AN INTEGRATED GEOLOGIC AND ENGINEERING RESERVOIR
CHARACTERIZATION OF THE NORTH ROBERTSON (CLEAR FORK) UNIT, GAINES COUNTY, TEXAS

Volume I

A Dissertation

by

LOUIS EDWARD DOUBLET

Submitted to the Office of Graduate Studies of Texas A&M University in partial fulfillment of the requirements for the degree of

DOCTOR OF PHILOSOPHY

December 2001

Major Subject: Petroleum Engineering
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Approved as to style and content by:

[Signatures of committee members]

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ABSTRACT

An Integrated Geologic and Engineering Reservoir Characterization of the North Robertson (Clear Fork) Unit, Gaines County, Texas. (December 2001)

Louis Edward Doublet,
B.S., Georgia Institute of Technology; M.S., Texas A&M University
Chair of Advisory Committee: Dr. Thomas A. Blasingame

An integrated geological, petrophysical and reservoir engineering study has been performed for a large, mature waterflood project (>250 wells, ~80% water cut) at the North Robertson (Clear Fork) Unit, Gaines County, Texas. Shallow-shelf carbonate (SSC) reservoirs such as the North Robertson (Clear Fork) Unit (NRU) share a number of common characteristics, including:

- Such reservoirs have a high degree of areal and vertical heterogeneity, and relatively low porosity (3 to 8 percent) and permeability (0.01 to 1 md).
- The degree of reservoir compartmentalization is significant and results in poor vertical and lateral continuity of the reservoir flow units and poor sweep efficiency.
- High permeability intervals and poor vertical continuity within the productive interval result in poor balancing of injection and production rates, and early water breakthrough in the most continuous reservoir intervals.
- Porosity and water saturation (as determined from analysis of well logs) do not always accurately reflect reservoir quality and performance.

Given these reservoir characteristics, the ability to accurately target infill well opportunities is critical since blanket infill drilling will be uneconomic in most cases.

The primary goal of this study is to develop a cost-effective integrated reservoir description for "targeted" (economic) 10-acre infill drilling and future recovery operations in a low permeability carbonate reservoir. Integration of the results from geological and petrophysical studies as well as reservoir performance analyses provide a rapid and effective method for developing a comprehensive reservoir description.
Our hypothesis is that focusing on reservoir surveillance and the optimization of completion and stimulation techniques can optimize future reservoir performance. It is our objective to demonstrate that a comprehensive analysis, interpretation, and prediction of well and field performance can be completed quickly, at a minimal cost, and that these analyses can be used to directly improve our understanding of reservoir structure and performance behavior in complex, low permeability formations.
DEDICATION

This dissertation is dedicated to Min-Yu Shih, whose hard work and ever-present smile made the analysis of a significant amount of production and injection data much easier. His untimely death was and is a great loss to us all.

This dissertation is also dedicated to my parents, who provided the constant encouragement that was the motivating factor for the completion of this work.

Finally, this dissertation is dedicated to the small independent oil and gas operators who are most likely to utilize the cost-effective analysis techniques outlined in this work. It is especially for those that continue to survive, and sometimes thrive, under sometimes trying economic conditions. They possess what is left of the pioneering spirit that our predecessors used to establish this industry.
ACKNOWLEDGMENTS

I would like to thank the U.S. Department of Energy as well as the Texas Engineering Experiment Station (TEES) and Department of Petroleum Engineering at Texas A&M University for providing me the opportunity and financial support for the five long years it took to complete this study.

I would especially like to thank Dr. Tom Blasingame of Texas A&M and P.K. Pande (formerly with Fina Oil & Chemical) of Anadarko Petroleum Corporation for the many long hours they spent initiating this project.

In addition, I would like to thank Dr. Blasingame for serving as my advisory committee chairman, as well as Dr. James Russell, Dr. Ching Wu, Dr. Wayne Ahr, Dr. John Gidley and Dr. Newell McArthur for serving as committee members.

The completion of this dissertation would not have been possible without the aid and encouragement of a number of people to whom I am eternally indebted:

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Dr. Peter Valko of Texas A&M University for providing insight and some of the software analysis tools utilized to complete this study.

Orville, Duane and Douglas Gaither of Gaither Petroleum Corporation for allowing me to take a leave of absence from work in order to complete my degree.
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CHAPTER I

INTRODUCTION

Production at the North Robertson (Clear Fork) Unit (NRU) is taken from the Lower Permian Glorieta and Clear Fork carbonates. The reservoir section is thick, with a gross height of approximately 1,300 feet and more than 90 percent of the interval has fairly uniform lithology (dolostone). This interval is characterized by a complex pore structure that is the result of extensive vertical layering and post-depositional diagenesis. The reservoir section consists of discontinuous pay intervals with high residual oil saturations (35 to 60 percent, based on steady-state measurements of relative permeability). The primary hydrocarbon-bearing interval extends from the base of the Glorieta to the base of the Lower Clear Fork, between correlative depths of approximately 6,160-7,250 feet. The Glorieta interval makes only a minor contribution to the total hydrocarbon production in most areas of the NRU, and will not be considered in this study.

1.1 – Historical Background

The NRU is located in Gaines County, west Texas, on the northeastern margin of the Central Basin Platform (Fig. 1.1). The unit includes 5,633 surface acres containing a total of 270 wells (August 1998). This includes 156 active producing wells, 113 active injection wells, and 1 fresh water supply well.

Production from the North Robertson Field began in the early 1950’s with 40-acre primary well development. This 40-acre primary development resulted in 141 producing wells by 1965. The North Robertson Unit was formed effective March, 1987 for the purpose of implementing waterflood and infill drilling operations and nominal well spacing was reduced from 40 acres to 20 acres. Secondary recovery (waterflooding) 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.

This dissertation follows the style of the *Journal of Petroleum Technology*. 
The well configuration at the NRU is an East-West staggered line-drive pattern, and was developed for optimum injectivity and pressure support. Sweep efficiency is difficult to quantify due to changes in depositional environment and the degree of post-depositional diagenesis that vary throughout the unit.

Original oil-in-place has been estimated to be between 200 MMSTB and 300 MMSTB.\(^1\) Individual well recovery efficiencies are between 5 and 10 percent for both primary and secondary (waterflood) recovery operations. Fig. 1.2 shows the production and injection history of the unit from development in 1956 through December 1999. The total oil and water volumes produced and injected since field development are shown in Table 1.1, below.
Table 1.1 – NRU cumulative production and injection.

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<th>Time</th>
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<th>Water Produced (MMBW)</th>
<th>Water Injected (MMBW)</th>
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<tr>
<td>As of June 1987 (primary)</td>
<td>17.5</td>
<td>8.2</td>
<td>0.0</td>
</tr>
<tr>
<td>July 1987-Dec. 1999 (late primary &amp; secondary)</td>
<td>13.0</td>
<td>44.5</td>
<td>87.3</td>
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Figure 1.2 – NRU production and injection history.

1.2 – Literature Review

There are many complicated factors that will affect the successful implementation of infill drilling programs in heterogeneous, low permeability carbonate reservoirs such as the Clear Fork interval at the NRU. We have conducted an extensive literature review to gain a better understanding of the producibility problems we will encounter in this study. Fortunately, this formation has 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 Clear Fork and other analogous reservoirs.
In a 1974 case study concerning waterflooding operations at the Denver (San Andres) Unit, Ghauri, et al.² gave valuable insights concerning reservoir discontinuity, injector-to-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, Stiles³ summarized the difficulties encountered in waterflooding operations at the Fullerton (Clear Fork) 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 describe the phenomenon that occurs when the most permeable layers of the reservoir achieve reservoir fill-up, while a significant gas saturation still exists 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.

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

In a 1978 review of west Texas carbonate reservoir waterflooding operations, George and Stiles⁴ outlined their recommendations for optimizing waterflood operations in the Means (San Andres), Fullerton (Clear Fork), and Robertson (Clear Fork) 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 achieve optimal reservoir development.
A "rock-log" model was formulated for the Robertson (Clear Fork) using a limited amount of core data and old gamma ray/neutron well logs that were available field-wide. Original oil-in-place (OOIP) was calculated using both volumetric and material balance methods. George and Stiles 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 allows consideration of 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 less than the amount of continuous pay, and contact with both could be optimized through infill drilling. The authors concluded that floodable pay must be continuous between injection and producing wells, must be injection supported, and should be effectively completed at the producing well.

In a 1980 summary of work completed at the Denver (San Andres) Unit, Ghauri 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 gave great detail in 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 were also highlighted.

Barber, et al. 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 effect 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 likely to be extremely pessimistic.

In 1987, Barbe and Schnoebelen \cite{7} summarized the results of an aggressive infill drilling program in the Robertson (Clear Fork) Unit. The authors found that obstacles associated with poor reservoir continuity in heterogeneous, low permeability carbonate reservoirs would likely only be overcome through infill drilling on a reduced nominal well spacing. In addition, reservoir performance data analysis and pressure transient test results indicated a roughly east-west directional permeability and fracture azimuth. Pay continuity was quantified using geological, reservoir performance, and pressure transient data. Wireline formation test results showed individual layers had widely different formation pressures, indicating a lack of vertical continuity within the Clear Fork.

The authors also concluded that the best 10-acre and 20-acre producers were in the same areas as the best 40-acre producers. This indicated 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.

1.3 – Research Objectives

The primary objective of our work is to introduce and summarize new and existing technologies that can be utilized to perform a thorough geologic and engineering reservoir characterization. These characterization techniques can be economically implemented by \textit{any} operator, regardless of the size of their operation. These analyses will allow the prediction of infill well locations on an areal basis and the identification of reservoir "pays" on a vertical basis. In addition, techniques will be introduced for the optimization of completion and stimulation operations in a low permeability, carbonate reservoir. This integration of "rock" data and the reservoir performance attributes uses existing data and can eliminate the need for "evaluation" wells, as well as avoiding the loss of production that occurs when wells are shut-in for testing purposes.
1.4 – Research Procedure

The following analyses will be performed as part of this study:

- **Geological/petrophysical analyses:** (core and well log data)
  - "Rock typing" based on qualitative/quantitative visualization of pore-scale features, and characteristic well log responses.
  - Development of a "core-log" model to estimate permeability using porosity and other properties derived from well logs. The core-log model will be based on "rock types."
  - Construction of a "core-log" transform to utilize rock mechanical property data derived from well logs to aid in the design of well stimulations (i.e., hydraulic fracture treatments).

- **Engineering analyses:** (production/injection history, pressure transient tests)
  - Material balance decline type curve analyses will be performed to estimate total reservoir volume, formation flow characteristics (flow capacity, skin factor, and fracture half-length), and indications of well and/or boundary interference.
  - Estimated ultimate recovery analyses will be performed to yield movable oil (or injectable water) volumes, as well as to indicate well and/or boundary interference.
  - Conformance studies using injection profiles and repeat formation test data.
  - Pressure transient test analyses will be utilized to provide estimates of flow capacity, indications of formation damage or stimulation, estimates of drainage (or injection) volume, and reservoir pressure.
  - Optimization of well completions and hydraulic fracture treatments.

- **Data Integration:**
  - Combine geologic, petrophysical and engineering data analyses to predict future performance and to identify infill drilling locations.
CHAPTER II

RESERVOIR GEOLOGY

The ability to accurately define reservoir "pay" intervals is absolutely essential in order to rigorously model flow processes in low permeability, complex carbonate reservoirs. A very significant problem with regard to completing both producing and injection wells at the North Robertson (Clear Fork) Unit (NRU) is the correct identification of these reservoir pay intervals, or the vertical sections of the reservoir that will produce hydrocarbons at economic rates and in economic volumes. Net pay can be easily estimated using volumetric or material balance techniques when historical production data are available, however, what we actually need to know prior to well completion is what intervals we should focus on when we perforate and subsequently hydraulically fracture any particular well.

The correct identification of these intervals becomes much more difficult in a complex carbonate reservoir that possesses many different types of porosity that are a function of the pore geometry, and usually include interparticle (intergranular or intercrystalline), vuggy (moldic, fenestral, etc.) and fracture porosity. The pore types and pore geometries discussed in this work follow those defined by Choquette and Pray, but will not be discussed in great detail here.

For many reservoir systems, permeability is an excellent indicator of reservoir pay and can be predicted directly from porosity using simple functional relations (often log $k$ versus $\phi$). These relationships can be improved if the reservoir is layered or divided into "flow units," which are reservoir sequences with similar reservoir characteristics (porosity, permeability, capillarity, etc.). Unfortunately, the multiple pore geometries that exist within the Clear Fork at NRU result in a very complex relationship between porosity and permeability (if such a relationship even exists). For this reason, we believe that it is necessary to segregate the reservoir into even smaller sub-units that
have similar pore geometry and lithology, since even individual flow units usually contain rock with distinctly different reservoir characteristics.

Historically, porosity and water saturation cutoffs were utilized to pick perforations at NRU. For the most part, those intervals with good porosity are the reservoir pay intervals—however, this practice may lead to bypassing reservoir intervals with fairly low porosities that have substantial permeability. This may have also resulted in the inclusion of intervals that have good porosity, but little connectivity (i.e., vuggy, moldic or fenestral porosity). In addition, the water saturation cutoff of 55 percent was based on using Archie's water saturation equation, assuming constant values for cementation factor, $m$, saturation exponent, $n$ and formation water resistivity, $R_w$, all of which vary significantly across the vertical extent of the reservoir.

Later in this work, we explain why the practice of using porosity and water saturation cutoffs may be an acceptable technique for choosing completion intervals. In fact, it may not be necessary to break the reservoir interval into more than just four or five sub-units. This will result in a more cost-effective (and practical) reservoir study.

**2.1 – Geologic Description**

The Clear Fork at the NRU is a shallow shelf carbonate (SSC) Leonardian Series reservoir (Fig. 2.1) located on the northeastern edge of the Central Basin Platform of the Permian Basin of west Texas. These reservoirs are typically very heterogeneous, both laterally and vertically, which results in a high degree of reservoir discontinuity and low recovery efficiencies.

275 feet of whole core from the 10-acre infill wells were quantitatively analyzed, and we had approximately 2,730 feet of core from four wells that were visually described on a foot-by-foot basis. We used these core data to accurately describe the various depositional environments that exist at the NRU. These new data were used together with approximately 6,500 feet of existing core data (from 40-acre development wells and 20-acre infill wells) to help quantify the extent of small-scale vertical and lateral heterogeneity, to refine the depositional model, to improve models for the prediction of
reservoir quality (i.e., porosity and permeability) and to enhance our ability to model fluid movement within the reservoir.

The depositional environments found within the Clear Fork section are those of a low-relief shoreline and shallow-marine shelf associated with an eastward-dipping, wave- and storm-dominated platform margin. Reservoir heterogeneity at the NRU is a function of rapid (in terms of geologic time) and frequent changes in sea level that produced numerous shallowing-upward cyclical deposits with complex stacking patterns and often abrupt lateral changes in lithofacies. In addition, primary depositional porosity types were subsequently altered by post-depositional diagenesis.

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Figure 2.1 – Stratigraphic units for the Permian Age on the Central Basin Platform.

These rapid sea level changes occurred over an area with little topographic relief. Localized highs with relief of only a few feet allowed the development of shallow water shoals within many different depositional environments from outer-marine open-shelf to tidal flat. Wave and current action organized peloidal, oolitic, carbonate sand and bio-
clastic debris into grainstone and packstone lithofacies. Subsequent changes in sea level allowed these lithofacies to be reworked and re-deposited in nearby paleotopographic lows. Therefore, both the high relief and low relief deposits have the potential for good porosity and permeability development, although the depositional lows are more mud-dominated, and for the most part, have relatively poorer reservoir characteristics. During periods of sea level decline, the topographic highs were subaerially exposed. This caused the formation of grain-dominated rock and the acceleration of reflux dolomitization and other diagenetic processes that resulted in the generation of rock with excellent reservoir characteristics that is typically the primary reservoir pay.

There are several significant new features described from the new whole core samples that were not noted in previous core descriptions. The first is the presence of large patch reefs and associated porous debris aprons in the Lower Clear Fork. Previous work suggested that a "shelf" edge existed on the east flank of the unit and that the large reefs would only exist along this shelf edge. This new core information implies that there is no shelf edge as such, just patch reefs and debris aprons scattered across the unit. This information could help explain the erratic distribution of good producing wells in the south-central portion of the unit. It is important to note that the debris aprons and shoals around these reefs typically have good reservoir quality. In addition, smaller and poorly developed reefs and bioherms have been noted in the upper portions of the Middle Clear Fork and Upper Clear Fork.

The second new feature described from core concerns the small sections of the Middle Clear Fork (+ 6,850 feet) that have been reinterpreted as solution collapse breccia with associated open natural fractures. These features were caused by dissolution of carbonate beneath extensive exposure surfaces. The existence of these surfaces is supported by the presence of coal beds, abundant "fresh" water plant debris zones, erosion lag soils and some root casts. Parts of the unit were only partially exposed, most probably as a series of small islands and associated carbonate sand beaches. This information is of important economic significance, because there is more natural fracturing within the
Middle Clear Fork interval than previously thought. Further analyses will determine the interconnection and influence of this natural fracturing on reservoir performance, if any.

2.2 – Depositional Environments

The primary environments of deposition for the Glorieta and Clear Fork at North Robertson are shown in Fig. 2.2. These and other significant environments of deposition are summarized below.

![Figure 2.2 – Idealized depositional model for the Clear Fork Formation.](image)

Open Marine (Fig. 2.3) – Grainstone-wackestone sediments that are bioturbated and/or burrowed with various types of allochems that were deposited seaward of the reefs and bioherms. The available core plug data indicates that the open shelf deposits have poor reservoir characteristics, and that there is very little of this depositional environment in the central regions of the NRU where the cored wells are located.
Figure 2.3 – Permeability-porosity relationship for open marine deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.

**Shoal** (Figs. 2.4–2.5) – Grainstone deposits with allochems composed primarily of fusulinids, bryzoans, skeletals, peloids and rare onkalites. Original sedimentary structure has been destroyed by dolomitization. Lack of depositional anhydrite and carbonate mud suggests deposition in a high energy, open marine environment. The available core plug data indicates that the shoal deposits contain some rock with fairly good reservoir characteristics. In addition, there are significant amounts of shoal deposits in the area around NRU #3533.
Figure 2.4 – Grainstone shoal with numerous pellets and fossil allochems – NRU 3319 (Lower Clear Fork).

Figure 2.5 – Permeability-porosity relationship for grainstone shoal deposits from quick plug core data from NRU wells 1509, 1510 and 3533.
Fusulinid Shoal (Fig. 2.6) – Grainstone shoals with fusulinids as the primary allochem. These differ from shoal deposits due to a strong bimodal porosity distribution that is a result of the presence of both moldic and intercrystalline porosity. Permeability varies greatly depending on which type of porosity is present. These deposits are not widespread as the lack of core plug data indicates.

![Figure 2.6 – Fusulinid shoal with numerous pellets and fusulinids – NRU 1509 (Lower Clear Fork).](image)

Intershoal (Figs. 2.7–2.8) – These regions exist laterally to grainstone shoals and contain relatively fewer allochems and substantially more carbonate mud. The available core plug data indicates that the intershoal deposits contain rock with poor to moderate reservoir characteristics, and that there is very little of this depositional environment present in the areas where the cored wells are located.
Figure 2.7 – Intershoal wackestone-packstone with pellets, fossil fragments and varying amounts of carbonate mud – NRU 3319 (Lower Clear Fork).

Figure 2.8 – Permeability-porosity relationship for intershoal deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.
Reef (Figs. 2.9–2.10) – Wave-resistant framestone containing a great number of bryozoans and rugose corals encased in carbonate mud. Clams, brachiopods, gastropods, crinoids and fusulinids are also present. Very well developed at the bottom of the Lower Clear Fork section at NRU. Available core plug data indicates that reef center deposits contain rock with fairly poor reservoir characteristics, and that there is very little of this depositional environment present in the areas in which the cored wells are located.

Figure 2.9 – Reef with rugose coral (upper left of slab) and dense white bryozoan in near growth position – NRU 1509 (Lower Clear Fork).
**Reef Center Facies**

Figure 2.10 – Permeability-porosity relationship for reef center deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.

**Reef Talus** (Figs. 2.11–2.12) – Adjacent to reef on lagoon (landward) side and contains grainstones with fairly steeply dipping bedding planes (away from reef). These grainstones are primarily deposited during storms and may contain rounded clasts of consolidated reef debris within their framework. Reservoir quality for this environment is typically fair to poor as indicated by available core plug data.
Figure 2.11 – Reef talus grainstone with prominent bedding – NRU 1510 (Lower Clear Fork).

Figure 2.12 – Permeability-porosity relationship for reef talus deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.
Reef Debris Apron (Figs. 2.13–2.14) – Grainstone deposits containing fusulinids, skeletals and reef-building animals that are complexly interbedded with the reef talus. These deposits do not possess much in the way of internal sedimentary structure (burrowing or bedding). Although they encircle the reef, they are more likely to be found on the lagoon side where the wave energy is lower. Debris aprons possess good reservoir characteristics as indicated by the core plug data, even more so when aprons from adjacent reefs intersect to form areally extensive blankets of grainstone debris.

Figure 2.13 – Reef debris apron grainstone with numerous allochems – NRU 1510 (Lower Clear Fork).
Open Lagoon (Fig. 2.15) – Wackestone-packstone deposits that are typically bioturbated and/or burrowed and lack any significant amounts of finely distributed anhydrite. These deposits occur landward of reef debris aprons and seaward of restricted lagoon deposits. Open lagoon rocks have moderate to good reservoir quality as indicated by the core plug data, and make up a significant portion of the total reservoir rock volume.
Bioherm – Similar to reef sections, these deposits were formed in protected marine conditions and contain Archimedes bryozoans, small and poorly developed bryozoans, crinoids and fusulinids. They possess a mottled appearance due to the contrast in color between the fossils and the carbonate mud that binds them. Bioherms do not generate a talus section, but do have debris aprons that are thinner and less well developed than reef debris aprons.

Restricted Lagoon (Fig. 2.16) – Wackestone-packstone deposits with a large volume of finely distributed anhydrite, nodular anhydrite, abundant burrowing, laminations, scat-
tered rip-up layers and faint graded bedding. These deposits are potential reservoir flow barriers although the core plug data does indicate that some rocks may have moderate reservoir potential.

Island Complex (Figs. 2.17–2.18) – Wackestone-packstone deposits with root casts, desiccation cracks, whole plant fragments, little burrowing and no allochems. Some burrowing is present in sediments from high-salinity ponds at the island centers. The core plug data indicate that the island deposits may have moderate reservoir potential.

Figure 2.16 – Permeability-porosity relationship for restricted lagoon deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.
Figure 2.17 – Dense and light gray burrowed island center – NRU 3319 (Lower Clear Fork).

Figure 2.18 – Permeability-porosity relationship for island deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.
Near Island Beach (Fig. 2.19) – Packstone-grainstone sediments found at the periphery of the island complex, but more prominent on the open lagoon side. Sediments were deposited during storms and reworked by continuous wave action. These deposits consist of abundant rounded allochems with some fine plant debris and have inclined bedding features. The core plug data indicate that these sediments have moderate reservoir potential.

Figure 2.19 – Permeability-porosity relationship for island beach deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.
**Island Algal Mat** (Fig. 2.20) – Thinnily bedded deposits that are interbedded with those of the near island beach. These sediments were deposited in shallow flats surrounding the islands and are thinly bedded with fenestral texture. They have very poor reservoir characteristics and are considered to be flow barriers.

**Outer Island Beach** – Interbedded with the near island algal mat deposits. These sediments were deposited during fair weather periods and have relatively poorer reservoir quality than the near island beach rocks.

**Tidal Flat** (Fig. 2.21) – Thinnily bedded mudstone-packstone sediments with desiccation cracks, wispy mud laminations, an abundance of fine anhydrite and little or no burrowing or allochems. The rocks are typically light gray to light tan in color with a
complex sedimentary structure that is the result of small sea level changes in an area of relatively low relief. As we would expect, the core plug data indicate these rocks have poor reservoir potential and may be considered flow barriers.

![Permeability-porosity relationship for tidal flat deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.](image)

**Figure 2.21** – Permeability-porosity relationship for tidal flat deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.

**Tidal Flat Algal Mat** (Fig. 2.22) – These finely laminated tidal flat sediments are light gray in color with few if any fossils and have a fenestral texture. These rocks may also be considered to be reservoir flow barriers.
Tidal Flat Channel (Figs. 2.23–2.24) – Mudstone-packstone sediments with prominent graded bedding, high-angle planar and festoon cross bedding, abundant scoured surfaces, some lag gravels, abundant fine plant debris (often bioturbated) and finely distributed anhydrite. The core plug data indicate that these deposits have rather poor reservoir characteristics.
Figure 2.23 – Tidal channel with burrowed top and abundant carbonaceous plant fragments on top of algal mat – NRU 3319 (Lower Clear Fork).

Figure 2.24 – Permeability-porosity relationship for tidal flat channel deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.
Shallow Sub-Tidal (Fig. 2.25) – Wackestone sediments containing large volumes of silt with graded and inclined bedding, large burrows, scour surfaces and finely distributed anhydrite. The available core plug data indicates that these rocks make up a significant portion of the total rock volume and that reservoir quality is usually rather poor. However, we see that some of these sediment types may possess good reservoir characteristics, if reworked during flooding events.

Figure 2.25 – Permeability-porosity relationship for shallow sub-tidal deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.
Supratidal (Figs. 2.26–2.27) – Wackestone-mudstone sediments with graded and cross-bedding, desiccation cracks, rip-up clasts, thinly bedded anhydrite, ripple laminations, algal mats and abundant silt and plant fragments. The core plug data indicate that these rocks have rather poor reservoir quality due to poor connectivity (fenestral texture), however, they do have some storage potential (porosity).

Figure 2.26 – Supratidal mud cracks and silty dolostone – NRU 1509 (Upper Clear Fork).
Figure 2.27 – Permeability-porosity relationship for supratidal deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.

Solution Collapse Breccia (Figs. 2.28–2.29) – Not truly a depositional environment, these post-depositional features are caused by the dissolution of rock below exposure surfaces. Usually associated with the presence of coal beds, abundant fresh water plant debris, erosion lag soils and some root casts. These sediments are often found in the island areas and their associated carbonate sand beaches. The core plug data indicate that these intervals have excellent reservoir quality and are often associated with significant natural fracturing. Unfortunately, these zones are rare within the Clear Fork section.
Figure 2.28 – Solution collapse breccia with oil staining outlining broken fragments – NRU 3533 (Upper Clear Fork).

Figure 2.29 – Permeability-porosity relationship for solution collapse breccia deposits based on quick plug core data from NRU wells 1509, 1510 and 3533.
2.3 – Rock Fabrics

There are four basic rock fabrics within the Clear Fork interval at the North Robertson Unit, as summarized below.

**Homogeneous** – This fabric consists of relatively uniformly distributed lateral and vertical porosity and permeability. The best example of this type of rock fabric is found within selected portions of the Upper Clear Fork. We are *not* implying that this zone is perfectly homogeneous like some silica clastic sands, however, this layer is much closer to this type of homogeneity than all other zones in the Clear Fork.

**Fractured** – This fabric is made up of solution collapse breccias (as described above). Fractures are 2 to 4 inches in length and very roughly estimated to be 4 to 6 inches apart. Not all of these fractures are open, as many have been plugged with anhydrite. Sections of the Middle Clear Fork provide good examples of this fabric.

**Bimodal** – This fabric has two distinct pore sizes. The larger size pores are typically formed from the dissolution of fossil debris, and the smaller pores are typically intercrystalline in origin.

**Heterogeneous** – This fabric consists of anhydrite nodules and porous dolostone. This fabric is common throughout much of the Clear Fork section. The size and distribution of these anhydrite nodules vary dramatically.

2.4 – Summary

Examining the permeability-porosity plots for the various depositional environments described above, it would appear that depositional environment would be the best mechanism for segregating the reservoir for analysis purposes. *Unfortunately, these depositional environments can not be directly predicted from conventional well log or core data, but only through visual and microscopic examination.*

Significant post-depositional diagenesis, which is typical for the Clear Fork section, usually masks any relationship between depositional environment, porosity and permeability. In addition, several depositional environments may overlap one another, further complicating any attempts to predict individual environments. Since we can not
predict depositional environment, we will attempt to segregate the reservoir on the basis of its lithologic and fluid-flow characteristics, which is very similar to separating the reservoir on the basis of rock fabric.
3.1 – Definition of Permeability and Its Importance in Reservoir Characterization

For the Clear Fork Formation at the NRU, we believe that permeability (most significantly, the effective permeabilities to oil and water) is the most important factor in identifying reservoir pay intervals. We also know that to rigorously design hydraulic fracture treatments (which are required for the Clear Fork), we require an accurate estimate of permeability in order to perform leak-off calculations (the loss of fracturing fluid through the fracture walls prior to fracture closure). In addition, as we wish to also perform numerical simulation of the flow processes within the reservoir, we require a fairly detailed description of the vertical and lateral permeability fields.

During the course of this work, we may well find that reservoir characteristics other than permeability are equally important (or more important) in the identification of productive intervals and in the prediction of reservoir performance. Certainly the prediction of permeability is a good starting point, but not necessarily the only reservoir parameter we will consider, or attempt to predict.

Due to economic constraints, we often have insufficient data (routine core and special core data) for the direct identification of reservoir pay intervals. As a result, we must resort to statistical correlations based on more abundant data types (i.e., well log data, seismic data, etc.). Statistical correlations often work fairly well even when they do not honor the underlying physical characteristics of the system they are being used to predict. However, when we attempt to predict permeability or flow capacity on the basis of well log responses, we often lose sight of the rock characteristics we are actually attempting to model.

If we examine the Darcy's law equation\(^\text{10}\) for horizontal, laminar, incompressible and isothermal fluid flow in porous media in terms of permeability (Eq. 3.1), we see that
permeability has dimensions of \([L^2]\), regardless of the units system. Note that the pressure gradient term, \((\Delta p/\Delta L)\), has been assumed to be negative for this example:

\[
k = \frac{q\mu \Delta L}{A\Delta p} = \frac{(L^3)(mT)(L)}{(L^2)(L)} = [L^2]. \tag{3.1}
\]

In a physical sense, we can visually relate this to the pore geometry of the rock in question, in particular, the pore size, the grain size and the pore geometry. Therefore, to honor the physical properties of the rock that we are attempting to predict using well log or laboratory data, we should first examine the capillary characteristics of the rock since the pore network controls the transmission of fluid. We should also determine the parameters that we can accurately estimate with petrophysical data, as well as how these data can be utilized to predict reservoir performance.

3.2 – Literature Review: Capillary Pressure Data for Permeability Prediction

Many of the references summarized below contain material that is beyond the scope of this work, however, we provide enough detail to orient the reader so that they could undertake a more detailed study.

Although the definition of permeability and the problems associated with its prediction had previously been considered within the geologic, civil engineering and chemical engineering literature,\(^{10-16}\) perhaps the most complete early treatment of the subject in the petroleum literature was provided by Muskat and Wyckoff\(^{17}\) in 1937. The authors felt that permeability was a constant determined only by the structure of the medium in which it was being measured and was entirely independent of the associated fluid type. Muskat and Wyckoff concluded that permeability could be predicted from porosity in homogeneous reservoirs with well-sorted intergranular porosity, but there was no inherent relationship between permeability and porosity.

Muskat and Wyckoff found that permeability was a function of porosity, grain size distribution, grain shape and the amount of cementation. The authors concluded that any statistical relationship for the prediction of permeability would have a very limited
range of applicability, and that if possible, permeability should be empirically measured
for the entire reservoir in question without resorting to the use of predictive equations.

In 1941, Leverett\textsuperscript{18} published the results of a semi-empirical study on the capillary
properties of unconsolidated sand packs. Leverett did not utilize the "bundle of capillary
tubes" analogy used by previous investigators,\textsuperscript{13,15-16} but instead, Leverett considered the
interfacial curvature existing at the phase boundaries between different reservoir fluids.

A relationship between saturation and the mean interfacial curvature was established,
and the effects of saturation hysteresis (drainage versus imbibition) on the shape of the
saturation-capillary pressure profile were discussed. Leverett concluded that \textit{the equili-
brium saturation condition obtained in his sand pack was inversely proportional to pore
size and the density difference between different reservoir fluids, and directly pro-
portional to interfacial tension}.

Leverett also introduced the "\textit{J-Function}" where he defined the \textit{J-Function} as a dimen-
sionless variable (Eq. 3.2) and plotted the \textit{J-Function} versus the wetting-phase saturation
in order to compare the relative reservoir quality of rocks with distinctly different
capillary characteristics:

\[ J(S_w) = \frac{\Delta \rho g h}{\sigma \cos \theta} \sqrt{\frac{k}{\phi}} = \frac{p_c}{\sigma \cos \theta} \sqrt{\frac{k}{\phi}}. \] ................................. (3.2)

For which \( \Delta \rho g h \) or \( p_c \) is the capillary pressure (dyne/cm\textsuperscript{2}), \( \sigma \cos \theta \) is the adhesive tension
(dyne/cm), \( \phi \) is porosity (fraction), and \( k \) is the permeability (cm\textsuperscript{2}).

In simple terms, the Leverett "\textit{J-Function}" is related to the interfacial curvature of the
fluid-fluid interface, \( (\Delta \rho g h/\sigma \cos \theta) \), and a factor that is a unique property of the rock,
\( (\sqrt{k/\phi}) \), where \( \sqrt{k/\phi} \) is presumed to approximate the average pore radius.

In 1944, Hassler, \textit{et al.}\textsuperscript{19} published the first capillary pressure versus saturation curves in
the petroleum literature for a California sandstone formation and a Texas dolomitic
limestone formation, both possessing moderate to good permeability. The authors
concluded that the capillary forces that exist within rock-fluid systems were directly
related to the pore geometry of the rock being studied.
Hassler, et al. found that the shape and position of capillary pressure curves were primarily a function of the pore size distribution and partly a function of the contact angle between the fluid phases present in the rock. The authors performed both two-phase and three-phase flow experiments and found that capillary pressure was a function of the size, shape, distribution and wetting characteristics of the rock pore space.

Hassler, et al. also investigated the effects of saturation history on the capillary pressure profile and formulated a semi-empirical expression for the capillary pressure of the California sandstone samples as a function of permeability and saturation.

In 1945, Hassler and Brunner\textsuperscript{20} published the results of capillary pressure studies conducted using a centrifuge apparatus. This was deemed to be a significant advance in the measurement of capillary characteristics over the use of a semi-permeable porous capillary diaphragm apparatus, although calculations were somewhat tedious and the equipment setup was often quite complex.

The centrifuge technique allowed capillary pressures to be measured on small core samples of actual reservoir rock, instead of the idealized, unconsolidated sand packs that had been utilized previously. The porous diaphragm could not be used to measure capillary pressures on actual reservoir rocks since the sample lengths that were required to record high capillary pressures (at or near the irreducible wetting-phase saturation) were impractical. In addition, the time required to perform these tests would have been cost-prohibitive. The centrifuge apparatus allowed much higher capillary pressures to be measured (up to approximately 150 psi) than were possible using the porous diaphragm (just above atmospheric pressure), and allowed many measurements to be made much more rapidly in hours (or days) versus weeks (or even months).

Of particular interest to our work, Hassler and Brunner concluded that permeability and capillary pressure were fairly well correlated for rocks with similar pore geometries, however, porosity and capillary pressure were found to be essentially uncorrelated. The authors found that capillary pressure and permeability were closely related for consolidated sandstone samples, but less well correlated for the lower permeability dolomitic limestone samples. Hassler and Brunner concluded that the lower permea-
bility samples possessed many more distinctly different pore geometries than the higher permeability rocks, but did not investigate this phenomenon further.

In 1949, Purcell\textsuperscript{21} published the results of capillary pressure studies conducted using a Mercury injection apparatus. As with the centrifuge apparatus,\textsuperscript{20} this was also deemed to be a significant advance in the measurement of capillary characteristics over the use of the porous diaphragm apparatus. A major advantage of the Mercury injection apparatus was the ability to rapidly measure capillary pressure data for small, irregularly-shaped core samples as well as for drill cuttings that had been previously used for qualitative descriptive purposes only. The injection of a non-wetting phase fluid (Mercury) was used to model the pore size distribution of reservoir core samples. The entire capillary pressure-saturation curve could be generated in approximately one hour, and much higher capillary pressures could be recorded than had previously been possible. This was especially important for the testing of lower permeability core samples that required higher injection pressures to investigate the entire pore space.

Using the Mercury injection data, Purcell validated the following semi-empirical expression for permeability in terms of porosity, saturation and capillary pressure:

\[
 k = 10.658 \left( \sigma_{Hg,A} \cos \theta \right)^2 F_p \phi \int_{S_{nwp} = 0}^{S_{nwp} = 1} \frac{dS_{nwp}}{P_c^2}.
\]

Where \( k \) is the permeability (md), \( \sigma_{Hg,A} \cos \theta \) is the adhesive tension for a Mercury-air system (368 dynes/cm), \( \phi \) is porosity (fraction), \( S_{nwp} \) is the non-wetting phase (Mercury) saturation (fraction), \( p_c \) is the capillary pressure (psi) and \( F_p \) is the Purcell lithology factor. This lithology factor accounted for the pore geometry deviation between actual reservoir rock and the bundle of capillary tubes model that was used as an analogy for the derivation of the equation for permeability. For the most part, the Purcell \( F_p \) was a variable that represented the tortuosity of the system, or the difference between the actual and ideal flow paths from inlet to outlet.
Purcell rearranged Eq. 3.3 to solve for the lithology factor, $F_p$, for several Texas reservoir core samples and drill cuttings including the Upper Wilcox, Paluxy, Frio and San Andres Formations. In addition, Mercury-air and brine-air capillary pressure data for the same samples were compared to find a conversion factor to convert from one system to the other. Purcell found that dividing the Mercury-air capillary pressure data by a factor of 5 would generally match the brine-air capillary pressure data recorded with a porous diaphragm apparatus, although the quality of the match varied from sample to sample.

In 1949, Rose and Bruce\textsuperscript{22} published a sensitivity study on the independent effects of interfacial tension, contact angle, porosity and permeability on the shape of the capillary pressure curve. The authors were able to show that capillary pressure measurements were a function of pore configuration, rock surface properties and fluid properties. *Rose and Bruce found that capillary pressure data could be used to characterize the distribution, orientation, shape and tortuosity of the pore system as well as to describe the interfacial and interstitial surface areas and the relative permeability to the wetting fluid phase.*

Rose and Bruce utilized a multiple-core porous diaphragm apparatus for their experiments. While this meant that they were somewhat limited in the magnitude of capillary pressures that they could record, they were able to evaluate several cores at once (using actual formation fluids), thereby accelerating the normally slow testing process associated with the porous diaphragm setup.

Rose and Bruce pointed out that although capillary pressure data could be used to infer important pore-scale features of the samples being tested, $p_c$ data do not truly capture the flow characteristics of the reservoir as a whole. The authors concluded that due to the heterogeneous nature of reservoir rocks, rock and fluid flow properties (*i.e.*, permeability, tortuosity, etc.) could only be accurately estimated by generating laboratory-derived statistical correlations based on the analysis of many rock samples, and not from theoretical formulations alone.
In 1949, Calhoun, *et al.*\textsuperscript{23} investigated the relationship between the vapor lowering pressure in an air-water system and the capillary pressure curve at low wetting phase saturations (high pressures). This work was performed primarily to overcome the limitations of the porous diaphragm apparatus (limited to low capillary pressures) that was used extensively at that time for the measurement of capillary characteristics. In addition, the authors measured capillary pressure with many different fluid systems in an effort to quantify the relationship between capillary pressure and the fluids used to investigate the pore system of an individual rock sample.

By extending the work of previous investigators,\textsuperscript{18-22} Calhoun, *et al.* were able to show that the Purcell lithology factor, $F_p$, was inversely related to formation tortuosity ($T$), and that the internal surface area of a rock could be defined in terms of the interfacial tension, contact angle and the area under the capillary pressure curve. The authors developed a semi-empirical relationship for permeability in terms of porosity, adhesive tension, capillary displacement pressure and the value of the Leverett "$J$-Function" at 100-percent wetting phase saturation. This relation is given by:

$$k = \frac{1}{p_d^2} \left[ J(S_w)_{1.0} \right]^2 (\sigma \cos \theta)^2 \phi. \qquad (3.4)$$

Which is in the form of the Purcell equation (Eq. 3.3) with:

$$F_p = 4 \left[ J(S_w)_{1.0} \right]^2 = 4/T \quad \quad (3.5)$$

and:

$$\frac{1}{p_d^2} = 2 \int_0^1 \frac{dS_w}{p_c^2}. \quad \quad (3.6)$$

Of course, this expression presumes that the pores that have been investigated at the displacement pressure are representative of the sample as a whole. This will hold true for high permeability rock, but not for "tight" low permeability samples.

In a 1950 study, Burdine, *et al.*\textsuperscript{24} investigated the utilization of pore entry radii and the distribution of fluid-filled pore volume to estimate the pore size distribution of reservoir
rocks using a Mercury injection apparatus. Burdine, et al. were able to show that samples with nearly equal air permeabilities could have distinctly different pore geometries. The authors concluded that permeability was a function of pore entry radii and the amount of Mercury-filled pore volume as Mercury injection proceeded. This functional relationship was expressed in equation form as:

\[ k = 126\phi \sum_{i=0}^{n} \frac{V_i R_i^d}{X_i^2 R_i^2} \]  

Where \( k \) is permeability (md), \( V_i \) is the incremental pore volume filled (fraction), \( R_i \) is the incremental pore entry radius (cm) and \( X_i^2 \) is the tortuosity factor (fraction).

Perhaps more importantly, Burdine, et al. found that they were sampling only 50 percent of the total sample pore volume at their maximum injection pressure (1,500 psig). The authors developed a high-pressure Mercury injection (10,000 psig) apparatus so that approximately 95 percent of the sample pore space could be investigated.

In 1952, Wyllie and Spangler\(^{25} \) used electrical resistivity measurements in order to solve for the tortuosity-dependent lithology factor (i.e., the constant in the Kozeny\(^{13} \) equation) that accounts for the deviation of flow behavior in actual reservoir rocks compared to the ideal case (i.e., the bundle of capillary tubes model).

In a previous treatment of the subject, Carman\(^{15} \) had expressed the Kozeny constant, \( c_k \), in terms of a shape factor term, \( c_{sh} \), and the tortuosity, \( T \), as:

\[ c_k = c_{sh} T = c_{sh} \left( \frac{L_e}{L} \right)^{2} \]  

In which \( L_e \) is the average path length through the media and \( L \) is the apparent path length (ideal case). Carman used a shape factor, \( c_{sh} \), of 2.5 and a Kozeny constant, \( c_k \), of 5.0 for an ideal packing of spheres. These assignments required that the tortuosity term, \( (L_e/L)^2 \), be equal to 2.0.

The determination of the Kozeny constant for actual reservoir rocks depends on the accurate measurement of the surface areas of irregularly shaped particles to determine shape factor and tortuosity, which at the time was difficult at best, and is often
impossible. Wyllie and Spangler took an alternate approach in order to estimate the Kozeny constant. The authors assumed that the shape factor term would be constant \( c_{sh} = 2.5 \) for the range of porosities encountered in actual reservoir rocks, therefore, they directed their efforts towards the estimation of tortuosity. Since they did not wish to attempt to measure the specific surface areas of the pores, they instead derived an expression for tortuosity in terms of electrical resistivity measurements.

Wyllie and Spangler were able to formulate an expression for permeability as a function of adhesive tension, porosity, saturation, tortuosity and capillary pressure. The authors were also able to derive an expression for relative permeability to the wetting phase by comparing the resistivity of partially saturated media to that of fully saturated media.

An expression for tortuosity was derived in terms of the Archie formation factor, \( F_R \), which is defined as:

\[
F_R = \frac{a}{\phi^m} \left( = \frac{R_t}{R_w} \text{ for } S_w = 100 \text{ percent} \right). \quad \text{................................. (3.9)}
\]

Where \( a \) is an empirical constant (usually \( \sim 1 \)) and \( m \) is the "cementation factor" (usually \( \sim 2 \)). Values for both \( a \) and \( m \) are thought to be controlled by pore type, pore geometry and lithology. Wyllie and Spangler also found that:

\[
F_R = \left[ \frac{L_e}{L} \right] = T^{0.5} \phi \quad \text{.......................................................... (3.10)}
\]

and, therefore:

\[
T = F_R^2 \phi^2. \quad \text{.......................................................... (3.11)}
\]

Using these formulations, Wyllie and Spangler derived an expression for permeability that was similar to that shown in previous investigations.\(^{19-20} \) This result is given as:

\[
k = \frac{(\sigma \cos \theta)^2}{c_{sh} F_R^2 \phi^2} \int_0^1 \frac{dS_w}{P_c^2} = \frac{(\sigma \cos \theta)^2}{2.5 F_R^2 \phi} \int_0^1 \frac{dS_w}{P_c^2}. \quad \text{................................. (3.12)}
\]
Wyllie and Spangler also derived expressions for relative permeabilities (for an oil-water system with water as the wetting phase) as ratios of the permeabilities of partially saturated mediums to the permeabilities of fully saturated mediums. The "Wyllie-Spangler" equation for the wetting phase relative permeability is given as:

\[
k_{rw} = \frac{1}{I^2} \int_0^1 \frac{dS_w}{p_c^2} \int_0^{S_w} \frac{dS_w}{p_c^2} \]

For which \( I \) is defined as the resistivity ratio, and is given by:

\[
I = \frac{T_e^{0.5}}{T^{0.5} S_w} \equiv S_w^{-n}.
\]

Where \( n \) is the Archie saturation exponent and \( T_e \) is the tortuosity for a partially saturated medium. Wyllie and Spangler concluded that the tortuosity ratio between a partially saturated medium and a fully saturated medium was simply:

\[
\frac{T_e}{T} = S_w^{2(1-n)}.
\]

In 1953, Burdine investigated the effect of the tortuosity term on predictive equations for two-phase relative permeability using Mercury injection capillary pressure data, and in particular, how the results compared to actual laboratory relative permeability data. Burdine used previous results to develop equations for effective wetting phase and non-wetting phase permeabilities, and then formulated relative permeability relations by taking ratios of the effective permeabilities to his previously derived expression for absolute permeability. Burdine's relative permeability relations for the wetting and non-wetting phases are given as:

\[
k_{rw} = 0.126 \phi \frac{\sum k_i \left( \frac{X_{wri}^2 V_i R_i^4}{X_i^2 R_i^2} \right)}{k_i}
\]
\[ k_{rnw} = 0.126 \phi \kappa \sum_{i=0} \frac{X_{rnwi}^2 V_i R_i^4}{X_i^2 R_i^2}. \]  \hspace{2cm} \text{(3.17)}

Where \( k \) is permeability (md), \( V_i \) is the incremental pore volume filled (fraction), \( R_i \) is the incremental pore entry radius (cm), \( X_i^2 \) is the tortuosity factor (fraction) for a fully-saturated medium, \( X_{rnwi}^2 \) is the wetting phase tortuosity ratio and \( X_{rnwi}^2 \) is the non-wetting phase tortuosity ratio.

Of particular interest to subsequent investigations, Burdine found that the wetting-phase tortuosity ratio term could be expressed in terms of the wetting phase saturation and irreducible wetting phase saturation as:

\[ X_{rw}^2 = S_w - S_{wi} \]  \hspace{2cm} \text{(3.18)}

We note that Burdine assumed that the residual non-wetting phase saturation was negligible, which is most likely for the case of high-pressure mercury injection tests.

In 1960, Thomeer\(^{28}\) performed an analysis of capillary pressure curves in order to define the internal pore structure of core samples. Thomeer concluded (as had previous investigators\(^{18-19,21-23,25}\)) that the shape and location of the capillary pressure curve was a function of pore geometry. \textit{Thomeer found that the location of the capillary pressure curve could be related to the interconnected pore volume and the cross-sectional area of the largest pore. In addition, the shape of the curve was a function of the connectivity of the pore system and the relative sizes of the pores contained within that system.}

In order to model the shape of the capillary pressure curve, Thomeer developed a hyperbolic equation that relates the capillary pressure to the bulk volume invaded by Mercury during an injection sequence as:

\[ \frac{(V_b)p_c}{(V_b)p_{oo}} = 10 \left[ -C^2 / \log(p_c/p_d) \right] = \exp \left[ -G / \log(p_c/p_d) \right]. \]  \hspace{2cm} \text{(3.19)}

Where the \( C^2 \) term represents the "shape" of the capillary pressure curve. The Thomeer pore geometrical factor, \( G \), can be expressed as \( 2.303 C^2 \) (or \( \ln[10] C^2 \)).
Using a "type curve" approach, Thomeer then constructed a family of curves, each with a different pore geometrical factor. Plots of capillary pressure versus Mercury saturation can then be overlain on this family of curves to find a unique value of $G$ for any data set. Thomeer also concluded that air permeability ($k_{air}$) is a function of the pore geometrical factor ($G$) and the porosity-displacement pressure ratio, $\phi/p_d$, although no experimental results were shown.

Capillary pressure curves that exhibited two distinct trends (i.e., mixed lithologies and vuggy carbonates) due to the presence of two different pore systems could be analyzed by separating the two trends and calculating a separate pore geometrical factor for each. However, Thomeer concluded that the pore system containing the largest pores would probably dominate the flow performance of the entire system.

In 1966, Brooks and Corey completed a study of fully- and partially-saturated porous media and the parameters that controlled fluid movement within these media. Brooks and Corey extended the work of previous investigators by formulating new expressions to relate capillary pressure, saturation and pore geometry for two-phase flow in homogeneous and isotropic media. The authors introduced a pore size distribution factor, $\lambda$, that was utilized to relate saturation to capillary pressure in the following manner:

$$S_e = S_w - S_{wi} \left(1 - S_{wi}\right) = \left[\frac{p_d}{p_c}\right]^\lambda \text{ for } p_c \geq p_d.$$  

(3.20)

For which $S_e$ is effective saturation (as defined by Brooks and Corey), $S_{wi}$ is irreducible wetting-phase saturation and $p_d$ is displacement pressure.

Burdine had previously established the relationship between effective saturation and tortuosity. As had Burdine, Brooks and Corey also assumed that the value of the critical saturation, $S_c$, would be fairly close to 1.0 for isotropic media. This assumption should also hold for all media when considering high pressure Mercury injection data where the non-wetting phase residual saturation (i.e., Mercury) does approach zero. However, if these relations are used to analyze data from centrifuge or porous diaphragm apparatus,
we must account for any residual non-wetting phase saturation that might exist. Using Burdine's results, the authors developed the following relations:

\[ X_{rw}^2 = \left( \frac{T}{T_e} \right)_{wp} \left( \frac{S_w - S_{wi}}{S_c - S_{wi}} \right)^2 = \left( \frac{S_w - S_{wi}}{1 - S_{wi}} \right)^2 = S_e^2 \] ........................................... (3.21)

\[ X_{rnw}^2 = \left( \frac{T}{T_e} \right)_{nwp} \left( 1 - \frac{S_w - S_{wi}}{S_c - S_{wi}} \right)^2 = (1 - S_e)^2. \] ............................................ (3.22)

The relationship given by Eq. 3.20 was then utilized to solve for the pore distribution factor, \( \lambda \), as a function of \( p_c \), \( p_d \), and \( S_e \). The pore distribution factor was simply the negative slope of the data trend on a log-log plot of effective saturation versus capillary pressure, as shown in Fig. 3.1.

Brooks and Corey found that \( \lambda \) was larger for homogeneous rock and smaller for more heterogeneous systems. For the samples analyzed in their paper, Brooks and Corey found that \( \lambda \) varied between 1.8 and 7.3. The examples shown in Fig. 3.1 indicate that NRU Clear Fork samples are extremely heterogeneous, even for rock with moderate to good permeability (core #15B).

![Figure 3.1 – Calculation of Brooks and Corey pore distribution factor – NRU 3533 (core #15B) and NRU 1510 (core #5D).](image_url)
Brooks and Corey used these relationships to formulate expressions for the wetting and non-wetting phase relative permeabilities and then validated the results empirically. The Brooks and Corey $p_c$ relations were incorporated into the Purcell-Burdine relations to yield:

$$k_{rw} = \left[ \frac{S_w - S_{wi}}{1 - S_{wi}} \right]^2 \frac{\int_0^{S_w} \frac{dS_w}{P_c^2}}{\int_0^1 \frac{dS_w}{P_c^2}} = S_e \left( \frac{2 + 3\lambda}{\lambda} \right) = \left[ \frac{P_d}{P_c} \right]^{2+3\lambda} \tag{3.23}$$

and:

$$k_{rnw} = (1 - S_e)^2 \frac{\int_0^1 \frac{dS_w}{P_c^2}}{\int_0^1 \frac{dS_w}{P_c^2}} = (1 - S_e)^2 \left[ 1 - S_e^{(2+\lambda)/\lambda} \right] = \left[ 1 - \left( \frac{P_d}{P_c} \right)^{2+\lambda} \right] \left[ 1 - \left( \frac{P_d}{P_c} \right)^{2+\lambda} \right]. \tag{3.24}$$

These equations are only valid for capillary pressures greater than or equal to the displacement pressure. Brooks and Corey noted that these formulations for relative permeability are more precise than those for effective or absolute permeability, since the adhesive tension, porosity and lithology factor terms all cancel.

In 1976, Wardlaw,\textsuperscript{30} as well as Wardlaw and Taylor,\textsuperscript{31} characterized the geometry of pores and pore throats for several carbonate rock systems using visual and microscopic (including scanning electron microscope – SEM) description techniques. Using Mercury injection and withdrawal sequences, Wardlaw was able to relate pore geometry to the recovery efficiency, which the author defined as:

$$RE = 100 \left[ \frac{\text{Volume of NWP ejected as } P_c \text{ declines to a minimum}}{\text{Volume of NWP at maximum } P_c} \right]. \tag{3.25}$$
Where NWP is the non-wetting phase (i.e., Mercury). Wardlaw found that the recovery efficiency was primarily a function of porosity (and not permeability) for the core samples that were evaluated.

Wardlaw concluded that for carbonate rocks undergoing dolomitization, a progressive change in pore geometry occurred as dolomite crystals grew and polyhedral and tetrahedral pores became connected by interboundary-sheet pores, resulting in a decrease in porosity. The pore system should no longer be modeled using the bundle of capillary tubes analogy, but instead should be characterized using a sheet or plate geometry. For this case, capillary pressure would be expressed as:

\[ p_c = \frac{1}{r}\sigma \cos \theta = \frac{2}{d}\sigma \cos \theta. \]

\[
(3.26)
\]

Which differs by a factor of 2 from the identity for the capillary tube model. Of course, this relation may not hold true if significant dissolution of pore-blocking material were to occur. We note that the model used to calculate pore throat diameter from capillary pressure data has little impact on any correlation between pore throat size, porosity, permeability or recovery efficiency since the resulting expressions only differ by a constant.

Wardlaw also concluded that although rock samples with distinctly different pore geometries could have similar Mercury injection capillary pressure curves (drainage - non-wetting phase increasing), the Mercury ejection curves (imbibition – wetting phase increasing) would be more distinctive, and should also be recorded when possible. Wardlaw found that there appeared to be no correlation between pore size and porosity, but that the pore body size-pore throat size ratios increased as porosity decreased.

In 1978, Wardlaw and Cassan\textsuperscript{32} studied the effect of pore geometry on recovery efficiency for carbonate core samples using Mercury-air capillary pressure data as well as visual and microscopic examination (including SEM) of pore casts. Wardlaw and Cassan noted that the most important characteristics of the pore system could be expressed in terms of the following parameters:

- pore size-pore throat size ratio ("aspect ratio")
- number of pore throats intersecting each pore ("coordination number")
- type and degree of nonrandom heterogeneity
- pore surface roughness

The authors attempted to estimate recovery efficiency based on the characteristics listed above (which could all be determined via microscopic examination), Mercury injection-withdrawal cycles and the total porosity.

As Wardlaw and Cassan pointed out, recovery efficiency will almost always increase with either a decrease in aspect ratio or an increase in coordination number if all other pore characteristics are kept the same. Similarly, recovery efficiency will decrease with an increase in the aspect ratio (pore bodies much larger than pore throats) or a decrease in coordination number (less pore throats connecting each pore body) given that all other system parameters remain constant. Non-random heterogeneities primarily fell into two categories, as shown below:

- When areas of the rock system with favorable pore characteristics (low "aspect ratio" and high "coordination number") are surrounded by regions with unfavorable pore characteristics resulting in a lower recovery efficiency.
- When areas of the rock with unfavorable pore characteristics (high "aspect ratio" and low "coordination number") are enclosed by regions with favorable pore characteristics. This results in little change in recovery efficiency due to the fact that fluid from the poorer quality rock would eventually feed in to the surrounding area consisting of higher quality rock.

Although Wardlaw and Cassan did not investigate the affect of surface roughness, the authors felt that rougher pore surfaces would result in lower residual wetting phase saturations due to a decrease in interfacial tension between the wetting phase and the pore walls.

Wardlaw and Cassan gathered laboratory data on 92 carbonate core samples and several sandstone core samples and found that recovery efficiency was strongly related to porosity, but was not correlated with permeability. The authors theorized that the correlation between recovery efficiency and porosity was directly related to the increase in "aspect ratio" and decrease in "coordination number" associated with decreasing
porosity. Wardlaw and Cassan also stated that these relationships would hold true for strongly-wetted rock, therefore, in the case of mixed or intermediate wettability, porosity and recovery efficiency may not be so strongly correlated. Obviously, this direct correlation with porosity would also be invalid for vuggy or fractured carbonates.

In addition, Wardlaw and Cassan examined the correlation between the type of carbonate porosity present and the recovery efficiency. The authors observed the relationships shown in Table 3.1.

<table>
<thead>
<tr>
<th>Classification</th>
<th>Aspect Ratio</th>
<th>Coordination Number</th>
<th>Recovery Efficiency</th>
</tr>
</thead>
<tbody>
<tr>
<td>Intercrystalline – High Porosity</td>
<td>Low</td>
<td>High</td>
<td>≥55 percent</td>
</tr>
<tr>
<td>Intercrystalline – Low Porosity</td>
<td>Variable</td>
<td>Low</td>
<td>&lt;20 percent</td>
</tr>
<tr>
<td>Interparticle – High Porosity</td>
<td>Low</td>
<td>High</td>
<td>45 percent</td>
</tr>
<tr>
<td>Vuggy Porosity</td>
<td>High</td>
<td>Variable</td>
<td>Low</td>
</tr>
</tbody>
</table>

The values for recovery efficiency should be treated as qualitative rather than quantitative measures of reservoir quality.

In a continuation of earlier investigations, Swanson published the results of a 1981 study on the empirical prediction of air and brine permeabilities utilizing the graphical characteristics of capillary pressure curves for two-phase fluid flow. Swanson felt that Thomeer's use of a hyperbola did not accurately depict the shape of the capillary pressure curves for drill cuttings. By considering the inflection point on the capillary pressure curve, between the region in which the larger pores dominated fluid flow (horizontal asymptote) and the region in which the smaller pores dominated fluid flow (vertical asymptote), Swanson found that the entire rock cross section could be modeled more accurately.

Swanson's method consisted of calculating the product of the non-wetting phase saturation (percent bulk volume) and the reciprocal of capillary pressure anywhere along a tangent line (45°) that intersected the inflection point of the capillary pressure curve. The author noted that the reciprocal of capillary pressure was proportional to the
dominant pore size connecting the effective pore space being sampled. This ratio, \((S_d/p_c)_A\), was then correlated with individual sample measurements of permeability (brine and air) in order to formulate predictive equations for permeability (brine and air) for both sandstone and carbonate samples. Swanson also developed predictive equations for brine permeability in terms of air permeability. It should be noted that Swanson omitted carbonate samples with vuggy, moldic or fenestral porosity since these samples had multiple inflection points.

In 1983, Lucia\(^{34}\) reported that permeability, capillary characteristics and cementation factor for selected carbonate rocks were related to particle size, the amount of interparticle porosity (intercrystalline or intergranular), the amount of separate vug porosity and the presence or absence of touching vug porosity. Lucia classified separate vugs as those vugs that were smaller than the thin-section cutting size. All these matrix and pore characteristics could be determined either visually or microscopically.

*Lucia noted that if vugs were not present within a rock sample, only particle size and the amount of interparticle porosity controlled permeability.* The author found that he could split the sample data into particle size groups and then develop more accurate permeability-porosity relationships for each grouping.

Lucia concluded that separate vug (isolated) porosity and in some cases, touching vug (connected) porosity, would adversely affect any attempt to relate porosity and permeability. The author also noted in order to model the in-situ pore geometry of rock samples, the samples must be described and tested under actual reservoir stress conditions (which is rarely the case). This would be especially true for reservoir rocks possessing fracture porosity, as less than 1-percent fracture porosity (percent of bulk volume) could significantly affect permeability measurements.

Lucia found that the cementation factor increased as the amount of separate vug porosity increased and theorized that the cementation factor decreased as the amount of touching vug porosity increased. Although the amount of vuggy porosity could be determined by subtracting the acoustic porosity from the neutron-density crossplot porosity, Lucia
noted that in order to determine the type of vuggy porosity present, visual (usually microscopic, specifically SEM) description of the rock was required.

In 1983, Thomeer\textsuperscript{35} formulated a predictive equation for air permeability using capillary pressure ($p_c$), displacement pressure ($p_d$), non-wetting phase saturation ($S_b$ - percent of bulk volume) and the pore geometrical factor ($G$) that he had defined in a previous study.\textsuperscript{28} The author noted that the pore geometrical factor was a function of pore throat size distribution and the associated pore volume. Thomeer utilized capillary pressure data and air permeability data for 279 rock samples for his study.

In his previous work,\textsuperscript{28} Thomeer developed the following relationship:

\[
\frac{(V_b)_{p_c}}{(V_b)_{p_\infty}} = 10 \left[ - \frac{C^2}{\log \left( \frac{p_c}{p_d} \right)} \right] = \exp \left[ - \frac{G}{\log \left( \frac{p_c}{p_d} \right)} \right]. 
\] ............................. (3.19)

For which \((V_b)_{p_c}\) is equal to the non-wetting phase saturation as a fraction of the bulk volume, and \((V_b)_{p_\infty}\) is the non-wetting phase saturation as capillary pressure approaches infinity (i.e., the total porosity).

Utilizing laboratory results for 165 sandstone core samples and 114 carbonate core samples from 54 different fields, Thomeer formulated the following predictive equation for permeability:

\[
k_a = 3.8068 G^{-1.3334} (\phi/p_d)^{2.0}. \] ..................................................................... (3.27)

Where Thomeer defined displacement pressure as the capillary pressure representing Mercury entrance into the largest pore throat observed by petrographic analysis. Using the bundle of capillary tubes model for a Mercury-air system, the expression for $p_d$ was:

\[
p_d = \frac{4 \sigma \cos \theta}{d_{\text{max}}} \equiv \frac{214}{d_{\text{max}}}. \] ................................................................................... (3.28)

Where the displacement pressure, $p_d$, is in psi, the interfacial tension, $\sigma$, is in dynes/cm and $d_{\text{max}}$ is in microns ($10^{-6}$ meters). It should be noted that this expression for displacement pressure would be difficult to replicate without a petrographic analysis,
and Thomeer's definition of \( p_d \) may be closer to the entry (threshold) pressure than the displacement pressure.

In 1984, Hagiwara\(^{36}\) developed a semi-empirical correlation (based on the bundle of capillary tubes model and by analogy to Archie's\(^{26}\) empirical equation for resistivity) for permeability as a function of porosity, cementation factor and the average pore throat radius. Utilizing a database consisting of 24 sandstone samples, the best least-squares line fit for air permeability was obtained using the following expression:

\[
k_a = 19.8 \phi^m \bar{R}_{pt}^2 \]

Where porosity is given as a fraction and \( \bar{R}_{pt} \) is the average pore throat radius in microns \((10^{-6} \text{ meters})\). Hagiwara noted that the constant multiplier (19.8 for these data) accounted for the effects of tortuosity and other pore geometrical factors.

We note that the use of an average pore throat radius weighs the contribution of the larger pores rather heavily. In order to model the entire rock system, it might be better to utilize the median pore throat radius or the pore throat radius associated with the capillary displacement pressure.

In 1985, Wells and Amaefule\(^{37}\) presented a simple graphical approach for rapidly determining the Swanson\(^{31}\) petrophysical parameter, \((S_b/p_c)A\), that had been used to predict air permeability from Mercury-air capillary pressure data. Wells and Amaefule developed correlations for core samples using both Mercury-air and brine-air pore fluid configurations. The authors found that a multiplicative constant did not adequately describe the difference between capillary pressure data for Mercury-air and brine-air fluid systems as Purcell had found previously.\(^{21}\) In addition, these discrepancies were greatly magnified for rocks with low permeability and porosity.

Wells and Amaefule found that by plotting the logarithm of Mercury saturation (percent of bulk volume) as the abscissa and the square root of the capillary pressure-Mercury saturation ratio as the ordinate, a well-defined minimum, which represented the inflection point of the capillary pressure curve, could be found. Subsequently, \((S_b/p_c)A\) could be calculated as the inverse of the squared minimum value. Of course, if we
simply plot the logarithm of Mercury saturation (percent bulk volume) as the abscissa and \((S_b/p_c)\) as the ordinate, a well-defined maximum that is equal to \((S_b/p_c)_A\), can be found directly. It is important to note that since many capillary pressure curves have multiple inflection points, it may be necessary to evaluate all inflection points separately in order to consider the contributions of both the large and small pores to total fluid flow for any sample.

Wells and Amaefule then correlated the Swanson parameter with air permeabilities for 35 tight gas sandstone samples. The air permeabilities were measured under actual reservoir stress conditions so that the results could be easily compared for both fluid systems (air-Mercury and air-brine). The authors developed the following predictive equations for air permeability:

\[
k_a = 30.5 \left( \frac{S_b}{p_c} \right)^{1.56}_{A,\text{air-Hg}}
\]

\[
k_a = 1.22 \left( \frac{S_b}{p_c} \right)^{1.61}_{A,\text{air-brine}}
\]

For which \(S_b\) is the non-wetting phase saturation in percent bulk volume, \(p_c\) is in psi and \(k_a\) is in md.

Wells and Amaefule found that mercury capillary pressures were approximately a factor of 10 greater than centrifuge air-brine capillary pressures for wetting-phase saturations greater than 50 percent in tight gas sands. The authors also felt that the use of Mercury-air capillary pressure data for the computation of gas-water relative permeabilities would lead to optimistic estimates of clean-up times required for gas wells completed and/or stimulated with water-based fluids.

As part of a 1986 study on the effects of temperature on oil and water relative permeability data, Nakornthap and Evans derived an expression for absolute permeability from first principles based on the previous investigations of Purcell and Brooks-Corey. Although very similar to Purcell's original equation (Eq. 3.3), the authors utilized pore geometry terms and incorporated the saturation terms developed by Brooks...
and Corey to account for tortuosity. The Nakornthap and Evans equation for absolute permeability (in field units) can be expressed as:

\[
k = 10.658 \phi^* (\sigma_{nwp,wp} \cos \theta)^2 \frac{\beta n d}{\sigma_{nwp,wp}} \int_0^1 \frac{dS_w^*}{p_c^2} \tag{3.32}
\]

for which:

\[
\phi^* = \phi (1 - S_{wi}) \tag{3.33}
\]

\[
S_w^* = \frac{S_w - S_{wi}}{1 - S_w} = S_e. \tag{3.34}
\]

\(\beta\) and \(n\) are empirical pore geometry terms that account for the dimensionless pore radius distribution (pore throat impedance) and the number of pore throats per pore body, respectively. \(S_w\) is the wetting phase saturation (fraction) and \(S_{wi}\) is the irreducible wetting phase saturation (fraction). In addition, \(\sigma_{nwp,wp}\) is the interfacial tension (dyne/cm) between the non-wetting and wetting phases having a contact angle \(\theta\), \(p_c\) is the capillary pressure (psi) that exists between the phases and \(k\) is absolute permeability (md).

In 1987 case study of the Ordovician Red River Formation of North Dakota, Jennings\textsuperscript{39} concluded that by considering the statistical parameters of the capillary pressure curve that a qualitative assessment of reservoir quality could be made. The author felt that these statistical measures, and the reservoir quality indexes (pore throat sorting, reservoir grade and oil column heights) that could be calculated from them, could be mapped on a local or regional basis in order to define new development and exploration plays.

Jennings found that the slope of the plateau on the capillary pressure curve gave an indication of sample sorting, with a horizontal plateau indicative of an extremely well sorted sample. On a semilog plot of capillary (injection) pressure (ordinate) versus non-wetting phase saturation (abscissa), Jennings found that by extending the slope of the plateau down to the ordinate-intercept that a good estimate of displacement pressure could be obtained.
Jennings provided a method for evaluating pore throat sorting ($PTS$) in reservoir core samples using capillary pressure data. The first-quartile and third-quartile non-wetting phase saturations were calculated using the following expressions:

\[ S_{nwQ_1} = 0.25(1 - S_{wi}) \]  
\[ S_{nwQ_3} = 0.75(1 - S_{wi}) \]

Where $S_{wi}$ is the irreducible wetting-phase saturation. At this point, the capillary pressures at these saturations (denoted as $p_{Q_1}$ and $p_{Q_3}$) were found, and $PTS$ was calculated as:

\[ PTS = \sqrt{\frac{p_{Q_3}}{p_{Q_1}}} \]

Low values for pore throat sorting represent good sorting (perfect sorting=1), while high values are indicative of poorly sorted rock. Jennings noted that rocks possessing poor sorting required much higher capillary pressure levels to obtain the same oil saturation as well-sorted rocks.

Jennings also defined "reservoir grade" ($RG$) as the percentage of linear area obtained by integrating under the capillary pressure curve. Obviously, rocks with higher reservoir quality had relatively less area under the $p_c$ curve than did poorer quality rock. A low $RG$ number was indicative of rock with large pore throats that could accept oil saturation at low displacement pressures, while high $RG$ numbers indicated the presence of smaller pore throats that required much higher pressures to obtain the same oil saturation as low $RG$ rocks.

Jennings also utilized oil column heights (as calculated from capillary pressure data) to define the productive limits of the reservoir under consideration. The author felt that a 50-percent initial oil saturation was indicative of a marginal zone, while a 75-percent initial oil saturation indicated an excellent producing zone. Of course, we should note that this type of analysis works best when productive intervals are well defined and there is a definitive trapping mechanism so that the vertical limits of any interval are known.
Jennings also found that the second-quartile capillary pressure ($p_{Q2}$) was well correlated with air permeability for well-sorted core samples, where $p_{Q2}$ was calculated in a similar fashion to the first-quartile and third-quartile capillary pressures. The author formulated the following expression:

$$k_a = \exp [-2.5 \ln (p_{Q2}) + 11.9]. \quad \text{................................................................. (3.38)}$$

Where $k_a$ is the air permeability in md and the second-quartile capillary pressure is in psi. We note that the value of $p_{Q2}$ is the capillary pressure obtained at the median pore throat radius ($MPTR$), therefore, a much more consistent correlation (from a dimensional standpoint) can be made between $MPTR$ and permeability without the intermediate steps.

Jennings concluded that as the PTS number increased, the relationship between pores, pore throats and porosity became poorly correlated with permeability, which Jennings described as a "dual-porosity effect." Jennings found that when the irreducible water saturation was greater than 25 percent (an indication of poor sorting), it became very difficult to predict permeability. In addition, when permeabilities fell below 1 md, it was extremely difficult to predict permeability due to the presence of different pore geometry-permeability relationships for poorly sorted rocks that had smaller, more constricted pore throats. Kamath\(^40\) subsequently confirmed this last finding in a 1988 study.

In 1994, Nelson\(^41\) published a comprehensive summary of the predictive equations used to relate permeability to porosity and other measurable petrophysical (rock) parameters. Nelson found that these relations could be separated into four distinct classes, as shown below.

- Empirical models based on grain size measurements for which permeability is a function of grain size, porosity and sometimes, grain sorting.
- Empirical models based on surface area measurements for which permeability is a function of surface area and porosity. Irreducible water saturation, exchange cation molarity and nuclear magnetic resonance decay time are often substituted for surface area when those data are not available.
- Empirical models based on *pore dimensional* measurements such as capillary pressure data for which permeability is a function of the pore opening size of the interconnected rock volume.

- Statistical models based on typically available *well log data* (i.e., gamma ray, bulk density, photoelectric capture cross section, resistivity, etc.) that have no true theoretical relationship to permeability.

For our study, we only have sufficient data to construct models based on pore dimensional measurements and well log data. Nelson concluded that for formations or reservoirs where core data and well log data were plentiful, a statistical model for permeability could be built using well log responses as the predictor variables. The author noted that such a model could be applied only to the reservoir or formation for which it was constructed.

In an unpublished 1995 work, Blasingame developed a type curve matching technique for permeability determination from capillary pressure data (non-wetting phase increasing). This work was based on the previous investigations of Purcell, Burdine, Brooks-Corey and Nakornthap-Evans. Blasingame used the Brooks and Corey formulation for effective saturation, \( S_w^* \) (Eq. 3.20) to derive an expression for the reciprocal of the squared capillary pressure in terms of \( S_w^* \) and the displacement pressure, \( p_d \), as shown below:

\[
\frac{1}{p_c^2} = \frac{1}{p_d^2} S_w^* \frac{2/\lambda}{\lambda} \quad \text{for} \quad p_c \geq p_d. 
\]

Blasingame then substituted this expression under the integral of the Nakornthap and Evans formulation for absolute permeability (Eq. 3.32), which yielded:

\[
k = 10.658 \phi^3 (\sigma_{nwp,wp} \cos \theta)^2 \frac{\beta}{n} \frac{1}{p_d^2} \left[ \frac{\lambda}{\lambda + 2} \right].
\]

Where \( \lambda \) is the Brooks and Corey pore distribution factor, defined above.

The results of a previous investigation by Blasingame and Ali indicated that the empirical constants for pore throat impedance (\( \beta \)) and the number of pore throats per pore body (\( n \)) could be substituted for in the following manner:
\[
\frac{\beta}{\pi} \equiv \alpha \frac{(1 - S_{wi})}{\phi}. \tag{3.41}
\]

Where \( \alpha \) is an empirical adjustment constant that is typically set equal to 1.

Making these substitutions, and using the previously defined expression for \( \phi^* \) (Eq. 3.33), Blasingame developed the following expression for absolute permeability (md):

\[
k = 10.658 \, (1 - S_{wi})^4 \left( \frac{\phi^2}{\rho_d} \right) \left[ \frac{\lambda}{\lambda + 2} \right]. \tag{3.42}
\]

In order to utilize Eq. 3.42, Blasingame developed a type curve matching technique to solve for \( S_{wi} \), \( p_d \) and \( \lambda \) simultaneously. The author defined the following dimensionless variables:

\[
S_{wD} = 1 - S_w^* = 1 - \frac{S_w}{1 - S_{wi}}. \tag{3.43}
\]

\[
p_D = \frac{p_c}{p_d} = S_w^{*-1/\lambda} = (1 - S_{wD})^{-1/\lambda}. \tag{3.44}
\]

Using this type curve approach, Blasingame would then overlay a plot of \( p_c \) (ordinate) versus \( 1 - S_w \) (abscissa) on top of a plot of \( p_d \) versus \( S_{wD} \). The "match point" values and \( \lambda \) could then be read directly off the type curve match and \( p_d \) and \( S_{wi} \) could be calculated as:

\[
p_d = \frac{(p_c)_{MP}}{(p_D)_{MP}}. \tag{3.45}
\]

\[
S_{wi} = \frac{(1 - S_w)_{MP}}{(S_{wD})_{MP}}. \tag{3.46}
\]

These results are then substituted into Eq. 3.42 to solve for absolute permeability. The Blasingame type curve is shown in Fig. 3.2, below.
This technique is typically used on data for which the non-wetting phase saturation is increasing. We note that if we apply these methods to capillary pressure data for which the wetting phase is increasing, then we must account for any residual non-wetting phase saturation, and Eq. 3.43 would be re-written as:

\[
S_{WD} = 1 - S_w^* = \frac{1 - S_{nwr} - S_w}{1 - S_{nwr} - S_{wi}} = \frac{S_c - S_w}{S_c - S_{wi}} \quad \text{................................................. (3.47)}
\]
3.3 – Application of Predictive Models for Permeability to NRU Data

Using only the Mercury-air capillary pressure data, we were able to generate predictive equations for effective air permeability as a function of capillary pressure, displacement pressure, saturation (wetting and non-wetting phases), median pore throat radii and porosity. We found that these predictive models could be built without dividing the data into sub-classes related to lithology and pore geometry.

3.3.1 – Special Core (SCAL) Data Available for NRU Study

The special core database available for this study consisted of capillary pressure, relative permeability, formation resistivity (for Archie $m$ and $n$ variables), mini-permeameter and formation compressibility data as summarized below in Table 3.2. These are not all the special core data available for the NRU, but these are the data that were available at the time these analyses were performed. The capillary pressure data are presented in tables in Appendix A for the 10-acre infill wells. The relative permeability data are presented in tables in Appendix B. The remaining SCAL data, which include electrical resistivity data, rock compressibility data and mini-permeameter data are given in Appendix C.

Only the capillary pressure and mini-permeameter data will be analyzed in this section. The formation resistivity data will be utilized in other sections of this report. As we will not be performing any fluid flow simulation work for this study, the relative permeability data will only be used as a qualitative indicator of reservoir performance (i.e., average irreducible water saturation and residual oil saturation) and reservoir wettability.
Table 3.2 – Special core analysis (SCAL) database.

<table>
<thead>
<tr>
<th>Time Period</th>
<th>Capillary Pressure Data</th>
<th>Relative Permeability Data (USS – unsteady-state)</th>
<th>Miniperm Data</th>
<th>Resistivity Data (m and n)</th>
<th>Formation Compressibility Data</th>
</tr>
</thead>
<tbody>
<tr>
<td>10-acre infill wells (1996)</td>
<td>92 high pressure Mercury-air data sets (4 wells)</td>
<td>13 native-state USS gas-oil data sets (3 wells)</td>
<td>150 feet across the primary pay intervals (1 well)</td>
<td>15 samples (3 wells)</td>
<td>6 samples (3 wells)</td>
</tr>
<tr>
<td></td>
<td>9 oil-water and water-oil centrifuge data sets (3 wells)</td>
<td>7 native-state USS water-oil and oil-water data sets (2 wells)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>2 native-state SS water-oil and oil-water data sets (2 wells)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>3 clean-state USS gas-oil data sets (3 wells)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>3 clean-state USS water-oil data sets (1 well)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>1 clean-state SS water-oil and oil-water data set (1 well)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>2 clean-state SS water-oil data sets (1 well)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>2 clean-state SS water-gas data sets (2 wells)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>20-acre infill wells (1987-1991)</td>
<td>29 Mercury-air data sets (3 wells)</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

We note that the special core data are limited in quantity and primarily cover only the high quality sections of the reservoir. Due to the relatively poor reservoir characteristics of the Clear Fork, these are the only intervals on which any fluid flow experiments, other than high-pressure Mercury injection, can be performed.

Many of the earlier mercury injection data from the 20-acre infill period (1987-1991) could not be utilized for quantitative analyses since they were taken at a relatively lower maximum injection pressure (2,000 psig) which resulted in only a partial invasion of the entire core sample pore space. In addition, air permeabilities were not measured for several of the sample tests. For these same samples, very large injection pressure increments made accurate estimation of the median pore throat radius or the Swanson parameter, \((S_d/p_c)A\), very difficult. As only 3 out of 29 sample test results were deemed
acceptable for quantitative analysis, we utilized only the Mercury-air capillary pressure data from the 10-acre infill wells drilled in 1996 for quantitative analyses. The 10-acre well oil-water centrifuge data was used qualitatively to help define the average irreducible water saturation and average residual oil saturation for the Clear Fork section.

3.3.2 – Predictive Equation for Air Permeability Using \((S_b/p_c)_A\)

Using the methodologies outlined by Wells and Amaefule,\textsuperscript{37} we easily calculated the Swanson\textsuperscript{33} correlating parameter, \((S_b/p_c)_A\), which is the inflection point of the capillary pressure curve. We then found that the measured air permeability was well correlated \((r^2 = 0.82)\) with the Swanson parameter as shown in Fig. 3.3, below.

Figure 3.3 – Prediction of air permeability from the Swanson correlating parameter, \((S_b/p_c)_A\), – SCAL plug trimmed ends.
As a data quality cross-check, we then utilized the predictive equation for air permeability as a function of \((S_b/p_c)_A\) to build a data overlay that could be used to quickly estimate air permeability from a capillary pressure profile, as shown in Figs. 3.4-3.5.

Although the overlay results did not always exactly agree with the measured air permeabilities (lack of fit at higher air permeabilities, see Fig. 3.3), the one-parameter model using \((S_b/p_c)_A\) did yield fairly accurate values for air permeability across the range of permeabilities typically found within the NRU Clear Fork interval. We note that a more robust predictive equation resulted when a second independent variable (porosity) was added to the model, however, that work is not presented here. The Swanson correlating parameter is by far the most statistically significant predictor variable of air permeability for these data. All pertinent data for this effort are given in Appendix A.

Figure 3.4 – Air permeability estimate from data overlay – NRU 3533, core sample #15B.
Hagiwara\textsuperscript{36} and Jennings\textsuperscript{39} both investigated the relationship between the median pore throat radius (\textit{MPTR}) calculated from Mercury-air capillary pressure data and the associated measured air permeability. We know from the work of Wardlaw\textsuperscript{30} that a better expression for pore throat radii in terms of capillary pressure and adhesive tension for carbonate rocks that have undergone dolomitization is:

\[
r = \frac{1}{p_c} (\sigma \cos \theta)_{Hg-\text{air}} \tag{3.48}
\]

For which \((\sigma \cos \theta)_{Hg-\text{air}}\) is the adhesive tension for a Mercury-air system (~368 dynes/cm), \(p_c\) is capillary pressure (psi) and \(r\) is pore throat radius in microns \((10^{-6} \text{ m})\).
However, all pore throat radii data shown in Appendix A were calculated using the relationship for the bundle of capillary tubes model, or:

\[ r = \frac{2}{p_c} (\sigma \cos \theta)_{Hg-air} \approx \frac{106.69}{p_c} \]  

........................................................................ (3.49)

Most core laboratories universally apply this equation (Eq. 3.49), although it is better suited to clastics than carbonates. We note that the model (Eq. 3.48 or Eq. 3.49) used to calculate pore throat radii from capillary pressure has little impact on any correlation between pore throat size and permeability since they differ by only a constant of 2.

Using Eq. 3.49, pore throat radii for each of the 92 Mercury-air trimmed-end sample data sets were calculated. The pore throat radius at the 50-percent saturation level (wetting or non-wetting phase) was defined as the median pore throat radius, MPTR. We found that the measured air permeability was well correlated \( (r^2 = 0.734) \) with \( MPTR \) as shown in Fig. 3.6, below.

Figure 3.6 – Prediction of air permeability from median pore throat radius, MPTR, – SCAL plug trimmed ends.
We note that a better predictive equation could be generated if a second independent variable (porosity) was added to the model. This agrees with the findings of Hagiwara,\textsuperscript{36} who found that air permeability was best correlated with porosity, cementation factor and the squared average pore throat radius (Eq. 3.29). We will use the median pore throat radius in our analyses as we feel that the average value is skewed by the contributions of the larger pore throats.

The average cementation factor from resistivity measurements on 15 core samples (Appendix C) was found to be 2.17. We know that this value represents a limited and high-graded portion of the Clear Fork interval, and we also know that $m$ varies significantly across the reservoir interval. If this two-parameter model is to be applied on a unit-wide basis, changes in $m$ must be accounted for, and we must be able to predict $MPTR$ from well log data. In order to overcome this potential problem, for our initial core analyses we did not assume exponents for either the porosity term or the $MPTR$ term, but rather let the data predict them for us. The results are shown in Fig. 3.7, below. The best fit of the data ($r^2 = 0.763$) was obtained using a porosity exponent of 1.1352 and a $MPTR$ exponent of 1.0462. In this case, the value of the porosity exponent should not be assumed to be representative of the cementation factor.

We could build a better predictive equation for air permeability by transforming the independent variables (core porosity and $MPTR$) or by using a non-parametric approach and assuming no specific functional relationship between independent variables or between independent variables and the dependent variable (air permeability). The use of the non-parametric approach will be discussed in detail in Chapter IV.

What is most important to our analyses at this point is that we have established fairly good correlations between both $(S_b/p_c)_A$ and $MPTR$ with the measured air permeability for the trimmed ends of 92 SCAL core plugs without having to segregate the data by pore types and lithologies. What remains to be seen is whether we will be able to predict permeability, $(S_b/p_c)_A$ or $MPTR$ from well log data on a unit-wide basis.
3.3.4 – Prediction of Absolute Permeability Using Type Curve Approach

For cases in which we have capillary pressure data, but have no core sample permeability data, we can employ the method proposed by Blasingame\textsuperscript{42} for the calculation of absolute permeability. As with all type curve analysis techniques, this method can be somewhat subjective, and is perhaps better suited for the analysis of more homogeneous, higher reservoir quality rocks (\textit{i.e.}, higher permeability) than are present within the NRU Clear Fork interval. Since we have air permeabilities available for all of the SCAL and conventional core samples analyzed in this work, we have no need to
calculate absolute permeabilities. This analysis technique is presented here so that interested readers may make their own investigations.

By overlaying a plot of $p_c$ (ordinate) versus $1-S_w$ (abscissa) on top of a plot of $p_D$ (ordinate) versus $S_{wD}$ (abscissa), capillary pressure and wetting phase saturation "match point" values together with the pore distribution factor, $\lambda$, can be read directly off the type curve. We may then calculate $p_d$ and $S_{wi}$ using Eqs. 3.45-3.46, and solve for the absolute permeability using Eq. 3.42. The type curve match results for the four example cases are shown in Figs 3.8-3.11, below.

![Type Curve Match](image)

**Figure 3.8** – Comparison between laboratory-measured $k_{a1}$ and type curve-calculated $k_{abs}$ – six core samples from four wells.
Figure 3.9 – Prediction of absolute permeability – NRU 1509, core #11A.

Figure 3.10 – Prediction of absolute permeability – NRU 3533, core #15B.
The results (Table 3.3) indicate very good agreement between the type curve match results and the available laboratory data. We note that the value obtained from the type curve match for the pore distribution factor, $\lambda$, is a good initial estimate that can be refined using the graphical technique shown in Fig. 3.1. The values obtained for displacement pressure agree very well with those obtained utilizing the plotting technique proposed by Jennings,\(^{39}\) which involves extending the slope of the capillary pressure plateau on a semilog plot of capillary (injection) pressure versus non-wetting phase saturation down to the ordinate-intercept in order to estimate $p_d$. For the cases presented, $S_{w,i}$ corresponds to the irreducible air saturation in a Mercury-air system.

If required, we could also generate relative permeability curves from the results of the type curve match using the formulations provided by Brooks and Corey\(^ {29}\) (Eqs. 3.23-3.24).
Table 3.3 – Comparison between lab data and type curve match results.

<table>
<thead>
<tr>
<th>Sample</th>
<th>Lab $k_{air}$ (md)</th>
<th>Type Curve $k_{abs}$ (md)</th>
<th>Lab $p_d$ (psi)</th>
<th>Type Curve $p_d$ (psi)</th>
<th>Lab $\lambda$ (dim.)</th>
<th>Type Curve $\lambda$ (dim.)</th>
<th>$S_{wi}$ (fraction)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Core 11A</td>
<td>0.29</td>
<td>1.18</td>
<td>26</td>
<td>28</td>
<td>0.43</td>
<td>0.75</td>
<td>0.10</td>
</tr>
<tr>
<td>Core 5B</td>
<td>0.15</td>
<td>0.05</td>
<td>40</td>
<td>44</td>
<td>0.27</td>
<td>1.00</td>
<td>0.25</td>
</tr>
<tr>
<td>Core 15B</td>
<td>12.00</td>
<td>40.50</td>
<td>17</td>
<td>19</td>
<td>0.80</td>
<td>1.00</td>
<td>0.00</td>
</tr>
<tr>
<td>Core 30C</td>
<td>5.81</td>
<td>9.17</td>
<td>18</td>
<td>25</td>
<td>0.69</td>
<td>1.00</td>
<td>0.06</td>
</tr>
<tr>
<td>Core 2D</td>
<td>0.83</td>
<td>1.48</td>
<td>38</td>
<td>43</td>
<td>0.37</td>
<td>1.00</td>
<td>0.07</td>
</tr>
<tr>
<td>Core 5D</td>
<td>0.01</td>
<td>0.13</td>
<td>40</td>
<td>40</td>
<td>0.22</td>
<td>0.22</td>
<td>0.10</td>
</tr>
</tbody>
</table>

3.4 – Assessment of Core Data Quality

As stated above, core data for the Clear Fork interval at the NRU has a tendency to be sample high-graded due to the fact that only the "best" sections of the reservoir possess sufficient permeability and porosity in order to perform laboratory fluid flow experiments (other than high-pressure Mercury injection).  Core samples chosen for special core analysis were screened to insure that we would actually be able to flow fluids (reservoir or synthetic) through them.

Conventional core results ("quick plug" data) were referenced to identify the most likely depth intervals for SCAL plug candidates.  All SCAL core samples were subsequently scanned using computed axial tomography (CAT scans) to identify and discard core samples with significant volumes of pore-blocking anhydrite, as shown in Fig. 3.12, below.  High CT numbers indicate higher density rock (in this case, anhydrite), which is represented as the lighter shading on the figure.  A short summary of the computed axial tomography work is provided in Appendix C.
North Robertson (Clear Fork) Unit, Gaines Co., TX
Small and Discontinuous Anhydrite Nodules

Fina/NRU 1509
Core No. 3, Slice D
Well Depth = 6349.9 ft
Min. CT No. = 2157
Max. CT No. = 2604
Avg. CT No. = 2322

Figure 3.12 – CAT scan and spectral display for 2-mm. slice of Upper Clear Fork core sample, NRU 1509.

3.4.1 - Statistical Validity of Laboratory Measurements

Taken as a whole, the models that were constructed to predict permeability from capillary pressure data gave fairly good results. Unfortunately, the Mercury-air capillary pressure data set available for analysis was insufficient for a statistically valid prediction of air permeability due to an extremely large sample variance. As a rule of thumb, the number of samples required to adequately describe a log-normally distributed parameter (i.e., permeability or median pore throat radius) can be approximated using the coefficient of variation, $C_v$, which also provides a measure of reservoir heterogeneity:\[ C_v = \sqrt{\exp(\sigma^2) - 1} \] (3.50)
Samples Required = \((10C_v)^2\). .......................................................... (3.51)

For which \(\sigma^2\) is the population variance, or in this case, the sample variance \((sv^2)\).

Based on the 10-acre well Mercury-air capillary pressure data, an infinite number of samples would be required to statistically model air permeability. As shown in Table 3.4 below, even if trim ends containing obvious fractures are dropped from the sample set, over 54 billion samples would be required to model air permeability. In addition, approximately four times the number of available samples would be required to build a valid statistical model for the prediction of median pore throat radius, \((MPTR\), which is directly related to air permeability\). These statistics give an indication of the extreme heterogeneity that exists within the Clear Fork section.

Table 3.4 – SCAL plug trim ends: air permeability and \(MPTR\) statistics.

<table>
<thead>
<tr>
<th>Trim End Statistic</th>
<th>Air Permeability (md)</th>
<th>Median Pore Throat Radius ((\mu)m)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Arithmetic Mean</td>
<td>2.1880</td>
<td>0.9160</td>
</tr>
<tr>
<td>Harmonic Mean</td>
<td>0.0278</td>
<td>0.0678</td>
</tr>
<tr>
<td>Geometric Mean</td>
<td>0.1651</td>
<td>0.2675</td>
</tr>
<tr>
<td>Median</td>
<td>0.1500</td>
<td>0.3790</td>
</tr>
<tr>
<td>Standard Deviation</td>
<td>4.4841</td>
<td>1.2144</td>
</tr>
<tr>
<td>Sample Variance</td>
<td>20.1072</td>
<td>1.4749</td>
</tr>
<tr>
<td>Coefficient of Variation</td>
<td>2.3240E+04</td>
<td>1.8359</td>
</tr>
<tr>
<td>Samples Required</td>
<td>5.4008E+10</td>
<td>337</td>
</tr>
<tr>
<td>Samples Available</td>
<td>89</td>
<td>89</td>
</tr>
<tr>
<td>Samples Dropped</td>
<td>3</td>
<td>3</td>
</tr>
</tbody>
</table>

If the capillary pressure data are segregated by rock type (based on lithology and pore geometry – discussed further in Chapter IV), there are sufficient data to adequately model only two out of the eight rock types defined for the Clear Fork interval (Table 3.5). We note that the reduction in sample variance that occurs when the data are split by rock type is primarily a function of the reduced number of samples for each sub-class rather than any decrease in sample heterogeneity due to groups with similar lithologies and pore geometries.
Table 3.5 – SCAL plug trim ends segregated by rock type: air permeability and median pore throat radii statistics.

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Trim End Statistic</th>
<th>Air Permeability (md)</th>
<th>Median Pore Throat Radius (µm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Sample Variance</td>
<td>11.0237</td>
<td>1.8438</td>
</tr>
<tr>
<td></td>
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<td>Sample Variance</td>
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<td>Coefficient of Variation</td>
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<td>0.6556</td>
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<td>Samples Required</td>
<td>3.2363E+04</td>
<td>43</td>
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<td>Sample Variance</td>
<td>0.4585</td>
<td>0.1231</td>
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<td>Coefficient of Variation</td>
<td>0.7627</td>
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<td>58</td>
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<td>Sample Variance</td>
<td>0.0529</td>
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<td>Coefficient of Variation</td>
<td>0.2331</td>
<td>0.0939</td>
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<td>Samples Available</td>
<td>10</td>
<td>10</td>
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<tr>
<td>5</td>
<td>Sample Variance</td>
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<td>Coefficient of Variation</td>
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</tr>
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<td>6</td>
<td>Sample Variance</td>
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<td>3.3105</td>
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<td>Coefficient of Variation</td>
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<td>1.7110E+19</td>
<td>2.640</td>
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<td>Samples Available</td>
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<td>7</td>
<td>Sample Variance</td>
<td>38.4670</td>
<td>1.9383</td>
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<td>Coefficient of Variation</td>
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<td>595</td>
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<td>Samples Available</td>
<td>10</td>
<td>10</td>
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<td>Sample Variance</td>
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<td>Coefficient of Variation</td>
<td></td>
<td></td>
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<tr>
<td></td>
<td>Samples Required</td>
<td>No samples</td>
<td>No samples</td>
</tr>
<tr>
<td></td>
<td>Samples Available</td>
<td>No samples</td>
<td>No samples</td>
</tr>
</tbody>
</table>

Therefore, while the analyses given above indicate that we could quantitatively examine the relationship between air permeability and the capillary parameters of interest (i.e., MPTR, \((S_b/p_c)_A\), etc.) using techniques described previously,\textsuperscript{33-38,42} we have insufficient data to build statistically valid models that can be utilized across the entire reservoir interval.

We note that this is certainly not an unusual occurrence when attempting to build statistical models using petrophysical parameters. Many of the models published in the petroleum literature are also statistically invalid or have very limited application. This
problem is exacerbated by the extreme heterogeneity present within the Clear Fork interval. We believe it would be difficult for us to find another hydrocarbon-bearing interval anywhere in the world that possesses a greater degree of heterogeneity.

We are somewhat skeptical of our ability to predict permeability across the entire reservoir interval using only the limited amount of capillary pressure data. In the next chapter, we will use the more abundant conventional core and well log data and attempt to construct a predictive model for permeability. We note, once again, in order to generate a predictive model for permeability that can be used on a unit-wide basis, we will need to be able to relate the results of conventional core analyses with well log responses (which are the only data available on a unit-wide basis).
CHAPTER IV

CORE-LOG MODELING FOR PERMEABILITY PREDICTION

4.1 – Application of Predictive Models to NRU Data

At the NRU, we found some correlation between porosity, permeability and depositional environment as shown in Chapter II. Different depositional environments exhibit similar ranges of porosity and permeability, which is somewhat surprising considering the rocks have undergone significant diagenetic alteration of their pore geometry after deposition. Unfortunately, the depositional environment can not be accurately predicted on a field-wide basis using available well log data.

As shown in Chapter III, permeability can be predicted as a function of median pore throat radius ($MPTR$) for individual core samples since these measurements are directly related to one another and have the same units [L$^2$]. The problem is that neither permeability nor $MPTR$ can be easily predicted from the available conventional well log data (as shown in Figs. 4.1–4.6, below) due to the fact that these data are essentially uncorrelated because they are from devices that do not measure the pore space directly. An exception to this is Nuclear Magnetic Resonance Log (NMR) data, which is unfortunately only available across selected intervals of two wells at the NRU.

In order to estimate permeability for the Clear Fork at NRU, it will be necessary to develop a permeability model at the pore scale level. The match between porosity (or other conventional well log measurements) and permeability should be better correlated if the rocks can be segregated on the basis of their characteristic pore structure. Therefore, it appears it will be necessary to segregate the reservoir by pore type and lithology in order to improve prediction of permeability or other reservoir characteristics of interest.
Figure 4.1 – MPTR versus gamma ray log.

Figure 4.2 – MPTR versus compensated neutron log.
Figure 4.3 – MPTR versus bulk density log.

Figure 4.4 – MPTR versus photoelectric capture cross-section log.
Figure 4.5 – MPTR versus deep resistivity log.

Figure 4.6 – MPTR versus shallow resistivity log.
4.2 – Literature Review: Use of Well Log Data for Permeability Prediction

There are a great number of references available concerning the use of well log data for the prediction of reservoir characteristics. As shown in Chapter III, this will usually involve the formulation of a statistical model for the prediction of the reservoir characteristic of interest.

In a 1950 study, Archie\textsuperscript{45} defined the term "petrophysics" to describe the study of the distribution of pore sizes and pore fluids within a porous medium. Archie examined the $k$-$\phi$ relationship for thirteen different sandstone and carbonate core samples from Texas and Louisiana and found that the pore size distribution controlled porosity and was related to permeability and water saturation. The author concluded that for any given formation, the porosity and permeability were only generally related and that this relationship would not necessarily improve as the reservoir was segregated into smaller sub-sets.

Archie pointed out the great need for a well logging device that could measure in-situ hydrocarbon volume ($\phi S_w$) and productivity ($k$) directly, since most well logs make indirect measurements of these properties. Archie also stressed the importance of analyzing both "pay" and "non-pay" rocks to avoid sample high-grading when constructing predictive models and pointed out the problems associated with analyzing core data that were measured at non-reservoir conditions.

In 1952, Archie\textsuperscript{46} developed a classification system for carbonate reservoirs based on pore structure and outlined the problems associated with defining "pay" quality rock in carbonates. Archie found that it was much more difficult to apply petrophysical relations to carbonates because of their high degree of vertical and lateral heterogeneity. Archie concluded that due to operational and economic constraints it might not always be possible to acquire the amount of conventional and special core data that would be necessary to accurately describe the pore structure of carbonate systems. Archie introduced the idea of using indirect data, such as well log data and drill cuttings data, to supplement whatever whole core data could be obtained in an individual well.
In 1968, Timur\(^{47}\) investigated permeability prediction for sandstone reservoirs using indirect in-situ measurements of porosity and residual water saturation obtained using an early version of the nuclear magnetic resonance (NMR) tool. Timur developed an empirical relation for effective permeability, \(k_e\), as a function of porosity, \(\phi\), and residual water saturation, \(S_{wi}\), using core and well log data for 155 sandstone samples from oil reservoirs in Texas, Colorado and California:

\[
k_e = A1 \left( \frac{\phi^{4.4}}{S_{wi}^{2}} \right)^{A2} = 0.136 \frac{\phi^{4.4}}{S_{wi}^{2}} \quad \text{for Timur's core study.} \quad \text{................................. (4.1)}
\]

The values of the constants \((A1\) and \(A2\)) depend on the formation and reservoir fluids under consideration. Timur found that the free-fluid index (FFI) measured by the NMR tool was directly related to the residual fluid saturation for the sandstone core samples in the study. \(S_{wi}\) was proven to be linearly related to the surface area term in the Kozeny\(^{13}\) equation by Rose and Bruce\(^{22}\), therefore, by simultaneously measuring NMR porosity and \(S_{wi}\), permeability could be estimated directly from well log data.

In a 1973 study, Coates and Dumanoir\(^{48}\) introduced a formation "textural" parameter, \(w\), that included the contributions of the Archie water saturation equation constant, \(a\), the cementation factor, \(m\), and the saturation exponent, \(n\). Coates and Dumanoir concluded that the three Archie parameters could be replaced by a single "textural" parameter, which was a function of pore structure and lithology. This result assumes that each given rock type has similar resistivity characteristics and that the ratio \((R_w/R_{ti})\) remains constant for a given rock type. The result is simply a re-arrangement of the Archie equation at the irreducible (initial) water saturation, as follows:

\[
S_{wi}^{n} = \frac{aR_w}{\phi^{m}R_{ti}} \quad \text{or} \quad \frac{S_{wi}^{n} \phi^{m}}{a} = \frac{R_w}{R_{ti}} \quad \text{or} \quad (S_{wi} \phi)^{w} = \frac{R_w}{R_{ti}} \quad \text{...................................... (4.2)}
\]

Where \(R_w\) is the formation water resistivity, \(R_{ti}\) is the true formation resistivity at irreducible conditions and \(S_{wi}\) is the water saturation at irreducible conditions.

This result was combined with that of Timur\(^{47}\) to derive an expression for effective permeability:
\[ k_e^{1/2} = \frac{C}{w^2} \left( \frac{\phi}{S_{wi}} \right)^w. \]  \hspace{1cm} (4.3)

Where \( C \) is an empirical constant that accounts for the hydrocarbon density within the pore space. These equations can be corrected for use at non-irreducible conditions and in shaly formations. These relations work well in homogeneous systems, but are often difficult to apply in heterogeneous, complex carbonate systems which possess multiple porosity types (i.e., intergranular, intercrystalline, vuggy, etc.) and are often fractured.

In 1982, Sera and Abbott\(^49\) studied the use of well log data to formulate high-resolution sedimentological descriptions of rock formations. In their work, the authors developed "electrofacies" (i.e., rock types) from multivariate analysis of well log data that could be directly correlated to actual rock facies when core data were available.

Sera and Abbott investigated how each different type of well log response could be used to describe the composition (mineral content), texture (size, shape, sorting and matrix cement type), sedimentary structure and fluid content of the rock. The authors found that certain conventional well log responses were best used to identify composition, while others might be best utilized to identify texture, structure or fluid content, as shown in Table 4.1.

<table>
<thead>
<tr>
<th>Characteristic</th>
<th>Primary Well Log Indicator</th>
</tr>
</thead>
<tbody>
<tr>
<td>Composition:</td>
<td>Spectral gamma ray and litho- or spectral density data</td>
</tr>
<tr>
<td>Texture:</td>
<td>Sonic and resistivity data (i.e., high-resolution resistivity data)</td>
</tr>
<tr>
<td>Sedimentary Structure:</td>
<td>Sonic and high-resolution resistivity data</td>
</tr>
<tr>
<td>Fluid Content:</td>
<td>Resistivity, SP and litho- or spectral density data</td>
</tr>
</tbody>
</table>

After environmental corrections and depth corrections were applied to the raw well log data, principle component analysis (log normalization and filtering), automatic zonation (based on pattern analysis) and cluster analysis (identifying primary rock types) were utilized to process the data and identify the different electrofacies types.

A 1991 study by Ahmed \textit{et al.}\(^50\) examined several commercially available permeability prediction models that often utilized unrelated predictor variables (i.e., well log data).
Model results are most often used to construct reservoir flow simulation models for future performance prediction, therefore, if the permeability models used do not make physical sense, the flow simulation results will be flawed.

Ahmed et al. illustrated the inherent weaknesses of predictive models that failed to consider several important considerations for the correlation of core data and well log data, as shown below.

- In-situ stress, pressure and temperature state of the rock
- Saturation history of the rock
- Direction of flow through core samples as compared to reservoir conditions
- Problems associated with comparing lab-scale measurements with reservoir-scale in-situ measurements (usually well log data)

Well log-derived methods typically predict effective permeability while core experiments usually measure absolute permeability. Unfortunately, reservoir flow processes are actually governed by relative permeability. The authors concluded that the prediction of a permeability value from an empirical or well log-based model that actually captured the in-situ flow performance of the reservoir is more of a favorable coincidence than a certainty.

Ahmed et al. felt that permeability prediction methods could be grouped in to three primary categories, shown below.

- Well Log-Derived Correlations
  - Correlation of permeability with porosity and irreducible water saturation
  - Correlation of permeability with NMR Free Fluid Index (FFI)
  - Correlation of permeability using mineralogy from geochemical logs
  - Correlation of permeability with Stonely wave velocity from Sonic Log
  - Correlation of permeability with pressure-time measurements from Formation Test Tool
- Empirical Correlations (summarized in Chapter III)
- Pressure Transient Tests
The authors concluded that pressure transient data were the best permeability predictors, if a formation production profile was available to capture the relative contribution of each layer and if single-phase flow could be maintained during the test.

In 1992, Howell et al.\textsuperscript{51} presented an integrated reservoir evaluation of the Clear Fork at the North Riley Field in Gaines County, Texas (offset to the NRU). Facies were segregated based on quantitative and qualitative core data analyses and visual and microscopic examination of slab and whole core. Separate equations for porosity, water saturation and permeability were developed for each facies type and extrapolated across the field to non-cored wells using well log data.

The results of the study were used in an attempt to improve sweep efficiency (active waterflood) and productivity in a cost-effective manner. Howell et al. concluded that production efficiency could be improved by decreasing well spacing and targeting individual reservoir "sweet spots" both laterally (interwell) and vertically (intrawell).

The authors utilized the Timur\textsuperscript{47} equation (Eq. 4.3) for permeability prediction and found it difficult to match well log-derived and lab-measured values of permeability. These problems were attributed to:

- differences in measurement scale between the well log and core data,
- difficulty in applying this relation to rock possessing vuggy or fracture porosity, and
- continuous porous intervals consisting of several facies types not easily segregated.

A 1993 study by Clerke et al.\textsuperscript{52} considers the problems associated with quantitative well log analysis of the heterogeneous and mixed-lithology rock contained within the Clear Fork and Glorieta intervals on the Central Basin Platform and Northern Platform of the Permian Basin. Clerke et al. developed the Dolomite-Anhydrite-Potassium (DAK) model. The DAK model utilizes conventional well log inputs such as Bulk Density, Photoelectric Capture Cross Section and spectral gamma ray data (for determining silt volume from potassium content) in order compute mineralogy and a lithology-corrected porosity.
The correct identification of silty zones is the key since these zones are typically regional and local correlation markers as well as non-productive flow barriers that mark the termination of fining-upward sequences that are usually defined as flow units within the Clear Fork–Glorieta sequence. The identification of intervals with significant anhydrite content is also important since the presence of anhydritic-dolomite can be associated with both the most productive intervals and reservoir flow barriers. These results must be correlated with available core data to determine the type of anhydrite present (pore-filling, nodular or matrix replacement) and to determine reservoir quality. These data also aid in our understanding of the diagenetic processes that have occurred as well as the scaling tendencies (gypsum) of the interval under waterflood conditions.

We note that Clerke et al. did not extend their study to consider the prediction of facies types and permeability using the results of the DAK model, but simply used lithology-corrected porosity as a "pay" indicator. They also did not consider the lime content of the reservoir interval in their model, which is significant in our analysis of the Clear Fork at the North Robertson Unit.

In 1993, Amaefule et al. investigated techniques for isolating hydraulic "flow units" (HFU) within rock facies. The authors found that even when reservoir intervals were segregated using mineralogy and pore structure, for any given porosity, permeability could vary significantly. This indicated the presence of several distinct flow units within each facies with different fluid flow characteristics.

Amaefule et al. used the Kozeny-Carman "bundle of capillary tubes" model and developed an expression for mean hydraulic radius to construct a graphical technique for isolating these flow units. The Kozeny-Carman equation was re-arranged to yield:

\[ \sqrt{\frac{k}{\phi_e}} = \left[ \frac{\phi_e}{1 - \phi_e} \right] \left[ \frac{1}{\sqrt{F_s \tau S_{gv}}} \right] \] ................................. (4.4)

Where \( k \) is permeability (10^{-12} m^2), \( \phi_e \) is the effective porosity, \( F_s \) is the shape factor, \( \tau \) is the tortuosity and \( S_{gv} \) is the surface area per unit grain volume (1/10^{-6} m). The authors then defined three plotting functions as:
\[ RQI = 0.0314 \sqrt{\frac{k}{\phi_e}} \] ................................................................. (4.5)

\[ \phi_z = \frac{\phi_e}{1 - \phi_e} \] ................................................................. (4.6)

\[ FZI = \frac{1}{\sqrt{F_s \tau S_{sv}}} = \frac{RQI}{\phi_z} \] ................................................................. (4.7)

Where \( RQI \) is the "reservoir quality index" in microns (10^-6 m), \( \phi_z \) is the pore volume-to-grain volume ratio and \( FZI \) is the "flow zone indicator" in microns (10^-6 m). On a log-log plot of \( RQI \) versus \( \phi_z \), all data with the same \( FZI \) (similar flow characteristics) will lie on a unit-slope line and the value of \( FZI \) can be determined at the intersection of the unit-slope line at \( \phi_z = 1 \), as shown in Fig. 4.7, below.

An expression was then formulated for permeability (md) from Eqs. 4.4 – 4.7 as:

\[ k = 1,014 (FZI)^2 \left[ \frac{\phi_e^3}{(1 - \phi_e)^2} \right] \] ................................................................. (4.8)

Where \( \phi_e \) is the effective porosity (fraction) and 1,014 is the conversion factor for permeability between m^2 and md.

The authors concluded that the flow zone indicator parameter, \( FZI \), incorporated mineralogy, texture and pore structure and that its calculation enabled intervals with similar fluid flow characteristics to be segregated correctly. In order to be applied correctly, this parameter had to be combined with mineralogical and textural data, capillary pressure data taken to characterize the rock’s pore structure as well as core permeability and porosity data taken at in-situ conditions. Amaefule et al. also found that the \( FZI \) parameter (and hence, permeability) could be predicted from conventional well log data using an appropriate statistical model, although no examples were shown to verify this statement. Johnson54 gives an excellent application example of the method of Amaefule et al. in a 1994 study performed on west Texas sandstone and carbonate reservoirs.
A problem arises when we must decide how many flow units actually exist in a particular reservoir. Fig. 4.7 shows that even when the reservoir is segregated by rock type (as defined in this study), it is still difficult to identify the numerous individual flow units. If we do not have a detailed core description, it is difficult to identify what properties the rocks possess that gives them similar fluid-flow characteristics. Without a foot-by-foot detailed core description, the method becomes rather difficult to apply. If sufficient data are available, this appears to be an excellent method for permeability prediction, if and only if, the reservoir can be segregated into well-defined hydraulic
units and well log data for these flow units can be used to predict statistically valid permeabilities. In addition, the process must be completed in a cost-effective manner.

In a 1994 study, Mohaghegh et al.\(^{55}\) used a three-layer, feed-forward, back-propagation neural network to predict permeability from well log data in a heterogeneous West Virginia sandstone reservoir. The authors concluded that because neural nets are model-free function estimators, a properly constructed and trained neural net should be able to solve the complex relationship that exists between reservoir permeability and geophysical (well log) data.

The reservoir was segregated into sub-units based on geologic interpretation prior to processing. The model was trained to solve for core permeability using well log depth, gamma ray log, bulk density log, deep induction resistivity log and zone assignment data. Mohaghegh et al. found that each of the predictor variables influenced reservoir permeability and should be included in the model (Table 4.2).

<table>
<thead>
<tr>
<th>Predictor</th>
<th>Effect on Permeability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Depth</td>
<td>formation pressure</td>
</tr>
<tr>
<td>Gamma Ray Log</td>
<td>clay content</td>
</tr>
<tr>
<td>Bulk Density Log</td>
<td>inversely related to porosity</td>
</tr>
<tr>
<td>Deep Resistivity Log</td>
<td>fluid saturation and possibly fluid migration</td>
</tr>
<tr>
<td>Zone Assignment</td>
<td>flow units with similar fluid flow characteristics</td>
</tr>
</tbody>
</table>

In subsequent studies, Mohaghegh et al.\(^{56-57}\) found that neural networks did a far superior job than statistical or empirical models for predicting permeability from data that it had not been "trained" on. Empirical and statistical models constructed using core and well log data in a limited number of wells are far less precise for permeability prediction in offset wells using only well log data. This is primarily due to the fact that the range of model-predicted values is always much smaller than the actual data since simple functions are often used to fit complex, non-linear relationships.

It should be noted, however, that a major weakness of neural network application is that the results can not be expressed in a simplified mathematical form (as of this writing) so
that they can be easily coded into a general solution algorithm. This is especially vital when a large well database must be processed.

In a 1995 paper, Abbaszadeh et al.\textsuperscript{58} provide a step-by-step procedure utilizing the methodologies outlined by Amaefule et al.\textsuperscript{53} for identifying hydraulic flow units (HFU) and estimating permeability based on the flow zone indicator (FZI). The authors utilized graphical probability methods, nonlinear regression or analytical algorithms to predict hydraulic flow units given conventional well log inputs. After estimating the most probable flow unit for a given set of well log responses (\textit{i.e.}, each depth increment), the mean FZI value for that HFU was utilized to predict permeability using Eq. 4.8.

In 1996, Hinterlong and Taylor\textsuperscript{59} constructed a core-calibrated geophysical model for permeability prediction in the San Andres Formation of the Midland Basin, west Texas. Hinterlong and Taylor modified the Kozeny-Carman\textsuperscript{15} equation by replacing the Kozeny\textsuperscript{13} constant with the gamma ray index (considered analogous to surface area per grain volume) and the tortuosity term with a well log derived cementation factor (as defined by Nugent\textsuperscript{60}).

The primary contribution of this paper to the literature is an excellent summary of the factors affecting core-log models for permeability prediction, as summarized below.

- **Systematic sampling differences** – core porosities and permeabilities are difficult to correlate with well log inputs due to sample high grading. The well logging tools average a one-foot to five-foot vertical section surrounding the wellbore, while the core measurements are performed on subjectively chosen samples in the reservoir intervals from which valid measurements can be made. Whole core data can be correlated easier with well log data than core quick plugs due to their respective measurement scales.

- **Saturation differences** – Core permeability measurements are made with Helium on cleaned and dried samples. Well log measurements are made in-situ on rock with a large range of wetting and non-wetting fluid saturations, and often with different wettability characteristics.

- **Stress differences** – If core measurements are not made under reservoir stress conditions, core permeabilities may be too optimistic when compared to in-situ well log measurements due to stress relief.

- **Effect of wettability on permeability prediction** – In a reservoir with mixed wettability, several predictive models for permeability may be required.
4.3 – Conventional Core and Well Log Data Available for NRU Study

The conventional core and well log data for the NRU is summarized in Tables 4.3 – 4.4, below. The quality of the core plug and whole core data from the original 40-acre development wells was questionable, and due to the fact that we had no accompanying well log data, these data were not used in our analyses. Full well log suites (gamma ray, compensated neutron, compensated density, photoelectric capture cross-section, shallow laterolog resistivity and deep laterolog resistivity) were available for all four cored 10-acre infill wells and two of the cored 20-acre infill wells. The conventional core data that were utilized for these analyses are presented in spreadsheet form in Appendix D. The conventional well log data for the cored wells are given in Appendix E.

Table 4.3 – Conventional core database.

<table>
<thead>
<tr>
<th>Time Period</th>
<th>Core Plug Data</th>
<th>Whole Core Data (Analyzed)</th>
</tr>
</thead>
<tbody>
<tr>
<td>10-acre infill wells</td>
<td>2404 plugs</td>
<td>275 feet</td>
</tr>
<tr>
<td>1996</td>
<td>(4 wells)</td>
<td>(4 wells)</td>
</tr>
<tr>
<td>20-acre infill wells</td>
<td>1247 plugs</td>
<td>1727 feet</td>
</tr>
<tr>
<td>1987-1991</td>
<td>(3 wells)</td>
<td>(5 wells)</td>
</tr>
<tr>
<td>40-acre wells</td>
<td>262 plugs</td>
<td>687 feet</td>
</tr>
<tr>
<td>1956-1964</td>
<td>(2 wells)</td>
<td>(3 wells)</td>
</tr>
<tr>
<td>Total</td>
<td>3913 plugs</td>
<td>2689 feet</td>
</tr>
</tbody>
</table>

Table 4.4 – Well log database.

<table>
<thead>
<tr>
<th>Time Period</th>
<th>Standard Well Logs</th>
<th>Other Well Logs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cored 10-acre infill wells</td>
<td>GR, RHOB, PE, CNL φ, LLS, LLD</td>
<td>Spectral GR, $\Delta t$, NMR</td>
</tr>
<tr>
<td>1996</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cored 20-acre infill wells</td>
<td>GR, RHOB, PE, CNL φ, LLS, LLD</td>
<td>Spectral GR, $\Delta t$</td>
</tr>
<tr>
<td>1987-1991</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Cored 40-acre wells</td>
<td>Old E-Logs, GR-Neutron</td>
<td></td>
</tr>
<tr>
<td>1956-1964</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

4.4 – Previous Permeability Modeling Efforts for the Clear Fork at the NRU

In order to identify "pay" intervals for the Clear Fork section at the NRU, the rock was examined at the pore-scale level. Pore geometries were defined on the basis of visual...
and microscopic inspection of thin sections and pore casts in order to identify several fairly distinct "rock types" that were then correlated with individual well log responses.

A geological/petrophysical model was developed for the reservoir based primarily on the measurement of pore geometrical parameters. These pore geometry attributes (and their associated capillary pressure characteristics) were utilized to define eight distinct "rock types" which were subsequently used in order to separate the reservoir into "pay" and "non-pay" intervals and to generate rock type-specific permeability, porosity and water saturation relationships. These data were then used to produce a foot-by-foot description of the reservoir in order to define flow units and to provide input for reservoir flow simulation.

This study was performed using the following methodologies:

- Development of a depositional and diagenetic model of the reservoir.
- Definition of "rock types" based on pore geometry and development of a core-log model for the prediction of rock type, permeability and water saturation.
- Prediction of these key parameters for non-cored wells using the core-log model and available conventional well log data.

No new wells were drilled to aid the initial reservoir description. The database consisted of conventional core data from eight wells, and relatively complete well log suites from approximately 120 20-acre infill wells drilled between 1987 and 1991, which included:

- Gamma ray, GR
- Photoelectric capture cross-section, PE
- Compensated neutron porosity, \( \phi_N \)
- Compensated formation bulk density, \( \rho_b \)
- Dual laterolog (LLD and LLS—deep/shallow resistivities)

4.4.1 – Pore Geometry Modeling

Analysis of 3D pore geometry data allowed reservoir characterization efforts to be pore system oriented. Analysis of pore geometry involved the identification of individual pore types and rock types.
Davies and Vessell\textsuperscript{61} used the quantitative analysis of pore geometry to develop the vertical reservoir layering profile of the reservoir (\textit{i.e.}, to identify vertical compartmentalization) at the NRU. Davies and Vessell found that integrating pore scale observations with depositional and diagenetic data allowed for determination of areal compartmentalization and the permeability distribution in the reservoir.

4.4.2 – Pore Types

The determination of pore types required the use of rock samples from conventional cores, sidewall cores and sometimes drill cuttings. In this study, analyses were based on 1-inch diameter "quick" plugs removed from conventional cores. Individual pore types were segregated using the following parameters:

- **Pore Body Size and Shape**
  - Determined using scanning electron microscope (SEM) image analysis of the pore system\textsuperscript{62}

- **Pore Throat Size**
  - Determined through capillary pressure analysis and SEM analysis of pore casts\textsuperscript{30}

- **Aspect Ratio**
  - The ratio of pore body to pore throat size. This is a fundamental control on hydrocarbon displacement\textsuperscript{63-64}

- **Coordination Number**
  - The number of pore throats that intersect each pore\textsuperscript{32}

- **Pore Arrangement**
  - The detailed distribution of pores within a sample\textsuperscript{32}

These parameters were combined to yield a classification of the various pore types in these rocks (Table 4.5). Pore types were identified in each core sample (350 samples in this study). Commonly, each sample (1-inch diameter core plug) contained several different pore types. It was therefore necessary to group pore types into "rock types."

For each sample, the volumetric proportion of each pore type was determined using SEM-based image analysis\textsuperscript{62}. Since the pore throat size was known for each pore type, it
was possible to develop a pseudo-capillary pressure curve for each sample using Thomeer's expression for displacement pressure (Eq. 3.28):

\[ p_d = \frac{4\sigma \cos \theta}{d_{\text{max}}} \approx \frac{214}{d_{\text{max}}}. \]  

(3.28)

Where the displacement pressure, \( p_d \), is in psi, the interfacial tension, \( \sigma \), is in dynes/cm and \( d_{\text{max}} \) is in microns (10\(^{-6}\) m).

The validity of the geologically determined rock types was evaluated using Mercury capillary pressure analysis of selected samples. The results revealed differences between rock types in their measured capillary characteristics (Table 4.6). Such cross-checks allowed for independent validation of the pore geometrical classification of rock types. Mercury capillary pressure data were also used in the estimation of pore throat sizes.

### Table 4.5 – Pore type and classification at the NRU.

<table>
<thead>
<tr>
<th>Pore Type</th>
<th>Size (10(^{-6}) m)</th>
<th>Shape</th>
<th>Coord. Number</th>
<th>Aspect Ratio</th>
<th>Pore Arrangement</th>
<th>Geologic Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>30-100</td>
<td>Triangular</td>
<td>3-6</td>
<td>50-100:1</td>
<td>Interconnected</td>
<td>Primary Interparticle</td>
</tr>
<tr>
<td>B</td>
<td>60-120</td>
<td>Irregular</td>
<td>&lt;3</td>
<td>200:1</td>
<td>Isolated</td>
<td>Shell molds and vugs</td>
</tr>
<tr>
<td>C</td>
<td>30-60</td>
<td>Irregular</td>
<td>&lt;3</td>
<td>100:1</td>
<td>Isolated</td>
<td>Shell molds and vugs</td>
</tr>
<tr>
<td>D</td>
<td>15-30</td>
<td>Polyhedral</td>
<td>~6</td>
<td>&lt;50:1</td>
<td>Interconnected</td>
<td>Intercrystalline</td>
</tr>
<tr>
<td>E</td>
<td>5-15</td>
<td>Polyhedral</td>
<td>~6</td>
<td>&lt;30:1</td>
<td>Interconnected</td>
<td>Intercrystalline</td>
</tr>
<tr>
<td>F</td>
<td>3-5</td>
<td>Tetrahedral</td>
<td>~6</td>
<td>&lt;20:1</td>
<td>Interconnected</td>
<td>Intercrystalline</td>
</tr>
<tr>
<td>G</td>
<td>&lt;3</td>
<td>Sheet/slot</td>
<td>1</td>
<td>1:1</td>
<td>Interconnected</td>
<td>Interboundary sheet and intercrystalline pores</td>
</tr>
</tbody>
</table>

### Table 4.6 – Capillary characteristics by rock type based on mercury injection.

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Entry Pore Throat Radius (10(^{-6}) m)</th>
<th>Displacement Pressure (psia)</th>
<th>Ineffective Porosity (porosity invaded by Hg at ( p_d &gt; 500 ) psia) (percent)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>7.6-53.3</td>
<td>2-10</td>
<td>8.2-29.6</td>
</tr>
<tr>
<td>2</td>
<td>2.7-3.6</td>
<td>30-40</td>
<td>23.1-49.5</td>
</tr>
<tr>
<td>3</td>
<td>0.4-1.3</td>
<td>80-300</td>
<td>61.6-72.3</td>
</tr>
<tr>
<td>4*</td>
<td>1.8</td>
<td>60</td>
<td>88</td>
</tr>
<tr>
<td>5</td>
<td>1.1-1.8</td>
<td>60-150</td>
<td>21.7-57.2</td>
</tr>
<tr>
<td>6*</td>
<td>0.1</td>
<td>800</td>
<td>100</td>
</tr>
</tbody>
</table>

* - Only one (1) measurement
4.4.3 – Rock Types

A "rock type" is an interval of rock characterized by a unique pore structure, but not necessarily a unique pore type. In this study, eight rock types were identified based on the relative volumetric abundance of each pore type, as shown in Fig. 4.8, below.

![Pore types by volume percent](chart.png)

Figure 4.8 – Volumetric proportions of pore types in each rock type.

Each rock type was characterized by its underlying pore type signature. For example, Rock Type 1 is dominated by Pore Type A, while Rock Type 2 contains few pores of Type A and is dominated by Pore Types B and C. Identification of rock types is fundamentally important because porosity and permeability may be related within a specific pore structure.

4.4.4 – Porosity-Permeability Relationship

At the NRU, the basic relationship between porosity and permeability exhibits a considerable degree of scatter (up to 4 orders of magnitude variation in permeability for a given value of porosity) as shown in Fig. 4.9. This phenomenon is typical for reservoirs in which significant post-depositional diagenesis has occurred.
In contrast, it was found that porosity and permeability appeared to be closely related for each rock type, as shown in Fig. 4.10. Regression equations for permeability as a function of porosity were developed for each rock type to quantitatively define each relationship (using log-log plots to avoid zero porosity intercepts). These equations were used in the field-wide prediction of permeability using well logs (permeability being a function of porosity and rock type).

Figure 4.9 – Core porosity versus core permeability for the Clear Fork interval.
Median values of porosity and permeability are given for each rock type in Table 4.7. We note that the highest porosity rocks at the NRU do not necessarily exhibit the highest permeability.

Table 4.7 – Porosity, permeability and lithology by rock type.\textsuperscript{61}

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Median Porosity (percent)</th>
<th>Median (Hg/air) Permeability (md)</th>
<th>Lithology</th>
<th>Reservoir Quality</th>
<th>Cross-flow Barrier Quality</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4.0</td>
<td>0.70</td>
<td>Dolostone</td>
<td>Excellent</td>
<td>Poor</td>
</tr>
<tr>
<td>2</td>
<td>5.6</td>
<td>0.15</td>
<td>Dolostone</td>
<td>Good</td>
<td>Poor</td>
</tr>
<tr>
<td>3</td>
<td>3.5</td>
<td>0.39</td>
<td>Dolostone</td>
<td>Moderate</td>
<td>Moderate</td>
</tr>
<tr>
<td>4</td>
<td>7.5</td>
<td>0.01</td>
<td>Dolostone</td>
<td>Poor</td>
<td>Moderate</td>
</tr>
<tr>
<td>5*</td>
<td>5.8</td>
<td>0.40</td>
<td>Limestone</td>
<td>Good (water-bearing)</td>
<td>Poor</td>
</tr>
<tr>
<td>6</td>
<td>1.0</td>
<td>&lt;0.01</td>
<td>Anhydritic Dolostone</td>
<td>None</td>
<td>Good</td>
</tr>
<tr>
<td>7</td>
<td>2.3</td>
<td>&lt;0.01</td>
<td>Silty Dolostone</td>
<td>None</td>
<td>Good</td>
</tr>
<tr>
<td>8</td>
<td>--</td>
<td>--</td>
<td>Shale and argillaceous dolostone</td>
<td>None</td>
<td>Good</td>
</tr>
</tbody>
</table>

* – Structurally low and wet at the NRU
4.4.5 – Rock-Log Model

Analyses of pore geometries revealed that eight rock types occur in the Clear Fork at the NRU. Six of the rock types are dolostone, one is limestone (non-pay – structurally low and wet), and one is shale. Individual rock types were segregated using specific "cut-off" values based on analysis of environmentally corrected and normalized well log responses. These results were then compared with a visual core-based determination of rock type.

As was shown previously (Fig. 4.10), permeability appears to be a function of both rock type and porosity. Davies and Vessell\textsuperscript{61} theorized that rock type and porosity could be determined from well log responses alone. Therefore, permeability could, in principle, be predicted using only conventional well log data. This gave us the ability to develop a vertical layering profile based on rock type and permeability in cored and non-cored wells.

Early indications were that by using multiple geologic "filters" it would be possible to dramatically reduce the scatter on porosity versus permeability crossplots, resulting in a more useful predictive model. These "filters" included depositional environment data, shallowing-upward sequence tops, rock type data, mud log data, and numerous open-hole log responses (\textit{i.e.}, PE Log, Spectral Gamma Ray Log and invasion profile).

Unfortunately, there were no Spectral Gamma Ray or Flushed Zone Resistivity data for most of the existing wells (those drilled before 1996).

Well log responses used to isolate the eight different rock types for the NRU study were:

- Apparent matrix density ($\rho_{maa}$), volumetric capture cross-section ($U_{maa}$) and Gamma Ray Log
  - This data plot allows the discrimination of dolostone, limestone, anhydritic dolostone, siltstone, and shale
  - Can be used to identify "pay" vs. "non-pay" reservoir rock

- Shallow and deep laterolog resistivities and porosity
  - Provides discrimination of "pay" Rock Types 1-3
The rock-log model was developed using data from eight cored wells. The model was extended to all wells with sufficient well log data (120 wells). Computational algorithms allowed for rock type identification on a foot-by-foot basis in each well. Fig. 4.11 illustrates how the "pay" and "non-pay" rocks were segregated, while Figs. 4.12–4.13 show how the "pay" rock types were segregated.

There is a general tendency at the NRU for the higher quality rocks (Rock Types 1 and 2) to occur in discrete trends on the northeast (high-energy) edge of the unit. Relatively lower quality rocks (Rock Types 3 and 4) are found most often in the southwest (low energy) portion of the unit. Within these general trends, variations exist in the distributions of permeability. These variations are important as they result in the lateral heterogeneity that is characteristic of the Clear Fork at the NRU. There are no faults cutting Clear Fork interval, and reservoir compartmentalization is entirely stratigraphic.

Figure 4.11 – Differentiating "pay" from "non-pay" reservoir rocks.
Figure 4.12 – Differentiating "pay" reservoir rocks.

Figure 4.13 – Differentiating rock types 3 and 4.
Individual reservoir flow units were identified after integrating rock type data, petrophysical properties (permeability and water saturation) and depositional facies. Evaluation of well log and core data for 120 wells revealed that rock types were not randomly distributed, but that the principal reservoir rocks (Rock Types 1, 2, and 3) generally occurred in close proximity, and typically alternated with lower quality rocks (*i.e.*, Rock Types 4 – 8).

Correlation of rock types between wells resulted in a layering profile in which 12 distinct layers, separated by no-flow boundaries, could be identified within the Clear Fork at the NRU. The results also indicate an approximate relationship between rock type and depositional environment. Rock Types 1 and 2 are common in high-energy deposits (shoals, sand flat and forebank). Rock Types 3 and 4 are common in low energy deposits (supratidal, tidal flat and lagoonal).

Maps of important petrophysical parameters were prepared for each of the reservoir flow units. The distributions of the principal rock types for each flow unit were also mapped. This allowed for identification of areas of the field dominated by either high or low quality reservoir for infill drilling purposes, and for a layering scheme to be utilized for reservoir flow simulation.

4.5 – Sources of Error

Although the methodologies utilized to construct the rock-log model are perfectly sound, our review of the available core and well log data indicated several shortcomings. Our major concerns are lack of correlation between whole core (or quick plug) permeability and the well log data used for its prediction and the statistical validity of the resulting models. These two factors may determine if we can construct a useful model for the prediction of permeability.

The solution algorithms used in the previous model were based on sometimes questionable core data from the 40-acre development wells and the 20-acre infill wells, however, that was the only data available at the time. Low permeability data (possible measurement errors) and extremely high permeability data (fractures and fissures) were
omitted from the data set in order to obtain a better permeability match. The model utilized only one predictor variable (porosity) for permeability estimation and did a less than adequate job of matching the core data, as shown in Figs. 4.14–4.15 below.

Much of the conventional core data used in the initial study often contained data from different reservoir scales (1-inch diameter quick plugs versus 4-inch diameter whole core) that were inadvertently mixed together. Most of the core data were taken in the primary pay intervals. This resulted in an incomplete sampling of the reservoir and "high-grading" of the data set.

Figure 4.14 – Whole core $k_{\text{max}}$ and model–calculated permeability versus depth for NRU 207.
When we attempt to predict reservoir rock properties on a foot-by-foot basis (which is the minimum vertical interval that we can evaluate with the available core and well log data), there are many instances in which a particular one-foot section might contain a number of different rock types. In this case, we might misidentify rock types and make erroneous predictions of well log-derived permeability and porosity. We might identify a particular interval as being of non-pay quality when it may actually contain producible hydrocarbons, or we might assign pay attributes to an interval that will not produce.
When the initial model was applied to data outside the training set, we found that rock type could often not be accurately predicted as shown in Fig. 4.16, below.

![Graph showing comparison of visually determined rock types with model-calculated rock types for SCAL plug clip end samples.](image)

Figure 4.16 – Comparison of visually determined rock types with model-calculated rock types for SCAL plug clip end samples.

It appears that there may not be a sufficient amount of core data in hand to accurately characterize the heterogeneity that exists in the Clear Fork interval. Additional statistical bias was introduced when many of the data that fell off of the main porosity-permeability trend line were often omitted from the final analysis although they may have been influential in the correct prediction of porosity and permeability. The question is, can a valid permeability model be generated for the Clear Fork at the NRU?
Water saturations were calculated using Archie's water saturation equation and the rock type-derived (lithology-corrected) porosity. The cementation factor, \( m \), the saturation exponent, \( n \), and the water resistivity, \( R_w \), were assumed to be constant across the entire Clear Fork interval. We know that these three critical parameters vary significantly in the Clear Fork due to multiple porosity types such as intergranular, intercrystalline, vuggy, moldic and fracture porosity, and salinity changes resulting from long-term water injection. We will address these problems in our current work.

We do not question the results and conclusions of the previous work, since we know that fluid flow properties are controlled by the pore-scale properties that are imbedded in the rock type definitions outlined in the previous section. However, due to the degree of heterogeneity present within the Clear Fork, segregation of the data by rock type is insufficient for accurate prediction of permeability and porosity from well log data. It is obvious that we must find an improved method for segregating data with similar flow characteristics before attempting to predict permeability. The remainder of this chapter summarizes the work performed to find that improved methodology.

We saw in our review of existing literature on the subject that there are several other concerns that must be addressed to improve the predictive model. Not all of these concerns can be addressed in a timely or cost-effective manner, therefore we will concern ourselves with those problems that we can control with the data we have in-hand, as summarized below.

4.5.1 – Measurement Scale
The use of quick plug permeability data introduces more vertical heterogeneity than can be accounted for when using well log data as predictor variables, therefore, whole core data will be preferred for the construction of a model for permeability prediction. We felt the full-diameter whole core data would be more representative of the section of the borehole "seen" by conventional well logging tools which have vertical resolutions ranging from six inches to three feet and lateral depths of investigation between six
inches and five feet. However, we may need to consider the use of the more abundant
tquick plug data if we can not achieve adequate results using the whole core data.

4.5.2 – Core Sample High-Grading
Since whole core data were taken primarily across "reservoir" sections of the Clear Fork
interval, we are unable to address the sample high-grading problem. However, we note
that the majority of the quick plug permeability and porosity measurements made in non-
reservoir sections are either questionable or too small to measure due to the fact that
fluids (including air) can not be easily injected through the poorer quality Clear Fork
rock. For this reason, it is sufficient that we are able to accurately predict permeability
within the "pay" sections of the reservoir.

4.5.3 – Core Measurements at Non-Reservoir Stress Conditions
The available whole core and quick plug data for this study were taken at minimal
confining stress conditions (500 psi). The range of in-situ confining stress for the Clear
Fork interval is approximately 2,000 psi – 4,000 psi, and varies non-linearly with depth
as a function of the degree of waterflood support in the continuous reservoir layers. If
core experiments are not performed at in-situ stress conditions, laboratory measurements
of porosity and permeability may be overly optimistic when compared to in-situ well
log-derived measurements due to stress relief. These differences are also a function of
the texture, composition and degree of fracturing present within individual samples.
Reduction in permeability is the most significant problem when relating laboratory
results at negligible confining stresses to in-situ conditions. This may lead to errors
when predictive models are constructed if there are significant differences in the net
overburden stress experienced by individual core samples.

A previous study by Jones and Owens68 on the effect of confining stress in low-
permeability gas sands (somewhat analogous to the Clear Fork) indicated that
permeability reductions ranged from less than three-fold to as much as twenty-fold with
increased confining stress. For the range of confining stresses across the Clear Fork
interval, we expect a stress-correction of as much as fifty percent when laboratory-
measured permeability data is corrected to in-situ conditions. We note that we do not expect the stress and fluid saturation corrections to affect permeability prediction to such a degree that we can not accomplish our main objective of identifying the primary pay intervals within the Clear Fork.

4.5.4 – Saturation Differences

Core permeability measurements are made with Helium on cleaned and dried samples. Well log measurements are made in-situ on rock with a large range of fluid saturations, and often with significantly different wettability characteristics. If we can predict air (or gas) permeability from well log data on a unit-wide basis, we would like to be able to convert those results to effective oil permeability at reservoir conditions so that results may be compared with pressure transient test and decline curve analyses. In order to make these stress and fluid distribution corrections, we utilized data from thirteen native-state, unsteady-state gas-oil relative permeability tests recorded for 3 wells at reservoir stress conditions (Appendix B) and mini-permeameter data for NRU #3533 (Appendix C).

Effective air and brine permeabilities were recorded with a mini-permeameter on 150 feet of the NRU #3533 whole core at a vertical spacing of 1.2 inches and a horizontal spacing of 1.2 inches. The ratio between the effective air permeability and the effective brine permeability was then calculated. In addition, the ratio between effective air and oil permeabilities taken as part of the unsteady-state gas-oil relative permeability tests was utilized to develop a ratio between air and oil permeabilities and then applied to the mini-permeameter data. As we would expect, corrections are most significant for the lower permeability data points, as shown in Fig. 4.17.
4.5.5 – Fluid Flow Direction

The whole core was cored, slabbed and sampled as shown in Fig. 4.18, below. Two horizontal whole core permeability measurements were made obliquely to one another – $k_{MAX}$ and $k_{90}$. Based on this core preparation, whole core permeabilities were calculated as the geometric mean of the $k_{MAX}$ and $k_{90}$ data. We examined the relationship between the two data sets to determine if the use of the geometric mean permeability could be justified. With few exceptions, we found that the two data sets were not significantly different and are linearly related (Fig. 4.19), therefore, we will utilize the geometric mean permeability, $k_{GEOM}$, for our analyses.

Figure 4.17 – Relationship between effective air, brine and oil permeabilities from mini-permeameter and native-state, unsteady-state relative permeability data – NRU 3533.
Figure 4.18 – Whole core preparation for NRU infill wells.  

Figure 4.19 – Linear relationship between whole core $k_{50}$ and $k_{\text{MAX}}$. 
4.5.6 – Statistical Validity of Model

Due to the extreme heterogeneity of the Clear Fork at the NRU and the multiple porosity types encountered in the reservoir and non-reservoir sections, it is very difficult to construct an accurate and statistically valid model for permeability prediction from conventional well log data.

The whole core permeability measurements were taken across primarily reservoir quality intervals in four 10-acre infill wells and two 20-acre infill wells (544 total samples). The quick plug permeabilities were taken every foot across the entire Clear Fork interval in four 10-acre infill wells (2348 total samples). Both core permeability data sets possess extreme heterogeneity. A Dykstra-Parsons coefficient of 0.5 is considered homogeneous rock, while coefficients greater than 0.85 are considered extremely heterogeneous. The Dykstra-Parsons coefficient for the whole core data was 0.84, while the coefficient for the quick plug samples was 0.88, as shown in Figs 4.20 – 4.21.

Figure 4.20 – Dykstra-Parsons coefficient calculation for whole core data.
We note that the whole core data appear to be normally distributed while the quick plug data are significantly skewed to non-reservoir quality rock, as shown in Figs. 4.22 – 4.23.
Figure 4.22 – Frequency histogram for whole core permeability measurements.

Figure 4.23 – Frequency histogram for quick plug permeability measurements.
Examining all available core permeability data, except for two discarded high permeability outliers, we see that the coefficient of variation ($C_v$), as calculated from Eqs. 3.50–3.51, indicates there are insufficient data to build statistically valid permeability models for any of the available core data sets, as shown in Table 4.8, below.

### Table 4.8 – Statistics for all core permeability data.

<table>
<thead>
<tr>
<th>Statistic</th>
<th>$k_{MAX}$</th>
<th>$k_{90}$</th>
<th>$k_{GEOM}$</th>
<th>$k_{plug}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum</td>
<td>0.005</td>
<td>0.005</td>
<td>0.010</td>
<td>0.010</td>
</tr>
<tr>
<td>Maximum</td>
<td>65.61</td>
<td>42.97</td>
<td>50.27</td>
<td>60.00</td>
</tr>
<tr>
<td>Mean</td>
<td>1.675</td>
<td>0.983</td>
<td>1.1950</td>
<td>0.5960</td>
</tr>
<tr>
<td>Median</td>
<td>0.240</td>
<td>0.140</td>
<td>0.2000</td>
<td>0.0500</td>
</tr>
<tr>
<td>Std. Deviation</td>
<td>5.6204</td>
<td>3.2112</td>
<td>3.7113</td>
<td>3.5088</td>
</tr>
<tr>
<td>Variance</td>
<td>31.5894</td>
<td>10.3120</td>
<td>13.7740</td>
<td>12.3117</td>
</tr>
<tr>
<td>$C_v$</td>
<td>7.2369E+06</td>
<td>173.4700</td>
<td>979.4426</td>
<td>471.4731</td>
</tr>
<tr>
<td>Data required</td>
<td>5.2373E+15</td>
<td>3.0092E+06</td>
<td>9.5931E+07</td>
<td>2.2229E+07</td>
</tr>
<tr>
<td>Data available</td>
<td>624</td>
<td>544</td>
<td>544</td>
<td>2,347</td>
</tr>
</tbody>
</table>

In order to construct a valid permeability model, it is necessary to remove data points that may have been the result of fractures or fissures. We can identify only a few data samples that are major outliers. However, in order to generate a statistically valid model using the coefficient of variation to calculate the number of samples required, we find that we must omit all data with permeability greater than 10 md. When this is done, the data that remain are for rock possessing intergranular or intercrystalline porosity. By omitting the highest permeability data we are introducing bias (systematic error). By reducing our sample size, we are also increasing standard error in the final result. We choose not to perform these omissions since the resulting permeability models may not capture the true heterogeneity of the reservoir.

As we stated previously, the quick plug data is not well correlated with the well log data due to different measurement scales. As a result, we can not generate accurate predictive equations for permeability. When the quick plug data are segregated by rock type, the multivariate predictive equations for permeability all have coefficients of multiple determination ($r^2$) less than 0.35, except for rock types 5, 7 and 8. For rock types 1–4 and 6, the models do not adequately describe relationships between core
permeability and the well log predictor variables. This is primarily a function of the type of porosity present in the core sample. Rock types 5, 7 and 8 are limestone, silt and shale, respectively. These samples possess simple intergranular porosity with no fracturing. Rock types 1–4 and 6 are dolomites, anhydritic dolomites and dolomitic anhydrites that possess intergranular, intercrystalline, moldic, vuggy, fenestral and fracture porosity with complex pore structures.

An additional problem with the quick plug data set is that 77 percent of the permeability data are less than 0.1 md. This makes it very difficult to accurately model permeabilities above 1 md. Only 30 percent of the whole core data are less than 0.1 md, since these data were taken primarily across reservoir “pay” intervals. For these reasons, we will utilize the whole core \( k_{GEOM} \) data set in our initial permeability modeling attempts. Since there were no rock type 8 whole core samples, we will use the quick plug core data to construct a permeability relation for this non-reservoir rock type.

Even when these data are segregated by rock type, there appears to be insufficient data for a rigorous quantitative analysis, as shown in Table 4.9, below. However, the resulting predictive equations for permeability are superior to those generated from the quick plug data set.

![Table 4.9 – Statistics for whole core permeability \( k_{GEOM} \) data by rock type.](image)

<table>
<thead>
<tr>
<th>Statistic</th>
<th>RT1</th>
<th>RT2</th>
<th>RT3</th>
<th>RT4</th>
<th>RT5</th>
<th>RT6</th>
<th>RT7</th>
<th>RT8</th>
</tr>
</thead>
<tbody>
<tr>
<td>Minimum</td>
<td>0.010</td>
<td>0.010</td>
<td>0.010</td>
<td>0.010</td>
<td>0.010</td>
<td>0.010</td>
<td>0.010</td>
<td>0.020</td>
</tr>
<tr>
<td>Maximum</td>
<td>11.01</td>
<td>14.92</td>
<td>4.04</td>
<td>7.88</td>
<td>1.84</td>
<td>50.27</td>
<td>4.55</td>
<td>0.13</td>
</tr>
<tr>
<td>Mean</td>
<td>1.339</td>
<td>1.158</td>
<td>0.425</td>
<td>1.004</td>
<td>0.276</td>
<td>1.333</td>
<td>0.890</td>
<td>0.049</td>
</tr>
<tr>
<td>Median</td>
<td>0.110</td>
<td>0.180</td>
<td>0.080</td>
<td>0.265</td>
<td>0.100</td>
<td>0.220</td>
<td>0.450</td>
<td>0.030</td>
</tr>
<tr>
<td>Std. Deviation</td>
<td>2.867</td>
<td>2.582</td>
<td>0.993</td>
<td>1.996</td>
<td>0.429</td>
<td>4.248</td>
<td>1.390</td>
<td>0.039</td>
</tr>
<tr>
<td>Variance</td>
<td>8.222</td>
<td>6.670</td>
<td>0.986</td>
<td>3.987</td>
<td>0.184</td>
<td>18.049</td>
<td>1.932</td>
<td>0.0016</td>
</tr>
<tr>
<td>( C_v )</td>
<td>61.0184</td>
<td>28.0613</td>
<td>1.2969</td>
<td>7.2744</td>
<td>0.4503</td>
<td>8306.9393</td>
<td>2.4304</td>
<td>0.0395</td>
</tr>
<tr>
<td>Data required</td>
<td>372,325</td>
<td>78,744</td>
<td>168</td>
<td>5,292</td>
<td>20</td>
<td>6.9005E+09</td>
<td>591</td>
<td>0</td>
</tr>
<tr>
<td>Data available</td>
<td>19</td>
<td>77</td>
<td>17</td>
<td>16</td>
<td>35</td>
<td>371</td>
<td>9</td>
<td>9</td>
</tr>
</tbody>
</table>
4.5.7 – Measurement Error
Over and above problems associated with sample size and statistical bias, we should also be aware of measurement errors that may have occurred. We are analyzing core measurements made at different times, in different labs and by different technicians.

4.6 – Current Work
The initial study was used as a guideline for developing the new predictive model (if a statistically valid model exists). We did not attempt to re-define pore types or rock types that were assigned as a result of the study of XRD, SEM and thin-section data. Not only do we not have the raw data, but also these assignments seem to make good geologic sense and there is no need to investigate further.

The previous permeability modeling work may be slightly improved by considering multivariate models, non-parametric models and neural networks. If segregation by rock type (and hence pore type) is insufficient for the accurate estimation of permeability, we will attempt to use hydraulic flow units, as defined by Amaefule et al.,\textsuperscript{53} to improve our predictions.

It is obvious that there are distinct lithologic and morphologic differences in the make-up of the Clear Fork as we move across the NRU, as illustrated in Figs. 4.24-4.26, below. Well #1509 is located in the south-central area of the unit in a depositional low that is more mud- and silt-dominated with typically poor reservoir characteristics. Well #3533 is located along the shelf edge to the northeast of the unit in an area of high relief where the rock is primarily grain-dominated and has excellent reservoir characteristics. Well #3319 is located along the southwestern margin of the unit in an area of relatively low relief, but fairly good reservoir quality. The rock compressibilities for this well are much higher than in other parts of the unit and the rock appears to be less compacted.

We most likely require different permeability models for each area of the unit possessing unique depositional characteristics, but we simply do not have sufficient data to build multiple predictive models. The optimal method for permeability prediction for the
Clear Fork will therefore most likely be geostatistical simulation using a "most likely" permeability realization that matches historical performance.

Figure 4.24 – Density-neutron crossplot – NRU 1509.
Figure 4.25 – Density-neutron crossplot – NRU 3533.
4.7 – New Rock-Log Model

Before attempting to construct new relations for permeability prediction, we will modify the previous model to improve estimates of rock type, porosity, cementation factor, saturation exponent, formation water resistivity and water saturation. The flowchart for the new algorithm is shown in Fig. 4.27. A step-by-step summary of our methodologies is also given below.

Figure 4.26 – Density-neutron crossplot – NRU 3319.
4.7.1 – Well Log Processing

The raw well log data was depth corrected, environmentally corrected and normalized prior to analysis. The processed well log data was then depth-averaged over a depth increment that most closely corresponded to the available core data (1-ft for whole core).
4.7.2 – Lithology and Rock Type Determination

We have five unknowns (four different lithologies and porosity), but only three well log inputs that will aid us in determining lithology and rock type – $\rho_b$, PE and $\phi_N$ (under-determined system). The deep and shallow resistivities are used to differentiate between rock types 1-4, and the gamma ray log will be used to separate rock types 7 and 8.

If additional well log inputs were available throughout the unit, we could solve for lithology directly without having to calculate it indirectly using the apparent matrix density ($\rho_{maa}$) and the apparent volumetric capture cross-section ($U_{maa}$). Sonic ($\Delta t_c$) and flushed zone resistivity ($R_{xo}$) data are available on five 20-acre wells and eighteen 10-acre wells, however, that is only one-tenth of the total number of wells in the unit. We found that when these additional well log inputs from selected wells were used to create a determined system of equations to solve for porosity and rock type, the results were similar to those obtained using $\rho_{maa}$ and $U_{maa}$.

To calculate $\rho_{maa}$ and $U_{maa}$, we need an initial estimate of lithology. This is obtained from a plot of $\rho_b$ versus PE, as shown in Fig. 4.28. Lithology-corrected porosities were then determined and used to calculate $\rho_{maa}$ and $U_{maa}$. Eqs. 4.9 – 4.13 were utilized to calculate density porosity as a function of rock type and lithology.

- **Dolomite (RT1 – 4)**
  \[
  \phi_{DOL} = \frac{2.87 - \rho_b}{2.87 - \rho_f} \tag{4.9}
  \]

- **Limestone (RT 5)**
  \[
  \phi_{LS} = \frac{2.725 - \rho_b}{2.725 - \rho_f} \tag{4.10}
  \]

- **Anhydritic Dolomite (RT 6)**
  \[
  \phi_{ANHY} = \frac{2.89 - \rho_b}{2.89 - \rho_f} \tag{4.11}
  \]

- **Silty Dolomite (RT7)**
  \[
  \phi_{SILT} = \frac{2.74 - \rho_b}{2.74 - \rho_f} \tag{4.12}
  \]
Shaly Dolomite (RT 8)

\[ \phi_{\text{SHALE}} = \frac{2.65 - \rho_b}{2.65 - \rho_f}. \quad \text{(4.13)} \]

Where \( \phi_D \) is porosity calculated from the bulk density log and \( \rho_F \) is the mud filtrate density of 1.10 g/cc (salt mud).

Compensated neutron limestone porosity (percent) was then converted to the appropriate lithology-corrected neutron porosity (in decimal form). Due to the fact that all rock types other than rock type 5 contain such large volumes of dolomite, we adjusted the compensated neutron porosities by matching results to the whole core helium porosities.
Expressions for lithology-corrected compensated neutron porosity are expressed using the digitized form of a lithology crossplot, as shown in Eqs. 4.14 – 4.16 below.

\[ \phi_{N,DOL} = 0.01 \times [(-0.0001678 \times \phi_{N,LS}^3) + (0.02372 \times \phi_{N,LS}^2) + (0.5025 \times \phi_{N,LS}) - 0.89621] \] .......... (4.14)

\[ \phi_{N,SILT/SHALE} = 0.01 \times [(0.0001817 \times \phi_{N,LS}^3) - (0.01283 \times \phi_{N,LS}^2) + (1.2797 \times \phi_{N,LS}) - 1.4198] \] .......... (4.15)

\[ \phi_{N,ANHY} = 0.01 \times [(-0.0001678 \times \phi_{N,LS}^3) + (0.02372 \times \phi_{N,LS}^2) + (0.5025 \times \phi_{N,LS}) - 0.89621]. \] .......... (4.16)

Where \( \phi_{N,LS} \) is the raw porosity (in percent) on a limestone scale from the compensated neutron log and \( \phi_{N,DOL}, \phi_{N,SILT}, \text{ and } \phi_{N,ANHY} \) are the neutron porosities for dolomite, silty dolomite and anhydritic dolomite lithologies in decimal form. We note that the neutron porosities for dolomite and anhydrite are the same. In addition, the same neutron porosity is used for both the silty and shaly dolomites. Lithology-corrected porosities (\( \phi_{C} \)) that were most well correlated with the available whole core data (\( r^2 = 0.49 \)) were then calculated, as shown below.

RT 1 – 2 (Dolomite)
\[ \phi_{C} = \frac{\phi_{N,DOL} + \phi_{D,DOL}}{2} \] .................................................. (4.17)

RT 3 – 4 (Dolomite)
\[ \phi_{C} = \phi_{D,DOL} \] .................................................. (4.18)

RT 5 (Limestone)
\[ \phi_{C} = \frac{\phi_{N,LS} + \phi_{P,LS}}{2} \] .................................................. (4.19)
RT 6 (Anhydritic Carbonate)
\[ \phi_C = \phi_{\text{ANHY}} \] ................................. (4.20)

RT 7 (Silty Carbonate)
\[ \phi_C = \frac{(\phi_{\text{NSILT}} + \phi_{\text{DSILT}})}{2} \] ................................. (4.21)

RT 8 (Shaly Carbonate)
\[ \phi_C = \frac{(\phi_{\text{NSHALE}} + \phi_{\text{DSHALE}})}{2} \] ................................. (4.22)

\( U_{\text{maa}} \) and \( \rho_{\text{maa}} \) were then calculated using these lithology-corrected porosities (Eqs. 4.23-4.24) and rock types were calculated based on the location of these values on the rock type break out plot shown in Fig. 4.29.

\[ \rho_{\text{maa}} = \frac{[\rho_B - (1.1 * \phi_C)]}{(1.0 - \phi_C)} \] ........................................... (4.23)

\[ U_{\text{maa}} = \frac{[PE * (\rho_B + 0.1883/1.0704)] - (\phi_C * 0.85)}{1.0 - \phi_C} \] ................................. (4.24)

Rock type discrimination lines were changed slightly to account for the new core and well log data from the 10-acre infill wells. Lithology matrix points were used as reference points for the lithology discriminators. Discrimination lines were situated so as to separate limey dolostone from anhydritic dolostone, limey dolostone from silt/shale, dolostone from silt/shale and dolostone from anhydritic dolostone.

All discrimination lines were drawn in order to segregate data with similar lithologies (and possibly pore characteristics). Rock types 1 – 4 were segregated using the shallow and deep resistivity data as shown in Figs. 4.30 – 4.31, below. Rock types 1 and 2 could be separated from rock types 3 and 4 on the basis of their deep resistivity response. Rock types 3 and 4 were then segregated on the basis of their shallow resistivity response. These four rock types were initially thought to represent reservoir "pay,"
however, based upon further study, it was found that any rock type could include reservoir quality rock except rock type 5 (limestone and wet) and rock type 8 (shaly carbonate).

Rock types 7 and 8 were differentiated using the gamma ray log. Samples with GR greater than or equal to 70 API units were classified as shaly carbonates, while samples with GR less than 70 API units were classified as silty carbonates.

Figure 4.29 – Differentiating "pay" from "non-pay" rock types.
Figure 4.30 – Segregating rock types 1 – 4 using deep resistivity data.

Figure 4.31 – Segregating rock types 3 and 4 using shallow resistivity data.
4.7.3 – Water Saturation Calculation

The Clear Fork interval is divided into 200-foot vertical intervals for the purpose of obtaining better estimates of water saturation, $S_w$. The 200-ft intervals were chosen after visually examining slabbed whole core, water injection profiles, fluid salinity reports and Repeat Formation Test (RFT) data in multiple wells. A 1996 fluid sampling program (Appendix F) performed on the new 10-acre infill wells indicated that there are a wide range of water salinities in the Clear Fork interval, as shown in Figs. 4.32 – 4.34. We must therefore make adjustments to the value of $R_w$ over fairly small vertical intervals if we wish to calculate usable water saturations.

![Figure 4.32 – Water salinities (ppm) for Lower Clear Fork (northern infill area).](image-url)
Figure 4.33 – Water salinities (ppm) for Middle Clear Fork (northern infill area).

Figure 4.34 – Water salinities (ppm) for Upper Clear Fork (northern infill area).
We sub-divided the reservoir into approximately six distinct sub-sections with regard to reservoir quality, waterflood support and pressure support. These parameters will all have a direct affect on formation water resistivity, $R_w$, and hence, water saturation. The intervals utilized are those shown below.

- 6,150 feet – 6,349 feet (Upper Clear Fork)
- 6,350 feet – 6,549 feet (Upper Clear Fork)
- 6,550 feet – 6,749 feet (Middle Clear Fork)
- 6,750 feet – 6,949 feet (Middle Clear Fork)
- 6,950 feet – 7,149 feet (Lower Clear Fork)
- Below 7,150 feet (Lower Clear Fork)

In order to solve Archie's well-known expression for water saturation (Eq. 4.25), we will require a lithology-corrected crossplot porosity, $\phi_C$, true resistivity, $R_t$, cementation factor, $m$, saturation exponent, $n$, formation water resistivity, $R_w$ and the constant $a$:

$$S_w^n = \frac{a R_w}{\phi_C^m R_t}. \hspace{1cm} (4.25)$$

The crossplot porosities were calculated together with rock type in the previous step. Since we have insufficient flushed-zone resistivity data for correcting the deep resistivity to the true formation resistivity, we must assume that the deep laterolog resistivity (LLD) approximates the true resistivity ($R_t$) for this low permeability, deeply invaded carbonate formation. Laboratory-derived values for $m$ and $n$ (Appendix C) are used for the first iteration. Since these values are averages for a limited number of core samples, and were measured on core from only the pay intervals, they are simply used as first-pass estimates. We know that $m$ and $n$ vary significantly across the reservoir.

The initial estimate of $R_w$ is computed from the mud and mud filtrate resistivities given on the well log headers. This value averaged 0.057 $\Omega$m for the older 20-acre wells and 0.075 $\Omega$m for the new 10-acre infill wells. The effect of continuous water injection (composed of produced and fresh water make-up) over time is to lower the salinity of the formation waters. To begin the iteration, we assume that the Archie constant, $a$, is equal to one.
Water saturations are initially calculated every foot over the entire Clear Fork interval. Water saturations greater than 90 percent are assumed to be water sands and each predefined 200-ft interval is then evaluated separately. The average value of formation water resistivity for the water sands in each 200-ft interval are then taken as the new estimates of $aR_w$. If there are no water sands present, we set $aR_w$ equal to the original input value depending on vintage of the well.

The updated $aR_w$ values are then used together with crossplot porosity and true resistivity to solve for an updated cementation factor for each 200-ft interval. In equation form, a rearrangement of the Archie equation for the case of $S_w = 1$ yields:

$$\log_{10} \left( \frac{\phi}{C} \right) = \left( -\frac{1}{m} \right) \log_{10} \left( R_t \right) + \log_{10} \left( aR_w \right).$$  \hspace{1cm} \text{(4.26)}$$

This can be expressed in graphical form as a Pickett plot (Fig. 4.35). We calculate new cementation factors using the slope of the 100-percent water saturation line.

![Figure 4.35 – Graphical illustration of cementation factor calculation.](image-url)
After the cementation factor has been calculated, the saturation exponent is also determined for each 200-ft interval using the slope of the data trend on a log-log plot of $R_o/R_t$ versus $S_w$. This can also be expressed in equation form as:

$$\log_{10} (S_w) = \left(\frac{1}{n}\right) \log_{10} \left(\frac{R_o}{R_t}\right).$$

(4.27)

Where $R_o$ is the resistivity of a 100-percent water sand and is expressed as:

$$R_o = \left(\frac{aR_w}{\phi_C}\right).$$

(4.28)

With these new values for the water saturation equation parameters, we then iterate on $S_w$, $R_w$, $m$ and $n$ for each 200-ft interval until convergence is achieved. The water saturation is constrained between zero and one. The cementation factor and saturation exponent are constrained between 1.1 and 4.0, which are the minimum and maximum values we should encounter in the Clear Fork. By performing these calculations, we are improving confidence in our water saturation estimates, which can then be used to better define "pay" quality sections of the reservoir.

### 4.7.4 – Permeability Prediction

We will utilize conventional well log responses as predictor variables in order to predict permeability for the six unit wells in which whole core permeabilities are available. We will utilize the rock type and corrected porosity (matched to core porosity) data from above, together with gamma ray log, photoelectric capture cross-section log and resistivity log data in order to construct permeability relations.

Pearson correlation coefficients for the whole core permeability and well log data used in these analyses (by rock type) are shown in Appendix F. An example for rock type 2 data is shown below in Table 4.10. These data can be utilized to find the best predictor variables for permeability and to check for any correlation or collinearity between predictors. The optimum predictor variables will be fairly well correlated with permeability and not correlated with one another.
Table 4.10 – Pearson correlation coefficients for statistically significant predictor variables for whole core $k_{90} - $RT2 (77 sample measurements).

<table>
<thead>
<tr>
<th>$LLD$</th>
<th>$\ln k_{90}$</th>
<th>$\ln LLD$</th>
<th>$\ln \phi_{N-LS}$</th>
<th>$\ln PE$</th>
<th>$\ln \rho_b$</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>-0.2043</td>
<td>1.000</td>
<td>-0.7666</td>
<td>0.2020</td>
<td>0.7555</td>
</tr>
<tr>
<td>$\phi_{N-LS}$</td>
<td>0.3927</td>
<td>-0.7666</td>
<td>1.000</td>
<td>-0.2850</td>
<td>-0.8072</td>
</tr>
<tr>
<td>$PE$</td>
<td>-0.0501</td>
<td>0.2020</td>
<td>-0.2850</td>
<td>1.000</td>
<td>0.1540</td>
</tr>
<tr>
<td>$\rho_b$</td>
<td>-0.3285</td>
<td>0.7555</td>
<td>-0.8072</td>
<td>0.1540</td>
<td>1.000</td>
</tr>
</tbody>
</table>

The relatively low correlation coefficients between well log inputs and core permeability (whole core and quick plug data) illustrate how difficult it will be to accurately predict permeability from well log data. The lack of correlation between whole core permeability ($k_{MAX}$) and well log predictor variables is illustrated in Figs. 4.36–4.38.

![Data From 4 Cored 10-Acre Wells](image.png)

Figure 4.36 – Whole core $k_{MAX}$ versus compensated neutron porosity.
Figure 4.37 – Whole core $k_{\text{MAX}}$ versus bulk density.

Figure 4.38 – Whole core $k_{\text{MAX}}$ versus deep resistivity.
4.7.4.1 – Multivariate Regression Models

Multivariate linear regression models were constructed using the Statistical Analysis Software\textsuperscript{70} package (SAS\textsuperscript{TM}). When using SAS\textsuperscript{TM} a functional relationship (log$_{10}$, ln, square root, etc.) must be assumed for the dependent (permeability) and independent (well log responses) variables.

Permeability equations were developed for each rock type using three or more predictor variables. Because permeability has a semilog relationship with porosity, we utilized the natural log of permeability as our dependent variable. Unfortunately, while the natural log of $k_{GEOM}$ could be matched fairly well at the core points, what resulted over the rest of the reservoir interval was an "over-fit" of the data that resulted in a large variation of predicted permeability values. The problem to be solved, as with most multivariate statistical correlations, is to balance the quality of the data fit with the simplicity of the model. Additional predictor variables do not necessarily improve the model fit.

In order to solve this problem, several predictor variables were dropped from each model using an adjusted coefficient of multiple determination ($r_{a}^{2}$), which is maximized by removing variables with large collinearity. The resulting reduced models were still unsatisfactory, since they produced an "under-fit" of the available core data. The results of this work were not an improvement over the existing one-predictor model that had been constructed previously. This is illustrated in Fig. 4.39 for the NRU 3533 well.
This lack of fit may be due to the fact that the relationship between whole core permeability and well log data, if such a relationship exists, is more complex than can be explained using linear regression techniques. As we have stated previously, segregation of the data by rock type is unlikely to yield a sufficient classification of the data to achieve accurate permeability estimates. We typically obtain quality data fits only for cases in which there is simple intergranular porosity (i.e., RT 5, 7 and 8).
Due to the heterogeneity that exists in the Clear Fork, rock with similar lithology will most likely not have similar pore characteristics. The initial study indicated that each rock type had its own unique pore characteristics, but we do not find this to be true at all, therefore, we need to find an additional way to segregate the data for estimation of permeability.

4.7.4.2 – Hydraulic Flow Unit Models

In order to get a more accurate match of whole core permeability data, we utilized techniques introduced by Amaefule et al. and Abbaszadeh et al., for which we segregate the data into pseudo-flow units (HFU) after separating the data on the basis of rock type. Individual hydraulic flow units are defined using a log probability plot of the flow zone indicator ($FZI$), which is normally distributed. As illustrated in Fig. 4.40, we identified multiple flow units for each different rock type. This indicates that our rock-typing scheme does not actually segregate rocks with similar pore level characteristics.

The $FZI$ values are calculated with whole core permeability and porosity data using Eqs. 4.5 – 4.7. A range of $FZI$ values ("bin") defined each flow unit. A representative $FZI$ value is then calculated for each hydraulic flow unit by taking the mean of the $FZI$ values within that particular HFU. An example of this work is shown in Table 4.11.

Table 4.11 – Determination of flow units using $\ln (FZI)$ for rock type 6.

<table>
<thead>
<tr>
<th>Number of Samples</th>
<th>Freq.</th>
<th>Cum. Freq.</th>
<th>$\ln (FZI)$ Bin Limits</th>
<th>$FZI$ Bin Limits ($10^6$ m)</th>
<th>Mean $FZI$ ($10^6$ m)</th>
<th>Flow Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>4</td>
<td>0.0400</td>
<td>0.0400</td>
<td>-1.8</td>
<td>0.1653</td>
<td>0.1460</td>
<td>HF1</td>
</tr>
<tr>
<td>3</td>
<td>0.0300</td>
<td>0.0700</td>
<td>-1.3</td>
<td>0.2725</td>
<td>0.2383</td>
<td>HF2</td>
</tr>
<tr>
<td>4</td>
<td>0.0400</td>
<td>0.1100</td>
<td>-0.8</td>
<td>0.4493</td>
<td>0.3845</td>
<td>HF3</td>
</tr>
<tr>
<td>7</td>
<td>0.0700</td>
<td>0.1800</td>
<td>-0.3</td>
<td>0.7408</td>
<td>0.6197</td>
<td>HF4</td>
</tr>
<tr>
<td>22</td>
<td>0.2200</td>
<td>0.4000</td>
<td>0.2</td>
<td>1.2214</td>
<td>1.0031</td>
<td>HF5</td>
</tr>
<tr>
<td>15</td>
<td>0.1500</td>
<td>0.5500</td>
<td>0.7</td>
<td>2.0138</td>
<td>1.6192</td>
<td>HF6</td>
</tr>
<tr>
<td>32</td>
<td>0.3200</td>
<td>0.8700</td>
<td>1.2</td>
<td>3.3201</td>
<td>2.5274</td>
<td>HF7</td>
</tr>
<tr>
<td>5</td>
<td>0.0500</td>
<td>0.9200</td>
<td>1.7</td>
<td>5.4739</td>
<td>4.6602</td>
<td>HF8</td>
</tr>
<tr>
<td>8</td>
<td>0.0800</td>
<td>1.0000</td>
<td>2.7</td>
<td>14.8797</td>
<td>8.1538</td>
<td>HF9</td>
</tr>
</tbody>
</table>
Attempts to predict the value of the flow zone indicator (and hence, permeability) directly from well log data using regression and neural network techniques were unsuccessful. We therefore took a probabilistic approach to the problem and individual flow units were predicted using conditional probabilities. The available well log data
and associated whole core data were segregated into hydraulic flow units based on their core-derived $FZI$ values. Individual well log responses were then separated into distinct data ranges to identify the probability of a particular HFU given a certain range of the well log predictor variable, as shown for rock type 6 in Table 4.12. The results for all rock types are given in Appendix F.

Table 4.12 – HFU probability for a given range of deep resistivity – rock type 6.

<table>
<thead>
<tr>
<th>Deep Resistivity, $\Omega$ m</th>
<th>&lt; 100</th>
<th>100 – 499.9</th>
<th>500 – 999.9</th>
<th>1000 – 1499.9</th>
<th>&gt; 1500</th>
</tr>
</thead>
<tbody>
<tr>
<td>p(HFU1)</td>
<td>0.0909</td>
<td>0.0323</td>
<td>0.0000</td>
<td>0.0000</td>
<td>0.0000</td>
</tr>
<tr>
<td>p(HFU2)</td>
<td>0.0455</td>
<td>0.0430</td>
<td>0.0154</td>
<td>0.0000</td>
<td>0.0000</td>
</tr>
<tr>
<td>p(HFU3)</td>
<td>0.2273</td>
<td>0.0753</td>
<td>0.0923</td>
<td>0.0000</td>
<td>0.0000</td>
</tr>
<tr>
<td>p(HFU4)</td>
<td>0.1818</td>
<td>0.2258</td>
<td>0.1692</td>
<td>0.0526</td>
<td>0.0690</td>
</tr>
<tr>
<td>p(HFU5)</td>
<td>0.1818</td>
<td>0.1935</td>
<td>0.2462</td>
<td>0.2105</td>
<td>0.0690</td>
</tr>
<tr>
<td>p(HFU6)</td>
<td>0.1818</td>
<td>0.2688</td>
<td>0.2462</td>
<td>0.3158</td>
<td>0.1379</td>
</tr>
<tr>
<td>p(HFU7)</td>
<td>0.0455</td>
<td>0.0968</td>
<td>0.1231</td>
<td>0.2632</td>
<td>0.4138</td>
</tr>
<tr>
<td>p(HFU8)</td>
<td>0.0455</td>
<td>0.0538</td>
<td>0.0923</td>
<td>0.0526</td>
<td>0.2069</td>
</tr>
<tr>
<td>p(HFU9)</td>
<td>0.0000</td>
<td>0.0108</td>
<td>0.0154</td>
<td>0.1053</td>
<td>0.1034</td>
</tr>
</tbody>
</table>

The lithology-corrected crossplot porosity, bulk density, photoelectric capture cross-section, deep resistivity and gamma ray logs were utilized to segregate the hydraulic flow units. The conditional probability for each HFU was determined by the adding the flow unit probabilities for each individual well log response. The flow unit with the maximum probability for each well log depth increment was determined, and the core-derived mean $FZI$ associated with that particular flow unit was assigned so that permeability (md) could be calculated from Eq. 4.29:

$$
k = 1014 \left( FZI \right)^2 \left[ \frac{\phi_c^3}{(1 - \phi_c)^2} \right]. \tag{4.29}
$$

Where $\phi_c$ is the lithology-corrected porosity determined for each rock type.

If sufficient core data are available, and if each well log response can be segregated into several data ranges, this is an excellent method for the determination of permeability. As we see in Fig. 4.41, the results are a distinct improvement over the previous model results using one predictor variable (porosity).
Unfortunately, we may have insufficient core data for proper application of the method. When the model is applied to the whole core permeability data used in its construction, we do not obtain an adequate fit of the data, as shown in Fig. 4.42. Certainly a coefficient of multiple determination of only 0.212 is unacceptable, although it is much improved over the original one-predictor model ($r^2 = 0.007$).
The probability of assigning the correct flow unit is directly related to the amount of data available for analysis. Each rock type has a dominant HFU (usually the mean of the data set), therefore, it is more likely that we will not accurately predict data on the high and low ends of the data set. What results is an "under-fit" of the permeability data, and the results can not be used to accurately represent the reservoir for flow simulation purposes.

Figure 4.42 – Whole core $k_{GEOM}$ versus HFU model-calculated permeabilities.

We should note that a very positive development arose from the application of this method. We were able to determine which well log responses were best predictors of "pay" quality rock. We found that Clear Fork intervals with good flow capacity
typically had crossplot porosities between 2 percent and 6 percent, bulk densities greater than 2.80 g/cc and deep resistivities above 500 Ωm. We also determined that the primary pay rock types (as defined in this study) were rock types 6, 2 and 1, in that order. *It appears that the amount of anhydrite in the rock is actually a positive factor with regard to flow capacity since its presence is often associated with fracturing.*

### 4.7.4.3 – Non-Parametric Models

The Alternating Conditional Expectation (GRACE) method\textsuperscript{71} offers a way to transform both dependent and independent random variables to achieve maximum correlation. The GRACE algorithm produces an optimal correlation between a dependent variable and multiple independent variables by generating non-parametric transformations of both the dependent and independent variables. In simple terms, this means that functional relationships (i.e., log\(_{10}\), ln, square root, etc.) do not have to be assumed between dependent and independent model variables, but that the algorithm itself chooses which data transformations are optimal.

These non-parametric transformations minimize the variance of linear relationships between the transformed dependent and independent variables. This would be done using joint probability distribution functions if the data set were infinite. For finite data sets the program simply uses a data-smoothing algorithm to find the best data fit by minimizing error residuals, which in this case will be a second-order quadratic equation, since the use of higher-order equations did not improve the results.

These transformations are a function of the data being analyzed, which means that for each different set of data different transformations will result. In addition, since each independent (predictor) variable is transformed separately with respect to the transformed dependent variable, if independent variables are removed from the model, then the optimal transformations may change to reduce error.

Predictive models were constructed for each individual rock type. In an effort to balance fit with simplicity, only three predictor variables were utilized for all cases. These included the lithology-corrected porosity (which includes \(\rho_b\) and \(\phi_N\)), the deep or shallow
resistivity (we can not use both since they are collinear) and either the gamma ray or PE log.

For this study, the best predictive models were obtained by taking the natural log of both the dependent and independent variables prior to transformation. Graphical illustrations of the process are shown for rock type 6 in Figs. 4.43 – 4.46. The results for all rock types are given in Appendix F.

![Graph of ln(GR) transformation for Rock Type 6](image)

Figure 4.43 – Optimal transformation of ln(GR).
Figure 4.44 – Optimal transformation of $\ln(\text{LLD})$.

Figure 4.45 – Optimal transformation of $\ln(\phi_c)$.
Predictive models for all rock types were developed and the resulting expressions for permeability were coded into our solution algorithm. The coefficients of multiple determination for each rock type are shown in Table 4.13, below. We note that the "goodness of fit" is again directly proportional to the amount of data available.

The results for the non-parametric model are a distinct improvement over the one-predictor variable model. On an individual well basis, as we see in Fig. 4.47, the HFU and non-parametric models for permeability prediction yield fairly similar results when compared to available whole core permeabilities, and to one another. When the model is applied to the whole core permeability data used in its construction, we obtain a better fit of the data than could be achieved using the HFU model, as shown in Fig. 4.48. The coefficient of multiple determination was 0.463, and although this is not as good as we had hoped to achieve, it is the best we can do with the data in-hand.
Table 4.13 – Summary of non-parametric modeling results by rock type.

<table>
<thead>
<tr>
<th>Rock Type</th>
<th>Predictor Variables</th>
<th>$r^2$</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>GR, LLS, $\phi$</td>
<td>0.557</td>
</tr>
<tr>
<td>2</td>
<td>GR, LLD, $\phi$</td>
<td>0.563</td>
</tr>
<tr>
<td>3</td>
<td>GR, LLS, $\phi$</td>
<td>0.958</td>
</tr>
<tr>
<td>4</td>
<td>PE, LLD, $\phi$</td>
<td>0.842</td>
</tr>
<tr>
<td>5</td>
<td>PE, LLS, $\phi$</td>
<td>0.743</td>
</tr>
<tr>
<td>6</td>
<td>GR, LLD, $\phi$</td>
<td>0.602</td>
</tr>
<tr>
<td>7</td>
<td>PE, LLD, $\phi$</td>
<td>0.864</td>
</tr>
<tr>
<td>8</td>
<td>PE, LLD, $\phi$</td>
<td>0.800</td>
</tr>
</tbody>
</table>

Figure 4.47 – Whole core $k_{GEOM}$ and model-calculated permeabilities versus depth for NRU 3533.
For the HFU model discussed above, the fit of whole core permeability would likely increase (probabilistic model) as more core data are added. For the non-parametric model (and other regression-type models), the quality of fit will likely decrease as more data are added due to the introduction of additional data extremes. This is not an indictment of the method, but simply a factor to be aware of when limited core data are available.

The quality of fit for the entire data set will obviously depend on the relative amount of each rock type in the whole core data set. Quality of fit will also be affected by a permeability constraint that was added to the solution algorithm so that the calculated permeability would not be less than 0.001 md, or greater than 50 md. These values roughly correlated to the minimum and maximum values found in the whole core data.
While this result may not be sufficient to represent the reservoir for flow simulation purposes, it is certainly adequate for purposes of pay prediction, which is the key objective from an operational standpoint. We will therefore use the non-parametric model to determine permeability for the Clear Fork at NRU.

4.7.4.4 – Nuclear Magnetic Resonance Free-Fluid Index

Nuclear Magnetic Resonance (NMR) logs were recorded over selected sections of two cored wells (NRU 1509 and NRU 3533) in an effort to obtain permeability, lithology-independent porosity, pore size distribution, and fluid saturation distribution from a single log. Most of the preliminary NMR work was performed to differentiate between oil and water in low-resistivity clastics, however, several recent projects performed in the Permian Basin area are adding to the understanding of NMR responses in high-resistivity carbonate reservoirs.

This device gave a good approximation of permeability, pore size, and the location of free hydrocarbons, however, data acquisition and processing are costly, and initially need to be closely calibrated with core. The distribution of free and bound fluids in the rock pores obtained from NMR analysis of selected core samples from the two wells indicated that the reservoir is oil wet. This fluid distribution was then used in the processing of the raw log data to yield a visual representation of the pore and fluid distribution in the reservoir.

Timur\(^{47}\) concluded that the free-fluid index (FFI) measured by the NMR tool was directly related to residual fluid saturation. Since \(S_{wi}\) was proven to be linearly related to the surface area term in the Kozeny equation\(^13\) by Rose and Bruce,\(^\text{22}\) by simultaneously measuring NMR porosity and \(S_{wi}\), permeability can be estimated directly from well log data using Eq. 4.1. As before, the constants \(A1\) and \(A2\) depend on the formation and reservoir fluids under consideration:

\[
k = A1 \left[ \frac{\phi^{4.4}}{S_{wi}^2} \right]^{A2}.
\]
As shown in Fig. 4.49, we noticed that the NMR free-fluid index (FFI), which is simply the NMR porosity minus the measured irreducible bulk volume, was analogous to permeability. We then constructed a predictive model for FFI using conventional well log data inputs. FFI could not be predicted with any degree of accuracy using multiple regression or non-parametric models, however, we were able to achieve a fairly good match of FFI using a general regression neural network ($r^2 = 0.74$). Unfortunately, when the model was applied to wells other than those used to train the network, the calculated FFI value did not match measured core permeability with any great degree of accuracy.

![Figure 4.49 – NMR permeability and FFI data matched with quick plug and whole core permeabilities for NRU 3533.](image-url)
As a pay zone indicator, the NMR log is ideally suited for use in the Clear Fork at the NRU. The permeabilities calculated from NMR well log data using Timur's empirical equation are accurate enough to yield a permeability profile that could be utilized in flow simulation work. Unfortunately, there were insufficient NMR data available for the NRU at the time these analyses were performed. As a result of the work performed in this project, these tools will be run in most future wells and the conventional logging suite may be abandoned. In this case, a long-spaced or full-wave sonic log should still be recorded in order to obtain rock mechanical properties for hydraulic fracture design.

4.7.4.5 – Neural Networks

Attempts to use either back-propagation or general regression neural networks to predict permeability from well log predictors yielded results similar to those obtained from the non-parametric models. Overall, the best coefficient of multiple determination that could be achieved in the prediction of whole core permeability was approximately 0.5.

We also attempted to predict the NMR free-fluid index, which is analogous to permeability, using conventional well log data. The value of $r^2$ for the prediction of NMR FFI was 0.74. The primary drawback in the use of a neural network is that the results could not be easily coded into an algorithm that could be run on all unit wells with sufficient well log data.

4.7.5 – Definition of Clear Fork "Pay"

The Clear Fork interval is characterized by both high residual oil saturation and high irreducible water saturation that is the signature of a complex, low permeability carbonate reservoir. Residual oil saturations average 35 percent and irreducible water saturations approach 30 percent. In this setting, it is very difficult to accurately interpret what rock can be classified as reservoir "pay."

Historically, a 3.6 percent porosity cutoff and a 55 percent water saturation cutoff have been utilized to delineate pay at the North Robertson Unit. We do not necessarily agree with the use of such a high porosity cutoff in a low permeability carbonate reservoir possessing some degree of fracture porosity, however, for the most part, productive
intervals in the Clear Fork typically possess at least 3 to 6 percent porosity. For this reason, we have placed a significant emphasis on the prediction of reservoir permeability so that we might be able to better define the pay intervals without depending so heavily upon the magnitude of porosity and water saturation.

Integration of all available completion data will show that the primary Clear Fork pay intervals are approximately 6,300' – 6,450', 6,750' – 6,875' and 7,050' – 7,150'. We will examine these intervals in several wells to determine what our pay cutoffs should be for model-calculated permeability, lithology-corrected porosity and water saturation. We are comfortable with a water saturation cutoff of 60 percent, therefore, we will use this as our reference point for assigning permeability and porosity cutoffs for pay definition. A graphical illustration is provided below for NRU 3533 (Figs. 4.50-4.51).

Figure 4.50 – Estimation of permeability cutoff for NRU 3533.
Based on core-log model results for 10-acre and 20-acre infill wells, *pay will be defined as any rock interval that has model-calculated permeability greater than or equal to 0.25 md and model-calculated lithology-corrected porosity greater than or equal to 3.5 percent and model-calculated water saturation less than 60 percent.*

Once we assign pay, we then calculate the effective flow capacity, $k_i h$, and the hydrocarbon pore volume, $\phi h S_o$, within the pay intervals. In order to obtain $k_i h$, we must convert the permeability predicted by our model, which is based on unstressed air permeability measurements, to in-situ effective oil permeability. The computation of effective oil permeability is based on unsteady-state gas-oil relative permeability tests on 13 native-state cores from the 10-acre infill wells (Appendix B). The relationship between unstressed air permeability measurements and in-situ oil permeability
measurements is illustrated in Figs. 4.21 and 4.52. The relationship is expressed in equation form by Eq. 4.30.

\[ k_{oil} = 0.3085 (k_{air})^{1.1059}. \]  ............................................................................. (4.30)

Air permeability measurements were made at minimal confining pressures, while the oil permeability measurements were made at confining pressures of 4,000 – 5,500 psi.

Since we have constrained absolute permeability to less than or equal to 50 md in our model, and it is further reduced by conversion to effective oil permeability, high permeability streaks associated with fractures will have less impact on the total \( k_o h \) value. We will sum \( k_o h \) and \( \phi h S_o \) on an individual well basis so that we can map these variables across the North Robertson Unit.
4.8 – Summary

The maps of petrophysical parameters and rock types resulting from our geological and petrophysical study will be compared to the performance maps derived from the results of material balance decline type curve analyses and pressure transient tests. If the pore modeling and rock typing exercises are performed properly, then we believe the resulting rock type and permeability distributions associated with the reservoir will mirror the historical production performance.

From these maps, we will be able to identify infill-drilling locations. After a well is drilled, we can utilize our well log analysis algorithm to identify the primary pay intervals. Model results will also be used together with results obtained from production data analysis to construct a predictive equation for individual well ultimate recovery from conventional well log data. All data integration results will be given in Chapter IX.

The results of the core-log model runs on available well logs from 10-acre and 20-acre infill wells are given in Tables 4.14 – 4.15, below. As we would expect, the targeted 10-acre infill wells have superior net pay, flow capacity and storage characteristics indicating that they are located in areas of higher reservoir quality.

<table>
<thead>
<tr>
<th>Well</th>
<th>net pay (feet)</th>
<th>(k, h) (feet)</th>
<th>(\phi h) (feet)</th>
<th>(\phi h S_o) (feet)</th>
<th>ave (\phi) (frac)</th>
<th>ave (S_o) (frac)</th>
<th>RT1-2 (frac)</th>
<th>RT6 (frac)</th>
<th>RT1-2&amp;6 (frac)</th>
</tr>
</thead>
<tbody>
<tr>
<td>505</td>
<td>135.0</td>
<td>104.1</td>
<td>10.02</td>
<td>6.23</td>
<td>0.074</td>
<td>0.378</td>
<td>0.21</td>
<td>0.02</td>
<td>0.61</td>
</tr>
<tr>
<td>1509</td>
<td>107.0</td>
<td>109.5</td>
<td>8.14</td>
<td>5.16</td>
<td>0.076</td>
<td>0.366</td>
<td>0.54</td>
<td>0.12</td>
<td>0.14</td>
</tr>
<tr>
<td>1510</td>
<td>62.0</td>
<td>66.0</td>
<td>4.54</td>
<td>2.58</td>
<td>0.073</td>
<td>0.432</td>
<td>0.47</td>
<td>0.08</td>
<td>0.15</td>
</tr>
<tr>
<td>1511</td>
<td>192.0</td>
<td>283.2</td>
<td>16.00</td>
<td>10.26</td>
<td>0.083</td>
<td>0.359</td>
<td>0.44</td>
<td>0.09</td>
<td>0.36</td>
</tr>
<tr>
<td>1512</td>
<td>122.0</td>
<td>101.0</td>
<td>9.80</td>
<td>6.01</td>
<td>0.080</td>
<td>0.387</td>
<td>0.36</td>
<td>0.05</td>
<td>0.40</td>
</tr>
<tr>
<td>2705</td>
<td>62.0</td>
<td>40.7</td>
<td>4.70</td>
<td>2.67</td>
<td>0.076</td>
<td>0.432</td>
<td>0.42</td>
<td>0.08</td>
<td>0.17</td>
</tr>
<tr>
<td>3017</td>
<td>78.0</td>
<td>51.0</td>
<td>5.59</td>
<td>3.37</td>
<td>0.072</td>
<td>0.397</td>
<td>0.55</td>
<td>0.10</td>
<td>0.14</td>
</tr>
<tr>
<td>3018</td>
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<td>7.48</td>
<td>4.67</td>
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<td>0.376</td>
<td>0.50</td>
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<tr>
<td>3319</td>
<td>244.0</td>
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<td>16.33</td>
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<td>145.0</td>
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<td>6.11</td>
<td>0.067</td>
<td>0.370</td>
<td>0.48</td>
<td>0.16</td>
<td>0.30</td>
</tr>
<tr>
<td>3533</td>
<td>243.0</td>
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<td>17.56</td>
<td>11.47</td>
<td>0.072</td>
<td>0.347</td>
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<td>0.15</td>
<td>0.48</td>
</tr>
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<td>4.92</td>
<td>0.063</td>
<td>0.409</td>
<td>0.35</td>
<td>0.09</td>
<td>0.27</td>
</tr>
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<td>13.86</td>
<td>0.085</td>
<td>0.328</td>
<td>0.23</td>
<td>0.06</td>
<td>0.63</td>
</tr>
<tr>
<td>3538</td>
<td>149.0</td>
<td>165.0</td>
<td>10.21</td>
<td>6.26</td>
<td>0.069</td>
<td>0.387</td>
<td>0.37</td>
<td>0.12</td>
<td>0.32</td>
</tr>
<tr>
<td>3539</td>
<td>168.0</td>
<td>234.0</td>
<td>11.69</td>
<td>7.94</td>
<td>0.070</td>
<td>0.321</td>
<td>0.37</td>
<td>0.15</td>
<td>0.37</td>
</tr>
<tr>
<td>3604</td>
<td>146.0</td>
<td>114.1</td>
<td>9.87</td>
<td>6.58</td>
<td>0.068</td>
<td>0.333</td>
<td>0.42</td>
<td>0.18</td>
<td>0.37</td>
</tr>
</tbody>
</table>

Average: 144.8 122.6 11.26 7.15 0.076 0.374 0.39 0.10 0.34 0.73
155

Table 4.15 – Summary of modeling results for 20-acre infill wells.

207
208
293
295
307
405
492
503
504
704
804
905
907
1007
1008
1104
1204
1391
1405
1507
1593
2108
2110
2227
2502
2703
2902
3108
3208
3211
3310
3311
3313
3315
3317
3527
3529
3691
3903
4201

net pay
(feet)
179.0
194.0
180.0
124.0
130.0
117.0
168.0
80.0
78.0
128.0
147.0
97.0
73.0
104.0
117.0
86.0
241.0
107.0
276.0
55.0
119.0
200.0
121.0
107.0
90.0
66.0
263.0
161.0
137.0
130.0
53.0
160.0
39.0
83.0
107.0
194.0
143.0
163.0
106.0
64.0

koh
(feet)
159.3
166.1
78.2
86.5
43.1
113.4
51.6
43.8
48.4
73.0
190.2
60.3
19.6
265.4
76.3
114.7
152.9
67.5
198.6
56.1
94.5
211.0
72.3
32.8
63.4
45.6
129.6
179.0
91.9
70.3
17.9
96.0
16.5
44.2
68.7
72.2
126.8
91.7
38.9
75.1

φh
(feet)
12.46
13.68
12.52
7.95
8.17
7.13
10.18
5.74
6.52
9.09
11.15
6.92
5.33
7.71
7.82
5.98
15.07
6.18
19.84
3.96
9.36
13.73
8.33
6.87
6.45
4.55
20.12
11.09
9.97
11.26
4.28
13.08
3.60
7.28
8.52
13.15
10.75
11.02
6.83
6.24

φhSo
(feet)
8.78
9.68
8.10
5.30
5.49
4.94
7.14
3.47
3.89
6.17
8.05
4.50
3.17
5.79
5.67
3.84
10.52
4.17
14.22
2.31
6.16
8.45
5.51
4.68
3.99
2.81
12.48
7.72
6.45
7.24
2.36
7.75
2.03
4.58
5.27
8.54
7.17
6.97
4.70
3.38

ave φ
(frac)
0.070
0.071
0.070
0.064
0.063
0.061
0.061
0.072
0.084
0.071
0.076
0.071
0.073
0.074
0.067
0.070
0.063
0.058
0.072
0.072
0.079
0.069
0.069
0.064
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0.077
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0.073
0.087
0.081
0.082
0.092
0.088
0.080
0.068
0.075
0.068
0.064
0.098

ave Swi
(frac)
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0.292
0.353
0.333
0.328
0.307
0.299
0.395
0.403
0.321
0.278
0.350
0.405
0.249
0.275
0.358
0.302
0.325
0.283
0.417
0.342
0.385
0.339
0.319
0.381
0.382
0.380
0.304
0.353
0.357
0.449
0.407
0.436
0.371
0.381
0.351
0.333
0.368
0.312
0.458

Average:

129.7

92.6

9.25

6.09

0.072

0.349

Well

RT1-2 RT1 RT6 RT1-2&6
(frac) (frac) (frac)
(frac)
0.18
0.04 0.68
0.86
0.38
0.15 0.42
0.80
0.67
0.25 0.05
0.72
0.40
0.09 0.32
0.72
0.33
0.10 0.38
0.71
0.31
0.08 0.30
0.60
0.66
0.27 0.17
0.83
0.33
0.05 0.31
0.64
0.44
0.06 0.18
0.62
0.26
0.04 0.52
0.77
0.33
0.07 0.50
0.82
0.67
0.18 0.10
0.77
0.41
0.02 0.29
0.70
0.44
0.12 0.27
0.71
0.41
0.14 0.39
0.79
0.43
0.04 0.31
0.74
0.25
0.03 0.61
0.85
0.48
0.13 0.34
0.82
0.54
0.17 0.36
0.90
0.35
0.05 0.25
0.60
0.41
0.06 0.19
0.60
0.49
0.17 0.28
0.77
0.63
0.17 0.09
0.72
0.54
0.19 0.25
0.79
0.44
0.06 0.21
0.65
0.46
0.06 0.20
0.66
0.33
0.01 0.38
0.71
0.21
0.02 0.60
0.81
0.47
0.11 0.27
0.74
0.50
0.09 0.17
0.67
0.35
0.03 0.13
0.48
0.48
0.05 0.19
0.67
0.41
0.03 0.07
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0.47
0.06 0.26
0.73
0.65
0.07 0.16
0.81
0.41
0.10 0.35
0.75
0.29
0.05 0.53
0.83
0.37
0.11 0.47
0.84
0.40
0.13 0.39
0.79
0.37
0.02 0.13
0.50
0.42

0.09

0.30

0.72


CHAPTER V

MATERIAL BALANCE DECLINE TYPE CURVE ANALYSES

5.1 – Introduction

In order to verify the results of the core-log modeling, long-term oil production and water injection data will be analyzed using advanced material balance decline type curve methods. The results of these analyses, which include original oil-in-place (OOIP), estimated ultimate recovery (EUR), skin factor \((s)\) or fracture half-length \((x_f)\) and flow capacity \((kh)\), will then be mapped for comparison to maps generated from the results of our petrophysical study in Chapter IV. In addition, the results of pressure transient test analyses (average reservoir pressure and flow characteristics) will also be incorporated to help correlate reservoir storage and fluid flow properties with historical performance.

The results of our material balance decline type curve analyses include the following:

- In-place fluid volumes
  - Contacted original oil-in-place
  - Movable oil or injectable water at current conditions
  - Reservoir drainage or injection area
- Reservoir properties (based on performance)
  - Formation flow capacity based on production performance, \(kh\)
  - Skin factor for near-well damage or stimulation, \(s\)
  - Fracture half-length, \(x_f\), (if appropriate)
- Estimating efficiency of reservoir drive mechanism(s)
- Calibration of reservoir simulation models.

We will focus on using data that operators acquire as part of normal field operations \((i.e.,\) production rates from sales tickets and pressures obtained 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.
The quantitative analysis of long-term production and injection data can yield many of the same fluid flow characteristics that we obtain from pressure transient tests. By using readily available historical production and injection data, we eliminate the loss of production that occurs when wells are shut in for pressure transient tests. In addition, we obtain an interpretation of well and field performance at little or no cost to the operator. This technique allows us to evaluate reservoir properties quickly and easily, and provides an additional method for locating the most productive areas within a field or region.

We will utilize decline type curves for liquid flow in vertical wells producing under both radial flow conditions (unfractured wells) and producing under fractured well flow conditions (hydraulically-fractured completions or wells fractured due to due long-term water injection above the parting pressure of the formation). The Fetkovich-McCray type curve approach has also been extended to horizontal wells, however, there are no horizontal wells at the North Robertson Unit.

5.2 – Literature Review: Liquid Case (Radial Flow)

The prediction of reservoir behavior using only rate and bottomhole pressure data as a function of time is the most cost-effective reservoir characterization tool at our disposal. 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. The theoretical application of this technique is for newer wells, at pressures above the bubble point, although we will show that the methods described here can be accurately applied at any time during a well's depletion history.

The development of modern decline curve analysis began in 1944 when Arps published a comprehensive review of previous efforts for the graphical analysis of production decline behavior. In that work, Arps developed a family of functional relations based on the hyperbolic decline model for the analysis of flow rate data. Arps provided a variety of results, including the exponential, hyperbolic, and harmonic rate decline relations that we use today for empirical decline curve analysis. Due to the
simplicity and consistency of this empirical approach, the Arps relations remain a benchmark in the industry for the analysis and interpretation of production data.

The utility of the Arps relations is the applicability of the hyperbolic family of curves to model a wide variety of production characteristics. In addition, the simplified analysis of exponential and hyperbolic data trends, such as the graphical techniques provided by Nind, maintain the popularity of the Arps relations.

The application of the Arps relations typically includes a semilog plot of rate versus time where the hyperbolic cases yield gently declining curves that have the straight-line, exponential decline case as a lower limit. Nind provides the development and illustration of plotting functions for the graphical analysis of rate data for the general hyperbolic decline case as well as the exponential decline case.

Another attraction of the Arps relations is their use in graphical as well as functional extrapolation. Many analysts rely uniquely on the Arps relations for performance predictions, often without realizing the empirical nature of such extrapolations. In this work we will use the exponential decline case as a basis for estimating movable oil at current conditions, $N_{p, mov}$. We will demonstrate that this approach can be derived theoretically for the case of a well produced at a constant bottomhole flowing pressure. We will also show that this approach works for wells that are not produced at such restrictive conditions.

The Arps relations for flow rate are given in Eqs. 5.1 – 5.3, below:

<table>
<thead>
<tr>
<th>Case</th>
<th>Rate Relation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exponential ($b = 0$)</td>
<td>$q(t) = q_i \exp(-D_i t)$ ... (5.1)</td>
</tr>
<tr>
<td>Hyperbolic ($0 &lt; b &lt; 1$)</td>
<td>$q(t) = \frac{q_i}{(1 + bD_i t)^{1/b}}$ ... (5.2)</td>
</tr>
<tr>
<td>Harmonic ($b = 1$)</td>
<td>$q(t) = \frac{q_i}{(1 + bD_i t)}$ ... (5.3)</td>
</tr>
</tbody>
</table>

Where $q(t)$ is the time-dependent rate and $q_i$ is the initial rate, both in STB/day, $b$ is the decline curve exponent, $D_i$ is the decline rate in days$^{-1}$ and $t$ is time in days.
The Arps relations for cumulative production are given in Eqs. 5.4 – 5.6, below:

<table>
<thead>
<tr>
<th>Case</th>
<th>Cumulative Production Relation</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exponential ((b = 0))</td>
<td>(N_p(t) = \frac{q_i}{D_i} [1 - \exp(-D_i t)] = \frac{1}{D_i} [q_i - q(t)] \ldots (5.4))</td>
</tr>
<tr>
<td>Hyperbolic ((0 &lt; b &lt; 1))</td>
<td>(N_p(t) = \frac{q_i}{D_i (1 - b)} \left[1 - (1 + b D_i t)^{1 - 1/b}\right]) (= \frac{q_i}{(1 - b)D_i} \left[1 - \left(\frac{q(t)}{q_i}\right)^{1-b}\right]) \ldots (5.5)</td>
</tr>
<tr>
<td>Harmonic ((b = 1))</td>
<td>(N_p(t) = \frac{q_i}{D_i} \ln (1 + D_i t) = -\frac{q_i}{D_i} \ln \left(\frac{q(t)}{q_i}\right) \ldots (5.6))</td>
</tr>
</tbody>
</table>

Where \(N_p(t)\) is the time-dependent cumulative production in STB.

In addition to presenting these fundamental relations, Arps\(^{75}\) later introduced methods for the extrapolation of rate-time data to estimate primary oil reserves using the exponential and hyperbolic decline curve models.

The use of "type curves" (dimensionless or normalized flow rate solutions plotted on a scaled graph) for analysis of production data was introduced to the petroleum industry in the late 1960's and early 1970's.\(^{76,77}\) In 1980 (preprint 1973), Fetkovich\(^{78}\) introduced the most significant development in the type curve matching of production data—the creation of a unified analytical solution (exponential decline) for a well produced at a constant bottomhole pressure during boundary-dominated flow conditions.

Fetkovich plotted his unified exponential decline solution simultaneously with the Arps hyperbolic decline stems, which are assumed to account for non-ideal reservoir behavior (changes in mobility, heterogeneous reservoir features, and reservoir layering). The final result is the so-called "Fetkovich" type curve, which provides for the simultaneous analysis of production data during transient and boundary-dominated flow conditions.

While the Fetkovich decline curve is an extraordinary tool for reservoir engineering, its use has certain limitations. Particular limitations arise in the analysis and interpretation of production data that exhibit significant variations in wellbore pressure, as well as the
effects of periodic shut-ins and other constraints imposed by operational considerations. To its credit, the Fetkovich decline curve is the most powerful tool available for the analysis of production data. Our present efforts serve only to extend the utility and applicability of this type curve analysis approach.

In 1986, Blasingame and Lee\(^7\) introduced the initial effort to incorporate rate and pressure changes into the analysis and interpretation of production data. This work provides analysis methods for determining drainage area size and shape from variable-rate production data in closed reservoirs using a Cartesian plot based on the relation shown in Eq. 5.7:

\[
\frac{\Delta p}{q} = m \bar{t} + b_{pss}, \quad \text{................................................................. (5.7)}
\]

Where \(\Delta p = p_i - p_{wfs}, \text{ (psi)}, \bar{t} \text{ is material balance time in days, } b_{pss} \text{ is a constant (psi-days/STB) and } m \text{ is a constant (psi/STB). The two constants in the pseudosteady-state equation for liquid flow are defined in Eqs. 5.8 – 5.9:}

\[
m = \frac{1}{N c_t} \quad \text{................................................................. (5.8)}
\]

\[
b_{pss} = 141.2 \frac{B \mu}{k_c h} \left[ \frac{1}{2} \ln \left( \frac{4}{e^\gamma} \frac{A}{C_A r_{wa}^2} \right) \right] \quad \text{................................................................. (5.9)}
\]

Where \(N\) is original oil-in-place in STB, \(c_t\) is the total compressibility in psi\(^{-1}\), \(B\) is formation volume factor in RB/STB, \(\mu\) is viscosity in cp, \(k_c\) is effective permeability in md, \(h\) is net pay thickness in feet and \(\gamma\) is Euler's constant (dimensionless). \(C_A\) is the reservoir shape factor (dimensionless), \(A\) is reservoir area in acres and \(r_{wa}\) is the effective wellbore radius in feet.

The "material balance time" is defined in Eq. 5.10, below:

\[
\bar{t} = \frac{N p}{q}. \quad \text{................................................................. (5.10)}
\]

The analysis method derived from Eq. 5.10 was observed to work best when rate changes are small and transients induced by rate changes do not obscure the boundary-
dominated flow behavior for long periods of time. Eq. 5.10 was derived using the Dietz result\textsuperscript{80} for the constant rate case, and verified by comparison to the Muskat\textsuperscript{17} solution for a bounded circular reservoir and by the analysis of simulated well performance data. 

In 1987, Fetkovich \textit{et al.}\textsuperscript{81} presented a series of field case studies evaluated by decline curve analysis using type curves. In addition to several excellent field examples, the authors also gave commentary regarding the analysis and interpretation of production data using decline type curves.

One of the major conclusions of this study was the observation that the \textit{analysis of transient production data using the Arps hyperbolic equations is invalid}. Transient flow theory states that the flow rate profile should be concave up, and as a declining function, the Arps stems are concave down. This clearly poses an inconsistency in both the analysis and interpretation of transient flow data. A curious development in the industry during the 1970's and 1980's was the emergence of a "rule-of-thumb" suggesting that an Arps stem of \(b>1\) should be used for the analysis of transient flow data. However, from the previous arguments it is obvious that this "rule" is without foundation and will ultimately lead to erroneous results as well as incorrect interpretations.

Put in a practical sense, transient flow data (production data functions which are concave up) should never be used to estimate reservoir volume. Specifically, Fetkovich, \textit{et al.} suggest that reservoir volumes and volume-related flow characteristics should not be estimated using decline curve analysis before boundary-dominated flow fully exists \textit{(i.e., production data exhibit a concave downwards behavior)}. 

In 1991, Blasingame \textit{et al.}\textsuperscript{83} expanded on the earlier work of McCray\textsuperscript{82} to develop a time function that would transform production data for systems exhibiting variable rate or pressure drop performance into an equivalent system produced at a constant bottomhole pressure. The motivation of this effort was to create an equivalent constant-pressure formulation for the analysis of variable-rate or variable-pressure drop production data. Unfortunately, the solution provided by Blasingame \textit{et al.}, while theoretically consistent, is somewhat difficult to apply because the approach appears to be very sensitive to erratic changes in rate and pressure. However, this approach provided both insight and
motivation for the development of a more robust and less complicated approach to analyze and interpret variable-rate or variable-pressure drop production data.

McCray proposed the relation shown in Eq. 5.11 as a definition for the "equivalent constant-pressure time," $t_{cp}$:

$$\frac{N_p}{\Delta p(t)} = \int_{0}^{t_{cp}} \left[ \frac{q(\tau)}{\Delta p(\tau)} \right] d\tau. \hspace{1cm} (5.11)$$

McCray provided a recursive-type trapezoidal rule formulation to solve Eq. 5.11 for $t_{cp}$. Blasingame et al. provided a series of derivative formulations for computing $t_{cp}$. As attractive as the concept of an equivalent constant pressure model is, the computational aspects of its application are unsatisfactory, especially for application to field data with erratic variations in the rate and bottomhole pressure profiles.

The utility of the $t_{cp}$ concept is significant given the use of the Fetkovich\textsuperscript{77} (liquid flow) and Carter\textsuperscript{84,85} (gas flow) type curves for analysis of production data, and given this potential, we recommend that the equivalent constant pressure concept be considered for further study.

In 1993, Palacio and Blasingame\textsuperscript{86} developed a solution for the general case of variable-rate/variable-pressure drop for the flow of either single-phase liquid or gas. Palacio and Blasingame concluded that for any particular production history, using the pressure drop normalized flow rate function ($q/\Delta p$) and the material balance time function ($\tau$) will yield a harmonic rate decline ($b = 1$ stem on a Fetkovich decline curve) for liquid flow.

The authors derived this method rigorously from the pseudosteady-state (or boundary-dominated) flow equation. Recalling the pseudosteady-state flow equation, Eq. 5.7, and the definition of the material balance time, $\tau$, Eq. 5.10, their derivation is shown below:

$$\frac{\Delta p}{q} = m\tau + b_{pss}. \hspace{1cm} (5.7)$$

$$\tau = \frac{N_p}{q}. \hspace{1cm} (5.10)$$
Taking the reciprocal of Eq. 5.7 gives:
\[
\frac{q}{\Delta p} = \frac{1}{m \bar{\tau} + b_{pss}}. \quad \text{(5.12)}
\]

Rearranging this result gives:
\[
b_{pss} \frac{q}{\Delta p} = \frac{1}{1 + \frac{m}{b_{pss}} \bar{\tau}}. \quad \text{(5.13)}
\]

Reducing to shorthand notation we have:
\[
\frac{q/\Delta p}{(q/\Delta p)_{int}} = \frac{1}{1 + D_i \bar{\tau}}. \quad \text{(5.14)}
\]

Where the \((q/\Delta p)_{int}\) term is defined as:
\[
(q/\Delta p)_{int} = \frac{1}{b_{pss}} = \frac{1}{70.6} \left( \frac{k h}{B \mu} \ln \left( \frac{4}{e^7} \frac{A}{C_A r_{wa}^2} \right) \right). \quad \text{(5.15)}
\]

and the \(D_i\) term is defined as:
\[
D_i = \frac{m}{b_{pss}} = 0.079545 \left( \frac{k}{\phi \mu c_f A} \right) \ln \left( \frac{4}{e^7} \frac{A}{C_A r_{wa}^2} \right). \quad \text{(5.16)}
\]

Making the final reduction of Eq. 5.14 we have:
\[
q_{Dd} = \frac{1}{1 + \bar{\tau}_{Dd}}. \quad \text{(5.17)}
\]

Where the definitions of \(\bar{\tau}_{Dd}\) and \(q_{Dd}\) for this case are given by:
\[
\bar{\tau}_{Dd} = D_i \bar{\tau}. \quad \text{(5.18)}
\]

and
\[
q_{Dd} = \frac{q/\Delta p}{(q/\Delta p)_{int}}. \quad \text{(5.19)}
\]
Recalling the Arps "harmonic" decline relation \((b=1)\) as defined by Fetkovich\textsuperscript{78} (and given as Eq. G-3 in Appendix G) we have:

\[
q_{Dd} = \frac{1}{1 + t_{Dd}}. \tag{5.20}
\]

Comparing Eqs. 5.17 and 5.20, we immediately recognize that these relations are identical. Further, if we consider the base relation for variable-rate/variable-pressure drop performance (Eq. 5.12), we note that during boundary-dominated flow, \(q/\Delta p\) data plotted versus \(\tau\) will exactly overlay the Arps \(b = 1\) stem on the Fetkovich decline curve. This was the foundation of analysis for the work by Palacio and Blasingame\textsuperscript{86} as well as the basis for our efforts in this present work.

5.3 – Fetkovich-McCray Decline Type Curve (Radial Flow Case)

The rigorous solution for any rate and pressure schedule for the case of a well producing under boundary-dominated flow conditions is given by Eq. 5.12:

\[
\frac{q}{\Delta p} = \frac{1}{m \tau + b_{pss}}. \tag{5.12}
\]

We recognize that Eq. 5.12 is a "harmonic" type of equation in which the "material balance time" function, \(\tau\), is given by Eq. 5.10:

\[
\tau = \frac{N_p}{q}. \tag{5.10}
\]

As such, we simply plot the pressure drop normalized rate function, \(q/\Delta p\), versus material balance time, \(\tau\), on a scaled log-log plot and match these data on the Fetkovich/McCray type curve,\textsuperscript{86} with the boundary-dominated flow data being force-matched (by definition) on the Arps \(b = 1\) depletion stem. The type curve matching procedures and the associated analysis methodologies are discussed later in this text, as well as in Appendix G.

The so-called "Fetkovich-McCray type curve" was first presented as a single entity in ref. 86, although components of this curve were presented by Fetkovich\textsuperscript{78} and McCray.\textsuperscript{82} The utility of the resulting "Fetkovich-McCray" solution is the ability to match flow rate
functions, as well as the flow rate integral and integral derivative functions simultaneously. In addition, the integral functions provide smoother data trends for clarity and ultimately, improved matching of data and type curves.

Although both Fetkovich\textsuperscript{78} and McCray\textsuperscript{82} provide the details of the development of their respective decline type curves, we believe that a unifying discussion is in order, particularly for readers interested in further developments of this type.

It is important to recall that the "analytical" stems (transient stems and the exponential decline case \(b = 0\) stem) on the Fetkovich-McCray type curve (or any "decline" type curve for that matter) are solutions for a well producing at a constant bottomhole flowing pressure. However, the methodology indicated by Eqs. 5.10 and 5.12 indicate that the Fetkovich-McCray type curve can be used to analyze any type of production data, including data exhibiting arbitrary changes in rate and pressure, so long as the boundary-dominated flow data are "force matched" on the \(b = 1\) (harmonic) stem.

In order to be consistent with current literature, we use the Fetkovich\textsuperscript{78} definitions of the dimensionless decline variables \((t_{Dd} \text{ and } q_{Dd})\) which are given below. The \(t_{Dd}\) function is given in terms of dimensionless variables as:

\[
t_{Dd} = \frac{2}{r_{eD}^2} \frac{1}{\ln r_{eD} - \frac{1}{2}} t_D. \quad \text{......................................................... (5.21)}
\]

In terms of real variables we have:

\[
t_{Dd} = 0.00633 \frac{kt}{\phi \mu c r A} \frac{2\pi}{\ln r_{eD} - \frac{1}{2}}. \quad \text{......................................................... (5.22)}
\]

In a similar fashion, the \(q_{Dd}\) function is given in terms of dimensionless variables as:

\[
q_{Dd} = \ln r_{eD} - \frac{1}{2} q_D. \quad \text{......................................................... (5.23)}
\]

In terms of real variables we have:

\[
q_{Dd} = 141.2 \frac{B \mu}{kh} \frac{q}{\Delta p} \ln r_{eD} - \frac{1}{2}. \quad \text{......................................................... (5.24)}
\]
A minor discrepancy in these definitions is that the 1/2 term should actually be 3/4 as noted by Ehlig-Economides and Ramey.\textsuperscript{87} We maintain the convention of using 1/2 rather than 3/4 for the purpose of type curve developments in order to be compatible with existing literature. But in fact, this "discrepancy" rarely makes more than a few percent difference in the interpretation, and is only noted here for completeness.

The rate integral and rate integral derivative functions introduced by McCray\textsuperscript{82} are given in dimensionless form below. The dimensionless rate integral function, \( q_{Di} \), is given as:

\[
q_{Di} = \frac{N_{pDd}}{t_{Dd}} = \frac{1}{t_{Dd}} \int_{0}^{t_{Dd}} q_{Dd}(\tau) \, d\tau. \tag{5.25}
\]

The dimensionless rate integral derivative function, \( q_{Ddid} \), is given as:

\[
q_{Ddid} = -\frac{dq_{Di}}{d(ln t_{Dd})} = -t_{Dd} \frac{dq_{Ddi}}{dt_{Dd}}. \tag{5.26}
\]

Where Eq. 5.26 can be reduced to the following result as shown in Appendix G:

\[
q_{Ddid} = q_{Ddi} - q_{Dd}. \tag{5.27}
\]

We also introduce the dimensionless rate derivative function, \( q_{Ddd} \), which is defined as:

\[
q_{Ddd} = -\frac{dq_{D}}{d(ln t_{Dd})} = -t_{Dd} \frac{dq_{Dd}}{dt_{Dd}}. \tag{5.28}
\]

Unfortunately, we do not expect Eq. 5.28 to be of much use in the analysis of production data due to the volume of random error found in production data, where these random errors are only magnified by the differentiation process.

In order to develop the Fetkovich-McCray type curve, we require values of the solution for a well produced at a constant bottomhole pressure, \( q_{D} \), as a function of dimensionless time, \( t_{D} \), which are then converted to \( t_{Dd} \) and \( q_{Dd} \) using Eqs. 5.21 and 5.23, respectively. These \( q_{D}(t_{D}) \) values can be obtained from tables in van Everdingen and Hurst\textsuperscript{88} or using numerical inversion\textsuperscript{89} of the Laplace transform solution developed by Matthews and Russell\textsuperscript{90}. The Laplace transform solution for constant rate production for a well centered in a bounded circular reservoir as solved by Matthews and Russell is given in Eq. 5.29, below:
\[
\tilde{p}_D(r_D,u) = \frac{K_0(\sqrt{u}r_D) I_1(\sqrt{u}r_{eD}) + K_1(\sqrt{u}r_{eD}) I_0(\sqrt{u}r_D)}{u[\sqrt{u}K_1(\sqrt{u}) I_1(\sqrt{u}r_{eD}) - \sqrt{u}I_1(\sqrt{u}) K_1(\sqrt{u}r_{eD})]}. \quad \text{(5.29)}
\]

However, we require the solution for a constant flowing bottomhole pressure rather than a constant flow rate. We can easily obtain the constant bottomhole pressure solution from the constant rate solution using the following relation in Laplace space given by Eq. 5.30 from van Everdingen and Hurst,

\[
q_D(u) = \frac{1}{u^2} \frac{1}{p_D(u)}. \quad \text{....................................................................................... (5.30)}
\]

Once the \(q_{Dd}(t_{Dd})\) values are obtained from \(q_D(t_D)\) values, the associated derivative and integral functions can be computed using standard techniques, or the derivative and integral functions can be computed simultaneously with the \(q_{Dd}(t_{Dd})\) values using the numerical Laplace transform inversion algorithm.

In Fig. 5.1 we present the original Fetkovich\textsuperscript{78} type curve for the radial flow case, along with the derivative function, \(q_{Ddd}\), as defined by Eq. 5.28. The \(q_{Ddd}\) stems illustrate a dramatic illustration of the transfer from transient to boundary-dominated flow, however, as we suggested before, we would not expect the \(q_{Ddd}\) concept to be particularly applicable due to random noise present in field data.

The Fetkovich-McCray type curve\textsuperscript{86} for the radial flow case is shown in Fig. 5.2, where \(q_{Dd}, q_{Di}\) and \(q_{Ddid}\) are all plotted versus \(t_{Dd}\) on the type curve grid. The pseudosteady-state flow equation has been solved using material balance time, \(\bar{t}\), and all boundary-dominated data functions are force-matched to the harmonic \((b = 1)\) stems. Note that we match on a unified boundary-dominated flow stem for each plotting function. This gives us a definitive matching technique in the boundary-dominated flow region, and hence, a more unique transient data match. We believe that Fig. 5.2 provides all of the necessary functions for both rigorous and empirical analysis of production data from unfractured wells.
Figure 5.1 – Fetkovich $q_{Dd}$ and $q_{Ddd}$ type curves for an unfractured well (radial flow case) centered in a bounded circular reservoir.

Figure 5.2 – Fetkovich-McCray $q_{Dd}$, $q_{Ddi}$ and $q_{Ddid}$ type curves for an unfractured well (radial flow case) centered in a bounded circular reservoir.
5.3.1 – Application to Analysis of Oil Production Data (Radial Flow Case)
A step-by-step procedure for the use of the Fetkovich-McCray type curve is given in Appendix G, and is abbreviated in this section for reference and use in applications. Our type curve analysis technique provides methods to estimate the original-oil-in-place and other volume-related properties, as well as the flow characteristics of the reservoir.

Our methodology is based on the use of the material balance time function, \( \bar{t} \), that yields a harmonic decline for the case of liquid production, regardless of the rate and pressure schedule. We provide the following procedure for the analysis and interpretation of production data from unfractured wells using decline type curves.

1. Compute material balance time from production data

\[
\bar{t} = \frac{N}{q}. \quad \text{.......................................................... (5.10)}
\]

Due to rate changes that occur throughout the life of a well (caused by pulling jobs, workovers and recompletions), material balance time will not always be a strictly increasing function. Therefore, the data may have to be edited after \( \bar{t} \) has been calculated to remove extraneous data points.

2. Compute the flow rate, flow rate integral and flow rate integral-derivative functions

Our approach in this study is to work with the pressure drop normalized rate function, \( q/\Delta p \), in order to be completely consistent with the theory given by Eq. 5.12. Our notation will follow this convention throughout the text, including cases where continuously measured bottomhole pressure data are not available, and we use the initial reservoir pressure, \( p_i \) as the normalizing condition. The pressure drop normalized rate plotting function is given by:

\[
\left( \frac{q}{\Delta p} \right) = \frac{q}{(p_i - p_{wf})} = \frac{q}{\Delta p}. \quad \text{.......................................................... (5.31)}
\]

The rate integral plotting function is given by:

\[
\left( \frac{q}{\Delta p} \right)_i = \frac{1}{\bar{t}} \int_0^{\bar{t}} \frac{q}{\Delta p} d\tau. \quad \text{.......................................................... (5.32)}
\]
The rate integral derivative plotting function is given by:

\[
(q/\Delta p)_{id} = -\frac{d[\frac{(q/\Delta p)_{i}}{d[\ln(\bar{\tau})]}]}{d[\ln(\bar{\tau})]} = -\bar{\tau} \frac{d[\frac{(q/\Delta p)_{i}}{d\bar{\tau}}]}{d\bar{\tau}}.
\] ................................................ (5.33)

The three plotting functions in Eqs. 5.31 – 5.33 are computed and plotted versus material balance time, \(\bar{\tau}\). These data trends are then overlain on the Fetkovich-McCray type curve, taking care to "force match" the boundary-dominated portion of the data onto the Arps \(b = 1\) (harmonic decline) stems. The "force matching" of boundary-dominated flow data is required by theory and provides the best possible estimate of oil-in-place, \(N\).

3. **Estimate oil-in-place**

Estimating the reservoir volume or oil-in-place, \(N\), from type curve analysis requires that we rearrange the definitions of \(t_{Dd}\) and \(q_{Dd}\) (given by Eqs. 5.22 and 5.24) to yield a "match point" result in terms of volume. Equating and isolating terms in Eqs. 5.22 and 5.24, we obtain the following relation:

\[
(q_{Dd})_{MP} (t_{Dd})_{MP} = \frac{5.6148B \phi Ahc_i}{5.6148B \phi Ahc_i} (q/\Delta p)_{MP} (\bar{\tau})_{MP}.
\] ........................................... (5.34)

Solving Eq. 5.34 for the oil-in-place, \(N\), we obtain:

\[
N = \frac{1}{c_i} \frac{(q/\Delta p)_{MP}}{(q_{Dd})_{MP}} (t_{Dd})_{MP}.
\] ..................................................... (5.35)

In order to solve for the pseudosteady-state constant, \(b_{pss}\), we will use the generalized definition of \(q_{Dd}\) given by Eq. G-5 in Appendix G. Recalling Eq. G-5 we have:

\[
q_{Dd} = 141.2 \frac{B \mu}{kh} \frac{q}{\Delta p} \left[ \frac{1}{2} \ln \left( \frac{4}{e^{\gamma}} \frac{A}{C Ar_w} \right) \right].
\] ...................................................... (5.36)

We note that Eqs. 5.24 and 5.36 are equivalent, but Eq. 5.24 is strictly valid only for the case of a well centered in a bounded circular reservoir while Eq. 5.36 is
valid for a general reservoir/well configuration using the appropriate reservoir shape factor, $C_A$.

Recalling the definition of $b_{pss}$, Eq. 5.9, we have:

$$b_{pss} = 141.2 \frac{B \mu}{kh} \left[ \frac{1}{2} \ln \left( \frac{4}{e^2} \frac{A}{C_A r_{wa}^2} \right) \right]. \quad (5.9)$$

Combining and solving Eqs. 5.9 and 5.36 for $b_{pss}$, we obtain the following match point relation:

$$b_{pss} = \frac{(q_{Dd})_{MP}}{(q/\Delta p)_{MP}}. \quad (5.37)$$

4. Estimate reservoir flow characteristics

The relations given below are used to estimate volumetric and flow characteristics of the reservoir based on the results of the type curve match and the available well data.

Reservoir Drainage Area, $A$

$$A = 5.6148 \frac{NB}{\phi h (1 - S_{wi})}. \quad (5.38)$$

Reservoir Drainage Radius, $r_e$

$$r_e = \sqrt{\frac{A}{\pi}}. \quad (5.39)$$

Effective Wellbore Radius, $r_{wa}$

$$r_{wa} = \frac{r_e}{r_{eD}}. \quad (5.40)$$

Effective Permeability, $k_e$

$$k_e = 141.2 \frac{B \mu}{h} \frac{1}{2} \ln \left[ \frac{4A}{e^2 \gamma C_A r_{wa}^2} \right] \frac{(q/\Delta p)_{MP}}{(q_{Dd})_{MP}}. \quad (5.41)$$

Combining Eqs. 5.37 and 5.41 we have:
\[ k_e = 141.2 \frac{B \mu}{h} \frac{1}{2} \ln \left[ \frac{4A}{e \gamma C A^2} \right] \left[ \frac{1}{b_{pss}} \right] \] ................................. (5.42)

**Skin Factor, s**

\[ s = -\ln \left( \frac{r_{wa}}{r_w} \right) \] ................................. (5.43)

For which \( S_{wi} \) is the irreducible water saturation (fraction), \( r_{eD} \) is the dimensionless reservoir drainage radius and \( r_w \) is the wellbore radius (feet).

**5.3.2 – Analysis and Interpretation Considerations (Radial Flow Case)**

In the following sections, we present analyses and interpretations for some verifying simulated data cases, as well as for NRU field data cases for oil production from unfractured (radial flow) wells or fractured wells that have radial flow regimes (short half-lengths). Our goal is to be able to analyze cases for which data is plentiful, but also to be able to accurately estimate movable oil volumes and fluid flow characteristics when high quality production data is scarce. We suggest that our methods for the analysis of long-term production data are easily transferable to any operator, in particular, operators that lack the ability to perform periodic pressure transient tests or long-term production tests.

We present as complete an analysis and interpretation procedure as possible for each data case. We are able to reduce the adverse affects of production anomalies that occur during the life of a well, and we obtained unique type curve matches using production rate and pressure functions, material balance time, and the Fetkovich-McCray type curve. These production rate functions are:

- pressure drop normalized rate function, \( q/\Delta p \),
- rate integral function, \( (q/\Delta p)_i \), and
- rate integral-derivative function, \( (q/\Delta p)_{id} \).

This process results in excellent estimates of original and movable oil volumes, as well as good estimates of permeability and skin factor. The formation flow characteristics
can be calculated with much greater accuracy and confidence if we have accurate early-
time (transient) data.

When the type curve match on either a transient or depletion stem is indeterminate,
anomalies in the production data can be removed by editing the data around a particular
anomaly. Examples of such "anomalies" are recompletions, mechanical failures, long-
term shut-ins and fluctuations in flow rate and pressure at early times in the life of the
well. When data editing is required due to anomalies in the production data, the
cumulative oil produced and original oil-in-place remain constant as long as the overall
data trend is honored.

The procedures for data preparations, analysis and interpretation include the verification
of pertinent rock, fluid, and completion data using available field records and fluid
property correlations. The critical data required for our analysis are shown below.

- total compressibility, $c_t$
- oil viscosity, $\mu_o$
- oil formation volume factor, $B_o$
- irreducible water saturation, $S_{wi}$
- porosity, $\phi$
- net pay interval, $h$
- wellbore radius, $r_w$

Initial screening of the production data is performed using semilog and log-log plots of
rate versus time. These plots are utilized to identify errors or anomalies in the data,
locate and annotate changes in completion practices and to edit the data where required.

After the data functions have been calculated, we match the functions on the type curve
to find the time and rate match points. These match points are then utilized to estimate
oil-in-place, $N$, pseudosteady-state flow constant, $b_{psss}$, and the dimensionless drainage
radius, $r_{eD}$. These parameters are then utilized to calculate reservoir drainage area,
effective permeability and near-well skin factor, as summarized in Section 5.3.1, above.

Depending on the amount of bottomhole pressure data available, we have three different
techniques for estimating the ultimate recovery for the current well completion, $N_{p,mov}$.
These options are outlined below. A complete treatment of the procedures used for the
estimation of movable oil can be found in Appendix G.
1. **Strictly rigorous approach** (requires $p_{wf}$ data)

   Plot calculated average pressure, $\bar{P}_{cal} = p_{wf} + qb_{pss}$, versus cumulative oil production, $N_p$, and extrapolate to $\bar{P}_{cal} = 0$. Where $\bar{P}_{cal}$ is the calculated average reservoir pressure.

2. **Semi-analytical approach**

   Plot $q/\Delta p$ versus cumulative oil production, $N_p$, and extrapolate to $q/\Delta p = 0$.

3. **Analytical approach – constant bottomhole pressure case**

   Plot the flow rate, $q$, versus cumulative oil production, $N_p$, and extrapolate to $q = 0$. This method is used when bottomhole pressure data are not available.

**5.3.3 – Simulated Data Examples (Radial Flow Case)**

We used a 2-D, radial, single-phase black oil simulator with thirty geometrically spaced grid blocks to model well performance in a single-layer reservoir with homogeneous and isotropic properties. These cases are used for verification of our type curve analysis and interpretation methods. A constant bottomhole pressure case was used as a benchmark and a second case with multiple rate and pressure changes (including shut-ins) was generated to verify the variable-rate/pressure drop performance of our approach.

The analysis method was verified using simulated data cases with a wide range of permeability, and numerous changes in rate and bottomhole pressure. Agreement between simulated performance and the results of decline curve analysis were checked for permeabilities of 1, 10, and 100 md. We present the analysis of simulated performance for the rate and pressure histories shown in Table 5.1, below.

The pertinent reservoir, rock, and fluid properties for these verification runs are also summarized below.
Table 5.1 – Rate and pressure histories for two simulated data cases.

<table>
<thead>
<tr>
<th>Case</th>
<th>Time (days)</th>
<th>$p_{wf}$ (psia)</th>
<th>Rate (STB/day)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 (Constant $p_{wf}$)</td>
<td>0.0001</td>
<td>100</td>
<td>variable</td>
</tr>
<tr>
<td></td>
<td>3000.0</td>
<td>100</td>
<td>variable</td>
</tr>
<tr>
<td>2 (Variable $p_{wf}$ with multiple shut-ins)</td>
<td>0.0001</td>
<td>variable</td>
<td>15.0</td>
</tr>
<tr>
<td></td>
<td>200.0</td>
<td>variable</td>
<td>0.0</td>
</tr>
<tr>
<td></td>
<td>210.0</td>
<td>2500</td>
<td>variable</td>
</tr>
<tr>
<td></td>
<td>310.0</td>
<td>1500</td>
<td>variable</td>
</tr>
<tr>
<td></td>
<td>410.0</td>
<td>variable</td>
<td>0.0</td>
</tr>
<tr>
<td></td>
<td>420.0</td>
<td>2000</td>
<td>variable</td>
</tr>
<tr>
<td></td>
<td>520.0</td>
<td>700</td>
<td>variable</td>
</tr>
<tr>
<td></td>
<td>620.0</td>
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<td>variable</td>
</tr>
<tr>
<td></td>
<td>4000.0</td>
<td>100</td>
<td>variable</td>
</tr>
</tbody>
</table>

Reservoir, Fluid Property and Production Data

**Reservoir Properties**
- Wellbore radius, $r_w$ = 0.25 feet
- Drainage radius, $r_e$ = 744.7 feet
- Net pay thickness, $h$ = 10 feet
- Porosity, $\phi$ (fraction) = 0.20
- Irreducible water saturation, $S_{wi}$ = 0.00
- Original nominal well spacing = 40 acres
- Effective oil permeability, $k_o$ = 1 md
- Original-oil-in-place, $N$ = 564,210 STB

**Fluid Properties**
- Oil formation volume factor, $B_o$ = 1.1 RB/STB
- Oil viscosity, $\mu_o$ = 1.0 cp
- Total compressibility, $c_t$ = $20.0 \times 10^{-6}$ psi$^{-1}$

**Production Parameters**
- Initial reservoir pressure, $p_i$ = 4,000 psia

5.3.3.1 – Simulated Case 1: Constant Bottomhole Pressure

The semilog and log-log production plots, together with the rate function plots are shown for the two simulated cases in Figs. 5.3 – 5.8. The rate function, $q/\Delta p$, rate
integral function, \((q/\Delta p)\), and rate integral-derivative function, \((q/\Delta p)_{id}\), are plotted versus material balance time, \(\tau\), and overlain on the Fetkovich-McCray type curve as shown on Fig. 5.9 (constant pressure case). The boundary-dominated portion of the rate functions are force matched on the \(b = 1\) (harmonic) decline stem as dictated by theory for the use of material balance time, and the appropriate match points are taken. The dimensionless drainage radius matching parameter, \(r_{eD}\), is estimated from the position of the data on the transient flow type curve stems. The \(r_{eD}\) parameter is then used to estimate effective oil permeability and near-wellbore skin factor.

Figure 5.3 – Semilog production plot for simulated case #1 (constant \(p_{wf}\)).

Figure 5.4 – Log-Log production plot for simulated case #1 (constant \(p_{wf}\)).
Figure 5.5 – Rate functions for simulated case #1 (constant $p_{wf}$).

Figure 5.6 – Estimated movable oil from rate history for simulated case #1 (constant $p_{wf}$).
We obtained excellent type curve matches on both the transient stems (for early-time data) as well as the depletion stems (for late time or boundary-dominated flow data), as shown in Fig. 5.9. The drainage area, total and movable oil volumes, permeability, and skin factor estimated by type curve analysis matched the input data to the simulator, verifying our approach for the constant pressure case. The results are shown below.
Figure 5.9 – Match of production data for simulated case #1 (constant $p_w$) on the Fetkovich-McCray type curve for an unfractured well centered in a bounded circular reservoir.

Type Curve Analysis Results (Fig. 5.9)

Matching Parameter: $r_e = 3,000$

- $[t_{Dd}]_{MP} = 1.0$
- $[\tau]_{MP} = 1,270$ days
- $[q_{Dd}]_{MP} = 1.0$
- $[q/\Delta p]_{MP} = 0.0089$ STB/day/psi days

Original-Oil-in-Place

\[
N = \frac{1}{c_t} \frac{(q/\Delta p)_{MP}}{(q_{Dd})_{MP} (\tau)_{MP}}. \quad \text{.................................................................................................. (5.35)}
\]

\[
N = \frac{(1270 \text{ days})(0.0089 \text{ STB/day/psi})}{20 \times 10^{-6} \text{ psi}^{-1}} = 565,150 \text{ STB}.
\]

Reservoir Drainage Area

\[
A = 5.6148 \frac{NB}{\phi h (1 - S_w)} \quad \text{.................................................................................................. (5.38)}
\]
\[ A = \frac{(5.6148 \text{ ft}^3/\text{RB})(565,150 \text{ STB})(1.1 \text{ RB/STB})}{(0.20)(10 \text{ ft})(1 - 0)} \]

\[ A = (1,745,262 \text{ ft}^2)(1 \text{ acre} / 43,560 \text{ ft}^2) = 40.07 \text{ acres}. \]

**Reservoir Drainage Radius**

\[ r_e = \sqrt{\frac{A}{\pi}} \] \hspace{1cm} (5.39)

\[ r_e = \sqrt{\frac{(1,745,262 \text{ ft}^2)}{\pi}} = 745.3 \text{ feet}. \]

**Effective Wellbore Radius**

\[ r_{wa} = \frac{r_e}{r_e D} \] \hspace{1cm} (5.40)

\[ r_{wa} = \frac{745.3 \text{ ft}}{3,000} = 0.2484 \text{ feet}. \]

**Effective Oil Permeability** \((C_A = 31.62 \text{ for bounded circular reservoir})\)

\[ k_o = 141.2 \frac{B\mu}{h} \left( \frac{1}{2} \ln \left[ \frac{4A}{\gamma C_A r_{wa}^2} \right] \right) \left( \frac{(q/\Delta p)_{MP}}{(qDd)_{MP}} \right) \] \hspace{1cm} (5.41)

\[ k_o = 70.6 \frac{(1.1 \text{ RB/STB})(1.0 \text{ cp})}{10 \text{ ft}} \ln \left[ \frac{(4)(1,745,262 \text{ ft}^2)}{(1.781)(31.62)(0.2484 \text{ ft})^2} \right] \left( \frac{0.0089}{1} \right) = 1.0 \text{ md}. \]

**Skin Factor**

\[ s = -\ln \left( \frac{r_{wa}}{r_w} \right) \] \hspace{1cm} (5.43)

\[ s = -\ln \left( \frac{0.2484 \text{ ft}}{0.25 \text{ ft}} \right) = 0.0. \]

**5.3.3.2 – Simulated Case 2: Variable Bottomhole Pressure With Shut-Ins**

Since most wells are not usually produced at a constant bottomhole pressure indefinitely, we developed our second verification case with multiple rate and pressure changes.
(including shut-ins). This case more closely models actual field performance and should be considered representative of the types of production histories for which our methodologies were developed.

The semilog and log-log production plots, together with the rate function plots are shown for the two simulated cases in Figs. 5.10 – 5.15. The rate function, \( q/\Delta p \), rate integral function, \( (q/\Delta p)_i \), and rate integral-derivative function, \( (q/\Delta p)_d \), are plotted versus material balance time, \( \tilde{t} \), and overlain on the Fetkovich-McCray type curve as shown on Fig. 5.16 (variable \( p_{wf} \) case).

Figure 5.10 – Semilog production plot for simulated case #2 (variable \( p_{wf} \)).

Figure 5.11 – Log-Log production plot for simulated case #2 (variable \( p_{wf} \)).
Figure 5.12 – Rate functions for simulated case #2 (variable $p_{wf}$).

Figure 5.13 – Estimated movable oil from rate history for simulated case #2 (variable $p_{wf}$).

Figure 5.14 – Estimated movable oil from pressure drop normalized rate history for simulated case #2 (variable $p_{wf}$).
Figure 5.15 – Estimated movable oil from $p_{cut}$ for simulated case #2 (variable $p_{wf}$).

Figure 5.16 – Match of production data for simulated case #2 (variable $p_{wf}$ with shut-ins) on the Fetkovich-McCray type curve for an unfractured well in a bounded circular reservoir.

We once again obtained excellent type curve matches on both the transient stems (for early-time data) as well as the depletion stems (for late time or boundary-dominated flow).
data), as shown in Fig. 5.16. The drainage area, total and movable oil volumes, permeability, and skin factor estimated by type curve analysis matched the input data to the simulator. The results were exactly the same as the constant pressure case, therefore, they are not shown here.

5.3.3.3 – Movable Oil Plots (Figs. 5.6 – 5.8, 5.13 – 5.15)

Plots of calculated average pressure, $\bar{p}_{cal}$, normalized daily rate, $q/\Delta p$, and daily rate, $q$, versus cumulative production, $N_p$, were constructed to estimate the movable oil volume, $N_{p,mov}$. Extrapolation of the plotted data to the $N_p$ axis-intercept yields movable volumes of between 46 and 47 MSTB for both simulated cases. The simulated estimate for movable oil was slightly less (approximately 45 MSTB).

These extrapolated values represent the movable oil volume at the time when all reservoir energy has been depleted. These volumes are usually slightly higher than the actual field value of movable oil due to the practical and economic inability to produce a well to such a low-pressure state.

When bottomhole pressures are available, the $\bar{p}_{cal}$ or $q/\Delta p$ plots should be used to estimate $N_p$. For cases in which no bottomhole pressure data are available, a plot of $q$ versus $N_p$ has been shown to yield accurate estimates of $N_p$.

\[
\begin{align*}
N_{p,mov} &= 45.0 \text{ MSTB (simulation)} \\
N_{p,mov} &= 46.0 - 47.0 \text{ MSTB (movable oil plots)} \\
\text{Recovery Factor} &= \left( \frac{47,000 \text{ STB}}{565, 150 \text{ STB}} \right) (100) = 8.3\%
\end{align*}
\]

5.3.3.4 – Summary

The simulated cases provide an excellent test for the utility of the type curve analysis method. Results of the decline type curve and material balance analyses are essentially the same as the data input to the simulator. Our method was shown to work well for a variety of producing scenarios, involving both variable rates and variable bottomhole pressures. This gives us confidence in applying these methods to field data cases.
5.3.4 – NRU Field Data Examples (Radial Flow Case)

At the NRU, we had average monthly Clear Fork production data on a tract basis allocated to individual wells, with little bottomhole pressure data. We do have a fairly good bottomhole pressure history on the new 10-acre infill wells, however, they make up a small percentage of the total producing well count. All the producing wells at the NRU are on rod-pump with low working fluid levels, therefore, the lack of $p_{wfp}$ data is not a great limitation.

For many of the wells we analyzed, the rock, fluid, and other pertinent formation properties were unknown and had to be estimated. The fluid properties were estimated using the available field data and from correlations provided in the fluid properties module of a commercial software package. The results are given in tabular form in Appendix I.

We suggest that fluid properties be evaluated at an average pressure when the reservoir is between the initial and bubble point pressures, and at a pressure just above the bubble point when the reservoir pressure is below the bubble point. Our experience has shown that these practices yield the best results when performing decline type curve analysis. Due to the difficulty in obtaining representative values of certain fluid properties, we suggest reporting a value for the $Nc_t$ product. This approach allows each individual analyst to supply their own estimates of fluid properties, and to provide their own interpretation of the calculated results.

In addition to difficulties in obtaining representative fluid properties, we also prefer to report a value for the permeability-thickness product, $kh$, in place of permeability because we lack accurate estimates of net pay thickness for many of the wells within the unit. However, to be consistent, we do present permeabilities and drainage areas based on estimated values of net pay thickness for all cases.

The inability to complete all results with a high degree of confidence is not related to the analysis or interpretation methodologies we present, but rather, to a lack of reservoir and fluid data with which to complete these calculations. We use this opportunity to point out the importance of early and complete data collection.
The North Robertson (Clear Fork) Field (Fig. 5.17) was developed on a nominal 40-acre well spacing beginning in 1956. The dominant reservoir producing mechanism for the original 141 wells was solution gas drive. The initial reservoir pressure in the Lower Clear Fork (LCF) was estimated to be 2,800 psia. As part of an infill drilling and waterflood project that began in 1987, 116 new wells were drilled, reducing well spacing to 20 acres, and resulting in uniform 40-acre 5-spot patterns. Original-oil-in-place (OOIP) was estimated to be between 250 – 300 MMSTB. Primary production before unitization in 1987 was 20.5 MMSTB and secondary production prior to January 2000 was approximately 10 MMSTB. Individual well primary and secondary recovery factors are low, ranging between 5 and 10 percent.

Figure 5.17 – North Robertson (Clear Fork) Unit, Gaines County, Texas.
The Lower Clear Fork is a shallow-shelf carbonate composed primarily of a massive dolomite section with varying degrees of anhydrite cement. The geologic setting at the time of deposition and subsequent diagenesis contributed to the heterogeneous nature of the Clear Fork formation. The Clear Fork is defined by extremely scattered reservoir "pay" intervals over a large vertical section, poor vertical and lateral continuity and low porosity (7.6 percent on average) and absolute permeability (often < 1 md). Although the reservoir may be difficult to characterize geologically, the Clear Fork does behave like a material balance reservoir, and the decline curve techniques outlined previously are extremely useful.

The wells were initially completed in the Lower, Middle, and Upper Clear Fork, at measured depths of between 6,200 and 7,200 feet. The majority of the original completion intervals were in the Lower Clear Fork (main field pay). Additional completions were added in the Upper Clear Fork and Glorieta during workover programs in the 1970's. At the inception of the waterflood project in 1987, many of the original wells were converted to injectors, and the remaining producers were re-completed up structure.

Much of the fluid property data and the net pay thicknesses (due to hydraulic fracture treatments over all intervals) have been estimated. The oil flow rate data was allocated to individual wells on a tract basis, and may be in error, although the errors are not likely to be significant because the wells were tested for allocation on a semi-annual basis. There is little producing bottomhole pressure data available for the North Robertson Unit. For analysis purposes we assumed $p_{wf} \sim 100$ psia, which is an average for the producing wells in the unit. This is a fairly reliable estimate based on producing (pumping) bottomhole pressure histories acquired on the 10-acre infill wells, as shown in Fig. 5.18, below. All wells have bottomhole producing (pumping) pressures of approximately 100 psia after three months of initial production.
5.3.4.1 – Field Example: NRU Well No. 4202

Fig. 5.19 shows the location of NRU Well 4202, in the southwest corner of the unit, with respect to its well pattern and the unit. This well was drilled in 1962, and completed in both the Lower and Upper Clear Fork. The well was stimulated with 3,000 gallons of acid, and hydraulically fractured with 60,000 gallons of fracturing oil and 90,000 pounds of 20/40 sand. The well initially tested at 141 STBO/day. It had produced approximately 229 MSTB as of July 1999.

Reservoir, Fluid Property and Production Data

*Reservoir Properties*

- Wellbore radius, $r_w$ = 0.33 feet
- Estimated gross pay interval = 1,000 feet
- Estimated net pay thickness, $h$ = 200 feet (varies)
- Average porosity, $\phi$ (fraction) = 0.075
- Average irreducible water saturation, $S_{wi}$ = 0.30
- Effective oil permeability, $k_o$ < 1 md
- Original nominal well spacing = 40 acres
- Current nominal well spacing = 20 acres
Fluid Properties
Average oil formation volume factor, $B_o$ = 1.25 RB/STB
Average oil viscosity, $\mu_o$ = 1.30 cp
Initial total compressibility, $c_{ti} = 12.0 \times 10^{-6}$ psi$^{-1}$
Average total compressibility, $c_t$ = $30.0 \times 10^{-6}$ psi$^{-1}$

Production Parameters
Initial reservoir pressure (LCF), $p_i$ = 2,800 psia
Average producing bottomhole pressure, $p_{wf}$ = 100 psia

Semilog and log-log production plots shown in Figs. 5.20 and 5.21 indicate that there were no significant rate fluctuations during primary production. It is interesting to note the decrease in decline rate at approximately 5,500 days of producing time that appears to be a response to an adjacent waterflood project that was initiated during that time. The response to the unit waterflood can be seen at approximately 9,000 days, when the oil rate increased sharply. The well is located on the periphery of the unit, therefore, it has never received full waterflood support. Since there were two (primary and secondary) production trends, the primary production data was used to estimate OOIP and reservoir flow characteristics. The type curve match is shown in Fig. 5.22.
Figure 5.20 – Semilog production plot for NRU 4202.

Figure 5.21 – Log-Log production plot for NRU 4202.
NRU 4202 – Type Curve Analysis Results (Fig. 5.22)

Matching Parameter: \( r_eD = 7.0 \)

\[
\begin{align*}
[t_{Dd}]_{MP} &= 1.0 & [T]_{MP} &= \text{2,900 days} \\
[q_{Dd}]_{MP} &= 1.0 & [q/\Delta p]_{MP} &= \text{0.02 STB/day/psi days}
\end{align*}
\]

Original-Oil-in-Place

\( Nc_i = 58.0 \text{ STB/psi} \)

\[
N = \frac{(2900 \text{ days})(0.02 \text{ STB/day/psi})}{30 \times 10^{-6} \text{ psi}^{-1}} = 1.933 \times 10^6 \text{ STB}.
\]

Reservoir Drainage Area

\[
A = \frac{(5.6148 \text{ ft}^3/\text{RB})(1.933 \times 10^6 \text{ STB})(1.25 \text{ RB/STB})}{(0.075)(200 \text{ ft})(1 - 0.30)}
\]

\[
A = (1,292,295 \text{ ft}^2)(1 \text{ acre} / 43,560 \text{ ft}^2) = 29.7 \text{ acres}.
\]
Reservoir Drainage Radius

\[ r_e = \sqrt{\frac{(1.292,295 \text{ ft}^2)}{\pi}} = 641.4 \text{ feet.} \]

Effective Wellbore Radius

\[ r_{wa} = \frac{641.4 \text{ ft}}{7.0} = 91.6 \text{ feet.} \]

Effective Oil Permeability (\(C_A = 31.62\) for bounded circular reservoir)

\[
k_o = 70.6 \left( \frac{(1.25 \text{ RB/STB})(1.3 \text{ cp})}{200 \text{ ft}} \right) \ln \left[ \frac{(4)(1.292,295 \text{ ft}^2)}{(1.781)(31.62)(91.6 \text{ ft})^2} \right] \left[ \frac{0.02}{(1)} \right] = 0.027 \text{ md}
\]

\[ k_o h = 5.49 \text{ md-feet.} \]

Skin Factor

\[ s = -\ln \left( \frac{91.6 \text{ ft}}{0.33 \text{ ft}} \right) = -5.63. \]

NRU 4202 – Movable Oil Plot (Fig. 5.23)

Due to the lack of bottomhole pressure data, the use of \(p_{cal}\) plotted versus \(N_p\) to estimate movable oil is not possible. Instead, we simply plot the daily oil rate, \(q\), versus \(N_p\) to find the movable oil volume. The extrapolation of this line to the \(N_p\) axis-intercept yields a movable volume at the time when all reservoir energy has been depleted.

Estimates for primary and secondary movable oil were 170 MSTB and 150 MSTB, respectively. Our results indicate that approximately 10,000 STB of primary movable oil remained in the drainage area of the well when the waterflood was initiated in 1987. Using the present secondary decline rate we estimate that approximately 90 MSTB of recoverable oil remained as of July 1999. Obviously, the actual movable oil volume may be less than the volume given as the well will not be produced to \(q = 0\).
Figure 5.23 – Estimated movable oil from rate history for NRU 4202.

\[ N_{p,mov} = 170.0 \text{ MSTB (primary)} \]
\[ = 150.0 \text{ MSTB (secondary)} \]
\[ \text{Recovery Factor} = 8.79 \text{ percent (primary)} \]
\[ = 7.76 \text{ percent (secondary)} \]

**NRU 4202 – Summary Discussion**

A pressure build-up test was performed on well NRU 4202 in 1988, and the permeability to oil was estimated to be 0.2 md, and the calculated skin factor was -3.7. Both of these values are consistent with the values obtained from our analysis, although it should be noted that the calculations for drainage area, permeability, and skin factor are adversely affected by the lack of an accurate value for the net pay interval.

A radial flow skin factor of –5.63 from the type curve match indicates that the initial hydraulic fracture treatments performed on the well were successful. The data from this well will be re-matched using the fractured well type curve to determine if any of the transient or boundary-dominated characteristics change.
5.3.4.2 – Field Example: NRU Well No. 1004

Fig. 5.24 shows the location of NRU Well 1004, in the southeast corner of the unit, with respect to its well pattern and the unit. The well was drilled in 1960, and completed in the Lower, Middle, and Upper Clear Fork. It had produced approximately 143 MSTB as of July 1999.

The semilog and log-log production plots shown in Figs. 5.25 and 5.26 indicate that there were several rate variations and an extended period of an apparently constant production rate during primary depletion. The well has only responded slightly to unit water injection since it is two well locations away from the nearest injector and on the southeast edge of the NRU. In order to achieve the best estimate of original oil-in-place, and transient flow properties, only production data prior to 5,500 days (primary production) was used in our material balance analysis. The type curve match is shown in Fig. 5.27.

Figure 5.24 – Location of NRU 1004.
Figure 5.25 – Semilog production plot for NRU 1004.

Figure 5.26 – Log-Log production plot for NRU 1004.
Figure 5.27 – Match of production data for NRU 1004 on the Fetkovich-McCray type curve for an unfractured well in a bounded circular reservoir.

NRU 1004 – Type Curve Analysis Results (Fig. 5.27)

Matching Parameter:  $r_e D = 18.0$

- $[t_{D}]_{MP} = 1.0$  
- $[T]_{MP} = 1.320$ days
- $[q_{D}]_{MP} = 1.0$  
- $[q/Δp]_{MP} = 0.0175$ STB/day/psi days

Original-Oil-in-Place

$N_c = 23.1$ STB/psi

$N = \frac{(1320 \text{ days})(0.0175 \text{ STB/day/psi})}{30 \times 10^{-6} \text{ psi}^{-1}} = 7.70 \times 10^5$ STB.
\[ A = \frac{(5.6148 \text{ ft}^3/\text{RB})(7.70 \times 10^5 \text{ STB})(1.25 \text{ RB/STB})}{(0.075)(200 \text{ ft})(1 - 0.30)} \]

\[ A = (514.690 \text{ ft}^2)(1 \text{ acre / 43,560 ft}^2) = 11.8 \text{ acres.} \]

**Reservoir Drainage Area**

\[ r_e = \sqrt{\frac{514,690 \text{ ft}^2}{\pi}} = 404.8 \text{ feet.} \]

**Reservoir Drainage Radius**

\[ r_{wa} = \frac{404.8 \text{ ft}}{18.0} = 22.5 \text{ feet.} \]

**Effective Wellbore Radius**

\[ k_o = 70.6 \frac{(1.25 \text{ RB/STB})(1.3 \text{ cp})}{200 \text{ ft}} \ln \left[ \frac{(4)(514,690 \text{ ft}^2)}{(1.781)(31.62)(22.5 \text{ ft})^2} \right] \left[ \frac{(0.0175)}{(1)} \right] = 0.043 \text{ md} \]

\[ k_o h = 8.59 \text{ md-feet.} \]

**Effective Oil Permeability** \((C_A = 31.62 \text{ for bounded circular reservoir})\)

\[ s = -\ln \left( \frac{22.5 \text{ ft}}{0.33 \text{ ft}} \right) = -4.22. \]

**Skin Factor**

NRU 1004 – Movable Oil Plot (Fig. 5.28)

Estimates for primary and secondary movable oil were 105 MSTB and 75 MSTB (using the average secondary decline for the unit). Our results indicate that approximately 25,000 STB of primary movable oil remained in the drainage area of the well when the waterflood was initiated in 1987. Using the present secondary decline rate we estimate that approximately 37 MSTB of recoverable oil remained as of July 1999. The actual movable oil volume may be less than this since the well will not be produced to \( q = 0 \).
Figure 5.28 – Estimated movable oil from rate history for NRU 1004.

\[ N_{p,mov} = 105.0 \text{ MSTB (primary)} \]
\[ = 75.0 \text{ MSTB (secondary)} \]

Recovery Factor = 13.64 percent (primary)
\[ = 9.74 \text{ percent (secondary)} \]

NRU 1004 – Summary Discussion

The results of our material balance and volumetric analyses indicate that the well is draining a very small area, although the primary recovery factor estimated from this analysis is high for wells in the unit. The primary performance problem with NRU 1004 is that it is located on the edge of the unit and receives little injection support. A radial flow skin factor of -4.22 from the type curve match indicates that the initial hydraulic fracture treatments performed on the well were only moderately successful. The data from this well will be re-matched using the fractured well type curve to determine if any of the transient or boundary-dominated characteristics change.
5.4 – Introduction and Review: Well with Infinite-Conductivity Fracture in the Center of a Bounded Circular Reservoir (Liquid Case)

We have provided an approach for the analysis and interpretation of production data (flow rates and bottomhole pressures) using a decline type curve for an unfractured well in order to estimate reservoir volumes and flow characteristics. This approach allows the analysis and interpretation of production data without requiring constant rates or constant bottomhole pressure, as was the case for previous decline type curve methods.

We now present the development of an analytically derived decline type curve for analysis of the depletion or injection performance of a well with an infinite-conductivity vertical fracture. This work evolved from our analysis of the production performance of wells in this field using the decline type curve for unfractured wells. Since all producing and injecting wells at the NRU are hydraulically fractured, we found that the unfractured well model was usually insufficient for the evaluation of production data.

We also wished to be able to perform quantitative decline type curve analysis on readily available injection rate and pressure data. Our initial analysis of the injection data showed that well performance could not be modeled using an unfractured well model. Recognizing the need for a fractured well type curve, we chose to focus on the infinite-conductivity vertical fracture model, as it seemed most appropriate for injection wells. Particularly for injection wells in carbonate formations and in formations where injection pressures are maintained at or above the fracture gradient of the formation.

We will now extend the use of the Fetkovich-McCray type curve concept to the analysis of fractured wells. We also supply techniques for the evaluation of long-term injection rate and pressure data as a waterflood surveillance tool. We have developed a new decline type curve for the case of a well with an infinite conductivity vertical fracture that is producing (or injecting) at the center of a bounded circular reservoir. Several field examples illustrate the utility of the new decline type curve for fractured wells. Application procedures and a detailed development of the new type curve are given.

We note that in a previous study by Fraim et al., a decline type curve was proposed for a well producing from the center of a bounded square reservoir with a finite or infinite
conductivity vertical fracture intersecting the well. Although the solution is correct, we have found that their formulation of the decline type curve is not well suited to the rate-integral type curves and their decline type curve correlation variables are not based on theory, but on regression. Our formulation is entirely consistent with pseudosteady-state flow theory and we are able to uniquely correlate all of the rate functions to a single type curve. The type curve matching procedures and the associated analysis methodologies are summarized here. A full discussion of this work is provided in Appendix H.

5.4.1 – Derivation of the Fractured Well Solution

The general form of the constant rate solution in the Laplace domain for a vertical well with a uniform flux or infinite conductivity vertical fracture is a recent development as presented by Houze et al.\textsuperscript{93} Ozkan,\textsuperscript{94} Ozkan and Raghavan\textsuperscript{95,96} and Raghavan.\textsuperscript{97} This solution is developed in complete detail in Appendix H.

The Laplace domain solution for a well with an infinite conductivity vertical fracture in a bounded (no-flow) circular reservoir produced at a constant flow rate is given below:

\[
\bar{p}_{D, \text{fracs}, \text{nb}}(|x_D| \leq 1, y_D = 0, u) = \frac{1}{2u} \left[ \int_0^{\pi(1-x_D)} K_0(z) dz + \int_0^{\pi(1+x_D)} K_0(z) dz \right] \\
+ \frac{1}{2u} \left[ \int_0^{\pi(1-x_D)} I_0(z) dz + \int_0^{\pi(1+x_D)} I_0(z) dz \right].
\]

\begin{equation}
(5.44)
\end{equation}

Where \(x_D = 0\) for the "uniform flux" vertical fracture case and \(x_D = 0.732\) for the infinite conductivity vertical fracture case.

The fractured well type curve requires the constant wellbore pressure solution rather than the constant rate solution given in Eq. 5.44. To obtain the constant pressure solution we will use the van Everdingen and Hurst\textsuperscript{88} convolution result for relating the constant rate and constant bottomhole pressure solutions in the Laplace domain. The van Everdingen and Hurst result was given previously in Eq. 5.30:
Substituting Eq. 5.44 into Eq. 5.30 yields the Laplace domain solution for a well producing at constant bottomhole pressure with an infinite-conductivity vertical fracture in a bounded (no-flow) circular reservoir. This solution serves as the basis for our new decline type curve, the development of which is discussed below. Real domain solutions of Eqs. 5.44 and 5.30 were obtained using the Stehfest numerical inversion algorithm.\textsuperscript{89}

**5.4.2 – Formulation of the Fractured Well Type Curve**

The decline type curve for a well with an infinite-conductivity vertical fracture producing from a bounded circular reservoir is developed in the same way as the unfractured well case shown previously. For the unfractured well case, Fetkovich\textsuperscript{78} used the pseudosteady-state solution to develop the appropriate dimensionless "decline" rate and time variables.

For the development of the fractured well type curve, we will follow the same approach. We recognize that all reservoir cases can be converted (or correlated) into decline variables using \textit{exactly the same formulation}, so long as the appropriate definition of the dimensionless pseudosteady-state constant, $b_{Dpss}$, is used. The definitions of dimensionless decline rate and time are developed in Appendix H and are shown below:

\[ q_{Dd} = q_D b_Dpss \] ................................................................. (5.45)

\[ t_{Dd} = \frac{2\pi}{b_{Dpss}} t_{DA} \] ................................................................. (5.46)

and the general form of the pseudosteady-state flow equation is:

\[ p_D = 2\pi t_{DA} + b_{Dpss} \] ................................................................. (5.47)

Therefore, for \textit{any} reservoir model or reservoir/well configuration, Eqs. 5.45 – 5.47 uniquely define the dimensionless decline variables. For the case of a fractured well, we simply solve for $b_{Dpss}$ as the y-intercept on a plot of $p_D$ versus $t_{DA}$ (or $2\pi t_{DA}$), as shown in
Fig. 5.29. The required $p_D$ values are obtained by numerical inversion of Eq. 5.44 using the Laplace transform inversion algorithm of Stehfest.\textsuperscript{89} The resulting values of $b_{Dpss}$ for each dimensionless drainage radius, $r_{eD}$, are shown on Fig. 5.29 and in Table 5.2. These results are then utilized to solve Eqs. 5.45 – 5.46 for $q_{Dd}$ and $t_{Dd}$.

![Fig. 5.29 – Cartesian plot of $p_D$ versus $t_{DA}$ solutions with pseudosteady-state solutions superimposed for the infinite-conductivity fracture case.](image-url)
Table 5.2 – Correlative values of \( b_{D_{pss}} \) and \( r_{eD} \) for a fractured well in a bounded circular reservoir (infinite-conductivity vertical fracture case).

<table>
<thead>
<tr>
<th>( r_{eD} )</th>
<th>( b_{D_{pss}} )</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>0.38534</td>
</tr>
<tr>
<td>2</td>
<td>0.75254</td>
</tr>
<tr>
<td>5</td>
<td>1.5775</td>
</tr>
<tr>
<td>10</td>
<td>2.2576</td>
</tr>
<tr>
<td>20</td>
<td>2.9475</td>
</tr>
<tr>
<td>50</td>
<td>3.8629</td>
</tr>
<tr>
<td>100</td>
<td>4.5559</td>
</tr>
<tr>
<td>1000</td>
<td>6.8585</td>
</tr>
</tbody>
</table>

So that we may still use \( r_{eD} \) as the decline type curve transient correlating parameter, we have developed a correlation between \( r_{eD} \) and \( b_{D_{pss}} \), as illustrated in Fig. 5.30.

Figure 5.30 – Correlation of \( b_{D_{pss}} \) and \( r_{eD} \) values for fractured well solutions – infinite-conductivity fracture case.
The correlating equation for these data is given as Eq. 5.48:

\[ b_{Dpss} = \ln(r_e D) - 0.049298 + 0.434645 r_e^2 D. \] ................................................ (5.48)

For the fractured well case, \( r_e D \) and fracture half-length, \( x_f \), are related as shown in Eq. 5.49. This relationship is valid regardless of the rate and pressure schedule:

\[ r_e D = \frac{r_e}{x_f}. \] ....................................................................................................... (5.49)

The \( b_{Dpss} \) values in Table 5.2 were used to construct a new type curve in the traditional \( q_{Dd} \) versus \( t_{Dd} \) format, as shown in Fig. 5.31. The procedure and the validation of this fractured well approach are illustrated and discussed further in Appendix H.

We note that Eq. 5.48, as well as the fractured well decline type curves presented here, are strictly valid only for the case of a well with an infinite-conductivity vertical fracture in a bounded circular reservoir. However, our experience has shown that this approach can be applied to a variety of reservoir/fracture configurations, provided that the fracture conductivity is relatively high (i.e., successfully stimulated), the well is relatively centered in its drainage area and the reservoir shape is symmetric.

We note that the \( b_{Dpss} \) correlation results in values of \( q_{Dd} \) and \( t_{Dd} \) that deviate from the exponential trend at late times. However, once the rate-integral function, \( q_{Ddi} \), and the rate-integral derivative function, \( q_{Ddid} \), are added, we obtain an excellent correlation for all solution trends.

As an alternative approach for determining the \( b_{Dpss} \) values directly, we could have simply combined the numerical inversion of Eq. 5.44 with Eq. 5.45. Gringarten\(^9^8\) developed such an analytical expression for the case of a fractured well in a rectangular reservoir, however this is an extremely complex and tedious result. Further, we felt that the graphical determination of the \( b_{Dpss} \) values would help the interested reader to visualize and reproduce our work. We note that our \( b_{Dpss} \) values compared well to the values given by Gringarten.\(^9^8\)
5.4.3 Rate Integral Functions

In order to complete our decline type curve for fractured wells, and in order to achieve more unique type curve matches, we need to add rate-integral and rate-integral derivative functions. The dimensionless rate-integral and rate-integral derivative functions are calculated in the same fashion as for the unfractured well case using methods given by McCray. The development of these relationships was given in section 5.3 and will not be repeated here. The application of these relations to the fractured well case is shown in Appendix H.

The Fetkovich-McCray type curve for the fractured well case is shown in Fig. 5.32, where \( q_{Dd} \), \( q_{DD} \), and \( q_{DDd} \) are all plotted versus \( t_{Dd} \) on the type curve grid. The
The pseudosteady-state flow equation has once again been solved using material balance
time, $\bar{t}$, and all boundary-dominated data functions are force-matched to the harmonic
$(b = 1)$ stems. We believe that Fig. 5.32 provides all of the necessary functions for both
rigorous and empirical analysis of production and injection data from wells with infinite-
or high-conductivity fractures.

Figure 5.32 — Fetkovich-McCray $q_{D,b}$, $q_{D,di}$ and $q_{D,did}$ type curves for a well with an infinite-
conductivity fracture centered in a bounded circular reservoir.

5.4.4 – Application to the Analysis of Oil Production or Water Injection Data
(Fractured Well Case)

The analysis of production or injection data is the primary application of fractured well
"decline" type curves. In our approach we assume that injection data represent a "re-
pressuring" of a closed system, which is the mirror image of the production case where a
closed system is depleted. Deviations from this assumption may cause the proposed
methodology to fail in the analysis and interpretation of well performance data, but we
will assume that we can proceed in the same fashion as we did for the production data analysis case. The procedures and analysis relations are also summarized below for convenience.

For the case of a well with an infinite conductivity vertical fracture, we can essentially estimate the same well and reservoir characteristics that we found for the unfractured well case. These characteristics are shown below:

- In-place or injected fluid volumes
  - Total system volume, \( N \) (or \( W_{tot} \))
  - Movable oil at current conditions, \( N_{p,mov} \)
    (or, injectable water at current conditions, \( W_{i,mov} \)).

- Reservoir properties
  - Effective permeability to the flowing phase, \( k_e \)
  - Pseudo-radial skin factor for near well damage or stimulation, \( s \)
  - Fracture half-length, \( x_f \)
  - Reservoir drainage (or injection) area, \( A \)

In some cases the unfractured and fractured well models will give similar, if not identical interpretations. However, this is not the case when wells have fractures with very long half-lengths (analogous to a very large negative skin effect). In such cases, the unfractured well (radial flow) model is invalid and we must resort to the more rigorous fractured well model.

Candidates for this type of analysis are production or injection wells in low permeability reservoirs with large stimulation treatments as well as injection wells for which the bottomhole injection pressures are maintained at or above the fracture gradient of the reservoir. The variables shown in this sample calculation section are for the oil production case, although they are directly interchangeable with the variables for the water injection case.

Our matching procedures are essentially identical to those for the unfractured well case, and in fact, the volumetric analyses (i.e., the estimation of \( N, A, \) and \( r_e \)) are identical. In contrast, we must use the appropriate fractured well variable(s) (i.e., the \( b_{Dpns} \) parameter, which is estimated from \( r_{eD} \)) in order to estimate reservoir parameters – \( k, x_f, \) and \( s \).
1. **Compute material balance time from production or injection data**

Assemble the production or injection well rates (STB/D) and bottomhole pressures (psia) versus time (in days). Compute the "material balance time" function given by:

\[ \tau = \frac{N_p}{q} = \frac{W_i}{q_{wi}}. \]  

(5.50)

Where \( W_{i,mov} \) is the total injectable water (STBW) and \( q_{wi} \) is the injection rate (STBW/day). Due to rate changes that occur throughout the life of a well (caused by pulling jobs, workovers and recompletions), material balance time will not always be a strictly increasing function. Therefore, the data may have to be edited after \( \tau \) has been calculated to remove extraneous data points.

2. **Compute the flow rate, flow rate integral and flow rate integral-derivative functions**

As for the unfractured well case, the pressure drop normalized rate plotting function is given by:

\[ (\frac{q}{\Delta p}) = \frac{q_o}{(p_i - p_{wf})} = \frac{q_o}{\Delta p} \text{ or } (\frac{q}{\Delta p}) = \frac{q_{wi}}{(p_{wf} - p_{wi})} = \frac{q_{wi}}{\Delta p}. \]  

(5.51)

Note that the definition of \( \Delta p \) for the injection well case accounts for increasing pressure with time. As before, the rate integral and rate-integral derivative plotting function is given by:

\[ (\frac{q}{\Delta p})_i = \frac{1}{\tau} \int_0^\tau \frac{q}{\Delta p} d\tau \]  

(5.32)

\[ (\frac{q}{\Delta p})_{id} = -\frac{d[(\frac{q}{\Delta p})_i]}{d[\ln(\tau)]} = -\frac{d[(\frac{q}{\Delta p})_i]}{d\tau}. \]  

(5.33)

The three plotting functions are computed and plotted versus material balance time, \( \tau \). These data trends are then overlain on the Fetkovich-McCray type curve, (Fig. 5.32) and we "force match" the boundary-dominated (depletion) portion of the data (which is also the re-pressuring data trend for injection) onto
the Arps $b = 1$ stems. The "force matching" of boundary-dominated flow data is required by theory and provides the best possible estimate of the system volume.

Once a "match" is obtained, we record the "time" and "rate" axis match points, as well as the $r_{eD}$ transient flow stem. Recall that for this case, $r_{eD} = r_e/x_f$. The rate-axis match point is any $(q/\Delta p)_{MP} - (q_{Dd})_{MP}$ pair and the time-axis match point is any $(\tilde{t})_{MP} - (t_{Dd})_{MP}$ pair. After matching the transient data to find $r_{eD}$, we then calculate the $b_{Dpss}$ value using Eq. 5.48:

$$b_{Dpss} = \ln(r_{eD}) - 0.049298 + 0.434645 r_{eD}^2.$$ ................................................. (5.48)

3. Estimate oil-in-place and total injected water

$$N \text{ or } W_{tot} = \frac{1}{c_t} \frac{(q/\Delta p)_{MP}}{(q_{Dd})_{MP}} \frac{t_{Dd})_{MP}}{(t_{Dd})_{MP}}.$$ ............................................................... (5.52)

4. Estimate reservoir flow characteristics

*Reservoir Drainage/Injection Area, $A$*

$$A = 5.6148 \frac{NB_o}{\phi h(1 - S_{wi})} - 5.6148 \frac{W_{tot}B_w}{\phi h(1 - S_{or} - S_{gr})}.$$ ............................................ (5.53)

For which $S_{or}$ is the residual oil saturation (fraction), $S_{gr}$ is the residual gas saturation (fraction), $B_o$ and $B_w$ are the oil and water formation volume factors, (RB/STB).

*Reservoir Drainage Radius, $r_e$*

$$r_e = \sqrt{\frac{A}{\pi}}.$$ ................................................................. (5.39)

*Effective Permeability, $k_e$*

$$k_e = 141.2 \frac{B \mu}{h} b_{Dpss} \left[\frac{(q/\Delta p)_{MP}}{(q_{Dd})_{MP}}\right].$$ ................................................................. (5.54)

*Fracture Half-Length, $x_f$*

$$x_f = \frac{r_e}{r_{eD}}.$$ ................................................................. (5.55)
Pseudo-Radial Flow Skin Factor, $s$

$$s = -\ln\left(\frac{x_f}{2r_w}\right).$$

(5.56)

5.4.5 – Analysis and Interpretation Considerations (Fractured Well Case)

The procedures for data preparations, analysis and interpretation are similar to those used for the radial flow cases. The critical data required for our analysis are shown below.

- total compressibility, $c_t$
- oil viscosity, $\mu_o$
- injected water viscosity, $\mu_w$
- oil formation volume factor, $B_o$
- water formation volume factor, $B_w$
- irreducible water saturation, $S_{wi}$
- porosity, $\phi$
- net pay or injection interval, $h$
- wellbore radius, $r_w$
- residual oil saturation, $S_{or}$
- residual gas saturation, $S_{gr}$

Initial screening of the production and injection data is performed using semilog and log-log plots of rate versus time. These plots are utilized to identify errors or anomalies in the data, to locate and annotate changes in completion or injection practices and to edit or smooth the data where required.

After the data functions have been calculated, we match the functions on the type curve to find the time and rate match points. These match points are then utilized to estimate the following:

- oil-in-place, $N$, or total volume available for water injection, $W_{tot}$
- pseudosteady-state flow constant, $b_{Dpss}$
- transient stem match parameter, $r_{eD}$

These parameters are then utilized to calculate the reservoir drainage or injection area, effective permeability and fracture half-length, as summarized in Section 5.4.1, above.

As we found for the unfractured well cases, and depending on the amount of bottomhole pressure data available, there are three techniques available for estimating the ultimate recovery, $N_{p, mov}$. To estimate the injectable water, $W_{l,mov}$, at current conditions we plot
\((q_{wi}/\Delta p)\) versus cumulative water injection, \(W_i\), and extrapolate to \((q_{wi}/\Delta p) = 0\).

While the procedures given above may seem lengthy and tedious, we will demonstrate the utility and value of this approach when we apply these procedures to field data.

As with most mature oilfields in the Permian Basin (and elsewhere), we simply do not have sufficient pressure and saturation histories to accurately estimate or simulate changes in the total compressibility. This may seem somewhat minor, but the total compressibility is the most critical variable for estimating in-place fluid volumes. The calculation of total compressibilities used for the analysis of the North Robertson Unit data are given in Appendix I.

For the unfractured well cases, we suggested that during depletion, fluid properties should be evaluated at the average reservoir pressure, \(\bar{P}\), when the reservoir pressure is between the initial and bubble point pressures (\(p_i > p > p_b\)), and at a pressure just above the bubble point when the reservoir pressure is below the bubble point (\(p < p_b\)). These recommendations agree reasonably well with the results of a simulation study on depletion performance of black oils developed by Camacho and Raghavan.99 Our goal is to give practical guidelines for the analysis and interpretation of field data, and these recommendations reflect our desire to provide accurate, but simplified analysis relations.

The Lower Clear Fork (LCF) reservoir is the dominant oil producing interval, producing 60 to 70 percent of the oil in most areas of the Unit. On the basis of the injection profiles, the Lower Clear Fork also appears to be taking the majority of the injected water. The current replacement-to-voidage ratio is about 1.4, with an average water cut of about 78 percent. For the study of injection performance data, we are once again confronted with problems associated with the estimation of certain rock and fluid property data. For consistency, we use a similar approach in estimating total compressibility as the reservoir re-pressures and fluid saturations change during the waterflooding process. On all decline type curve matches, we chose to report a value for the \((W_{tot})(c_t)\) product. This permits comparison of the type curve matches without arguing the value of total compressibility. However, for each field case, we also used an
estimate of total compressibility to calculate $\omega_{tot}$, where we have attempted to account for the production/injection history in making our estimate of the total compressibility.

In addition to the difficulties in obtaining representative fluid properties, we also prefer to report a value for the permeability-thickness product, $kh$, rather than effective permeability unless representative estimates of net pay thickness for the reservoir considered in this work. The Clear Fork at NRU is 1,200 thick and individual wells are perforated sporadically and hydraulically fractured. We do have net pay thickness estimates for those NRU wells in which we possess well logs. To be consistent, we do present effective permeability estimates and injection-drainage areas calculated using estimated values of net pay thickness for each well.

The well completions for the original 40-acre producers and the 20-acre production and injection wells drilled from 1987 to 1991 most often involved the use of limited-entry perforating (defined as >2 bbl/min/perf injection rate) and two to three hydraulic fracture treatments. Due to the fact that the Clear Fork specific pay intervals were not well defined, hydraulic fracture treatments were pumped over fairly large vertical increments (200 to 500 feet). Most NRU hydraulic fracture treatments were designed to yield fracture half-lengths on the order of 250 feet. However, fracture treatments performed over such large vertical intervals in a reservoir with no barriers to vertical fracture propagation will typically result in short, radial and very high conductivity fractures (as evaluated from the analysis of well test and production data).

The result of these fracture treatments can be seen when we perform type curve matches on the producing wells. The typical formation flow characteristics of a producing well at NRU are illustrated in Fig. 5.33. A match of the oil production data on the Fetkovich-McCray decline type curve for a fractured well is shown for NRU 4202. The type curve match yielded an oil-in-place of 1.99 MMSTB, an effective oil permeability of 0.041 md, and a pseudo-radial skin factor of –5.28 ($x_f = 130$ feet). These values are fairly typical for the producing well completions at NRU.

We note that the results are similar to those obtained from our match on the unfractured well type curve ($N = 1.93$ MMSTB, $k_o = 0.027$ md and $s = -5.63$). This shows that if the
well is only moderately stimulated (from the standpoint of fracture half-length), that either type curve may be utilized for analysis. In addition, this also indicates that we can use a type curve developed for a well with an infinite-conductivity fracture to evaluate wells with finite conductivity fractures – at least to bound the results.

Figure 5.33 – Match of production data for NRU 4202 on the Fetkovich-McCray type curve for a well with an infinite-conductivity fracture centered in a bounded circular reservoir.

An important point to remember is that we are evaluating commingled production and injection data for all Clear Fork intervals (LCF, MCF and UCF) simultaneously, therefore, it is difficult to evaluate individual fracture treatments unless the production or injection data can be allocated by zone.

Another point to consider when comparing results from decline type curve analyses, results from well log evaluation (Chapter IV) and results from pressure transient tests is
the change in pressure, saturation and fluid properties with time. The analysis of a pressure buildup for well NRU 4202 acquired from an acoustic well-sounder (AWS) test in 1988 is shown in Fig. 5.34. The results indicate an effective oil permeability of 0.32 md and a pseudo-radial skin factor of −2.87 ($x_f = 12.5$ feet). We note that these results reflect the performance of the well at a specific point in time, while the analysis of long-term production or injection data tends to give average properties over long time periods during the life of a well.

Figure 5.34 – Final data match on log-log plot for NRU 4202 pressure buildup test data (Nov. 1988). Matched using the model for a well with a finite conductivity vertical fracture in an infinite-acting homogeneous reservoir.
As we will find later, after the original producing wells were converted to injection, their fracture characteristics were substantially altered due to long-term water injection at or above the parting pressure of the formation. In short, we found that the continuous injection of large water volumes at high pressures caused significant increases in the computed fracture lengths. These issues will be discussed in great detail in Chapter VI.

5.4.6 – Field Data Examples (Fractured Well Case)

A general summary of the reservoir and fluid properties, and the production and injection parameters is summarized below.

Reservoir, Fluid Property, Production and Injection Data

Reservoir Properties:
- Average reservoir depth = 6,600 feet
- Wellbore radius, \( r_w \) = 0.33 feet
- Estimated gross pay interval = 1,100 feet
- Average net pay thickness, \( h \) = 200 feet
- Average porosity, \( \phi \) (fraction) = 0.075
- Average irreducible water saturation, \( S_{wi} \) = 0.30
- Average residual oil saturation, \( S_{or} \) = 0.35
- Average residual gas saturation, \( S_{gr} \) = 0.05
- Average effective permeability, \( k_e \) < 1 md
- Original nominal well spacing = 40 acres
- Current nominal well spacing = 20 acres
- Dominant fracture orientation ~ east-west

Fluid Properties:
- Average water FVF, \( B_w \) = 1.01 RB/STB
- Average oil FVF, \( B_o \) = 1.25 RB/STB
- Average water viscosity, \( \mu_w \) = 0.84 cp
- Average oil viscosity, \( \mu_o \) = 1.30 cp
- Average total compressibility, \( c_t \) = 50.0x10^{-6} \text{ psi}^{-1}
  (During re-pressuring – used for water injection analysis)
- Current total compressibility, \( c_t \) = 30.0x10^{-6} \text{ psi}^{-1}
  (At or just below bubble point – used for oil production analysis)

Production Parameters:
- Initial reservoir pressure (1956), \( p_i \) = 2,800 psia (LCF)
- Average reservoir pressure at depletion = 1,000 psia
- Average current reservoir pressure, \( \bar{p} \) = 2,900 psia
5.4.6.1 – Field Example: NRU Well No. 102

Fig. 5.35 shows the location of NRU Well 1004, in the southeast corner of the unit, with respect to its well pattern and the unit. NRU Well 102 was drilled in 1959 in the southeast portion of the Unit, and was initially completed only in the Lower Clear Fork interval. A Middle Clear Fork completion was added by at the end of 1960. The initial stabilized production rate from the Lower and Middle Clear Fork completions was 60 STBO/day, with 3 STBW/day. The zones were commingled after 1967 and Upper Clear Fork and Glorieta completions were added in December 1981, at which time the well was producing less than 15 STBO/D. The well had produced approximately 177.3 MSTBO as of April 1989. It was converted to a water injection well in 1989, at which time more Upper Clear Fork perforations were added and acidized.

The average reservoir pressure for the well at the time of conversion was estimated to be 1,500 psia. The current average reservoir pressure after 10 years of water injection is estimated to be 2,650 psia. The well has not been worked over since its conversion.

Figure 5.35 – Location of NRU 102.
NRU 102 – Stimulation History

**Lower Clear Fork**
- **Date**: May 1959
- **Interval**: 7,035 to 7,163 feet
- **Stimulation**: 5,500 gallons of 15 percent NEFE acid
- **Hydraulic Fracture**: 20,000 gallons of 7.5 percent HCl acid and 40,000 pounds of 20/40 sand

**Middle Clear Fork**
- **Date**: December 1960
- **Interval**: 6,729 to 6,856 feet
- **Stimulation**: 5,000 gallons of 15 percent NEFE acid
- **Hydraulic Fracture**: 20,000 gallons of refined oil and 40,000 pounds of 20/40 sand

**Lower, Middle, Upper Clear Fork & Glorieta**
- **Date**: December 1981
- **Interval**: 5,999 to 7,157 feet
- **Hydraulic Fracture**: 3,000 gallons of 20 percent HCl acid and 47,000 pounds of 20/40 sand

**Upper Clear Fork**
- **Date**: May 1989
- **Interval**: 6,466 to 6,597 feet
- **Stimulation**: 5,000 gallons of 15 percent NEFE acid

NRU 102 – Oil Production Analysis

The semilog and log-log production plots shown in Figs. 5.36 and 5.37 indicate that there were several rate variations associated with workovers and recompletions that occurred during primary depletion. The type curve match is shown in Fig. 5.38.
Figure 5.36 – Semilog production plot for NRU 102.

Figure 5.37 – Log-Log production plot for NRU 102.
NRU 102 – Type Curve Analysis Results (Fig. 5.38)

Matching Parameter: \( r_{cD} = 20.0 \)

\[
\begin{align*}
[t_{D}]_{MP} &= 1.0 \\
[q_{D}]_{MP} &= 1.0 \\
[\frac{q}{\Delta p}]_{MP} &= 0.027 \text{ STB/day/psi days}
\end{align*}
\]

Original-Oil-in-Place

\( N_{c} = 56.7 \text{ STB/psi} \)

\[
N = \frac{(2100 \text{ days})(0.027 \text{ STB/day/psi})}{30 \times 10^{-6} \text{ psi}^{-1}} = 1.89 \times 10^{6} \text{ STB.}
\]
Reservoir Drainage Area

\[
A = \frac{(5.6148 \text{ ft}^3/\text{RB})(1.89 \times 10^6 \text{ STB})(1.25 \text{ RB/STB})}{(0.075)(200 \text{ ft})(1 - 0.30)}
\]

\[
A = (1,263,330 \text{ ft}^2)(1 \text{ acre} / 43,560 \text{ ft}^2) = 29.0 \text{ acres.}
\]

Reservoir Drainage Radius

\[
r_e = \sqrt{\frac{(1,263,330 \text{ ft}^2)}{\pi}} = 634.1 \text{ feet.}
\]

Pseudosteady-state Flow Constant

\[
b_{Dpss} = \ln(20) - 0.049298 + 0.434645(20)^{-2} = 2.9475.
\]

Effective Oil Permeability \((C_A = 31.62 \text{ for bounded circular reservoir})\)

\[
k_o = 141.2 \frac{(1.25 \text{ RB/STB})(1.30 \text{ cp})}{(200 \text{ ft})}(2.9475) \left[ \frac{0.027}{1} \right] = 0.091 \text{ md.}
\]

Fracture Half-Length

\[
x_f = \frac{634.1 \text{ ft}}{20} = 31.7 \text{ feet.}
\]

Pseudo-Radial Flow Skin Factor

\[
s = -\ln\left(\frac{31.7}{2(0.33)}\right) = -3.87.
\]

NRU 102 – Movable Oil Plot (Fig. 5.39)

NRU 102 had produced 177 MSTBO prior to conversion to injection. This indicates there may have been approximately 38 MSTBO remaining in the well's drainage area to be recovered by subsequent 20-acre infill wells. From a reservoir pressure standpoint, this well depleted its drainage area.

\[
N_{p,mov} = 177.0 \text{ MSTB (primary)}
\]

Recovery Factor = 9.37 percent (primary)
NRU 102(WI) – Water Injection Analysis

NRU 102 was converted to water injection in 1989. Fig. 5.40 shows the semilog rate and Cartesian injection pressure history since the well's conversion. An injection rate increase can be seen at approximately 1,450 days, when the injection pressure was increased following a step-rate test (March 1993). The fractured well type curve match is shown in Fig. 5.41.
Figure 5.40 – Semilog rate and Cartesian injection pressure versus time for NRU 102(WI).

Figure 5.41 – Match of injection data for NRU 102(WI) on the type curve for a well with an infinite-conductivity fracture centered in a bounded circular reservoir.

**Results: NRU #102 (WI)**

\( \frac{q_{wi}}{h_{wi}} \to \frac{q_{wi}}{h_{wi}} \to 0.087 \text{ STB/day/psi} \)

\( t_{inj} = 1500 \text{ Days} \)

\( h_{2} = \frac{q_{2}}{h_{1}/h_{2}} \to 11.44 \text{ psi/STB/day} \)

\( W_{w1} = 131.11 \text{ STB/psi} \)

\( W_{p1} = 2.62 \text{ MMSTB} \)

\( W_{nfr} = 600 \text{ MSTB} \)

\( r_{s} = 5.0 \)

\( b_{2} = \ln(5) - 0.094928 + 0.434645 (5)^{2} = 1.5775 \)

\( k_{s} = 141.2 \text{ psi/STB/day} \)

\( h = 200 \text{ ft} \)

\( k_{s} = 0.082 \text{ md} \)
We now consider the type curve matching of the rate, \( q_{wi}/\Delta p \), rate integral, \( (q_{wi}/\Delta p)_i \), and rate integral derivative, \( (q_{wi}/\Delta p)_{id} \), functions plotted versus the material balance time, \( \bar{t} \), on the Fetkovich/McCray type curve for a well centered in a bounded circular reservoir with an infinite conductivity vertical fracture. The three rate functions are "force matched" on the Arps \( b=1 \) (harmonic) decline stem as is required by pseudosteady-state theory, after matching, the appropriate match points are obtained.

The injection rate and pressure histories indicate that this well has entered the boundary-dominated flow region. We obtained a good match on the \( b=1 \) depletion stem as well as a unique match on the transient stem for an interpolated \( r_eD \) value of 20. Using \( r_eD \), and the time and rate match points, we calculate values for total system volume, injection area, permeability to water, fracture half-length, and skin factor.

Matching Parameter: \( r_eD = 5.0 \)

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>([t_Dd]_{MP})</td>
<td>1.0</td>
<td>([\bar{t}]_{MP}) = 1,507 days</td>
</tr>
<tr>
<td>([q_Dd]_{MP})</td>
<td>1.0</td>
<td>([q/\Delta p]_{MP}) = 0.087 STBW/day/psi days</td>
</tr>
</tbody>
</table>

**Total System Volume for Water Injection**

\[
W_{tot} = \frac{(\bar{t})_{MP} (q_{wi}/\Delta p)_{MP}}{(t_Dd)_{MP} (q_Dd)_{MP}} = (1507 \text{ days})(0.087 \text{ STBW/d/psi}) = 131.1 \text{ STBW/psi}
\]

\[
W_{tot} = \frac{(131.1 \text{ STBW/psi})}{50 \times 10^{-6} \text{ psi}^{-1}} = 2.62 \times 10^6 \text{ STBW}.
\]

**Reservoir Injection Area**

\[
A = \frac{(5.6148 \text{ ft}^3/\text{RB})(W_{tot})(B_w)}{(\phi)(h)(1 - S_{or} - S_{gr})} = \frac{(5.6148 \text{ ft}^3/\text{RB})(2.62 \times 10^6 \text{STB})(1.01 \text{ RB/STB})}{(0.075)(200 \text{ ft})(1 - 0.35 - 0.05)}
\]

\[
A = (1,652,250 \text{ ft}^2)(1 \text{ acre} / 43,560 \text{ ft}^2) = 37.9 \text{ acres}.
\]

**Reservoir Injection Radius**

\[
r_e = \sqrt{\frac{(1,652,250 \text{ ft}^2)}{\pi}} = 725.2 \text{ feet}.
\]
Pseudosteady-state Flow Constant

\[ b_{Dpss} = \ln(5) - 0.049298 + 0.434645 (5)^{-2} = 1.5775. \]

Effective Water Permeability (\(C_a = 31.62\) for bounded circular reservoir)

\[ k_w = 141.2 \frac{(1.01 \text{ RB/STBW})(0.84 \text{ cp})}{(200 \text{ ft})} (1.5775) \left( \frac{0.087}{1.0} \right) = 0.082 \text{ md}. \]

Fracture Half-Length

\[ x_f = \frac{725.2 \text{ ft}}{5} = 145.0 \text{ feet}. \]

Pseudo-Radial Flow Skin Factor

\[ s = -\ln \left( \frac{145.0}{2(0.33)} \right) = -5.39. \]

NRU 102(WI) – Injectable Water Plot (Fig. 5.42)

By plotting the injectivity index, \((q_w/\Delta p)\), versus cumulative water injection (Fig. 5.42), we can estimate the "injectable" water volume. Choosing either injection trend (before or after injection pressure increase), we estimate a total injectable water volume for NRU Well 102 of 600 MBW. The cumulative injection for the well to date is 383.3 MBW. This is 63.9 percent of the well's total injectable water under current operating conditions and 27.6 percent of the total system volume available for water injection.

\[ W_i = 383.3 \text{ MBW} \]
\[ W_{imov} = 600.0 \text{ MBW} \]
NRU 102 – Summary Discussion

The results of our material balance and volumetric analyses indicate that this well is injecting into a larger area than it drained during primary production. The well's key fluid flow characteristics have changed as the pre-existing fracture has propagated due to long-term water injection. It is apparent that the injection pressure has been maintained at a fairly high level in order to maintain injectivity, and as a result, the existing fracture has grown by a factor of five. We note that the effective permeability to injected water is very close to that of produced oil, which indicates that this area of the reservoir may be slightly water-wet or possess a mixed wettability. Continued injection at these pressures is likely to cause a channel along the injection row since fracture propagation is oriented east-west.

5.4.6.2 – Field Example: NRU Well No. 301

Fig. 5.43 shows the location of NRU 301, in the south-central area of the unit, with respect to its well pattern and the unit. NRU 301 was drilled in 1959 in the eastern part of the unit, and was initially completed in only the Lower Clear Fork interval. The
initial production rate was approximately 35 STBO/day. Additional intervals in the Upper/Middle Clear Fork and Glorieta were added in 1979, after which the well made approximately 15 STBO/day. As of July 1987 the well had produced approximately 135.9 MSTBO. The Upper/Middle Clear Fork and Glorieta were re-acidized prior to the conversion of the well to injection in August 1987.

The average reservoir pressure for the well when it was converted to water injection was estimated to be 800 psia. The current average reservoir pressure is estimated to be about 3,700 psia. In addition, the Lower and Middle Clear Fork intervals were re-acidized during a conventional workover in November 1992.

![Figure 5.43 – Location of NRU 301.](image)

NRU 301 – Stimulation History

**Lower Clear Fork**

- **Date**: October 1959
- **Interval**: 7,006 to 7,194 feet
- **Stimulation**: 10,000 gallons of 15 percent HCl acid
- **Hydraulic Fracture**: 20,000 gallons of refined oil and 40,000 pounds of 20/40 sand
Lower, Middle, Upper Clear Fork & Glorieta

Date March 1979
Interval 7,006 to 7,194 feet
Stimulation 8,000 gallons of 15 percent acid
Interval 6,764 to 6,909 feet
Stimulation 10,000 gallons of 20 percent acid
Interval 5,950 to 6,646 feet
Stimulation 35,000 gallons of 20 percent acid

Middle, Upper Clear Fork & Glorieta

Date July 1987
Interval 5,968 to 6,922 feet
Hydraulic Fracture 2,000 gallons of 15 percent NEFE acid

Lower & Middle Clear Fork

Date November 1992
Interval 6,503 to 7,194 feet
Stimulation 21,000 gallons of 15 percent NEFE acid

NRU 301 – Oil Production Analysis

The semilog and log-log production plots shown in Figs. 5.44 and 5.45 indicate that for the most part, the well produced with a consistent decline rate, with very few major rate fluctuations. The type curve match is shown in Fig. 5.46.
Figure 5.45 – Log-Log production plot for NRU 301.

Figure 5.46 – Match of production data for NRU 301 on the Fetkovich-McCray type curve for a well with an infinite-conductivity fracture centered in a bounded circular reservoir.
NRU 301 – Type Curve Analysis Results (Fig. 5.46)

Matching Parameter: \( r_e D = 20.0 \)

\[
[t_{Dd}]_{MP} = 1.0 \quad [\tilde{T}]_{MP} = 2,640 \text{ days}
\]

\[
[q_{Dd}]_{MP} = 1.0 \quad [q/\Delta p]_{MP} = 0.0148 \text{ STB/day/psi days}
\]

**Original-Oil-in-Place**

\( N_{CT} = 39.07 \text{ STB/psi} \)

\[
N = \frac{(2640 \text{ days})(0.0148 \text{ STB/day/psi})}{30 \times 10^{-6} \text{ psi}^{-1}} = 1.30 \times 10^6 \text{ STB.}
\]

**Reservoir Drainage Area**

\[
A = \frac{(5.6148 \text{ ft}^3/\text{RB})(1.30 \times 10^6 \text{ STB})(1.25 \text{ RB/STB})}{(0.075)(200 \text{ ft})(1 - 0.30)}
\]

\[
A = (870,561 \text{ ft}^2)(1 \text{ acre} / 43,560 \text{ ft}^2) = 20.0 \text{ acres.}
\]

**Reservoir Drainage Radius**

\[
r_e = \sqrt{\frac{(870,561 \text{ ft}^2)}{\pi}} = 526.4 \text{ feet.}
\]

**Pseudosteady-state Flow Constant**

\[
b_{Dpss} = \ln(20) - 0.049298 + 0.434645 (20) - 2 = 2.9475.
\]

**Effective Oil Permeability** (\( C_A = 31.62 \) for bounded circular reservoir)

\[
k_o = 141.2 \frac{(1.25 \text{ RB/STB})(1.30 \text{ cp})}{(200 \text{ ft})} (2.9475) \left[ \frac{0.0148}{1} \right] = 0.05 \text{ md.}
\]

**Fracture Half-Length**

\[
x_f = \frac{526.4 \text{ ft}}{20} = 26.3 \text{ feet.}
\]

**Pseudo-Radial Flow Skin Factor**

\[
s = - \ln \left( \frac{26.3}{2(0.33)} \right) = -3.69.
\]
NRU 301 – Movable Oil Plot (Fig. 5.47)

NRU 301 had produced 135.9 MSTBO prior to conversion to injection. This indicates there may have been approximately 34 MSTBO remaining in the well's drainage area to be recovered by subsequent 20-acre infill wells. From a reservoir pressure standpoint, this well depleted its drainage area. The recovery factor was actually significantly higher than the average primary recovery factor for the unit, and we note that the well is located in an area of fairly good reservoir quality.

\[
N_{p,mov} = 170.0 \text{ MSTB (primary)}
\]

Recovery Factor = 13.08 percent (primary)

Figure 5.47 – Estimated movable oil from rate history for NRU 301.

NRU 301(WI) – Water Injection Analysis

NRU 301 was converted to water injection in 1987. Fig. 5.48 shows the semilog rate and Cartesian injection pressure history since the well's conversion. An injection rate increase can be seen at approximately 1,800 days, when the injection pressure was increased following a major workover (November 1992). The initial injection rate decline is extrapolated to estimate the injectable water, \( W_{i,mov} \). The fractured well type curve match is shown in Fig. 5.49.
Figure 5.48 – Semilog rate and Cartesian injection pressure versus time for NRU 301(WI).

Figure 5.49 – Pre-workover match of injection data for NRU 301(WI) on the Fetkovich-McCray type curve for a well with an infinite-conductivity fracture centered in a bounded circular reservoir.
NRU 301(WI) – Type Curve Analysis Results (Fig. 5.49)

The rate functions for the type curve match were calculated prior to the 1992 workover. It is obvious that the acid job performed at that time greatly increased the area of influence of this well and the well no longer behaves as a material balance system as the decline trend falls off the $b = 1$ stem at late times. Based on recent pressure falloff test data, it appears that this well is now in direct communication with NRU 2601 (direct offset injector). The exact magnitude of the channel/fracture between these wells is difficult to estimate due to interference affects, but it is safe to say that the fracture is now extensive. The injection rate and pressure histories indicate that this well has entered the boundary-dominated flow region. We obtained a unique match on the transient stem for $r_{eD} = 10$.

Matching Parameter: $r_{eD} = 10.0$

$[t_{Dd}]_{MP} = 1.0 \quad [\overline{T}]_{MP} = 1,326$ days

$[q_{Dd}]_{MP} = 1.0 \quad [q/\Delta p]_{MP} = 0.114$ STBW/day/psi days

**Total System Volume for Water Injection**

$$W_{tot} = \frac{(\overline{T})_{MP} (q_{w}/\Delta p)_{MP}}{(t_{Dd})_{MP} (q_{Dd})_{MP}} = (1326 \text{ days})(0.114 \text{ STBW/day/psi}) = 151.2 \text{ STBW/psi}$$

$$W_{tot} = \frac{(151.2 \text{ STBW/psi})}{50 \times 10^{-6} \text{ psi}^{-1}} = 3.02 \times 10^6 \text{ STBW}.$$

**Reservoir Injection Area**

$$A = \frac{(5.6148 \text{ ft}^3/\text{RB})(W_{tot})(P_w)}{(\phi)(h)(1 - S_{or} - S_{gr})} = \frac{(5.6148 \text{ ft}^3/\text{RB})(3.02 \times 10^6 \text{STB})(1.01 \text{ RB/STB})}{(0.075)(200 \text{ ft})(1 - 0.35 - 0.05)}$$

$$A = (1,902,918 \text{ ft}^2)(1 \text{ acre} / 43,560 \text{ ft}^2) = 43.7 \text{ acres}.$$

**Reservoir Injection Radius**

$$r_e = \sqrt{\frac{(1,902,918 \text{ ft}^2)}{\pi}} = 778.3 \text{ feet}.$$
**Pseudosteady-state Flow Constant**

\[ b_{D_{ps}} = \ln(10) - 0.049298 + 0.434645(10)^{-2} = 2.2576. \]

**Effective Water Permeability** (\(C_A = 31.62\) for bounded circular reservoir)

\[
k_w = 141.2 \left( \frac{1.01 \text{ RB/STBW}}{0.84 \text{ cp}} \right) \left( \frac{200 \text{ ft}}{2.2576} \right)^{0.114} = 0.154 \text{ md.}
\]

**Fracture Half-Length**

\[
x_f = \frac{778.3 \text{ ft}}{10} = 77.8 \text{ feet.}
\]

**Pseudo-Radial Flow Skin Factor**

\[
s = -\ln \left( \frac{77.8}{2 \times 0.33} \right) = -4.77.
\]

**NRU 301(W1) – Injectable Water Plot (Fig. 5.50)**

We have extrapolated the final decline trend on a plot of \(q_{wi}\) versus \(W_i\) in order to estimate the injectable water. We estimate a total injectable water volume for NRU Well 301 of 1.45 MMBW. The cumulative injection for the well to date is 861 MBW. This is 59.4 percent of the well's total injectable water under current operating conditions, however, we note that it is only 28.5 percent of the total system volume available for water injection (3.02 MMBW).

\[
W_i = 861.0 \text{ MBW} \\
W_{i,mov} = 1.45 \text{ MMBW}
\]

A second type curve match (post-workover) shown in Fig. 5.51 indicates that the total system volume may be as much as 5.4 MMSTB. In this case, cumulative injection is only 15.9 percent of the total system volume, and our estimate of injectable water may need to be adjusted upward. However, we note that since the well is now in communication with injection from NRU 2601, it may be difficult to maintain injectivity in NRU 301.
Figure 5.50 – Estimated injectable water from a plot of pressure drop normalized injection rate versus cumulative injection for NRU 301(WI).

Figure 5.51 – Post-workover match of injection data for NRU 301(WI) on the Fetkovich-McCray type curve for a well with an infinite-conductivity fracture centered in a bounded circular reservoir.
NRU 301 – Summary Discussion

A pressure falloff test and Hall plot analysis (see Chapter VI on Reservoir Surveillance) have shown this well is in direct communication with NRU 2601. The estimated fracture half-length from the post-workover data-match indicates that the size of the fracture has tripled since the 1992 workover and increased by a factor of eight since the primary producing period. Injection in this well now influences the reservoir's pressure distribution in an area of 78 acres around the well. We note that the rate functions from the pre-workover data deviate from the harmonic stem ($b = 1$) at late times. This indicates that the system was no longer in material balance, therefore, the pre-workover analyses are most likely in error and the results should only be used qualitatively. Regardless of the exact values of permeability and fracture half-length, it is obvious that a communication problem exists. The most likely cause of the problem was a 1992 acid job that became an acid-frac.

5.5 – Summary

In this chapter, we have developed material balance decline type curves for the case of unfractured (radial flow case) as well as fractured (infinite-conductivity fracture) wells producing in the center of a bounded circular reservoir. The methodologies required for data analysis have been outlined in detail. We have shown that the Fetkovich-McCray decline type curve analysis techniques can be used for reserves evaluation and rate forecasting, as well as for surveillance of active waterfloods.

These techniques are especially useful for finding problems with well performance, such as the occurrence of interwell communication shown above. This problem could easily have been identified without the additional expenditure for a pressure falloff test. The use of the Fetkovich-McCray decline type curve as a surveillance tool will be discussed in greater detail in Chapter VI. Summary spreadsheets and individual type curve matches illustrating the results of decline type curve matches on all 40-, 20- and 10-acre producing wells and the 20-acre injection wells are given in Appendices J, K, L and M, respectively.
CHAPTER VI

RESERVOIR SURVEILLANCE

The reservoir surveillance tools summarized in this chapter may be used to help characterize reservoir heterogeneity, quantify differential depletion and identify preferential flow paths in the reservoir. The acquisition of all surveillance data may not be economically feasible for smaller operators, however, as a minimum, it is necessary to acquire continuous (and accurate) rate and pressure data for surveillance and performance analyses.

The goals of the reservoir surveillance program at the North Robertson Unit (NRU) are:

- Cost-effective acquisition and analysis of pressure transient data from injection and production wells (surface data acquisition) and confirmation of results with a limited number of downhole shut-in pressure buildup tests ("baseline" data set).
- Improvement of injector and producer conformance by targeting zones that are continuous between wells using the results of the rock-log model analysis, flow simulation and injection profile mapping.
- Identification of effective completion and stimulation techniques for large producing intervals without vertical barriers to hydraulic fracture propagation.
- Continuous monitoring of injection water quality.

The reservoir surveillance techniques available for use at the NRU are:

- Pressure falloff tests on water injection wells:
  - Allows for unit-wide estimates of formation flow characteristics, average reservoir pressure and the degree of injection-induced fracturing without shutting in producing wells.
  - Provides input parameters for reservoir flow simulation.
- Pressure buildup tests on producing wells:
  - Allows for unit-wide estimates of formation flow characteristics, average reservoir pressure and completion efficiency.
  - Provides input parameters for reservoir flow simulation.
• Long-term data analyses:
  – Evaluation of water injection well behavior using Hall plots.\textsuperscript{100,101}
  – Evaluation of long-term injection trends using material balance decline type curve analysis.
• Cased-hole well log surveys:
  – Allows for monitoring changes in reservoir water saturation that can be used to calibrate the reservoir flow simulation work.
  – Aids in the quantification of injection efficiency, completion efficiency and differential depletion.
• Formation pressure test (FT) surveys on new wells:
  – Allows for monitoring individual layer pressures that can be used to alter injection schemes and to calibrate reservoir flow simulation models.

6.1 –Pressure Transient Test Overview
Pressure transient tests can be either single-well or multi-well tests. Single-well tests include pressure buildup, drawdown, falloff and injectivity. These tests are used to determine average formation properties in part, or in all of the drainage area of the well. Multi-well tests include interference and pulse tests and are used to determine formation properties in a region centered along a line connecting pairs of wells. Multi-well tests are more sensitive to directional variation in properties such as permeability.

6.1.1 – Single-well Tests
A pressure buildup test is performed by stabilizing a well at some fixed rate for a sufficient period of time, placing a bottomhole pressure measuring device in the well, and then monitoring the change in pressure after shut-in. The rate of pressure buildup is used to estimate both well and formation properties.

A pressure drawdown test is performed by producing a well at a known or measured rate and recording the bottomhole pressure decline with time. The rate of pressure drawdown is used to estimate both well and formation properties.

A pressure falloff test is run on an injection well. After a stabilized injection rate has been achieved, the well is shut in. The subsequent decline in pressure with time after shut-in is used to estimate well and formation properties. The falloff test is analogous to
a pressure buildup test in a producing well.

An injectivity test may also be run on an injection well. Fluid is injected into a well at a measured rate. The rate of pressure increase over time is used to estimate well and formation properties. The injectivity test is analogous to a pressure drawdown test in a producing well.

6.1.2 – Multi-well Tests

The objective of a multi-well test is to produce from (or inject into) one well (source or active well), and observe the pressure response in one or more nearby offset wells (observation well). Permeability and porosity can then be estimated at the source well area and between the source and observation wells. This "interwell" data is especially important when and if the reservoir is simulated numerically.

During interference testing, the source well is usually produced at a constant rate throughout. For best results, the entire field should be shut in so that any observed pressure response is known to originate at the source well.

In a pulse test, the source well is produced and then shut in, for as many time cycles as is necessary to produce the required response. Production and shut-in periods do not normally last more than a few hours each (this is a function of formation permeability). This repetitive sequence produces a pressure transient that is easier to identify than with interference testing, and other wells in the field may be produced while testing due to the unambiguous nature of the pressure pulse.

6.1.3 – Limitations

Pressure transient tests are useful tools for reservoir description, but they have many limitations. Most importantly, their interpretation is not unique. There are several different types of reservoir conditions that can produce the same response to a pressure transient. The availability of additional information, particularly geological, may be required for an accurate interpretation.

Pressure transient analysis is usually based on very simple reservoir models that make
many assumptions about rock and fluid properties. Actual field data is usually too complex to be accurately fit by any one model. The analyst must recognize this limitation, and use other tools for complex model analysis, such as numerical simulation, to get the best possible interpretation.

Pressure transient tests can be quite expensive to perform. Simple buildup or flow tests can require long testing times, particularly in low permeability reservoirs, to adequately sample the drainage area. Pulse and interference tests involving many well pairs may not be economically justified except in special cases.

6.2 – Pressure Transient Testing at the NRU

We use a limited number of pressure buildup tests on producing wells in order to verify the results of the pressure falloff testing and to determine the degree of pressure support that the producing wells are receiving. In order to identify the most cost-effective method of data acquisition, we perform both bottomhole and surface shut-ins. Initial tests are performed using downhole shut-ins and a bottomhole memory gauge to obtain a comprehensive "baseline" data set. Subsequent buildup tests are recorded using surface pressure data acquisition. The quality of data obtained from surface tests is sufficient for analysis, and they are obviously more economic as the associated well preparation costs are lower.

When performing pressure transient tests in the low permeability reservoirs of the Permian Basin (such as the NRU), it has been our experience that a test of at least two to three weeks is required for a comprehensive analysis (undistorted radial flow) to be possible. The low permeability character of these reservoirs, combined with often severe wellbore storage effects, distorts test data and conventional analysis techniques cannot be used until these effects end. One remedy is a downhole shut-in device, but this device can be difficult to install, it requires considerable well preparation, and is quite expensive.

Our approach was to minimize the test time by simultaneously acquiring using real-time surface data for analysis. In this way, we can monitor the test and terminate once a valid
analysis is obtained, but in many cases we continued data acquisition until the downhole power source depleted. We did this for two reasons – we wanted to acquire as much data as possible and we wanted to establish the practical operating limits of different data acquisition systems. In order to estimate well drainage radius and identify flow boundaries, we found from pressure falloff tests that a total test duration of between five and eight weeks is required. Obviously, it is not economically feasible to shut-in producing wells for this period of time.

Pressure transient testing at the NRU consisted of the acquisition and analysis of pressure buildup and pressure drawdown data on producing wells and pressure falloff data on injection wells. Only single-well tests will be considered since the permeability and reservoir continuity at the NRU does not permit multi-well tests to be performed in a cost-effective (timely) manner. All tests except the pressure drawdown tests from the new 10-acre infill wells were run with the entire Clear Fork section open to the wellbore. It was neither operationally feasible nor cost-effective to attempt interval tests in existing wells. Since we are sampling the entire Clear Fork interval together, we may find some misleading results with regard to estimates of completion or injection efficiency.

The 10-acre infill wells were tested on an interval basis to determine specific interval flow properties and pressures in the Lower, Middle, and Upper Clear Fork. In addition, individual layer or flow unit pressures were obtained using formation test tools during the open-hole logging program. In this way, we were able to identify the relative contributions of individual zones within the producing interval.

In the majority of operating environments, the most critical issue during most pressure transient tests is the timely return of the well to production or injection. We present two cost-effective surface data acquisition methodologies that minimize test time while fulfilling the data acquisition requirements. We will show that these methods may be performed in a cost-effective manner using surface-derived pressure data from fluid level measurements on producing wells and surface gauge installations on injection wells. This eliminates the loss of injection or production during the pre- and post-testing periods and the cost of "pulling" the well for testing.
In 1994, a unit-wide pressure transient data acquisition and analysis program was initiated to obtain additional reservoir characterization data. Approximately forty-five pressure buildup, pressure drawdown and pressure falloff tests recorded between 1988 and 1997 are available for analysis. These data can be used to confirm or disprove the results of geologic, geophysical or petrophysical studies, but cannot provide a unique reservoir description when used alone. If used in conjunction with our previous studies, we can rigorously characterize the reservoir.

The accurate acquisition and analysis of pressure transient data is an integral part of the reservoir surveillance process. The term "pressure transient test" refers to a survey in which the change of a generated pressure "wave" is monitored over time. By analyzing the characteristic shape of the pressure-time profile we can determine the properties shown below.

- Reservoir-well model (i.e., homogeneous or dual-porosity reservoir conditions, hydraulically-fractured or horizontal well behavior, wellbore storage conditions, etc.)
- Current drainage area pressure
- Radial flow skin factor (fracture half-length for fractured well completions)
- Effective permeability to the flowing phase
- Estimates of completion and stimulation efficiency
- Hydrocarbons-in-place (if a boundary is reached during test)
- Existence of and approximate distance to flow barriers (faults, fractures, no-flow or constant-pressure outer boundaries, etc.)
- Porosity (multi-well tests – not performed at the NRU)
- Diagnosis of productivity or injectivity problems in individual wells
- Identification of the best and worst areas of the unit with regard to waterflood pressure support.
- Representative comparisons with tests recorded prior to the initiation of water injection to evaluate the effects of long-term water injection
- Communication between well pairs (if present, this yields fracture orientation)
6.3 – Data Acquisition

6.3.1 – Pressure Falloff Tests

We utilized surface data acquisition for the pressure falloff tests. This was necessary at the NRU (and for most mature waterfloods) due to poor casing and packer integrity in the injection wells (formerly the original producers). In addition, the expense of pulling the wells for testing made these surveys uneconomic. The operator (without third party charges) was able to acquire pressure falloff data in a cost-effective manner using a low-resolution gauge (+1 psi) installed at the wellhead. Integral smoothing was performed on the raw data to remove the effects of poor gauge resolution, large time increments between data points (one minute increments in the early time region) and unstable injection rates without significantly altering the embedded reservoir signature.

We tested wells that had fairly stable injection histories and had not been off injection for any significant time during the previous 6-month period. We assumed that the injection wells held a full column of a single-phase fluid (produced or fresh make-up water) initially. This is likely a valid assumption for this particular low permeability carbonate reservoir, however, we note that the vast majority of water injection wells have lower working fluid levels or take water on a vacuum. If oil or gas are present, even in relatively small volumes, we are most probably underestimating effective water permeability and slightly overestimating bottomhole pressure.

The pressure falloff tests helped to explain some of the major problems associated with waterflooding a low permeability carbonate reservoir. In an effort to identify interference and boundary effects on the injection well falloff tests, an effort was made to let the tests run as long as possible. This is especially important in identifying the problems that may affect reservoir sweep efficiency. The extremely long falloff times indicated that the wells might be receiving a great deal of interference from offset injectors. These long falloff periods may also be due to the presence of formation scale plugging or wellbore fill which can be identified from waterflood diagnostic plots.
6.3.2 – Pressure Buildup and Drawdown Tests

We acquired both real-time surface data and downhole memory gauge data for the pressure buildup and pressure drawdown tests. Downhole memory gauge data was recorded on all tests after 1994 and used as the baseline standard. Real-time surface data was recorded using both a standard acoustic well-sounder (AWS) system and a new electromagnetic (EM) transmission system\textsuperscript{106} in order to evaluate both systems for future stand-alone use. The typical downhole testing configuration is shown in Fig. 6.1.

Figure 6.1 – Downhole configuration for majority of NRU pressure buildup and pressure drawdown tests (1994 – 1997).
Pressure drawdown tests were recorded on selected Clear Fork intervals in the new 10-acre infill wells after their initial completions. Downhole gauges were installed prior to first production (during fracture stimulation). For pressure buildup tests, we have successfully used the following procedure for memory gauge installations as well as the real-time EM and AWS systems.

1. Well on pump for extended period ≥ 6 months
2. Tag well TD and clean out wellbore fill 3 days
3. Place well on pump 24 days
4. Run packer and downhole gauge 8-12 hours
5. Place well on pump 4 days
6. Set packer and shut in well for buildup 21 days

6.4 – Data Analysis Procedures

We will utilize conventional semilog\textsuperscript{107,108} and log-log type curve techniques for unfractured\textsuperscript{109-112} and fractured wells\textsuperscript{95,96,113-117} to analyze the data. A final optimization is performed by comparing the data with an analytical solution that is solved using the results from the type curve match. The input parameters ($k$, $s$, $C_D$, etc.) are then adjusted until a final solution is obtained.

Although our discussion will primarily concern the producing-well tests, the same analysis techniques apply for the water injection wells. The fluid properties data utilized for the analysis of all pressure transient data is given in Appendix I.

6.4.1 – Time Functions

Due to our lack of detailed knowledge regarding the production and injection history at the NRU, we chose to use the actual shut-in time, $\Delta t$, in both the semilog and log-log analyses. This is in contrast to using superposition (i.e., the Horner\textsuperscript{107} plot), that is theoretically rigorous, but results in quite arbitrary results when an accurate rate history is unavailable, especially for estimates of average reservoir pressure.

All producing wells at NRU are pumping wells, and the issue of a well's production history or even a "lumped" estimate of producing time becomes extremely complex.
since it is difficult to determine what actually constitutes a stabilized rate. These wells have been on pump-off controllers since completion and fluid levels are kept at a fairly constant level, however, the rates change continuously. The water injection wells are on an automated system and injection rates can also vary quite significantly.

After short shut-in periods for running downhole memory gauges or cleaning wellbore fill, we have noted that the wells "pump-off" (return to a stable fluid level) fairly quickly, however, this does not equate to a stabilized rate, and the prior rate history still significantly affects test data. By experimenting with different testing sequences, we have found that in order to minimize producing time effects associated with short shut-in periods during the buildup tests, we must produce the well for a period of time approximately six to eight times as long as its previous shut-in.

We examined the use of both the shut-in time and effective time functions (Horner plot for semilog analysis and Agarwal plot for log-log analysis) for constant-rate and variable-rate pressure buildup cases. We found that the constant rate buildup case (using only shut-in time, \( \Delta t \), i.e., no superposition) gave the most consistent and interpretable results. For a more thorough discussion of time functions used in pressure transient analysis, we refer the reader to ref. 102.

6.4.2 – Type Curve Analysis

Type curves are plots of theoretical solutions to fluid flow equations and are extremely useful in well test analysis, particularly when used together with conventional semilog analysis of test data. Type curves aid in the identification of the appropriate reservoir model, finding the location of the end of wellbore storage distortion of test data and in the estimation of well and reservoir properties. They are particularly useful for the analysis of gas well tests, if pseudopressure and pseudotime are utilized.

Type curves are used to improve pressure transient analysis. Pressure buildup and flow test analysis becomes much less ambiguous when type curves are used together with semilog analysis. Although analysis with type curves alone may be extremely qualitative, it can be used to confirm or disprove the more quantitative semilog analysis,
and can be used to define the limits for which these conventional techniques apply.

The primary use of semilog analysis for pressure buildup and falloff analysis is to determine an estimate of the average reservoir pressure. However, rigorously estimating average reservoir pressure requires accurate knowledge of both the well's producing history as well as the affected reservoir volume, neither of which are typically available. Due to the availability of commercial software packages for pressure transient analysis, almost all operators now perform log-log analysis, as well as "conventional" (or traditional) semilog analysis. We focus primarily on log-log analysis since this approach gives a complete view of all of the test data, as opposed to semilog analysis, which can only be used to interpret data specifically in the radial flow regime.

In general, log-log analysis provides a better resolution of a well's producing mechanisms (producing time effects, wellbore storage, etc.) as well as most, if not all, of the flow regimes that occur in a particular test. Semilog analysis is used for validation of permeability and skin factor, which can also be obtained from log-log (or type curve analysis). Semilog analysis methodologies are provided in Appendix N.

In this study we have focused on the use of the type curve model for a well with a finite conductivity vertical fracture in an infinite-acting homogeneous reservoir that includes wellbore storage effects. As some of the tests that we have analyzed at the NRU show only slight damage or stimulation, we have also used the type curve solution for an unfractured well in an infinite-acting homogeneous reservoir with wellbore storage and skin effects. The models are quite similar in both form and function, except the solutions for lower conductivity fractures. The type curve analysis relations are provided in Appendix N for both unfractured and fractured wells.

As mentioned above, we will use shut-in time, $\Delta t$, rather than the more rigorous effective time function, $\Delta t_e$, as we do not have a detailed production history. Once the appropriate pressure drop and pressure drop integral functions are plotted versus $\Delta t$ on a log-log plot, these data are then overlain and matched onto the appropriate type curve (i.e., Figs. 6.2 – 6.5) and the match points are used to calculate $k_e$, $s$ and $C_D$. 
6.4.3 – Data Smoothing

We note that both surface and downhole pressure data were analyzed in exactly the same fashion. For consistency, test data were filtered (as required) using the integral smoothing technique of Blasingame et al.\textsuperscript{103,104} The pressure integral calculation provides a technique for smoothing data that may be affected by "noise" (random errors) as well as for data which are affected by systematic errors such as "stair steps" caused by low gauge resolution. No such "stair steps" were noted in the pressure buildup or drawdown data, however, it was very evident in the pressure falloff data.

The pressure integral method gave us more consistent data trends (only 1 smoothing "pass" was used) and improved the resolution of both the pressure drop and pressure drop derivative functions, especially for the data transmitted to surface (EM) or acquired at surface (AWS). The pressure and rate integral methods are useful tools for analyzing both pressure transient test data and long-term production data.

Figure 6.2 – "Pressure" type curve for an unfractured well in an infinite-acting homogeneous reservoir.\textsuperscript{108,111}
Figure 6.3 – "Pressure-Integral" type curve for an unfractured well in an infinite-acting homogeneous reservoir.

Figure 6.4 – "Pressure" type curve for a well with a finite conductivity vertical fracture in an infinite-acting homogeneous reservoir.
Figure 6.5 – "Pressure-Integral" type curve for a well with a finite conductivity vertical fracture in an infinite-acting homogeneous reservoir.

6.4.4 – Methodology

Data analyses were performed in the following manner:

1. The raw pressure data (real-time surface and bottomhole memory pressures versus Δt) were smoothed using the pressure integral in order to reduce the noise associated with typical field data.

2. Conventional semilog analyses using the Miller-Dyes-Hutchison method were performed on the shut-in pressure, \( p_{ws} \), and shut-in pressure integral, \( p_{wsi} \), data in order to obtain preliminary estimates of permeability, \( k \), and the skin factor, \( s \).

3. The semilog permeability estimates were used to "force-match" the pressure drop and pressure drop derivative data on the log-log type curves (Fig. 6.6) for both the unfractured and fractured well models. The "matches" were refined slightly to yield estimates of skin factor, \( s \), and the dimensionless wellbore storage coefficient, \( C_D \), for unfractured wells or fracture half-length, \( x_f \), and the dimensionless wellbore storage coefficient, \( C_{Df} \), for fractured wells. The fracture half-length is obtained from the dimensionless fracture conductivity, \( C_{fD} \).
4. The average reservoir pressure, $\bar{p}$, was estimated (Fig. 6.7) using the rectangular hyperbola asymptote method (RHM) proposed by Mead.\textsuperscript{119}

5. Finally, we simulated the pressure buildup tests using the results of the semilog and log-log analyses. For the unfractured well model $k_s$, and $C_D$ were optimized and for the fractured well model $k_f$, $x_f$, and $C_{Df}$ were optimized. As a means of ensuring consistency, the pressure drop, pressure drop derivative, pressure drop integral, and pressure drop integral derivative functions were all matched simultaneously by the optimization program. This is illustrated in Fig. 6.8.

Figure 6.6 – Preliminary type curve match for NRU 2703 pressure buildup test data for a well with a finite conductivity vertical fracture in an infinite-acting homogeneous reservoir.
The raw data for the all pressure transient tests are given in Appendix O. The final results and optimized log-log plot data matches for the 1988 pressure buildup tests, 1994 pressure falloff tests, 1995 pressure buildup tests, 1996 pressure drawdown/pressure buildup interval tests and the 1997 pressure buildup tests are given in Appendix P.

The results for effective permeability (or permeability-thickness, $kh$) and fracture half-length (or skin factor) can also be mapped and compared to the results from core-log modeling and production data analysis. This data integration will be discussed in Chapter VIII.
6.5 – Estimation of Average Reservoir Pressure

As shown above, the average reservoir pressure can be estimated from pressure transient data using the rectangular hyperbola method (RHM) introduced by Mead. Although designed for use with boundary-dominated flow data, this method has been shown to yield acceptable estimates for \( \bar{p} \) when boundary-dominated flow data (BDF) are not available. For the NRU tests, we typically have no BDF data and very little pressure data in the radial flow (middle-time) region. For this reason, we place no great
confidence in our estimates for $\bar{p}$, however, they are certainly more realistic estimates for average reservoir pressure than $p^*$ from semilog analysis, particularly when there are little, if any, radial flow data available for analysis.

Average reservoir pressure was estimated for each pressure transient test. As a result, we were able to construct maps of average reservoir pressure to illustrate how the reservoir depleted and was re-charging since water injection began. This can be correlated with performance history to locate areas requiring remediation, waterflood pattern balancing or infill drilling locations. These data integration results will also be discussed in Chapter VIII.

The results (referenced to datum at –3,550 feet subsea) are shown in Table 6.1. A graphical illustration is provided in Fig. 6.9.

Table 6.1 – NRU shut-in bottomhole pressure estimates (1985-1997).

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In short, we found that the regions of the reservoir with the highest reservoir quality are at a relatively lower pressure due to increased fluid withdrawal that is directly related to greater continuity and higher permeability. The areas with relatively higher reservoir quality appear to be well "swept" by water injection. The south-central area of the unit, in which a less continuous lagoonal facies dominates, appears to be producing under a pressure maintenance mechanism in which the oil is being "squeezed" out rather than moved by "piston-like" displacement.

6.6 – Field Examples
6.6.1 – Case Study: Comparison of Real-Time EM Data with Memory Gauge Data
In an attempt to introduce new, cost-effective technologies, we recorded several pressure buildup tests with a downhole tool that transmits real-time pressure and temperature data
to surface via the wellbore tubulars and the formation. These surveys can be performed for approximately the same cost as those utilizing memory gauge data collection techniques. This system has been used in the past to monitor bottomhole pressure and temperature during hydraulic fracturing and drill-stem testing operations. The technology offers a distinct advantage over running "blind" downhole gauges that cannot be accessed until they are pulled from the well.

Using this data acquisition system, we are able to analyze data in real time as the survey is being recorded, and we can terminate the test in a time-efficient manner if there is a downhole problem or the data quality is poor. This instantaneous feedback allows us to return wells to production faster and reduce the associated loss of production. Real-time data acquisition has only been available in the past for short-term pressure transient tests run using electric wireline, which is obviously not economically feasible for the long-term tests that we conduct.

This technology may also be extremely useful for long-term bottomhole pressure monitoring in active producing or injection wells. Daily bottomhole pressure data would greatly increase confidence in our material balance decline type curve analyses that are adversely affected by the assumption of a constant bottomhole pressure. In older, less prolific producing areas such as the Permian Basin, these data are not available. The acquisition of these data would also be extremely useful when performing reservoir flow simulation since it would provide an extremely important parameter for history matching.

Our experience suggests that the telemetry system can be feasible for tests on the order of 3 weeks. In addition, the system is self-contained and requires no monitoring other than periodic data collection. By contrast, the use of a wireline-conveyed, real-time pressure data acquisition system is cost prohibitive for tests of more than 2 or 3 days and requires continuous monitoring to ensure proper equipment performance.

The results obtained using the EM tool were very good, and were similar to the results we obtained from other "conventional" pressure transient tests taken at NRU (both buildup and falloff tests). We have included analyses of both the real-time surface data
and bottomhole memory gauge data in order to show how favorably these data compare. Our analyses show the utility of transmitting data to the surface on demand so that the data can be analyzed while the test is proceeding, as is done on many short-term wireline-conveyed pressure transient tests.

### 6.6.1.1 – Equipment Set-Up

The EM tool transmits the data to the surface using a proprietary noise-rejecting modulation scheme. The voltage arriving at the surface is measured differentially between the wellhead and a remote electrode placed in the ground at some distance from the wellhead (~150 feet). The tool is set downhole using a slick line, sand line, or electric wireline when casing hangers are required, or via a bundle carrier on tubing during through-tubing operations.

### 6.6.1.2 – Gauge Accuracy and Resolution

The pressure transducer currently used in the EM tool is a strain gauge device that can be changed according to the expected bottomhole pressures and the type of test being run. For our pressure buildup tests we utilized a transducer with an accuracy of ±0.15 percent at a full-scale reading of 5,000 psia, a resolution of ±1 psi, and a temperature rating of 300°F. The temperature probe has an accuracy of ±0.5°F, and a resolution of ±1°F.

Although this accuracy and resolution is sufficient for our pressure measurement requirements, some operators may require a more accurate, higher resolution quartz pressure gauge. Future modifications may allow data transmission at almost the same frequencies that data are stored downhole.

### 6.6.1.3 – Data Analysis: NRU Well No. 905

NRU 905 was drilled in 1989 as a 20-acre infill producer. This well was acidized and hydraulically fractured in two stages – the Lower and Middle Clear Fork interval followed by the Upper Clear Fork interval. Pertinent well and production data are given below.
NRU 905 – Completion, Reservoir, Fluid Property and Production Data

**Completion Data**
- Total depth = 7,350 feet
- Plug back depth = 7,318 feet
- Production casing (5-1/2") = surface to 7,345 feet
- Perforated interval = 5,931 feet to 7,197 feet
- Total perforations = 100 holes
- Rates prior to test:
  - $q_o$ = 25 STBO/D
  - $q_w$ = 105 STBW/D
  - $q_g$ = 2 MSCF/D
- Cumulative oil production = 63.1 MSTB
- Estimated ultimate recovery = 95.0 MSTB

**Reservoir Properties**
- Average reservoir depth = 6600 feet
- Wellbore radius, $r_w$ = 0.33 feet
- Estimated gross pay interval = 1,000 feet
- Estimated net pay thickness, $h$ = 200 feet (varies)
- Average porosity, $\phi$ (fraction) = 0.075
- Average irreducible water saturation, $S_{wi}$ = 0.30
- Effective oil permeability, $k_o$ < 1 md
- Current nominal well spacing = 20 acres

**Fluid Properties**
- Average oil formation volume factor, $B_o$ = 1.25 RB/STB
- Average oil viscosity, $\mu_o$ = 1.30 cp
- Initial total compressibility, $c_{ii}$ = 12.0x10^{-6} psi^{-1}
- Average total compressibility, $c_i$ = 30.0x10^{-6} psi^{-1}

**Production Parameters**
- Initial reservoir pressure (LCF), $p_i$ = 2,800 psia
- Current avg. reservoir pressure, $\bar{p}$ = 2,900 psia
- Average producing bottomhole pressure, $p_{wf}$ = 80 – 150 psia

Coupling the geologic model with the historical performance, we believe that NRU 905 is in an area of moderate reservoir quality. We also note that this area has responded fairly well to waterflooding operations on 20-acre nominal spacing. However, since the well is near the southern edge of the unit, its five-spot pattern is incomplete and the well is only partially supported by water injection (Fig. 6.10).

NRU 905 had been on production for several months prior to shutting-in the well for approximately three days to remove wellbore fill. The well was then placed back on
production for approximately one month before the downhole assembly was run through tubing. The well was put on production for 4 days before being shut-in for the pressure buildup test. The EM tool and its downhole assembly were set in the casing at 7,076 feet, approximately 55 feet below the pump and 274 feet above the casing shoe. A full-bore packer was set above the perforations.

![Figure 6.10 – Location of NRU 905.](image)

For consistency, we "forced" the pressure drop functions (vertical scale match) to correspond to the permeability estimate obtained from the semilog analysis. The semilog plot and the analysis results are shown in Fig. 6.11. For completeness, we matched the pressure data functions on type curves for both an unfractured well (Fig. 6.12) and a fractured well (Fig. 6.13). Since all of the producing wells at NRU are hydraulically fractured, we used the fractured well model for our final analysis.
After the vertical axis "force match" was made (based on the permeability from semilog analysis), we shifted the data horizontally (along the time axis) until a match was obtained with a type curve for a particular wellbore storage case. We recorded the "matched" value of the dimensionless wellbore storage coefficient, $C_{Df}$, as well as the "time" axis match point. We then computed the fracture half-length, $x_f$, from the "time" axis match point.
In Fig. 6.13 below, we see that both the pressure drop and pressure drop derivative trends are smooth. In matching these data, we obtained excellent agreement between the data and fractured well model for "early" times during the wellbore storage dominated period (i.e., the "unit slope line") as well as during the wellbore storage distortion period. However, as the test began the transition from the wellbore storage distortion period to the undistorted radial flow period we note that the pressure derivative data appear to oscillate slightly and that this trend eventually falls on the $C_{Df} = 1$ line.
There are several possible explanations for the behavior of the pressure derivative data, including the following:

- Differential pressures in different layers causing crossflow into lower pressure zones. We know that there are several zones at NRU that are not injection-supported and as the fluid rises in the wellbore, these zones take fluid.
- The influence of lateral heterogeneities such as changing permeabilities. Comparing core and well log data we know that such features exist, but we cannot resolve their influence using a simple, homogeneous reservoir model.
- Random and systematic data noise in the acquisition system.

**Type Curve Match Results – NRU 905**

The data were matched on the type curve for a well with a finite conductivity vertical fracture with wellbore storage effects. We note that the calculations and results are identical for the pressure integral data.
Matching Parameters: $C_{DF} = 0.9$, $C_{FD} = 1 \times 10^3$

\[
\begin{align*}
[t_{DF}/C_{DF}]_{MP} &= 1.0 & [\Delta t]_{MP} &= 4.85 \text{ hrs} \\
[p_{wD}]_{MP} &= 1.0 & [\Delta p]_{MP} &= 800.0 \text{ psi}
\end{align*}
\]

**Pressure Analysis**

- $k_o = 0.114 \text{ md}$
- $x_f = 12.1 \text{ feet}$

**Permeability**

The effective permeability to oil, $k_o$, is calculated from the pressure match point:

\[
k_o = 141.2 \frac{q_{B{o,MP}}}{h} \frac{[p_{wD}]_{MP}}{[(\Delta p)_{func}]_{MP}}.
\]  

Using the match points to solve for the effective oil permeability, we obtain:

\[
k_o = 141.2 \left( \frac{25 \text{ STB/day} \times (1.25 \text{ RB/STB}) \times (2 \text{ cp})}{(97 \text{ ft})} \right) \left( \frac{1}{800} \right) = 0.114 \text{ md}.
\]

**Fracture Half-Length**

The fracture half-length, $x_f$, is computed from the time match point using:

\[
x_f = 0.01624 \sqrt{\frac{k_o}{\Phi_{\rho,\omega,c_o} C_{DF}}} \frac{1}{[t_{func}]_{MP}}.
\]

Solving for the fracture half-length, $x_f$, we obtain:

\[
x_f = 0.01624 \sqrt{\frac{0.114 \text{ md}}{(0.055)(2 \text{ cp})(10 \times 10^{-6} \text{ psi}^{-1})} \left( \frac{1}{0.9} \right) \left( \frac{4.85}{1.0} \right)} = 12.1 \text{ feet}.
\]

**Simulation and Parameter Optimization – NRU 905**

After obtaining estimates of $k_o$, $C_{DF}$ and $x_f$ from the log-log type curve analysis, we then performed simulation to optimize these parameter values in a statistical sense. To ensure consistency, we simultaneously optimized the simulation on all of the data functions (pressure drop, pressure drop derivative, pressure drop integral, and pressure drop integral derivative).
The downhole memory gauge data are considered the "standard" against which we should verify our real-time surface data. Recall that the "surface" data are simply selected intervals of data that have been transmitted up hole during the test. As such, we chose to plot the computed solutions for the bottomhole pressure data \((i.e.,\) the complete data set) along with both the surface and bottomhole pressure data. The optimization results for the fractured well model are shown in Fig. 6.14.

**Optimized Final Solutions from Simulation – NRU 905**

*Bottomhole Memory Gauge Data (Fractured Well Model)*

**Input:**
- \(C_{Df} = 0.9\)
- \(k_o = 0.114 \text{ md}\)
- \(x_f = 12.1 \text{ feet}\)

**Output:**
- \(C_{Df} = 0.902\)
- \(k_o = 0.110 \text{ md}\)
- \(x_f = 8.24 \text{ feet}\)

*Real-Time Surface Data (Fractured Well Model):*

**Input:**
- \(C_{Df} = 0.9\)
- \(k_o = 0.114 \text{ md}\)
- \(x_f = 12.1 \text{ feet}\)

**Output:**
- \(C_{Df} = 0.795\)
- \(k_o = 0.110 \text{ md}\)
- \(x_f = 8.28 \text{ feet}\)
Summary for NRU 905

We note excellent agreement in the final solutions for permeability and fracture half-length for both the surface and bottomhole data. The calculated permeabilities are identical, and the fracture half-lengths are within 0.5 percent. These comparisons indicate that the surface data are of sufficient quality to perform accurate, real-time analysis of a pressure transient test, while the test is actually being run.

The fracture half-length was calculated to be approximately 8 feet. It is difficult for us to make a quantitative evaluation of the hydraulic fracture treatments performed at NRU.
since we are testing such a large interval (approximately 1,000 feet). Previous limited-entry fracture treatments over extremely large intervals appear to have resulted in the initiation of several short, parallel ("pancake") hydraulic fractures. Pressure buildup tests have indicated that although these treatments did remove near-wellbore damage, no significant lateral fracture extension was created. While these short computed fracture half-lengths may be cause for concern, it is important to realize that the near wellbore area appears to be well stimulated (a skin factor of -2.78 was computed from both semilog and log-log methods using the unfractured well model).

The average reservoir pressure in the area surrounding the well at the time the data were recorded was estimated to be 2,871 psia (7,000-ft datum) using the rectangular hyperbola method. Given the fact that the fluid injection and withdrawal rates are about average in this area of the unit we expect the reservoir pressure in this area to be close to the estimated unit-wide average pressure at that time (approximately 3,000 psia).

This was the first buildup test we performed using the EM tool and the battery life of the tool was only sufficient to record data up to the start of the undistorted radial flow period (4-day drawdown, 12-day buildup). It should be noted, however, that the duration of the test data was sufficient to obtain a comprehensive analysis and the data quality was excellent. In most formations we would consider a 12-day pressure buildup test to be more than sufficient to sample reservoir properties. However, due to the extremely low permeability and high degree of heterogeneity in the Clear Fork, a 12-day pressure transient test would not be long enough for most of the wells at the NRU.

For subsequent tests, additional batteries were added to the tool, and the downhole-to-surface transmission rates were optimized to prolong battery life. With these changes we were able to achieve a three-week pressure buildup sequence. We note that future improvements must include an increase of the data transmission rate to improve the quality of the early-time data, therefore power requirements will increase.

6.6.2 – Case Study: Comparison of AWS Data with Memory Gauge Data

Between February and August 1997, pressure buildup tests were recorded on four wells
at the NRU for which simultaneous measurements of pressure-time data were made using both downhole memory gauges and acoustic well sounder (AWS) devices at surface. These tests were conducted to determine the feasibility of performing future pressure buildups using AWS technology alone. Analysis procedures are summarized and a representative illustrative example is shown below for NRU 207.

### 6.6.2.1 – Data Analysis Procedure

The AWS and memory gauge data for each well were analyzed as follows:

1. Graphical comparisons are made of raw AWS and memory gauge pressure data for each well. The AWS shut-in pressure is referenced to the bottom hole gauge depth for each case.

2. Preliminary analyses of both data sets are made using semilog (MDH) analysis and the type curve for a well with a finite conductivity vertical fracture in an infinite-acting homogeneous reservoir, including wellbore storage (all NRU wells are hydraulically-fractured). The pressure and pressure derivative data ($\Delta p$ and $\Delta p'$) are matched on the pressure type curve, and the pressure integral and pressure integral derivative data ($\Delta p_i$ and $\Delta p_i'$) are matched on the pressure integral type curve for completeness. Estimates are obtained for effective permeability to oil ($k_o$), fracture half-length ($x_f$) or pseudoradial skin factor ($s_{pr}$) and wellbore storage ($C_s$ or $C_{Df}$).

3. Statistical optimization is performed on the final type curve results for both the AWS and memory gauge data. For the unfractured well model $k$, $s$, and $C_D$ are optimized and for the fractured well model $k$, $x_f$, and $C_{Df}$ are optimized. As a means of ensuring consistency, the pressure drop, pressure drop derivative, pressure drop integral, and pressure drop integral derivative functions are all matched simultaneously.

4. Steps (2) and (3) are repeated after generating integrally smoothed data sets. For this particular case, the analysis results for both the raw and smoothed data sets were identical for each case, therefore data smoothing is probably not necessary.

5. Semilog and log-log summary plots are then generated to show analysis results for both the AWS and memory gauge data sets. The memory gauge results were taken as the "correct" evaluation for each well.

6. Extrapolated estimates of average reservoir pressure, $\bar{p}$, for both the AWS and memory gauge data were made using the equation for a rectangular hyperbola (RHM).
6.6.2.2 – Data Analysis: NRU Well No. 207

NRU 207 was drilled and completed as a producing oil well during the 20-acre infill program conducted between 1987 and 1991. During this time, eighty percent of all original 40-acre wells were converted to water injectors and the other twenty percent remained as producers, primarily along the periphery of the unit. NRU 207 is located near the center of Section 5, which is in the southeast corner of the NRU (Fig. 6.15). The SYCO (Clear Fork) Unit is located directly to the east and the Robertson (Clear Fork) Unit is located to the south. The wellbore schematic for the test and the well's completion history are shown in Fig. 6.16. The oil production rate prior to shut-in was 12 STBO/day. Fluid properties data are provided on the plots.

A comparison of pressure data acquired from the AWS system and bottom hole memory gauge is shown in Fig. 6.17. We note that the AWS shut-in pressures are significantly higher than the memory gauge shut-in pressures. The Clear Fork oil at the NRU has foaming tendencies, therefore, accurate pressure estimation (i.e., fluid level height measurement) using the AWS system is often difficult.

Figure 6.15 – Location of NRU 207.
Figure 6.16 – NRU 207 wellbore schematic and completion history.
Figure 6.17 – Comparison of raw AWS and bottomhole memory gauge pressure buildup data for NRU 207.

Type Curve Match Results for NRU 207 – Smoothed AWS Data

The data were matched on the type curve\textsuperscript{114} for a well with a finite conductivity vertical fracture with wellbore storage effects. We note that the calculations and results are identical for the pressure integral data. The preliminary type curve match is shown in Fig. 6.18.

Matching Parameters: $C_{Df} = 0.09$, $C_{ID} = 1 \times 10^1$

\[
\begin{align*}
[t_D/C_{Df}]_{MP} &= 1.0 \\
[\Delta t]_{MP} &= 17.5 \text{ hrs} \\
[p_{wD}]_{MP} &= 1.0 \\
[\Delta p]_{MP} &= 1,300.0 \text{ psi}
\end{align*}
\]
Pressure Analysis

\[ k_o = 0.019 \text{ md} \]
\[ x_f = 27.1 \text{ feet} \]

Permeability

Using the match points to solve for the effective oil permeability, we obtain:

\[ k_o = \frac{141.2 \times (12 \text{ STB/day})(1.25 \text{ RB/STB})(2.037 \text{ cp})}{(179 \text{ ft})} \left\{ \frac{1}{1300} \right\} = 0.019 \text{ md} . \]

Fracture Half-Length

Solving for the fracture half-length, \( x_f \), we obtain:

\[ x_f = 0.01624 \sqrt{\frac{0.019 \text{ md}}{(0.065)(2.037 \text{ cp})(10 \times 10^{-6} \text{ psi}^{-1})} \left\{ \frac{1}{(0.09)} \right\} \frac{17.5}{1.0} } = 27.1 \text{ feet} . \]

Figure 6.18 – Preliminary results for NRU 207 smoothed AWS pressure buildup test data. Matched on the type curve for a well with a finite conductivity vertical fracture in an infinite-acting homogeneous reservoir.
Type Curve Match Results for NRU 207 – Raw Memory Gauge Data

The data were matched on the type curve\textsuperscript{114} for a well with a finite conductivity vertical fracture with wellbore storage effects. We note that the calculations and results are identical for the pressure integral data. The preliminary type curve match is shown in Fig. 6.19.

Matching Parameters: $C_{Df} = 0.1$, $C_{Df} = 1 \times 10^1$

\begin{align*}
[t_D/C_{Df}]_{MP} &= 1.0 & [\Delta t]_{MP} &= 9.5 \text{ hrs} \\
[p_{wD}]_{MP} &= 1.0 & [\Delta p]_{MP} &= 900.0 \text{ psi}
\end{align*}

**Pressure Analysis**

\begin{align*}
k_o &= 0.027 \text{ md} \\
x_f &= 27.1 \text{ feet}
\end{align*}

**Permeability**

Using the match points to solve for the effective oil permeability, we obtain:

\[
k_o = 141.2 \frac{(12 \text{ STB/day})(1.25 \text{ RB/STB})(2.037 \text{ cp})}{(179 \text{ ft})} \left[\frac{1}{900}\right] = 0.027 \text{ md} .
\]

**Fracture Half-Length**

Solving for the fracture half-length, $x_f$, we obtain:

\[
x_f = 0.01624 \sqrt{\frac{0.027 \text{ md}}{(0.065)(2.037 \text{ cp})(10 \times 10^{-6} \text{ psi}^{-1}) \left[\frac{1}{0.1}\right] \left[\frac{9.5}{1.0}\right]}} = 22.6 \text{ feet} .
\]
Figure 6.19 – Preliminary results for NRU 207 memory gauge pressure buildup test data. Matched on the type curve for a well with a finite conductivity vertical fracture in an infinite-acting homogeneous reservoir.

Optimized Final Solutions from Simulation – NRU 207 (Fig. 6.20)

**Bottomhole Memory Gauge Data** *(Fractured Well Model)*

**Input:**
- \( C_{Df} = 0.1 \)
- \( k_o = 0.027 \) md
- \( x_f = 22.6 \) feet

**Output:**
- \( C_{Df} = 0.0109 \)
- \( k_o = 0.026 \) md
- \( x_f = 67.0 \) feet

**AWS Surface Data** *(Fractured Well Model)*

**Input:**
- \( C_{Df} = 0.09 \)
- \( k_o = 0.019 \) md
- \( x_f = 27.1 \) feet
Output:

\begin{align*}
C_{Df} & = 0.0153 \\
k_o & = 0.018 \text{ md} \\
x_f & = 64.1 \text{ feet}
\end{align*}

The difference in fracture half-length for the optimized results indicates that the initial match was performed on the wrong $C_{Df}$ stem. Optimization indicates that a better match is obtained on or near the $C_{Df} = 0.01$ stem rather than the 0.1 stem. The permeability calculation is unaffected.

Figure 6.20 – Final data match on log-log plot for NRU 207 pressure buildup test data (Jan. 1997). Matched using the model for a well with a finite conductivity vertical fracture in an infinite-acting homogeneous reservoir.
The average reservoir pressure estimates are shown in Fig. 6.21. The final results are summarized in Table 6.2.

![NRU 207 Pressure Buildup Data](image)

**Figure 6.21** – Average reservoir pressure estimates for raw AWS and bottom hole memory gauge pressure buildup data for NRU 207 using the equation for a rectangular hyperbola (RHM).

**Table 6.2 - Summary of results for well NRU 207.**

<table>
<thead>
<tr>
<th>$k_o$ (md)</th>
<th>$x_f$ (feet)</th>
<th>Raw Bottomhole Memory Data</th>
<th>Smoothed AWS Data</th>
<th>$wk_f$ (md-feet)</th>
<th>$p_{avg}$ @ 7,000' (psia)</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.026</td>
<td>67.0</td>
<td>-4.62</td>
<td>-4.58</td>
<td>2.18</td>
<td>2,145</td>
</tr>
<tr>
<td>0.018</td>
<td>64.1</td>
<td>-4.62</td>
<td>-4.58</td>
<td>2.87</td>
<td>2,887</td>
</tr>
</tbody>
</table>
Summary for NRU 207

We found that the AWS pressure buildup data analyses yielded fairly similar results to those obtained from the memory gauge analyses for formation flow characteristics (effective permeability, fracture half-length (or pseudoradial skin factor). Unfortunately, estimates for average reservoir pressure varied by 150 psi to 700 psi for the three wells analyzed.

Due to the low permeability of the Clear Fork Formation, it is not feasible to shut in producing wells long enough to see any boundary-dominated features from which accurate estimates of well drainage area or average reservoir pressure can be made. For this reason, the difference in the shut-in pressure measurements between the AWS system and bottomhole memory gauge does not condemn the use of stand-alone use of the AWS system. However, if the goal of the analyst is to obtain reservoir volume by increasing the length of the shut-in period, then bottom hole gauges should be utilized.

The difference in the character of the recorded pressure-time data (i.e., anomalies) between the AWS system and the bottom hole memory gauge was fairly significant for all three wells. The pressure-time profile was extremely different for well NRU 2703, as what appeared to be a changing wellbore storage (afterflow) or crossflow characteristic on the AWS data was not present in the memory gauge data. This is primarily due to difficulties encountered in trying to measure the height of the fluid column using acoustic techniques and the foaming tendencies of the Clear Fork oil.

Performing these data comparisons for the Clear Fork interval at the NRU is an extreme test for AWS technology. Because we are dealing with a 1,000-ft test interval, with individual layers possessing different flow characteristics and pressures, it is often difficult to interpret bottom hole memory gauge data, let alone surface-acquired AWS data. The AWS pressure buildup test can be performed for between one-half and one-third the cost of a test utilizing downhole gauge installation. If a number of pressure buildup tests are to be performed, AWS data acquisition is the most cost-effective technique available.
6.7 – Water Injection Well Surveillance

6.7.1 – Material Balance Decline Type Curve Analysis

In most mature reservoirs, long-term production and injection information may be the only data that are available for performance analysis. As was discussed in Chapter V, we can utilize material balance decline type curve analysis to determine injectable water volumes, re-pressuring trends and reservoir flow characteristics for water injection wells. In Chapter V, we found that these techniques could be applied to converted producers in order to monitor the change in fracture half-length due to long-term water injection above the parting pressure of the reservoir.

These methodologies are not adversely affected by the presence of variable pressures and rates during injection. We can utilize decline type curve analysis to evaluate a well’s entire injection history and not just the steady-state or pseudosteady-state flow periods considered by simple graphical methods.

The graphical techniques (i.e., Hall\textsuperscript{100} and Hearn\textsuperscript{105} plots) available for the evaluation of injection well performance consider the remediation of a physical problem (pore plugging, scaling and water channeling), or yield extremely qualitative results for the evaluation of waterflood performance. These methods can produce results that are often misleading or difficult to interpret. They should be utilized to complement our surveillance studies rather than being used as a stand-alone tool.

We developed a decline type curve for the evaluation of long-term injection data for wells having an infinite-conductivity vertical fracture in a bounded circular reservoir (Fig. 6.22). This case was considered since most of the wells we are analyzing (and most injection wells in low permeability carbonate reservoirs) have been hydraulically-fractured during completion, or fractured as a result of long-term water injection at pressures near or above the parting pressure of the reservoir.
Figure 6.22 – Fetkovich-McCray type curves for a well with an infinite-conductivity fracture centered in a bounded circular reservoir.

In a review from Chapter V, we know that decline type curve analyses performed on long-term water injection data will yield:

- In-place fluid volumes
  - Total system volume for injection, $W_{tot}$
  - Injectable water at current conditions, $W_{i,mov}$
  - Reservoir "injection" area, $A$

- Reservoir properties
  - Fracture half-length, $x_f$
  - Effective water permeability, $k_w$

These results have been utilized to perform the following tasks:

- Estimate waterflood efficiency
- Identify individual well problems requiring remediation
- Construct maps of reservoir injection potential and hydraulically-induced fracturing
- Estimate waterflood-induced fracturing and "adjust" fluid flow models
Pressure transient data analyses indicated that previous limited-entry fracture treatments over extremely large intervals appear to have resulted in the initiation of several short, parallel ("pancake") hydraulic fractures in the producing wells. The typical formation flow characteristics of a producing well at NRU are shown in Fig. 6.23. The decline type curve match yielded an effective oil permeability, $k_o$, of approximately 0.048 md, and a pseudo-radial skin factor of –4.81 ($x_f = 81$ feet). When examining these results, we must remember that we are evaluating production data from all three productive Clear Fork intervals (LCF, MCF and UCF) simultaneously, therefore it is difficult to quantitatively evaluate individual fracture treatments unless the production data can be segregated by zone.

![Figure 6.23 – Match of production data for NRU 3510 on the Fetkovich-McCray type curve for a well with an infinite-conductivity fracture centered in a bounded circular reservoir.](image-url)
We now compare the results of our production data analyses with those obtained from a pressure buildup test recorded before the well was converted to water injection, shown in Fig. 6.24.

![Figure 6.24](image)

The pressure buildup test results indicated that the well was slightly stimulated ($s_{pr} = -2.77$) with an effective oil permeability of 0.22 md. We note that the results of a transient test performed at a specific point in time (pressure buildup) are somewhat different than those obtained from the analysis of long-term production data ($k_o = 0.05$).
md, \( s_{pr} = -4.81 \)). This is a function of both the periods of time being considered and our inability to account for the change in fluid properties over time. It is obvious that the well's completion efficiency deteriorated prior to its conversion. From a qualitative standpoint, both the pressure transient results and production data analysis results seem to indicate that the well was only marginally stimulated as a producer.

When we performed decline type curve analysis on the initial long-term water injection data for the well after conversion, we found that the flow characteristics, specifically the fracture half-length, had changed significantly. Analysis of long-term water injection data indicated that the fracture might be propagating due to excessive injection pressure. The effective permeability to water was 0.137 md and the fracture half-length had increased to 259 feet \( (s_{pr} = -5.97) \), as shown in Fig. 6.25.

![Figure 6.25 – Match of water injection data for NRU 3510 on the Fetkovich-McCray type curve for a well with an infinite-conductivity fracture centered in a bounded circular reservoir.](image)
A pressure falloff test was performed on this well in 1994. It confirmed the results of the long-term water injection data analysis and indicated that the fracture was propagating as the result of water injection. The problem may be more severe than what was indicated by injection data analysis. The fracture half-length was approaching 500 feet, as shown in Fig. 6.26, below. We note that the bottomhole injection pressure prior to shut-in was 4,722.5 psia, which is at or above the reservoir parting pressure.

![Figure 6.26 – Final data match on log-log plot for NRU 3510(WI) pressure falloff test data (Aug. 1994). Matched using the model for a well with a finite conductivity vertical fracture in an infinite-acting homogeneous reservoir.](image-url)
Since injection wells are configured on east-west rows that coincide with the preferential fracture orientation, we must continually monitor injection well data to prevent well-to-well communication and a loss of "sweep" efficiency. Fig. 6.27 illustrates the use of decline type curve analyses to monitor hydraulic fracture propagation as the result of long-term water injection. In this way, "problem" areas can be selected for remediation.

Summary spreadsheets and individual type curve matches illustrating the results of decline type curve matches on all 20-acre injection wells are given in Appendix M. Pressure falloff test analyses are presented in Appendix P.

It is apparent that we can utilize decline type curve analysis to monitor injection well behavior, however, we require additional surveillance tools to further aid in our field
diagnoses. Since it will not be cost-effective to perform a great number of pressure transient tests, we consider the use of the Hall plots, step-rate test data and injection water quality monitoring as additional water injection well surveillance tools. We will also utilize cased-hole well logs, qualitative pressure transient analysis and formation pressure tests (FT) surveys on new wells to quantify injector-producer conformance. We will discuss the use of multiple surveillance tools in the case study section of this chapter, in which we combine analysis techniques to identify problems requiring remediation.

6.7.2 – Hall Plots

In order to maintain injectivity at the NRU, it is usually necessary to inject at bottomhole pressures greater than the fracture or "parting" pressure of the reservoir. Changes in well behavior, such as pore plugging or fracturing, are monitored using Hall plots.

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

Fig. 6.28 is a schematic of injection well characteristics that can be identified using Hall plots. We note that linear trends that 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 possible fracture propagation due to injection at a pressure greater than the formation parting pressure.
Figure 6.28 – Hall diagnostic plot.\textsuperscript{101}

An example of possible water injection at pressures above the parting pressure of the formation and water channeling is shown in Fig. 6.29. The Hall plot for NRU 403 shows an increase in slope that is indicative of formation damage (pore plugging), followed by a decrease in slope that is characteristic fracturing out-of-zone.

At the NRU, regular step-rate tests are recorded in order to set surface injection pressures. If a well has formation damage that is not immediately apparent, then the step-rate test will obviously indicate that a higher injection pressure is required. When the injection pressure is eventually increased above the reservoir parting pressure, formation fracturing will result. Since the parting pressure of the reservoir increases as more water is injected (due to pore pressure change), it is extremely important that regular surveillance is performed on all injection wells using long-term injection data.
6.7.3 – Step-Rate Tests

Since the start of water injection at the NRU, step-rate tests have been used to set surface injection pressures in an attempt to maximize injection rates while trying to prevent formation fracturing. This tactic is common among waterflood operators of low permeability carbonate reservoirs in the Permian Basin. Unfortunately, balancing injection rates and pressures to prevent fracturing has proved extremely difficult at the NRU.

The analysis of step-rate data collected between 1988 and 1996 for eighty-five NRU injection wells indicated that the estimated formation parting pressure had been steadily increasing from year to year due to increased pore pressure resulting from continuous water injection. We feel that after reservoir fill-up has occurred, the utility of step-rate tests is limited since the reservoir pore pressure has been increased to the point where it is difficult to accurately estimate the true parting pressure of the formation.
It is obvious that 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 plots, injection well decline type curve analyses and pressure falloff test analyses to determine not only the optimum injection pressure for individual wells, but also to identify problems affecting individual injection well efficiency.

Fig. 6.30 illustrates the increase in the average reservoir parting pressure due to continuous water injection.

Figure 6.30 – Individual well and average reservoir parting pressure trends from step-rate tests performed at the NRU.
6.7.4 – Injection Water Quality Monitoring

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. A cost-effective water quality surveillance program was initiated to identify and resolve potential problems. At the same time, an injection well workover program was implemented to remediate the scaling problems in individual wells. The entire water quality program is outlined in detail in Ref. 120. At present, quarterly tests are conducted on individual wells, and field-wide tests are conducted biannually.

At the NRU, both fresh (Ogallala aquifer) and produced water are used for injection. Both waters must 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 in order to identify potential problems.

- Physical properties
  - Total dissolved solids
  - pH
  - Particle size distribution
- Filtration
  - Suspended solids
  - Acid solubles
  - Hydrocarbon solubles
- Dissolved Gases
  - Oxygen
  - Carbon dioxide
  - Hydrogen sulfide
- Bacteria
  - Anaerobes
  - Aerobes
  - Dissolved iron
Although the injection waters were found to be compatible, both the produced and fresh waters were found to have substantial plugging and scaling tendencies. The water handling facilities were redesigned and programs were implemented to: 1) prevent the formation of solids; and, 2) remove all remaining solids from the system.

6.8 – Reservoir Conformance Studies

Previous completion methodologies resulted in the perforation of the entire Clear Fork interval without regard to rock quality. By utilizing an integrated reservoir description, more emphasis can be placed on maintaining conformance between producers and injectors across the primary "pay" quality intervals of the reservoir that effectively contribute to oil production. This integrated description should include a detailed geologic description, core-log modeling, long-term production and injection data analyses, pressure transient analyses and conformance analyses.

In addition, efforts must 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. By targeting the reservoir's "sweet spots," completion and stimulation designs can be optimized and costs can be reduced. The surveillance tools that we have utilized to aid in the study of reservoir conformance at the NRU are listed below.

6.8.1 – Interwell Tracer Surveys

The estimation of the preferential flow direction from interwell tracer surveys can be used to guide subsequent reservoir flow simulation, characterization and placement of infill wells. We performed interwell tracer surveys in the areas of the unit in which the nominal well spacing has been reduced to 10 acres in order to determine the directional flow trends and the degree of anisotropy at NRU.

The results were rather disappointing and somewhat inconclusive. What we did learn is that tracer breakthrough times for wells on 10-acre spacing ($r_e = 372$ feet for circular reservoir) were on the order of ten months. In addition, tracer acquisition was often made several patterns away with no preferential flow direction. This indicates that the
reservoir flow processes can not be described in a simple and straightforward manner, and confirms much of what we find when we attempt to correlate injector and producer performance within individual five-spot patterns. We often do not see a great deal of conformance between wells in the same five-spot. In fact, many producing wells appear to be supported by injection wells two or three patterns away.

This can be explained to a certain degree by our belief that waterflooding operations in heterogeneous, low permeability carbonate formations operate under more of a pressure maintenance mechanism than a waterflood "sweep" mechanism (Fig. 6.31). This also accounts for the fact that tracer material placed in an injection well is not necessarily seen at nearby producing wells, since it is likely carried along the east-west injector rows that coincide with the regional fracture azimuth.

Figure 6.31 – Waterflood recovery mechanisms.
6.8.2 – Cased-Hole Well Log Surveys

6.8.2.1 – Injection Profiles

Injection-production well conformance is achieved when the open (unplugged) perforations for injection wells coincide with the open (unplugged) perforations for offset producing wells in all "pay" quality intervals. To test the conformance at NRU in a cursory manner, we examined all available injection (radioactive tracer intensity and velocity) profile and temperature survey information.

The injection profiles 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 continuous between injectors and producers, and by identifying any potential "thief" zones that might exist in the reservoir. We use radioactive tracer logs in an effort to monitor the preferential movement of fluid in the near-wellbore regions of the injection wells (intrawell). Radioactive tracer surveys yield the best quantitative results for injection profiling work, can be recorded fairly inexpensively on a periodic basis, and should be one of the main components of any reservoir surveillance plan.

We illustrate the use of the injection profile as a surveillance tool with some field examples. NRU 4201 is a 20-acre producing well situated in the southwest corner of the NRU, between water injection wells NRU 1601 and NRU 2901, as shown in Fig. 6.32.

Figure 6.32 – Location of NRU 4201.
Production from NRU 4201 is injection supported not only by the two adjacent wells, but also by NRU wells 3307, 3308 and 3005 to the north and NRU 4001 to the south. Injection profile information from 1996 surveys for NRU 1601 and NRU 2901 are provided in Figs. 6.33 – 6.34, below.

Figure 6.33 – 1996 injection and temperature profiles for NRU 1601(WI).
We see that the majority of the water injection from the two supporting wells is to the Upper Clear Fork (UCF) section above 6,450 feet, with moderate support for the Lower Clear Fork (LCF) and no Middle Clear Fork (MCF) injection support. When we examine a water saturation profile for the UCF in NRU 4201 (Fig. 6.35), which includes the calculated initial water saturation (1987) and the 1995 water saturation from a thermal neutron decay log (TND, discussed below), we see that the most productive layers in this interval remain unswept.
In addition, updated water saturations for NRU 4201 indicate no injection support in the MCF and moderate support in the LCF, which is what we would expect from the injection profile results. So we must ask, which wells is the UCF injection from NRU 1601 and 2901 supporting? Since we have no other cased-hole water saturation information in the area, we must examine historical production performance. Production plots for NRU 4201 and nearby 20-acre producers, NRU 4203 and NRU 1604, are provided in Figs. 6.36 – 6.38.
Figure 6.36 – Estimated ultimate recovery for NRU 4201.

Figure 6.37 – Estimated ultimate recovery for NRU 1604.
Although inconclusive without additional injection profile and water saturation information, it appears that producing wells to the north and south of NRU 4201 are receiving better injection support. This may support the findings of the interwell tracer results – producing wells do not always receive good support from near-offset injectors. This may be partly due to the pressure maintenance mechanism described above and to local changes in reservoir quality that can be determined from our core-log modeling work or long-term production data analyses.

The original oil-in-place estimates from material balance decline type curve analyses for NRU 1604 and NRU 4203 were between 1.0 MMSTB and 1.2 MMSTB, while the estimate for NRU 4201 was less than 0.5 MMSTB. Core-log modeling results indicated that NRU 4201 had only 64 feet of net pay, while NRU 1604 and NRU 4203 had 150 – 200 feet off effective net pay. It would appear that in this case, the north and south offset producers have higher reservoir quality, and are therefore more responsive to offset water injection.

6.8.2.2 – Thermal Neutron Decay Logs

While the costs associated with recording a great number of thermal decay time logs (TND) may eliminate its use for most operators, the periodic utilization of TND logs is
an extremely useful tool for monitoring water saturations and preferential fluid movement in the near-wellbore regions of producing wells. These data will be collected to form a "baseline" data set for future TND logging surveys to monitor fluid saturation changes and can be used in conjunction with injection profiling at injection wells in order to identify areas of bypassed production. These data can also be used as an additional input parameter (updated saturation) for reservoir flow simulation calibration and history matching.

Previous reservoir surveillance in Clear Fork waterfloods has not included the use of TND logs because they did not perform well in the low porosity and low salinity conditions that exist in many active waterfloods of low permeability carbonate reservoirs. Recent advances in tool design have produced tools that work well in both fairly fresh formation water and low porosity formations.

We provide an additional field example for a 20-acre producing well, NRU 3527, to further demonstrate the utility of the TND log as a surveillance tool. NRU 3527 is located in the northeast section of the NRU, which is an area with the highest reservoir quality within the unit. The well's location with respect to nearby injection wells is shown in Fig. 6.39. 1997 TND water saturation plots for the UCF, MCF and LCF are given in Figs. 6.40 – 6.42.
Figure 6.40 – Comparison of original open-hole and 1997 TND water saturations for the Upper Clear Fork – NRU 3527.
Figure 6.41 – Comparison of original open-hole and 1997 TND water saturations for the Middle Clear Fork – NRU 3527.
As for the case of NRU 4201 (regardless of relative reservoir quality issues), we see that the Upper Clear Fork appears to receive the best injection support, while the Lower Clear Fork receives moderate support and the Middle Clear Fork receives poor support.

Injection profiles were recorded on two offset injection wells, NRU 3511 and NRU 3516. We see from the profile for NRU 3511 (Fig. 6.43) that this well exhibits the
optimum "stair-step" injection profile from which it appears that all intervals are receiving fairly good support. However, the profile for NRU 3516 (Fig. 6.44) indicates that all water is being injected into the top of the Upper Clear Fork and therefore the MCF and LCF are receiving no injection support from this well.

Whether these two injection wells directly support production from NRU 3527 is a problem that would require additional data and further study, however, it appears that we have identified a unit-wide problem associated with waterflooding the MCF interval. This apparent problem may be confirmed by utilizing an addition surveillance tool – Formation Test pressure data from newly drilled wells.

Figure 6.43 – 1996 injection and temperature profiles for NRU 3511(WI).
6.8.3 – Formation Pressure Tests

The Formation Test tool (FT) provides individual layer pressures and qualitative (more accurate for higher permeability formations) estimates of permeability that can be used to better understand the way in which particular intervals deplete (or re-pressure) across a reservoir. This can be used not only as a formation evaluation tool, but also as a reservoir development and reservoir conformance tool.\textsuperscript{121}

The vertical pressure profile can be utilized for reservoir simulation history matching, material balance calculations, hydraulic fracture design and to plan and implement waterflood operations by evaluating the degree of lateral pressure communication between wells. The open-hole formation pressure test information will probably be the highest quality pressure data obtained during an individual well’s lifetime. Subsequent pressure transient tests yield volumetrically-averaged results, usually over large vertical intervals, which are useful for evaluating completions and/or stimulations as well as
general reservoir pressure trends, but do not provide the type of data that is easily correlated with foot-by-foot core and well log data.

The FT tool is a very useful development drilling survey because it allows us to see the manner in which the reservoir is depleting during primary production, or re-pressuring during secondary recovery operations. Each individual well's vertical pressure profile is directly influenced by production (or injection) in adjacent wells. Using these data, we can identify zones that appear to be laterally continuous and target these intervals for secondary recovery. We can also identify intervals that may be discontinuous or act as reservoir barriers, and avoid attempting to flood zones that will not accept injected fluid.

6.8.3.1 – Data Acquisition

Acquiring FT data in a low permeability, heterogeneous formation such as the Clear Fork, is extremely difficult. We utilized a low-force snorkel, a slow-drawdown choke with a very small pretest chamber (5 cc) and a very soft packer pad (60 durometer) in order to have the best chance of obtaining valid layer pressures. In addition, it is important to "mud-up" prior to reaching total depth to ensure the presence of a "stable" mudcake prior to well logging. Most operators will drill carbonate formations with brine water, and no mudcake will be formed. Approximately 200 feet above total depth, we increased fluid viscosity using a gel-starch mixture to induce some wall cake formation.

Taking the these precautions, we were still only able to obtain valid pressures on about 15 – 20 percent of the tool sets, however, the data we did obtain proved essential in defining the vertical continuity within the reservoir section. If more attention was given to increasing the mud's wall cake building capacity prior to well logging, we feel we would have achieved better results. All available FT pressure-time data is given in Appendix Q.

When testing a low permeability carbonate, we will see a fairly rapid drawdown period followed by a rather long buildup period. It will often be necessary to "sit" on the formation for 30 to 40 minutes in order to obtain a good estimate of layer pressure. This is of course why we do not attempt to take fluid samples in these low permeability
intervals, as the time increment required to obtain a valid fluid sample would be on the order of days, not hours. Obviously, the highest permeability intervals will have a tendency to build mudcake and should be the test targets in these low permeability environments. From a diagnostic standpoint, intervals that test tight, or in which a good packer seat is difficult to obtain, are usually not productive intervals.

6.8.3.2 – Vertical Pressure Profiles

From the diagnostic plot below (Fig. 6.45), we can see that the nature (homogeneous or heterogeneous) of any particular reservoir can be determined from its vertical pressure profile. Obviously, homogeneous formations exhibit much more uniform pressure profiles compared to heterogeneous formations.

Figure 6.45 – Idealized vertical pressure profiles for homogenous and heterogeneous reservoirs.
Northern Unit Area

Fig. 6.46 shows FT data from wells in an area of the unit with relatively high reservoir quality. The well locations for this area are shown in Fig. 6.39, above. Even in the most prolific producing area of the NRU, we see definite indications of heterogeneous reservoir behavior.

The Lower Clear Fork is typically the most permeable interval within the reservoir section. Unfortunately, due to the fact that the entire productive interval is flooded together, this interval often receives most of the injected water due to its relatively higher permeability.

The Middle Clear Fork possesses a greater degree of lateral discontinuity (differing pressures) and receives greatly different degrees of waterflood support from well to well. The Middle Clear Fork has produced a significant amount of oil in this area of the unit during primary production, but is not currently being effectively waterflooded. This would be an interval that could be more effectively drained by targeting water injection (see NRU 3527 example, above) or by reducing well spacing. We note that two 10-acre injection wells have been added in the area and were specifically completed in order to target the Middle Clear Fork.

The Upper Clear Fork takes a large water volume because it has several small stringers associated with an interval of solution collapse breccia with open natural fractures (see Chapter II) and not necessarily because it is continuous between injection and producing wells. The UCF is actually more heterogeneous than the MCF, which actually contains larger brecciated intervals, however, the UCF naturally fractured zone is higher in section, meaning that it will fracture more easily than the MCF.

Obviously, these permeable streaks cause a major conformance problem. Injection wells in this area of the unit need to be re-configured in order to provide better support the MCF section, which has significant potential for additional secondary production.
**Southern Unit Area**

Fig. 6.47 shows the location of the survey wells in Section 327 of the NRU. Fig. 6.48 contains the pressure profile data for these wells, which are in an area of moderate to poor reservoir quality. We had difficulty obtaining good FT packer seats for wells in this area due to the relatively low reservoir permeability (i.e., lack of wall cake).
In this area of the unit, we see from Fig. 6.48 that the Upper Clear Fork appears to receive moderate waterflood support, the Middle Clear Fork receives good to excessive waterflood support and the Lower Clear Fork receives varying degrees of pressure support from well to well.

As stated above, the Upper Clear Fork section takes a large water volume due to the naturally fractured interval above 6,200 feet. The Middle Clear Fork interval takes a large water volume because it has the highest reservoir quality in this area of the unit (south central), including a large brecciated interval below 6,800 feet. The Lower Clear Fork section has relatively lower reservoir quality than in most areas of the unit, and therefore its under-support is a rock quality issue rather than a conformance issue.
When we examine injection profiles (Figs. 6.49 – 6.50) for near-offset injection wells to the north and south of the survey wells, we see that the majority of the injected water does appear to be going in to the UCF and MCF intervals. Whether this is due to conformance issues, reservoir quality changes or operational problems is still open to interpretation.
Figure 6.49 – 1996 injection and temperature profiles for NRU 1591(WI).

Figure 6.50 – 1996 injection and temperature profiles for NRU 3004(WI).
A thermal neutron decay log run in 1997 for well NRU 1509 is shown in Fig. 6.51. This survey was performed less than one year after the well was drilled and completed. The results confirm the FT pressure data shown in Fig. 6.48. We see that the Lower Clear Fork has received excessive injection support in the area of this well and most of the porous and permeable intervals appear to be swept or drained.

Figure 6.51 – Comparison of original open-hole and 1997 TND water saturations for the Lower Clear Fork – NRU 1509.

Hall plots for all surrounding injection wells indicate periods of severe pore plugging followed by fracture extension and possible interwell communication. Therefore, even
though the high reservoir quality intervals are currently receiving injection support in this area of the unit, there are major conformance issues that must be addressed.

6.8.3.3 – Pore Pressure Estimation

A major requirement in most reservoirs is the estimation of individual layer pore pressures. These data are required to estimate both the fracture closure and initiation pressures for hydraulic fracture design work. Pore pressure can vary greatly due to differential depletion (or uneven waterflood support). We utilized the pressure buildups from approximately fifty tool sets to estimate reservoir pressure using the RHM technique. A pore pressure gradient was then generated for the Clear Fork section. The results are shown in Fig. 6.52, below. The results indicate that the reservoir is slightly over-pressured as the result of thirteen years of continuous water injection.

![NRU pore pressure gradient estimate from FT pressure data on seven unit wells in Sections 327, 329 and 362.](image)
Fracture closure pressure (FCP) and fracture initiation pressure (FIP) are calculated for each zone of every well utilizing available open-hole log data (Sonic, Bulk Density and FT data). The following relationships can be used:

\[
\text{FIP} = \text{Depth} \times \left\{ 2 \left[ \frac{\nu}{1-\nu} (g_{ob} - \alpha g_{pore}) \right] + \alpha g_{pore} + \sigma_{ext} \right\} \quad \text{.......................... (6.3)}
\]

\[
\text{Biot’s Constant} = \alpha = 1 - \frac{K}{K_{ma}} \quad \text{................................................................. (6.4)}
\]

\[
\text{FCP, } \sigma_x = \text{Depth} \times \left\{ \left[ \frac{\nu}{1-\nu} \right] \left( g_{ob} - \alpha g_{pore} \right) \right\} + g_{pore} \quad \text{.......................... (6.5)}
\]

Where \( g_{ob} \) and \( g_{pore} \) are the overburden pressure gradient and pore pressure gradient (psi/ft), respectively.

After fracture initiation, Biot’s constant in the direction of least principal stress (horizontal, in this case) is no longer a function of rock compressibility and may be assumed to be equal to 1. Therefore, it is not included in the expression for closure pressure. The external stress, \( \sigma_{ext} \), accounts for any externally applied stresses (tectonic, thermal, etc.), which are negligible at the NRU. Poisson ratio \( \nu \), Young's modulus, \( E \), and bulk modulus, \( K \), (10^6 psi) can be estimated using sonic and bulk density data. Hydraulic fracture stimulation design will be discussed in greater detail in Chapter VII.

6.8.4 – Qualitative Pressure Transient Data Analysis

Raw pressure-time data from pressure buildup and falloff tests can also be used as a qualitative reservoir continuity indicator to better define interwell conformance. The character of the pressure-time trend (as shown in Fig. 6.53) from pressure buildups recorded on NRU wells 2227, 2703 and 3208 indicates the differences in injection support for individual layers, and hence, reservoir continuity within the Clear Fork.

We note that the shape of the \( \Delta p \) versus \( t \) plot is also a reservoir quality indicator. An erratic pressure increase is indicative of many different non-communicating layers that
communicate at the wellbore. A smoother pressure-time trend represents a greater degree of reservoir homogeneity, if such a thing exists in the Clear Fork.

6.9 – Field Example: Combining Waterflood Surveillance Diagnostic Tools

We saw in the previous sections that several profile logs indicated that all injection water was going into one reservoir interval, specifically the Upper Clear Fork. When this occurs, there is a fairly good chance that an extensive fracture is being propagated between injection wells along the east-west preferential fracture orientation. This is a major conformance problem at the NRU.
As we have noted previously, almost all water injection wells at the NRU are converted producers. Previous pressure transient and production data analyses indicated that producing wells were marginally stimulated (i.e., no extensive hydraulic fractures). Several of the pressure falloff test analyses indicated that water injection wells were extensively hydraulically fractured and several injection wells appear to be in direct hydraulic communication. Surveillance tools, such as pressure transient analysis, long-term data analysis, Hall plots, step-rate tests and injection profiles do not always immediately identify injection well problems when used as stand-alone analysis techniques. However, if they are used in concert, it is rather easy to identify problem wells, as shown in the case study, below.

6.9.1 – Offset Injection Wells in Direct Hydraulic Communication

A map showing the location of injection wells NRU 301 and NRU 2601 is shown in Fig. 6.54, below.

![Map showing the location of injection wells NRU 301(WI) and NRU 2601(WI).](image_url)

Figure 6.54 – Location of wells NRU 301(WI) and NRU 2601(WI).
East Offset Injector – NRU 301(WI)

*Pressure Transient Analysis*

While running a pressure falloff survey on NRU 301(WI), we noticed that the pressure changed every time the rate and pressure cycled on the injection well one well location (approximately 1,320 feet) to the west, NRU 2601 (WI). This phenomenon is illustrated graphically in Figs. 6.55 and 6.56.

![Figure 6.55 – Data match on semilog plot for NRU 301(WI) pressure falloff test data (Aug. 1994).](image-url)
Figure 6.56 – Final data match on log-log plot for NRU 301(W1) pressure falloff test data (Aug. 1994). Matched using the model for a well with a finite conductivity vertical fracture in an infinite-acting homogeneous reservoir.

The pressure transient analysis is most likely invalid due to the fact that the majority of the test data is all wellbore storage, however, the pressure anomaly seems to show direct communication between NRU 301 and its west-offset injection well, NRU 2601. We now examine the results of our other surveillance diagnostics to check for direct hydraulic communication.
**Hall Plot**

As illustrated in Fig. 6.57, the Hall plot for NRU 301 indicated a period of severe pore plugging or scaling followed by what appears to be fracture extension or water channeling between wells.

![Hall plot for NRU 301(WI)](image)

Figure 6.57 – Hall plot for NRU 301(WI).

**Semilog Injection Rate and Cartesian Injection Pressure**

The semilog rate plot (Fig. 6.58) indicated a significant injection rate increase after a November 1992 well workover. An acid job was performed on the well at that time and it appears that a fracture or channel was opened between the two offset injectors.
Injectivity Factor ($q_w/Δp$) versus Cumulative Injection

The estimate of injectable water increased from 700 MSTBW to 1.45 MMSTBW after the 1992 workover. The well is now influencing a much larger area, as illustrated in Fig. 6.59, below.

Figure 6.58 – Injection rate and bottomhole injection pressure for NRU 301(WI).

Figure 6.59 – Plot of injectivity factor (pressure drop normalized rate) versus cumulative water injected for NRU 301(WI).
Material Balance Decline Type Curve Matches

Prior to the 1992 workover, NRU 301 had a fracture half-length of only 78 feet and an effective permeability to water of 0.154 md based on the analysis of long-term injection rate and pressure data, as shown in Fig. 6.60, below. This plot indicates that there was already a deviation from material balance behavior since the data falls of the harmonic \((b = 1)\) stem in the boundary-dominated flow region. This infers that the wells were already in communication.

After the 1992 acid job, the apparent fracture half-length had tripled and the effective water permeability had doubled, as shown in Fig. 6.61. It appears that the acid job may have actually been an acid frac.
Figure 6.61 – Match of post-workover injection data for NRU 301(WI) on the type curve for a well with an infinite-conductivity fracture centered in a bounded circular reservoir.

West Offset Injector – NRU 2601(WI)

Hall Plot

As illustrated in Fig. 6.62, the Hall plot for NRU 2601 indicates severe pore plugging for a significant time period. This response is actually caused by pressure communication with NRU 301. The wells must fight each other for an area of influence, and it appears that NRU 301 is the dominant well. The 1996 injection profile for NRU 2601 (Fig. 6.63) indicates that the well can not maintain any appreciable injection rate.
Figure 6.62 – Hall plot for NRU 2601(WI).

Figure 6.63 – 1996 injection and temperature profiles for NRU 2601(WI).
**Semilog Injection Rate and Cartesian Injection Pressure**

The Cartesian rate plot (Fig. 6.64) indicated a significant pressure increase after the November 1992 workover on NRU 301.

![Figure 6.64 – Injection rate and bottomhole injection pressure for NRU 2601(WI).](image)

Injectivity Factor versus Cumulative Injection

The initial estimate for injectable water of 550 MSTBW will not be reached under current operating conditions, as shown in Fig. 6.65. The injection rate for NRU 2601 has essentially been reduced to zero.
Material Balance Decline Type Curve Match

Prior to the workover on NRU 301, NRU 2601 had a fairly stable injection trend and similar flow characteristics to its near offset. The fracture half-length was 165 feet and the effective water permeability was 0.129 md based on the analysis of long-term injection rate and pressure data, as shown in Fig. 6.66 below. There is no evidence of deviation from material balance behavior. No analysis can be performed after the end of 1992, since the well has never achieved a stabilized injection rate in after that time.
The final, easiest and perhaps most definitive proof of direct hydraulic communication between these wells can be seen by simply plotting injection rate and injection pressure for both wells together, as shown in Fig. 6.67 – 6.68 below.
Figure 6.67 – Semilog plot of injection rates for communicating wells.

Figure 6.68 – Cartesian plot of bottomhole injection pressures for communicating wells.
6.10 – Summary

Selective injection into a single interval is not possible without major expenditure, since the entire Clear Fork section is opened in all wells. Due to reservoir permeability constraints, these wells must be fracture-stimulated in order for them to take injection water. However, after water injection is initiated, the bottomhole injection pressure must be increased regularly to maintain injectivity. As a result, pre-existing fractures are extended to the point where offset wells are in direct communication.

A 10-acre infill injection well, NRU 3019(WI), was drilled and completed offset to NRU 3004(WI) in 1998. After fracture stimulation, it was found that the well was in direct hydraulic communication with NRU 3004 in the Upper Clear Fork. The injection profile for NRU 3004 is shown in Fig. 6.50. The Hall plot, a 1994 pressure falloff test and long-term injection data analysis performed on the well are shown in Figs. 6.69 – 6.71.

Figure 6.69 – Hall plot for NRU 3004(WI).
Figure 6.70 – Final data match on log-log plot for NRU 3004(WI) pressure falloff test data (Aug. 1994). Matched using the model for a well with a finite conductivity vertical fracture in an infinite-acting homogeneous reservoir.
All these analyses hint at the presence of a communication problem between wells in this area of the unit. NRU 3019 should not have been completed in the Upper Clear Fork, and in fact, should not have been drilled offsetting NRU 3004.

We have found that by combining available injection profile data, water saturation monitoring techniques, FT pressure data, pressure transient data and the analysis of long-term production and injection data that we can form a very effective reservoir surveillance tool. We can now apply this suite of analysis tools to improve injection-to-production well conformance at the NRU and to aid in the optimization of completion and stimulation techniques that will be discussed in Chapter VII.