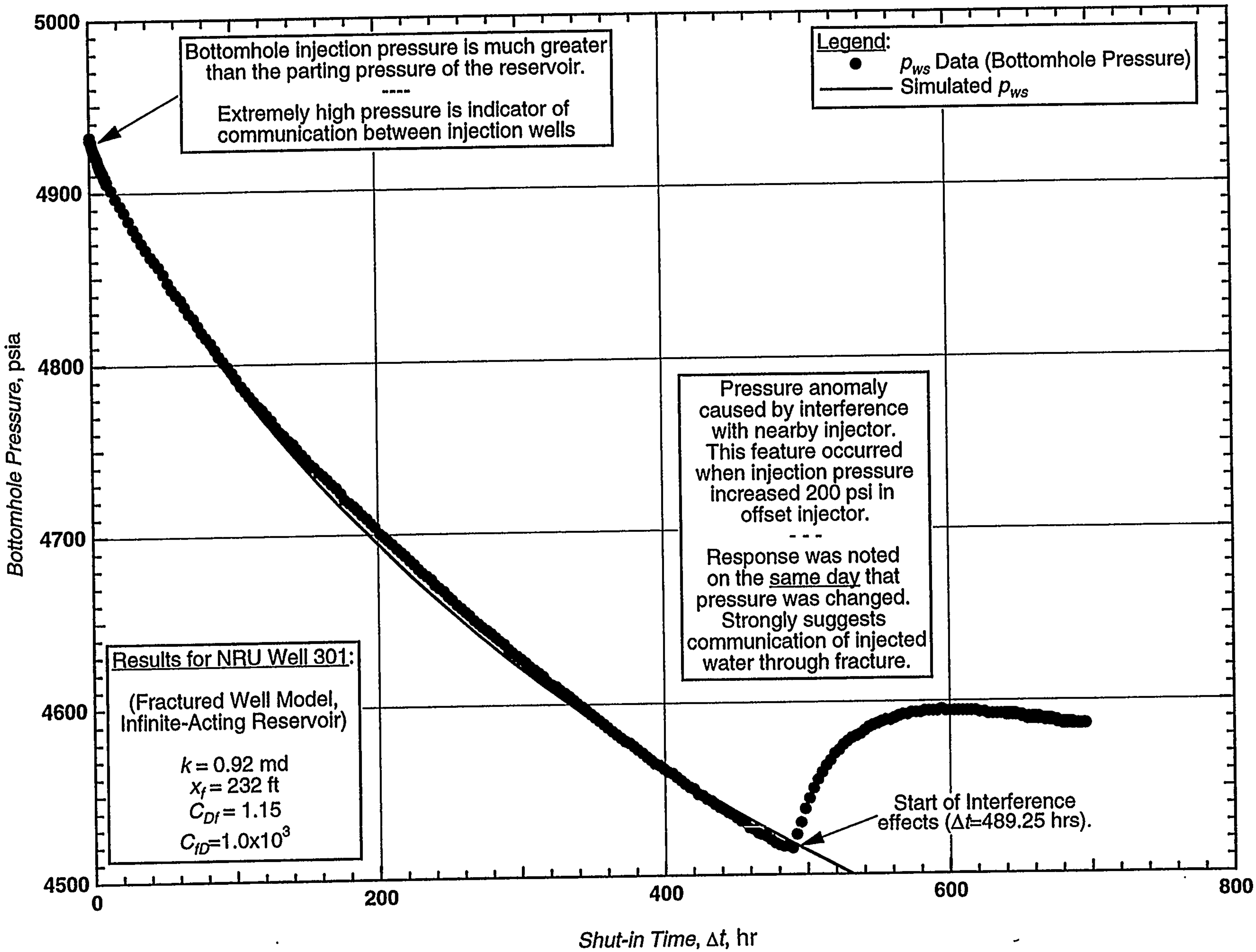


Figure 40 - Cartesian Plot of P_{ws} versus Shut-in Time for NRU Well 301 Pressure Falloff Test.

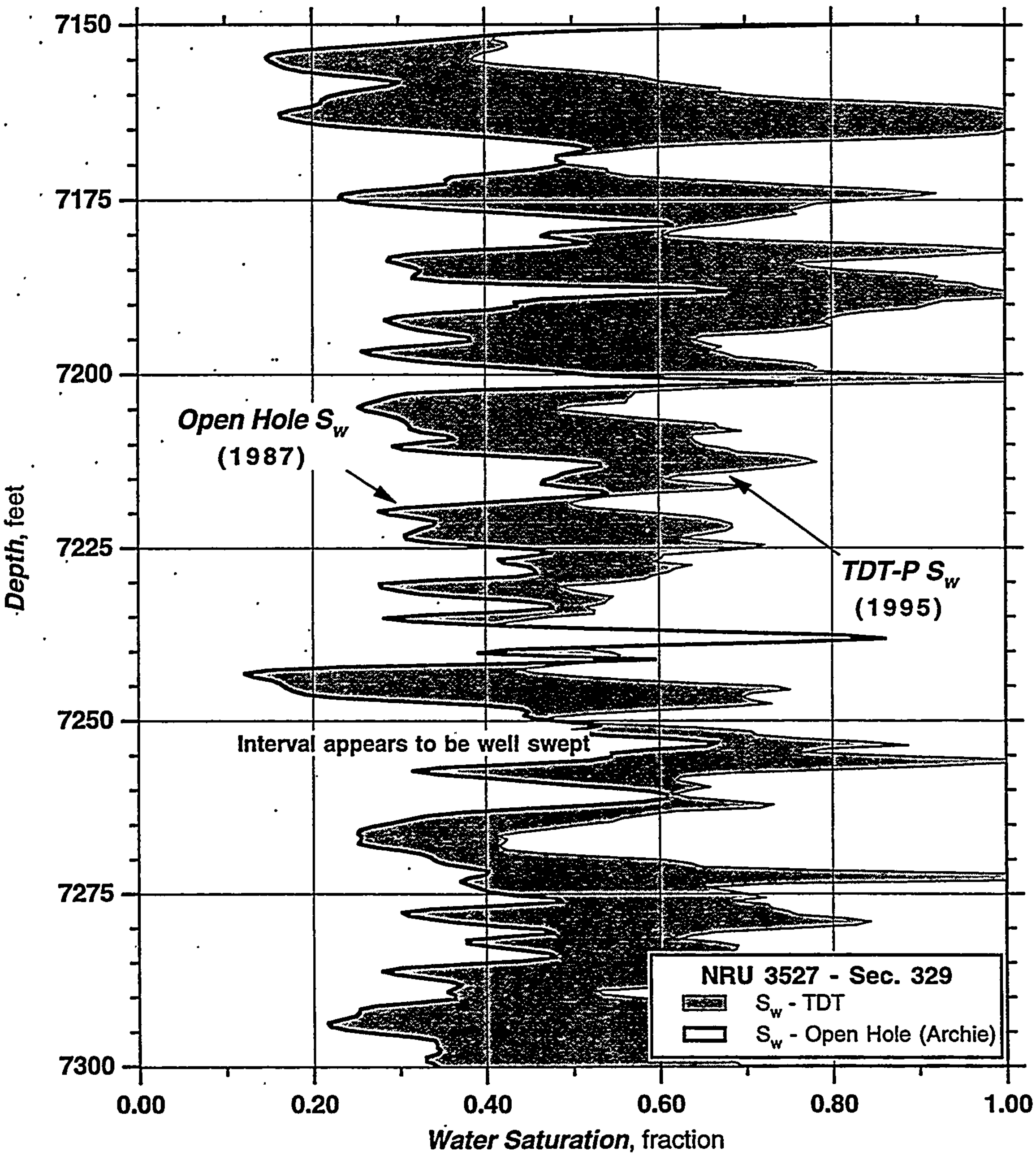


Figure 41 -Monitoring Sweep Efficiency and Fluid Movement in the Reservoir Using TDT-P (Lower Clearfork)

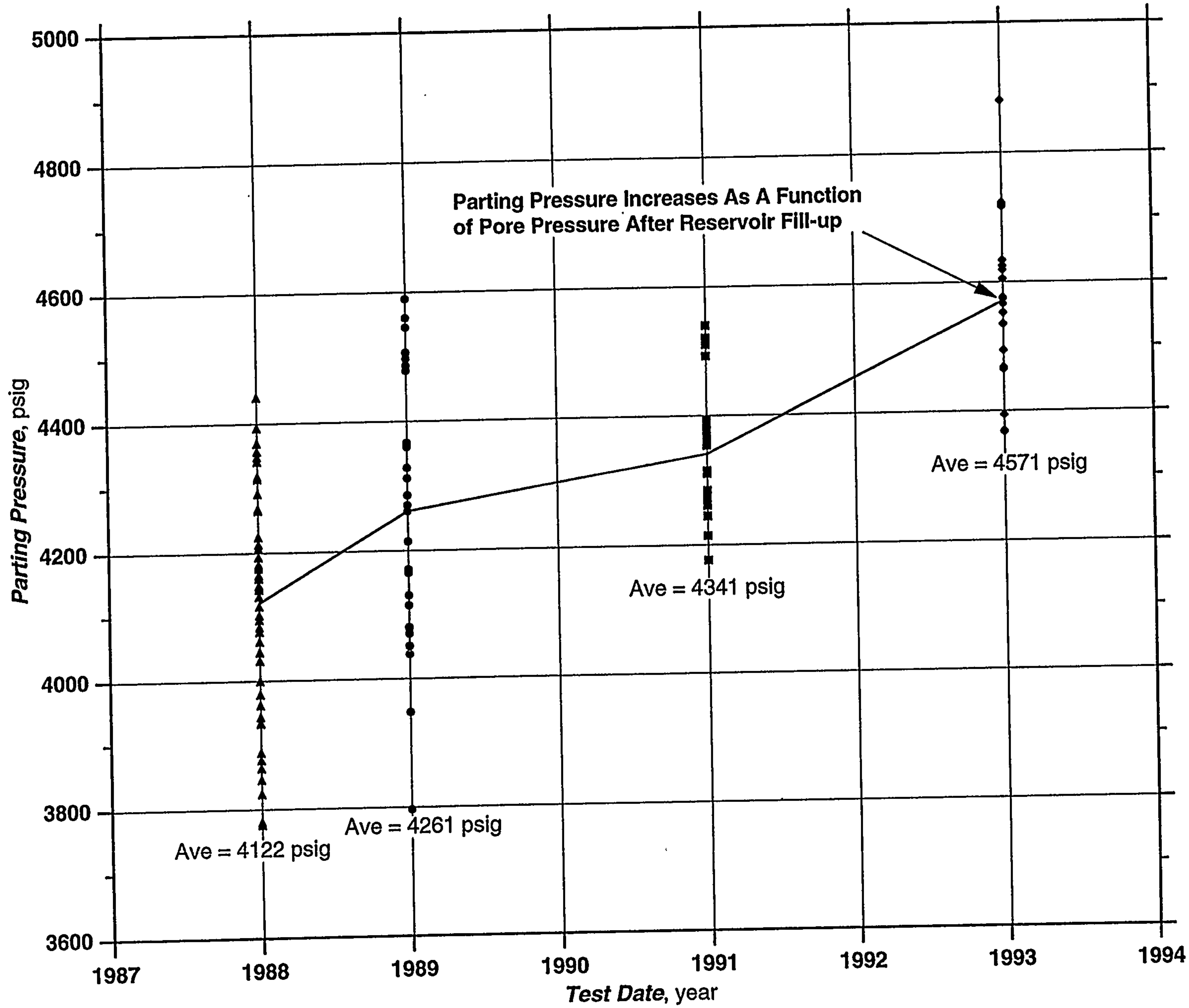


Figure 42 - Comparison of Average Parting Pressures from Step-Rate Tests (1988-1993).

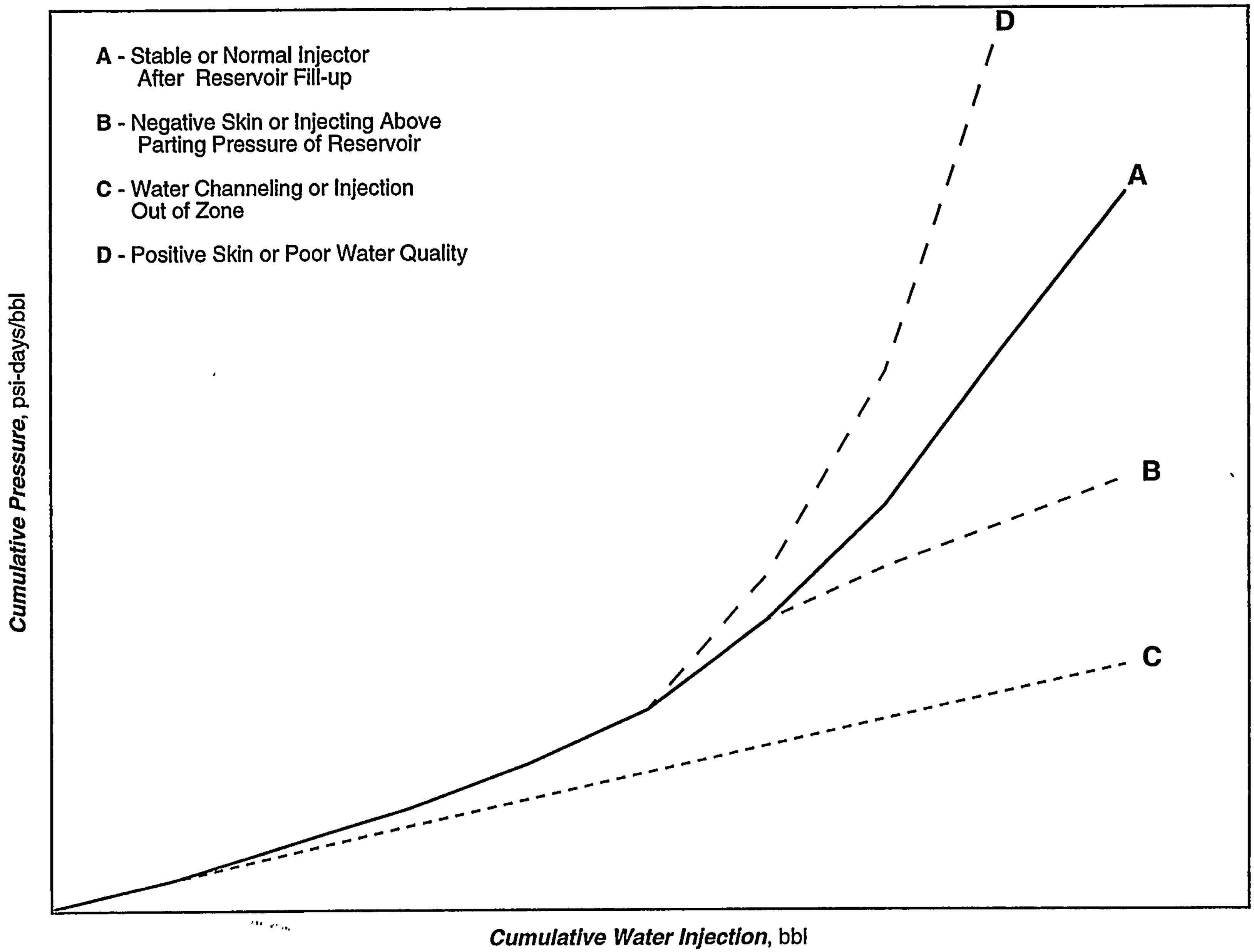


Figure 43 - Example of Hall Plot, after Thakur (Ref. 24).

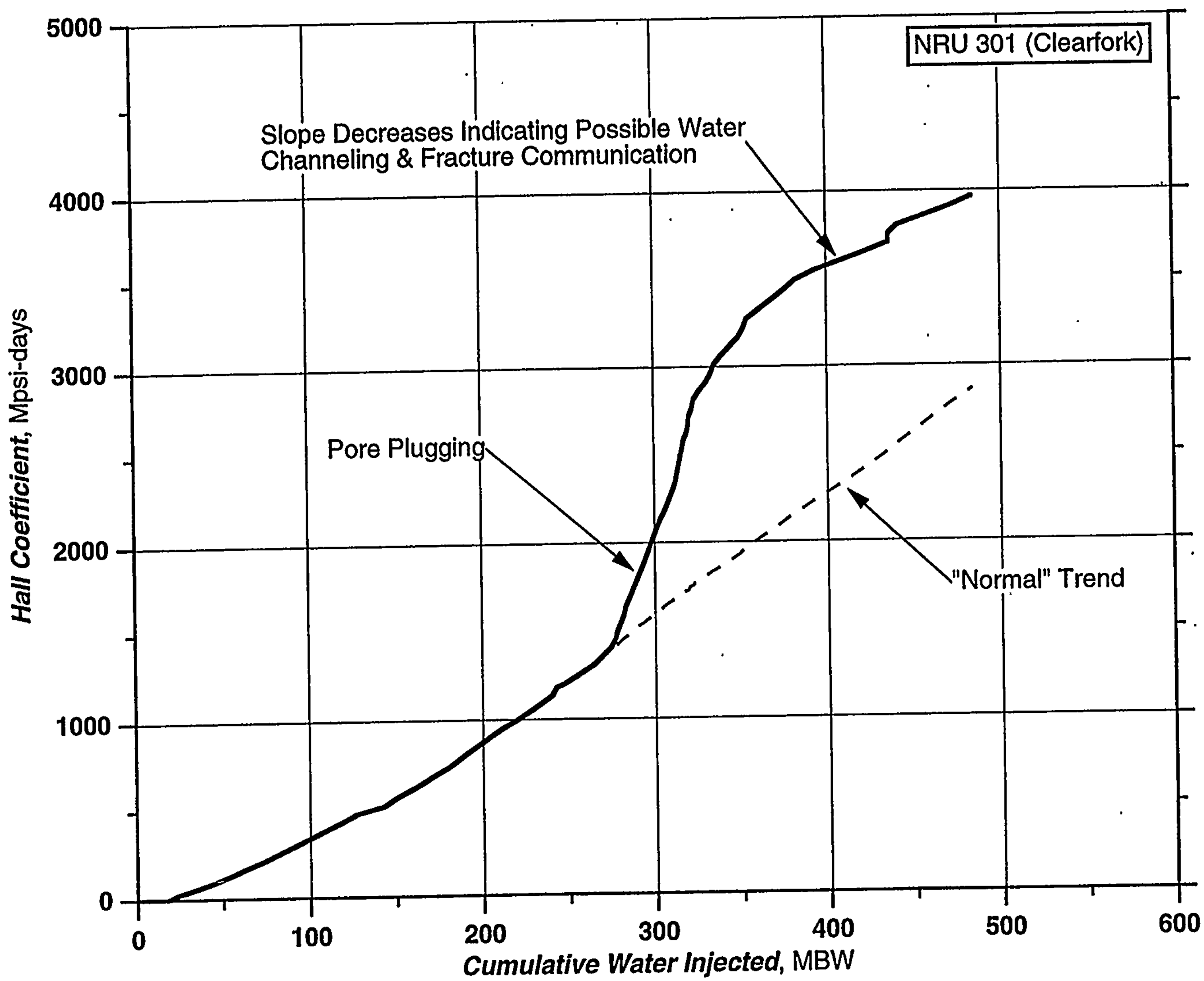


Figure 44 - Hall Diagnostic Plot For NRU 301.

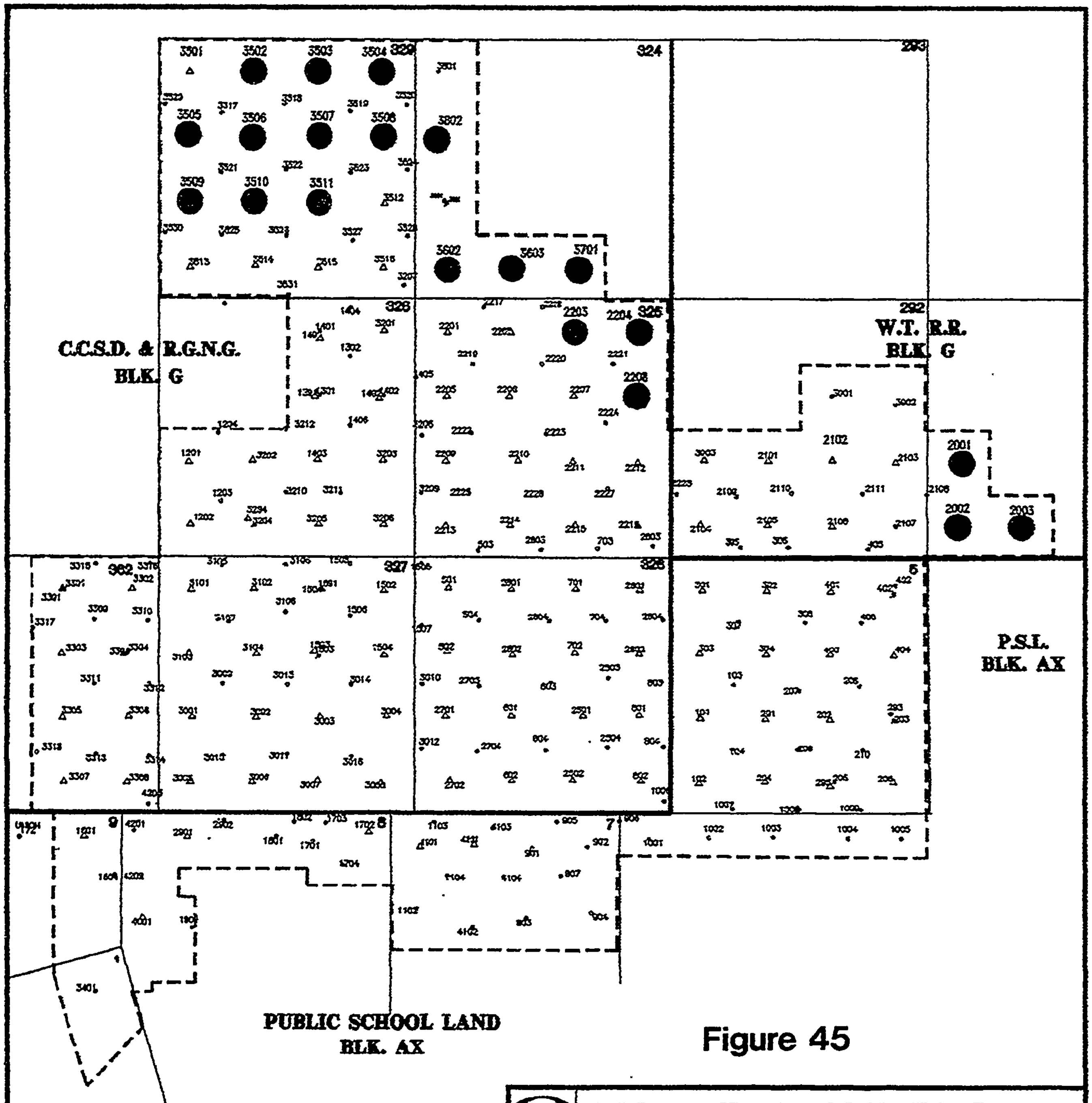


Figure 45

Producers Deepening/Recompleting

- 450 - 650'
- 140 - 180'

Injectors Deepening/Recompleting

- 505'
- 167 - 193'
- 108 - 136'
- 67 - 97'

FINA OIL & CHEMICAL CO.
WEST TEXAS DIVISION

NORTH ROBERTSON UNIT
GAINES COUNTY, TEXAS

DEEPENING AND ASSOCIATED RECOMPLETION CANDIDATES

Geology by:	Drawing : NRU-WTR Scale: NONE	Date: 4-95	Revised:	Drafted by: J.V.A.

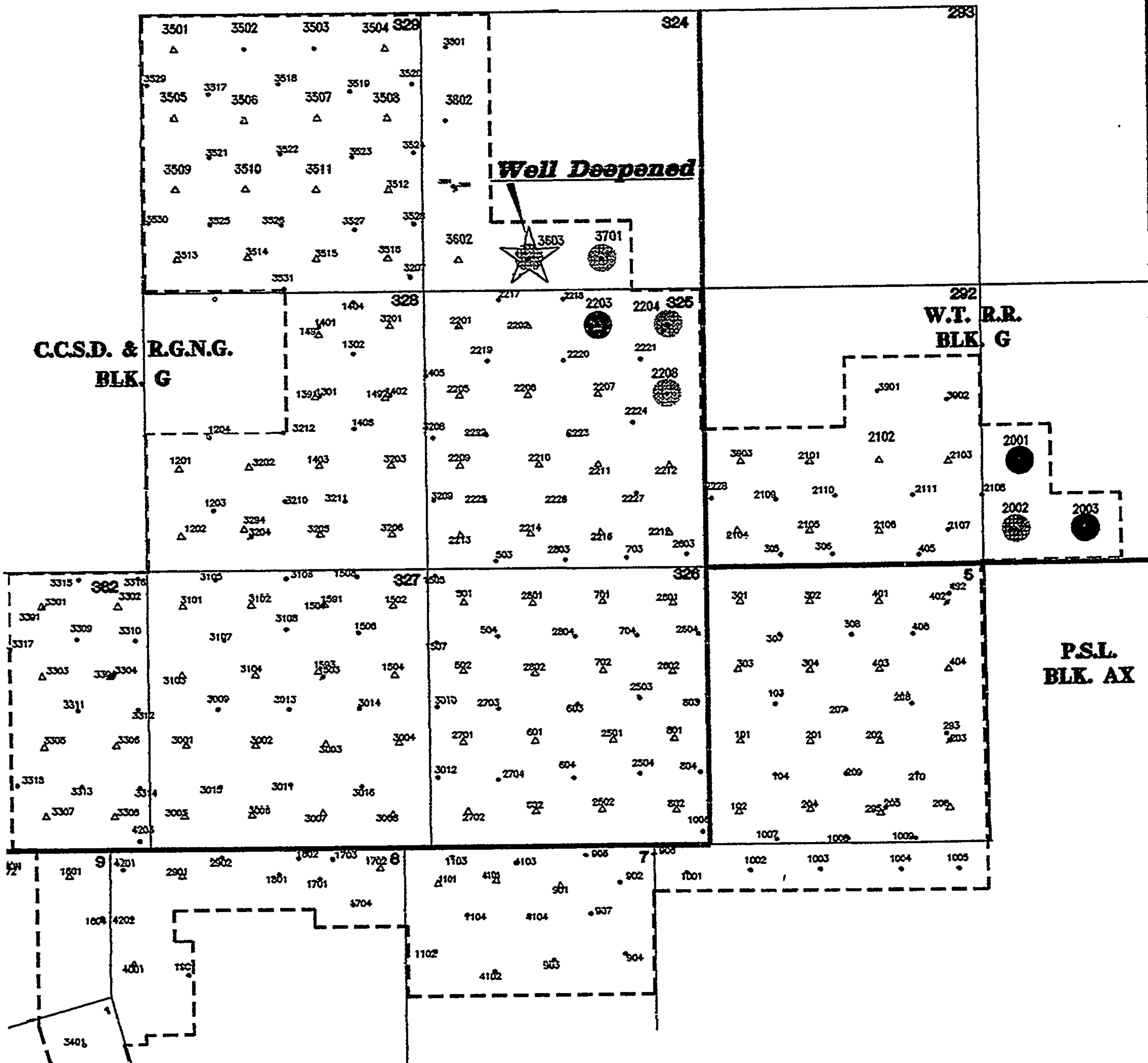


Figure 46

Producers Deepening/Recompleting

- 450 - 650'
- 140 - 180'

Injectors Deepening/Recompleting

- 108 - 136'

FINA OIL & CHEMICAL CO.
WEST TEXAS DIVISION

NORTH ROBERTSON UNIT
GAINES COUNTY, TEXAS

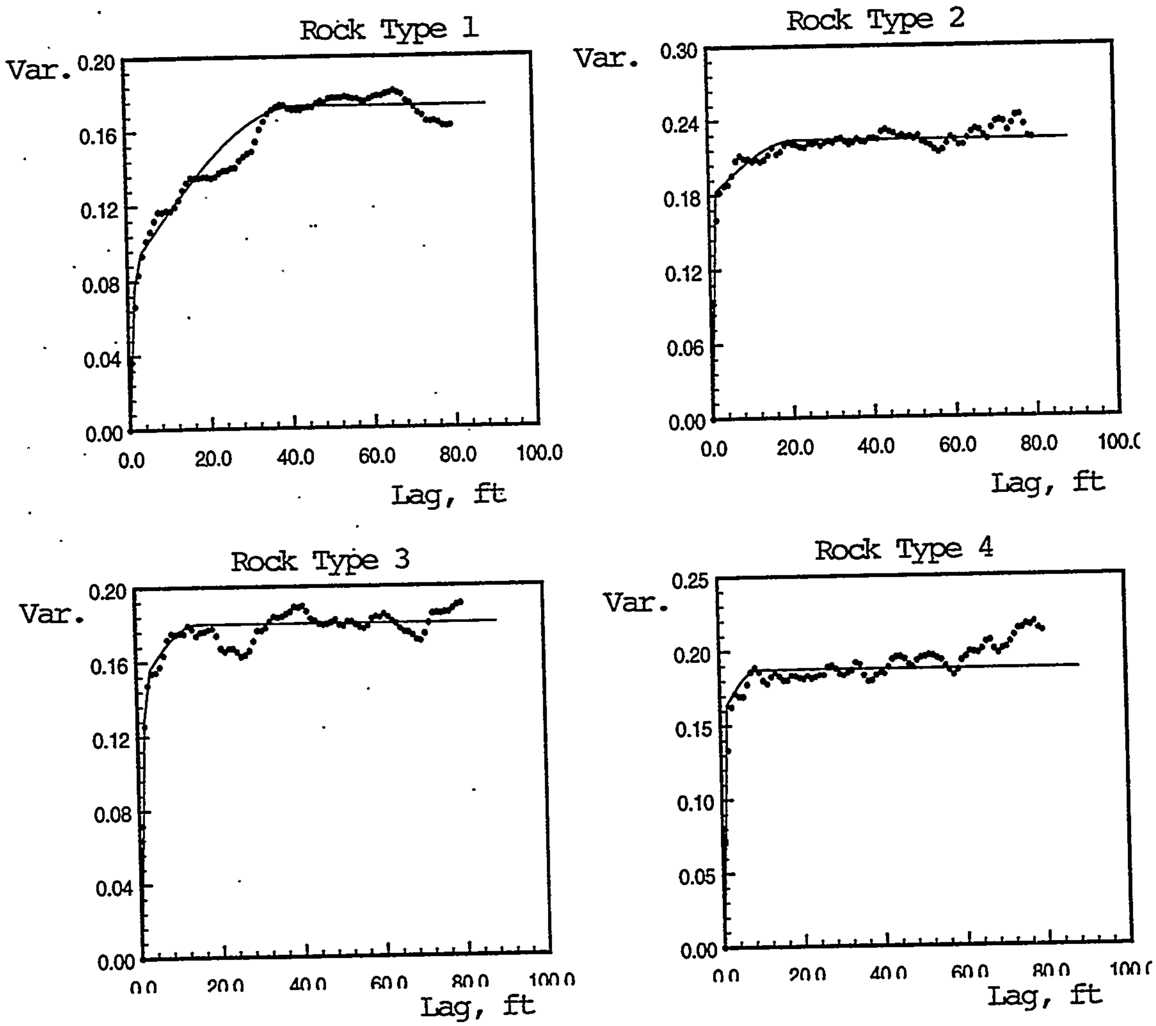
DEEPENING AND ASSOCIATED RECOMPLETION CANDIDATES

Geology by:	Drawing : NRU-WTR Scale: NONE	Date: 1-96	Revised:	Drafted by: J.V.A.

	Section - 329	Section - 5
GL1a GL1	Layer 1, Thickness =176 ft	Layer 1, Thickness =176 ft
GL2 GL3	Layer 2, Thickness =147 ft	Layer 2, Thickness =109ft
GL4 CF1 CF2	Layer 3, Thickness =137 ft	Layer 3, Thickness =126 ft
CF3 CF4	Layer 4, Thickness =141 ft	Layer 4, Thickness =117 ft
MF1b MF1	Layer 5, Thickness =169 ft	Layer 5, Thickness =160 ft
MF1a MF2	Layer 6, Thickness =184 ft	Layer 6, Thickness =192 ft
MF2a MF2b	Layer 7, Thickness =135 ft	Layer 7, Thickness =121 ft
MF3	Layer 8, Thickness =153 ft	Layer 8, Thickness =157ft
MF4	Layer 9, Thickness = 73 ft	Layer 9, Thickness = 79 ft
TUB MF5	Layer 10, Thickness =136 ft	Layer 10, Thickness =132 ft
MF6	Layer 11, Thickness =151 ft	Layer 11, Thickness =111 ft

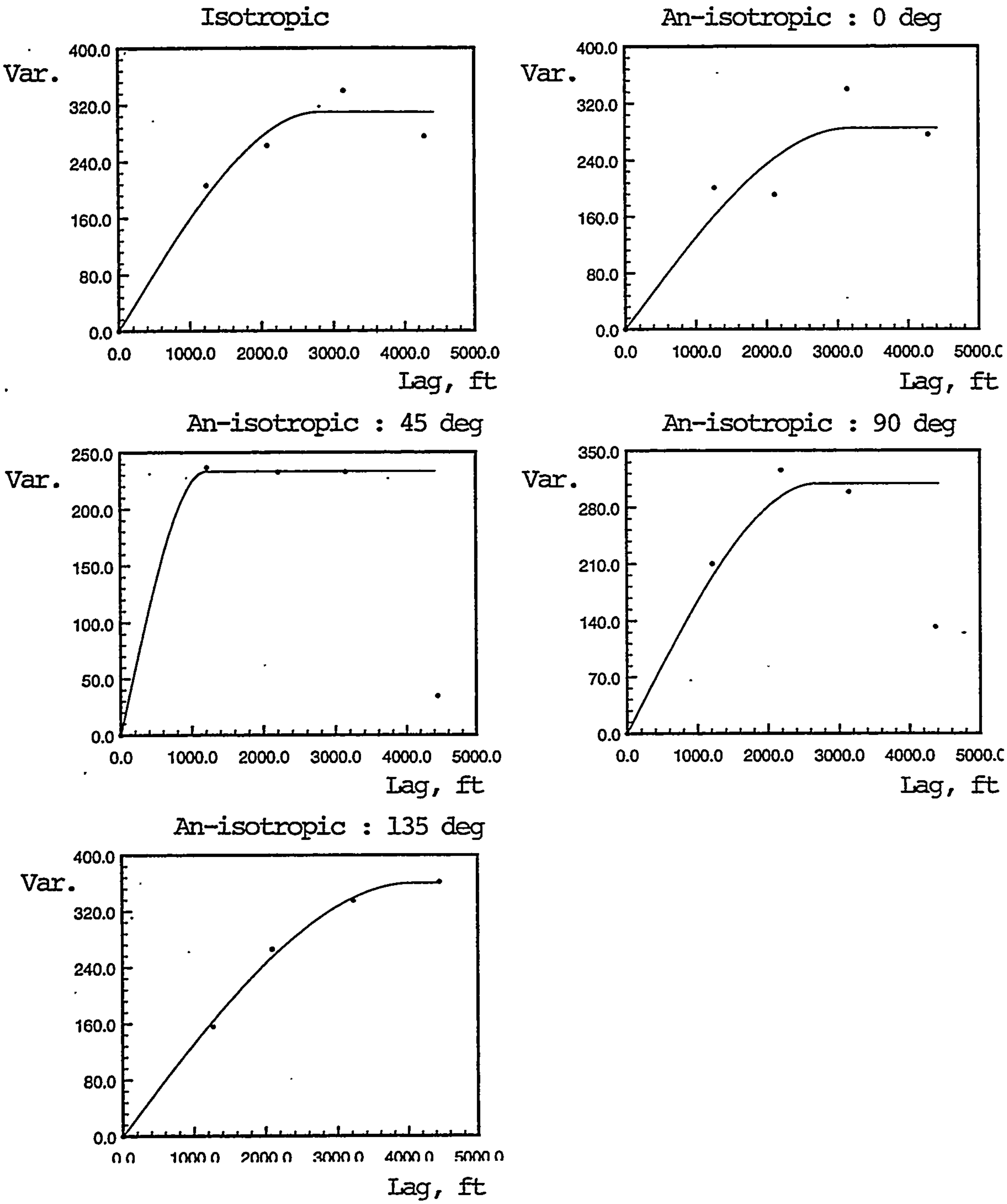
Layer definition and its thickness for geostatistical simulation.

Figure 47



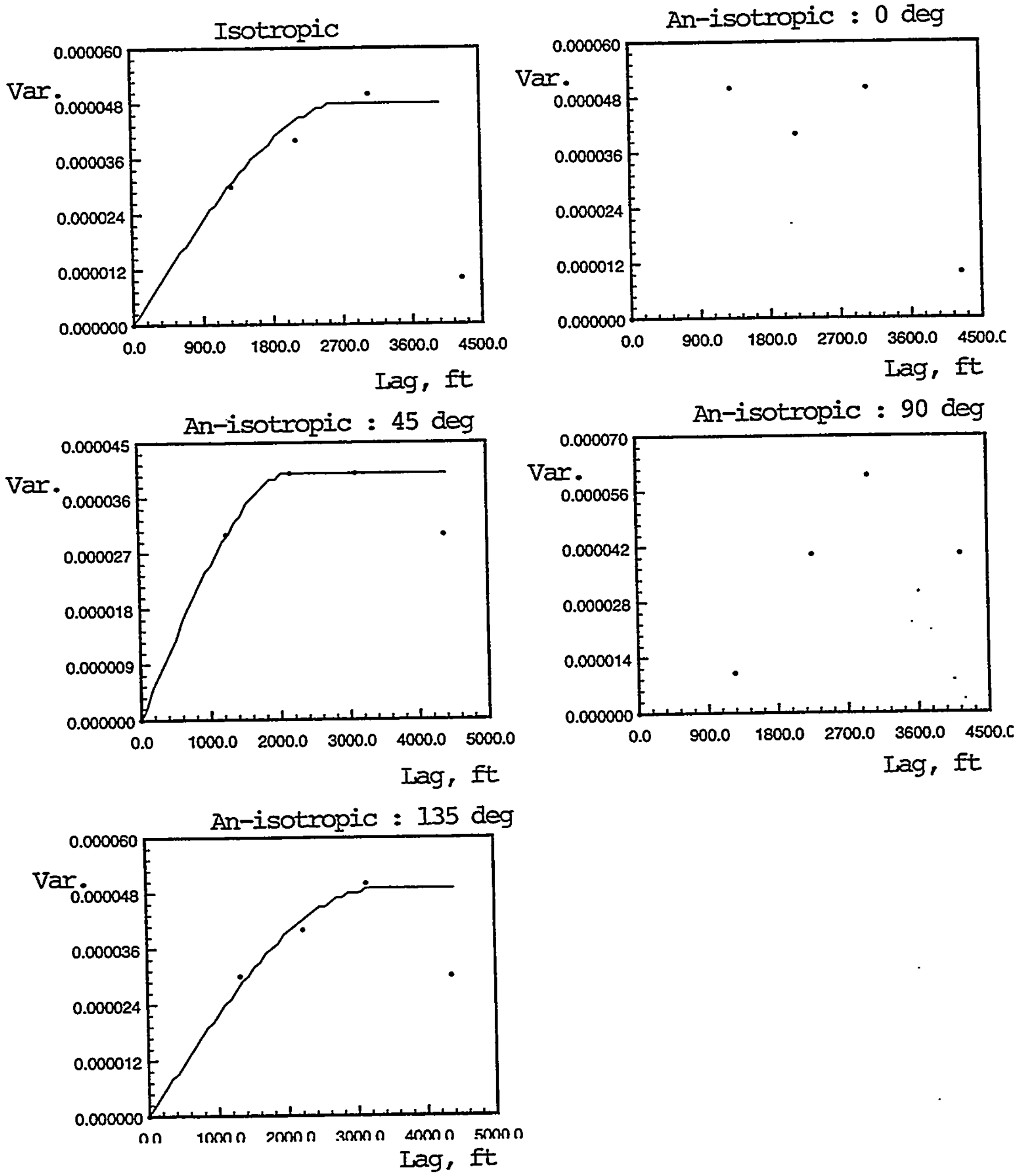
Vertical variogram for rock types 1, 2, 3, and 4 of Layer 6 - Section 329

Figure 48



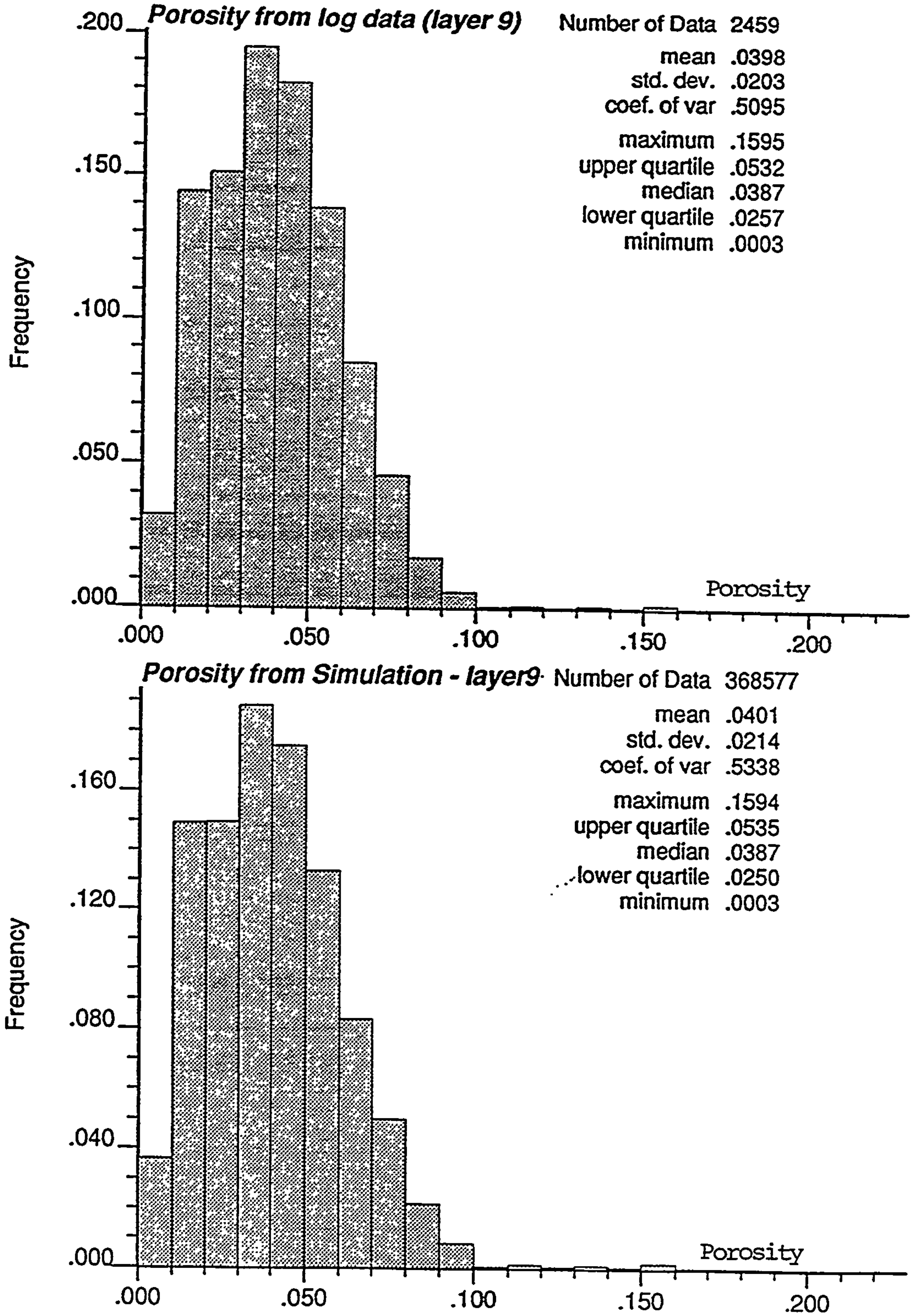
Horizontal variogram of the Thickness of Rock Type 1 - Layer 1 - Section 329

Figure 49



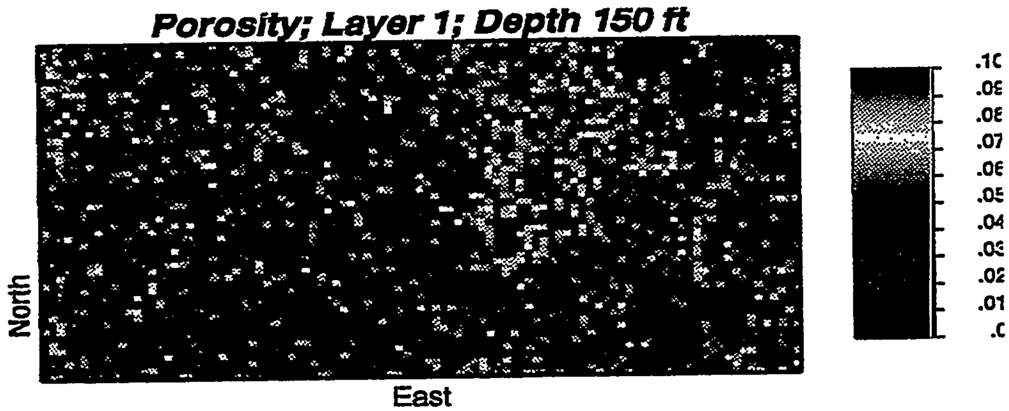
Horizontal variogram of average porosity - Layer 2 - Section 329

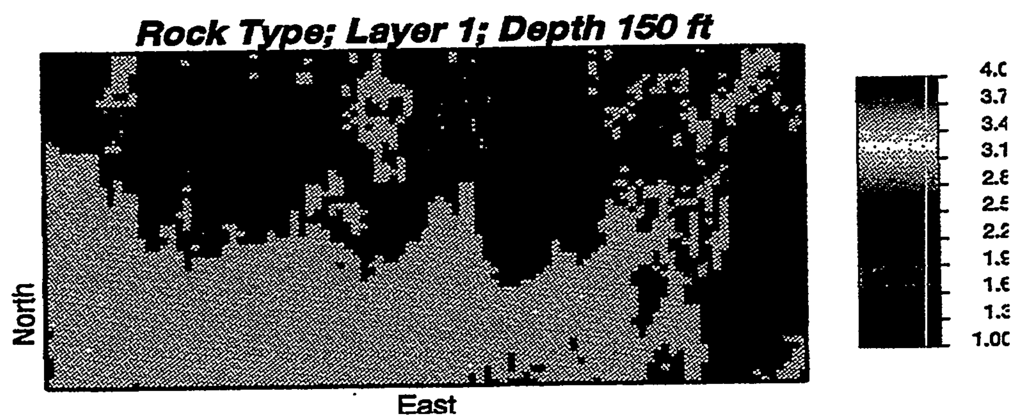
Figure 50



Comparison of the histogram between conditioning data and simulation result for porosity of Layer 9 - Section 329.

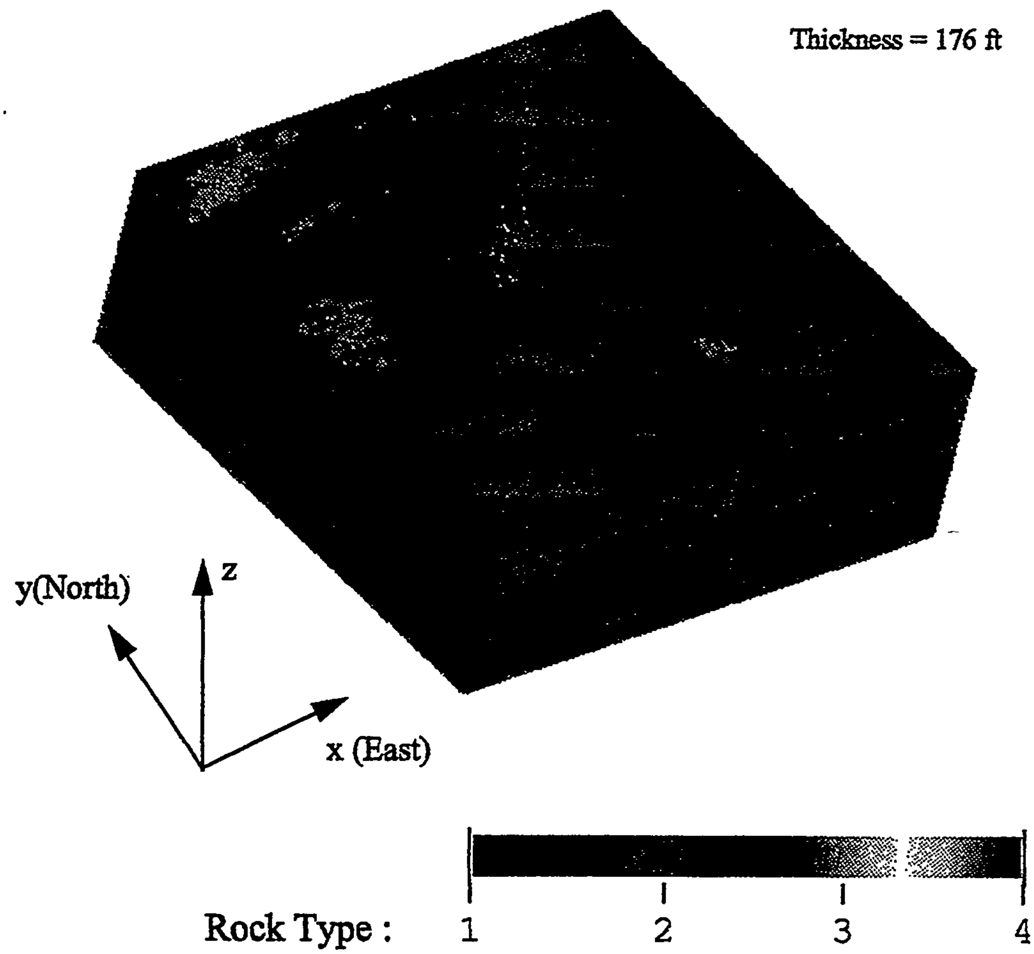
Figure 51





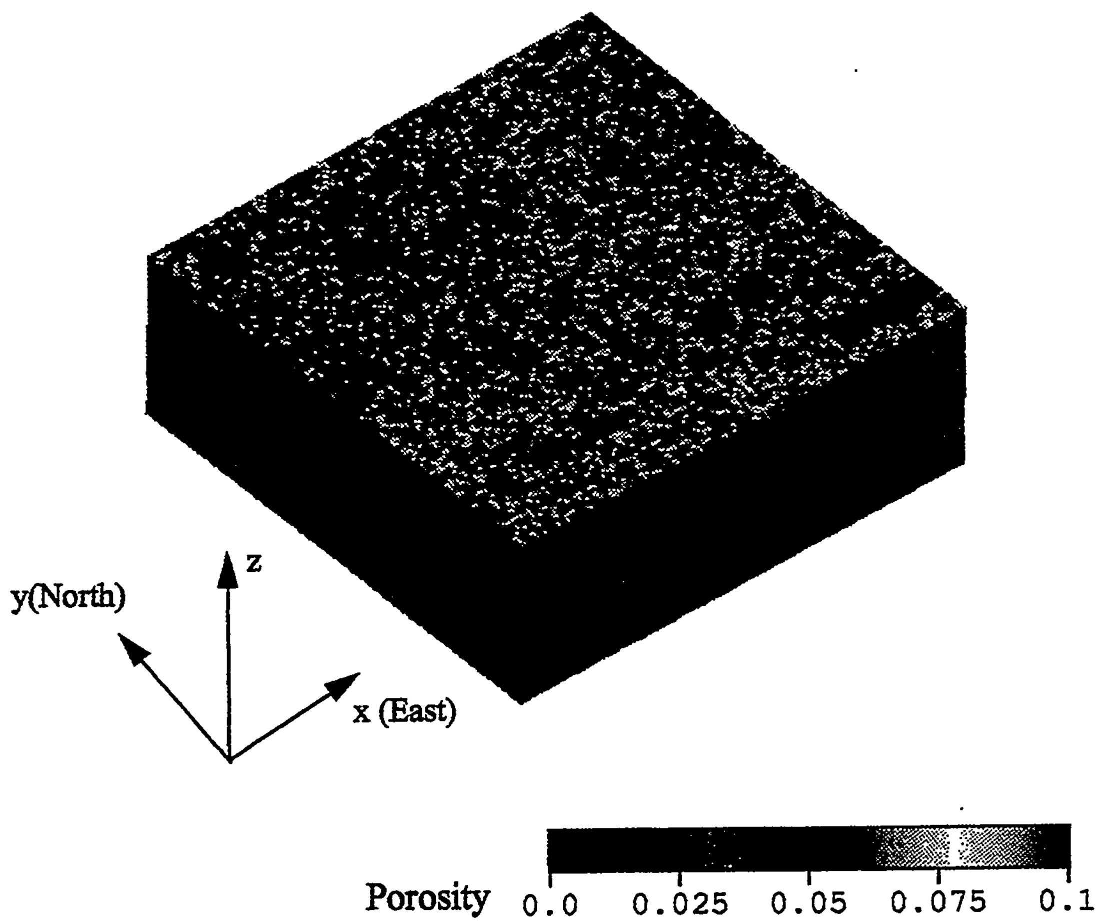
Porosity and Rock Type Cross Sections at 150 ft below the top of Layer 1 - Section 329

Figure 52



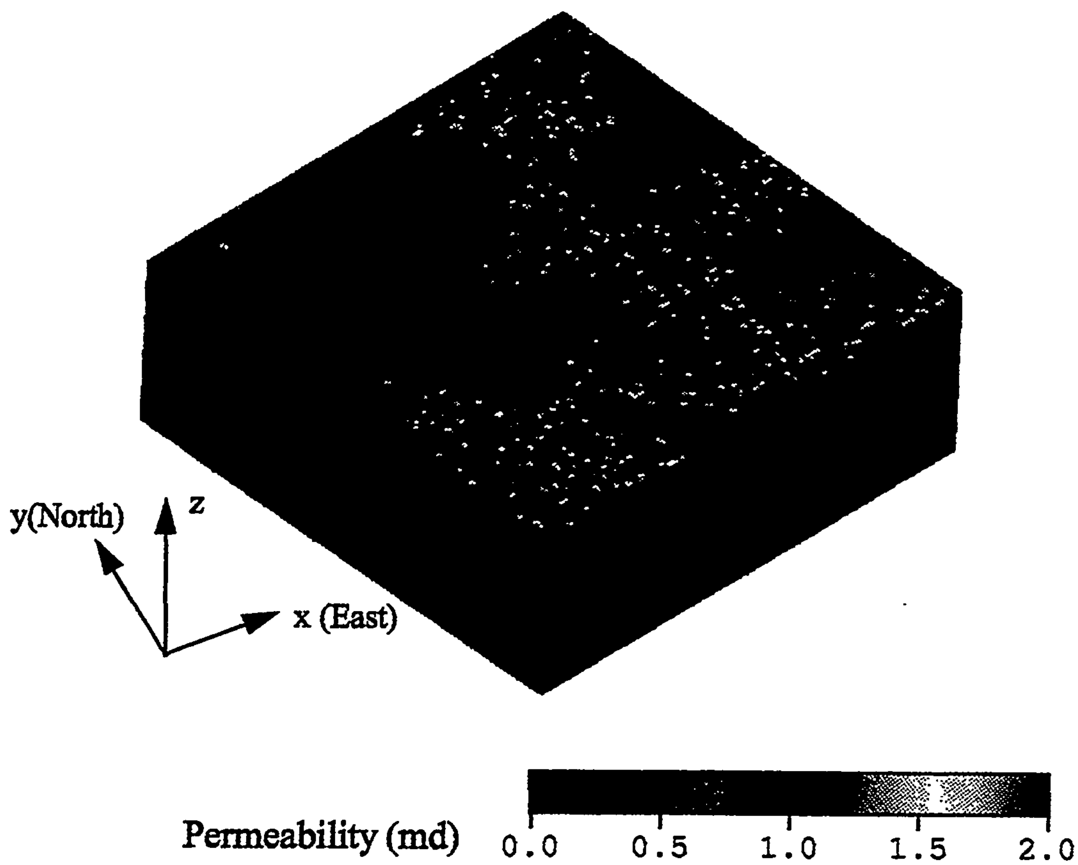
3D View of Rock Type of Layer 1 - Section 5

Figure 53



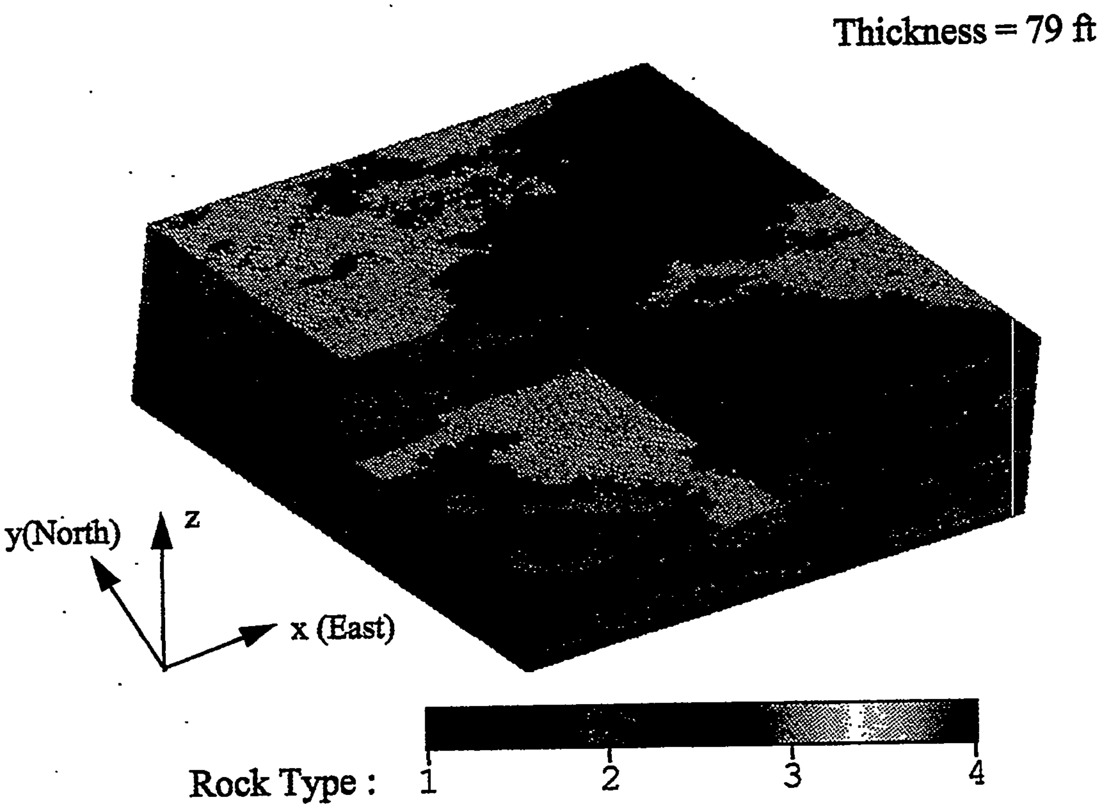
3D View of porosity Layer 1 - Section 5

Figure 54



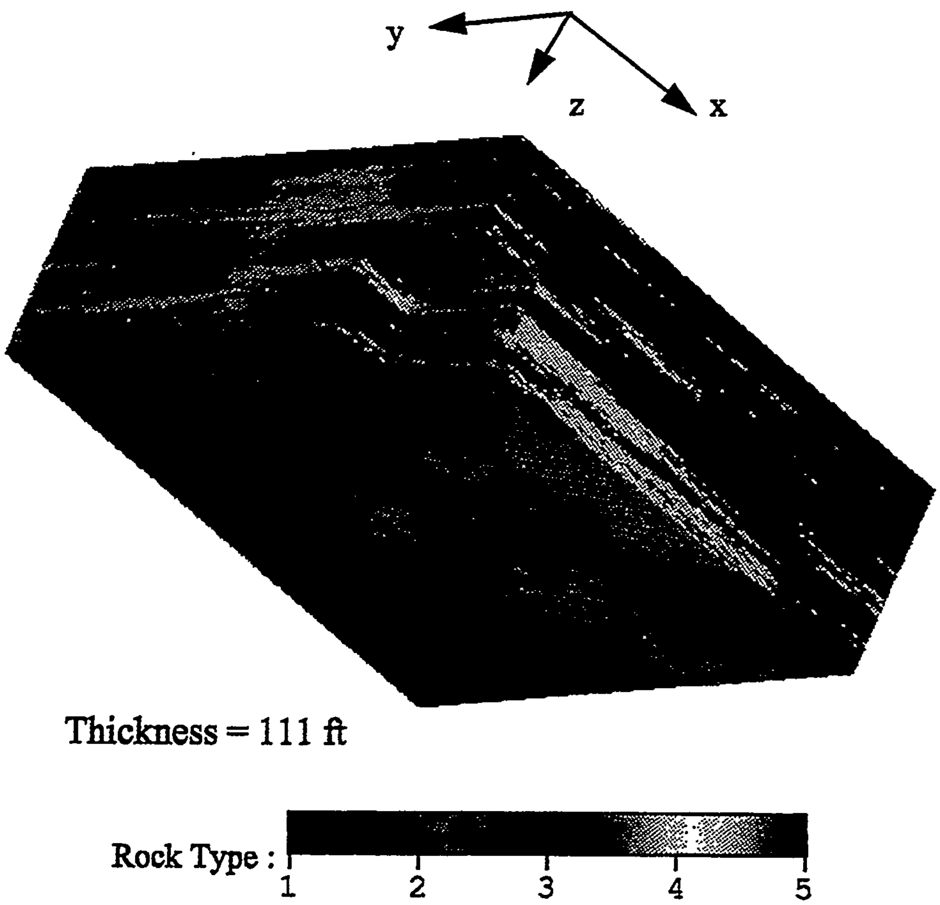
3D View of Permeability of Layer 1 - Section 5

Figure 55



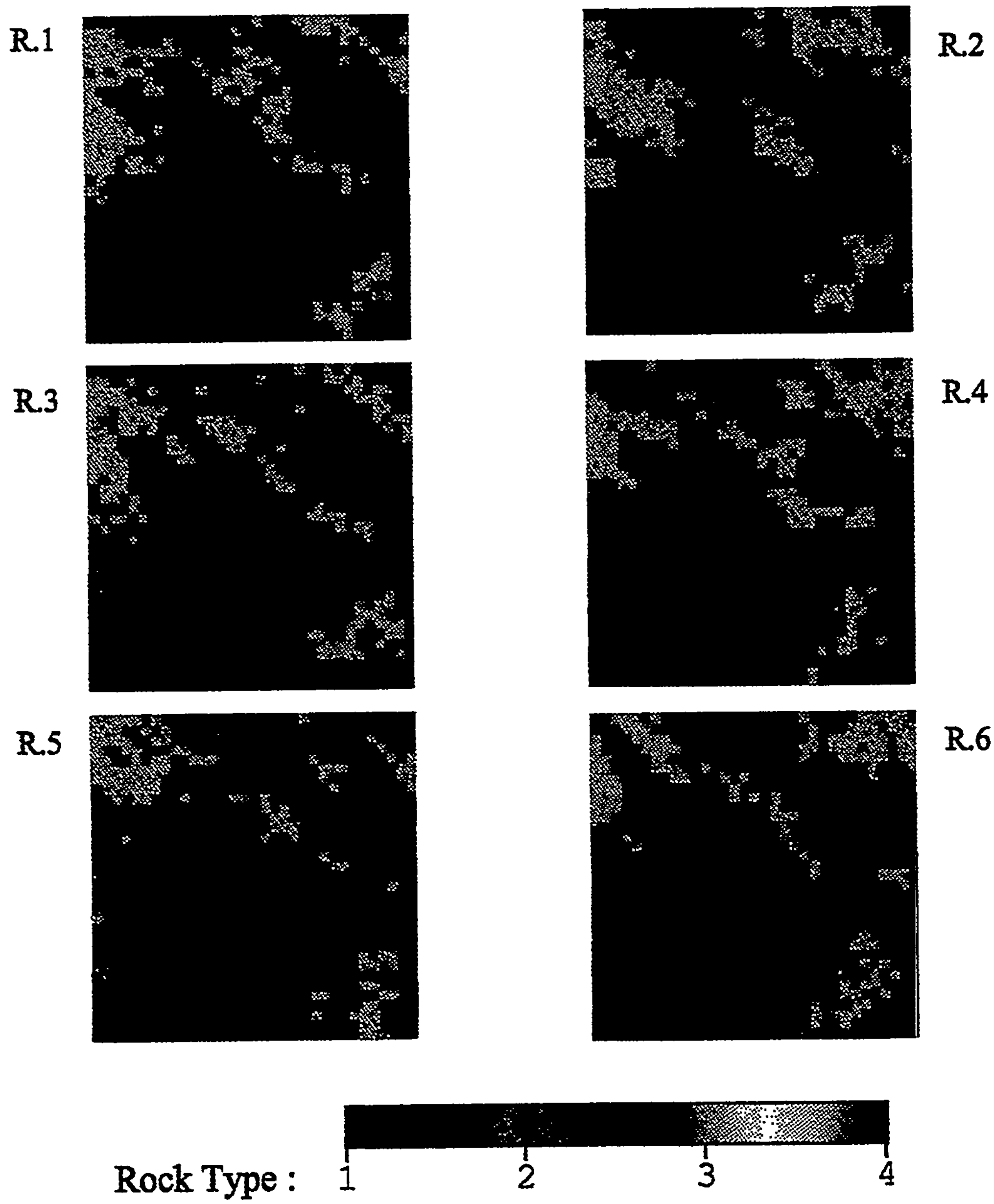
3D View of Rock Type of Layer 9 - Section 5

Figure 56



3D View of Rock Type of Layer 11 - Section 5

Figure 57



Rock Type Cross Sections at 50 ft below the top of Layer 5 - Section 5 for 6 different realizations

Figure 58

CONNECTIVITY

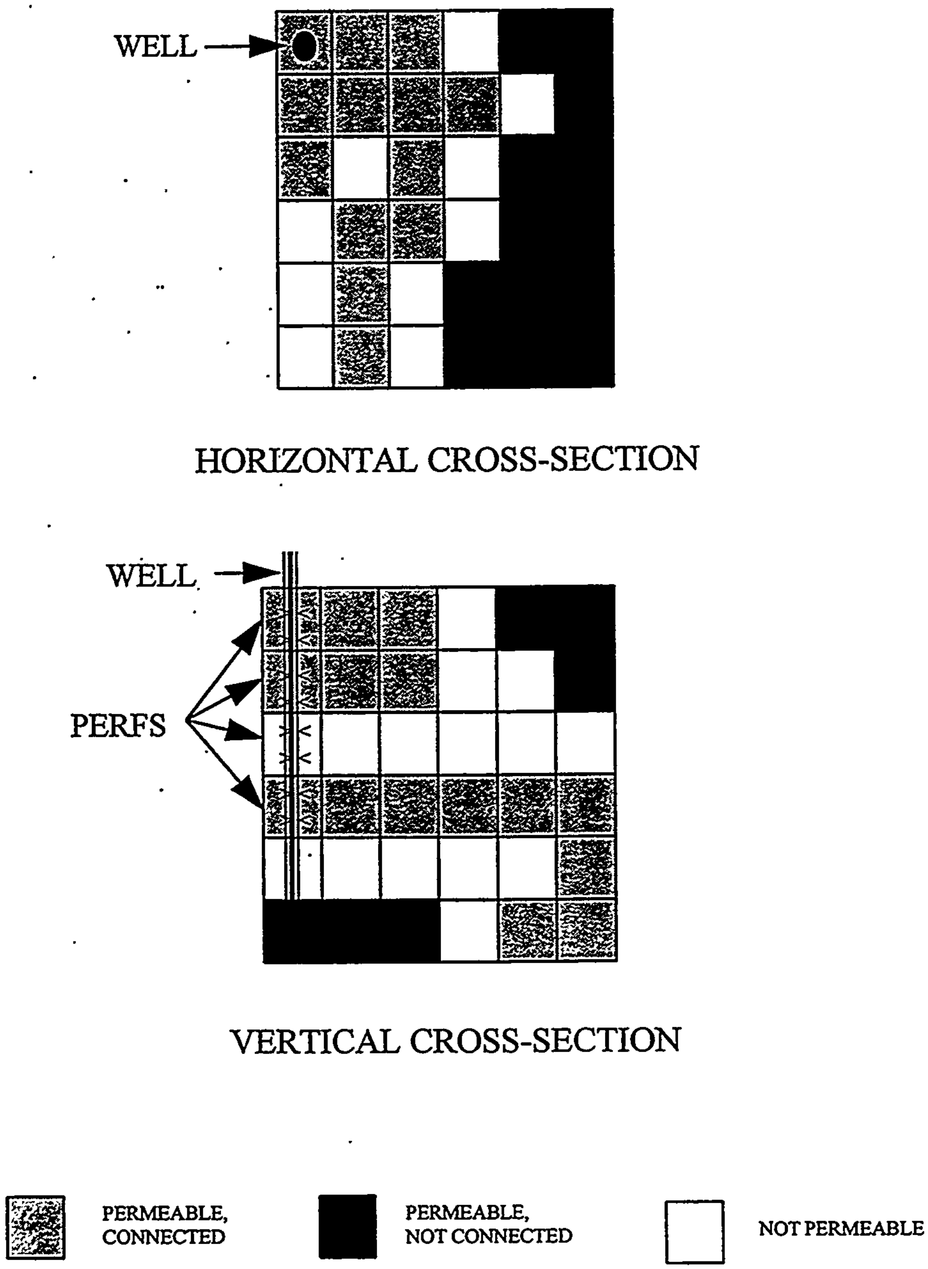


Figure 59

LAYER 4
HORIZONTAL CROSS SECTIONS

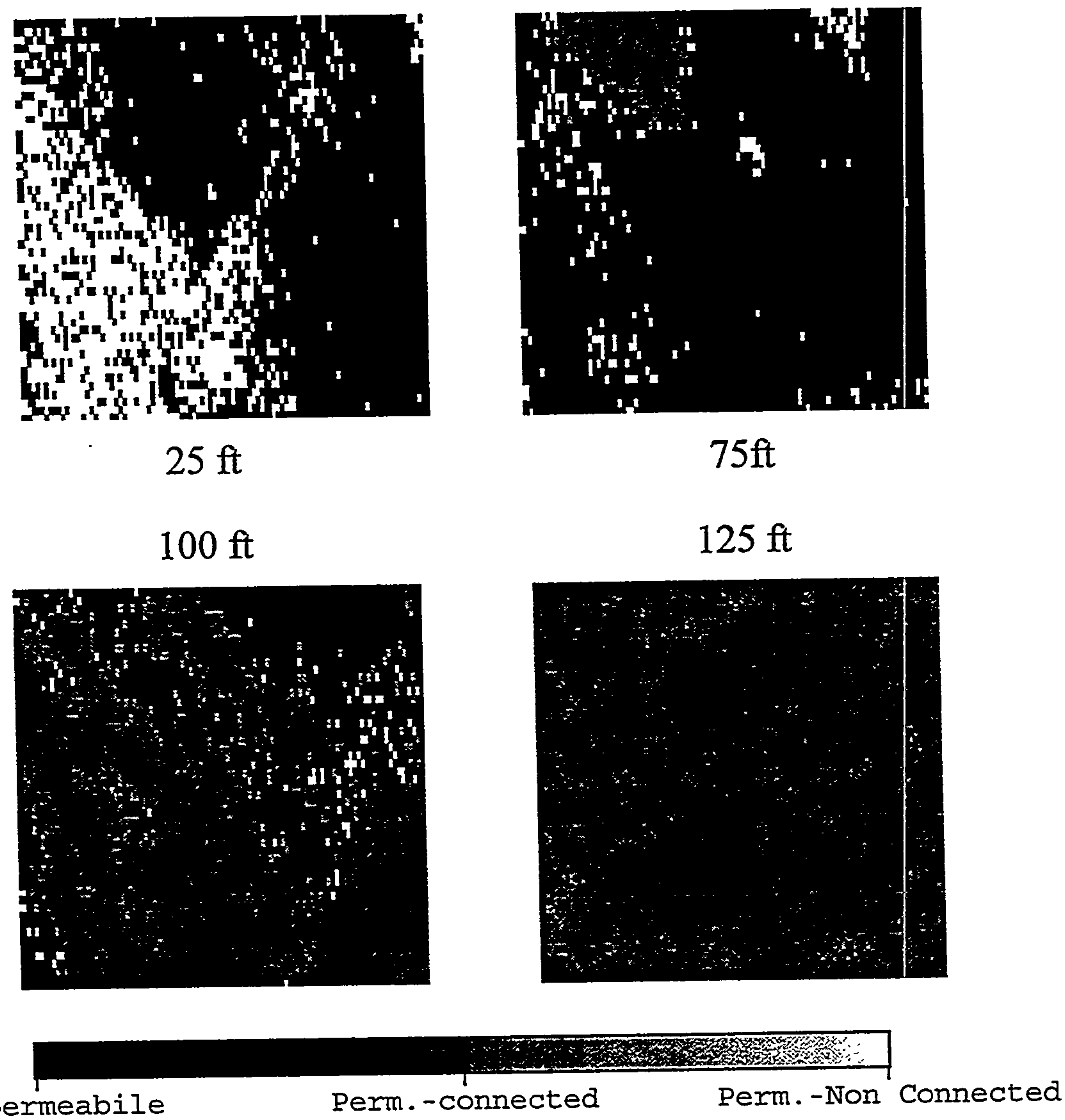


Figure 60

LAYER - 4
VERTICAL CROSS SECTIONS

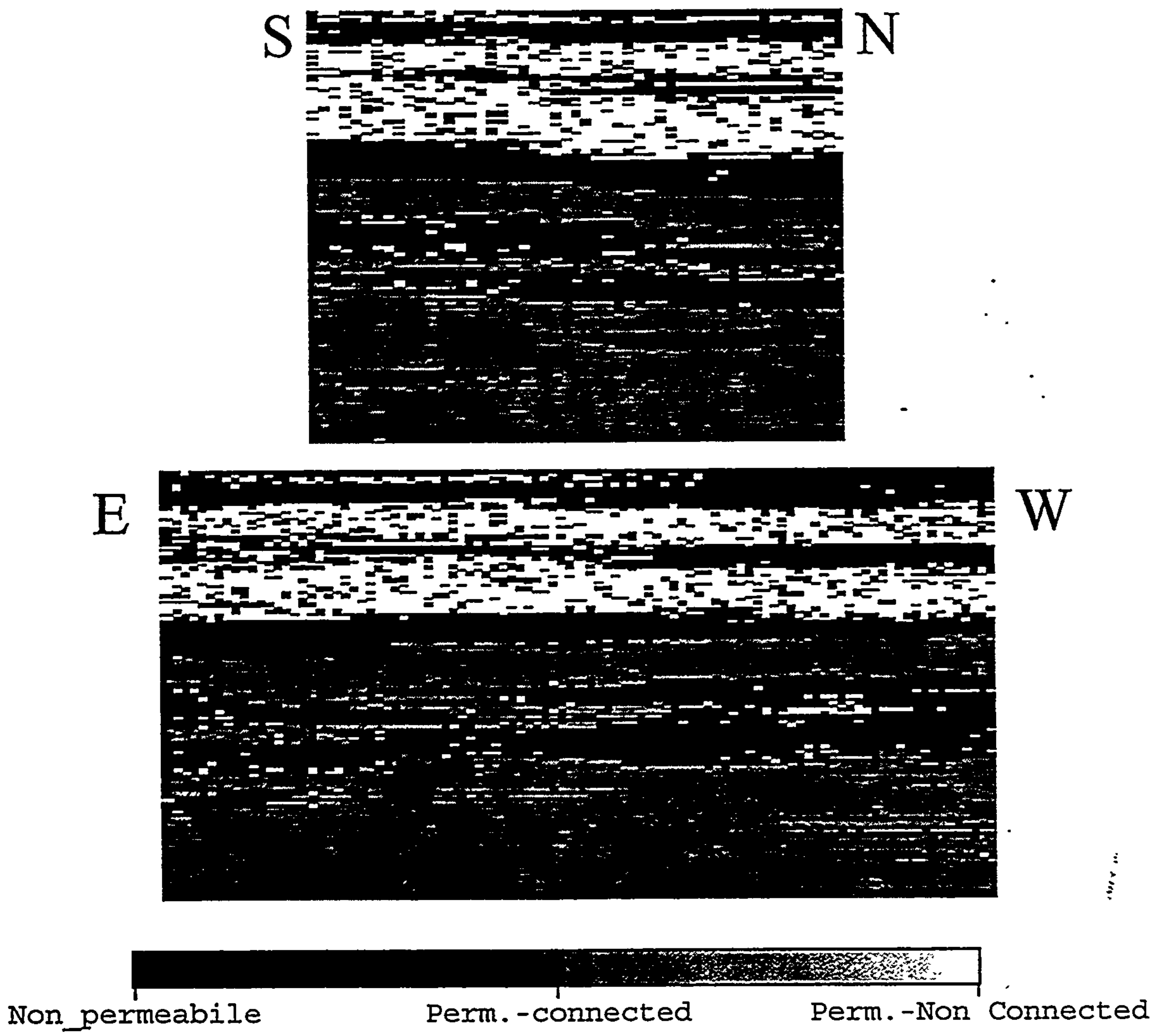
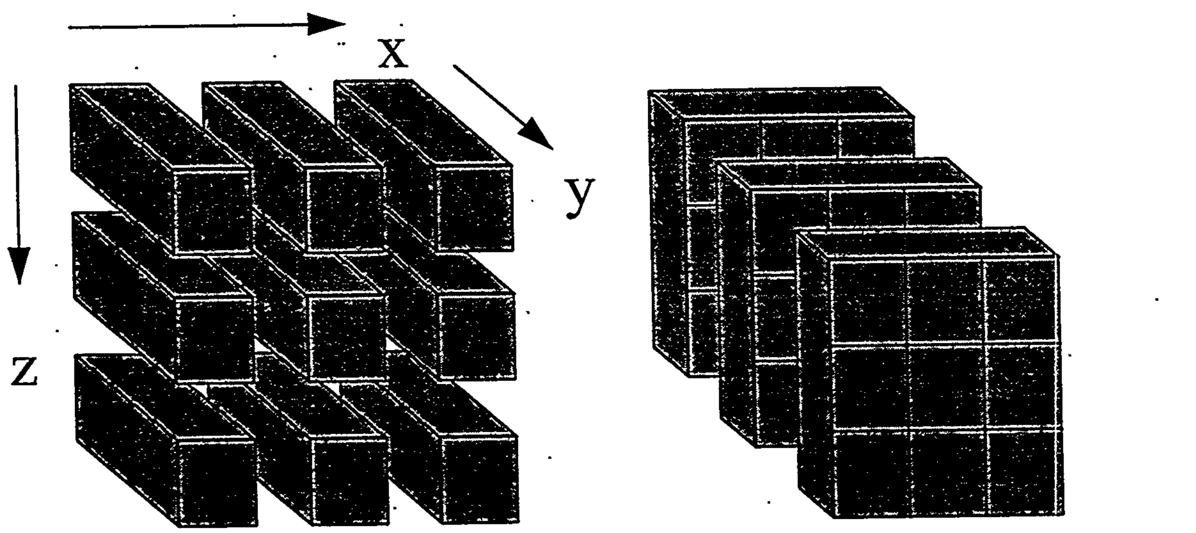


Figure 61

INCOMPLETE LAYERS METHOD TO SCALE UP PERMEABILITY

NO CROSS FLOW VERTICAL EQUILIBRIUM



$$k_{yik} = \frac{n_j}{\sum_{j=1}^{n_j} \frac{1}{k_{yijk}}}$$

$$k_y = \frac{1}{n_i}\frac{1}{n_k}\sum_{k=1}^{n_k}\sum_{i=1}^{n_i} k_{yik}$$

$$k_{yj} = \frac{1}{n_i}\frac{1}{n_k}\sum_{k=1}^{n_k}\sum_{i=1}^{n_i} k_{yijk}$$

$$k_y = \frac{n_j}{\sum_{j=1}^{n_j} \frac{1}{k_{yj}}}$$

Figure 62

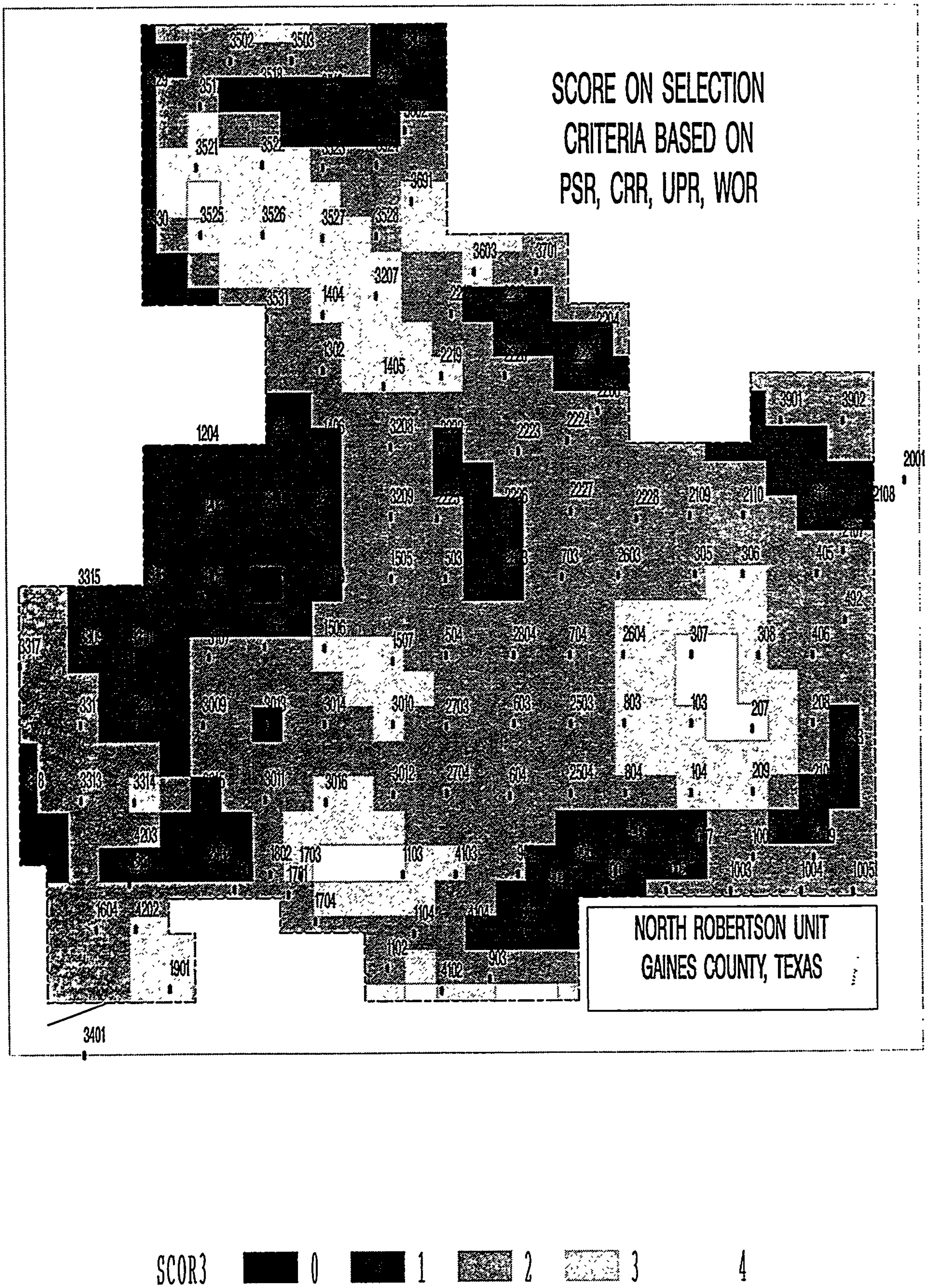
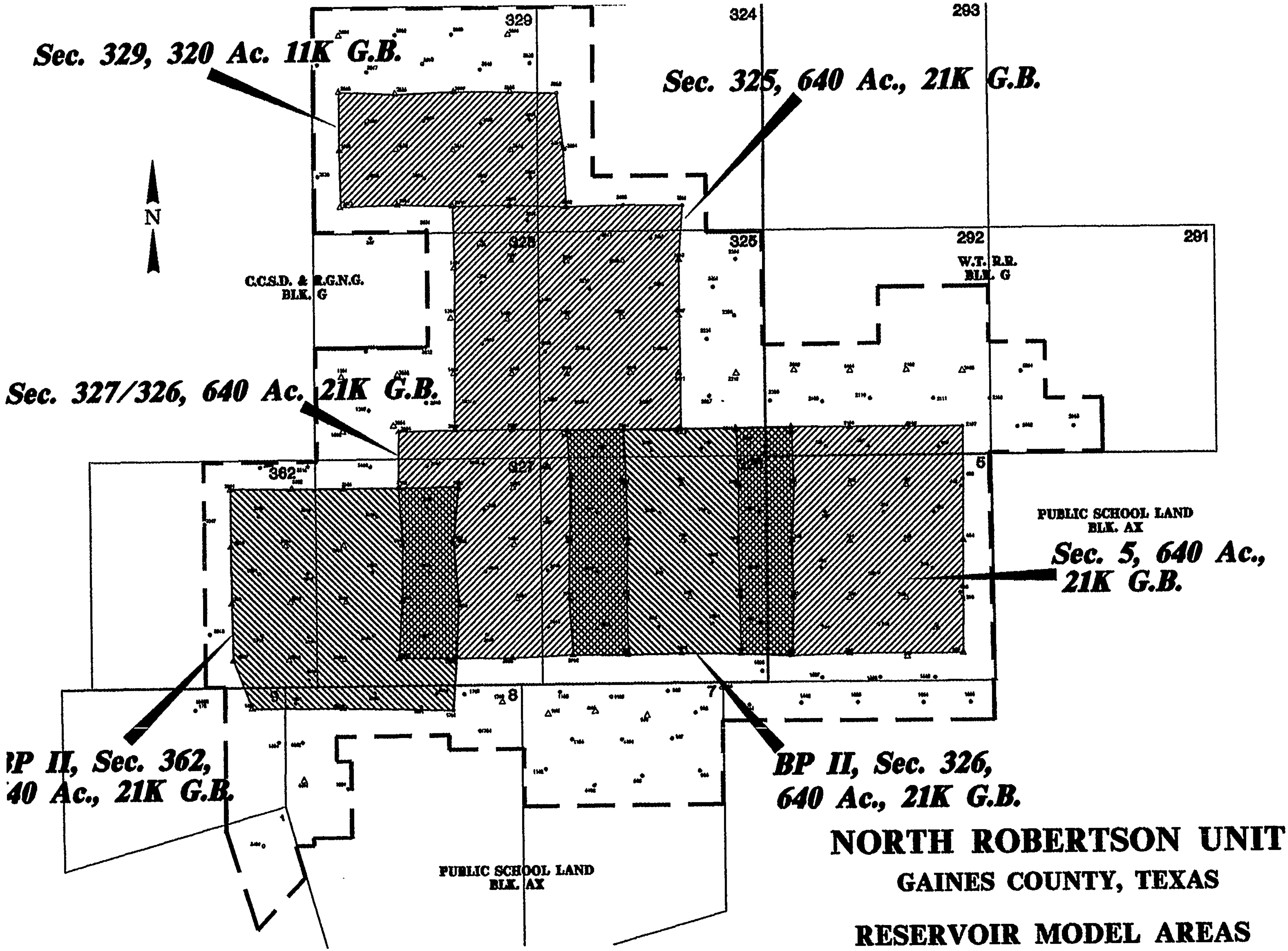

SCORE ON SELECTION CRITERIA BASED ON PSR, CRR, UPR, WOR
NORTH ROBERTSON UNIT
GAINES COUNTY, TEXAS
SCOR3 0 1 2 3 4

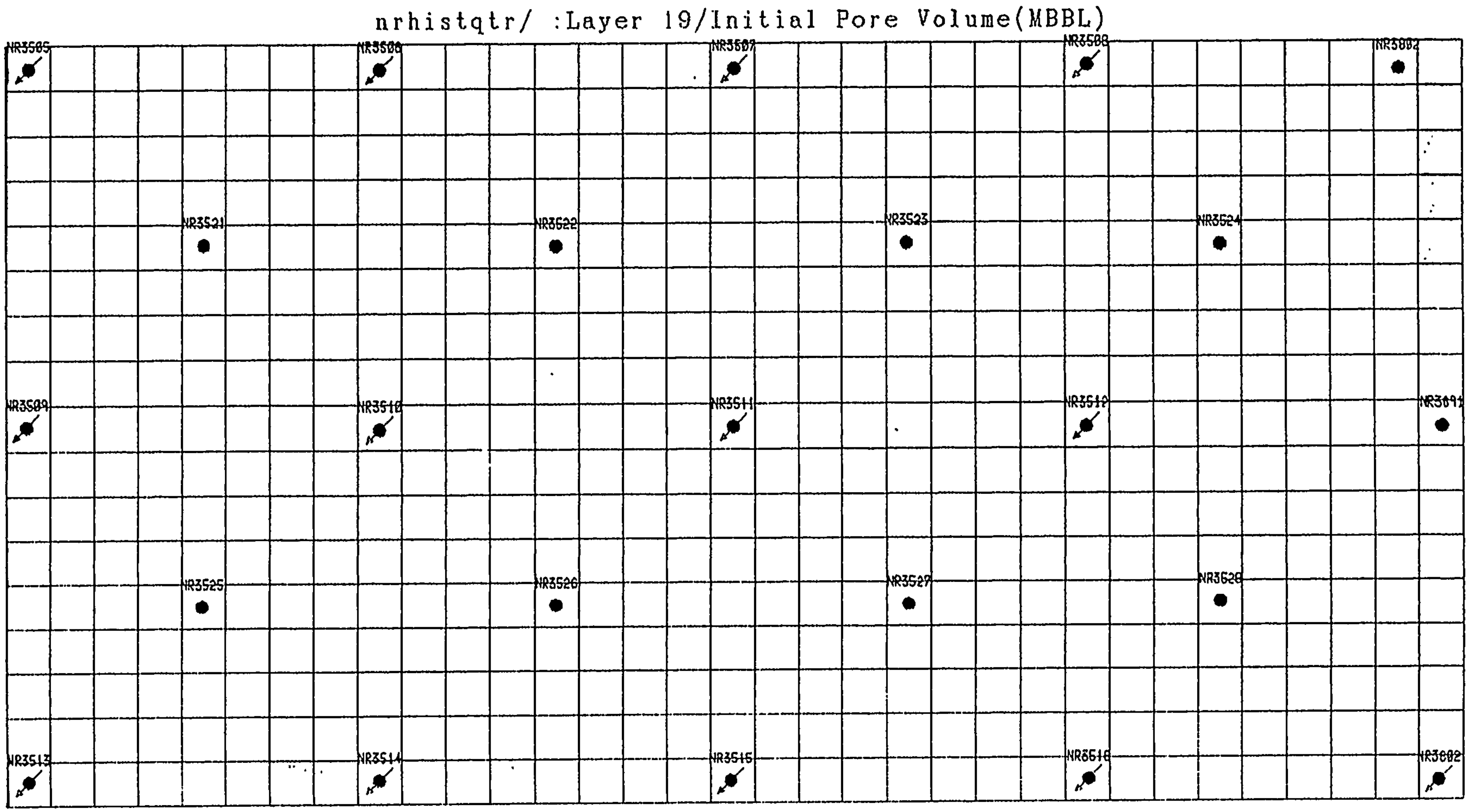
Figure 63

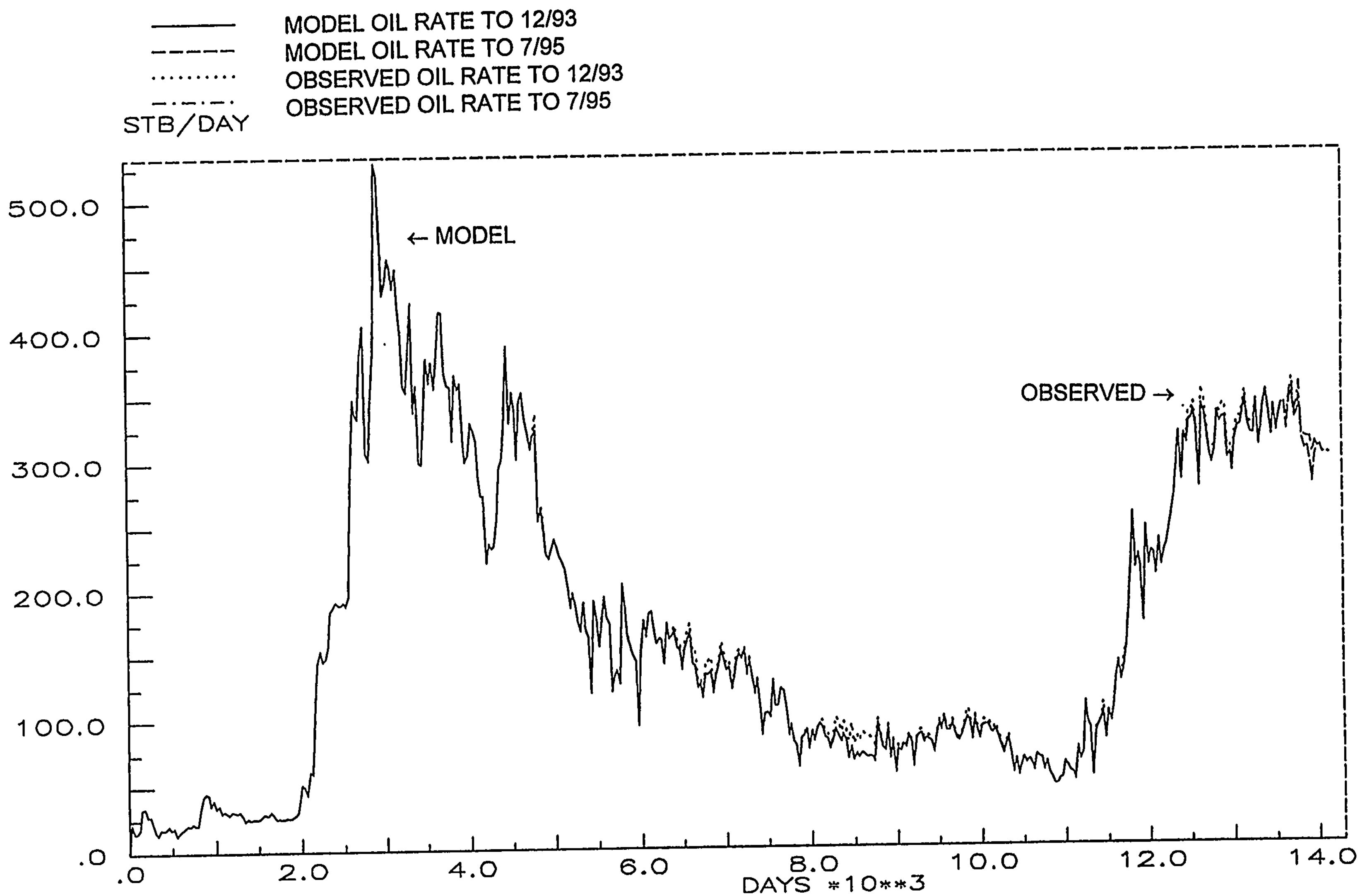


NORTH ROBERTSON UNIT
GAINES COUNTY, TEXAS

RESERVOIR MODEL AREAS

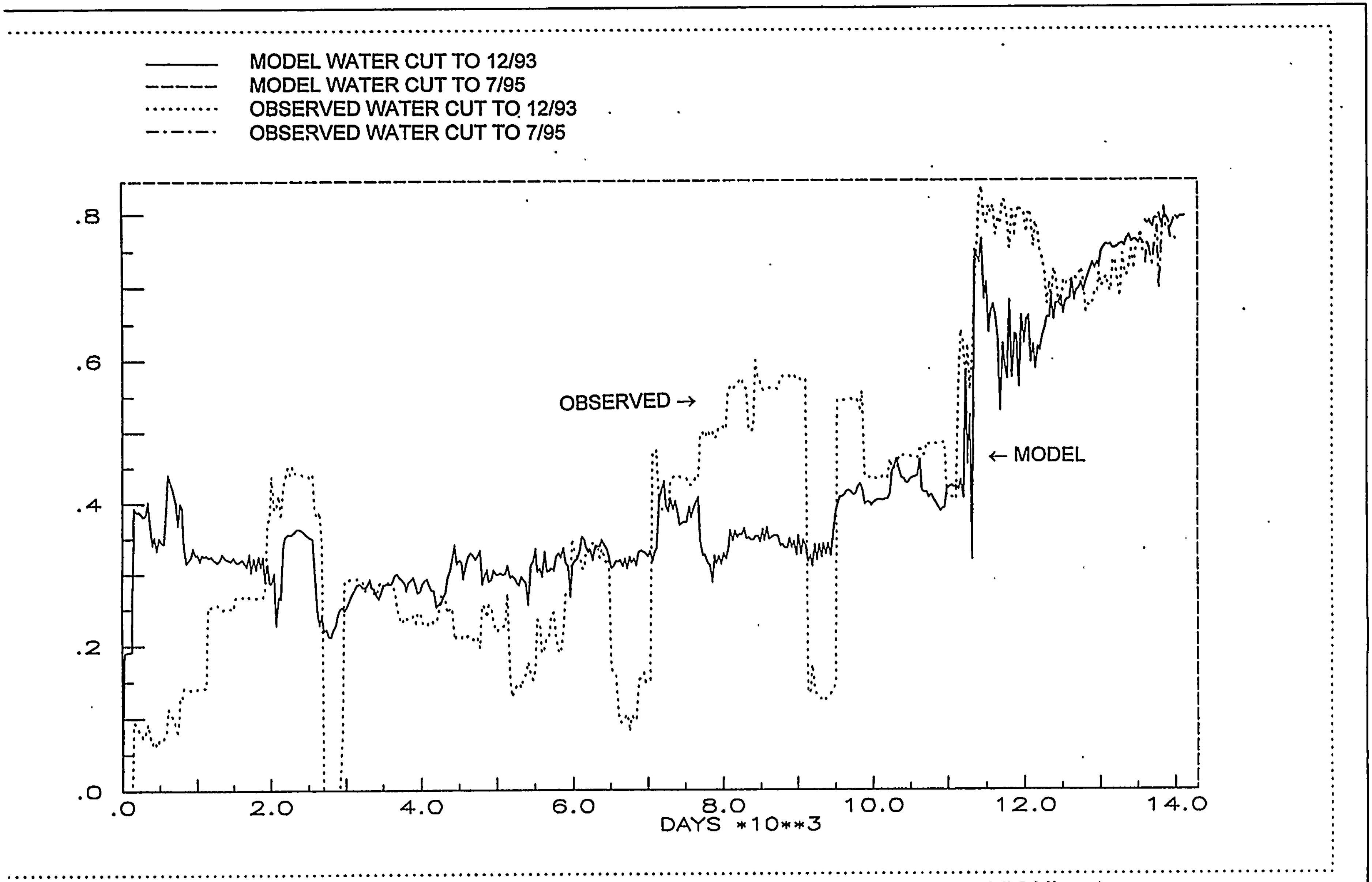
Figure 65 - Grid Configuration Section 329 Model





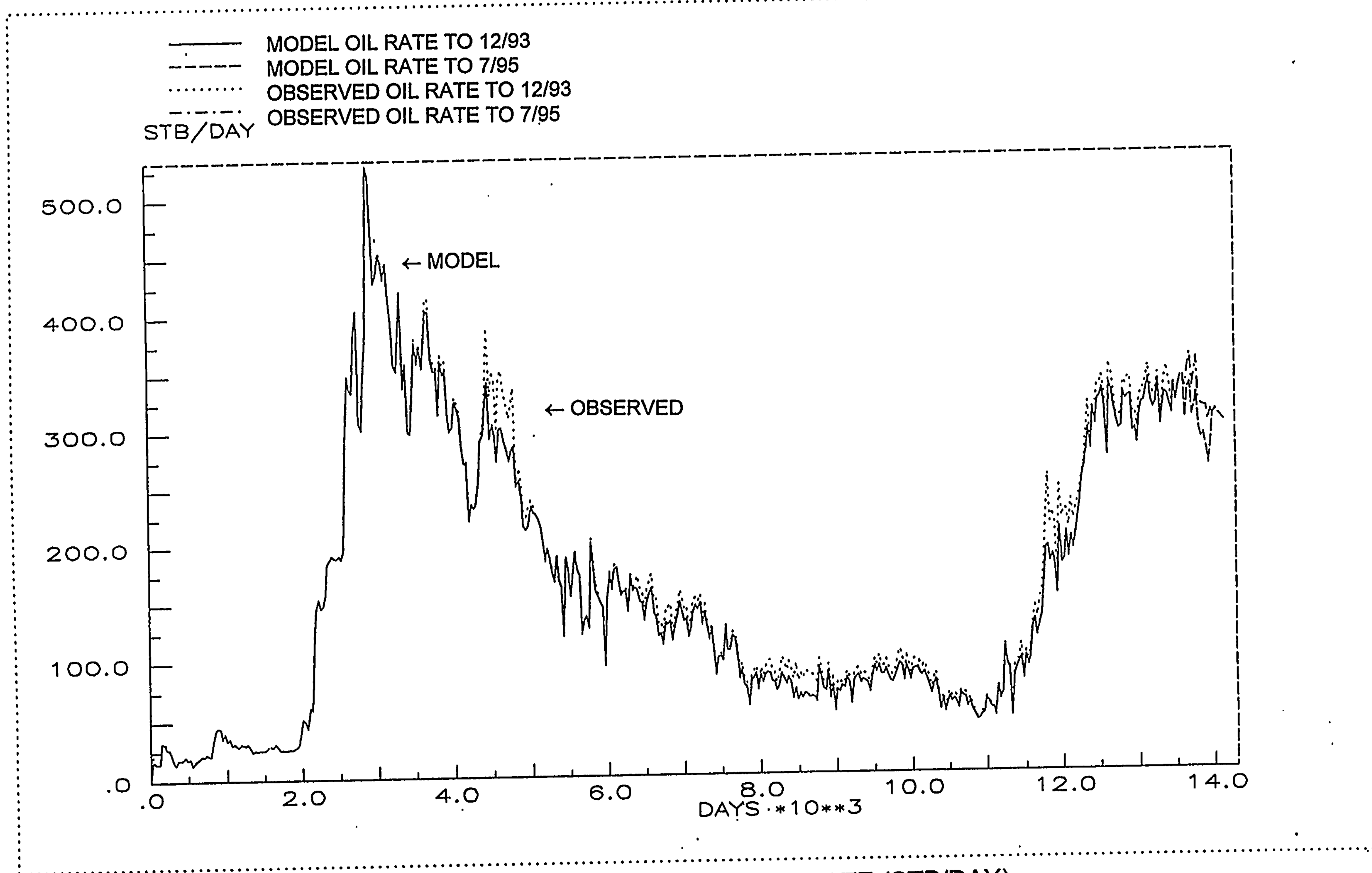
DETERMINISTIC MODEL HISTORY MATCH: OIL PRODUCTION RATE (STB/DAY)

Figure 66



DETERMINISTIC MODEL HISTORY MATCH: WATER CUT (FRACTION)

Figure 67



GEOSTATISTICAL MODEL HISTORY MATCH: OIL PRODUCTION RATE (STB/DAY)

Figure 68

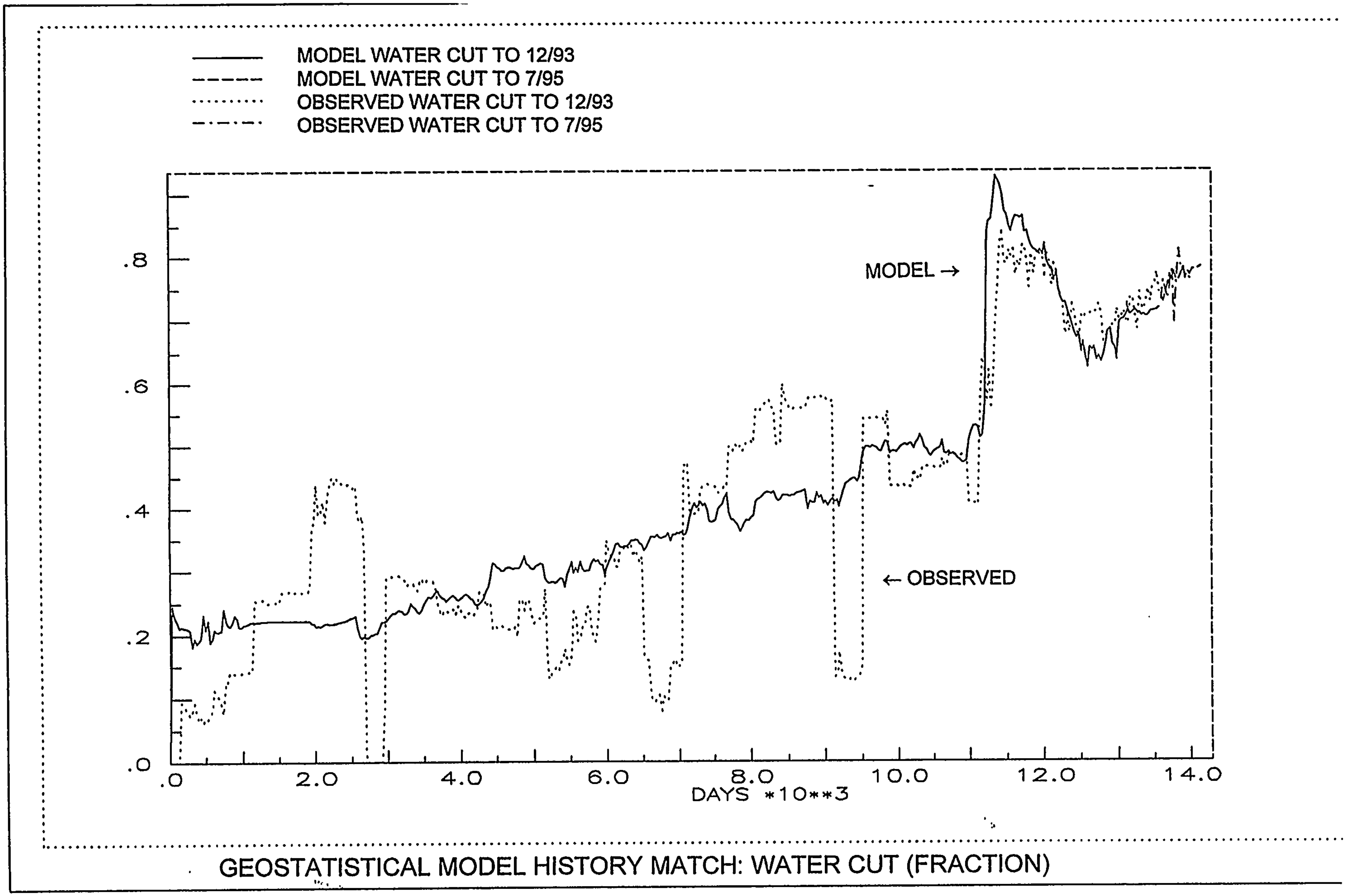

MODEL WATER CUT TO 12/93
MODEL WATER CUT TO 7/95
OBSERVED WATER CUT TO 12/93
OBSERVED WATER CUT TO 7/95
.0
.2
.4
.6
.8
.0
2.0
4.0
6.0
8.0
10.0
12.0
14.0
DAYS *10**3
MODEL →
← OBSERVED
GEOSTATISTICAL MODEL HISTORY MATCH: WATER CUT (FRACTION)

Figure 69

MODEL AREA #1 GRID WITH LINE DRIVE INFILL WELLS FOR CASE 4A

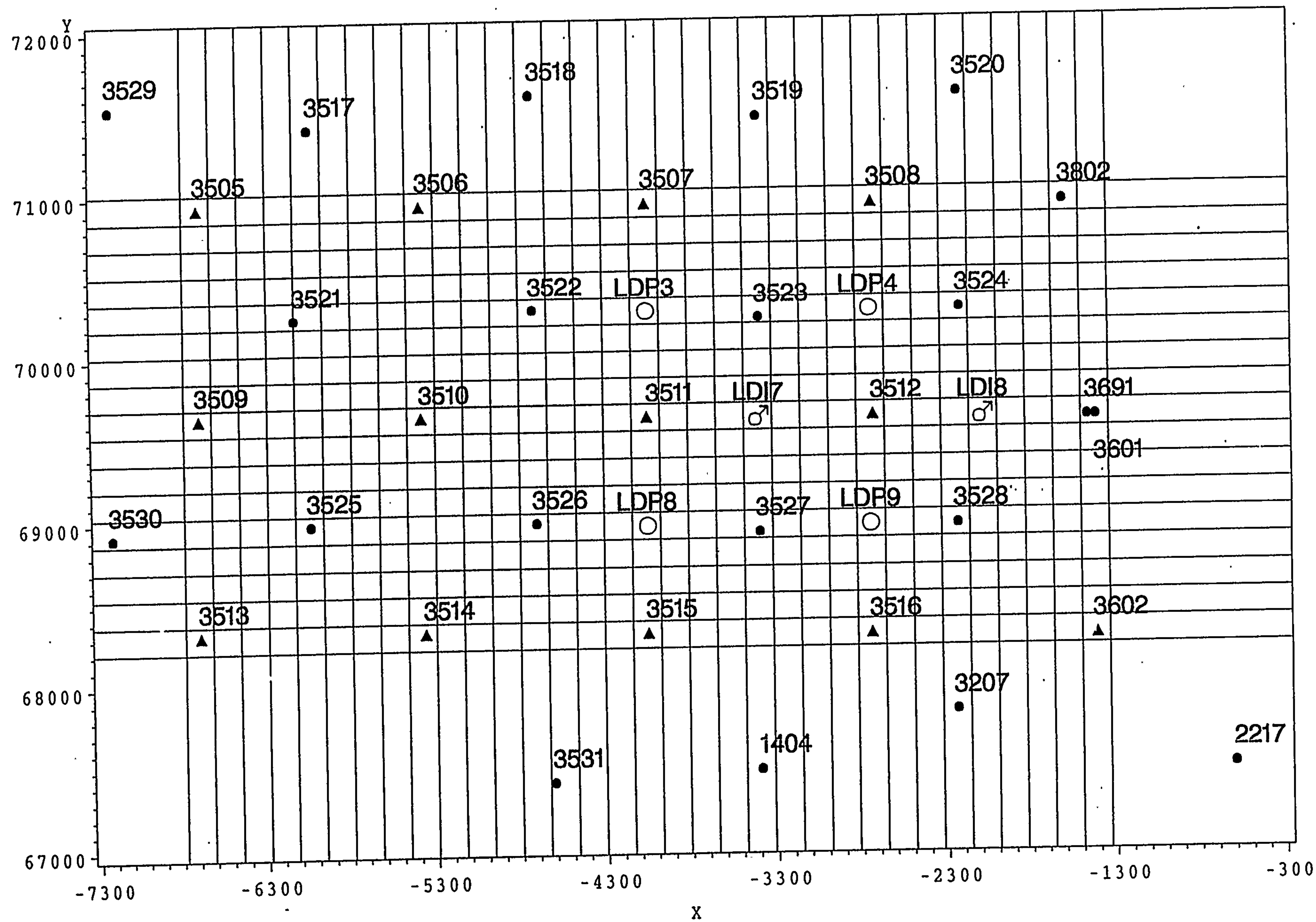
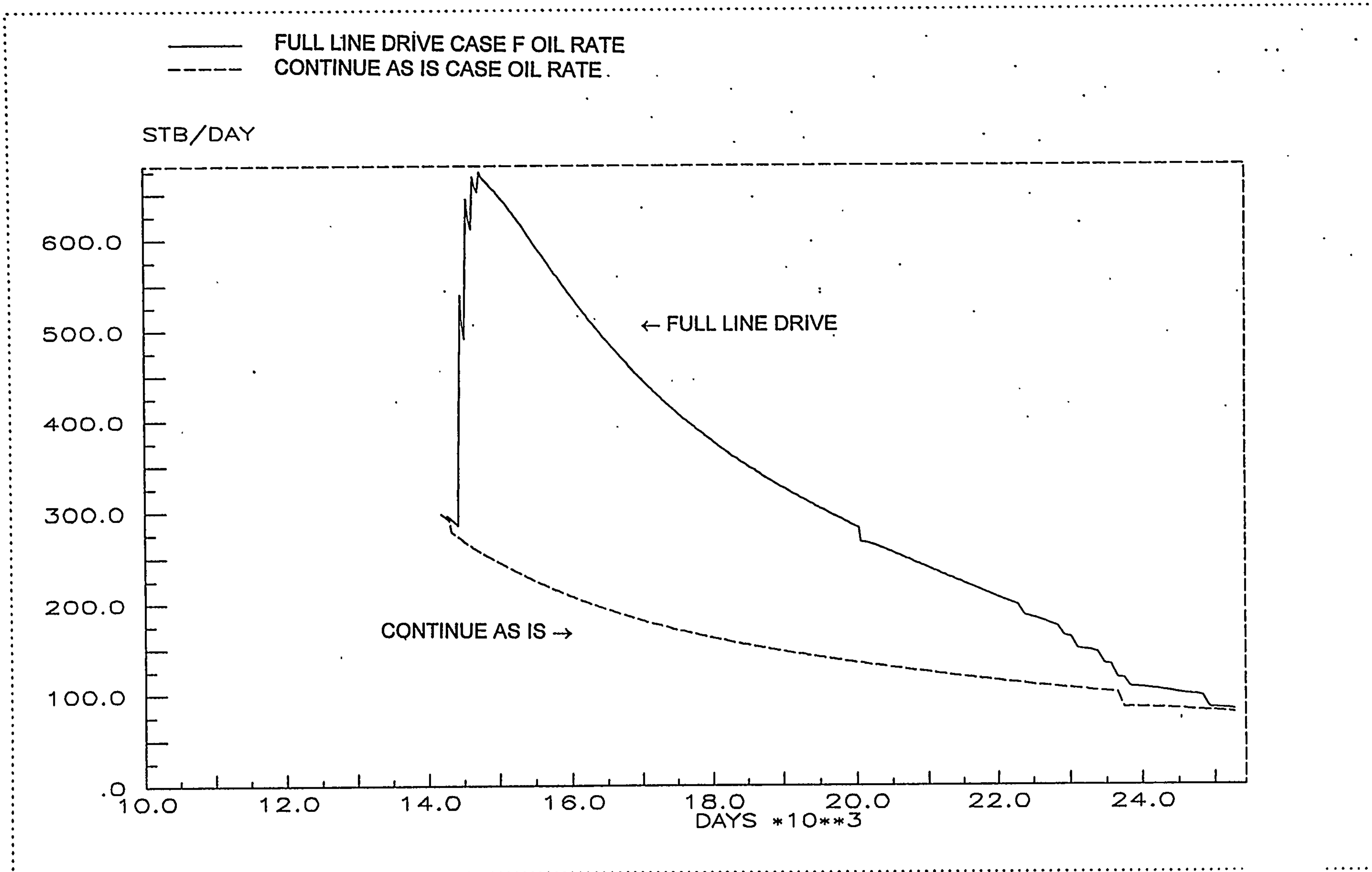
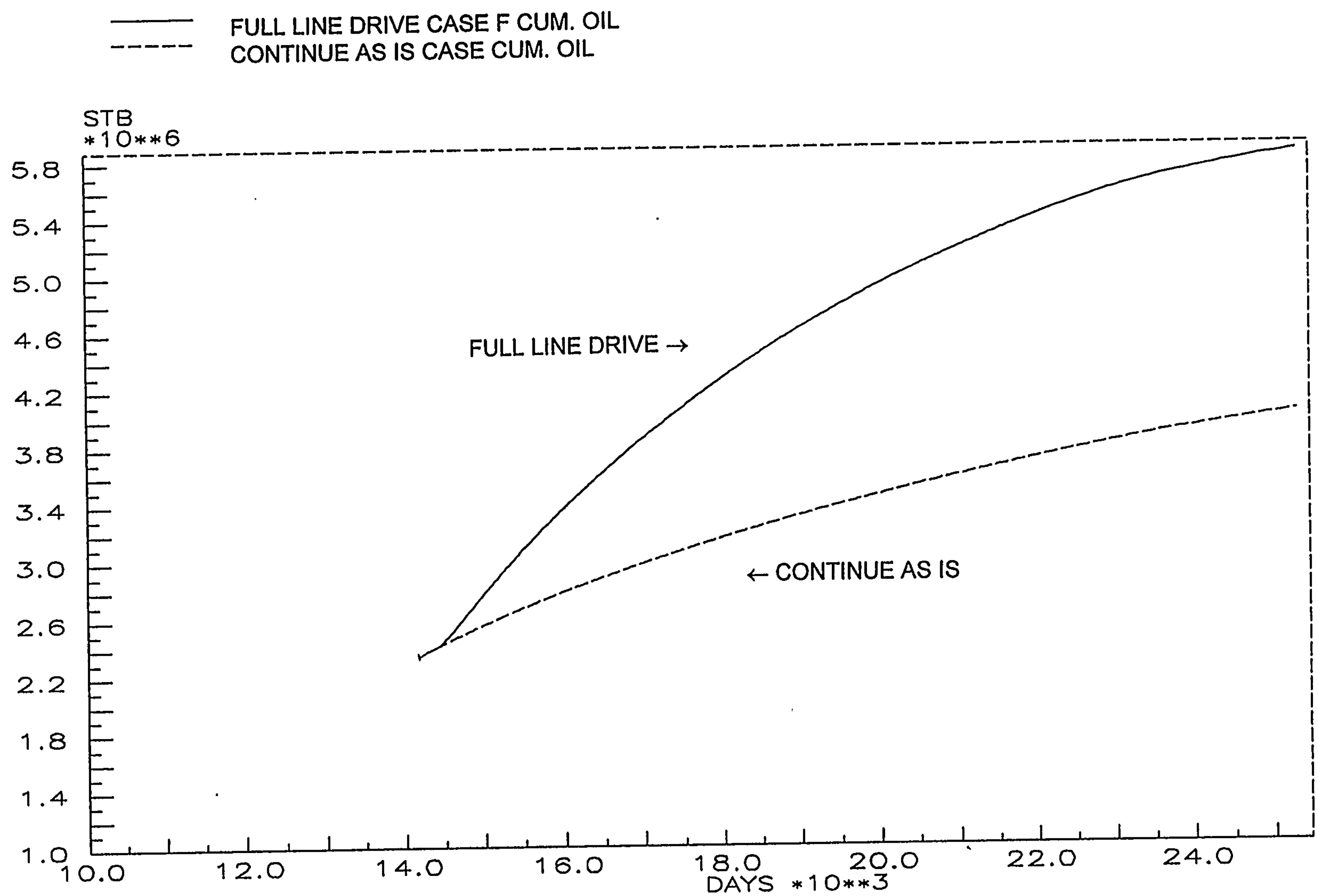


Figure 70



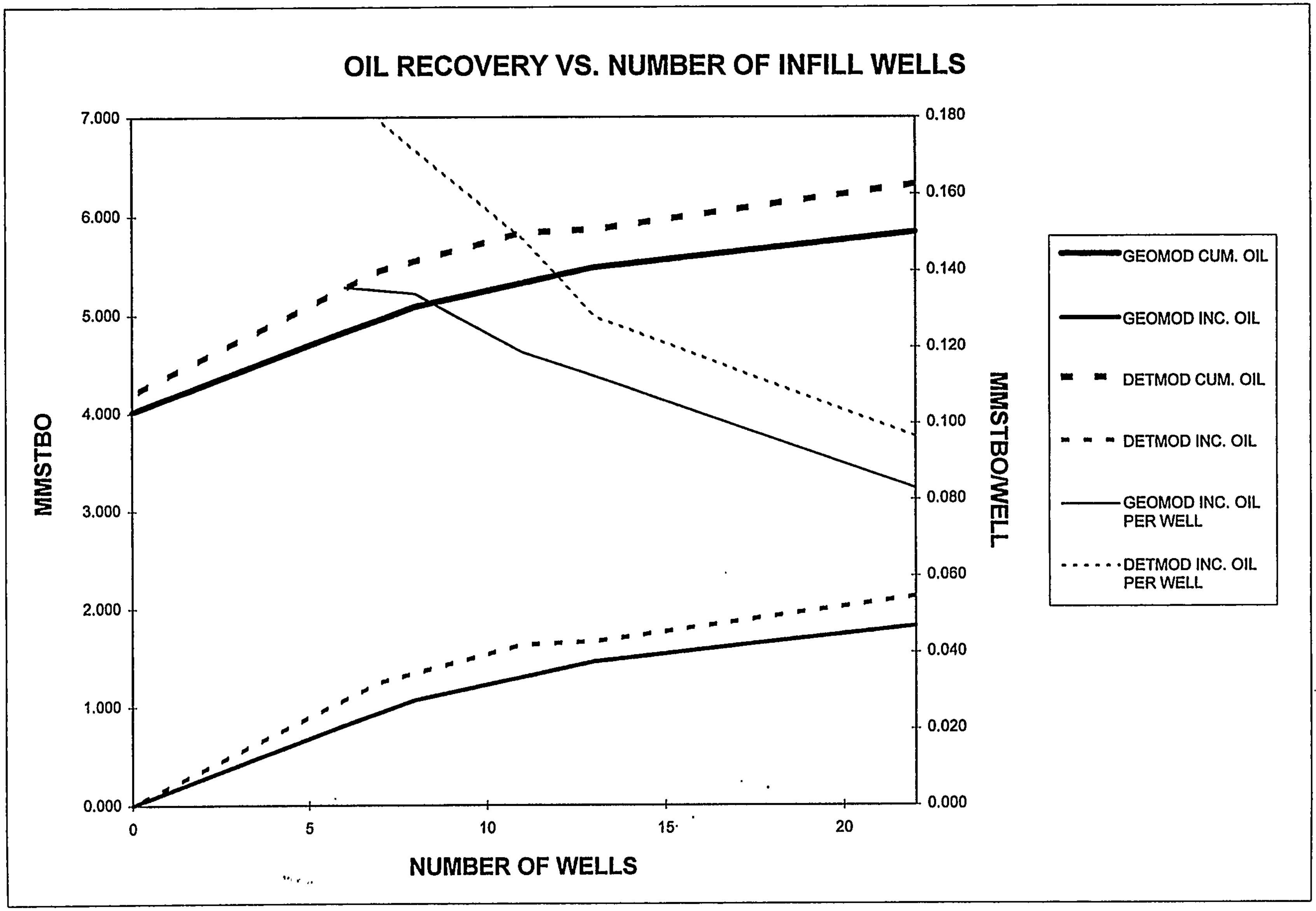
GEOSTATISTICAL MODEL FORECAST: OIL PRODUCTION RATE (STB/DAY)

Figure 71



GEOSTATISTICAL MODEL FORECAST: CUM. OIL PRODUCTION (MMSTB)

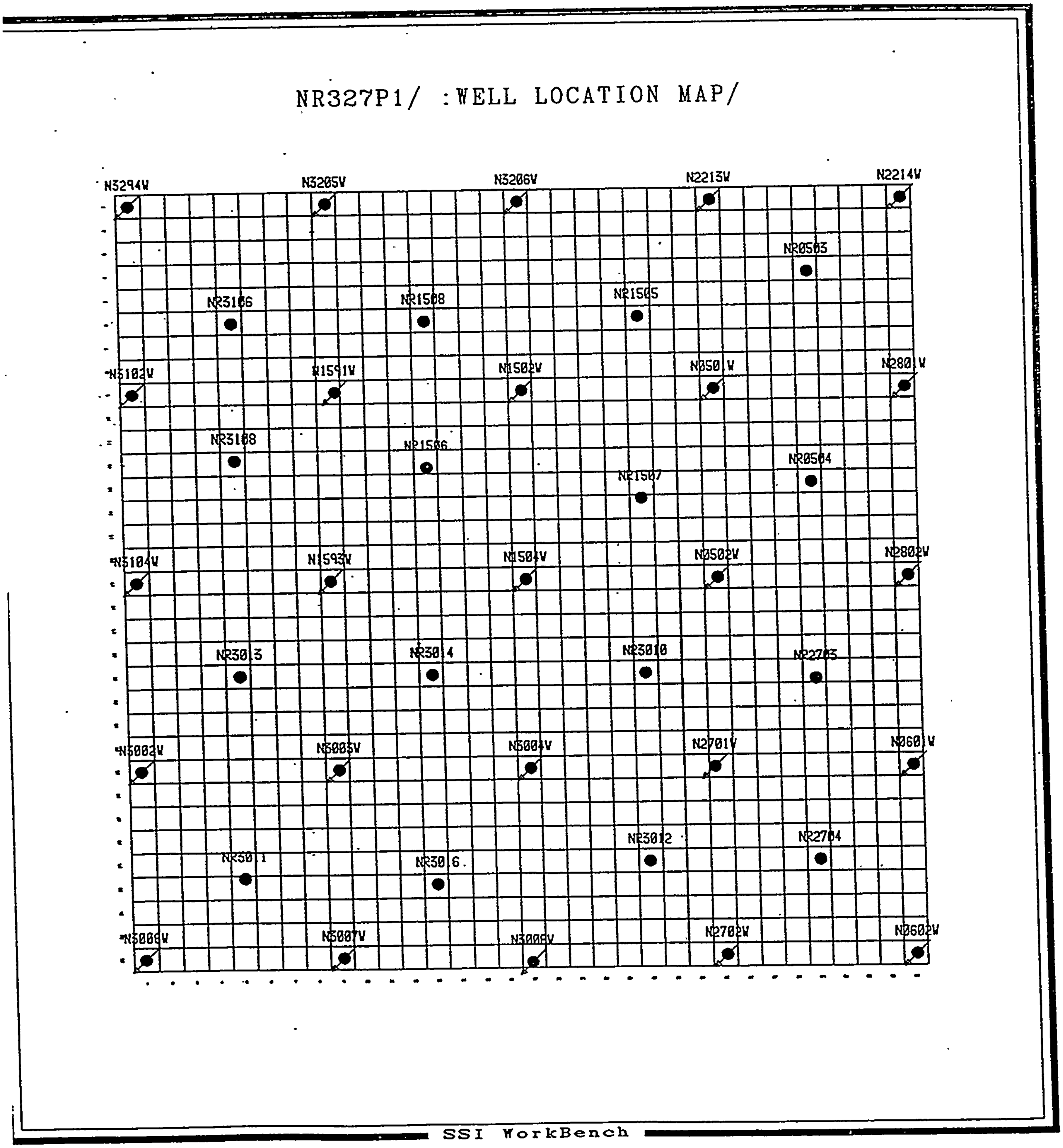
Figure 72

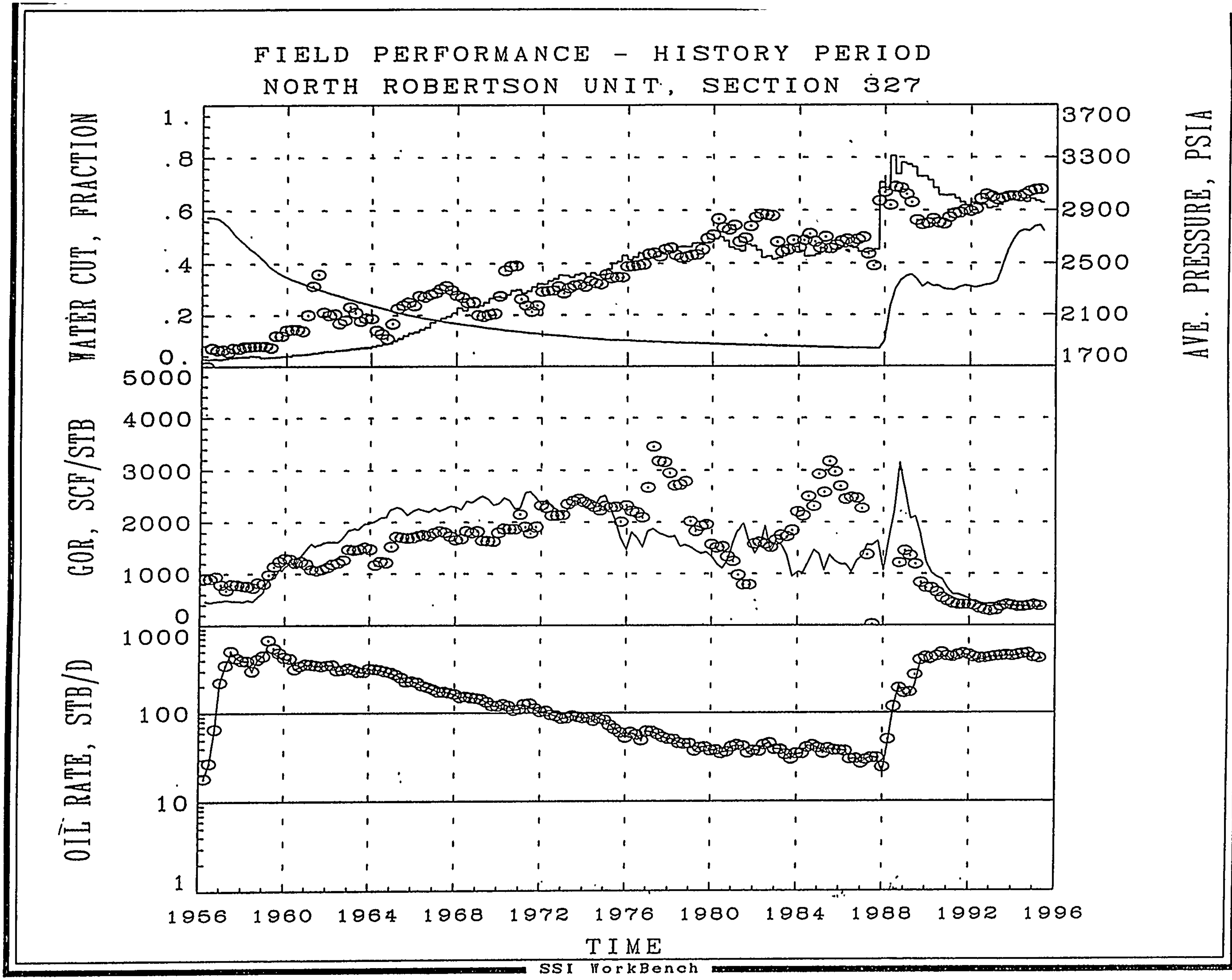


OIL RECOVERY VS. NUMBER OF INFILL WELLS
7.000
6.000
5.000
4.000
3.000
2.000
1.000
0.000
MMSTBO
0.180
0.160
0.140
0.120
0.100
0.080
0.060
0.040
0.020
0.000
MMSTBO/WELL
0
5
10
15
20
NUMBER OF WELLS
GEOMOD CUM. OIL
GEOMOD INC. OIL
DETMOD CUM. OIL
DETMOD INC. OIL
GEOMOD INC. OIL PER WELL
DETMOD INC. OIL PER WELL

Figure 73

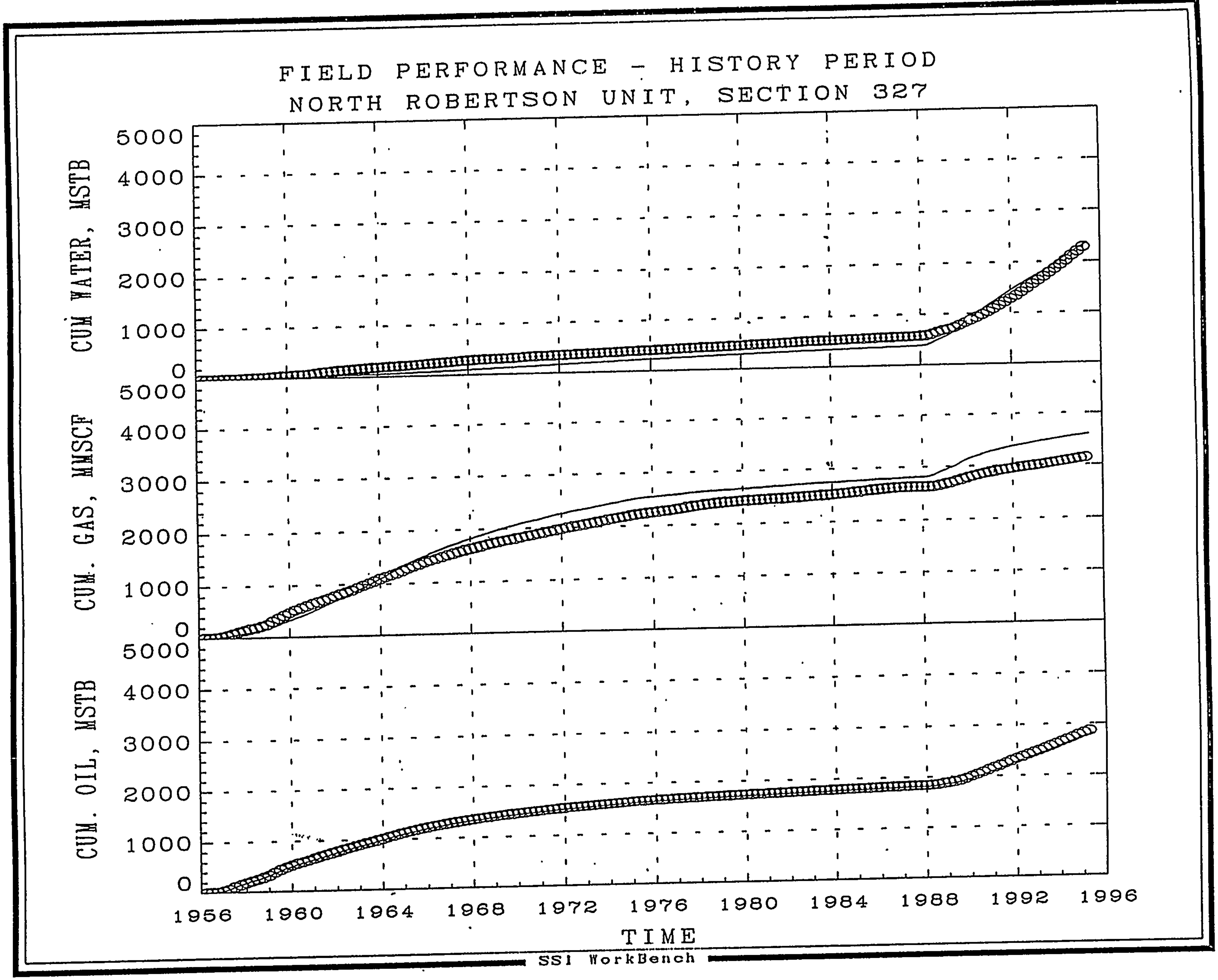
Figure 74


NR327P1/ :WELL LOCATION MAP/
N3204W
N3205W
N3206W
N2213W
N2214W
NR0503
NR3106
NR1508
NR1505
N3102W
N1501W
N1502W
N0501W
N2801W
NR3108
NR1506
NR0504
NR1507
N3104W
N1503W
N1504W
N0502W
N2802W
NR3013
NR3014
NR3010
NR2703
N3002W
N3003W
N3004W
N2701W
N0601W
NR3012
NR2704
NR3011
NR3016
N3006W
N3007W
N3008W
N2702W
N0602W
SSI WorkBench



FIELD PERFORMANCE - HISTORY PERIOD
NORTH ROBERTSON UNIT, SECTION 327
WATER CUT, FRACTION
GOR, SCF/STB
OIL RATE, STB/D
AVE. PRESSURE, PSIA
TIME
SSI WorkBench

Figure 75


FIELD PERFORMANCE - HISTORY PERIOD
NORTH ROBERTSON UNIT, SECTION 327
CUM WATER, MSTB
CUM. GAS, MMSCF
CUM. OIL, MSTB
5000
4000
3000
2000
1000
0
1956
1960
1964
1968
1972
1976
1980
1984
1988
1992
1996
TIME
SSI WorkBench

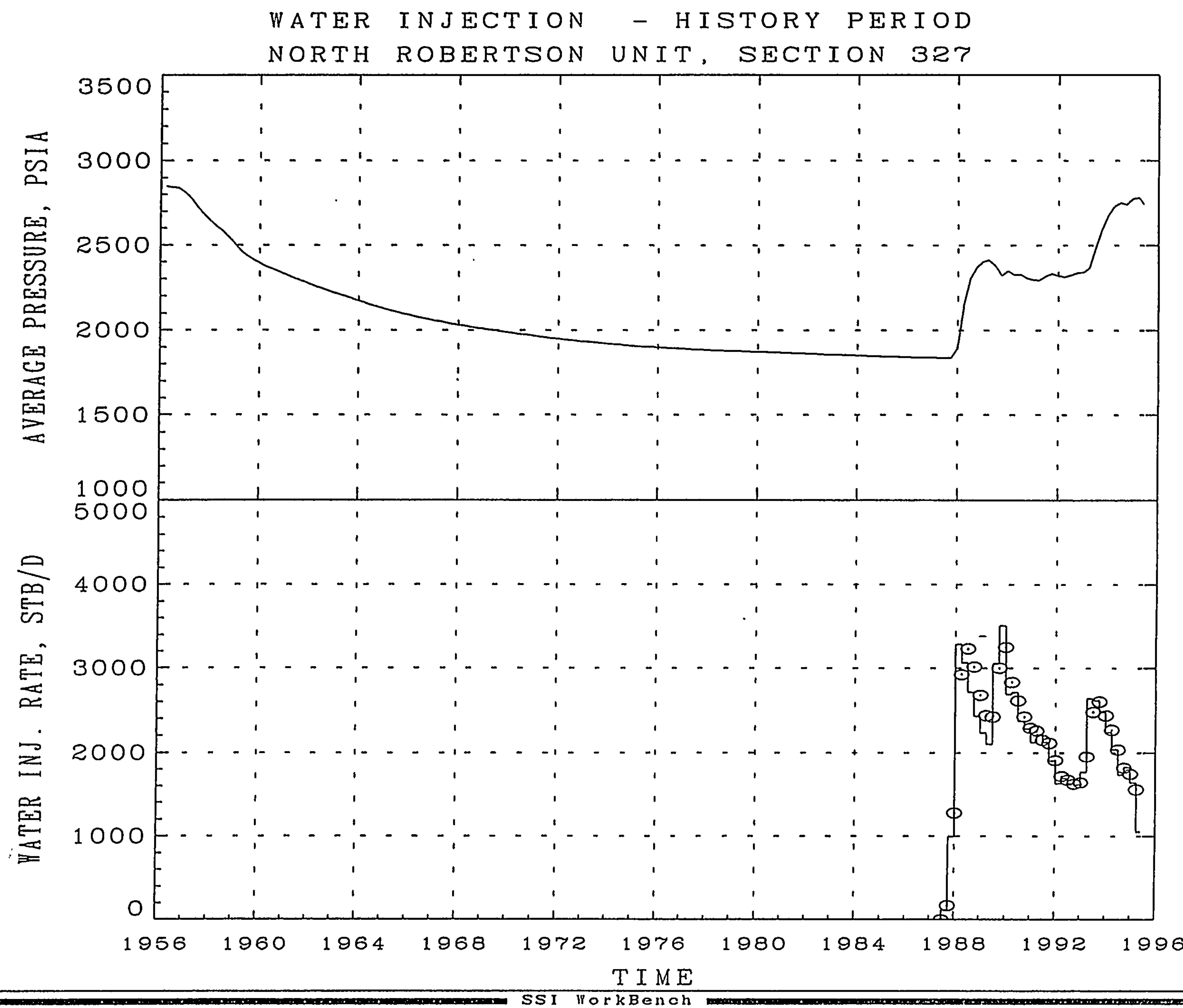
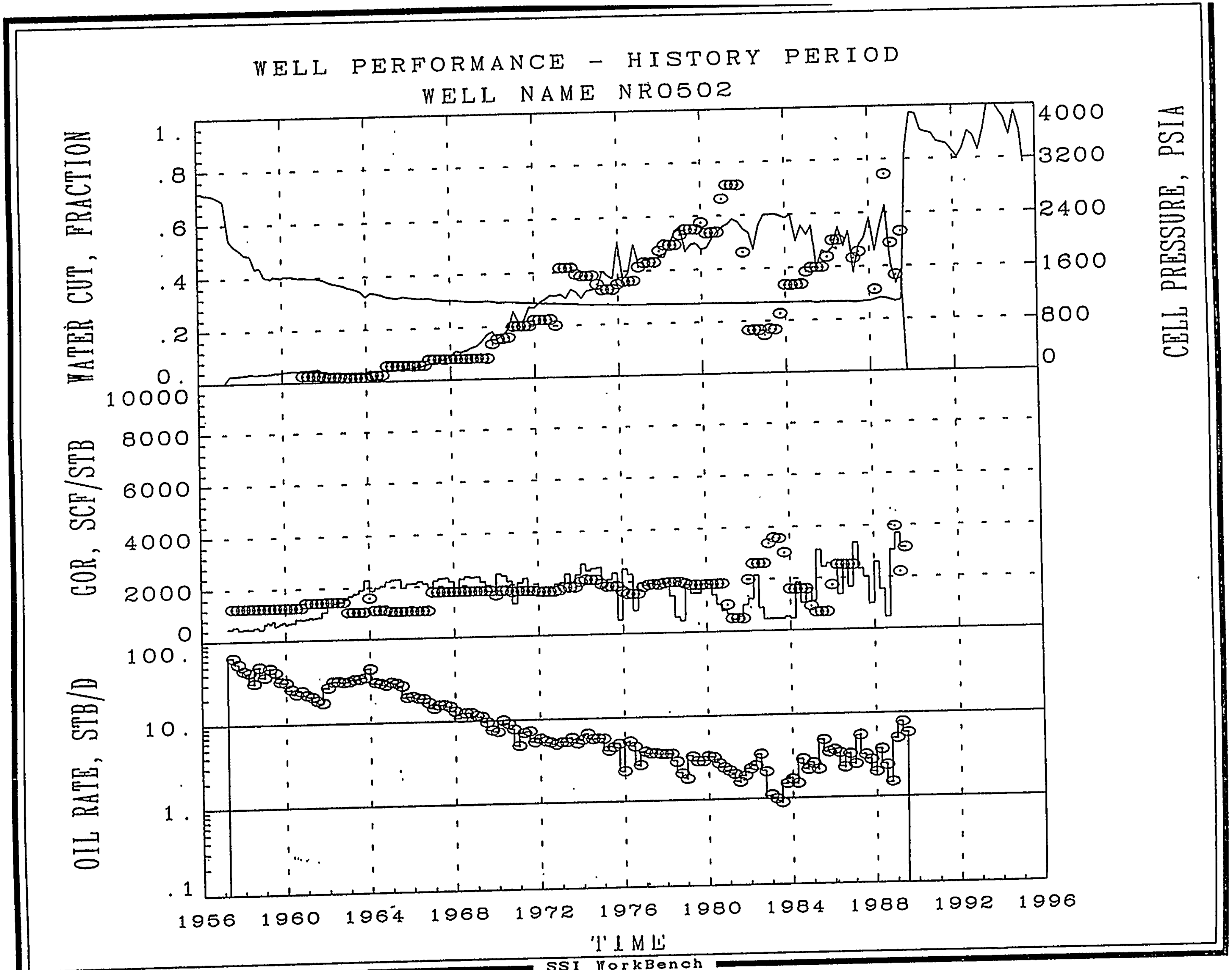

WATER INJECTION - HISTORY PERIOD
NORTH ROBERTSON UNIT, SECTION 327
AVERAGE PRESSURE, PSIA
3500
3000
2500
2000
1500
1000
WATER INJ. RATE, STB/D
5000
4000
3000
2000
1000
0
1956
1960
1964
1968
1972
1976
1980
1984
1988
1992
1996
TIME
SSI WorkBench

Figure 77



WELL PERFORMANCE - HISTORY PERIOD
WELL NAME NR0502
WATER CUT, FRACTION
GOR, SCF/STB
OIL RATE, STB/D
CELL PRESSURE, PSIA
TIME
1956 1960 1964 1968 1972 1976 1980 1984 1988 1992 1996
4000 3200 2400 1600 800 0
1. .8 .6 .4 .2 0.
10000 8000 6000 4000 2000 0
100. 10. 1. .1
SSI WorkBench

Figure 78

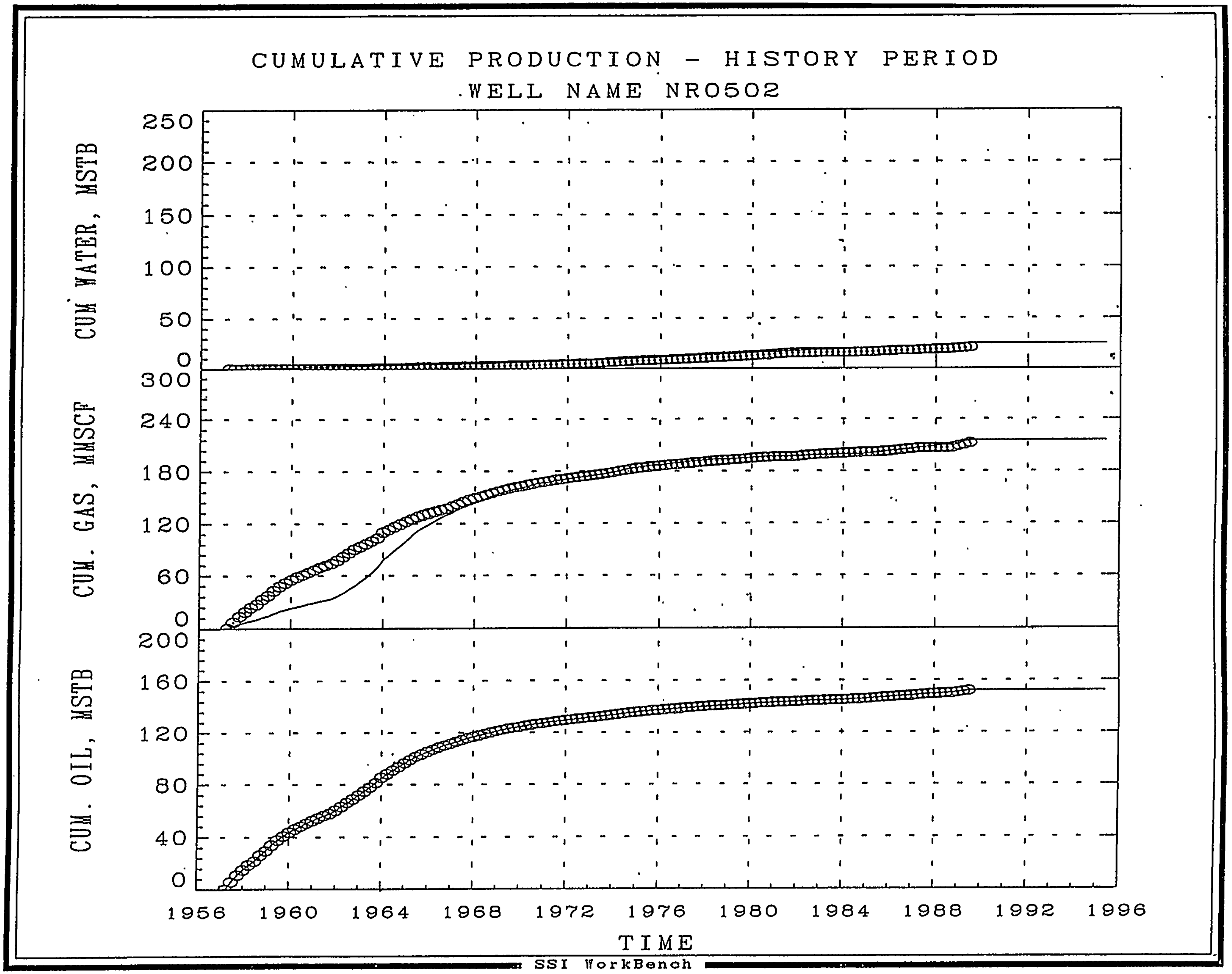

CUMULATIVE PRODUCTION - HISTORY PERIOD
WELL NAME NR0502
CUM WATER, MSTB
CUM. GAS, MMSCF
CUM. OIL, MSTB
250
200
150
100
50
0
300
240
180
120
60
0
200
160
120
80
40
0
1956
1960
1964
1968
1972
1976
1980
1984
1988
1992
1996
TIME
SSI WorkBench

Figure 79

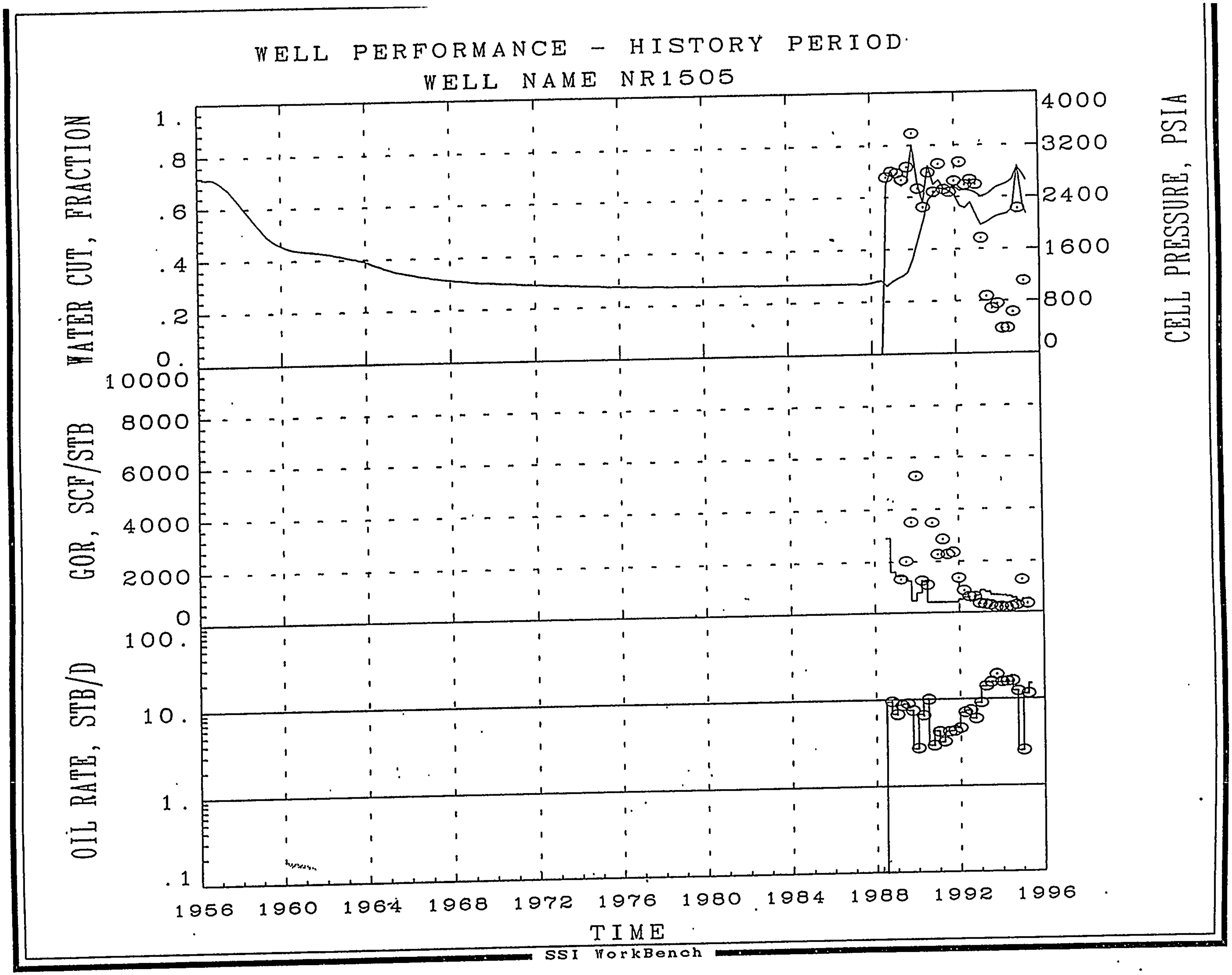

WELL PERFORMANCE - HISTORY PERIOD
WELL NAME NR1505
WATER CUT, FRACTION
GOR, SCF/STB
OIL RATE, STB/D
CELL PRESSURE, PSIA
TIME
SSI WorkBench

Figure 80

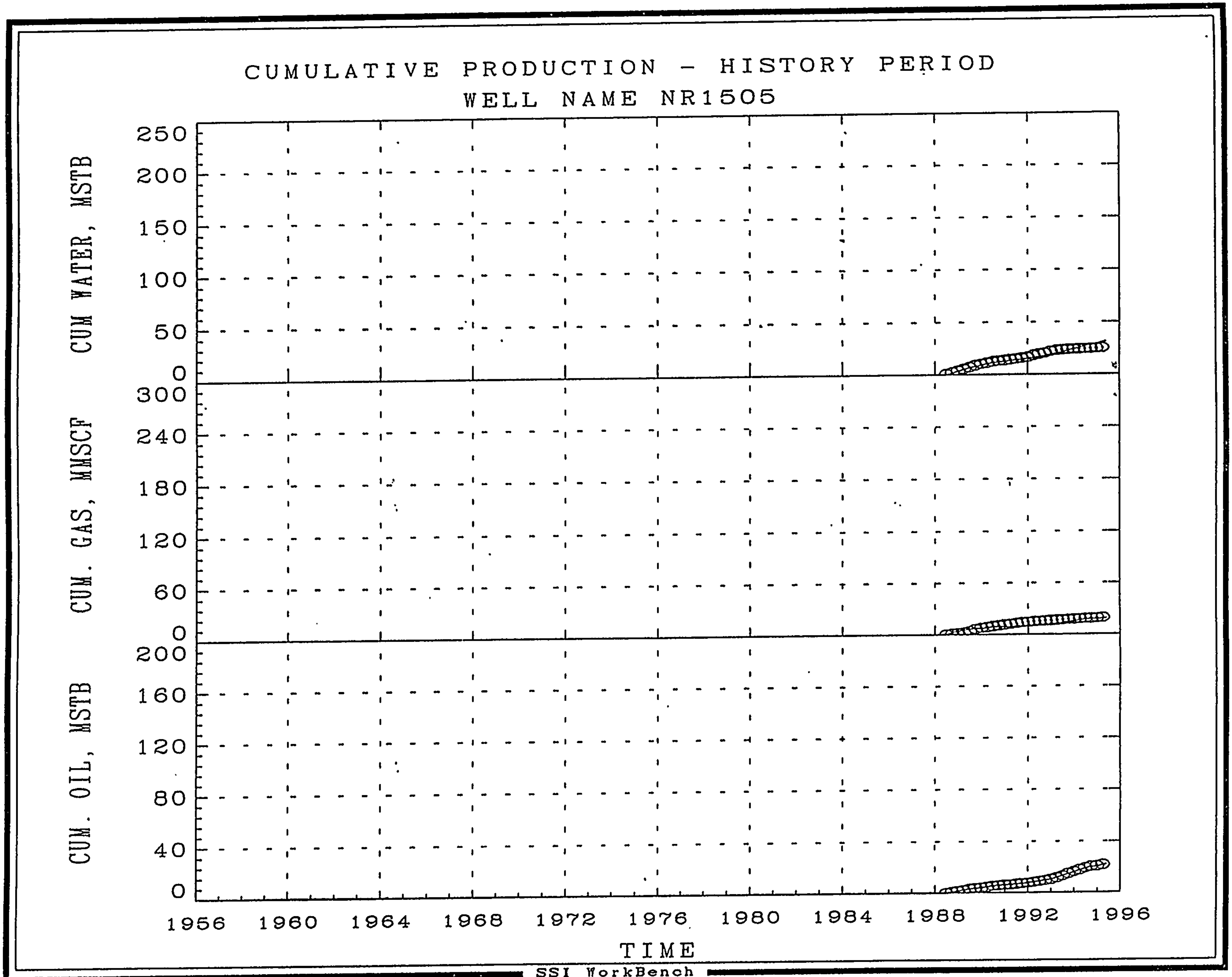

CUMULATIVE PRODUCTION - HISTORY PERIOD
WELL NAME NR1505
CUM WATER, MSTB
250
200
150
100
50
0
CUM. GAS, MMSCF
300
240
180
120
60
0
CUM. OIL, MSTB
200
160
120
80
40
0
1956
1960
1964
1968
1972
1976
1980
1984
1988
1992
1996
TIME
SSI WorkBench

Figure 81

Figure 82 - Oil Saturation Map, Lower Clearfork, Section 327 Area

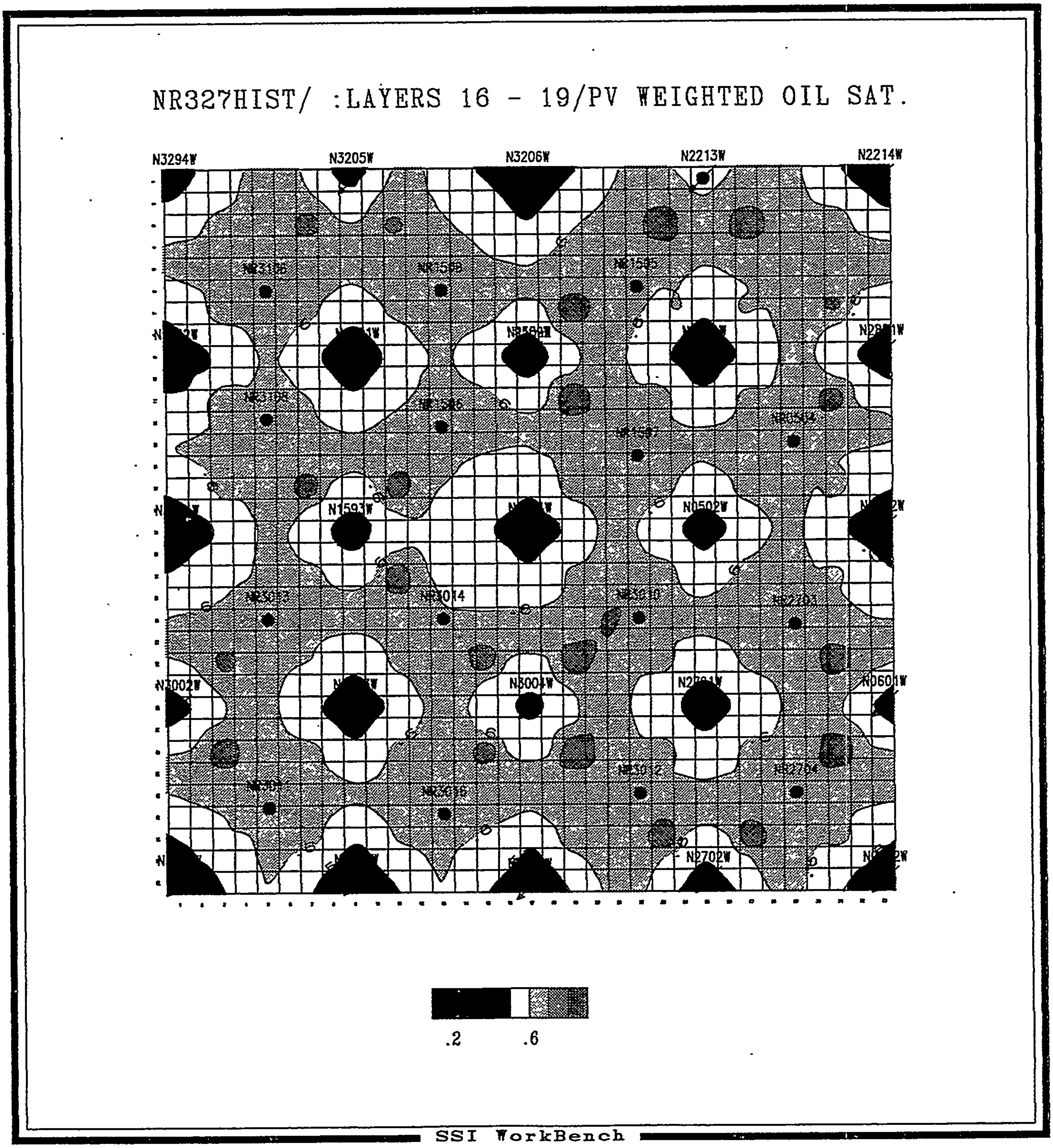


Figure 83 - Cumulative Oil With Line Drive Pattern, Section 327

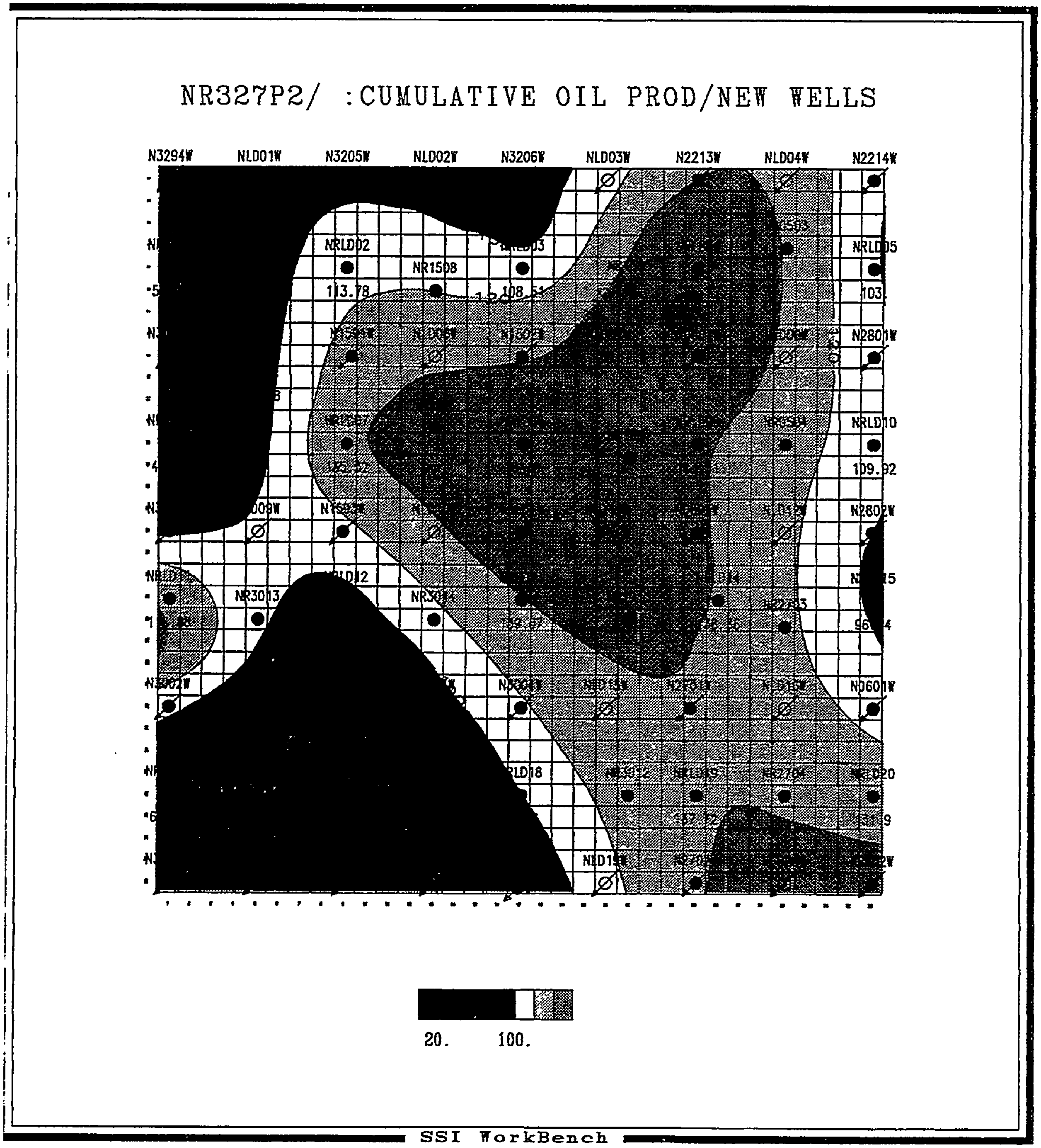
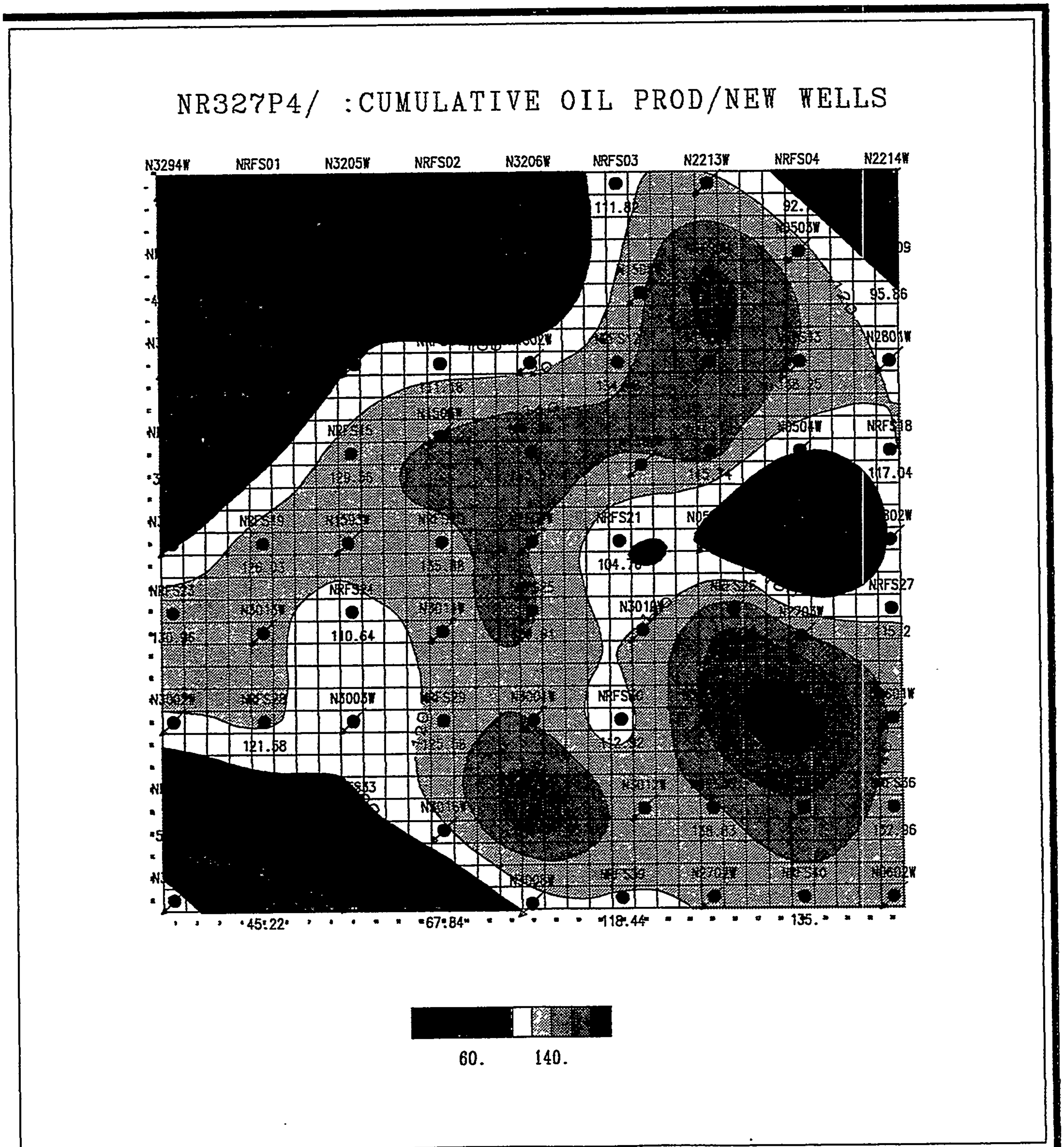


Figure 84 - Cumulative Oil With Line Drive Pattern, Section 327



SSI WorkBench

Figure 85 - History Match Results, Section 5 Model

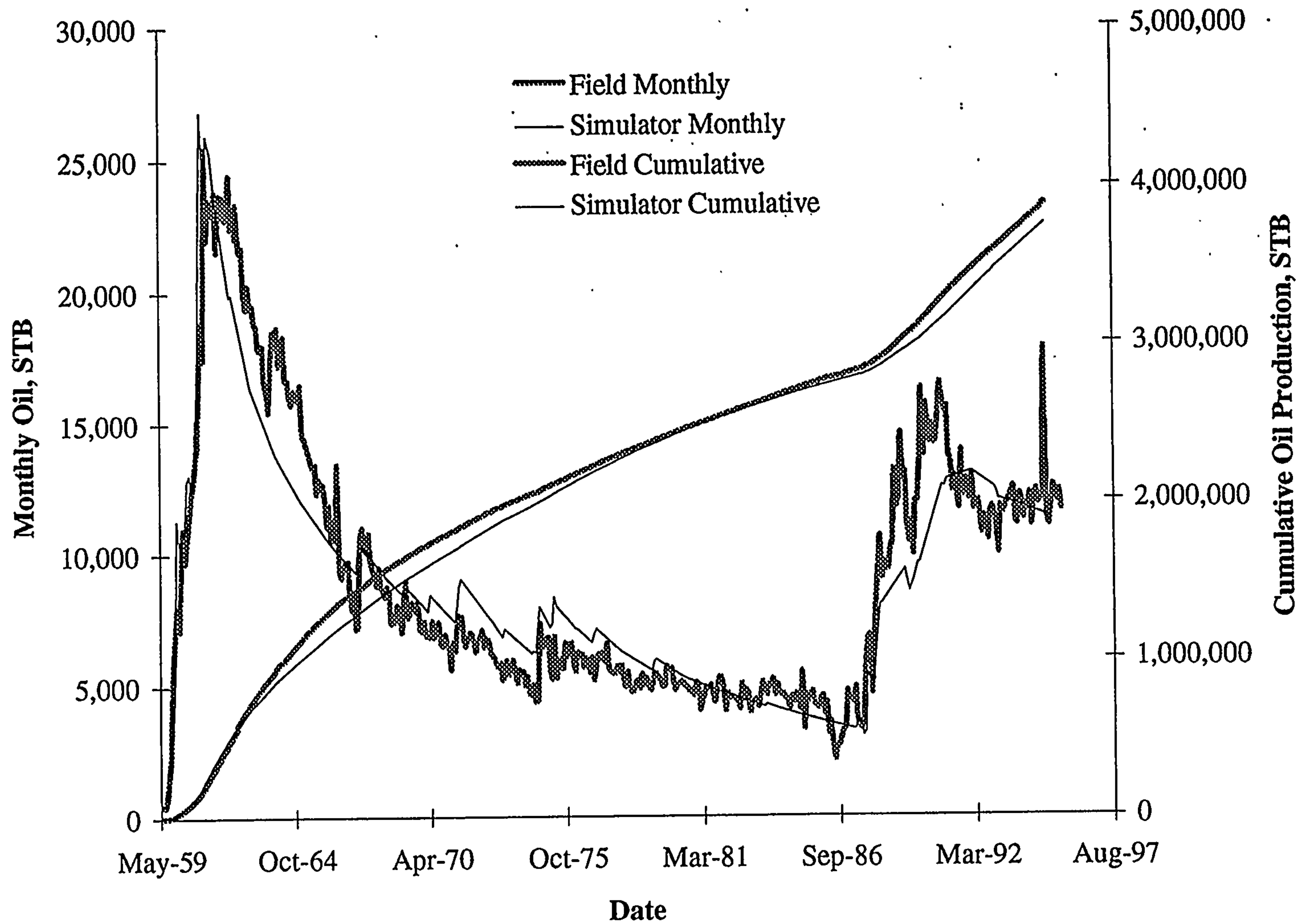


Figure 86, Injection Volumes, Section 5 Model