

AN INTEGRATED GEOLOGIC AND ENGINEERING RESERVOIR CHARACTERIZATION OF THE NORTH ROBERTSON (CLEARFORK) UNIT, PART 1

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Brief Summary

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 carbonate reservoirs. 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 geologic, 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 modeling, and rigorous decline type curve analysis can be used to quantify reservoir quality and the degree of interwell communication. These results can be used to develop a 3-D simulation model for prediction of infill locations. In this work, we will demonstrate the application of reservoir surveillance techniques to identify additional reservoir "pay" zones, and to monitor pressure and preferential fluid movement in the reservoir. These techniques are: long-term production and injection data analysis, pressure transient analysis, and advanced open and cased hole well log analysis.

The major contribution of this paper is our summary 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.

Introduction

There are many complicated factors that will affect the successful implementation of infill drilling programs in heterogeneous, low permeability carbonate reservoirs such as the Clearfork/Glorieta of west Texas. Before we began this project, we conducted an extensive literature review to gain a better understanding of the producibility problems we face at the North Robertson Unit (NRU). Fortunately, these reservoirs have a long producing history and there is a large quantity of useful data available from case studies for primary, secondary, and tertiary operations in the Clearfork and other analogous reservoirs.

In a 1974 case study concerning waterflooding operations at the Denver (San Andres) Unit, Ghauri, *et al*¹ gave valuable insights concerning reservoir discontinuity, injector-producer conformance, and the effect of reservoir quality on reservoir sweep efficiency.

Poor reservoir rock quality and the existence of discontinuous pay between injection and producing wells resulted in a recommendation to reduce nominal well spacing from 40 acres to 20 acres. An outcrop study on the San Andres was performed to verify reservoir discontinuity. Injection wells were completed and stimulated preferentially in an effort to flood only the continuous layers of the reservoir. The original peripheral injection design was converted to inverted nine-spot patterns in an effort to decrease the amount of water channeling and early water breakthrough via the most permeable members.

In 1976, Stiles² summarized the difficulties encountered in waterflooding operations at the Fullerton (Clearfork) Unit. The author noted that increasing the injection rate would never result in an equal response at the producing wells. The concept of "pseudo fill-up" was introduced to explain that although reservoir fill-up may occur in the most permeable or continuous layers of the reservoir, a large gas saturation still existed in the poorer quality reservoir rock. For this reason, the theoretical maximum producing rate would never be achieved without contacting the discontinuous areas through infill drilling.

A statistical study was performed to quantify reservoir continuity as a function of interwell distance on the basis of continuous and discontinuous reservoir layers. Stiles maintained that injection pressures above the parting pressure of the formation was required in order to maintain acceptable injection rates in the reservoir.

In a 1978 review of west Texas carbonate reservoir waterflooding operations, George and Stiles³ outlined their recommendations for optimizing waterflood operations in the Means (San Andres), Fullerton (Clearfork), and Robertson (Clearfork) Units. These authors stressed the importance of infill drilling and pattern modification to overcome pay rock stratification, and the need for continuous interaction between geologists and engineers in order to produce a program of optimal reservoir development and depletion.

A "rock-log" model was formulated for the Robertson (Clearfork) using a limited amount of core data and old gamma ray/neutron logs that were available field-wide. Original oil-in-place (OOIP) was calculated by both volumetric and material balance methods. The authors pointed out that the ratio of material balance OOIP to volumetric OOIP should yield a *qualitative* measure of reservoir continuity since the material balance calculation only considers intervals that are continuous or effectively completed, while the volumetric calculation considers all "pay" quality reservoir rock.

George and Stiles provided a method to identify "floodable" pay, which was differentiated from continuous pay on the basis of the most probable geometry of a continuous layer between an injection and producing well. Obviously, the amount of floodable pay in the reservoir was always slightly less than the amount of continuous pay, and both could be optimized through infill drilling. The authors concluded that floodable pay must be continuous between injection and producing wells, be injection supported, and be effectively completed at the producing well.

In a 1980 summary of work completed at the Denver (San Andres) Unit, Ghauri⁴ outlined the importance of integrated geologic and engineering studies in the development of the Wasson (San Andres) field from primary through tertiary depletion. The author goes into great detail describing the processes that were utilized to increase sweep efficiency, optimize completion and stimulation procedures, and improve well

conformance. The design and installation of automated artificial lift systems are also highlighted.

Barber, *et al*⁵ provided a case study in 1983 describing infill drilling results in nine carbonate and clastic reservoirs in Texas, Oklahoma, and Illinois. This work resulted in an extremely important observation regarding the affect of reduced well spacing on pay continuity. Using data for 20-acre wells in the Means (San Andres) Unit, a 4 percent increase in pay continuity was expected when nominal spacing was reduced to 10 acres. However, after pay continuity was recalculated on the basis of 10-acre well data, it was found that the actual pay continuity increase was 14 percent. The authors noted that *past observations regarding additional recovery from infill wells made prior to drilling were probably extremely pessimistic.*

In 1987, Barbe and Schnoebelen⁶ summarized the results of an aggressive infill drilling program in the Robertson (Clearfork) Unit. The authors found that obstacles associated with poor reservoir continuity in heterogeneous, low permeability carbonate reservoirs could only be overcome through infill drilling on a reduced nominal well spacing.

In addition, performance data analysis and pressure transient test results indicated a roughly east-west directional permeability or fracture orientation. This will be the most likely direction of preferential water movement in the Robertson (Clearfork). Pay continuity was quantified using geological, reservoir performance, and pressure transient data, and all three methods gave similar results. Wireline formation test results showed that individual layers had widely different formation pressures, indicating a lack of vertical continuity within the Clearfork.

A further conclusion was made regarding the best locations for the infill wells. Barbe and Schnoebelen found that the best 10-acre and 20-acre producers were in the same areas as the best 40-acre producers, which indicates that the identification of areas of high quality reservoir rock is perhaps more important than finding the areas of poor reservoir continuity when deciding on infill well locations.

The primary objective of our work is not to explain the concepts behind the initiation of a successful waterflood and subsequent infill drilling program for heterogeneous, low permeability carbonate reservoirs as this has been effectively discussed in the literature.¹⁻⁶ Rather, we will use the tools discussed in our work to aid in our analyses, and we will introduce new and existing technologies that can be economically implemented by all operators.

Examples of these technologies include:

1. Formulation of a "rock-log" model to identify the highest quality pay intervals using available open hole well log data for the extrapolation of core properties from a limited number of wells.
2. Calculation of total and movable fluid volumes and estimation of formation flow characteristics using a rigorous decline type curve method for the analysis of readily available oil production data.
3. Low cost acquisition and analysis of pressure falloff data from injection wells using surface pressure gauges.
4. Development of spatial relationships for reservoir variables of interest at unsampled (interwell) locations across the Unit using geostatistical techniques.
5. Performing 3-D reservoir simulation for history matching, infill drilling development forecasting, and validation.

Historical Background

The NRU is located in Gaines County, Texas in the northern part of the Central Basin Platform of the Permian Basin (Fig. 1). The producing horizons are the Glorieta and Clearfork Formations (referred to as the Upper and Lower Clearfork). 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 contains a total of 259 wells as of January, 1995. This includes 144

active producing wells, 109 active injection wells and 6 water supply wells. For the purposes of this study, the Unit has been divided into three pre-demonstration study areas (PDSA) as shown in Fig. 2.

Development and Production History

Production from the North Robertson field area began in the early 1950s with 40-acre primary depletion development. This 40-acre primary development resulted in 141 producing wells. 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 STB/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 relevant fluid, formation, and production data are shown in Table 1.

The cumulative produced and injected fluid volumes are summarized below. Fig. 3 shows the production and injection history of the Unit from development in 1956 through September 1994.

	N_p (MMSTB)	Q_w (MMBW)	Q_{wi} (MMBW)
As of 1987	17.5	8.2	N/A
1987-1994	7.4	20.8	52.3

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 calculated 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 3,200 STB/D, 1,400 MCF/D and 11,000 BW/D. Water injection volumes are approximately 20,000 BW/D, with injection water comprised of produced water, and fresh water from the Ogallala aquifer obtained from water supply wells within the Unit.

Methodology

This paper will summarize both completed and scheduled work in the following areas:

- Geological/Petrophysical Study
 - Formulation of geologic model
 - Core analysis
 - Formulation of rock-log model
 - Flow unit identification and reservoir layering
 - Continuity analysis of reservoir pay
- Cross-Borehole Tomography
 - Theory/methodology
 - Preliminary results
 - Plan for future data acquisition
 - Integration of cross-borehole seismic data for reservoir characterization
 - Operational considerations
- Reservoir Performance Data Analysis
 - Oil production data analysis using decline type curves (Reservoir quality maps)
 - Reservoir performance bubble maps
 - Waterflood performance analysis (Injection well performance plots)

- Reservoir Surveillance Plan
 - Water quality program
 - Pressure transient data acquisition and analysis
 - Step-rate testing
 - Review of completion/stimulation procedures
 - Coiled-tubing workovers
 - Cased-hole well logging program
 - Future data acquisition
- Geostatistical Simulation
 - Methodology
 - Conditional simulation techniques
 - Approach at North Robertson Unit
- 3-D Reservoir Simulation
 - Methodology
 - Reservoir performance criteria
 - Selection of areas for modeling
 - Model initialization
 - PVT and rock-fluid interaction data
 - History match criteria

Geological/Petrophysical Study

A geologic model was constructed on the basis of both macroscopic data (visual) and microscopic data (petrographic thin section and scanning electron microscope) obtained from analysis of available whole core from a limited number of wells throughout the Unit (Fig. 4). This development of the geologic model includes the depositional setting and variability, depositional environments, diagenetic effects, lithological variations, effects of pore system geometry, physical properties, and natural fractures.

Due to the lack of conventional core (a common problem in older reservoirs), there was a need to develop a unit-wide geological/petrophysical model so that individual rock types could be identified on the basis of well log responses in areas where core was not available. The rock-log model that was developed is based on the petrophysical and lithological study of 4,600 feet of whole core from eight wells in the NRU. This work involved detailed sedimentologic observations of the whole core, thin-section analyses, x-ray diffraction (XRD), special core analysis (SCAL), and pore geometry investigations using scanning electron microscope (SEM) image analysis. The relationships between pore volumes and pore throats have been quantified by direct measurements of pore casts.

Quantitative rock type porosity-permeability relationships were established in order to identify the most attractive pay intervals. The distribution of pay rock types in individual wells has been calculated and will be used to generate interwell reservoir quality maps using geostatistical methods. The results will then be used to describe the reservoir for 3-D simulation.

Geologic Model

Depositional Environments

The interpretations for depositional environments (Figs. 5 and 6) have been derived primarily from qualitative descriptions and thin-section studies of the whole core samples. The depositional environments for the Clearfork and Glorieta Formations are as follows:

- Highstand Lithofacies Tracts
 - supratidal and subaerial deposits
 - intertidal and channelized tidal flats

- open and restricted lagoons
- grainstone shoals
- subtidal
- open shelf
- Transgressive Lithofacies Tracts
 - shelfal and patch reef
- Low Stand Lithofacies Tracts
 - inland sabkha

Lower Clearfork

In general, the Lower Clearfork, which is defined as the portion of the Clearfork directly overlain by the Tubb (transgressive marine shaly dolostone interval), was deposited 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/or wave dominated and organized) of grainstone deposits (primarily fusulinid or peloidal) which comprise a dolograinstone reservoir facies with some preservation of primary porosity.

A study of historical production data using contour maps of reservoir performance suggests that these outer shelf grainstone reservoirs appear to be in communication with one another and the amount of compartmentalization and heterogeneity may not be as pronounced as in the Middle and Upper Clearfork (which overly the Tubb marker). This concept may also be attributed, in part, to more widespread and uniform conditions of deposition with less cyclicity (fewer changes in sea level and/or water depth). A structure map of the Tubb formation is shown in Fig. 7.

Middle/Upper Clearfork and Glorieta

The remainder of the Clearfork and the Glorieta sequences are typified by highstand lithofacies characterized by highly cyclic depositional environments consisting of inner shelfal subtidal flats, restricted and open lagoons, tidal flats which are frequently channelized, intertidal and supratidal sabkha flats.

The lower portion of the Middle Clearfork, which immediately overlies the Tubb Marker, is characterized by a transgressive lithofacies tract (approximately 150 to 250 feet thick). Within this interval there is some evidence of possible patch reef developments represented by the existence of non-porous, mottled boundstones that contain sponge, algae, coral, and bryozoan fragments.

Reservoir performance contour maps suggests that the dolostone reservoir rocks that characterize these depositional environments have generally poorer reservoir parameters. Porosity and permeability are reduced as these dolostones tend to be silty and argillaceous and are frequently anhydritic. Cyclicity has resulted in a high degree of compartmentalization and heterogeneity and variations in petrophysical properties reflect the presence of numerous crossflow barriers which are indicative of reservoir compartmentalization.

Pay quality reservoir rocks, where present, are once again represented by grainstones and wackestones (ooidal and/or skeletal) that were deposited in response to shoaling depositional environments. Oomoldic and biomoldic porosity may be well developed, however, interconnectivity is usually poor, resulting in low quality reservoir rock. Structure maps for the Upper Clearfork and Glorieta are shown in Figs. 8 and 9.

Diagenesis

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 which has resulted in the development of intercrystalline porosity. Periods of leaching and dissolution are probably

related to sea level fluctuations and predate diagenetic dolomitization.

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.

Pore Geometry

Reservoir quality and continuity are dominated by variations in pore geometry.⁷ 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.^{8,9} Extreme variation in pore geometry is characteristic of heterogeneous, low permeability carbonate reservoirs such as the Clearfork/Glorieta.

Pore types were quantitatively defined for 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 - $(\text{pore perimeter}^2 / 4\pi \text{ pore area})$
 - Length to width ratio
- Pore throat measurement¹⁰
 - Coordination number $(\text{number of pore throats/pore})$
 - Aspect ratio $(\text{pore body size/pore throat size})$
- 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 2.

Rock Typing

A total of eight rock types have been identified of which four have reservoir potential (one being limestone and water bearing). 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. 10. Average core values for porosity, permeability, and estimated recovery efficiency are presented for each of the eight rock types in Table 3. Recovery efficiency was estimated using the methods outlined by Wardlaw and Cassan¹⁰ 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 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.

From the standpoint of oil production, the best reservoir rock is rock type 1, which consists primarily of grainstones and has some primary porosity preserved (average core porosity is approximately 5.4 percent). Coordination numbers and aspect ratios are less favorable than for the other reservoir quality rock types (2,3, and 5). However, the interconnectibility is much more favorable, resulting in good fluid flow potential (average core permeability is approximately 5.5 md). The less favorable reservoir rock types have generally low coordination numbers and high aspect ratios reflecting relatively poor flow potentials.

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 development and the abundance of small pore throats in the Glorieta/Clearfork result in poor reservoir continuity, directional permeability and fracture trends, as well as poor sweep efficiency during secondary and tertiary recovery operations. These same characteristics suggest that infill drilling on a reduced spacing and a vigilant reservoir surveillance program are required.

Special Core Analysis

In order to accurately model reservoir flow conditions, we need representative rock-fluid interaction data. The present capillary pressure and relative permeability data sets will be augmented with additional data from proposed infill wells. 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 flow. This data will be used as initial input data for reservoir simulation, as well as being a guide for future data acquisition.

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. The capillary pressure curves for rock type 1 are shown in Fig. 11.

Using the methods presented by Thomeer,¹¹ 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 4. On average, rock type 1 again appears to be 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.

Relative Permeability Measurements

The oil/water relative permeability data were taken at various water saturations on twelve core samples from a single well in the Unit (NRU 3522). Relative permeability curves for rock type 1 are shown in Fig. 12. These results confirmed 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 and lower entry pressure, however, the predicted residual oil saturation appears to be extremely high. The planned acquisition and analysis of additional data will give us the opportunity to further study the relative permeability characteristics of the various rock types.

Rock-Log Model

The objective of the rock-log model work is to facilitate the delineation of reservoir flow units. Eight rock types have been identified of which only three can be truly classified as potential oil producing pay (one of which is limestone and water wet). The need for a reservoir model that has field-wide application is essential as only a limited number of wells in the NRU have been cored in the Glorieta/Clearfork Formations.

As a whole, there was no simple, direct relationship between core porosity and core permeability (Fig. 13). However, when the data were segregated by rock types generated from core analysis, the relationship between porosity and permeability became fairly unique and simple linear relations could be used to define the permeability on the basis of porosity (Fig. 14). If reservoir rock types can be defined using core data, then the same porosity/permeability relationship should also apply for wireline log data, and the model can be extended throughout the Unit to all wells with the requisite well log data.

Our rock-log model 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

Sonic and Microlaterologs would have been extremely useful in isolating "pay" rock types, however, these well logs were run with insufficient frequency to be used.

The rock-log model was formulated to take advantage of the large amount of modern well log data (123 wells) that was available due to the completion of a 20-acre post-unitization infill drilling program between 1987 and 1991. A type log for NRU Well 207 is shown in Fig. 15. These modern well log suites allow for a more comprehensive evaluation of formation properties than would be possible using older porosity/resistivity well log suites.

The wells drilled prior to unitization do not have the requisite well log suites to apply the model. However, since there is usually an abundance of older wireline log data for many fields such as North Robertson Unit, we note that these well logs should yield an extremely good rock-log model if the well log data are properly interpreted. All of this, with little additional expenditure for the operator.

The wireline log data has been corrected for wellbore environment, normalized on the basis of core porosity and the average porosity across the interval of interest (when required), and depth shifted. Rock types 1-4 are differentiated from rock types 5-8 on the basis of apparent matrix density, apparent photoelectric capture cross-section, gamma ray response, and lithology (Fig. 16). The primary reservoir rock types can then be further delineated using a crossplot of apparent porosity versus the calculated cementation factor. Permeability is calculated using a lithology-corrected crossplot porosity and the core-derived permeability-porosity relationships for each particular rock type.

Results are generated on a foot-by-foot basis for crossplot porosity, permeability, and rock type in both cored wells, and non-cored wells which have the necessary well log suites. The intrawell rock type, porosity, and permeability data can then be extended to an interwell basis using geostatistical simulation, and reservoir quality maps can be generated.

Reservoir Layering

Flow Unit Delineation

The formulation of a rock-log model has provided us 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 4,600 feet of whole rock cores from eight 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 16 stratigraphic units (Fig. 17). Further work may necessitate the definition and recognition of additional units. Each of these stratigraphic units (potential flow units) are bounded by potential crossflow barriers that are thought to be representative of a sabkha or 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 boundaries are time-defined (isochronous), and the resulting depositional packages within the stratigraphic units are therefore contemporaneous in nature. 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 changes in eustasy produced highly cyclic sequences. These parasequences are carbonate-dominated with insignificant clastic influences.

Structure maps have been constructed for the top of each stratigraphic unit, and have been observed to stack. Isopachs have also been made for each unit to ascertain where changes in shelfal accommodation for sediments has occurred.

The relative distributions of potential reservoir rock types (1, 2, 3, and 5) and non-reservoir rock types (4, 6, 7, and 8) for each stratigraphic unit will be determined by predictive facies analysis. This involves showing the distribution of a particular reservoir rock as a function of:

- Total thickness of reservoir rock/total thickness of reservoir and non-reservoir rock
- Thickness of a particular reservoir rock type/total thickness of non-reservoir and reservoir rock.
- Thickness of a particular reservoir rock type/total thickness of all reservoir rocks

There should be a relationship(s) between the sediment accommodation indicated by the respective stratigraphic unit isopachs and the distribution(s) of the various reservoir rock types. There should also be a correspondence between the occurrence of the reservoir rock types and the areas of the reservoir with good reservoir performance 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 will also be constructed for each stratigraphic

unit. There should be some very discernible 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 from this work are forthcoming and will be incorporated within the geostatistical analysis of the reservoir. Areas that have been qualitatively evaluated as very favorable, favorable and unfavorable for infill drilling will then be quantified. This quantification will involve 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 will be 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.

A study based on 40-acre well log data was performed prior to unitization on thirty-nine wells in Sections 5, 325, and 329 using methods introduced by Stiles.² Prior case studies^{2,5} indicate that the 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 we will be contacting a much larger volume of the reservoir. This 40-acre continuity data, and the estimated results of 20- and 10-acre well analyses are shown in Fig. 18.

Cross-Borehole Tomography

The objective of the cross-borehole tomography work is 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.¹²

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.¹³

Seismic Travel Time Tomography Approach

Seismic travel time tomography has been in use for several years.¹²⁻¹⁶ Seismic energy transmitted through the formation is expressed in terms of a source-to-receiver travel time and inverted to a velocity field representation of the formation.

In order to have a sufficient number of ray paths for inversion to the velocity field, many combinations of source/receiver pairs are recorded. The recording design is based on reservoir conditions and imaging requirements. A schematic diagram of the tomographic data acquisition operation is shown in Fig. 19. An example showing the number of ray paths from the tomogram recorded between NRU wells 207 and

403 is shown in Fig. 20.

Seismic travel time inversion tomography measures changes in velocity between the wells, for which the relationship of rock properties to velocity is the principle concern. A decrease in velocity is expected with an increase in porosity (higher fluid content).

Completed and Planned Tomography

A cross-well tomography survey using NRU wells 207 and 403 was completed during July, 1994. A future survey is planned for pre-demonstration study area (PDSA) III of the Unit using NRU wells 3522, 3511, and 3528 (Fig. 21). One reason these areas were chosen is that fully cored wells are available as control points for data analysis (NRU wells 207 and 3522).

Survey parameters on 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), 1048 feet vertical distance surveyed
- Interwell spacing of approximately 1040 feet.

It is expected that an order of magnitude more ray paths can be obtained in the survey for PDSA III as a new generation prototype tool will be used. It is also expected that the survey will be recorded at a greater range of operating frequencies, and at a reduced depth sampling interval than the first survey. This should result in better quality data for processing and interpretation.

Processing Completed and Results

Processing of results from one survey is in progress and is only partially complete. Another survey is planned for the first quarter of 1995. Since the tomography profile processing is presently incomplete, the interwell continuity of the reservoir has been investigated using a simpler "connectivity mapping" process for the NRU well 207/403 survey data.

Connectivity mapping is an effective imaging technique in mapping the continuity of the interwell formations. The technique is based on the principles of wave guide phenomena. Wave guides are formed in bed layers possessing different acoustic velocities. The principle is similar to that of a focused resistivity tool. As in fluid flow analysis, seismic waves will always follow the path of least resistance.

This processing method utilizes spectral analysis of the specific acoustic wave trains (channels) formed in each frequency domain of interest in order to estimate bed connectivity on the basis of the quality of wave transmission through it. The advantage of this method is that it requires only a small portion of the full tomographic data set for processing.

There are several data analysis steps required for processing as shown on the flow diagram (Fig. 22) and described in Ref. 16. Fig. 23 shows the connectivity map of the NRU 403/207 survey based on these spectral characterizations. The connectivity map displays the interwell continuity of the beds from the source well to the receiver well. The lightest areas of the map correspond to intervals with good connectivity. This does not mean they are continuous, simply that they have the same acoustic properties throughout the section.

This connectivity map is well correlated with the existing sonic and gamma ray logs. Interwell heterogeneities can be easily identified from the map, and are especially apparent in the lower portion of the Middle Clearfork, which would be expected from the geologic interpretation of the interval. The results also indicate that several formations show good interwell continuity. This is not surprising, since the results of geologic and reservoir performance work indicate this area of the Unit has relatively high reservoir continuity.

When the flow unit layering scheme (Fig. 17) is compared to the connectivity map (Fig. 23), we note

fairly good correspondence between the two, indicating that connectivity mapping may be an effective tool for layering the reservoir for flow simulation purposes. It should be noted that due to the diagenetic processes that are common in carbonate reservoirs, the resulting wave guides that form will not always follow depositional boundaries, but may also form along zones in which post-depositional porosity has been created via diagenesis.

Additional processing of the present data set (velocity map, inversion tomography, reflection profiling) is currently in progress. These results, as well as the results from the survey scheduled for PDSA III, will be discussed in greater detail in a subsequent work.

Operational Considerations

Approximately half the expenditures on the initial survey pertained to pre- and post-survey well preparation costs. The planning required for the use of producing wells for tomographic surveys is much more straightforward (and economic) than for injection wells. In waterfloods such 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 (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 generate revenue for further development will survey costs be reduced to the point where tomographic services can become a part of standard reservoir characterization and surveillance operations.

Reservoir Performance

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 Curve Analysis of Long Term Production Data
- Reservoir Performance Bubble Maps
- Waterflood Performance Analysis

Material Balance Decline Curve Analysis

In order to verify the results of the rock-log modeling, the analysis of long-term production data is being performed using a rigorous material balance decline type curve method.¹⁷ An initial study of the primary

40-acre producers has been completed utilizing the Fetkovich/McCray Type Curve.¹⁸⁻²⁰ (Fig. 24). A step-by-step procedure for the use of this technique is given in Ref. 17.

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 increase 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:

- Reservoir properties:
 - Skin factor for near well damage or stimulation, s
 - Formation flow capacity, kh
- In-place fluid volumes:
 - Original oil-in-place, N
 - Movable oil at current conditions, $N_{p,mov}$
 - Reservoir drainage area, A

We focus on 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 any types of data are limited. This approach *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 also provides an additional method for locating the most productive areas of the reservoir, and identifying any preferential flow paths that may exist.

An example analysis on NRU well 3510 is provided below. For Clearfork data, we prefer to report flow capacity instead of permeability due to the fact that accurate values for net pay interval are not available. Average fluid properties were used in the analysis.

Example Analysis: NRU Well No. 3510

Fig. 25 shows the location of NRU Well 3510 with respect to its well pattern and Section 329. This well was drilled in 1963, and completed in the Lower, Middle, and Upper Clearfork. The Lower Clearfork was stimulated with 2,000 gallons of acid, and hydraulically fractured down casing with 21,500 gallons of fracturing oil and 60,000 pounds of 20/40 sand. The Middle and Upper Clearfork were stimulated with 2,000 gallons of acid, and fractured down casing with 86,000 gallons of fracturing oil and 180,000 pounds of 20/40 sand.

The well initially tested at 55 STBO/D from the Lower Clearfork and 127 STBO/D from the Middle and Upper Clearfork. It had produced approximately 226 MSTB as of July 1989, when it was converted to a water injection well. Semilog and log-log production plots shown in Figs. 26 and 27 indicate that there was a significant rate fluctuation after a workover/recompletion that occurred in 1968. The data set was reinitialized in time to eliminate this data "spike". At the time of its conversion to injection, there had been no visible response to Unit water injection that began in 1987.

Type Curve Analysis Results: (Fig. 28 and 29)

We now consider the type curve matching of the rate, rate integral, and rate integral derivative functions plotted versus material balance time on the Fetkovich/McCray type curve. The three rate functions are force matched on the Arps $b=1$ (harmonic) decline stem as dictated by theory for the use of material balance time,^{17,20} and the appropriate match points are obtained.

To obtain the best type curve match, the data was reinitialized at a time of 2227 days. After reinitialization, we obtained a good match on the depletion stems and a unique match on the $r_{eD} = 800$ transient stem. From the log-log production plot (Fig. 27), we note that the transient flow period introduced by the well workover had not ended at a time of 2227 days, and the transient match should be valid. Using this dimensionless radius and the time and rate match points, we calculate values for in-place oil, drainage area, flow capacity, and skin.

Matching Parameter: $r_{eD} = 800$

$$[t_{Dd}]_{MP} = 1.0 \quad [t]_{MP} = 10,000 \text{ days}$$

$$[q_{Dd}]_{MP} = 1.0 \quad [q/\Delta p]_{MP} = 0.009 \text{ STB/D/psi}$$

Based on our estimated value for total compressibility we find:

$$Nc_t = 90.0 \text{ STB/psi}$$

$$N = 3.60 \text{ MMSTB}$$

$$A = 43.1 \text{ acres}$$

$$r_e = 773.0 \text{ ft}$$

$$kh = 12.75 \text{ md-ft}$$

$$s = -1.1$$

A pressure buildup test was performed on well NRU 3510 in 1988, and the permeability to oil was estimated to be 0.43 md, with a calculated skin factor of -1.93. For decline type curve analysis, the calculated skin factor was -1.1, and using the estimated net pay interval for the well (150 feet), the calculated permeability was 0.085 md. The large discrepancy in the permeabilities is due in large part to the fact that the decline curve calculation is based on twenty-five years of production history, while the pressure buildup results reflect reservoir pressure behavior near the well over a 250 hour period. The flow capacity in the near-wellbore region may be good, but due to the fact that this well is in an area of relatively lower reservoir connectivity compared to the surrounding wells, the flow capacity calculated from decline type curve analysis is fairly poor.

Material Balance Analysis Results: (Fig. 30)

Since there are no bottomhole flowing pressure data available, we plot the daily oil rate, q , versus N_p to find the movable oil volume. The extrapolation of the data trend to the N_p axis intercept yields a movable volume at the time when all reservoir energy has been depleted.

The calculation of movable oil volume using the q versus N_p plot yields acceptable results unless p_{wf} varies significantly. Simulated data cases were used to verify that the q versus N_p plot yielded similar results to those predicted by more rigorous plots that could be made when bottomhole flowing pressure data were available. This conclusion has also been confirmed for field data cases for which both surface and bottomhole flowing pressure data were available.¹⁷

The estimate for primary EUR was 270 MSTB. Our results indicate that approximately 44 MSTB of primary movable oil remained in the drainage area of the well when it was converted to water injection. Obviously, the actual movable oil volume will be slightly less than the volume extrapolated for production to zero oil rate.

Volumetric Analysis Results

$$N_p = 226.0 \text{ MSTB}$$

$$N_{p, \text{mov}} = 270.0 \text{ MSTB (primary EUR)}$$

$$\text{Recovery Factor} = 7.5\% \text{ (primary)}$$

The results of the type curve match and material balance analysis yield rigorous estimates for original oil-in-place and movable oil, and qualitative estimates for drainage area, flow capacity, and skin factor. The primary recovery factor calculated using the value of OOIP from the type curve match is typical for wells in this unit.

Summary

The results of the decline type curve analysis were used to generate reservoir quality maps of in-place oil, primary estimated ultimate recovery (EUR), kh , and estimated drainage area (Figs. 31-34). The total original oil-in-place for analyses of all 40-acre primary producing wells was 259.8 MMSTB. Previous estimates of OOIP for the Unit have ranged between 200 and 300 MMSTB based primarily on analogy to offsetting properties.

The estimated primary EUR for the Unit from material balance decline type curve analysis was 19.5 MMSTB, which is in close agreement with the estimate of 20.5 MMSTB made prior to unitization. The average estimated ultimate recovery for the primary wells was 142.3 MSTB, with an average primary decline rate of 7.51 percent. Estimates for the reservoir flow characteristics indicated that the producing intervals possessed extremely low effective permeability, and that the wells were only marginally stimulated with short fracture half-lengths.

The results of these analyses also show that the majority of the original primary producing wells drained areas less than 40 acres (Fig. 34). The average drainage area for all 40-acre primary wells based on an average net pay thickness of 250 feet was 22.7 acres. This gives an indication of the lack of reservoir continuity, and shows why nominal well spacing was reduced to 20 acres. The analysis of the 20-acre well production data will give an indication of how effective the further reduction to 10-acre well spacing will be. Analysis work on the 20-acre producing wells drilled between 1987 and 1991 is in progress. The analysis will most likely be limited to calculation of oil-in-place and estimation of flow capacity and skin factor. The estimation of secondary EUR will be difficult since most of these wells are not on decline.

These maps verify that the highest quality areas of the Unit are in the northwest (Section 329), and southeast (Section 5), as was the case for the geological/petrophysical analysis. In addition, there also appears to be an extremely good area to the southwest (Section 327). Each area has higher than average OOIP, kh , drainage area, and primary EUR. Due to the fact that the geologic, petrophysical, and engineering analyses have verified one another, we suggest that both the reservoir quality and continuity are comparatively better in these areas and they should be considered for flow modeling and subsequent infill drilling.

Statement on Data Quality and Quantity

Due to the fact that oil production has been commingled for a large portion of the producing life of the wells that make up the NRU, the entire Clearfork and Glorieta producing intervals were analyzed as one unit. Volumetric calculations may be affected by the existence of additional productive layers of the reservoir that were not effectively completed during primary production and not in communication with the wellbore. In addition, average values for formation and fluid properties had to be used in order to perform the analyses, and formation net pay thickness is almost impossible to determine accurately in the Clearfork due to extremely long intervals that are preferentially completed and stimulated.

The inability to complete all results with a high degree of confidence is not related to the analysis or interpretation methodologies we used, but rather, to a lack of reservoir and fluid data with which to complete these calculations. While the material balance decline type curve analyses have yielded extremely good results, we use this opportunity to again point out the importance of early and complete data collection.

Reservoir Performance Bubble Maps

An extremely simple method for identifying areas of the Unit in which we want to concentrate our efforts is the use of reservoir performance bubble maps made using a commercially available software package.²¹ As an example, we have plotted the cumulative volumes of oil and water production, and water injection prior to, and after the inception of secondary recovery operations at the NRU (Figs. 35-39). These maps can be used as qualitative indicators of relative reservoir quality because we can easily identify the most prolific producing areas and relate this to our previous geologic and engineering interpretations.

Fig. 35 shows that the most productive areas of the reservoir during primary depletion were Section 329 in the north, Section 5 in the east, and Section 327 in the southwest. High water production was limited to a few wells spaced throughout the field (Fig. 36). Secondary oil production has been extremely good along the northern and southern perimeters of the Unit, with insignificant contributions from the central region (Fig. 37). Cumulative volumes of water injected and produced have been high in both the northern and eastern sections of the Unit, with a few wells making the greatest contributions (Figs. 38 and 39).

Waterflood Performance Analysis

The NRU was developed using 40-acre five-spot patterns (1:1 injector/producer ratio) for optimum injectivity and pressure support. Sweep efficiency is still low due to the discontinuous nature of the reservoir and propagation of fractures along preferential paths (east-west) between injection wells. We require some additional tools to help delineate the nature of the problem.

We feel that the analysis of waterflood performance using conventional techniques such as Buckley-Leverett, Stiles, and Dykstra-Parsons will be difficult due to the problems associated with obtaining accurate estimates of net pay thickness in the Clearfork/Glorieta. During the next phase of the project, we will determine if these methods can be effectively used in the development of a waterflood model for comparison to 3-D simulation results. The formulation of a conventional waterflood model without performing simulation is important because it may not be economically feasible for smaller, independent operators to purchase a commercial simulation package, or obtain the training required to use it correctly.

There are many simple graphical waterflood performance evaluation techniques that can be applied in order to identify the problems that affect flood efficiency. These diagnostic plots can be made using long-term production and injection data, which should be available to all operators.

We can use a plot of daily injection rate and total fluid production rate versus cumulative water injected to estimate the current waterflood efficiency. Figure 40 shows that the injection-to-production ratio has steadily decreased since reservoir fill-up (at approximately 20 MMBW injected). Since unitization, the ratio of total injected to produced fluids is approximately 1.85:1.0. The current ratio is about 1.35:1.0, indicating that some of the injected water may still be leaving the Unit, but that recent water quality, remediation, and pattern balancing work have been fairly effective.

Jordan Plot

Jordan²² provided a straightforward graphical technique for evaluating waterflood performance using cumulative produced and injected fluid volumes. A plot of cumulative total fluid production and cumulative oil production versus cumulative water injected can be used to characterize waterflood efficiency (Fig. 41). The following "rules" can be applied to the plot to evaluate waterflood performance:

- The slope of the total fluids produced line is an indicator of sweep efficiency
- The deviation of the cumulative secondary oil produced line from the total fluids produced line at early time is indicative of early water breakthrough
- The slope of the cumulative secondary oil line is an indicator of what the eventual secondary recovery will be under current operating conditions

The low slope (< 45 degrees) of the total fluids curve indicates that the NRU waterflood has a poor sweep efficiency. The deviation of the cumulative oil production line from the cumulative total fluid production line at an extremely low volume of cumulative water injection indicates the Unit had extremely early water breakthrough. This line also appears to be nearing an asymptotic value for secondary EUR that will be lower than that predicted (20.5 MMSTB) prior to unitization.

While these results indicate early water breakthrough, poor sweep efficiency, and low secondary EUR, it should be noted that they "better-than-average" for west Texas carbonate waterfloods. Targeted infill drilling, and the optimization of completion and stimulation procedures should greatly enhance the current flood efficiency.

Hall Plot

Hall²³ provided a straightforward graphical technique for the analysis of long-term injection well performance data. The Hall coefficient, which can be 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. These are presently the primary tool utilized in decisions regarding water injection well workovers at the NRU.

From a plot borrowed from the work of Thakur²⁴ (Fig. 42), we see 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. Fig. 43 shows an example Hall plot of an NRU injection well that became plugged and was subsequently worked over to remove formation scale and wellbore fill.

We would expect to see data fall below the "normal" line if injection wells are in fracture communication, however, if the near-well regions had already been repressured at the time when fracture communication began, they would be difficult to see on the Hall plot. An example of this phenomenon is shown in Fig. 44. The Hall plot for NRU well 301 shows an upward trend in the line that appears to indicate pore plugging. However, the results of a recent pressure falloff test indicate the well is not plugged, but is in fracture communication with an offset injector. The well's injection rate has declined drastically, and the injection pressure has gradually increased over the past year.

We conclude that if injection wells are in communication with each other, we might well see an upward trend on the Hall plot similar to that caused by pore plugging, indicating that it became more difficult to maintain injectivity due to pressure support from an offset well. In addition, a sudden change in injection pressure or rate would also be indicative of offset pressure support.

We believe that in order to better identify injection well responses such as those summarized above, we need to develop type curve techniques similar to those currently used in decline curve and pressure transient analysis. Since one of the main goals of this study is to identify useful and economical data analysis methods, we will work towards developing such a method for the analysis of long-term injection data.

Reservoir Surveillance

As summarized by Robertson and Kelm,²⁵ there are a number of factors to consider when initiating a comprehensive reservoir surveillance program. These include:

- Allowing for a maximum pressure differential to exist between the producing and injecting wells without exceeding the formation parting pressure
- Performing early and continuous pressure buildup tests on the producing wells to detect formation damage and monitor reservoir pressure

- Carrying out a systematic program of cased hole surveys (temperature and fluid tracer) to monitor fluid injection profiles on a regular basis
- Utilizing continuous pressure falloff testing on the injection wells to monitor the growth of vertical fractures due to continuous injection

We will add the following as part of our surveillance program:

- Continuously monitor injection water quality to increase injection 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
- Optimize well conformance by injecting only into zones which are continuous between injectors and producers
- Implement a continuous program of completion and stimulation optimization to improve sweep efficiency
- Utilize Thermal Decay-Time (TDT) logs on a periodic basis to monitor the movement of reservoir fluids in the near-wellbore regions of the producing wells

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 operators reservoir surveillance plan. 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
- Dissolve 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 a work by Nevans, *et al.*²⁶

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.

Pressure Transient Analysis

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 (Table 5). 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 producing problems related to water-flood sweep efficiency.

The majority of the tests are pressure falloffs on injection wells, so as to minimize the loss of oil production. At present, we plan to run fifty to sixty falloff tests, and ten to fifteen pressure buildup tests. At this time, nine recent falloff tests and seventeen buildup tests recorded just after unitization (1988) are available for analysis. We have used both pressure and pressure integral data to perform semilog analysis, and log-log analysis using radial homogeneous and fractured well type curves with wellbore storage effects. The results of these analyses were then used to match simulated results generated by optimizing on the formation flow characteristics (permeability, skin factor, wellbore storage coefficient, and fracture half-length) to the raw pressure and pressure integral data.

Pressure Buildup Test Analysis

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 extremely good, however, fifteen of the tests were of sufficient quality to perform complete analyses. The results are summarized below, and example analyses for NRU wells 1008 and 3510 are shown in Figs. 45 and 46. As with the material balance decline curve analysis, we prefer to report a value for the flow capacity rather than the permeability due to the fact that the net pay thicknesses are estimated values.

Well #	kh, md-ft	Skin-Factor	X _f , feet	SIBHP, psia
201	7.5	-3.7	25.0	1033
208	28.6	-4.1	36.0	719
1008	37.0	-3.1	14.2	985
4202	49.5	-4.7	71.0	507
2217	44.6	-3.8	27.4	1350
2224	7.9	-4.1	37.0	1074
2225	2.7	-3.6	22.0	1228
804	75.6	-3.2	15.0	985
2704	14.3	-3.1	14.0	1431

2804	4.9	-5.0	90.0	1292
1506	32.8	+1.0	0.0	840
3011	61.6	-3.5	20.0	992
3510	64.5	-1.9	0.0	384
3517	78.6	-3.8	26.0	939
3523	32.4	-3.1	15.0	1199

We see that even though the majority of these wells were newly drilled, completed, and stimulated at the time of the surveys, the hydraulic fracture treatments were for the most part unsuccessful. 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 two wells (NRU 1506 and 3510) had no propped fracture length at all, and NRU 1506 appears to be damaged.

From the analysis of NRU 3510 (Fig. 46), we see that as we surmised from the material balance decline type curve analysis, the quality of the reservoir rock in the near-wellbore region is fairly good, however, a relatively low estimated bottomhole shut-in pressure indicates that this well is in a region of poor reservoir connectivity as it is more pressure-depleted than the surrounding wells (NRU 3517 and 3523).

Most of these pressure buildups were not recorded for a sufficient length of time to see any boundary or interference effects. One of our major goals for future buildup and falloff tests is to record sufficient data to be able to see these effects, and to better define the reservoir's producing mechanisms. In addition, if it is economically feasible, we will perform pressure buildups using downhole shut-ins in an effort to reduce wellbore storage effects and obtain better quality data for interpretation.

Pressure Falloff Test Analysis

The pressure falloff data was 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. Results to date have been excellent, and have helped a great deal in explaining some of the major problems associated with waterflooding a low permeability carbonate reservoir. Bottomhole pressure buildup tests will be done to verify the estimates of average reservoir pressure obtained from the injection falloffs.

The pressure falloff test is the most popular tool for monitoring waterflood pressure performance. By using surface pressure data acquisition, we feel that tests can be performed easily and economically with greater frequency. 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.²⁷

Again, in an effort to identify interference/boundary effects on the injection well falloff tests, we have made an effort to let the tests run as long as possible. We feel that 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. This may also be due to the presence of formation scale plugging or wellbore fill which can be identified from waterflood diagnostic plots.^{22,23}

Pertinent falloff test data for each of the recently completed surveys is shown below:

Well #	q_{inj} , BW/D	p_{inj} , psig	Type	Test Time, days
102	138	4570	fresh	65
295	330	4530	fresh	16
3510	260	4705	prod	38
3511	270	4580	fresh	53
301	420	4950	prod	29
401	520	4740	prod	49
702	270	4730	fresh	49
1591	125	4730	fresh	59

3004 240 4850 prod 46

Individual analyses for NRU injection wells 301 and 3510 are shown in Figs. 47 and 48. The results of all completed falloff tests are summarized here for the readers convenience:

Well # *kh*, md-ft Skin Factor X_f , feet Est. SIBHP, psia

102	32.0	-5.0	89	2950
295	130.0	-5.0	88	3730
3510	27.0	-6.7	492	3400
3511	51.0	-6.0	250	3150
301	184.0	-5.9	232	4200
401	188.0	-5.3	126	3400
702	124.0	-6.3	323	4000
1591	158.0	-6.1	281	4250
3004	210.0	-5.9	217	4000

The shut-in bottomhole pressures were estimated using the methods of Hazebroek, *et al.*²⁸ We note that these pressures approach the initial parting pressure of the reservoir (approximately 4250 psia in the Lower Clearfork), and are well above the initial bubble point pressures of both the Upper and Lower Clearfork (Table 1). The bottomhole injection pressures are all above the initial formation parting pressure.

We note that the type of water injected (fresh or produced) seems to have little affect on the longevity of the tests, however, wells with produced water injection are more likely to have pore plugging and well-bore fill problems.²⁶ The falloff time seems to be primarily a function of how much pressure support the wells are receiving from offset injectors.

Comparison of the pressure buildup and falloff tests on NRU 3510 shows how severe this problem may be. The buildup test 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. The falloff results show the well currently has an effective fracture length of 492 feet, which must be the result of continued water injection at excessive bottomhole pressures.

It appears that the fractures created by this excessive injection have propagated along the preferential fracture direction in the Clearfork, which is approximately east to west⁶. We see from a falloff test run on NRU 301, 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. 49). The existence of direct communication through the fractures between injectors will drastically reduce the sweep efficiency of the injection operation. Unfortunately, this is a common problem in west Texas carbonate waterfloods, for which injection pressures must be kept near or above the parting pressure of the reservoir to maintain injectivity.

If we are able to optimize future injection well fracture treatments by preferentially stimulating only intervals that contribute to production in offset producing wells, and are able to subsequently lower bottomhole injection pressures to avoid excessive fracture propagation, then sweep efficiency can be increased.

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 reservoir fill-up (Fig. 50). 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 in the reservoir.

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 Hall diagnostic plots and pressure falloff test analyses, not only to determine the optimum injection pressure for individual wells, but also to identify problems affecting injection well efficiency. All of these reservoir surveillance techniques can be applied easily and economically by all operators.

Optimization of Completion/Stimulation Procedures

Well Conformance

Previous completion efforts have concentrated on the completion of all intervals that were "open" in offsetting injection and producing wells, 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 work 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 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. Due to the fact that these simple pay cutoffs do not identify pay rock on the basis of reservoir rock quality or continuity, we feel that there may be additional uncontacted pay rock within the reservoir.

Fracture Design

The 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 (1200-1500 feet). This interval was completed and stimulated in two or three separate stages, depending on the characteristics of individual wells.

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 must be maintained to prevent communication between successive completion stages. Over the development history of the Unit, the number of perforations per stage have 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. Fracture jobs have been designed to create fracture half-lengths of 120 feet.

As we have seen from the analysis of pressure buildup data on some of the 20-acre producing wells drilled

in 1987 and 1988, these optimized stimulation treatments did still not create effective pressure sinks at the wellbore due to insufficient fracture propagation. Future fracture jobs must be designed to create vertically contained, fairly short, high conductivity 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 waterflood sweep efficiency. If we complete and stimulate only the most continuous layers of the reservoir, then long hydraulic fractures are not required.

Recent efforts by service companies and operators in the Permian Basin have resulted in a new fracture treatment called a "pipeline" fracture. This type of fracture treatment can be summarized as follows:

- Perforate only the top 5-10 percent at high density
- Pump normal fracture job (75,000 to 100,000 lbs of sand)
- Monitor pressures and rates carefully to ensure lateral growth and effective proppant distribution
- Initiate forced closure and flow well for cleanup
- Add additional perforations in "pay" rock intervals at normal perforation density

By utilizing this technique, the stimulation of large perforated intervals at one time is eliminated. The downward growth of the fracture is limited and the proppant material is well distributed. 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. This technique has been applied successfully in the Lower Clearfork by an offset operator. Through the implementation and design of more effective hydraulic fracture treatments such as the "pipeline" fracture, we hope to improve fracturing efficiency at the NRU.

Coiled Tubing Workovers

A workover program has been devised to work over all injectors that show significant losses in injectivity over any given six month period. Coiled tubing has proven to be a viable method of operation for cleaning out and stimulating injection wells at the NRU. The numerous casing problems encountered when entering wellbores that are now almost forty years old (original 40-acre producing wells) make conventional well workovers extremely risky and costs prohibitive. Leaking packer seats and collapsed casing strings were the major problems encountered. By using coiled tubing, injection packers are left in place, and the exposure of the casing to corrosive stimulation fluids is minimized. The results obtained from coiled tubing treatments have been about equal to those obtained conventionally, and stimulation costs have been reduced by approximately one-third.

Cased-hole Logging

Injection Wells

We plan to use radioactive tracer logs in an effort to monitor the preferential fluid movement in the near-wellbore regions of the injection wells. These surveys yield the best quantitative results for injection profiling work, can be recorded fairly inexpensively on a periodic basis, and will be one of the main components of our reservoir surveillance plan. The tracer surveys will aid in the optimization of our injection well conformance work by verifying that the intervals we utilize as the result of our integrated reservoir description are, in fact, continuous between injectors and producers, and by identifying any potential "thief" zones that might still exist in the reservoir.

The use of temperature logs would be preferable since they do not produce the radioactive residue that accompanies the use of tracer surveys, however, they are not especially effective in mature waterfloods, where there may not be a discernible downhole temperature variation due to the volume of water injected, and in this case, an extremely low initial reservoir temperature (110°F). The results of this survey would

probably only give an extremely qualitative injection profile. The use of flowmeter surveys was also considered, however, the length of time required for well stabilization does not allow for proper tool calibration and negates the use of the flowmeter for quantitative analysis, although flowing passes could be made and a qualitative interpretation could be performed.

Producing Wells

While the cost associated with recording a great number of thermal neutron capture cross-section logs (TDT) may be cost prohibitive for most operators, the periodic utilization of TDT logs is an extremely useful tool for monitoring the preferential fluid movement in the near-wellbore regions of producing wells. We will run approximately ten surveys in order to get updated fluid saturation values for some of the 20-acre producing wells drilled in 1987-1991 for use in the history matching segment of reservoir simulation.

Previous reservoir surveillance in Clearfork waterfloods has not included the use of TDT logs because they do not work well in the low porosity, low salinity conditions that exist. Advances in tool design over the past five years have produced a tool that works well in both fairly fresh water and low porosity formations. If we achieve positive results using this new generation tool, it may become a part of our reservoir surveillance and monitoring program for the NRU.

The use of ordinary gamma ray logs to identify preferential flow paths will also be considered. Depleted intervals and zones through which reservoir waters have passed are likely to be lined with uranium salts, which can be easily detected using a natural gamma ray tool. This phenomenon was noted on correlation logs recorded prior to the tomographic survey on NRU wells 403 and 207, and may be useful in delineating the reservoir flow units.

Data Acquisition - Infill Drilling

During the infill drilling phase of this project, we hope to acquire as much new data as is economically feasible 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 FMI tool to identify intervals with substantial secondary porosity and possible by passed pay
 - Use of the RFT tool to record pressure data in each of the identified reservoir 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 hydraulic fracture treatments

Geostatistical Simulation

Geostatistics will be utilized in this project to develop spatial relationships of reservoir description variables of interest at unsampled (interwell) locations across the Unit. Geostatistics was originally developed²⁹ for applications in mining engineering, and has been increasingly used in reservoir engineering to characterize reservoir properties.³⁰ In this paper, the geostatistical techniques to be used for the NRU project are described. A subsequent paper will describe the results.

We should be able to identify the degree of reservoir continuity by weighting input data based on the method of acquisition, quality, and scale. Reservoir properties and heterogeneities can be effectively defined using four scale levels:^{30,31}

- Microscopic
 - micro scale data
 - pore and grain size distributions
 - pore throat radius
 - rock lithology
- Macroscopic
 - core scale data
 - permeability
 - porosity
 - saturation
 - wettability
- Megascopic
 - simulator grid block scale data
 - wireline logs
 - seismic data
- Gigascopic
 - reservoir scale data
 - pressure transient tests
 - geologic model

In order to utilize the different types of data and measure reservoir properties on a common scale (such as a reservoir simulator grid block), the affect of the support volume of each data type must be accounted for. In addition, the volume scales of different types of reservoir heterogeneities must also be described in order to model reservoir performance. By utilizing an integrated modeling approach, in which personnel from all disciplines of the geosciences are involved, we will obtain the most complete reservoir description possible.

Conditional Simulation Methods

Two conditional simulation methods, simulated annealing and genetic algorithm, will be used in this project. The advantages of using conditional simulation techniques over conventional interpolation are as follows:

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 interval in terms of the total sample distribution.

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 simulation allows construction of multiple pictures of the reservoir, all observing the same constraint(s).

Simulated Annealing and Genetic Algorithm Methods

The simulated annealing and genetic algorithm methods are attractive since they are very robust and flexible and allow incorporation of various scales of data in describing the reservoir properties. This includes geological, petrophysical, cross-borehole seismic, reservoir performance, and pressure transient data. One disadvantage of the method is that the algorithms are slow and computationally intensive, however, they still run faster than conventional reservoir flow simulators with the same number of gridblocks.

These methods involve the definition of an arbitrary objective function which must be minimized. The more constraints (data types) that are imposed on the objective function, the more computationally intensive these methods become. As we intend to incorporate all available data types in order to produce the most complete reservoir description possible, these methods best satisfy our requirements. With a new generation of high-speed personal computers coming on to the market, computational demands should not be a problem, and these techniques can be used by all operators.

Approach at North Robertson Unit

The interwell distribution of primary pay, secondary pay, and non-pay rock will be generated from intrawell rock type data using the conditional simulation techniques described above. The project geologists will then review these rock type distributions and determine if they honor the geologic model developed for NRU (qualitative check). After realistic rock type distributions have been achieved, petrophysical parameters (porosity and permeability) will be assigned for each of the pay rock intervals by honoring the point data (cores and well logs), incorporating tomography data to understand the interwell changes in petrophysical properties, and by honoring reservoir performance, pressure transient, and other available engineering data.

The geostatistical analysis will be extremely useful in identifying the best infill locations within the high quality areas of the reservoir, however, the quality and quantity of data is probably insufficient to assign a relative probability of success to any particular infill well location.

Reservoir Simulation

An important objective of this project is to perform 3-D reservoir simulation for history matching, infill drilling development forecasting, and validation. The results of conventional deterministic simulation runs will be compared to the results of stochastic simulation runs (using geostatistical realizations) to optimize results. A black oil, three-phase simulator will be utilized. We will focus on three main areas:

- 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

Full-Unit vs. Partial-Unit Models

The types of models which are being 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 the decline type curve analysis.

A full-unit model will not be constructed due to the large number of wells in the Unit (259 wells), and the

need to focus on detailed flow simulation in areas with the best potential for infill drilling. By using partial-unit models, we will be able to reduce both the number and size of grid blocks to optimize results. 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 represent this vertical heterogeneity (approximately 15-20 layers).

Reservoir Performance Criteria

Reservoir performance factors have been considered to delineate the areas 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
 - Primary decline much higher than normal primary and secondary decline (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.

Selection of Modeling Areas

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

For which 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. 51. 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. These desirable areas coincide with those identified by reser-

voir performance maps generated from decline type curve analysis on the 40-acre primary producing wells (Figs. 31-34). In addition, these desirable infill drilling areas are consistent with other reservoir performance characteristics described above, such as the consideration of primary and secondary decline rates to identify areas of poor reservoir connectivity.

Four areas in the Unit have been selected for detailed reservoir simulation (Fig. 51). Areas 1, 2, and 3 have good apparent infill drilling potential. Area 4 has poor apparent infill potential but will be simulated for validation purposes. The total number of wells in each modeling areas ranges between 18 and 32 wells.

Injectors serve as boundary wells for all the simulation areas. This configuration was chosen since it is more practical to allocate injection than production in the boundary wells. Also for allocation purposes, the injection rate data are more reliable than the production data since water injection commenced more recently than production.

Reservoir surveillance activities, consisting primarily of pressure transient tests recorded to monitor reservoir pressure and formation flow characteristics, and TDT logs run to monitor water movement in the reservoir, will be focused on the modeling areas to obtain additional information for history matching and development forecasting.

Simulation Initialization

Initialization of each simulation model requires phase behavior (PVT) data and rock-fluid interaction parameters. Each of the data types required for initialization are discussed below:

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 with 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 6. The data on the table 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 this data (Table 7) 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 we have undertaken, will allow the physical processes occurring in the reservoir to be accurately modeled. By using the original data, the simulator will automatically adjust 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 can be properly represented.

Rock-Fluid Interaction Data for Initialization

Existing special core data which will be used for the simulation are primarily relative permeability data. A total of thirteen steady-state displacements for two cored wells (NRU wells 207 and 3522) have been 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 phase of the project.

History Match Criteria

Allocated production data (oil, water, gas) have been determined to be reliable and will be the primary

history match criteria. Pressure data are available for the primary depletion phase of the history match (1956-1987). The initial reservoir pressure is known, and pressures prior to water injection and during reservoir fill-up are available for 45 wells throughout the Unit (Table 5). Additional pressure data will be available from pressure falloff and buildup tests that are currently being recorded.

In the initial simulation and history match it will be assumed that there is no flux across the areas to be modeled since all of the model areas lie in multi-patterned waterflood areas of the Unit. It is possible that this simplifying no-flow boundary assumption is invalid due to suspected interwell fracture communication from pressure falloff test results. This assumption may need to be reconsidered on a case-by-case basis for each of the model areas if it is difficult to obtain a history match and it is determined that the flow boundary assumption has an important mechanistic role in the displacement process.

This project is very much a work in progress. The results of current and future analyses, specifically, geostatistical and 3-D reservoir simulation, will be summarized in great detail in a subsequent work (Part 2) during the field demonstration (infill drilling) phase.

Summary and Conclusions

As a result of this study we hope to identify useful and cost effective measures for the exploitation of the shallow shelf carbonate reservoirs of the Permian Basin. The techniques that are outlined in this work 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.

1. A detailed reservoir characterization can be performed with a minimum of core data, as long as a competent geologic model has been constructed, and there is sufficient wireline log, pressure transient, and historical production data available for analysis.
2. Aside from the cross-borehole seismic and geostatistical simulation work, all of the data acquisition and analysis techniques used for this integrated reservoir description are readily and economically available to all operators.
3. The material balance decline type curve techniques summarized in this work give excellent estimates of 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 analysis, without the associated cost of data acquisition, or loss of production.
4. In order to better identify injection well responses and improve the analysis of long-term injection data, we need to develop type curve techniques similar to those currently used in decline curve and pressure transient analysis.
5. At the NRU, we see the same problems that are associated with the majority of heterogeneous, low permeability carbonate reservoirs--a lack of reservoir continuity, low waterflood sweep efficiency, early water breakthrough, and water channeling.
6. Surface pressure acquisition during pressure falloff tests yields data of sufficient quality for interpretation even when low precision pressure gauges are utilized. This is a cheap and effective waterflood surveillance tool.
7. The preferential fracture direction at the NRU appears to be east-west. Several of the injection wells are in communication via hydraulically induced fractures resulting from long-term injection at pressures well above the fracture pressure of the reservoir.
8. Water quality monitoring should be a major part of an effective waterflood surveillance plan.
9. The results of the previous hydraulic fracture treatments at the NRU have been extremely poor, resulting in extremely short, low conductivity fractures.
10. As with all oil field operations, we recommend that quality data be taken early and often to ensure more accurate analyses and interpretations.

Nomenclature

Field Variables

Formation and Fluid Parameters:

- A = drainage area, ft²
- B = oil formation volume factor, RB/STB
- c_t = total system compressibility, psi⁻¹
- c_{ti} = initial total system compressibility, psi⁻¹
- ϕ = porosity, fraction
- h = formation thickness, ft
- S_{wirr} = irreducible water saturation, fraction
- k = formation permeability, md
- r_e = reservoir drainage radius, ft
- r_w = wellbore radius, ft
- r_{wa} = apparent wellbore radius (includes formation damage or stimulation effects), ft
- μ = fluid viscosity, cp.

Pressure/Rate/Time Parameters:

- b = Fetkovich/Arps¹⁸ decline curve exponent
- b_{pss} = constant in the pseudosteady-state equation for liquid flow
- q = oil flow rate, STB/D
- N = original oil in place, STB
- N_p = cumulative oil production, STB
- $N_{p,mov}$ = movable oil, STB
- p = pressure, psia
- p_i = initial reservoir pressure, psia
- p_{wf} = flowing bottomhole pressure, psia
- Δp = $p_i - p_{wf}$, pressure drop, psi
- r = radial distance, ft
- t = time, days
- t = N_p/q , material balance time, days

Dimensionless Variables: Real Domain

- q_{Dd} = dimensionless decline rate function as defined by Fetkovich¹⁸
- q_{Ddi} = dimensionless decline rate integral as defined by McCray¹⁹
- q_{Ddid} = dimensionless decline rate integral derivative function as defined by McCray¹⁹
- r_D = r/r_w , dimensionless radius
- r_{eD} = dimensionless drainage radius of reservoir
- s = skin factor for near well damage or stimulation
- t_{Dd} = dimensionless decline time as defined by Fetkovich¹⁸

Special Subscripts

- Dd = dimensionless decline variable
- MP = match point
- pss = pseudosteady-state
- i = integral
- id = integral derivative
- 0 = initial value

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Table 1 - Reservoir and Fluid Property Data for the North Robertson (Clearfork) Unit

Reservoir Properties	
Wellbore radius, r_w	0.31 feet
Estimated average gross pay interval	1200 - 1500 feet
Average net pay thickness, h	unknown
Average porosity, ϕ	0.075
Average irreducible water saturation, $S_{w,irr}$	0.30
Formation permeability, k	0.1 - 10 md
Reservoir temperature	110°F
Original nominal well spacing	40 acres
Current nominal well spacing	20 acres
Fluid Properties	
Initial saturation pressure	1700 psia (UCF) 1540 psia (LCF)
Initial formation volume factor, B	1.285 RB/STB (UCF) 1.382 RB/STB (LCF)
Initial oil viscosity, μ	1.05 cp (UCF) 0.81 cp (LCF)
Initial total compressibility, c_{ti}	12.0×10^{-6} psi ⁻¹
Initial API oil gravity at 60°F/60°F	34.4° (UCF) 39.6° (LCF)
Average formation volume factor, B	1.30 RB/STB
Average oil viscosity, μ	1.30 cp
Average total compressibility, c_{ti}	25.0×10^{-6} psi ⁻¹
Production Parameters	
Initial reservoir pressure, p_i	2625 psia (UCF) 2950 psia (LCF)
Flowing bottomhole pressure, p_{wf}	unknown

Table 3 - Rock Types Defined for the Clearfork and Glorieta Formations

Rock Type	Lithology	Dominant Pore Type	Secondary Pore Types	Average Core Porosity (%)	Average Core Permeability (md)	Recovery Efficiency (%)	Reservoir Quality	Crossflow Barrier Quality
1	Dolostone	A	B,C,D	5.41	5.52	35 - 45	Excellent	Poor
2	Dolostone	B,C	D,E	6.10	1.73	30 - 35	Good	Poor
3	Dolostone	C	D,E	4.19	0.20	20 - 30	Poor	Moderate
4	Dolostone	B	F	6.09	0.02	35	Poor	Moderate
5	Limestone	C	A,D,E,F	7.52	0.14	30 - 35 (Water Bearing)	Good (Water Bearing)	Poor
6	Anhydritic Dolostone	C,D	F	1.89	0.03	0	None	Good
7	Silty Dolostone	E,F	---	3.61	0.01	0	None	Good
8	Shale	G	---	3.73	0.01	0	None	Good

Table 2 - Pore Types Identified from Core Thin-sections, XRD, and SEM Analysis

Pore Type	Size (μ m)	Shape	Coordination Number	Aspect Ratio	Arrangement	Geologic Description
A	30 to 100	Triangular (Interparticle)	3 to 6 (Moderate)	> 50:1 (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	$\approx$ 6 (High)	< 50:1 (Low)	Interconnected	Inter-crystalline
E	5 to 15	Polyhedral	$\approx$ 6 (High)	< 30:1 (Low)	Interconnected	Inter-crystalline
F	3 to 5	Tetrahedral	$\approx$ 6 (High)	< 20:1 (Low)	Interconnected	Inter-crystalline
G	< 3	Sheet/Slit	1 (Inter-crystalline Pore Throats)	1:1 (Inter-crystalline Pore Throats)	Interconnected	Interboundary Sheet pores - Interconnect Inter-crystalline Pores

Table 4 - Quantitative Analysis of Mercury-Air Capillary Pressure Data, after Thomeer (Ref. 11)

Rock Type	Throat Radius (μ m)	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 5 - Bottomhole Pressure Data for Reservoir
Simulation History Matching**

SECTION NO.	Prior to Utilization (3/87)		During Fillup Period (10/88 - 11/88)		End of Reservoir Fillup (7/90 - 5/91)	
	WELL NO.	SBHP (psia)	WELL NO.	SBHP (psia)	WELL NO.	SBHP (psia)
5	101	202	201	1033	307	2200
	204	653	208	719		
	304	452	307	1157		
			1008	985		
7					4103	1320
8	2901	584	4202	507	4202	1280
9	1601	564				
292	2102	268	2108	706	2108	1200
	2105	1247				
325	2203	536	2217	1350	2217	1010
	2209	1007	2224	1074	2224	2400
	2211	776	2225	1228	2225	1550
	2216	719				
326	602	375	804	985	804	2100
	2802	953	2704	1431	2704	1130
			2804	1296	2804	1410
327	1504	804	1506	840	1506	1900
	3001	372	3011	992	3013	1550
	3003	1001				
	3006	1159				
	3008	257				
	3104	776				
328	1403	320				
	1206	473				
329	3501	1958	3510	394	3517	2100
	3506	1077	3517	939		
	3516	867	3523	1199		

**Table 6 - 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 7 - Results of PVT Analysis on Original
Bottomhole Fluid Samples (Upper & Lower Clearfork)**

Fluid Properties	Well Fee B-2L	Well Fee E-4U
Zone	Upper Clearfork	Lower Clearfork
Sampling Date	July 16, 1958	January 17, 1947
"Original" Bubble Point Pressure	1,700 psia	1,540 psia
Initial Reservoir Pressure	2,625 psia	2950 psia
Oil Viscosity at Bubble Point	1.05 cp	0.81 cp
Oil Formation Volume Factor at Bubble Point	1.285 RB/STB	1.382 RB/STB
Stock Tank Oil API Gravity at 60°F	34.4°	39.6°

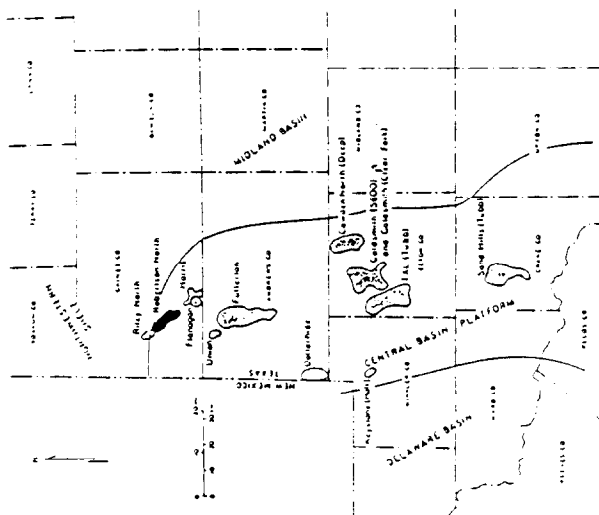


Figure 1 - Location of the North Robertson (Clearfork) Unit, Permian Basin, West Texas

WELL PRODUCTION/INJECTION (1956-1994)

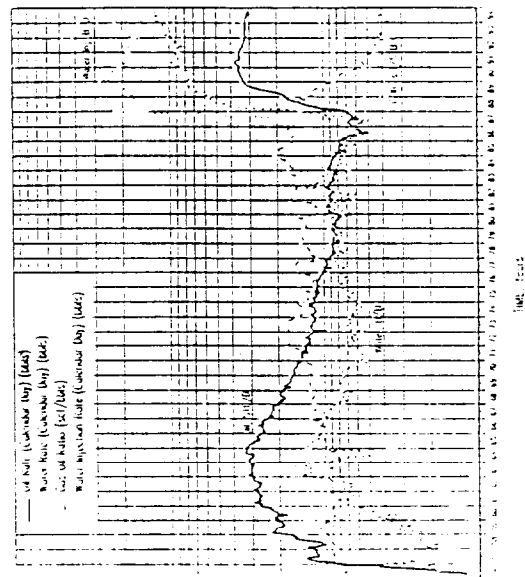


Figure 3 - Production and Injection History of the North Robertson (Clearfork) Unit

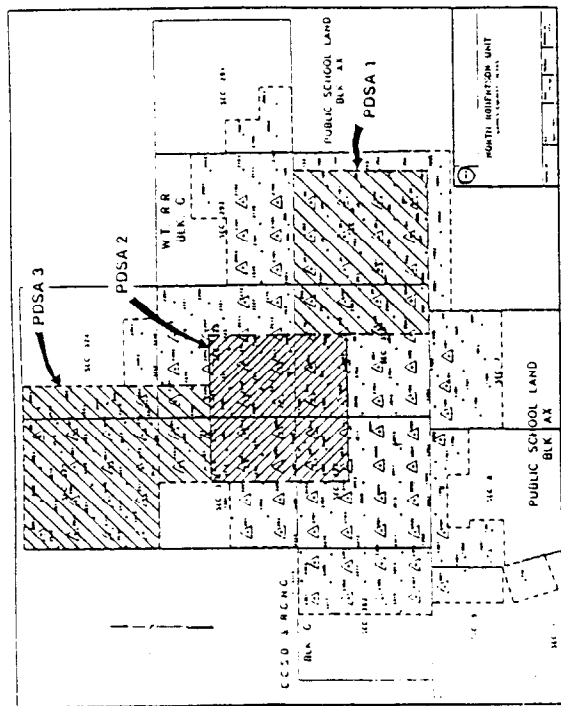


Figure 2 - Map of North Robertson (Clearfork) Unit

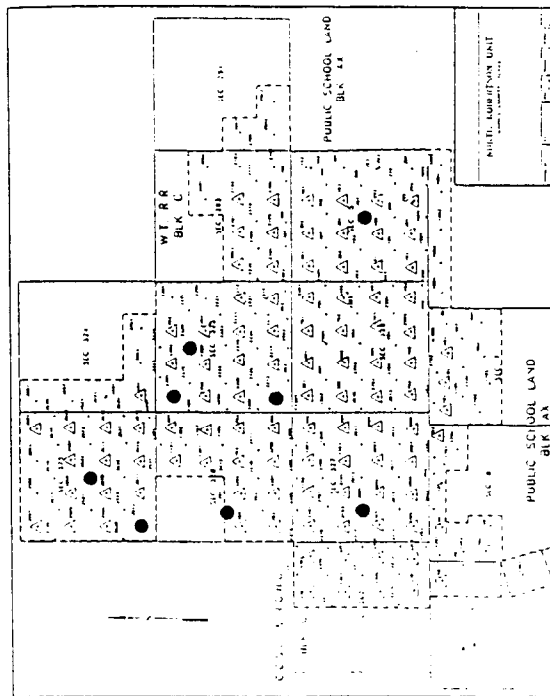
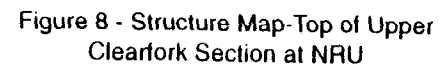
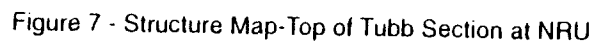


Figure 4 - Location of Cored Wells within the North Robertson (Clearfork) Unit



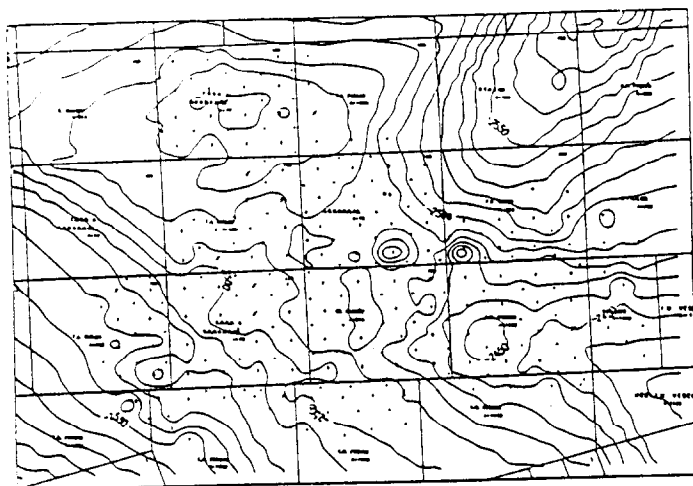


Figure 9 - Structure Map-Top of Glorieta Section at NRU

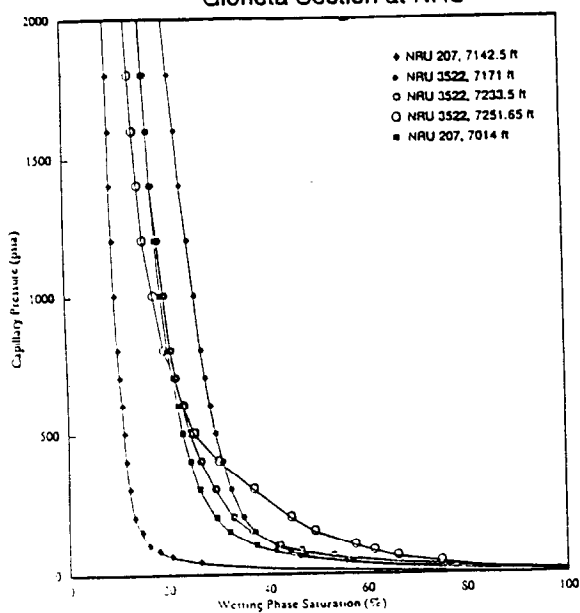


Figure 11 - Mercury/Air Capillary Pressure Curves-Rock Type 1

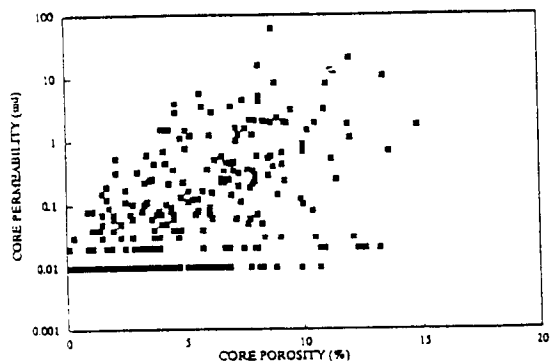


Figure 13 - Porosity/Permeability Relationship-Entire Clearfork/Glorieta Section

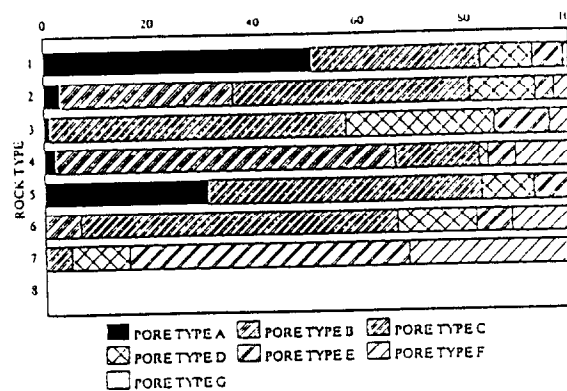


Figure 10 - Relative Volume Proportions of Pore Types (A-G) in Each Rock Type (1-8)

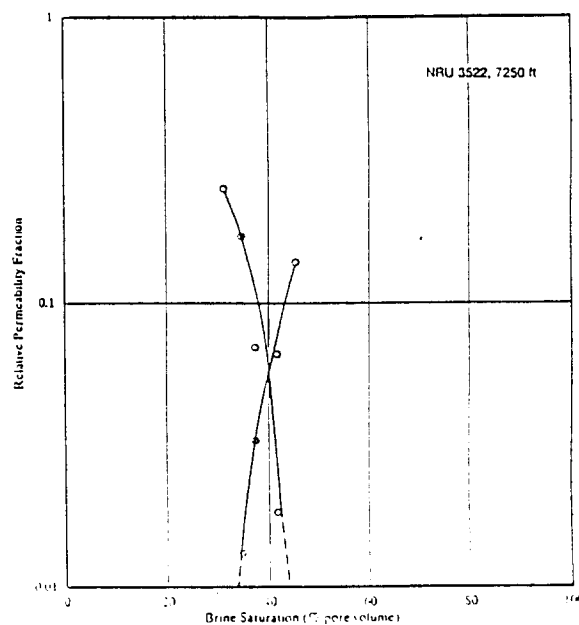


Figure 12 - Water/Oil Relative Permeability Curves-Rock Type 1

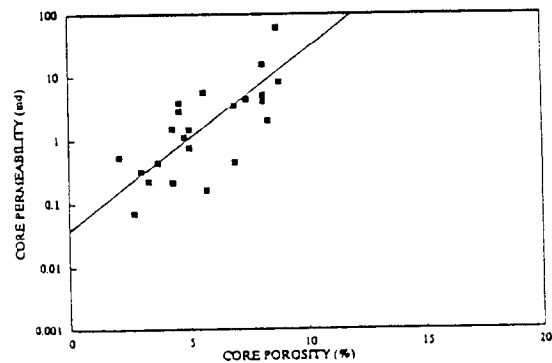


Figure 14 - Porosity/Permeability Relationship by Rock Type-Rock Type 1

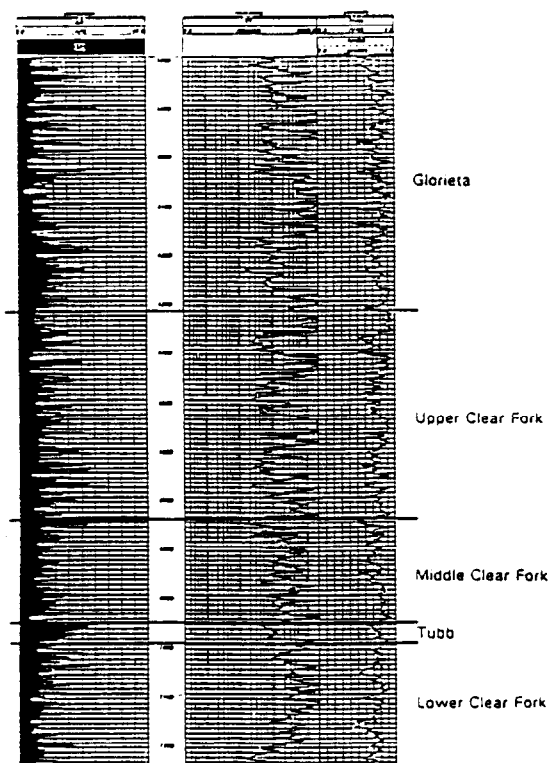


Figure 15 - Clearfork/Glorieta Type Log-NRU Well 207

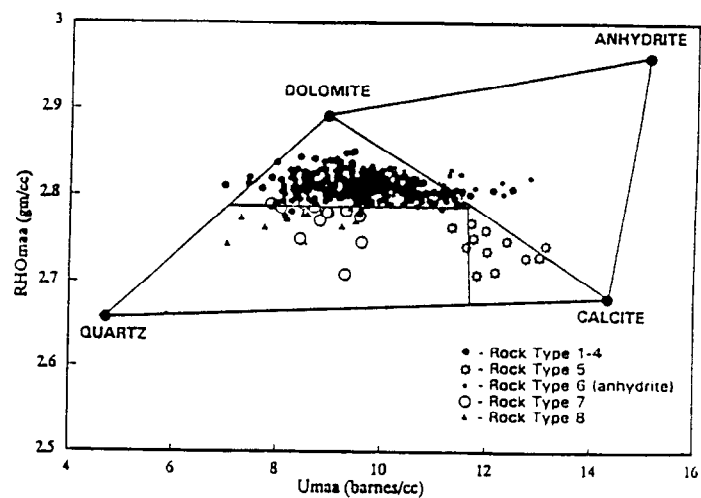


Figure 16 - Rock Type Delineation Plot

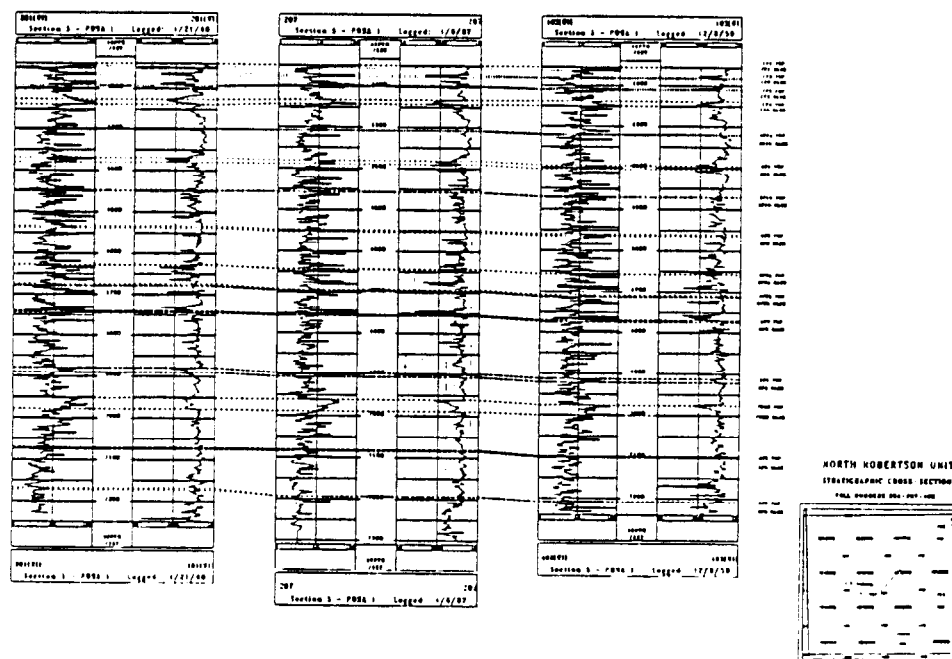


Figure 17 - Layering Scheme Developed from Core Analysis and Rock Typing

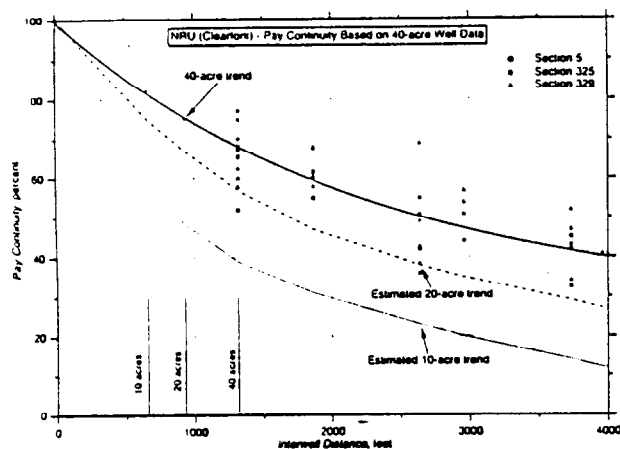


Figure 18 - Continuity Study From 40-acre Well Data-NRU Sections 5, 325, 329

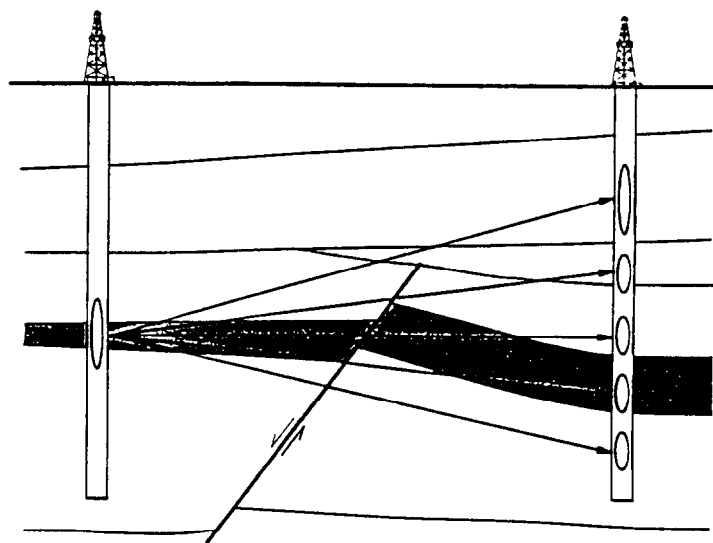


Figure 19 - Schematic Illustration of Tomographic Data Acquisition

Cross Borehole Tomography Data Acquisition

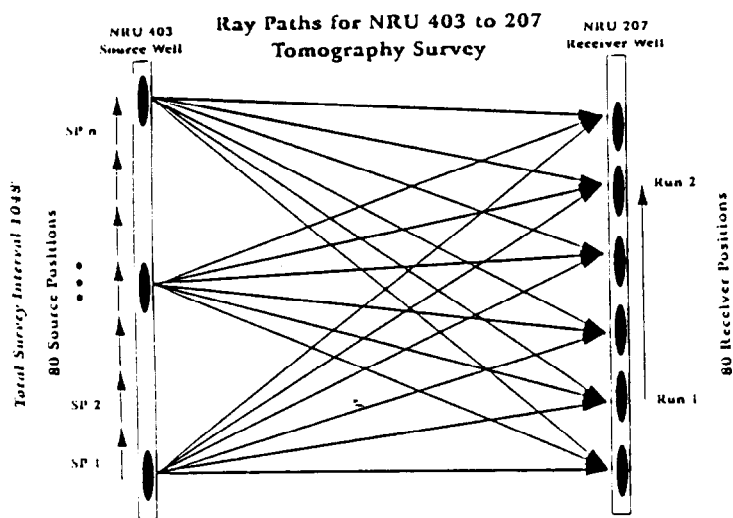


Figure 20 - Ray Paths for NRU 403/207 Tomography Survey

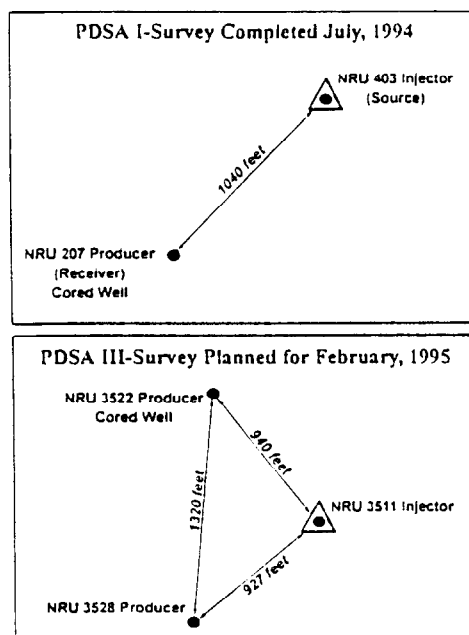


Figure 21 - Completed and Planned Tomography Work (Sections 5 & 329)

Connectivity Mapping Processing Flow Chart

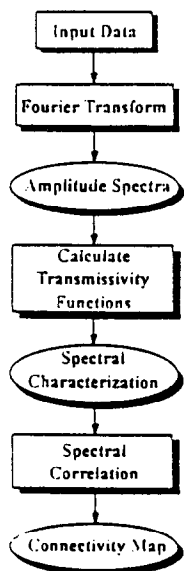


Figure 22 - Processing Flow Chart for Connectivity Mapping

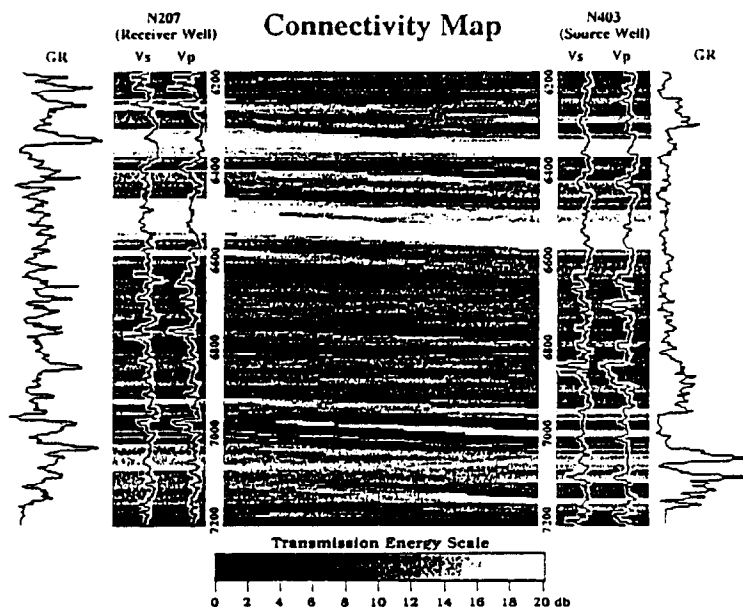


Figure 23 - NRU 403/207 Connectivity Map with Gamma Ray and Velocity Logs

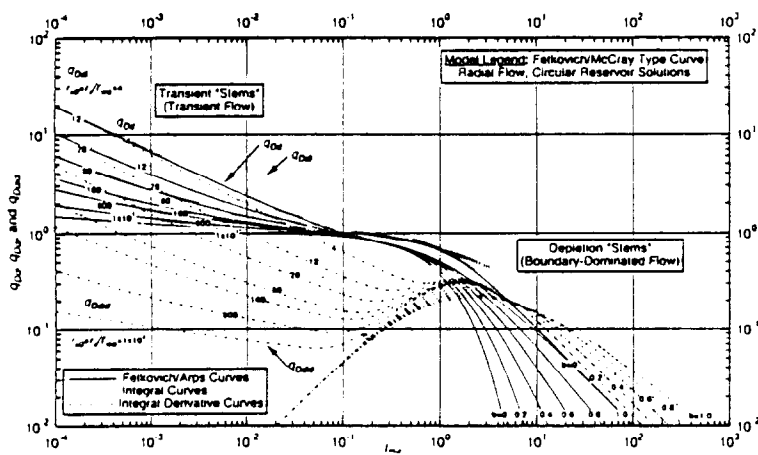


Figure 24 - Fetkovich/McCray q_{Dst} , q_{Dst} , and q_{Dst} Type Curves

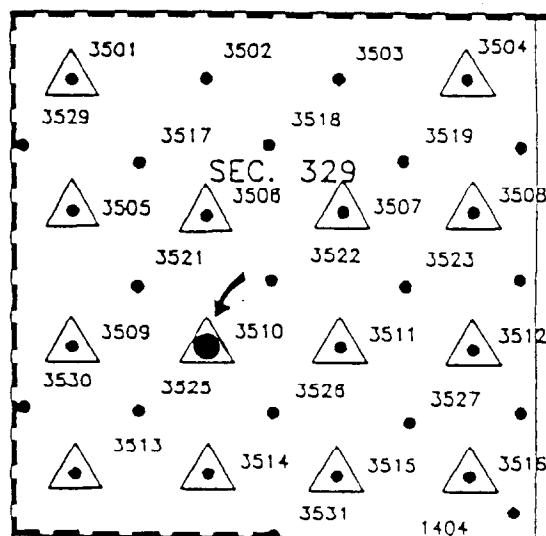


Figure 25 - NRU Well 3510-Section 329 of North Robertson (Clearfork) Unit

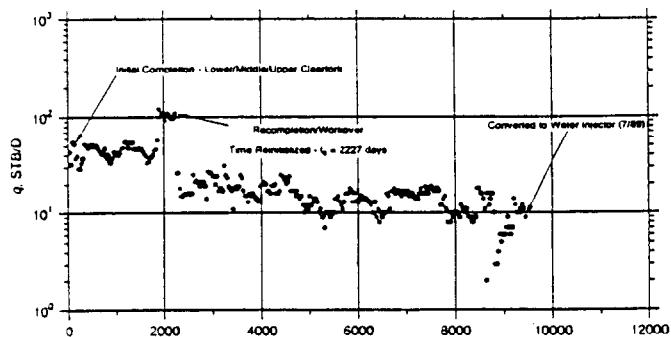


Figure 26 - Semilog Production Plot for NRU Well 3510-(Clearfork)

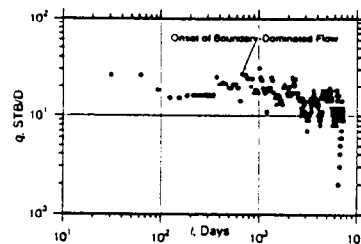


Figure 27 - Log-log Production Plot for NRU Well 3510-(Clearfork)

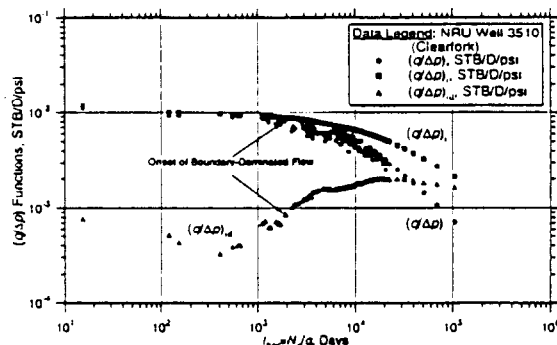


Figure 28 - Rate Functions for NRU Well 3510-(Clearfork)

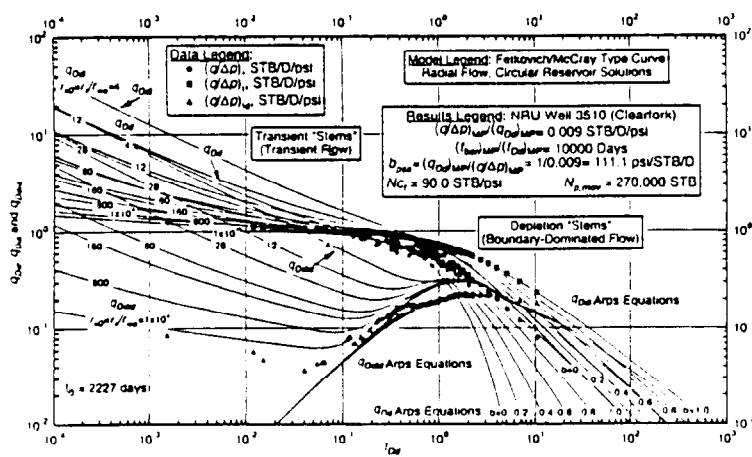


Figure 29 - Match of Production Data for NRU Well 3510-Clearfork (Radial Flow Type Curve)

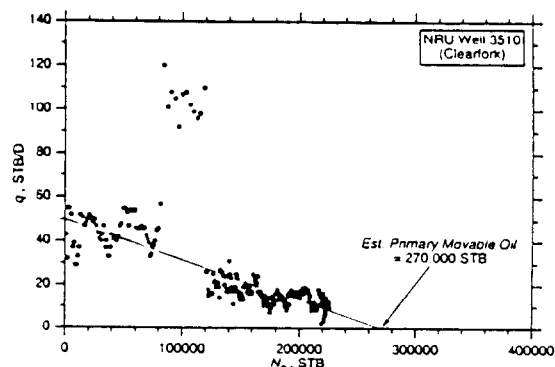


Figure 30 - Movable Oil Estimation from Rate History

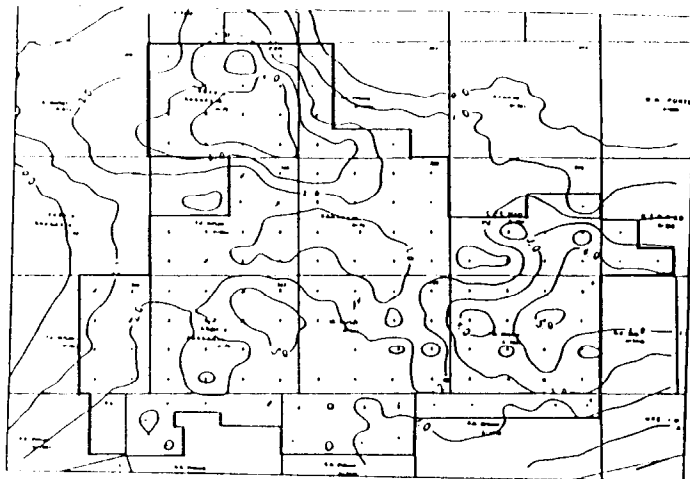


Figure 31 - Material Balance Decline Type Curve
Analysis-Map of Original Oil-in-Place, MMSTB

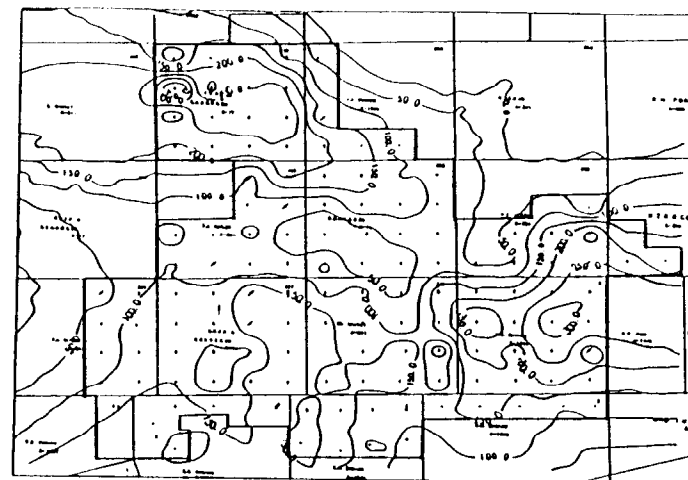


Figure 32 - Material Balance Decline Type Curve
Analysis-Map of Primary EUR, MSTB

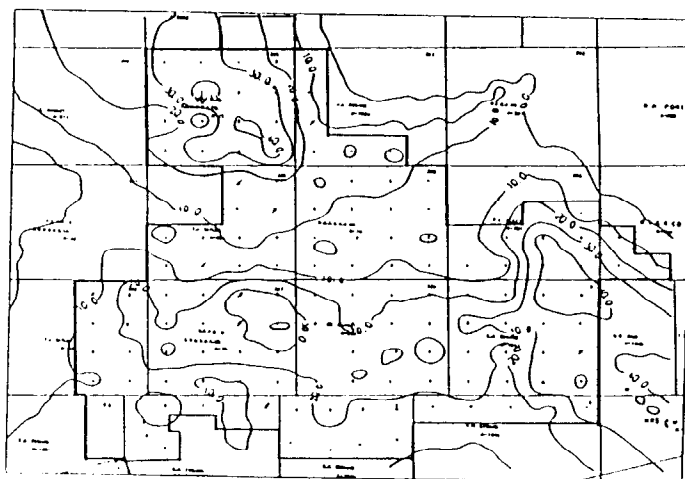


Figure 33 - Material Balance Decline Type Curve
Analysis-Map of Flow Capacity (kh), md-feet

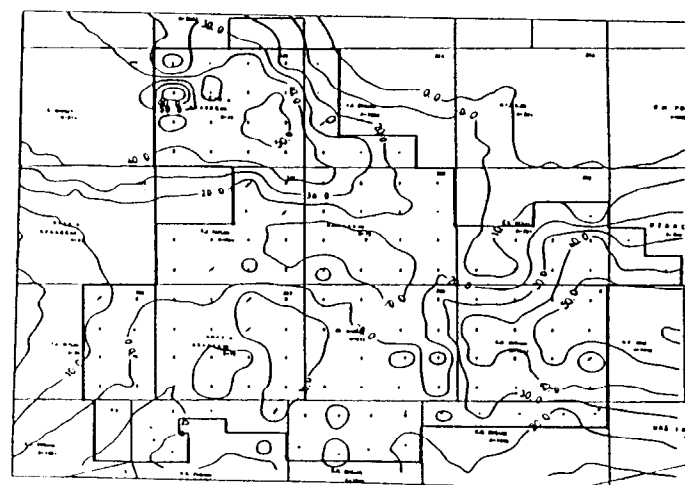


Figure 34 - Material Balance Decline Type Curve
Analysis - Map of Estimated Primary Drainage Area, acres

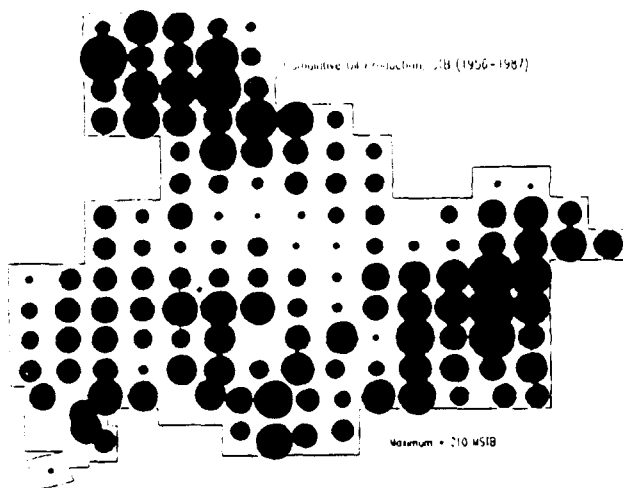


Figure 35 - Bubble Map of NRU Primary Cumulative Oil Production (1956-1987)

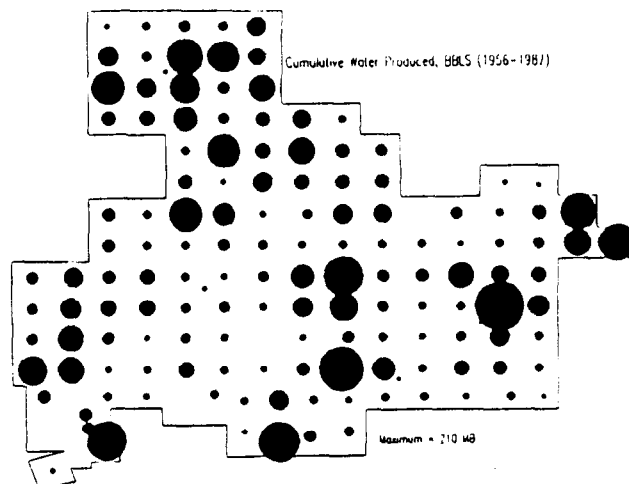


Figure 36 - Bubble Map of NRU Primary Cumulative Water Production (1956-1987)

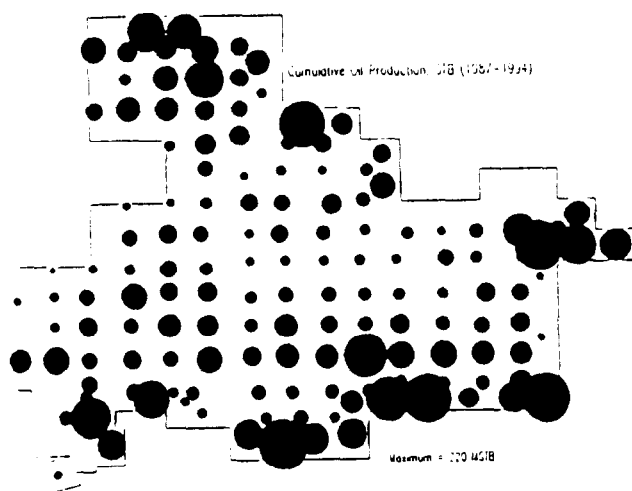


Figure 37 - Bubble Map of NRU Secondary Cumulative Oil Production (1987-1994)

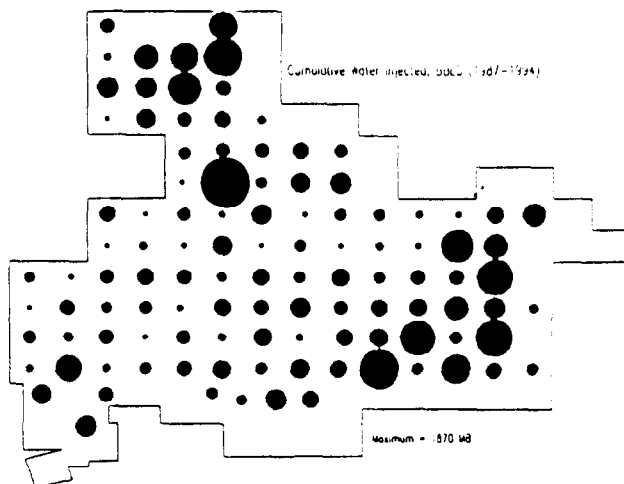


Figure 38 - Bubble Map of NRU Secondary Cumulative Water Production (1987-1994)

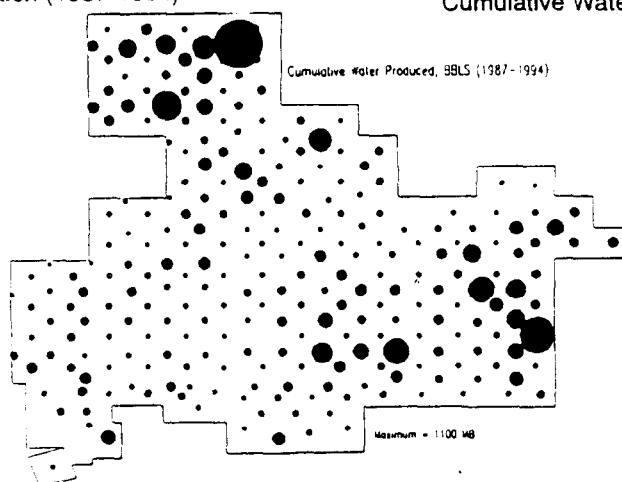


Figure 39 - Bubble Map of NRU Cumulative Water Injection (1987-1994)

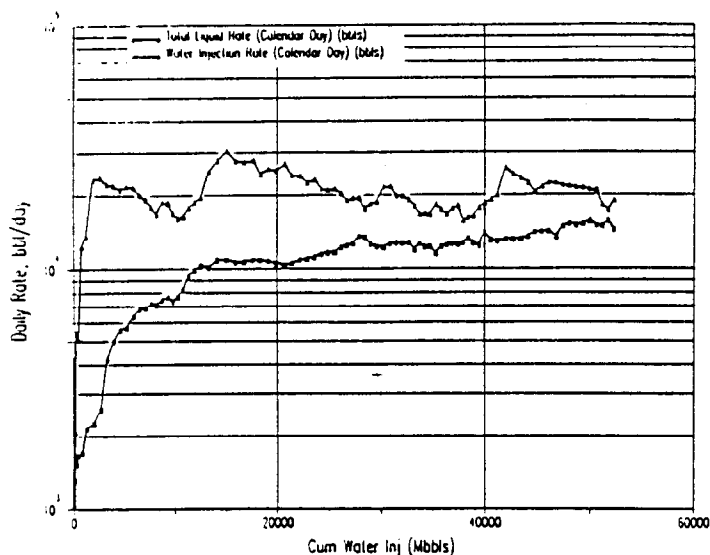


Figure 40 - NRU Daily Total Injected and Produced Fluid Volumes (1987-1994)

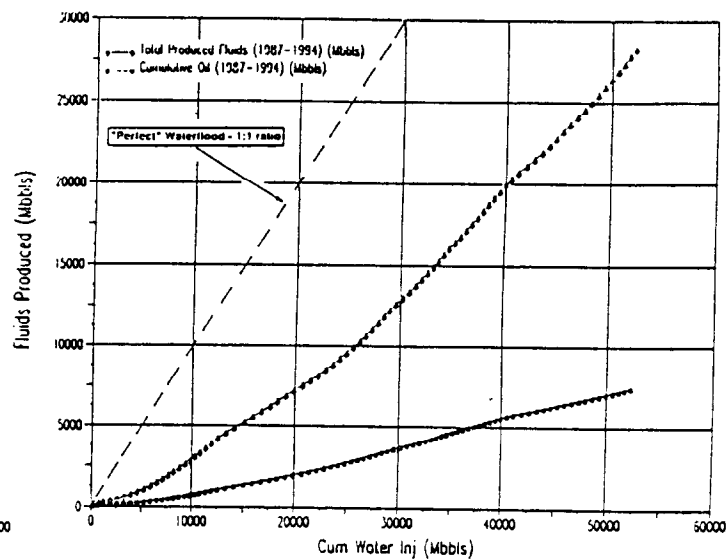


Figure 41 - Waterflood Performance Diagnostic Plot, after Jordan (Ref. 22)

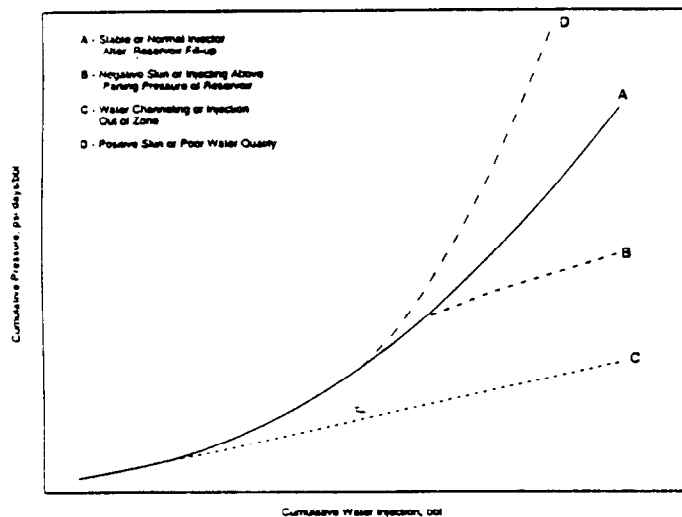


Figure 42 - Example of Hall Plot, after Thakur (Ref. 24)

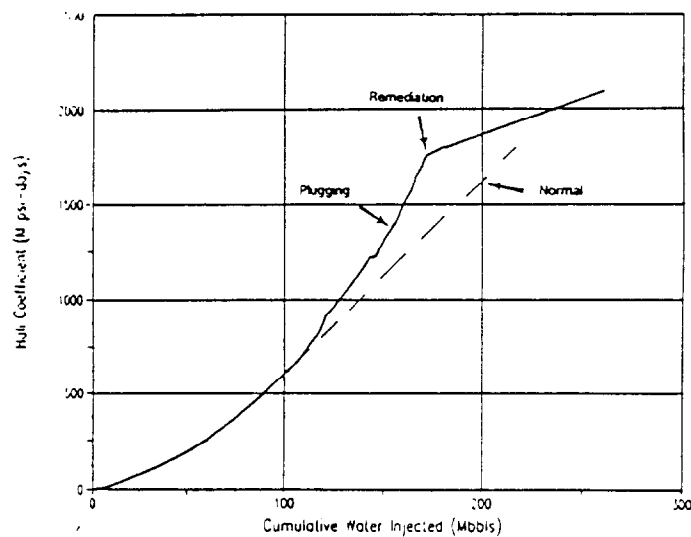


Figure 43 - Hall Plot Field Example

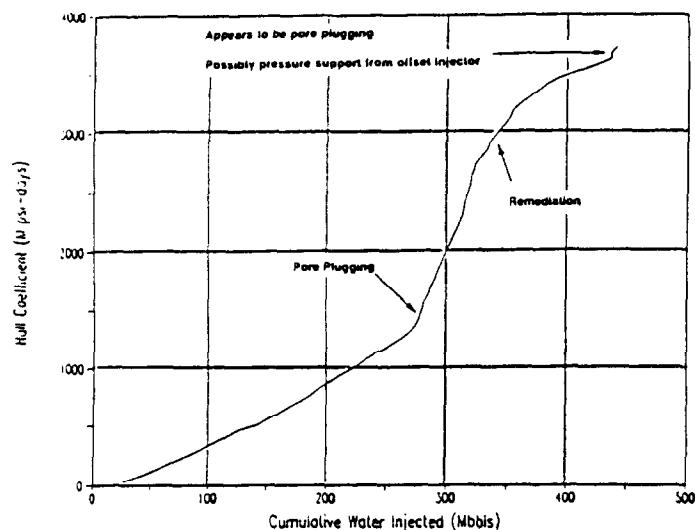


Figure 44 - Hall Plot for NRU Well 301

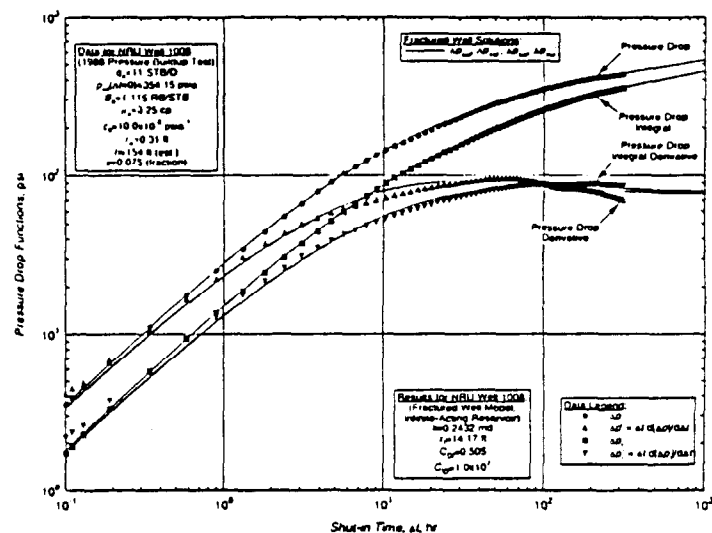


Figure 45 - NRU Well 1008 Pressure Buildup Using Derivative and Integral Analysis

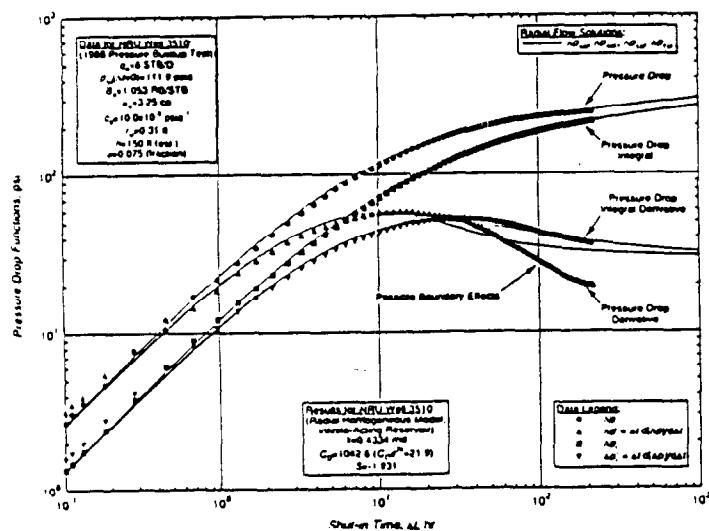


Figure 46 - NRU Well 3510 Pressure Buildup Analysis Using Derivative and Integral Analysis

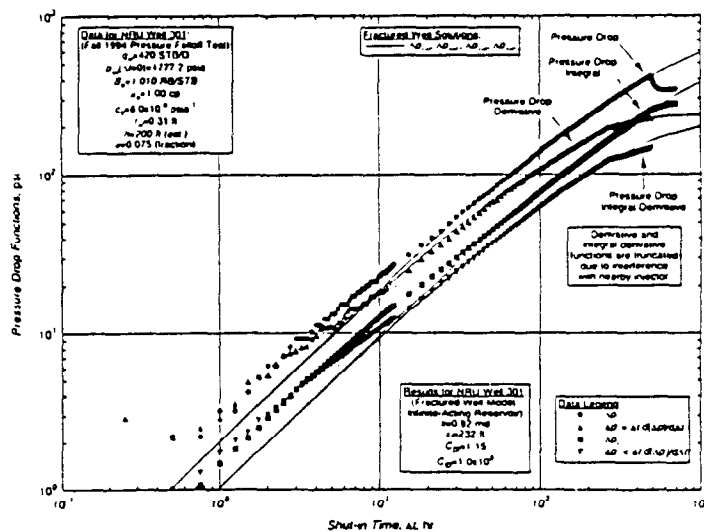


Figure 47 - NRU Well 301 Pressure Falloff Analysis Using Derivative and Integral Analysis

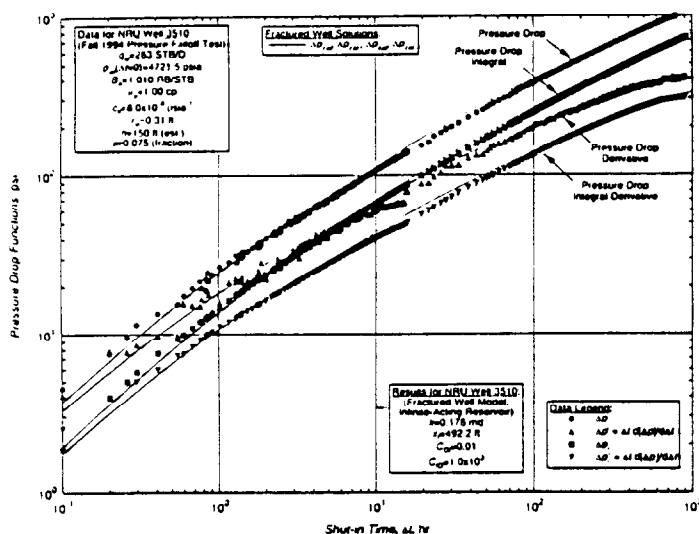


Figure 48 - NRU Well 3510 Pressure Falloff Analysis Using Derivative and Integral Analysis

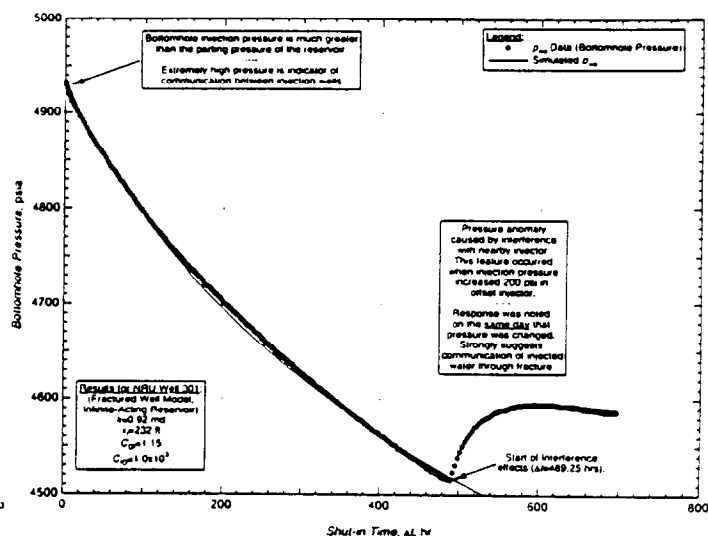


Figure 49 - Cartesian Plot of P_{ws} versus Shut-in Time for NRU Well 301 Pressure Falloff Test

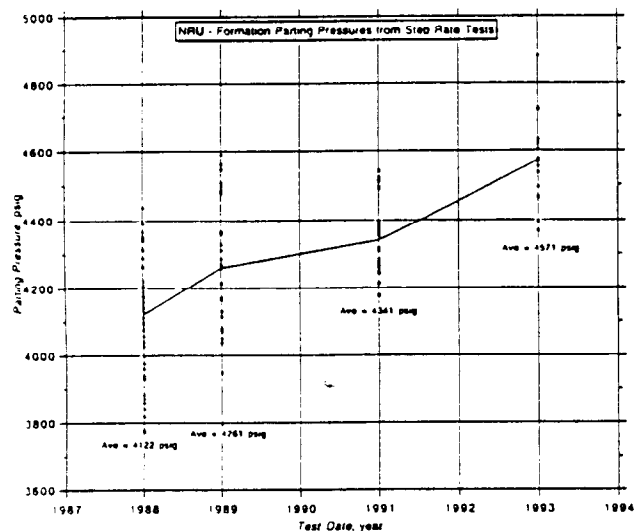


Figure 50 - Comparison of Average Parting Pressures from Step-Rate Tests (1988-1993)

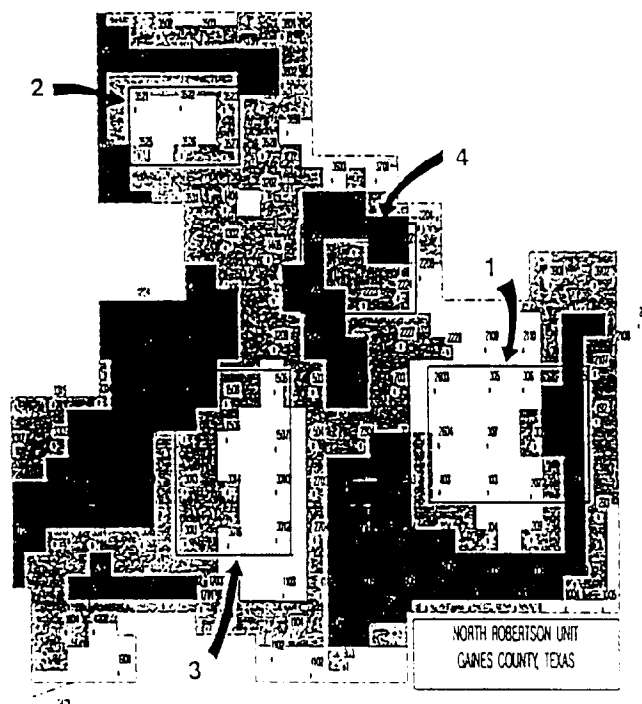


Figure 51 - Map of Partial-Unit Model Areas to be Used for Reservoir Simulation