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A Computerized Simulation Of A Heterogeneous Aquifer Storage Formation

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ABSTRACT

A multi-dimensional, two-phase numerical reservoir simulator has been used to model a completely heterogeneous aquifer formation in which natural gas is stored. The mathematical model accounts for the variables which affect aquifer storage performance, such as capillary pressure, gravity effects, aquifer strength, reservoir heterogeneity and variable fluid properties. A procedure was utilized which permits automatic history matching of the field pressure response to gas injection and withdrawal.

Results are presented which indicate that a reliable reservoir description was obtained which allowed for a satisfactory match of historical pressure response and will serve as a basis for future reservoir studies.

The usefulness of the automatic matching procedure to determine reservoir parameters based on matching of field response is emphasized.

INTRODUCTION

A company which utilizes underground gas storage must be confident of the dependability of the facility. It is imperative that the reservoir performance be accurately predicted to insure that the reservoir is capable of delivering the withdrawal rates as required. This guarantees the satisfaction of customer demands by incorporation of the storage field performance with the more easily determined mainline capacity.

While all storage facilities have unique design and operational difficulties, perhaps the most difficult is gas storage in natural aquifers. This stems in part from the many variables which influence performance, the lack of performance data prior to development, and the introduction of a foreign hydrocarbon into a 100% water saturated zone.

The engineers responsible for the development and operation of storage fields have historically been forced to make many simplifying assumptions in order to predict a field's performance, determine optimum development schemes, etc. This situation is not unlike the problems faced by reservoir engineers concerned with the depletion of natural-occurring hydrocarbon reserves. The availability of high-speed digital computers and mathematical reservoir models offers a means to more rigorously study various gas storage problems incorporating the many variables which must be considered.

This paper describes the approach we are taking to more accurately predict aquifer storage reservoir performance. The application of a field is presented in detail with emphasis on the determination of a reservoir description from available performance data.

RESERVOIR DATA AND HISTORY

Northern Natural Gas Company determined the need for natural gas storage to aid in leveling its fluctuating demand curve early in the 1950's. Due to the absence of depleted gas and/or oil fields in the proximity of its market areas, exploration was initiated to find aquifer formations with reservoir characteristics suitable for gas storage.

A suitable structure was located by means of aeromagnetic and gravity surveys, and its characteristics were determined by numerous core tests. The aquifer formation is located at an approximate depth of 2700 to 2800 feet, its areal extent is 3 by 5 miles, and it has been described as a doubly plunging asymetrical anticline. The maximum vertical relief is 150 feet, while the net reservoir thickness is approximately 40 feet. The original discovery pressure was 1045 psi at top of structure, and the porosity averages 15.8%. Figure 1 shows the structure of the field.

The formation exhibits high horizontal core permeabilities in the range of 300 to 600 md with a vertical to horizontal permeability ratio of 0.05 to 0.10 and was initially 100% water saturated. The formation is heterogeneous with respect to permeability, as evidenced by the wide variation in observation well pressure response and the nonuniform manner in which the gas bubble has developed.

Gas injection into the formation was begun on July 2, 1957. One injector was utilized which was located near top structure. Gas injection continued on an intermittent basis through 1959 at which time the 27 injection-withdrawal wells shown on Figure 1 were in use. The reservoir was considered "in-service" in 1961; that is, it was being used to provide contract demand volumes. We have experienced a maximum gas-in-place of 69.9 Bcf and a maximum seasonal withdrawal of approximately 25 Bcf.

Available reservoir performance data include pressures at the 8 observation wells noted on Figure 1 and some information indicating the maximum areal penetration of gas during reservoir growth.

THE MODEL

The model used for this study was developed by Northern's Gas Supply Research Department[1], in cooperation with Dr. K. H. Coats of the University of Texas. It is a multi-dimensional, unsteady-state compressible model, simulating two-phase immiscible fluid flow in reservoirs. It calculates unsteady-state pressure and saturation distributions which develop during gas injection or withdrawal.

The calculations are based on continuity equations for both fluid phases and Darcy's Law including relative permeability. The two basic

$$\nabla \cdot \frac{k\, k_{rw}}{\mu_w} \rho_w^2 \nabla \Phi_w + q_w = \phi \frac{\partial}{\partial t} (\rho_w S_w) \tag{1}$$

$$\nabla \cdot \frac{k\, k_{rg}}{\mu_g} \rho_g^2 \nabla \Phi_g + q_g = \phi \frac{\partial}{\partial t} (\rho_g S_g) \tag{2}$$

The equations were solved using an ADI technique.[2] The model simulates two- or three-dimensional, two-phase compressible fluid flow and accounts for effects of reservoir heterogeneity, injection-production rate, aquifer strength, fluid and rock properties.

The infinite aquifer surrounding the two-phase region under consideration is accounted for by utilizing the approximate influx calculation proposed by Carter and Tracy.[3] Their method accounts for the transient flow in the aquifer, as opposed to a "pot" aquifer which delivers a fixed number of barrels of water for each unit potential drop in the outer blocks of the system.

As will be described more fully in a later section, it was necessary to modify the model in the process of completing this study. The most significant involved the use of an automatic matching procedure.[4] This procedure allowed the reservoir description to be determined automatically by selecting a set of reservoir parameters which, when used as a basis of prediction, match known reservoir performance. It utilizes the output from a number of simulator runs (15), each with a random reservoir description. A least squares linear programming technique then processes the data output from these runs to determine a reservoir description which satisfied the match criteria.

APPLICATION

The objective of this study was to determine a reservoir description resulting in a good match between calculated and observed pressures at the 8 observation wells. The first decision made in performing the study was to use a two-dimensional areal, as opposed to three-dimensional, representation of the field. This decision followed from the facts that core analyses indicated no continuous barriers to vertical communication and no field data by zones were available for matching purposes. The grid employed is also shown on Figure 1. This grid places no more than one well in a block and places no wells in boundary blocks. The elevation of each block in the grid is different, thus accounting for the structure shown in Figure 1. This variation of elevation is utilized in the numerical reservoir model to account for gravity forces in the areal (x-y) flow directions.

Relative permeability and capillary pressure-saturation relationships were defined by tables, a drainage-type capillary pressure curve was employed. Compressibility of gas and water was represented by tables of formation volume factors versus pressure.

The match of reservoir performance data was originally to cover the entire period of reservoir history from July, 1957, to December, 1966. The available data on the 8 observation wells were scanty and quite poor during early years of reservoir growth. Significantly better pressure data were recorded during the 88-week period from April, 1965, to December, 1966. The match of reservoir data was therefore restricted to the last 28 of these 88 weeks since good, continuous (weekly) data were available on all 8 wells in this period. Also, considerable injection-production rate variation occurred over the last 28 weeks so that correspondingly significant variations existed in responding pressures.

For the 8 years from July, 1957, to April, 1965, we specified yearly average injection-production rates for each of the 27 flowing wells. Starting at the latter date, we specified the actual weekly rates for each well. One simulator run covering the entire period (July, 1957, to December, 1966) required about one minute of UNIVAC 1108 computer time.

Initial simulator runs employed a homogeneous system--that is, permeability and porosity were uniform and aquifer strength was uniform around the entire reservoir boundary. The resulting match of the 8 observation well pressures over the last 88 weeks was quite poor, indicating the need for a heterogeneous representation of the reservoir.

Subsequent computer calculations with variable reservoir parameters indicated that transmissibility (kh product) and aquifer strength were the predominant variables. The computer program was therefore modified to allow for insertion of variable transmissibility regions and aquifer strengths varying along the perimeter of the grid system. Porosity was left uniform.

Considerable difficulty was encountered in the manual attempts to match performance with variable parameter regions. The influence of transmissibility across regional limits served to counter the value changes incorporated from one run to another. It became a very tedious operation to make logical parameter value changes while acknowledging the influence from surrounding regions. The interaction of the regions prohibited a satisfactory match from being obtained.

Economics dictated a better approach was required to reach a satisfactory match. The computer time and manhours required to manually adjust the reservoir parameter values had become prohibitive. The automatic history-match procedure, mentioned earlier, was then incorporated.

A review of the earlier runs indicated that nine parameters would provide sufficient reservoir detail. Six were transmissibility strength on the perimeter of the system. Figure 2 shows these nine parameters. Our best estimates of these nine parameters were made and 100% limits for the random selector were imposed, (e.g. 16000 md-ft $\leq (kh)_2 \leq$ 32000 md-ft). A set of 15 simulator runs was made, and the reservoir description was then backed out by the least squares linear programming (LSLP) method.[4] Five of the nine parameter values equalled their upper or lower limit value. Therefore, we shifted those limits and performed a second set of 15 runs. We applied the LSLP method to this output to again back out the nine parameter values. These values constitute the final description obtained in this study.

RESULTS

The basis of the history match in this study was an 88-week period of field operation. This period encompasses an injection-withdrawal cycle, a second injection period, and ends in the middle of a second withdrawal season. The study was keyed to obtaining a satisfactory match of pressure response through the last portion of the 88-week period.

Figures 3 through 10 show the relationship of predicted to observed pressure on the 8 observation wells. These figures show only the last 22 weeks of the match period. This is the most critical period of time, since we are reaching maximum pressure in the reservoir and corresponding maximum gas-in-place.

We feel that the match obtained is satisfactory, considering the degree of confidence placed in the observed data. This match which had as its basis the automatic-matching procedure, as previously discussed, far exceeds in accuracy the match obtained by earlier manual adjustments of the reservoir parameters.

We experienced more variability in the level of pressure response than in response time. Pressure level is dependent upon the influence of the aquifer surrounding the two-phase region.

The authors are confident that the reservoir description which serves as the basis of the match obtained can be used to reliably predict future field performance.

We are in the process of applying this model and reservoir description to some of the more unique problems of gas storage operations. These include determination of optimum operating strategies, non-recoverable gas volumes, and studying the use of water injection to restrict gas migration to the spill-point.

CONCLUSIONS

We have concluded from this study that numerical modeling is applicable to a heterogeneous formation used for the storage of natural gas. The satisfactory match of observed reservoir performance indicates the utility of the model in predicting future performance.

The automatic history-matching procedure, as utilized in this study, relieves the user of reservoir parameters to obtain a satisfactory history match and reservoir description. This reduces the money and effort which must be expended in determining reliable reservoir data.

ACKNOWLEDGMENTS

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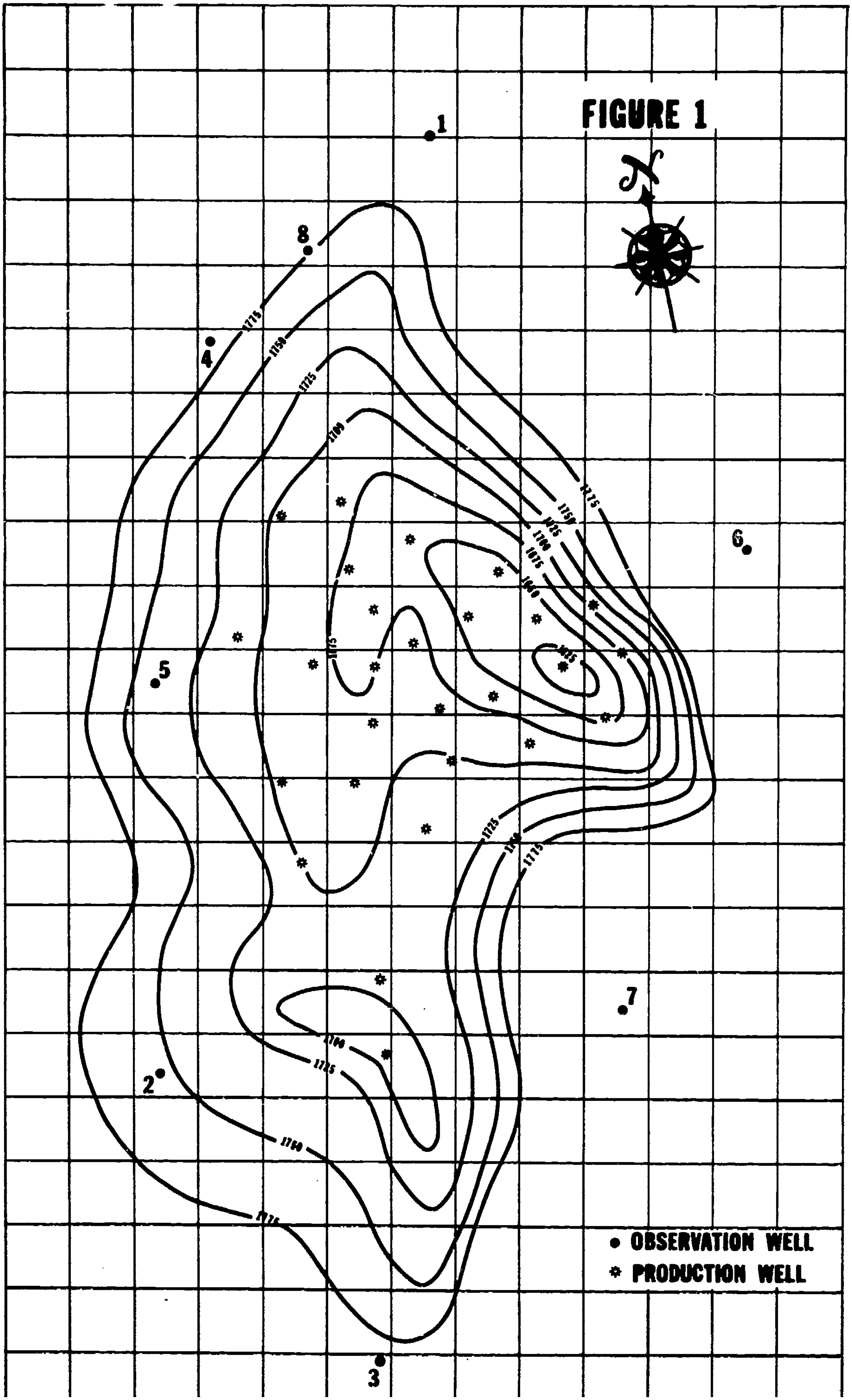
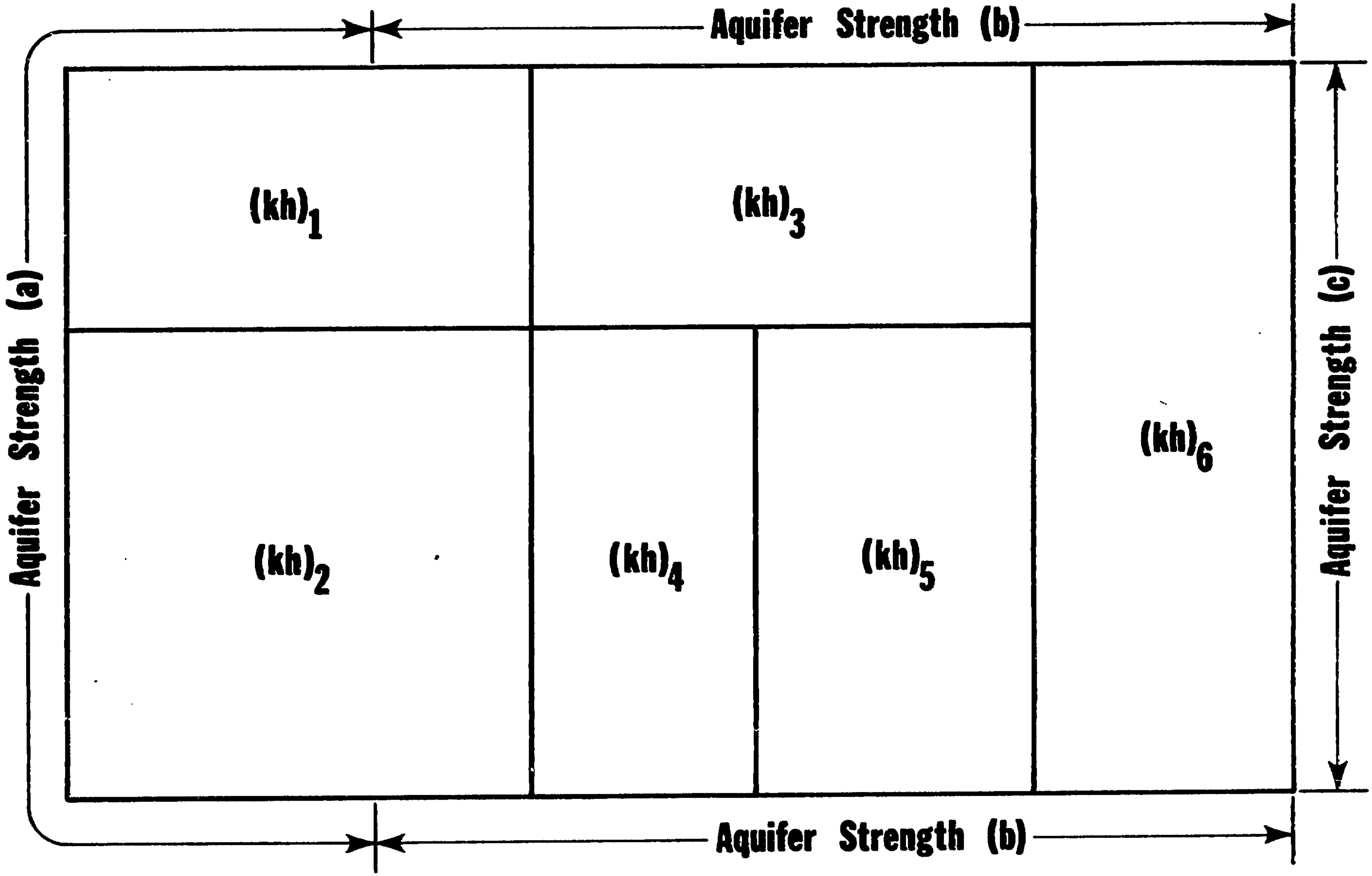
FIGURE 1





RESERVOIR DESCRIPTION IMPOSED

FIGURE 2

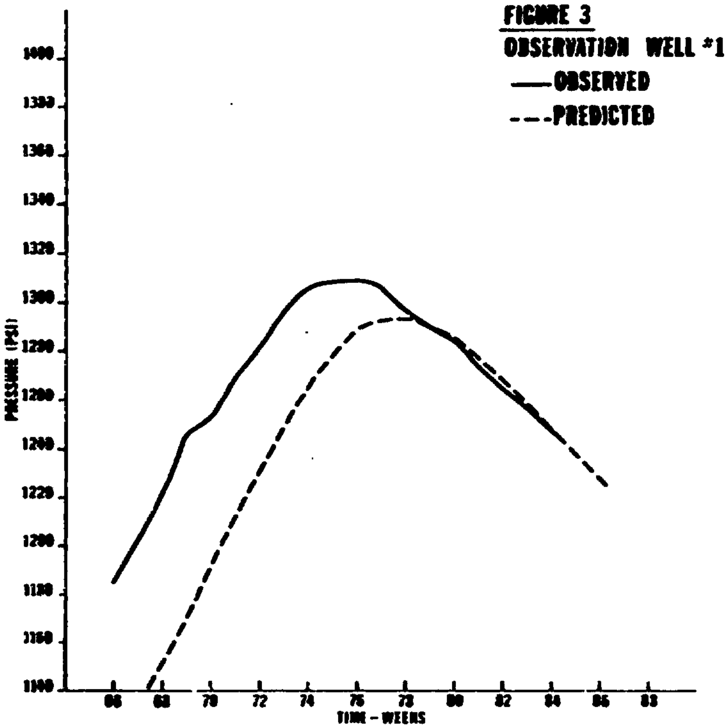


FIGURE 3
OBSERVATION WELL #1

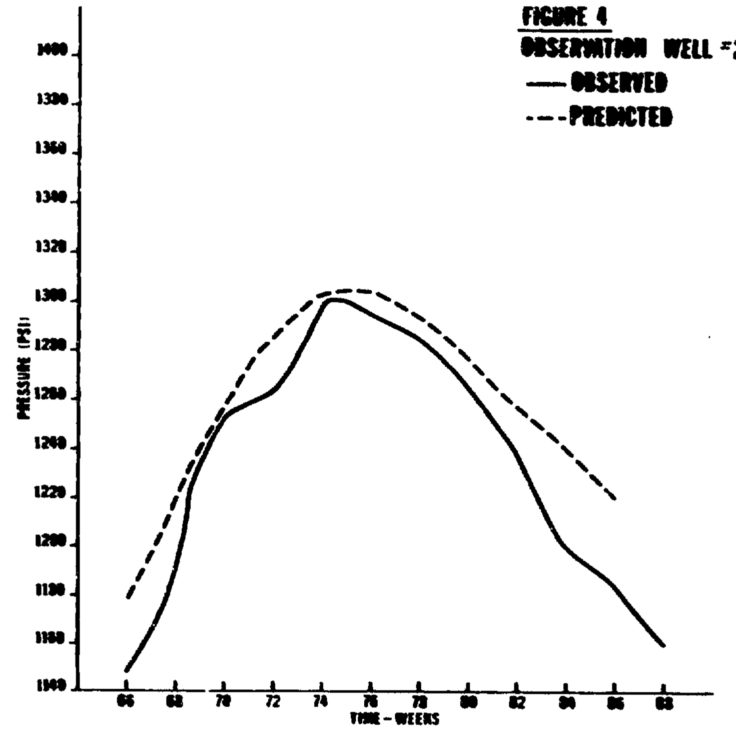


FIGURE 4
OBSERVATION WELL #2

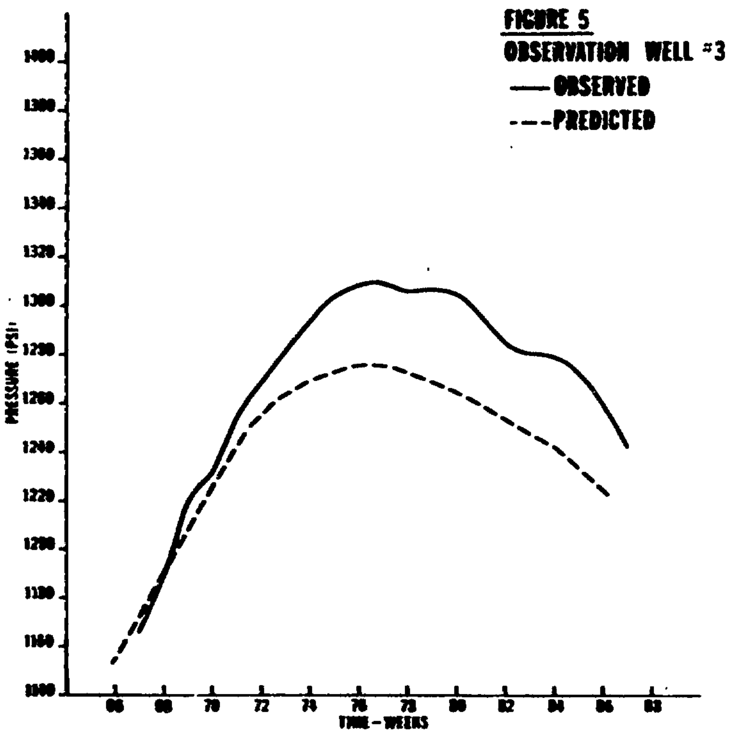


FIGURE 5
OBSERVATION WELL #3

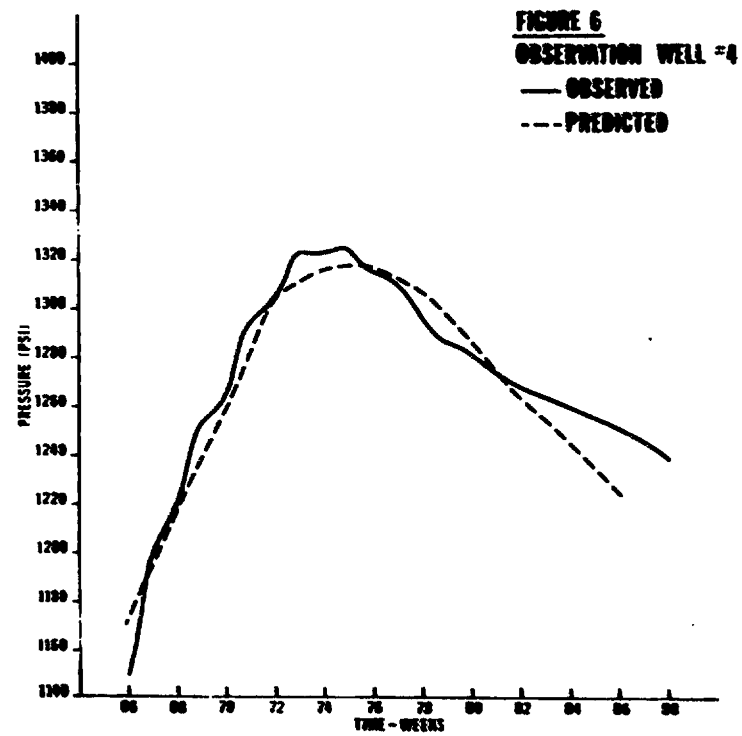
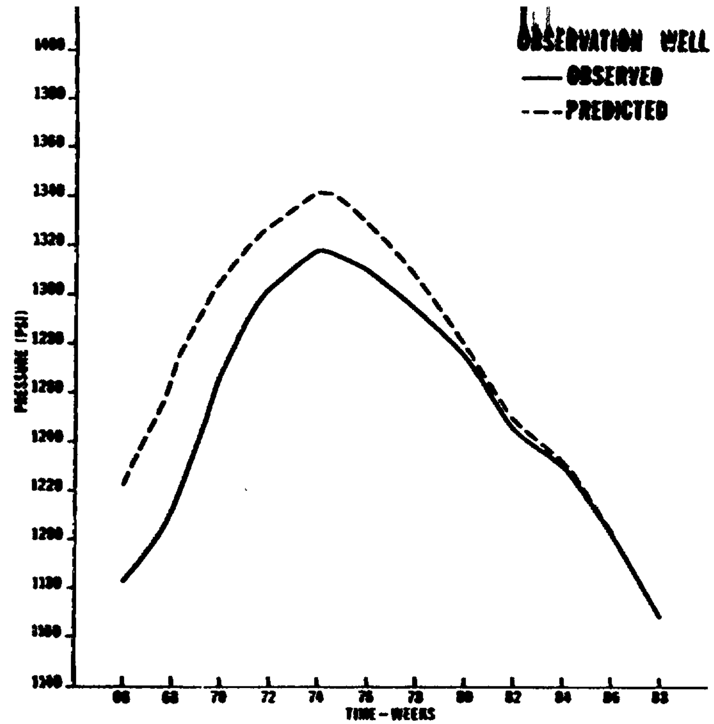
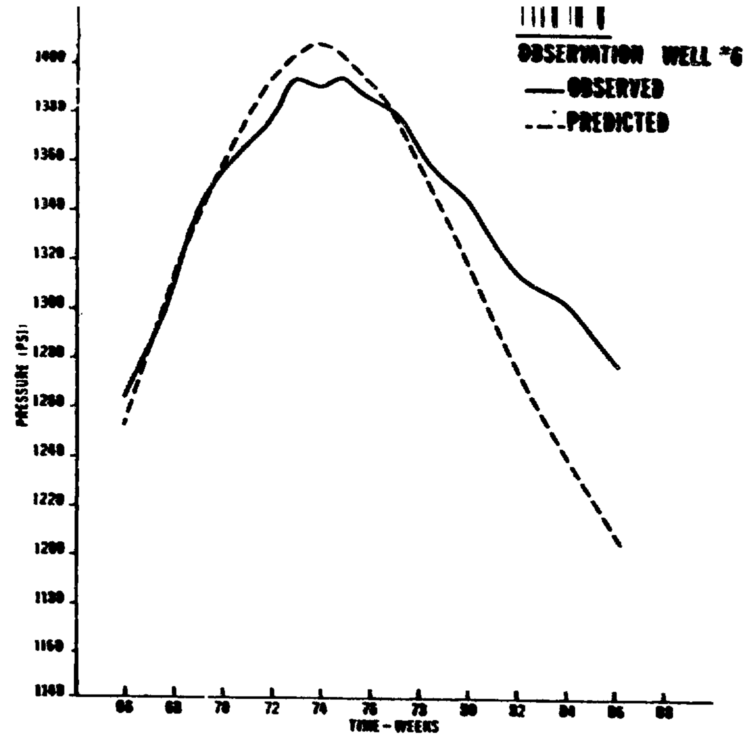


FIGURE 6
OBSERVATION WELL #4



OBSERVATION WELL #5



OBSERVATION WELL #6

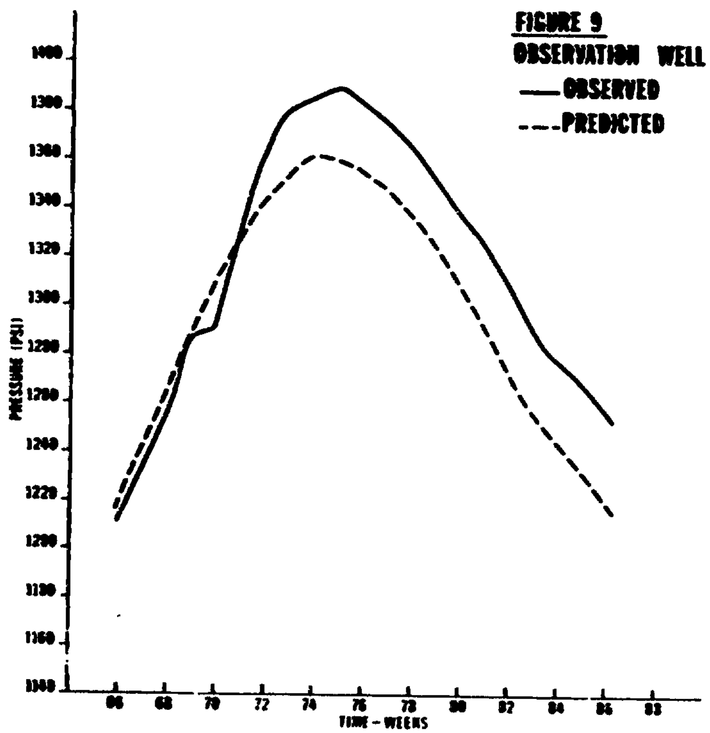


FIGURE 9
OBSERVATION WELL #7

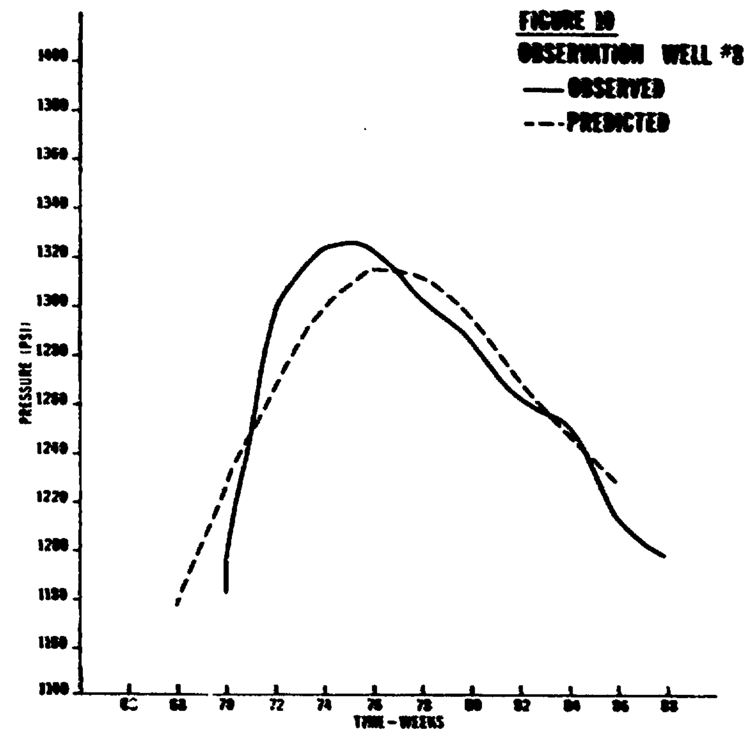


FIGURE 10
OBSERVATION WELL #8