A CARBONATE RESERVOIR MODEL FOR PETERSILIE FIELD IN NESS COUNTY, KANSAS: EFFECTIVE WATERFLOODING IN THE MISSISSIPPIAN SYSTEM

by

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Abstract

The Petersilie oil field in Ness County, Kansas produces out of the Mississippian System, a reservoir composed mainly of shallow water carbonates, at depths of around 4375 ft (1334 m). The lithology of the field ranges from limestone to dolomite, to interlaminated limestone-dolomite beds. Chert is commonly found throughout. Petersilie field lies to the west of the Central Kansas Uplift, and to the east of the Hugoton Embayment. The field saw much drilling activity in the 1960's, when it reached a production peak of nearly 378,000 barrels of oil per year. Production declined swiftly after that until the late 1990's, when waterflooding was successfully employed.

In this study, a reservoir model was produced for the Mississippian as it occurs in Petersilie field using the Department of Energy's EdBOAST reservoir modeling software, with the intent of providing a reference for future drilling activity in the Mississippian and determining reservoir characteristics that may have contributed to the effectiveness of waterflooding in this area. The reservoir model was checked by simulation with a companion reservoir simulator program, BOAST 98. Subsequent comparison of simulated and actual oil production curves demonstrates the reliability of well log and drill stem test data for the field and proves the reservoir model to be a good fit for the Mississippian in Petersilie.

Production curve analysis of Petersilie indicates the field was an ideal candidate for waterflooding because it has a solution-gas drive mechanism. As the field approached depletion from primary recovery, oil saturations remained high. Petersilie also exhibits high porosity and good permeability. The BOAST software was found to be an effective and inexpensive means for understanding the Mississippian reservoir in central to south-central Kansas. It was determined that BOAST has potential for practical use by smaller independent oil companies targeting the Mississippian in Kansas.

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Dedication

This work is dedicated to my family, near and far. I'll never be able to thank you all enough for loving and supporting me through this journey. You made me who I am. I know that no matter where Trent and I are in the world, we'll always have a home with you.

Chapter 1 - Introduction

Petroleum has been produced in Ness County, Kansas in the United States as early as the 1920's. At that time, fields were discovered and oil was struck using mainly subsurface mapping methods and random drilling. Production was focused in the east, but as time progressed, oil exploration continued to reach westwards in Kansas, influenced by the spreading knowledge of the existence of the Nemaha Uplift and later, the discovery of the Central Kansas Uplift. From 1860, the start of drilling for oil in the state of Kansas, to 1956, the year that oil production in Kansas reached a peak of 124.7 million barrels per year, virtually all of the state's large oil fields were discovered (Newell, et. al., 1987). In less than a century after the discovery of oil in Kansas, the petroleum industry was booming, and the technology and methodology employed in the hunt for oil mirrored its meteoric rise.

Besides subsurface mapping, geologists in Kansas were now using shallow core-hole drilling and geophysical techniques such as reflection seismology. Smaller oil fields were still being discovered. Yet after 1956, oil production began to decline as swiftly as it had risen. A smaller peak of 75.7 million barrels per year was reached in the mid-1980's, reflecting an increase in exploration and production of the southwestern part of the state during the 1970's. However, the overall trend of decline continued until more recent times, when a national shift in drilling from vertical to horizontal prevailed. Hydraulic fracturing and secondary and tertiary recovery methods began to be widely employed in Kansas (Kansas oil, 2014). The state's petroleum industry experienced a revitalization, with annual production increased from a low of approximately 33 million barrels per year up to over 45 million barrels per year and growing (Newell, et. al., 1987).

One of the secondary recovery techniques that has been successfully employed in the Petersilie oil field of Ness County is waterflooding. Waterflooding is a well-known and widely used technique that involves the injection of water into the reservoir to maintain or increase reservoir pressure and encourage oil to move towards producing wells to be extracted. The water injected is usually a brine, and can sometimes be recycled from the water which is extracted from the reservoir during oil production. Waterflooding, when applied appropriately, can improve reservoir productivity by up to 20% (Water injection, 2014). Before the utilization of this technique, Petersilie oil field, like many southwestern Kansas fields, had begun a trend of decline in production. Its peak production had occurred in 1968, reaching over 377,000 barrels per year, but had fallen quickly after that (Petersilie, 2013). Petersilie produces out of the Mississippian System and the Marmaton Group, with the Mississippian being the primary producer and the focus of this work. The Mississippian System is predominantly comprised of shallow water carbonates (limestones and dolomites) that are bounded by shales (Goebel, 1968). In the late 1990's, some of the Petersilie wells were converted to water injection wells (Petersilie, 2013). It is one of the few fields in Ness County that have been successfully waterflooded. One of the key questions this work strives to answer is, "what factors may have led to waterflooding being an effective secondary recovery method in the Mississippian in Petersilie field?" Constructing a comprehensive reservoir model for the Mississippian System as it appears in this region will not only provide a reference for future drilling operations in the area, but also insight into why waterflooding was successful in the Petersilie field.

Distribution of Oil and Gas in Kansas

Petroleum production is an important part of the Kansas economy. The state is ranked thirteenth in production as of 2012 (Rankings, 2012). While production in Kansas began promisingly, with large fields discovered, inevitably the fields discovered in more recent times grew smaller, reflecting the state's exploration maturity. Currently, proven oil reserves in Kanas stand at about 370 million barrels of oil, with original oil in place estimated at 16.6 billion barrels (Newell et al. 1987). By employing secondary recovery methods, it has been concluded that about 2-3 billion barrels could be recovered (Ebanks, 1975). Of the total volume of produced and known reserves of oil in Kansas, Mississippian, Devonian, and Silurian rocks account for approximately 14% , making them the third most productive reservoirs (Adler, 1971). Figure 1-1 illustrates the distribution of oil and gas in Kansas.

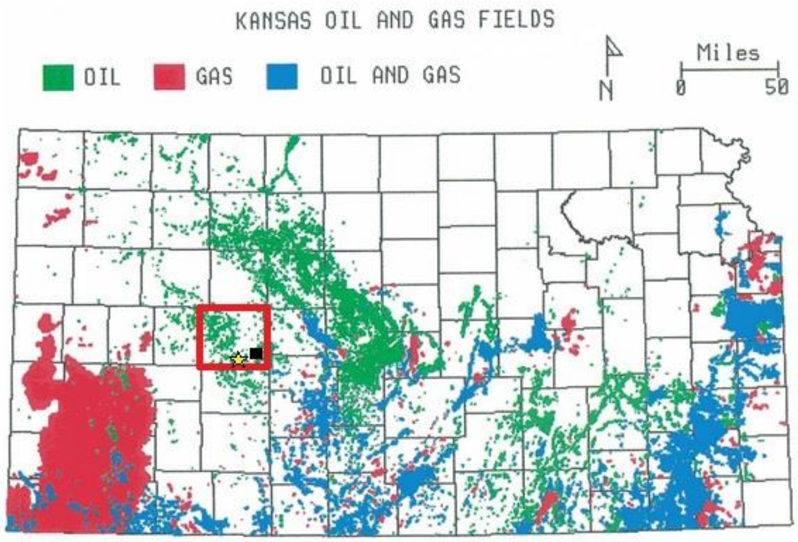


Figure 1-1: Map showing the distribution of oil and gas fields in present day Kansas. Ness County is outlined in red. Petersilie oil field is indicated by the yellow star. Schaben field is indicated by the black square (Image modified from Newell, et al., 1987).

Mississippian oil fields are scattered throughout the central and south-central portion of the state, as seen in Figure 1-2. Innovations in drilling technology at the start of the century have led to United States petroleum producers to reconsider plays formerly held to be “tapped out”, or unproductive. This has also been the case in Kansas. With the use of horizontal drilling and fracking techniques, the Mississippian continues to be a major player in Kansas’s oil and gas industry (Evans and Newell, 2013). Today, oil production in the Mississippian in Kansas continues to dominate along the flanks of the Nemaha uplift and the western side of the Cherokee basin. In densely drilled areas, subtle stratigraphic traps occurring where reservoir quality varies due to the chat and overlying basal Pennsylvanian conglomerates remain exploration targets (Newell, et al. 1987).

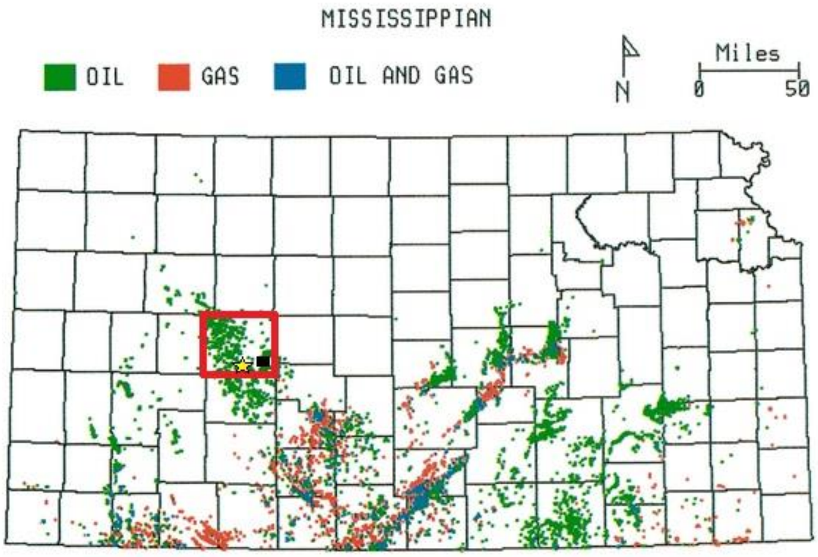


Figure 1-2: Map showing the distribution of oil and gas fields in Kansas that produce from the Mississippian system. Ness County is outlined in red. Petersilie oil field is indicated by the yellow star. Schaben field is indicated by the black square. Note the high concentration of oil fields producing the Mississippian in Ness County (Image modified from Newell et al., 1987).

Study Area

Petersilie oil field is located in south-central Ness County in the west-central part of Kansas in the United States. Structurally, Ness County lies on the southwestern flank of the Central Kansas Uplift (Figure 1-3). This structure may be subtly noted in the subsurface of the Petersilie field. Petroleum exploration began in Ness County in 1922. Today, Ness County remains a vital part of the petroleum industry in Kansas. Production grew through present day times and has remained steady at around 1.8 million barrels per year since the mid-1990s. The number of producing wells in the county has gradually increased to 1175 in 2014. Approximately 117 million barrels of oil have been produced in Ness County cumulatively as of 2014. Ness County is currently ranked fourth most productive county in Kansas (Kansas Geological Survey, 2014). Most production comes from Mississippian-aged reservoirs; however, some production has also been established from Pennsylvanian-aged sandstone and limestone.

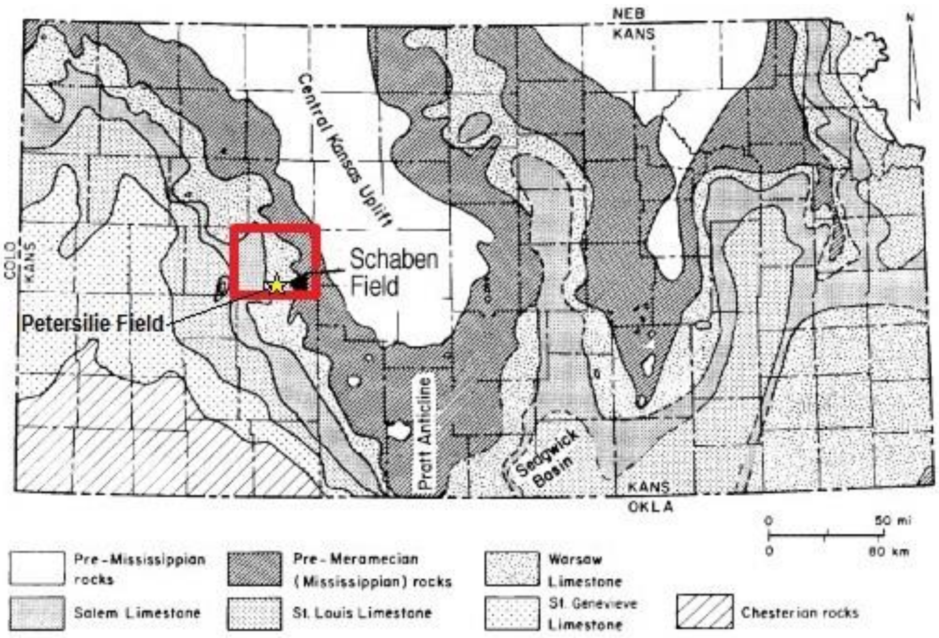


Figure 1-3: Study Area with stratigraphic layers and key structural features. Ness County is outlined in red; Petersilie oil field is indicated by the yellow star. Note that Petersilie's structure will be influenced by the Central Kansas Uplift. Neighboring Schaben oil field is discussed on page 10 (Image modified Kansas Geological Survey, 2014).

Paleogeography and Depositional Setting

Some notable subsurface geologic features surrounding the region are the Central Kansas Uplift to the east, the Pratt Anticline to the southeast, the Cambridge Arch to the northeast, and the Hugoton Embayment to the southwest. These features were formed during the Mississippian and on into the Early Pennsylvanian. The Mississippian began to be deposited approximately 350 million years ago. Although Kansas spent much of the Mississippian submerged under the shallow, warm waters of an epicontinental sea, some tectonic activity as well as regression of the sea was responsible for gentle uplift and periodic exposure of some areas. This led to older Mississippian lithologies being of marine origin, while some terrestrial influence may be noted in younger deposited lithologies (Goebel, 1968). Figure 1-4 illustrates the general topography in Kansas during the Mississippian and the major subsurface features that may influence petroleum production today. The Mississippian appears almost everywhere in Kansas's subsurface, with the exceptions of the tops of the Central Kansas Uplift and Cambridge Arch, and parts of the Nemaha Uplift, where erosion occurred (Merriam, 1963).

The area of present-day Ness County, Kansas would have originally been a marine ramp depositional environment. Specifically, the depositional environments of Mississippian rocks in

Ness County range from shelf margin regions to inner shelf embayments and supratidal zones. The well-known Mississippi "chat", a varied combination of limestone, chert, and dolomite which generally tops Mississippian-aged rocks in Kansas, was created as a result of sponge-spicule deposition at shelf margin locations. Where the main shelf and inner shelf met, vertically and horizontally alternating layers of echindoderm-rich packstones or grainstones occurred with sponge spicule-rich packstones or wackstones. The inner shelf contained mudstones or wackstones. The supratidal zone is responsible for the formation of dolomitic layers of the Mississippian (Dubois, 2003).

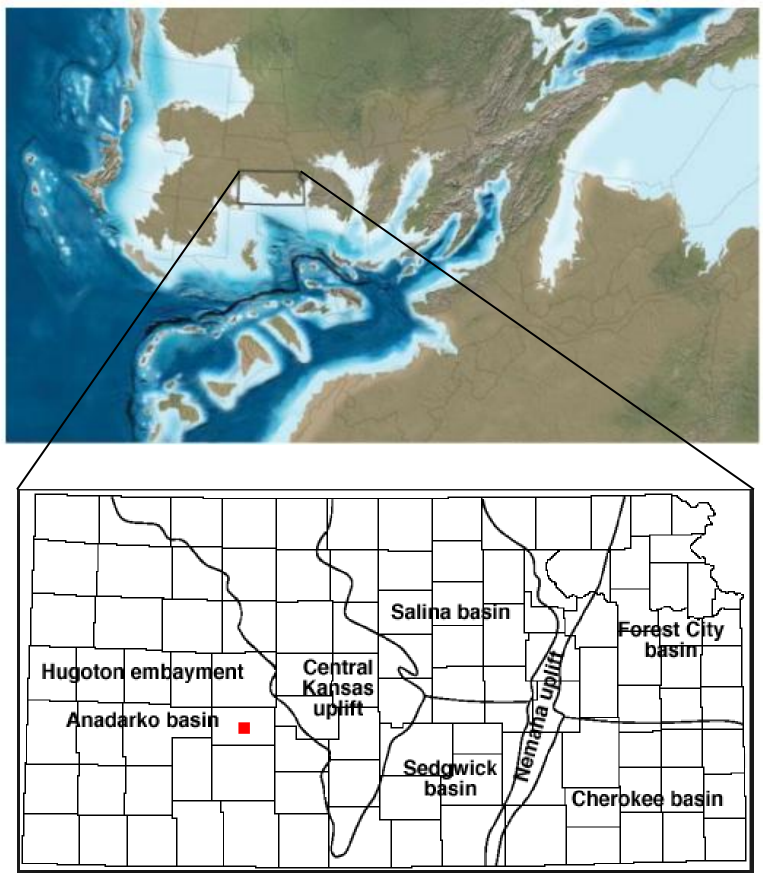


Figure 1-4: Image showing the topography in Kansas during Mississippian deposition. Kansas was partially submerged in an inland sea. The inset highlights the major subsurface structural features present in Kansas today. Study area is indicated by the red box (images modified from Goebel, 1968 and Baars et al. 2001).

Stratigraphy of the Mississippian System

The Mississippian can be defined in two subgroups: the Lower Mississippian Series and the Upper Mississippian Series (Evans & Newell, 2013). The Lower Mississippian encompasses the Kinderhookian and Osagian stages. It is composed mainly of cherty dolomite and limestone. The Upper Mississippian encompasses the Meramecian and Chesteran stages. This part of the system has limestone and dolomite beds with comparatively less chert, as well as interspersed shale and sandstone beds (Figure 1-5). Erosional unconformities are seen throughout the Mississippian, the most obvious of which occurs as the Cowley Facies, created via erosion of a basin and subsequent deposition during the Meramecian. The only place the Mississippian outcrops in Kansas is in the very southeastern-most corner of the state (Goebel, 1968). Today, oil production occurs primarily in upper Osagian-aged and lower Meramecian-aged rocks.

The Osagian Stage contains formations comprised primarily of limestone, dolomite, chert, and cherty dolomite. Older Osagian formations occurring in southern Kansas are overlapped to the north by younger formations. An angular unconformity separates Osagian and underlying Kinderhookian rock layers. The Osagian Stage's main formations are the Fern Glen Limestone and the undifferentiated Burlington and Keokuk limestones. The Fern Glen Limestone consists of the white, semi-granular and coarsely granular noncherty crinoidal St. Joe Limestone Member overlain conformably by the sometimes slightly dolomitic, gray or buff semi-granular, fine-textured Reeds Spring Limestone Member. The Reed Spring Limestone Member is especially cherty in south-central Kansas. The overall distribution and structure of the Fern Glen Limestone suggests gentle deformation of the southern part of the Central Kansas Uplift and the Nemaha anticline before or during deposition. The Burlington and Keokuk Limestones are often difficult to tell apart in Kansas. Both are made up mostly of siliceous limestones and dolomites and have high chert content, the Keokuk containing at least 50% chert throughout the state.

The Meramecian Stage rocks lie disconformably on Osagian rocks. While the upper formations consist primarily of granular, sandy, fossiliferous limestone, the lover formations are dolomite or dolomitic, cherty limestones. Meramecian rocks for the most part were likely originally extended throughout Kansas but eroded away considerably before deposition of

Pennsylvanian rocks. The Meramecian Stage contains the aforementioned Cowley Facies, a silty and siliceous dolomite and limestone facies of the sequence from the St. Louis Limestone to the Chattanooga Shale. Other major formations of the Meramecian Stage include the Warsaw Limestone, the Salem Limestone, the St. Louis Limestone, and the Ste. Genevieve Limestone. The Warsaw Limestone is mostly as semigranular limestone interlaminated with dolomite and containing much chert. The coarsely crystalline ooilitic limestone and dolomitic limestone formation, known as the Salem Limestone, conformably overlies the Warsaw. The St. Louis Limestone contains noncherty limestone but also widespread oolitic limestone beds and calcarenite. Lastly, the Ste. Genevieve Limestone, lying disconformably beneath Chesteran rocks but conformably on the St. Louis Limestone, consists of silty to sandy fossiliferous limestone interbedded with oolitic limestone and calcarenite (Goebel, 1968).

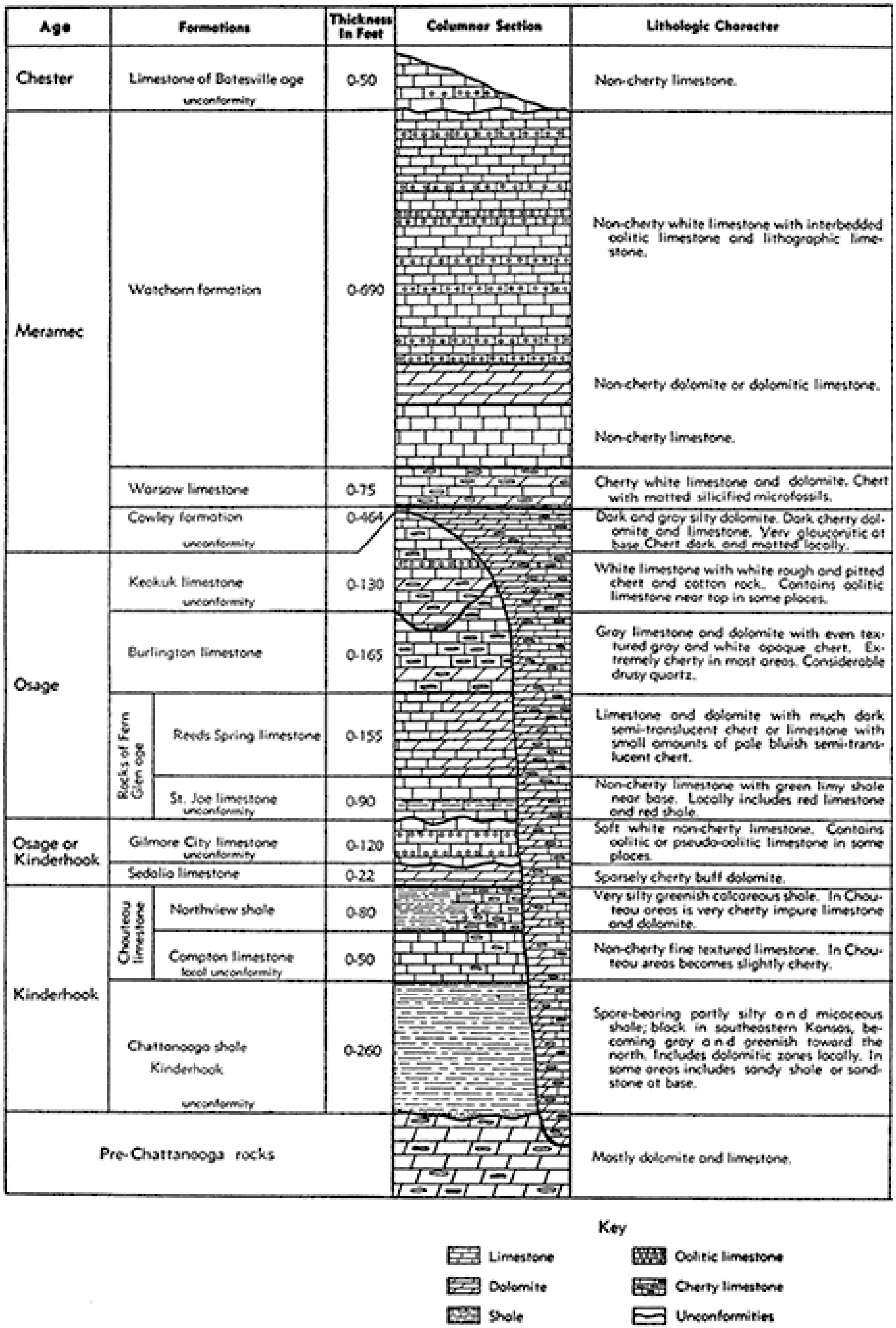


Figure 1-5: Stratigraphic column of the Mississippian System (image from Goebel, 1968).

Related Work

A study similar to this one was undertaken for the Mississippian in the Schaben oil field, also located in Ness County, Kansas. The Schaben field study was conducted by a team of geologists on behalf of the United States Department of Energy. The purpose was to establish that new PC-based reservoir modeling software available free of charge through the U.S. Department of Energy's National Energy Technology Lab was effective in increasing oil production in fields in western Kansas, where smaller independent oil companies may not have access to more expensive technologies available for increasing reservoir efficiency. The team analyzed core and petrophysical data from both existing and newly-acquired logs, and production information, and input that data into the reservoir modeling software to create a reservoir model and run simulations in a reservoir simulator. While waterflooding was not necessary in Schaben because the field had maintained adequate pressure due to being situated on top of an aquifer, the simulations showed that infill drilling would be an effective means of increasing oil production. This was eventually found to be true when implemented (Montgomery, et. al., 2000). The Schaben study is important because it provides a basis for understanding the Mississippian in western Kansas. However, it may be argued that applying similar analytical techniques on a much smaller budget and with fewer resources, as in this study, is more representative of the ways in which smaller oil companies may be able to obtain information on the Mississippian's prospects and identify changes in the reservoir as it nears the Central Kansas Uplift. Unlike the Schaben study, this study did not require the use of core or drilling new wells, and was undertaken on a desktop computer by a single person rather than a team of geologists. As such, the costs for achieving useful results were reduced to next to nothing, proving the potential for successful implementation of the BOAST software by a company with limited resources.

Chapter 2 - Black Oil Applied Simulation Tool (BOAST)

Reservoir simulation involves the use of computer models to mathematically predict the flow of oil, water and gas through rock. Reservoir simulation is useful for optimizing development plans in new oil or gas fields, and for helping companies to make operational and investment decisions. Elements of a reservoir model such as that produced in this study may be input into a reservoir simulator to view the dynamic behavior of the reservoir fluids and predict reservoir performance. Reservoir simulators consist of three main components: a volumetric grid with descriptive cell properties, a flow model describing the movement of fluids within the reservoir, and a well model which describes fluid flow in and out of the reservoir (Lie and Mallison, 2013). Black oil simulators are the most commonly used software for modeling reservoir flow in today's petroleum industry.

Black oil simulators function on the black-oil model, which is a flow model that employs a pressure-volume-temperature, or PVT, description where the hydrocarbons are split into two components at surface conditions. These are the "heavy" hydrocarbon component, which is defined as oil, and the "light" hydrocarbon component, which is taken to be gas. The chemical compositions remain constant at all times. The black-oil model adheres to conservation laws that describe the relationship of such factors as formation volume factors (relate volumes of oil, gas, or water at reservoir conditions and at surface conditions) and a gas solubility factor (volume of gas, measured at standard conditions, dissolved at reservoir conditions in a unit of stock-tank oil at surface conditions). The model is designed to conserve volumes at standard conditions (Lie and Mallison, 2013). Most commercial simulators solve the nonlinear system represented by the conservation laws via a fully implicit discretization (Peaceman, 1991). The black-oil model equations are shown in Figure 2-1 below.

$$\frac{\partial}{\partial t}\left[\phi\left(\frac{S_o}{B_o}+\frac{R_V S_g}{B_g}\right)\right]+\nabla\cdot\left(\frac{1}{B_o}\vec{u}_o+\frac{R_V}{B_g}\vec{u}_g\right)=0$$
$$\frac{\partial}{\partial t}\left[\phi\left(\frac{S_w}{B_w}\right)\right]+\nabla\cdot\left(\frac{1}{B_w}\vec{u}_w\right)=0$$
$$\frac{\partial}{\partial t}\left[\phi\left(\frac{R_S S_o}{B_o}+\frac{S_g}{B_g}\right)\right]+\nabla\cdot\left(\frac{R_S}{B_o}\vec{u}_o+\frac{1}{B_g}\vec{u}_g\right)=0$$

Figure 2-1: The equations of the black-oil model which are employed to conserve reservoir oil, water, and gas volumes at standard conditions for simulation purposes. In these equations, $\vec{u}_o, \vec{u}_w, \vec{u}_g$ represent Darcy velocities of each of the three phases (oil, water, and gas) in the reservoir and ϕ represents porsosity. Sw, So, and Sg represent the saturations of water, oil, and gas, respectively. Bo, Bw, and Bg are the formation volume factors for oil water, and gas, respectively. Finally, Rs is a solution of gas in the vapor phase and Rv is a vaporized oil in gas phase (Trangenstein and Bell, 1989).

There is a variety of black oil simulating software available for download on the Internet. However, acquiring the software may be cost-prohibitive to small independent oil companies in Kansas. Because one of the key foci of this study was to use exclusively cost-effective resources that could be acquired and maintained with reasonable ease by a small independent oil producer in Kansas, the black oil simulator selected was BOAST 98. BOAST 98 is a public domain, desktop-operated tool developed by the U.S. Department of Energy. The software is available at no cost, making it an ideal option for use in this study. BOAST 98 and its companion product, EdBOAST, are available for download from the U.S. Department of Energy's National Energy Technology Laboratory (NETL) website at http://www.netl.doe.gov/research/oil-and-gas/software/simulators. Downloading the software is virtually instantaneous and both programs can be tested and put to use immediately after download, making BOAST 98 and EdBOAST faster and easier to acquire than other downloadable options such as Schlumberger's ECLIPSE black oil simulator, which must be accessed through dialogue with Schlumberger. BOAST 98 and EdBOAST are defined further in the sections below.

EdBOAST

EdBOAST is a dialogue-oriented reservoir data editor that allows the creation of input files that are directed to BOAST 98. EdBOAST interacts directly with BOAST 98, meaning once input files have been created, they may be transferred within EdBOAST to BOAST 98. A separate screen will be opened for BOAST 98, containing the file created in EdBOAST, which may subsequently be simulated. EdBOAST is the first step in simulating a reservoir with the BOAST tools. It allows the user to enter the reservoir model data collected and compile the data into one file that both programs can read. EdBOAST consists of a Start screen, with tab options for File Name, Directory, Extension, Options, Help, and Quit (Figure 2-2).

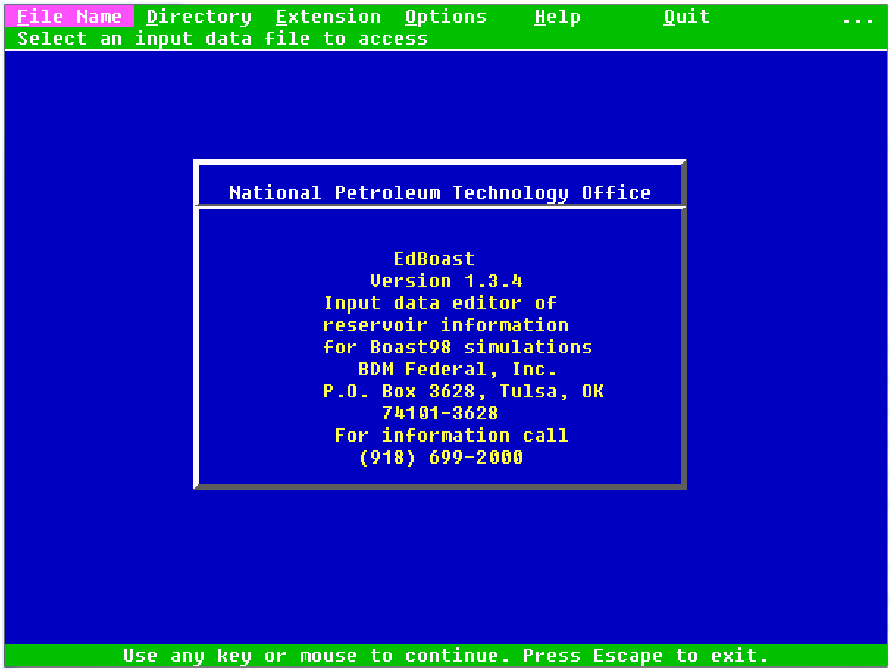


Figure 2-2: EdBOAST Start screen, the main navigation screen for the program.

New input files may be created through the Options tab. Once a new input file has been named and accepted, EdBOAST directs the user to a home screen containing fourteen buttons: BEGIN, GRID, PORPERM, TRANSM, TABLE, INITIAL, CODES, AQUI, WELLS, RECURR, DEFAULT, NEXT, ACCEPT, ABORT (Figure 2-3). Clicking on each button allows the user to input codes and information for the reservoir into the file being created and save the data via the ACCEPT button displayed in every screen, except for the GRID screen, which requires the user to select the NEXT tab in order to save data. Coding options are entered into the editing program as 1, 0, or -1, and correspond with data specifications for anything from water saturation to whether the user desires a printout of the data upon completion of the input file.

Figure 2-3: Starting a new file leads the user to the home screen, where data may be input for the file.

The BEGIN button allows the input of the project header, or name. It also contains coding options for an initialization run and for the creation of an output file. The GRID button allows the user to manually insert values into a defined number of cells pertaining to the extent of the reservoir in the x- and y- and z-direction in feet, or to upload these values via a .csv file. Coding options are available for changes in all grid dimensions. PORPERM allows specification of porosity and permeability values and modifications to those values throughout the reservoir. TRANSM contains control parameters for the flow between grid cells. TABLE provides for the input of rock and fluid properties of the reservoir, and any variations. INITIAL allows the user to enter the initial pressures and saturations of the reservoir. CODES is a processing-related screen through which modifications to processing control parameters may be coded. AQUI allows input of any influential aquifer data. The WELLS button is important for defining a set number of wells and entering their qualities, such as permeability and productivity index value, for use in simulation. RECURR allows for defining the data to be saved as well as other characteristics of the wells. The DEFAULT button contains a default set of values and codes for the entire program that can then be altered according to the reservoir. This button must be selected before data can be input into EdBOAST, or EdBOAST will not effectively save the data. The NEXT button is used to navigate from primary to secondary screens when buttons contain more than one screen. This occurs when data is being entered in GRID. It is vital that the NEXT button is used in GRID rather than the ACCEPT button, or data will not be saved. ACCEPT is the button to save data in almost all screens. ABORT will allow the deletion of any data previously entered and return the user to the home screen. Once an input file has been created to represent the reservoir in EdBOAST, the user can navigate to the Transfer tab under the Options button to export the file to BOAST 98 for reservoir simulation.

BOAST 98

BOAST 98 is the most recent and updated version of BOAST simulators available through the National Energy Technology Laboratory. It is defined as “a three-dimensional, three-phase Black Oil Applied Simulation Tool used for performing evaluation and design work in modern petroleum reservoir engineering. BOAST 98 simulates isothermal, Darcy flow in three dimensions. Like all black oil simulators, it assumes the description of reservoir fluids by three fluid phases: oil, water, and gas. It also assumes these three fluid phases are of constant chemical composition and that their physical properties are solely dependent on pressure. BOAST 98 is widely applicable and capable of simulating oil and/or gas recovery by gravity drainage, displacement, fluid expansion, and capillary imbibition mechanisms. BOAST 98 evaluates reservoir performance based on explicit saturation and finite difference, implicit pressure. It has options for both direct and iterative methods of solution. Some other options that are included in the program are steeply dipping structures, bubble point tracking, material balance checking for solution stability, multiple rock and PVT regions, multiple wells per grid block, automatic time step control, and rate or pressure constraints on well performance (BOAST Simulators, 2014).

The Start screen in BOAST 98 is very similar to that of EdBOAST, containing tabs for File Name, Directory, Extension, Options, Help, Quit, and About. After assuring that the file name is the correct file that was transferred from EdBOAST, the user may navigate to the Options button for a drop down list of items to include VIEW, SIMULATE, PLOT and EDIT. The VIEW button allows the user to see the contents of the file that was transferred from EdBOAST. The SIMULATE button begins a quick simulation run of the reservoir data, simulating pressure throughout the reservoir while simultaneously displaying a graph of oil production in standard barrels per day throughout time. PLOT allows the user to more closely inspect the results in one-, two-, or three-dimensional graphs. Depending on the type of information requested by the user, the plots could be of water, oil or gas saturation, or oil production, among other options. Finally, EDIT is an option that may be used to edit the data in the file before or after running a simulation.

Limitations and Benefits of BOAST

Both programs, EdBOAST and BOAST 98, recommend 32 MB of memory and require at least Windows98. BOAST 98 has the additional constraint of potentially requiring up to 100 MB of disk space. Limiting factors for both programs are similar, with BOAST 98 being slightly more constrictive. Limitations include too large of a grid size forcing the program to slow down considerably. Also, there can be a maximum of 200 grid cells, 8000 time steps, 200 data sets, and 150 wells with a maximum of ten nodes per well. There can be a maximum of five distinct rock and PVT regions defined, and a maximum of 25 table entries for relative permeability and capillary pressure curves. For EdBOAST specifically there can be 55 modifications to porosity, transmissibility, and permeability. Other negative factors include the lack of extensive resources for learning how to use and maintain the programs. The user manuals for both programs are very short, comprised largely of descriptions of the coding language used in each, and do not describe how to accomplish many of the processes required to complete an input file in EdBOAST and run a subsequent simulation in BOAST 98. Benefits of using BOAST software are the cost-savings, and the speed and ease of using the software once it is understood. Also, BOAST software has proven effective in other field studies such as the aforementioned Schaben field study by the U.S. Department of Energy in production history-matching and successfully predicting means of enhancing reservoir productivity.

Chapter 3 - Waterflooding

Primary oil recovery methods rely on naturally-producing mechanisms such as solution gas drives, water influx, and gravity drainage to recover oil. However, these mechanisms are not always satisfactorily effective in drawing oil to wells to be extracted (Table B-1). Primary oil recovery methods are known to leave behind a majority of original oil in place. This amount can be up to 80% (Figure 3-1). The next step in recovering that left over oil is employing a secondary recovery method.

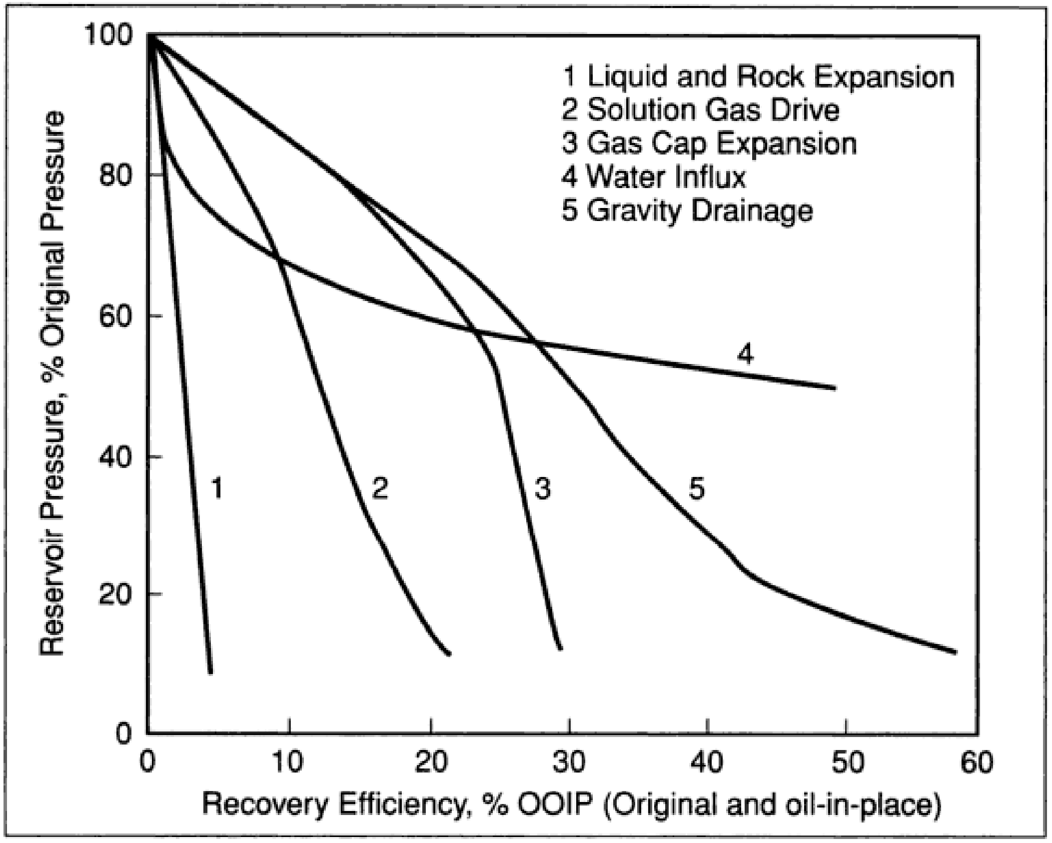


Figure 3-1: Recovery efficiency of various naturally-producing mechanisms of reservoirs. Primary recovery relies on these mechanisms, which may leave up to 80% of original oil in place in the ground (image from Thakur and Satter, 1986).

Secondary recovery refers to the production of oil or gas by artificially augmenting reservoir energy (Rottman et. al, 1998). Secondary recovery methods include water injection and gas injection. The two methods rely on similar principles and seek to increase and maintain pressure in reservoirs where pressure was previously depleted via primary production, displacing oil such that it migrates towards production wells. Gas injection, or gas flooding, utilizes primarily carbon dioxide to usher oil towards producing wells (Figure 3-2). One major difference between gas and water injection is that in gas injection the pressurizing agent, carbon dioxide, is injected into the gas cap of the formation. In water injection, water is injected into the production zone of the formation (Water Injection, 2014).

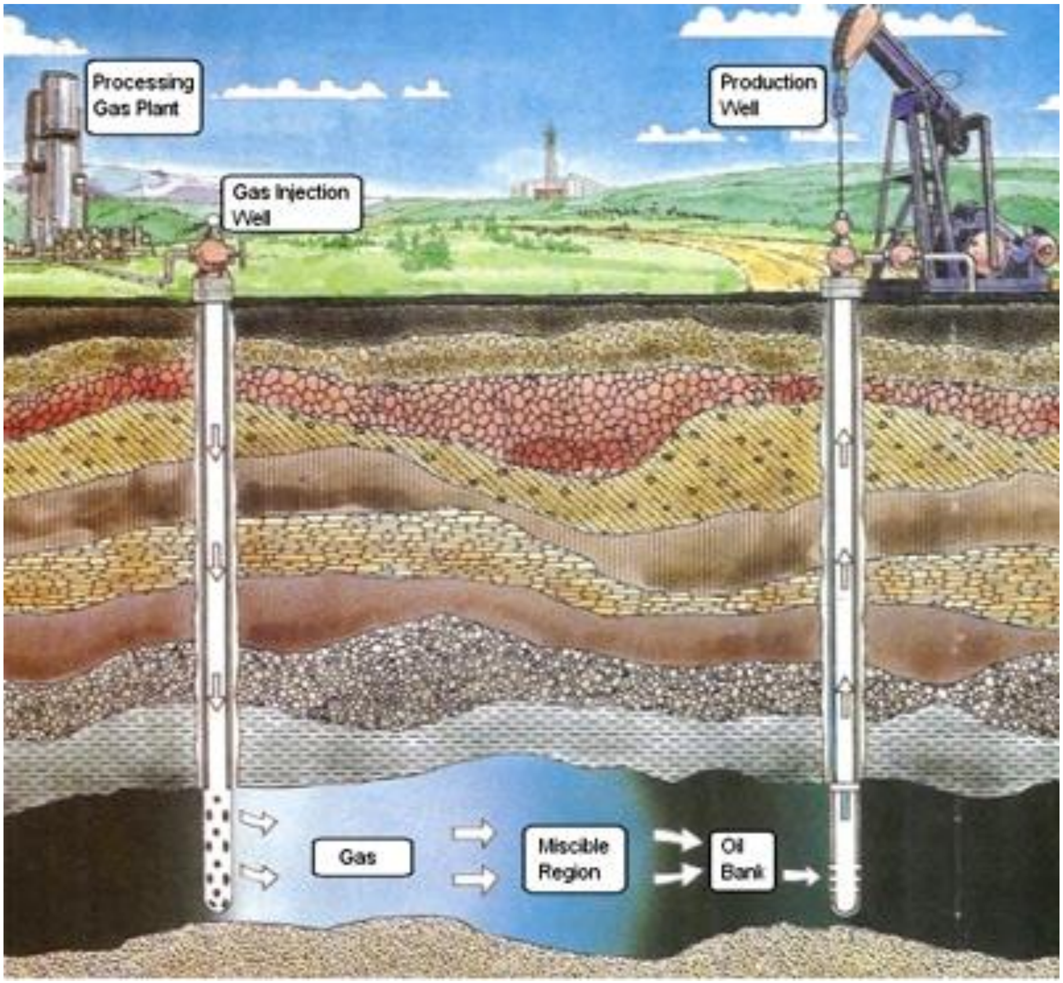


Figure 3-2: Depiction of the gas injection process. Carbon dioxide is injected into the gas cap of the formation via a gas injection well, sweeping oil towards a production well for extraction (image from Water Injection, 2014).

While demand for gas injection during secondary recovery has grown with the growth of unconventional drilling, water injection remains the most widely-used secondary recovery method in the United States, with nearly half of oil produced annually in the U.S. coming from waterflooded reservoirs in 2012 (Asadollahi, 2012). Waterflooding is used in both on- and offshore drilling. Water injection, or waterflooding, is a secondary recovery method that involves injecting water through a water injection well into the production zone of a formation in order to force the movement of oil towards a producing well where it may be recovered. The water used in this method is often a brine. It may be recycled water produced from the formation itself (Water Injection, 2014). Two types of well clustering methods are common in waterflooding:

peripheral or central flooding (wells are grouped together), and pattern flooding (a pattern of well clusters is repeated throughout the field). Pattern flooding is commonly line drive or five spot patterns. Line drive patterns place injection wells beside producers and push oil in a line towards the producing wells. Five spot patterns place four injection wells in a square shape to encourage oil towards the producing well at their center. In all cases, the positioning and proximity of the injection wells around the producing wells is dependent upon many different factors, including the volume of the reservoir, the reservoir geology, and economic considerations (Asadollahi, 2012). Figure 3-3 illustrates common injection well placements during waterflooding operations.

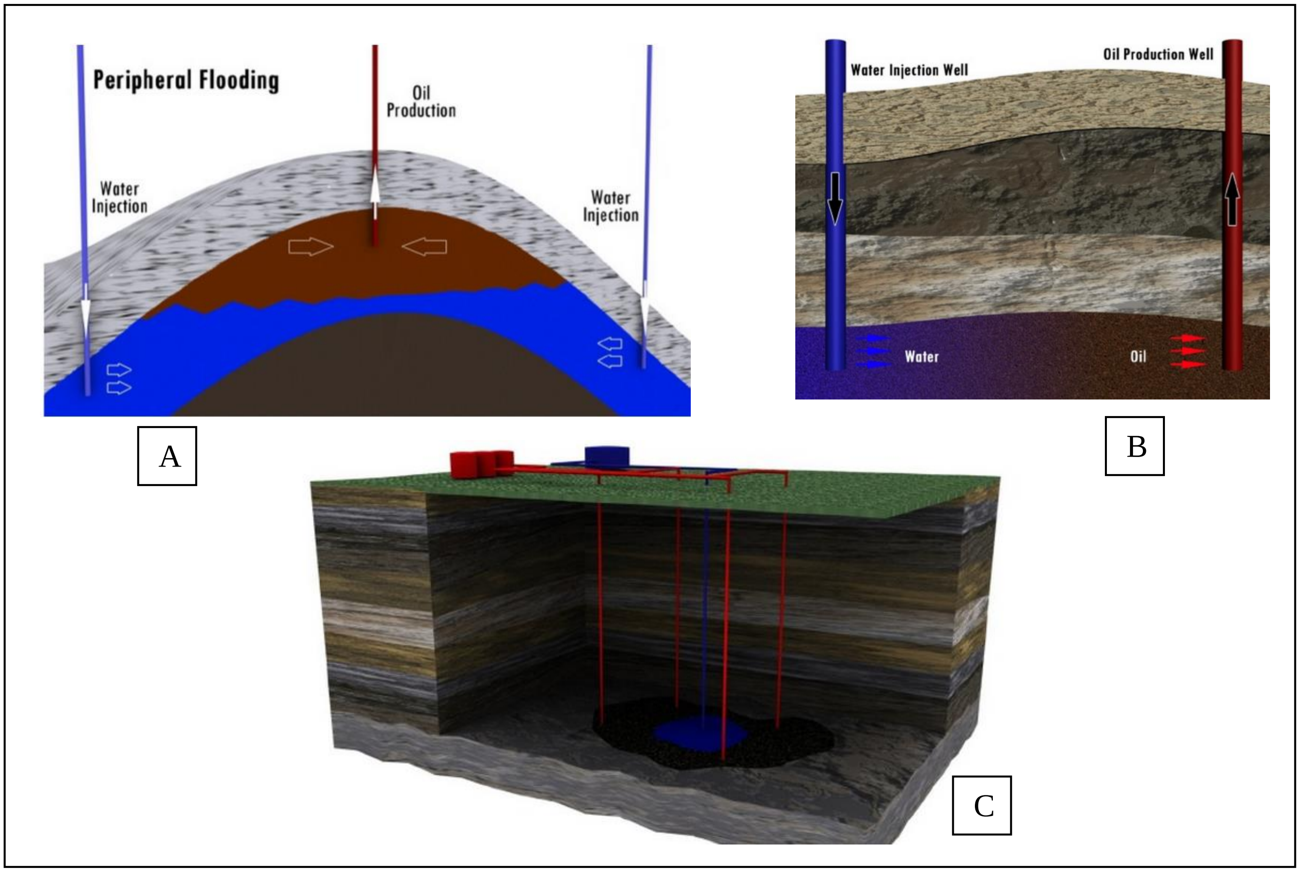


Figure 3-3: Peripheral or central flooding is depicted in diagram **A**. Diagram **B** depicts line drive flooding, a form of pattern flooding. Diagram **C** depicts five point pattern flooding (images modified from Asadollahi, 2012).

Waterflooding is a popular method of secondary recovery for many reasons. Water is generally readily available for water injection purposes. Waterflooding requires low capital investment and it costs relatively little to maintain operations. Water is easy to inject and spreads readily throughout an oil reservoir. Finally, water is efficient at displacing all but heavy oils. Light to medium gravity oils usually respond favorably to water injection (Thakur and Satter, 1986). Waterflooding is in most cases the most effective and economically sound method of secondary recovery, making it a potentially ideal technique for increasing the recovery of depleted reservoirs.

The first water injection occurred by accident in the Pithole City area of Pennsylvania in 1865, when water from a shallow water-bearing formation leaked into the oil column of a well, majorly reducing the well's production, but increasing production in surrounding wells (Asadollahi, 2012). Waterflooding grew through the 1930's, spreading from Pennsylvania to

Oklahoma and Texas. However, although it was widely used in those few states, it did not become recognized as a beneficial method on a national scale until the 1950's (Rottman et. al, 1998). Recently, waterflooding has been turned to as a possible means of recovering even more oil from the successfully-producing unconventional plays of the United States. With the increase in shale oil production, attitudes about waterflooding in unconventional plays have changed. What was once speculated to be inefficient or impossible is now receiving a second look: in 2012, a popular oil and gas website referred to waterflooding of unconventional plays as "the next big profit phase of the shale oil revolution" (Schaefer, 2012), and a more recent 2013 study showed promising results for enhanced recovery of unconventional reservoirs with waterflooding (Morsey, Sheng, and Ezewu, 2013).

Evaluating a Waterflood Prospect

Evaluating a reservoir for potential increase in recovery via water injection begins with studying the efficiency of the primary depletion and the drive mechanism of the reservoir. The three major reservoir drive mechanisms are water drive, solution-gas drive, and gas-cap drive. Water drive reservoirs are unsealed petroleum reservoirs that have contact with aquifers and subsequently experience considerable movement of water from the aquifer to the petroleum reservoir. A field such as Schaben, which sits atop an aquifer and produces a large amount of water with its oil, could potentially be classified a water drive reservoir. In gas-cap drive reservoirs, the gas cap (free gas zone overlying an oil zone) is responsible for gas expansion, which is the main mechanism for oil production. Finally, solution-gas drive reservoirs don't initially contain free gas but develop it upon pressure depletion. Hence, in solution-gas drive reservoirs, the drive mechanism applies once the reservoir pressure has fallen below the bubblepoint, or the pressure at which the gas begins to break out of an under-saturated oil and form free gas within the matrix or gas cap (Muskrat, 1949). Figure 3-4 illustrates curves for gas-oil ratio versus percentage of oil produced for the three primary drive mechanisms.

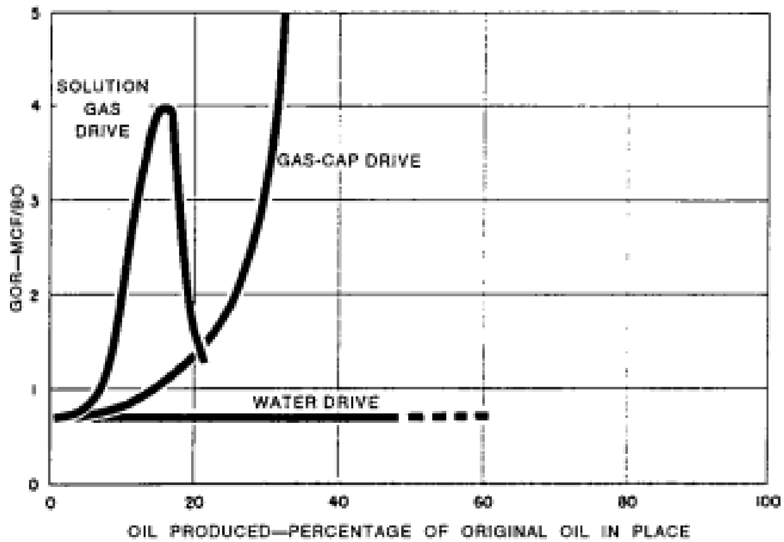


Figure 3-4: Depiction of typical gas-oil ratio curves for solution-gas drive, gas-cap drive, and water drive mechanisms. Note that reservoirs whose primary production is due to a solution-gas drive mechanism will initially recover a very low percentage of the original oil in place (image from Rottman et.al, 1998).

Solution-Gas Drive Reservoirs

Secondary recovery candidates may appear economically attractive due to a large amount of oil produced during primary production. However, one of the most ideal reservoirs for waterflooding is a solution-gas-drive reservoir. In solution-gas-drive reservoirs, gas is produced very quickly and rapidly dies off. The gas-oil ratio is essentially a very steep parabolic curve (Figure 3-5). There are four idealized stages of primary production in reservoirs with a solution-gas drive mechanism. Stage 1 occurs with production while the oil is under-saturated. In this initial stage, there is no free gas and the producing gas-oil ratio is equivalent to the initial dissolved gas-oil ratio. Reservoir pressure quickly drops. While Stage 1 is usually short, the higher the initial under-saturation, the longer this stage will last. In Stage 2, some free gas begins to appear, however, saturation is too little for it to be mobile. The reservoir pressure is still below the bubblepoint but the producing gas-oil ratio has climbed and the rate of pressure decrease has slowed. The free gas attains mobility in Stage 3 and there is an increase in the gas-oil ratio. Gas recovery exceeds oil recovery in this stage, which consumes 85-95% of primary recovery in solution-gas drive reservoirs. This is generally the stage at which primary production is stopped and abandonment occurs or secondary recovery methods are initiated. In Stage 4, reservoir pressure is very low and the producing gas-oil ratio is drastically decreased. Stage 4 will not occur if primary production is halted in Stage 3 (Muskrat, 1949).

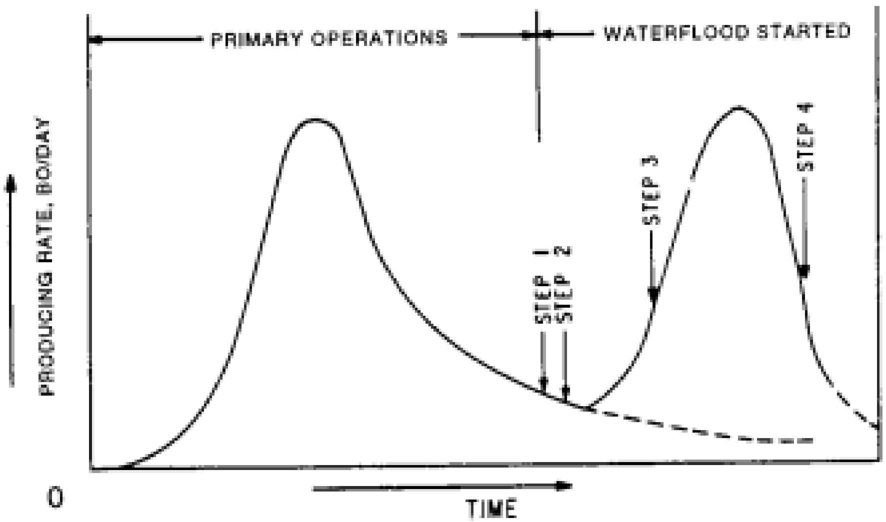


Figure 3-5: Example production curves for a solution-gas-drive reservoir during primary production and after initiation of waterflooding. Step 1 demonstrates the reservoir at or near abandonement. In Step 2, injection wells have been placed and waterflooding has begun. Step 3 shows the "fill-up" stage. In Step 4, the "water breakthrough" stage, water production increases and oil production decreases (image from Rottman et. al, 1998).

Due to the reasons outlined above, solution-gas-drive reservoirs are initially inefficient producers. However, they ultimately contain higher oil saturations at depletion, making such reservoirs ideal candidates for secondary recovery via waterflooding. Once waterflooding begins in a solution-gas-drive reservoir, the oil displaced by the water forms an oil bank, which re-saturates the gas pore space. The injected water forms what is known as the water bank (Figure 3-6). Later at the fill-up point the gas pore space has been filled by the displaced fluids and oil production in the targeted production well is greatly increased in response to the oil bank having been forced by the water bank into contact with the producing well. The oil bank will eventually be depleted, and once the water bank reaches the production well, water breakthrough will occur. At this point, water production will increase at the expense of oil production and a productive economic limit is reached. Beyond this limit, the producing well becomes economically unviable (Rottman et. al, 1998). At this final stage, the well is generally abandoned.

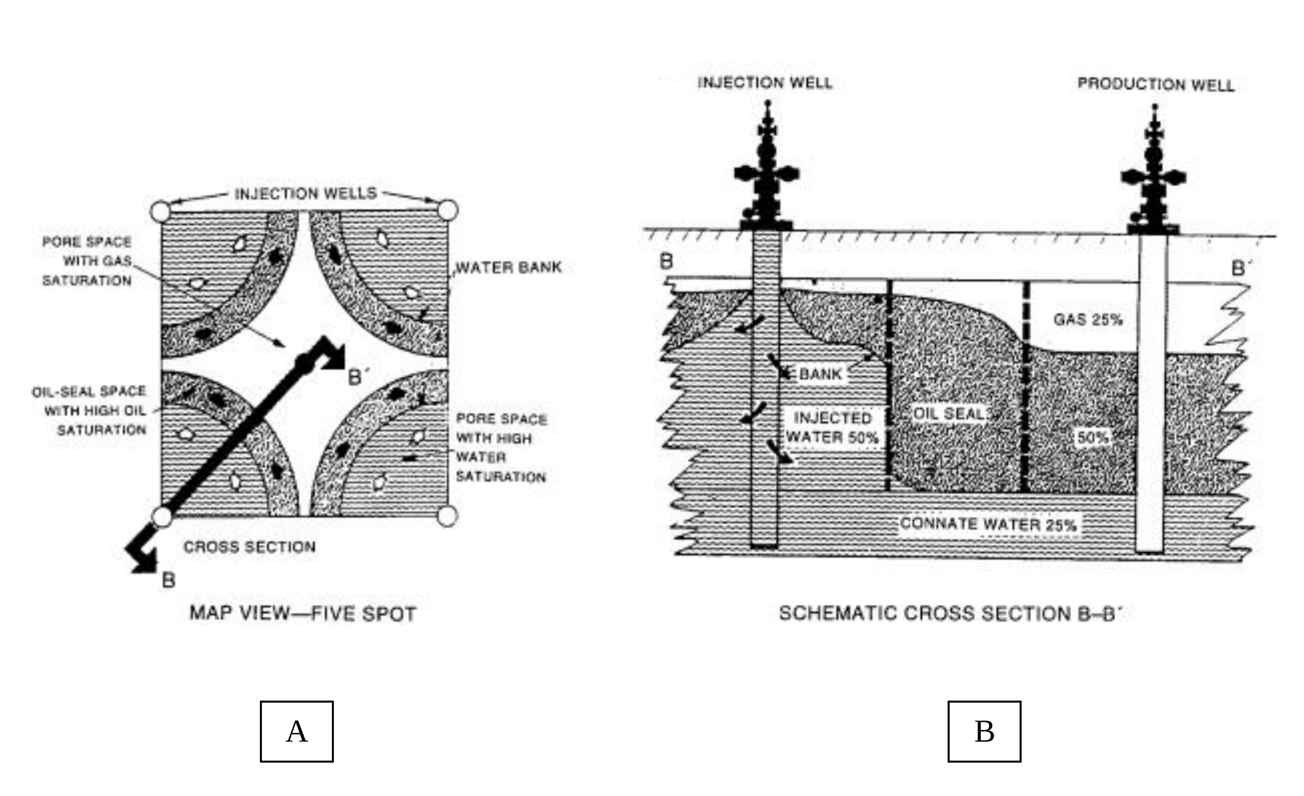


Figure 3-6: Diagram **A** depicts an "aerial" view of the reservoir with a five spot pattern of waterflooding. In Diagram **B**, a cross-sectional view of B-B' is shown. In both depictions, the water bank created by the injection wells at each corner is forcing the oil bank towards the production well at the center of the pattern (images from Rottman et. al, 1998).

Waterflooding in Petersilie Oil Field

Water injection began to be employed in the Petersilie oil field in 1992 as a means of increasing reservoir pressure and enhancing oil recovery. Chesapeake Operating, Inc. based in Oklahoma City, was responsible for drilling two water injection wells and reworking one former production well into an injection well. The injection wells and their accompanying production wells are positioned in a line-drive flooding pattern. The injection wells are Lehner 13 owned by Hugoton Energy Corporation, Lehner 18 owned by Vess Oil Corporation, and Petersilie 3 owned by Herman L. Loeb. LLC (Figure 3-7). Lehner 13 was operative for six years from October 1992 to May 1998, when it was plugged and abandoned. Lehner 18 was completed in 1997, and Petersilie 3 followed shortly after in 1999. Lehner 18 and Petersilie 3 are the only currently operating injection wells in the Petersilie field, with Lehner 18 producing two barrels of oil and

350 barrels of water per day, and Petersilie 3 producing 37 barrels of oil and little to no water per day.

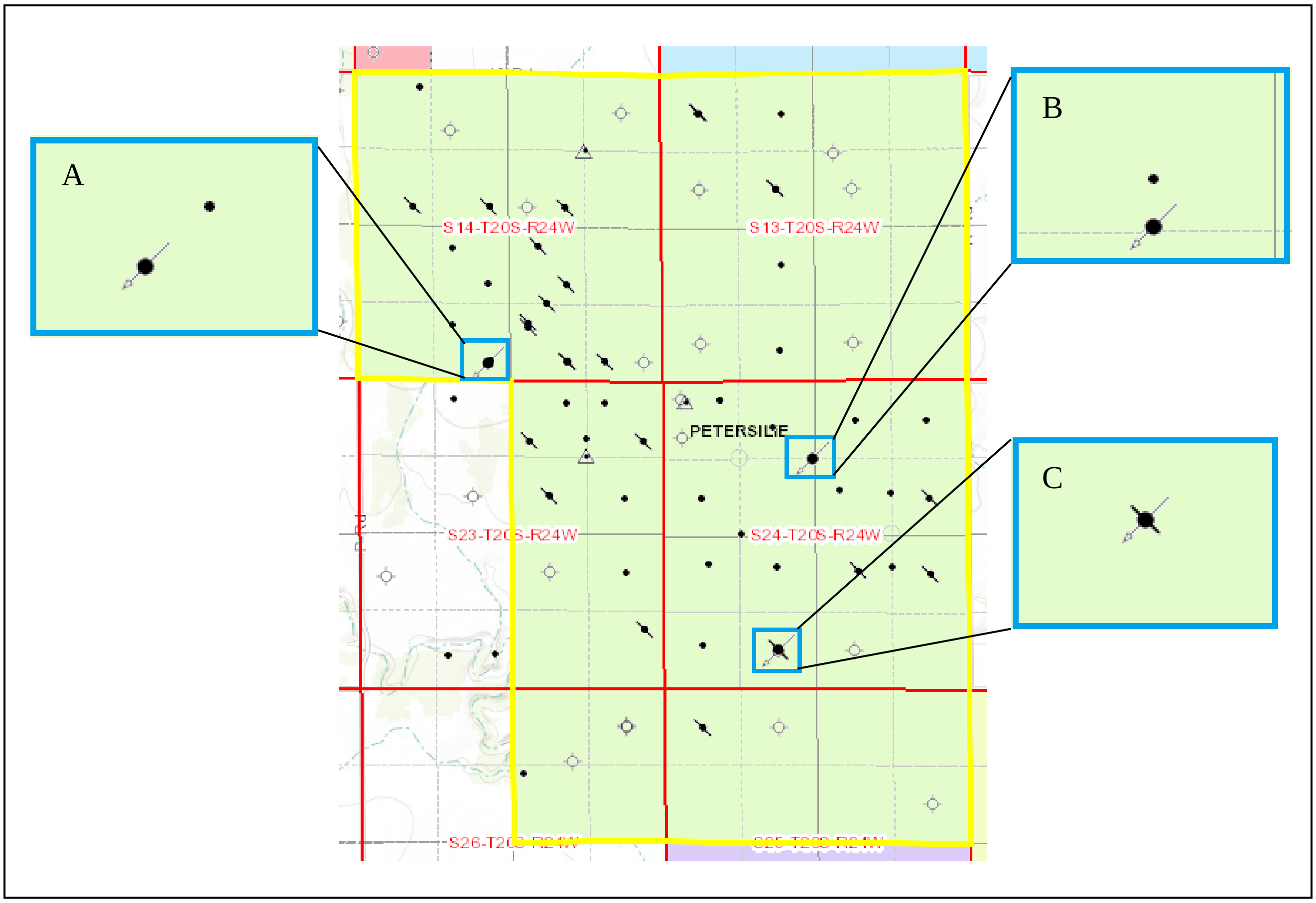


Figure 3-7: Positioning of water injection wells in Petersilie Field. Inset **A** shows the Petersilie 3 injection and production wells, which are spaced 80 feet apart. Inset **B** shows the Lehner 18 injection and production wells, spaced 20 feet apart. Inset **C** shows the Lehner 13 wells, which were plugged and abandoned in 1998 (image modified from Kansas Geological Survey, 2014).

Response of Petersilie to Waterflooding

Oil production in Petersilie began with a bang, increasing at a rapid rate in the field's early years as interest in the area grew. Unfortunately, as drilling increased, many dry holes were drilled as a result of lack of structural understanding of the Mississippian in Petersilie, which just as rapidly led to a drastic decrease in production. In the early to mid-1970s, another kick in production occurred as exploration technology evolved and operators began to obtain a greater understanding of reservoir structure. However, following the trend of a solution-gas drive reservoir, production began a steep decline after the mid-1970s. Before the initiation of water injection in 1992, Petersilie oil production was decreasing at a rate of approximately 10,500 barrels per year (Figure 3-8).

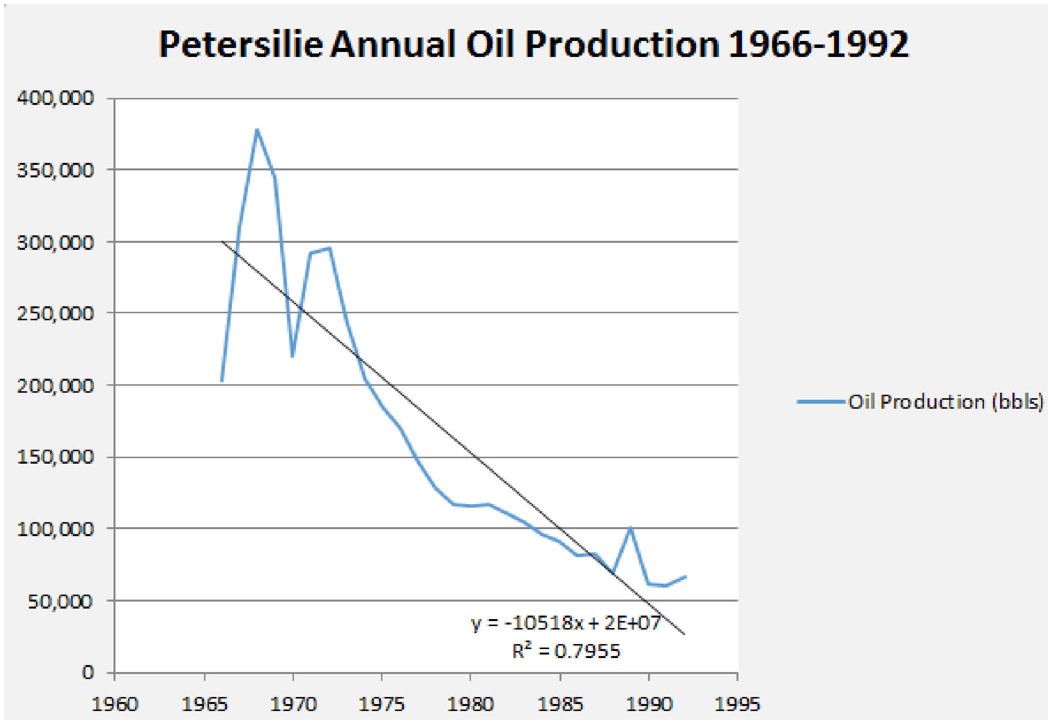


Figure 3-8: From the start of drilling in Petersilie oil field until waterflooding was introduced in 1992, field production was declining at a rate of about 10,500 barrels per year.

With the onset of waterflooding, the rate of decline in production in Petersilie was mitigated. From 1992 to 2104, the rate of decline had dropped from 10,500 barrels per year to approximately 1,487 barrels per year, an improvement of nearly 86% (Figure 3-9). Although waterflooding operations in Petersilie occurred on too small a scale to spur a rise in production in the depleted field, they were sufficient to drastically slow production decline. It is unknown why waterflooding was not implemented to a greater degree in the field, given its success with just three initial wells, only two of which remain functional. With better understanding of the reservoir, it is possible that waterflooding could be more efficiently employed and to a larger extent.

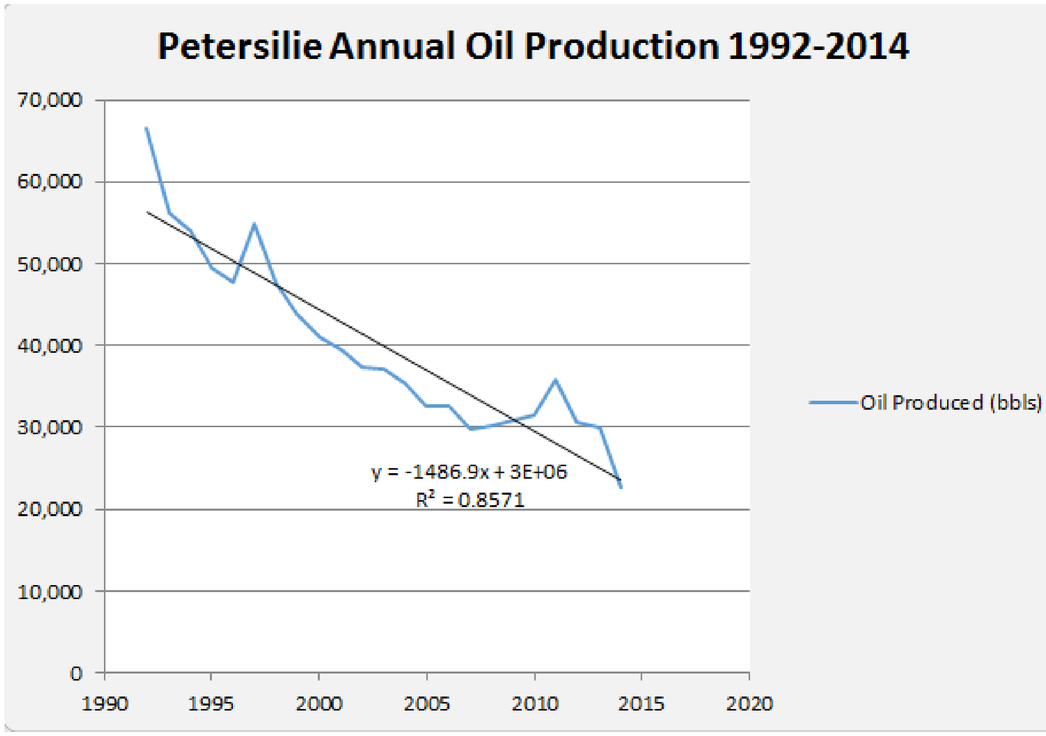


Figure 3-9: Once water injection was initiated, Petersilie's rate of decline was decreased by 86%, to approximately 1487 barrels per year.

Chapter 4 - Methods

This study was comprised of four goals: to construct a reservoir model for Petersilie field, to check and improve the reservoir model to a reasonable extent using only available information, well cuttings, well logs, and production data to simulate the reservoir model to achieve a production history match that could provide insight into the fit of the model to the reservoir in Petersilie. The work for this study was conducted largely in a computer lab using Dell desktop computers and processors. This allowed for downloading and running the two software programs, EdBOAST and BOAST 98, which were utilized in building and simulating the reservoir model. This was also useful for examination of scanned wireline logs available for download through the Kansas Geological Society's website. A literature search was done initially to gain insight into the fundamentals of reservoir modeling and simulation.

Using Petra to Enhance the Reservoir Model

Petra geological mapping software was made available through an academic license to Kansas State University from IHS, Inc. Petra was a vital component in the construction of the reservoir model used in this study, because part of the modeling process involved the creation of a grid which was spatially descriptive of the Mississippian reservoir's extent in Petersilie field and continuous within the confines of the field. The extent of the reservoir had to be described three-dimensionally. In order to achieve thickness values, or z-direction values on an x, y, z grid, an isopach map had to be made and evaluated. This was accomplished in Petra using three main steps: creating a well database, using the well database information to create an isopach map, and interpolating thickness values for locations where no wells had been drilled using the isopach map.

Creating the Well Database in Petra

A well database including 87 wells in Township 20S-24W was created in Petra. Well information was made available for free public use through the Kansas Geological Survey's website. This information was downloaded and imported into the Petra program. Well information used in creating the database included well header information, unique well identification numbers, well symbols for oil, gas, plugged and abandoned, and converted wells, spot locations, operators, lease names, and any remarks made on the wells. Well locations were referenced using the North American Datum 83. All formation tops information available for the wells through the KGS website, including those for the two producing formations in Petersilie field, the Marmaton and Mississippian limestones, was also entered into Petra for mapping purposes. Cartographic data was downloaded from the State of Kansas Data Access and Support Center (DASC) website at www.kansasgis.org, a free public resource for obtaining geospatial data for Kansas. This data was also imported into the map module of Petra. All well data downloaded and imported into Petra from KGS was checked for accuracy by comparison to scout cards and wireline logs also available through the KGS website. A base map was first created for the field and a contour map was created for the Mississippian (Figure 4-1).

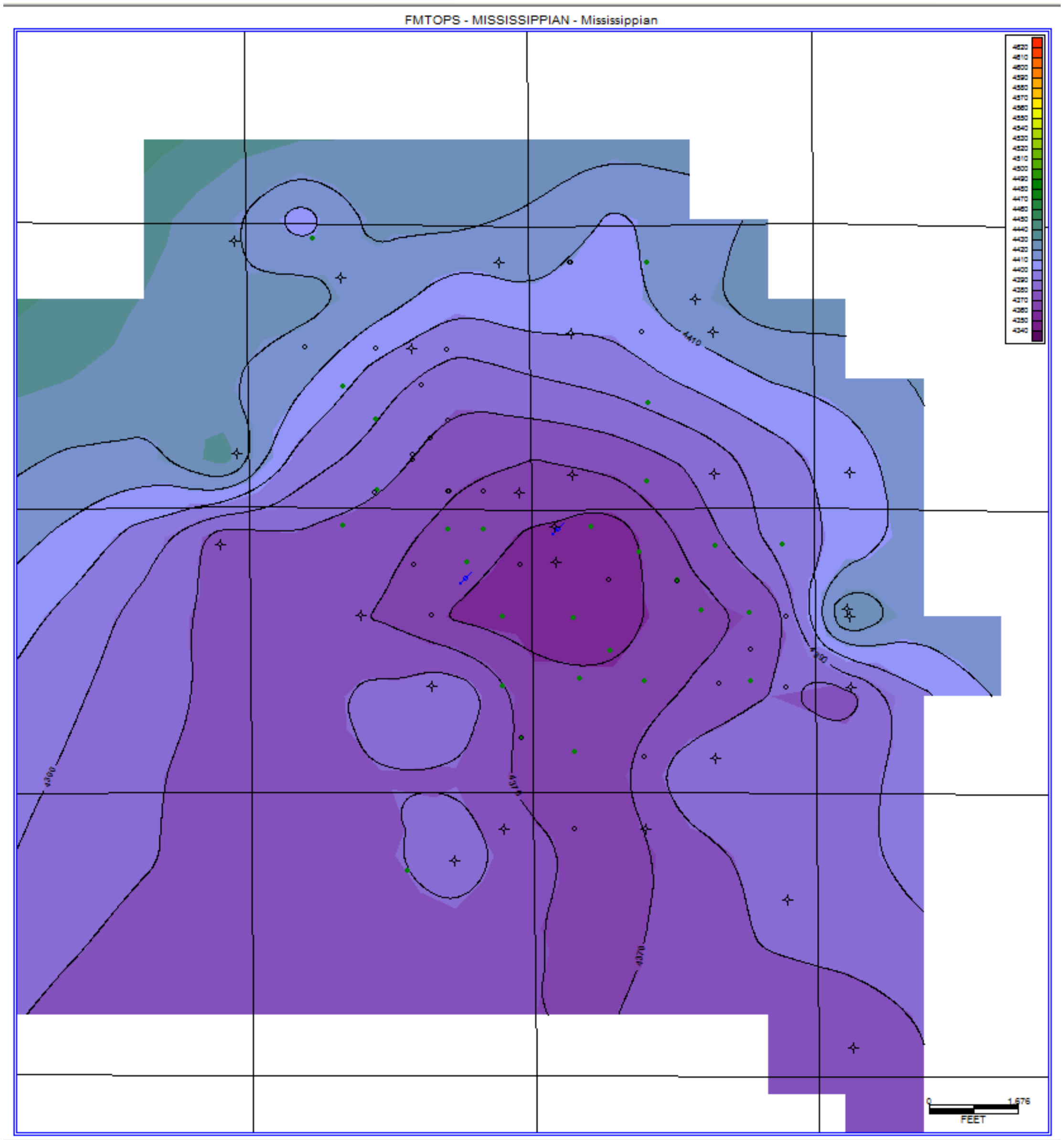


Figure 4-1: Structure map of the Mississippian formation in Petersilie field.

Creating an Isopach Map for the Mississippian System

In order to establish thickness of the reservoir, an isopach map (effectively an oil pay map) was generated for the extent of Petersilie field. The thickness of the zone was said to be the difference in feet between the Mississippian formation tops and the oil-water contact. The oil-water contact sits below the pay zone and is a constant depth throughout the reservoir. Examining well logs to determine where in the reservoir the resistivity dropped dramatically, to just a few ohms, led to the oil-water contact being defined at 4400 ft. However, to create a grid for the oil-water contact in order to make the isopach, Petra requires variation in values. Because the oil-water contact is said to be a constant value, it could not be successfully gridded. In order to get around this problem, four wells were given an oil-water contact value of 4398 feet, providing enough variation in values for Petra to allow the gridding of contours for the oil water contact. A grid was also created for the Mississippian formation tops. Once both grids were completed, grid calculations were performed, in the manner of C= A-B, or the thickness output grid is equal to the oil-water contact values minus the tops of the Mississippian. This gave the isopach map displayed in Figure 4-2 below, showing the thickness of the reservoir throughout Petersilie field.

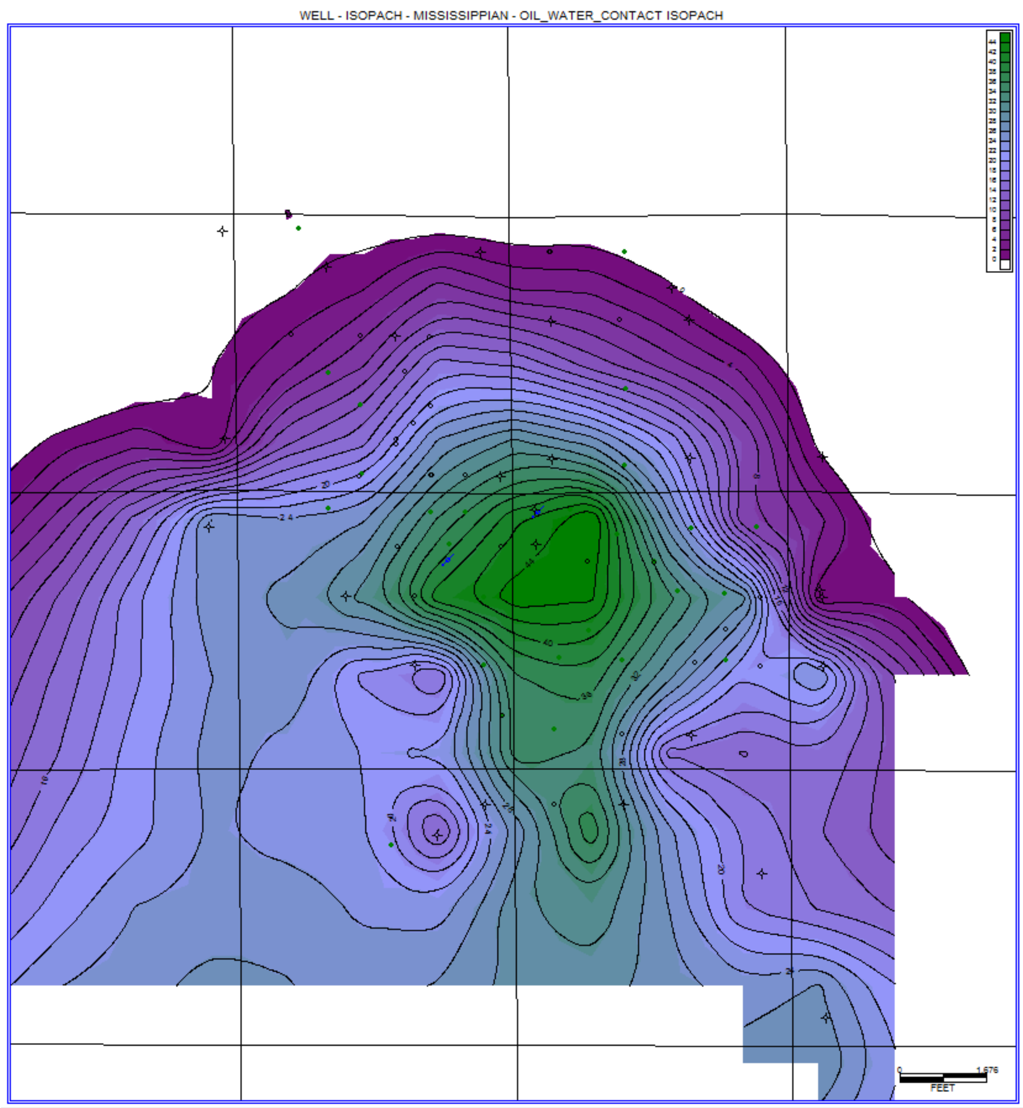


Figure 4-2: Isopach map of the Mississippian reservoir in Petersilie field displaying the thickness of the Mississippian above the oil-water contact. Thicknesses were taken to be the difference between the Mississippian formation tops and the oil-water contact at 4400 feet. Thickness increases towards the center of the field.

Interpolating thickness values with the isopach map

With the isopach map, z-values could be determined for entry into the reservoir model. The z –values are simply the thickness of the reservoir at each well. The z-values were necessary to create a grid displaying reservoir thickness that could be entered into EdBOAST. The grid was defined as sixteen by twenty block grid, with each block representing a 1,320 square foot area of the field. For most well locations, z-values were known from the isopach map and could simply be entered into the EdBOAST grid. Wells that were drilled too deep (past the oil water contact), and were therefore dry holes, were assigned a default z-value of zero by Petra. Also, some grid locations did not have z-values because of lack of recorded well information or because there was no well at that location. EdBOAST requires the thickness grid to have continuity, so locations that didn’t have z-values or had false default values of zero, had to be interpolated. This was accomplished via the isopach map, where filled contours allowed for estimation of z-values at each undrilled location. The map below shows the grid established for the field. Each block contains or is said to contain one well, such that it was possible to define z-values for all locations within the grid (Figure 4-3).

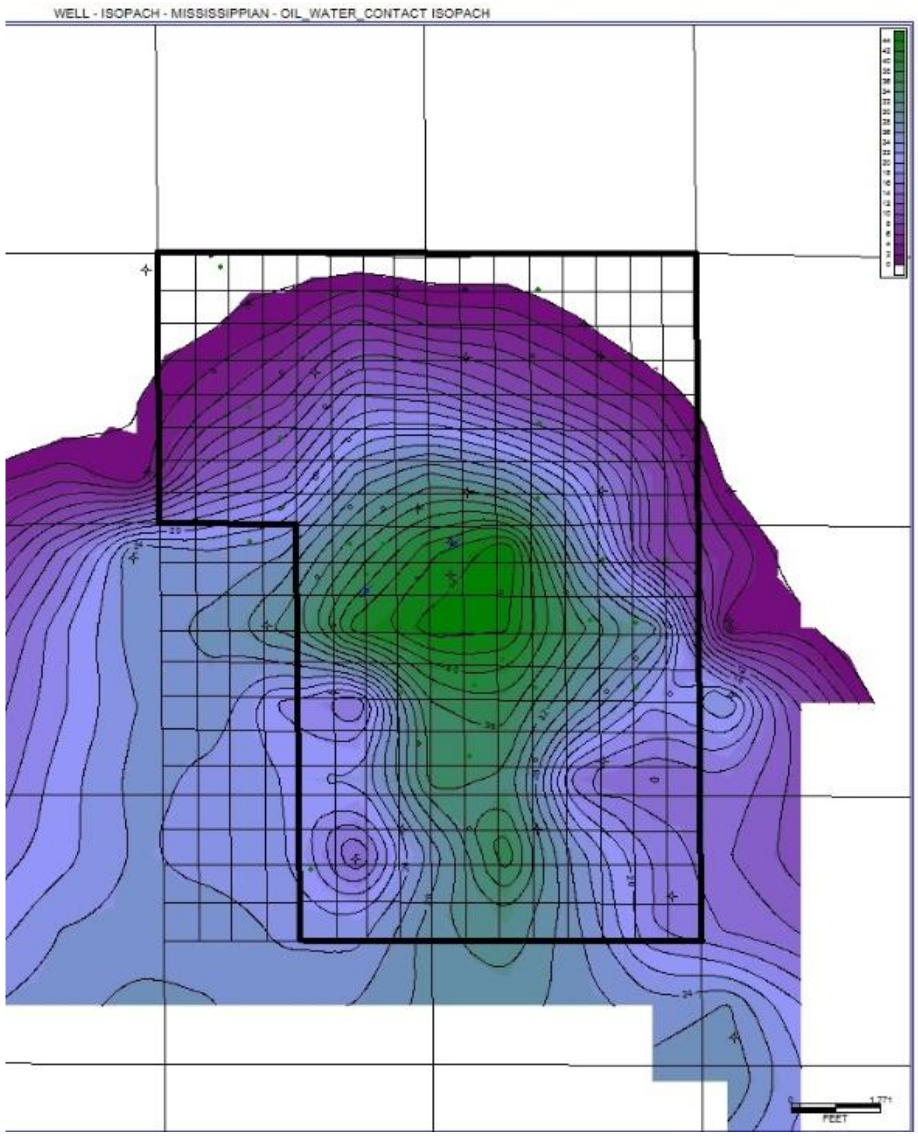


Figure 4-3: Petersilie sectioned according to the EdBOAST grid dimensions and overlain on the Mississippian isopach map. Generally, one well occurs in every grid block. Where wells do not occur, thickness values for the Mississippian reservoir were interpolated.

Preparing Data for the Reservoir Model

Defining the Limits of the Reservoir

One of the components of the EdBOAST reservoir model is the grid, which is a representation of the extent of the reservoir in the x- and y-directions, as well as the thickness in the z-direction. In order to create a grid, Petersilie was divided into sections. Petersilie has an area of approximately 2660 acres. However, for simplicity purposes because EdBOAST grid must be in rectangular form, that area defined as Petersilie was expanded, including five wells just to the west of the field. It was then possible to create a sixteen by twenty block grid, with each block a size of 1320 feet by 1320 feet, which was determined sufficient for modeling purposes. At this scale, wells were unlikely to overlap. Wells that were very close to the sectioning lines or on the lines were placed in the grid block they trended towards.

Data from Well Logs

Data achieved through examination of well logs included depth of the oil-water contact for the Mississippian in Petersilie, depth to the top of the grid blocks, and an average porosity value. By obtaining these values, it was possible to calculate average water saturation, original oil in place, and reservoir thickness values throughout the field. In order to estimate an average porosity for the Mississippian in Petersilie, wireline logs were downloaded from the Kansas Geological Society's website for eight wells located throughout Petersilie field (Figure A-1). The logs were Radiation Guard Logs, containing readings for gamma in API gamma ray units, neutron gamma in API neutron units, and resistivity in ohms. The neutron tool in Radiation Guard Logs is useful for estimating porosity. These logs are typically used to evaluate a well before deciding to run production casing. Limestone reservoirs will generally exhibit good porosity and moderate to high resistivity, so by determining where porosity and resistivity values were consistently high within the extent of the reservoir on the logs, average porosity values could be estimated. Well log data was also used to calculate other values such as an original oil in place value. To do this, factors such as water resistivity, oil formation volume factor, and water saturation were calculated. Water resistivity was calculated by averaging three data entries available for water resistivity in Ness County from the Kansas Geological Survey's Brine Catalog. The oil formation volume factor was estimated using the Standing Correlation. Archie's Equation was used to calculate water saturation values for each of the eight wells. Those values were averaged to achieve an average water saturation value for input into the reservoir model. Table B-2 identifies the wells used and shows the calculated data for each.

Carbonate Porosity Considerations

One of the potentially key influences in the reservoir model is reservoir porosity and porosity distribution. Porosity expresses the fractional volume of void space, or pores, in the rocks. Porosity may affect permeability, the ease at which fluids flow in the reservoir, depending on the type. For example, a rock with larger pores will exhibit higher permeability- fluid flows more easily through the pores. Both porosity and permeability are functions of the diagenetic and sedimentation processes that a rock undergoes and affect the productivity of the wells in a field. For rocks of known hydrocarbon-bearing potential, the value of effective porosity tends to fall within a narrow range. At less than 10%, porosity is poor and productivity is doubtful. From 10-15%, porosity is fair. At 15-25%, porosity is good and productivity is favorable. This is the range of porosity which most productive reservoirs fall into. Finally, at over 25%, porosity is extremely good, but is also unlikely to occur (Dikkers, 1985).

Besides the value of porosity in a reservoir, the porosity type may also play a large role in productivity. As such, it was important to have an understanding of carbonate porosity types. Choquette and Pray’s 1970 classification of carbonate porosity was used as a guideline for examining porosity in the thin sections. The Choquette and Pray model emphasizes the importance of pore space genesis. The classification divisions are genetic rather than petrophysical, dividing all carbonate pore space into fabric selective and non-fabric selective as seen in Figure 4-4 (Choquette and Pray, 1970).

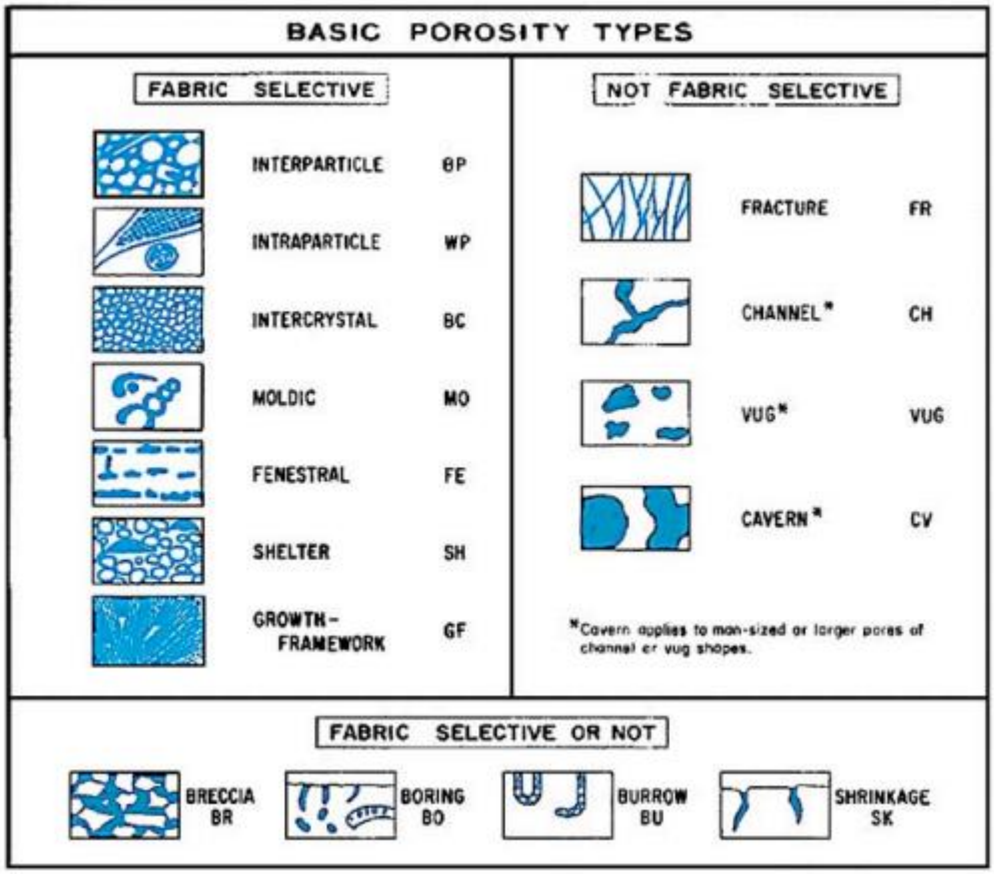


Figure 4-4: Illustrations of basic carbonate porosity types, including interparticle and intercrystalline porosity (image from Choquette and Pray, 1970).

Estimating Permeability from Drill Stem Tests

Permeability for a reservoir would usually be determined with the use of core; however, in this case, no core was available. Instead, drill stem tests were used to estimate permeability. Achieving permeability values for the reservoir was difficult because there were only three drill stem tests for the Mississippian in Petersilie available in the Kansas Geological Survey database. Copies of the drill stem test files were downloaded from the KGS website. Two drill stem tests were performed by Trilobite Testing, Inc. operating out of Hays, Kansas. The wells were DaMar Resources Inc.'s Evel Unit #1 and Travis #1. One drill stem test was performed by Diamond Testing out of Hoisington, Kansas. The well was Har-Ken Oil Company's Petersilie #1.

The drill stem test conducted on Travis #1 was at an interval of 4376 feet to 4424 feet. There was a recovery of 0.05 barrels of oil. The Trilobite Testing drill stem test conducted on Evel Unit #1 recovered a total of 8.16 barrels of oil at an interval of 4352 feet to 4365 feet. Lastly, Diamond Testing's drill stem test performed on Petersilie #1 recovered 1.81 barrels of oil at an interval of 4382 feet to 4395 feet. The drill stem test data for Petersilie #1 included two Horner plots that yielded permeability values of 15.85 md and 14.09 md for the Mississippian. To determine permeability values for the other two drill stem tests, the data for each were uploaded into a KGS program that assists in creating Horner plots, available for free online at the KGS website. Once permeability values were determined, all four permeability values were averaged to achieve a constant permeability value for the Mississippian in Petersilie to be entered into the reservoir model. The Horner plots and quantitative analyses for each drill stem test are shown in Appendix A.

Pressure, Volume, and Temperature Considerations

Some pressure, volume, and temperature considerations were necessarily included in the construction of the reservoir model. Key components that were required included pressure initialization and saturation initialization coding options, depth of the pressure datum, fluid gradient for pressure, pressure at and depth to the oil water contact and gas oil contact, initial oil and gas saturations for each region, and initial pressure and oil, gas, and water saturations for each layer. Temperature was averaged from drill stem test data. Depth of the pressure datum was said to be equivalent to the depth to the top of the reservoir. Pressure at the pressure datum was applied from drill stem test data. A fluid gradient for pressure was adopted from values determined in the Horner plots created for permeability estimation. Initial oil saturation was calculated after determining water saturation within the reservoir. Default values for the EdBOAST program were used for all other specifications.

Creating the Reservoir Model with EdBOAST

A new file was created in EdBOAST entitled "Petersilie.sim". Once the new file was created, it could be modified and values could be entered that were specific to the Mississippian in Petersilie. The home screen in EdBOAST is shown below. To start, a header was given to the project by navigating from the EdBOAST home screen to the BEGIN button. The DEFAULT button was selected to enter default values into the model which could be modified later. Without prior selection of the DEFAULT button, EdBOAST would not save any subsequent data modifications.

Next, the extent of Petersilie field and the reservoir was defined in the GRID section. A total of sixteen columns, twenty rows, and one layer were entered. Grid input controls in the x-, y- and z-directions were entered such that the grid dimensions were the same for all blocks in the grid in the x- and y- directions, and z- direction values (thickness values) were read for every block in the model. The grid dimensions in the x- and y-directions were 1320 feet by 1320 feet. Values in the z-direction indicating thickness of the reservoir were entered manually into the grid, and were repeated for the grid of net z-values (Figure 4-5). Depth to the top of the grid blocks and dip angle direction values and controls were specified such that the dip angle was zero and depth to the top of the grid block was 2080.73 feet, the depth to the top of the Mississippian in Petersilie field.

I1:J1= 0.0000

	I1	I2	I3	I4	I5	I6	I7
J1	0.0000	3.0000	0.0000	0.0000	0.0000	0.0000	0.0000
J2	0.0000	0.0000	0.0000	0.0000	0.0000	4.0000	2.0000
J3	0.0000	0.0000	0.0000	0.0000	4.0000	8.0000	8.0000
J4	2.0000	0.0000	0.0000	4.0000	4.0000	17.0000	14.0000
J5	2.0000	2.0000	2.0000	14.0000	6.0000	18.0000	22.0000
J6	4.0000	8.0000	9.0000	22.0000	18.0000	21.0000	24.0000
J7	8.0000	14.0000	14.0000	14.0000	18.0000	24.0000	32.0000
J8	14.0000	18.0000	24.0000	28.0000	22.0000	35.0000	36.0000
J9	20.0000	20.0000	32.0000	34.0000	22.0000	32.0000	37.0000
J10	20.0000	24.0000	34.0000	34.0000	36.0000	45.0000	46.0000
J11	24.0000	24.0000	34.0000	34.0000	46.0000	46.0000	48.0000
J12	24.0000	28.0000	34.0000	24.0000	44.0000	46.0000	44.0000
J13	24.0000	28.0000	28.0000	24.0000	34.0000	44.0000	30.0000
J14	24.0000	24.0000	28.0000	24.0000	34.0000	38.0000	28.0000
J15	24.0000	24.0000	24.0000	24.0000	26.0000	28.0000	24.0000
J16	20.0000	20.0000	20.0000	24.0000	26.0000	14.0000	18.0000
J17	20.0000	20.0000	20.0000	24.0000	20.0000	18.0000	20.0000
J18	20.0000	20.0000	20.0000	24.0000	18.0000	18.0000	20.0000
J19	24.0000	20.0000	20.0000	22.0000	18.0000	20.0000	18.0000
J20	24.0000	24.0000	24.0000	22.0000	20.0000	24.0000	22.0000

Figure 4-5: Gridded z-values, or reservoir thickness values, in EdBOAST. The "I" columns correspond to the grid block in the x-direction and the "J" columns correspond to the grid block in the y-direction. The field is represented by a total of sixteen grid blocks in the x-direction and twenty grid blocks in the y-direction.

The PORPERM button allows for entering of porosity and permeability specifications. In the PORPERM section, input control values were entered for porosity and permeability distribution control and modification. These included input controls for permeability in the x-, y- and z-directions. Porosity input control was set to read one constant porosity value of 0.241, or 24.1% porosity, as determined from well log examination. Permeability controls were set to read one constant permeability value of 26.0 md in every direction, as determined from the Horner plots.

In the TRANSM section, default values were used. There were no modifications made to grid blocks to account for transmissibility, or the flow between grid blocks. One distinct rock region and one distinct pressure-volume-temperature region were defined in the TABLE section. Relative permeability and capillary pressure values used were default values (Figure 4-6). There were a total of six entries to the relative permeability table. Irreducible water saturation was given as 0.12, or 12%. PVT data for oil, water and gas in this section were taken to be the default values due to lack of means of obtaining these values through laboratory testing.

Figure 4-6: Relative permeability and capillary pressure values in the TABLE section.

The INITIAL button contains options for entering and coding data for the initial pressures and saturations of the reservoir. The pressure initialization option was chosen so that the pressure would be specified by layer. The saturation initialization option was also coded to be specified by layer rather than input for the entire grid. A value of 2080.7 feet was entered for depth to the pressure datum. Fluid gradient for pressure correlated to the depth pressure datum was entered as 0.362 psia/ft, as was recorded in drill stem tests. Pressures and saturations were the same for the region and the rock layer for purposes of simulation. Initial pressure for the layer was entered as 1251.5 psia/ft. Pressure at the oil-water contact for the layer was entered as 1258.7 psia with a calculated depth to the oil-water contact of 2116 ft. Initial oil saturation for the region was given as 0.764, or 76.4%. Initial water saturation was 0.236 or 23.6%. Gas saturations were ignored due to lack of recorded data for gas production in Petersilie field. Gas saturation was given a value of 0.

No values were changed in the CODES section. Maximum time steps allowed before termination of the program and maximum real time in days to be simulated were both acceptable values for the run time expected for this model. All other processing commands were acceptable. In AQUI, modifications could be made to include influence from a water-bearing layer in contact with the producing layer. Because this condition does not exist in Petersilie, the program was coded to exclude aquifer influence.

In the WELLS section, modifications were made to include the input of the three wells that drill stem test data were available for. The locations of the wells in the x-, y- and z-directions were entered according to the grid and the wells were coded as vertical wells. The RECURR button allowed for further modification of well characteristics. The wells were coded as producing wells according to their status and their productivity index values were entered. The completed file was saved and transferred to the BOAST 98 program for simulation.

Reservoir Simulation Using BOAST 98

Once the file was transferred from EdBOAST to BOAST 98, it was opened and viewed by navigating to the Options tab in the home screen and selecting View. It was determined that all of the data had transferred correctly before navigating back to Options to select Simulate and run the model. The model ran within a few seconds, although right-clicking on the screen halted the run in order to examine the data. The data displayed during the simulation was reservoir pressure and barrels of oil produced per day over a time period of 365 days. The simulation data was viewed repeatedly and images of the simulation as it was running were taken for later comparison to the known production history of the Mississippian in Petersilie. Also in the Options dropdown menu, Plot was selected to create plots for oil saturation and pressure values throughout the field. The plots were also saved for further examination and comparison.

Chapter 5 - Results

Reservoir Grid, Porosity, Permeability, and PVT Data

As was previously mentioned, an area of approximately 2660 acres was calculated for Petersilie field. A sixteen foot by twenty foot grid composed of 1320 square foot grid blocks was deemed appropriate for modeling the reservoir. Thickness values, or values in the z-dimension, for the grid were interpolated from Petra isopach mapping and an average thickness of 31.9 feet was determined for the Mississippian throughout Petersilie (Figure 5-1). Porosity was estimated at 24.1% or 0.241 from examining the neutron tool readings on the Radiation Guard Logs.

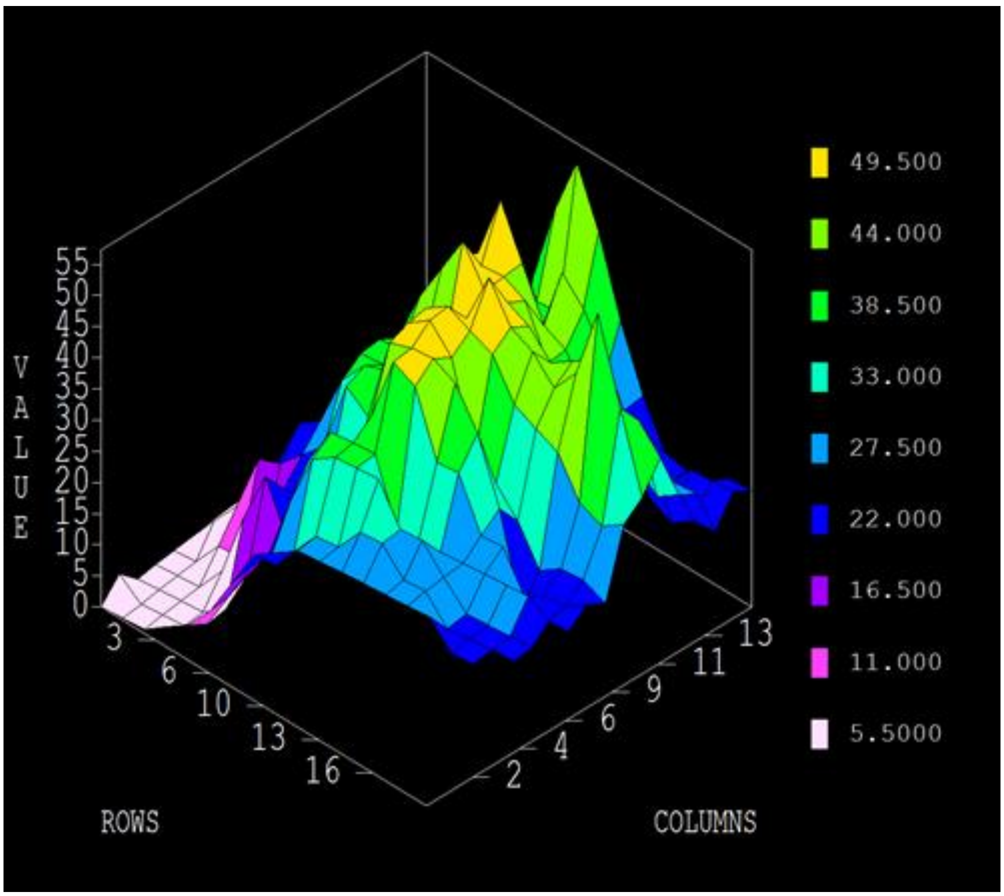
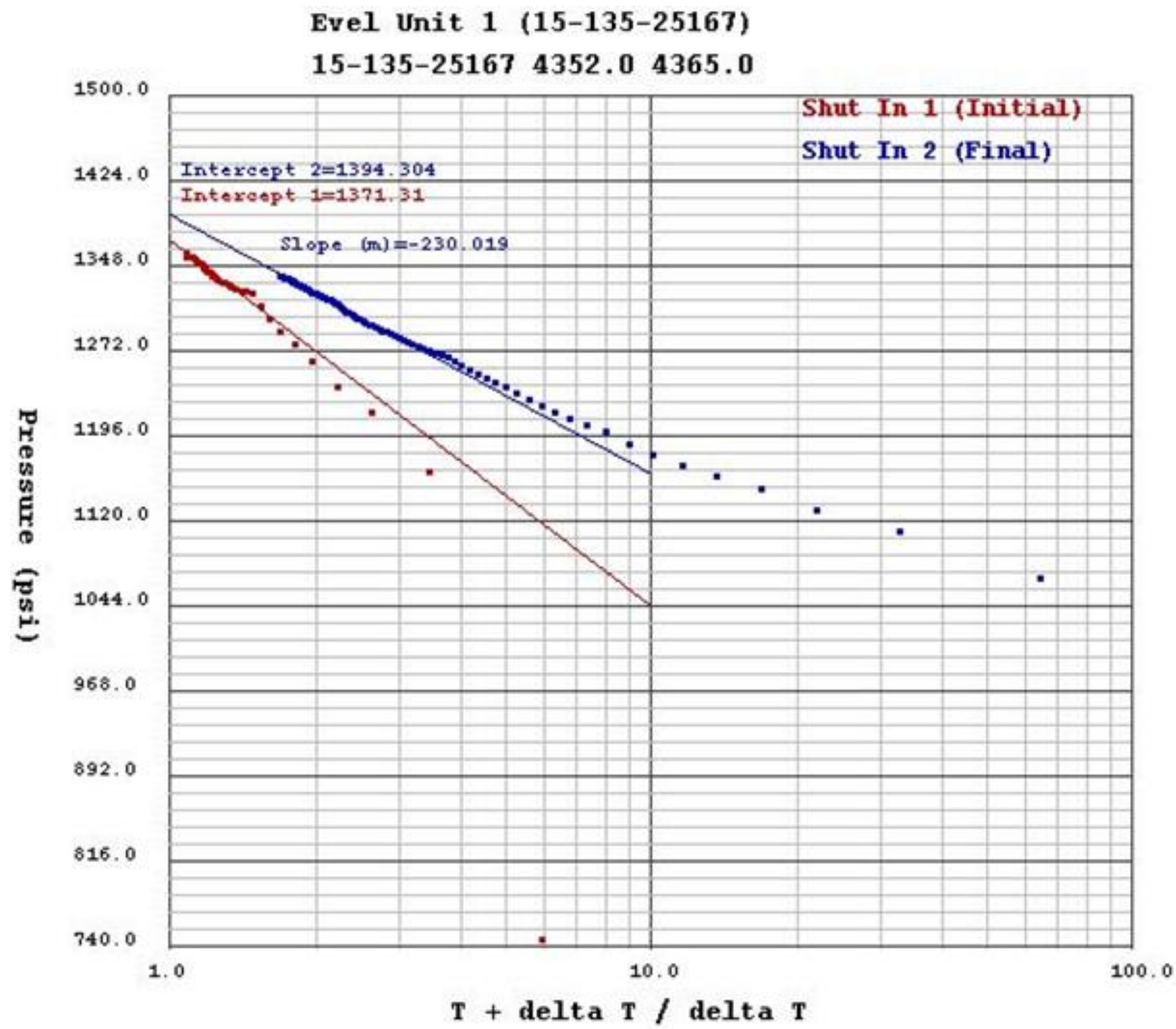


Figure 5-1: BOAST 98 three-dimensional graph of thickness values throughout the Mississippian reservoir in Petersilie field. Thickness of the reservoir in every location was said to be the difference between the depth of oil-water contact and the depth of the formation tops of the Mississippian.

Permeability was estimated at an average of 26.0 md from the Horner plots that were constructed from the drill stem test data. Also taken from the drill stem test data was information on initial pressure throughout the reservoir and temperature, which were estimated at 1251.5 psia and 120 degrees Fahrenheit, respectively. The Horner plots that were created for Evel #1 and Travis #1, and their respective quantitative analyses, are shown below in Figures 5-2 and 5-3. Figures 5-4 and 5-5 are the Horner plots and quantitative analyses of the initial shut-in period and final shut-in period of the drill stem test for Petersilie #1.

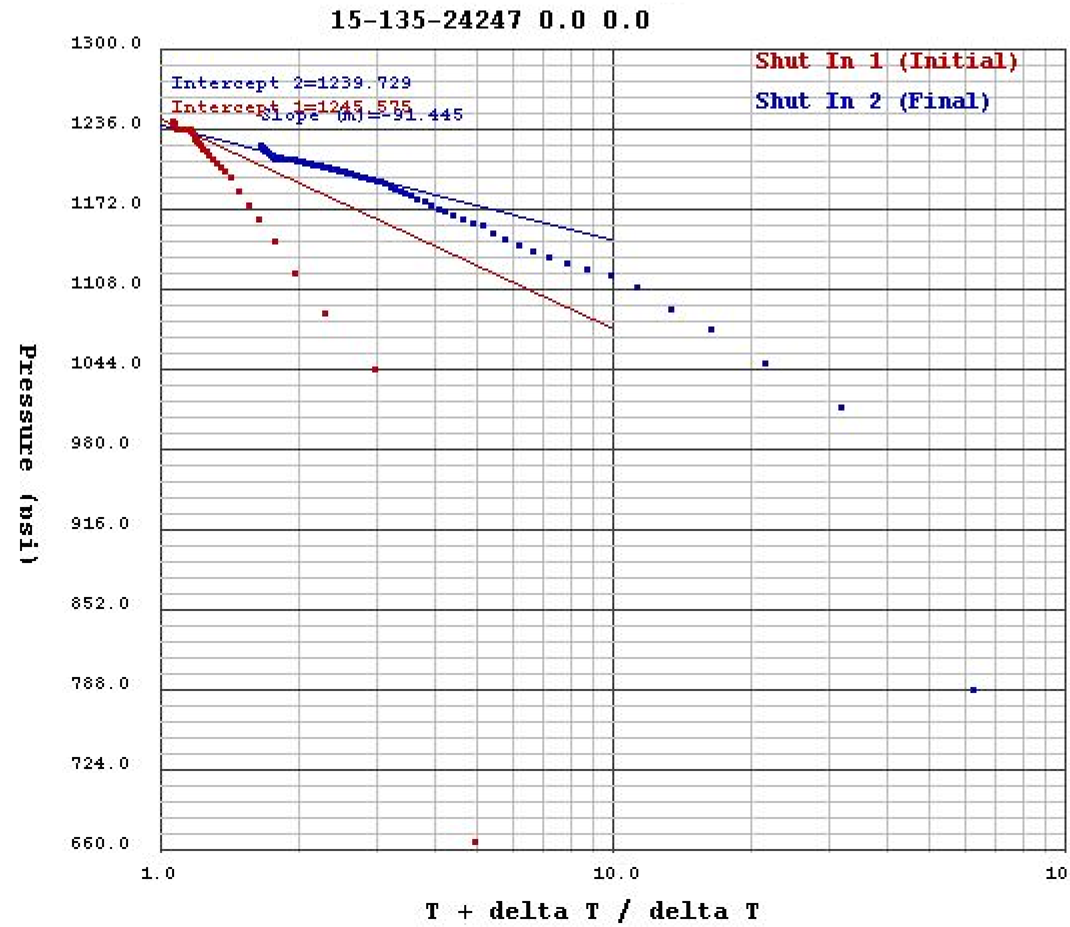
Depth to the pressure datum was said to be equivalent to the depth to the top of the grid blocks, averaged at 2080 feet. A fluid gradient for pressure was taken from the drill stem test data as 0.362 psia/ft. Depth to the oil-water contact was determined through Petra mapping. It was found to be 2116 feet. Pressure at the oil-water contact was estimated at 1258 psia. An oil formation volume factor of 1.023 was calculated. Water resistivity was averaged at 0.299 ohms. Water, oil, and gas saturations were then calculated. Water saturation was 23.6%, or 0.236. Oil saturation was 76.4%, or 0.764. Gas saturation was negligible since gas is not produced in Petersilie field. Finally, an original oil in place value of nearly 50 million barrels was calculated, of which almost six million have been produced as of 2014.

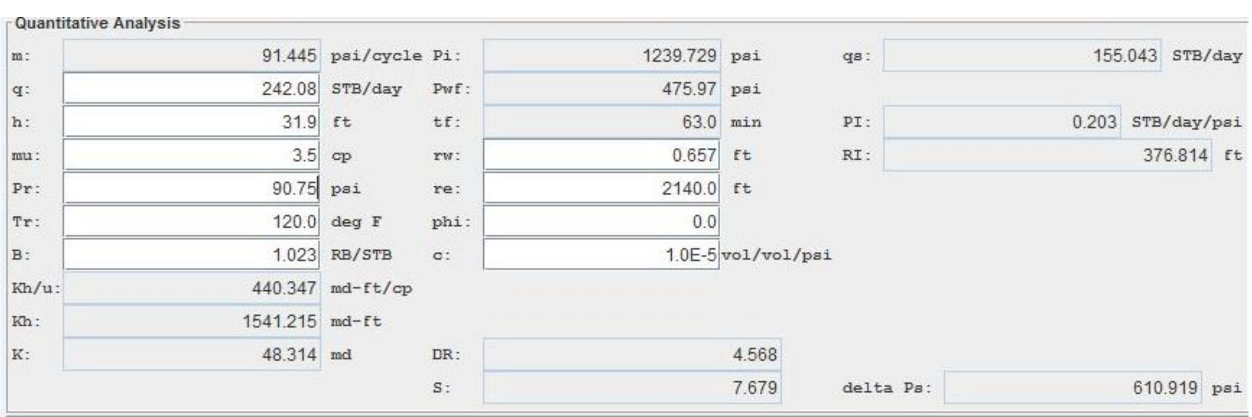


Quantitative Analysis

m:	230.019	psi/cycle	Pi:	1394.304	psi	qs:	112.658	STB/day
q:	180.753	STB/day	Pwf:	267.72	psi			
h:	31.9	ft	tf:	65.0	min	PI:	0.1	STB/day/psi
mu:	3.5	cp	rw:	0.638	ft	RI:	27762.24	ft
Pr:	1210.0	psi	re:	2140.0	ft			
Tr:	120.0	deg F	phi:	0.241				
B:	1.023	RB/STB	c:	1.0E-5	vol/vol/psi			
Kh/u:	130.713	md-ft/cp						
Kh:	457.496	md-ft						
K:	14.342	md	DR:	0.582				
			S:	1.697		delta Ps:	339.598	psi

Figure 5-2: Horner plot and quantitative analysis for Evel #1, API #25167.

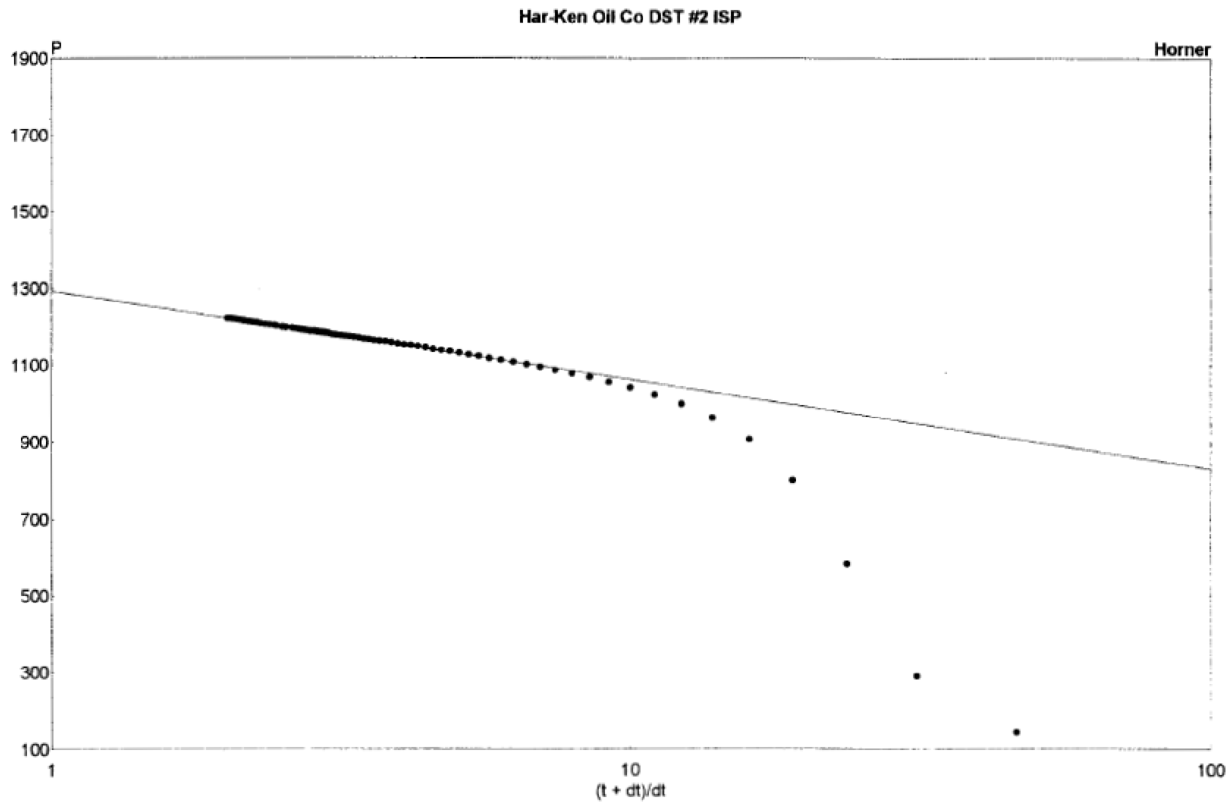




Quantitative Analysis

m:	91.445	psi/cycle	Pi:	1239.729	psi	qs:	155.043	STB/day
q:	242.08	STB/day	Pwf:	475.97	psi			
h:	31.9	ft	tf:	63.0	min	PI:	0.203	STB/day/psi
mu:	3.5	cp	rw:	0.657	ft	RI:	376.814	ft
Pr:	90.75	psi	re:	2140.0	ft			
Tr:	120.0	deg F	phi:	0.0				
B:	1.023	RB/STB	c:	1.0E-5	vol/vol/psi			
Kh/u:	440.347	md-ft/cp						
Kh:	1541.215	md-ft						
K:	48.314	md	DR:	4.568				
			S:	7.679		delta Ps:	610.919	psi

Figure 5-3: Horner plot and quantitative analysis for Travis #1, API #25247.



Analysis Results: Horner

Parameters:

Slope = -230.74

m(1 hr) = 1238.21

Prd Time: = 0.75 hr

Calculated Values:

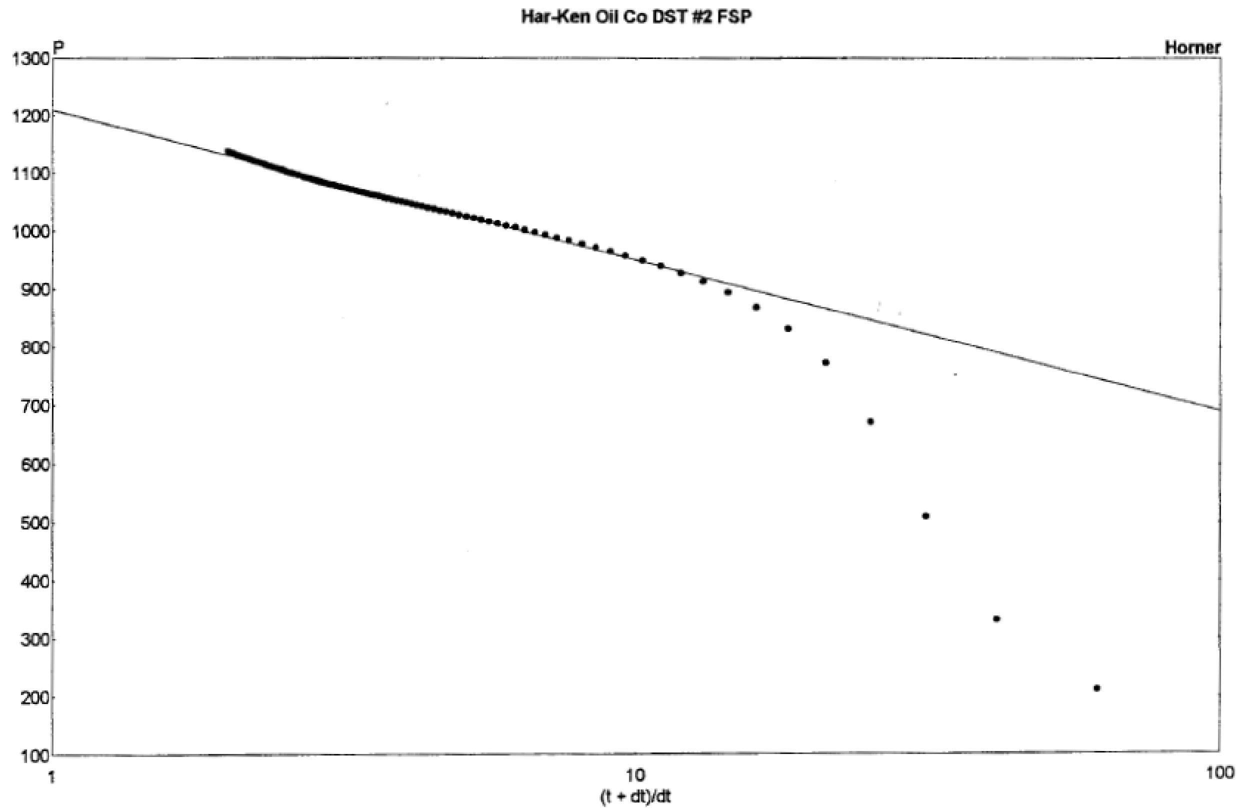
kh = 158.523 md-ft

k = 15.8523 md

Skin = 4.68742

P* = 1294.3 psi

Figure 5-4: Horner plot and quantitative analysis for initial shut-in of Petersilie #1, API #24108.



Analysis Results: Horner

Parameters:

Slope = -259.601

m(1 hr) = 1131.64

Prd Time: = 1 hr

Calculated Values:

kh = 140.9 md-ft

k = 14.09 md

Skin = 5.63931

P* = 1209.8 psi

Figure 5-5: Horner plot and quantitative analysis for final shut-in of Petersilie #1, API #24108.

Chapter 6 – Discussion

Evaluating a waterflood candidate is the first step in determining the success of a waterflood. Generally, a team of geologists would work on this evaluation in conjunction with a team of engineers. This study was conducted by a single person, making it a more reliable estimation of how a smaller company with fewer people to devote to such projects might still be able to achieve useful data. The process traditionally involves a review of reservoir data, including initial production, gas/oil ratios, pressure information, and core information. Then, if the initial review meets the criteria for a waterflood candidate, a more thorough review of pressure, volume and temperature data is undertaken. Means of obtaining this data were restricted to what could be determined or estimated from well logs and drill stem tests. However, although limited, the data ultimately produced a simulated oil production curve that closely matched the actual production curve.

As was previously discussed, reservoir drive mechanisms play a very important role in determing whether a waterflood candidate will be successful. Drive mechanisms may be inferred from production curves, and production-curve analysis is an integral part of evaluating a waterflood candidate (Rottman, et. al, 1998). In Figure 6-1, Petersilie's production curve is compared to typical production curves for the three main reservoir drive mechanisms. Petersilie's production curve showed a very steep rise in barrels of oil produced per day followed by a rapid fall in a short amount of time. Taking into account human error in producing this field, this trend in production nevertheless mirrors that of a solution-gas drive reservoir, an ideal reservoir for waterflooding due to high oil saturation remaining upon the field's depletion. In a solution-gas drive reservoir, the gas-oil ratio is a very steep parabolic curve. Even without the input of gas data for the field, Petersilie's production curve matches this description. Although reservoir pressure was not increased to a point where a secondary production curve is abundantly apparent, the fact that three injection wells were sufficient to slow the rate of production decline drastically is promising for the future of waterflooding as a secondary recovery method in the Mississippian in Petersilie.

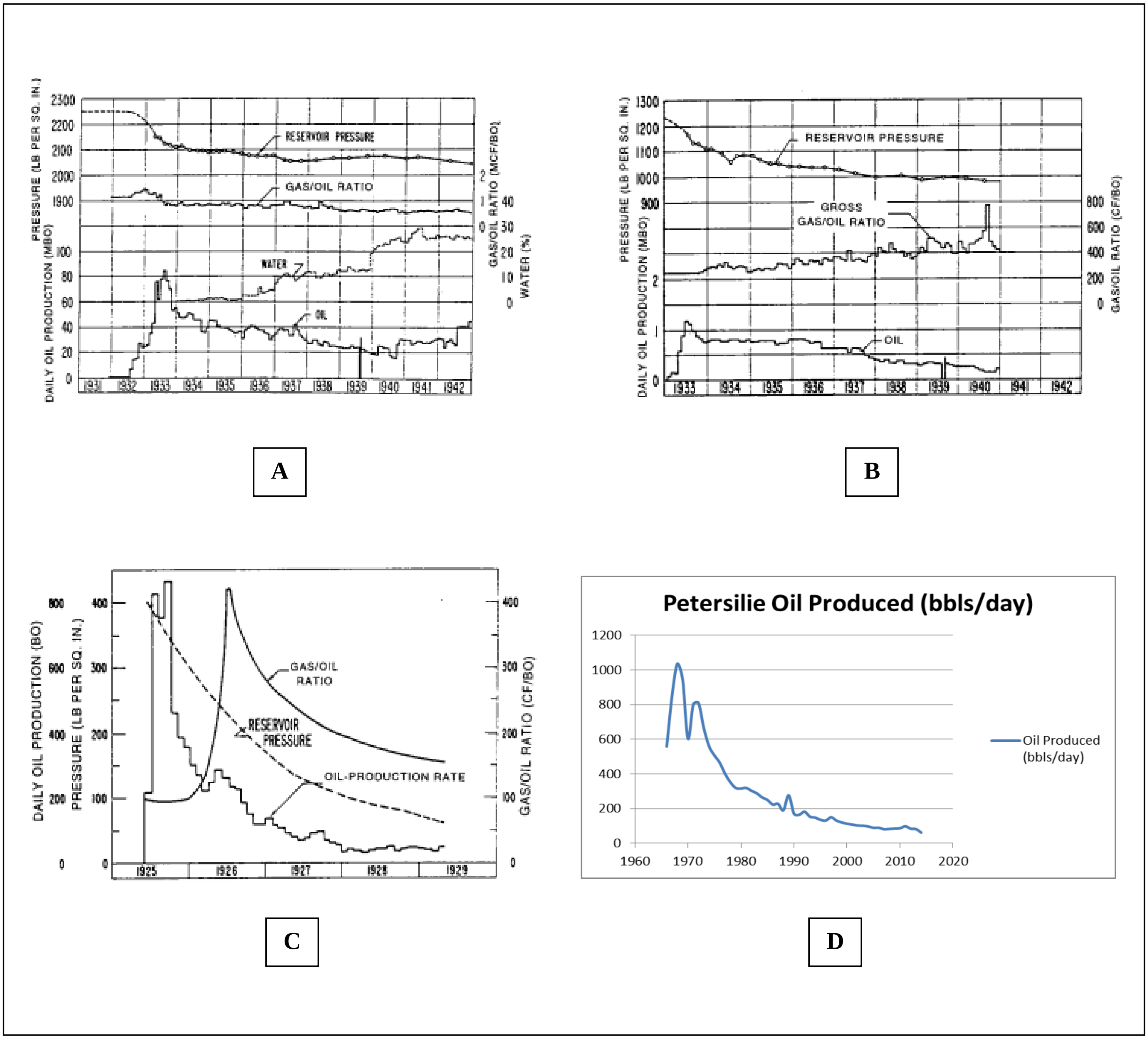


Figure 6-1: Graphs depicting typical oil production curves for a water drive reservoir (**A**), a gas-cap drive reservoir (**B**), and a solution-gas drive reservoir (**C**). Petersilie's production curve is shown in graph **D**. Production curve analysis indicates that Petersilie is a solution-gas drive reservoir, making it a good candidate for waterflooding (images from Rottman, et. al, 1998).

Ultimately, Petersilie field responded favorably to waterflooding. From the onset of drilling activities in the field in 1966, to the start of waterflooding operations in 1992, Petersilie was being depleted at a rate of approximately 10,500 barrels per year. After waterflooding was begun in 1992, the rate of decline in production was decreased to about 1487 barrels per year. This is important because waterflooding in Petersilie consisted of the implementation of only three water injection wells, two of which are currently operative. The use of these three wells alone decreased the rate of production decline by 86%. With the use of waterflooding, individual well productivity was also improved. The effect was variable on each well, however. While one well on the eastern side of the field currently produces only two barrels of oil per day with 350 barrels of water, the well on the western side of the field produces 37 barrels of oil. This could provide insight into the location and movement of the oil bank within the field and surrounding the wells.

This study proved successful in determining data usually acquired through core and more complete well logs. The close match of the production histories, both simulated and real, means that the reservoir model created is largely descriptive of the Mississippian's behavior in Petersilie field. More specifically, it means that the data collected from Radiation Guard Logs and drill stem tests was a good fit for the reservoir. This is a major find because Radiation Guard Logs are the traditional means of reading the subsurface by producers in the area and are widely used throughout Kansas. The logs provided a porosity value that ultimately proved successful in the modeling process. Drill stem tests were not widespread in Petersilie, but the data from each of the three tests conducted was nevertheless adequate to determine an appropriate permeability value. Obtaining core or drilling new wells to achieve better well logs can be prohibitively expensive for oil companies, especially companies such as those that are currently operating in Petersilie field- small independents with limited resources at their disposal for better understanding the reservoir being produced. The success of this work is directly related to the reliability of the publicly-available drill stem test and well log data that was obtained at no cost for the field.

From examining well logs and drill stem test data, average porosity and permeability values of 24.1% and 26 md respectively, were determined. Since most productive reservoirs must have porosity of between 15-25%, the porosity of the Mississippian in Petersilie is very good, and is favorable for production. Generally, the larger the pores, the easier fluids may flow through the rock. Therefore, porosity in this case may have a favorable impact on permeability. Both of these factors could potentially enhance the success of waterflooding operations. Also helpful are the large size of the reservoir and the lack of hindering structural influences.

Comparison of Actual Production and Simulated Production

Because there was limited data available for modeling purposes due to only three drill stem tests having been conducted for the entirety of the Mississippian in Petersilie field, simulation of the reservoir model was limited to the three wells that the drill stem tests were performed on. However, even while simulating a fraction of the wells in the field, the reservoir simulation was still a close match to the actual production of the three wells. The reservoir simulation showed the production decreasing from 50 barrels per day to about 42.5 barrels per day at an approximate rate of 0.021 barrels per day. The actual production of the three wells varied between 43 and 30 barrels throughout the year, but generally declined at a rate of 0.034 barrels per day. Hence the difference between the simulated production and actual production for the three wells was about 0.013 barrels per day. Fluctuations in actual production occurred that were not represented by the simulation. Reservoir pressure was consistent throughout the field with the exception of decreasing around the three wells during later times and towards the lower edge of the field. Figure 6-2 is an image of the simulation as it was running, including the simulated production curve. The insets highlight the actual oil produced by the three wells versus the simulated production in barrels per day.

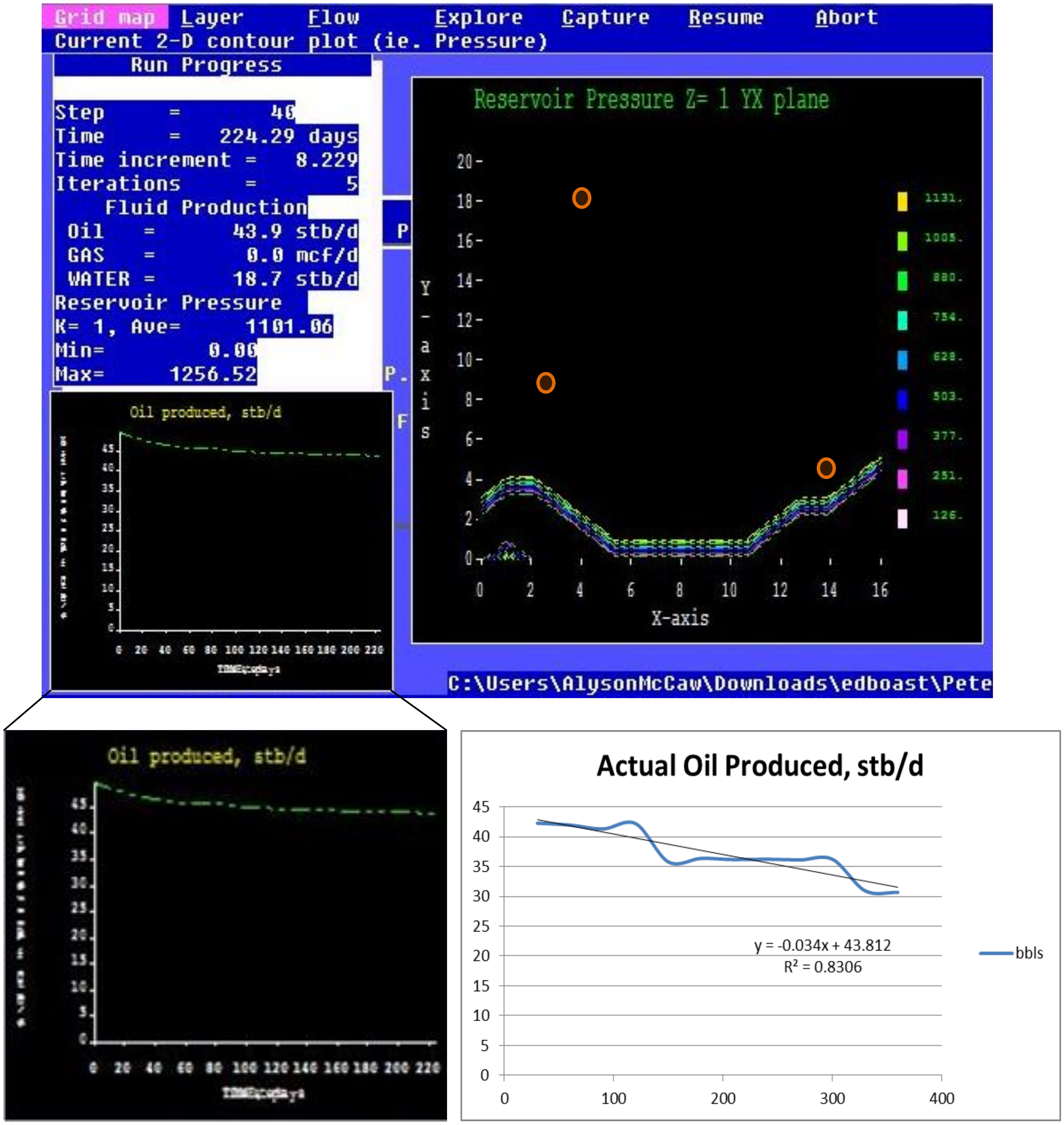


Figure 6-2: The top image shows the reservoir simulation as it was running. Pressure fluctuated around the well sites and decreased towards the southern edges of the reservoir. Fluctuations in actual production rate were not taken into account in the simulated production curve. The locations of the three drill stem-tested wells are indicated by the orange circles.

Chapter 7 - Conclusions

Petersilie oil field was waterflooded beginning in 1992 as a means of recovering more oil from a rapidly-depleting reservoir. While the waterflooding was successful, the reasons for its success had not previously been examined. The Mississippian in Petersilie field is largely representative of the reservoir as it occurs in most of central to south-central Kansas, and is produced mainly by small independent Kansas oil companies, making Petersilie a good candidate for study. Gaining a better understanding of the Mississippian reservoir has the potential to provide such companies with the opportunity to make effective drilling decisions given the limited resources available to them.

To maintain cost-effectiveness, all resources used in this study were only what would be readily available to an independent company for free or the price of gas to retrieve them. Reservoir modeling and simulation is no longer limited solely to big companies thanks to work undertaken by the U.S. Department of Energy's National Energy Technology Laboratory to create free modeling and simulating products in the mid-1990s. The reservoir modeling program EdBOAST and its companion reservoir simulating program, BOAST 98, were downloaded for free online and proved effective in modeling and simulating the Mississippian in Petersilie field. A comparison of the actual oil production history for the three wells tested to the simulated production history was a close match, with little more than a hundredth of a barrel per day difference. This was a major find because it showed that not only was the reservoir model a good fit for the Mississippian as it occurs in Petersilie, but the drill stem test and well log data were very reliable. For these reasons, there is great potential for the successful implementation of the EdBOAST and BOAST 98 in-house by a company with limited funds to spend on expensive testing or modeling through an outside party.

Petersilie was successfully waterflooded for a few key reasons. Reservoir quality of the Mississippian in the field is good, with high porosity and moderate permeability for a limestone reservoir. There is no major disruptive structure present in the reservoir. The reservoir pay zone is fairly thick, growing thickest towards the middle of the field and tapering towards the edges, especially to the south. The most influential component in evaluating a successful waterflood candidate is the reservoir drive mechanism. Reservoir drive mechanisms can be determined through oil production curve analysis. Production curve analysis of Petersilie led to the determination that the drive mechanism for the Mississippian in this area is a solution-gas drive. As is typical of a solution-gas drive mechanism, reservoir pressure was depleted rapidly as gas was quickly lost. However, this was ultimately ideal for waterflooding purposes since there was a high degree of oil saturation remaining in the reservoir upon depletion. Expansion of waterflooding practices in Petersilie could help continue the increase in production that the field experienced at the onset of waterflooding and further restore pressure.

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Appendix A

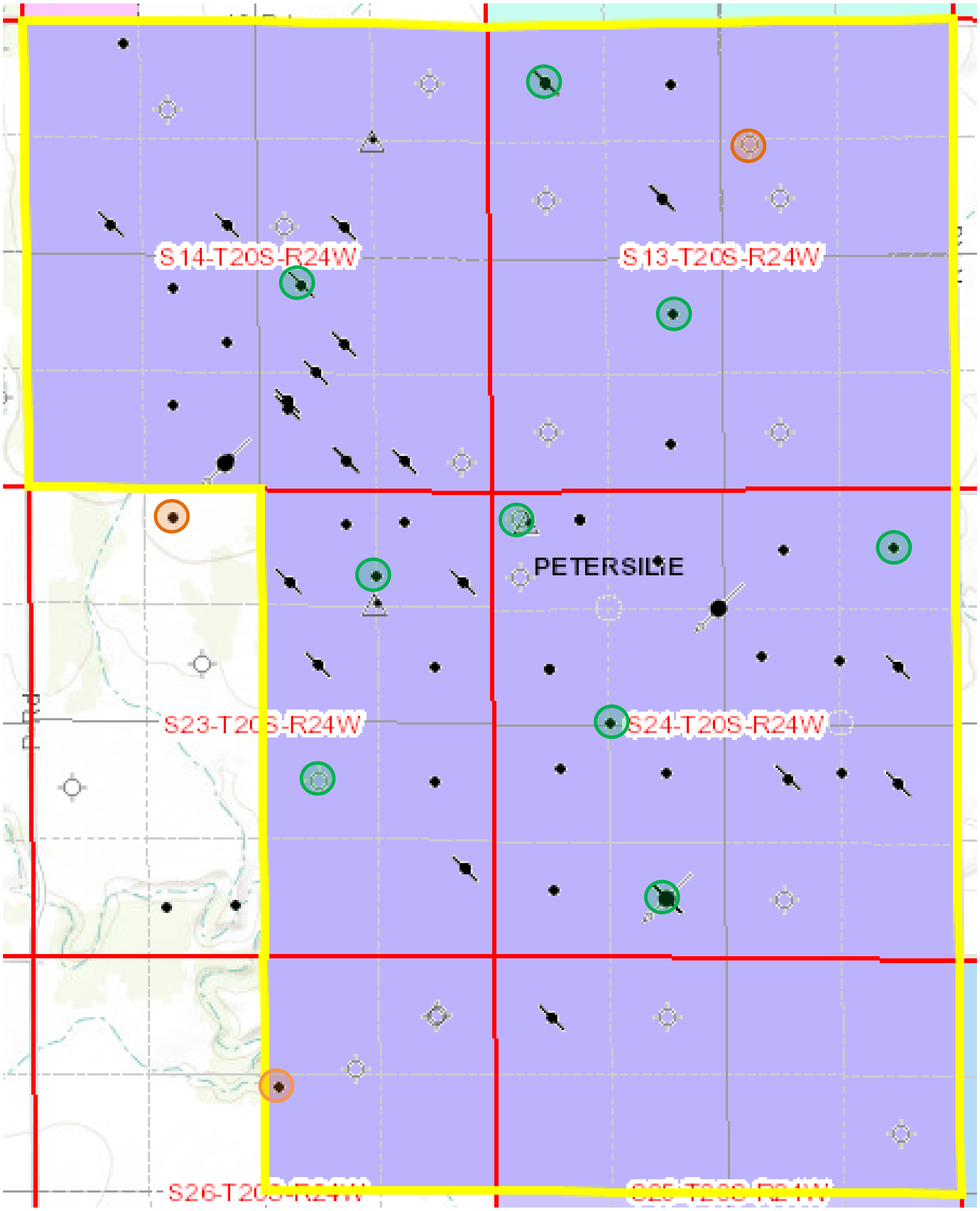

Figure A-1: Wells used to establish porosity indicated in green; wells used to establish permeability indicated in orange (image modified from Kansas Geological Survey, 2014)

Appendix B

Mechanisms	Reservoir Pressure	GOR	Water Production	Efficiency	Others
1. Liquid and rock expansion	Declines rapidly and continuously P_i (initial pressure) > P_b (bubble point pressure)	Remains low and constant	None (except in high S_w reservoirs)	1-10% Avg. 3%	
2. Solution gas drive	Declines rapidly and continuously	First low, then rises to maximum and then drops	None (except in high S_w reservoirs)	5-35% Avg. 20%	Requires pumping at an early stage
3. Gas cap drive	Falls slowly and continuously	Rises continuously in up-dip wells	Absent or negligible	20-40% Avg. 25% or more	Gas breakthrough at a down dip well indicates a gas cap drive
4. Water drive	Remains high. Pressure is sensitive to the rate of oil, gas, and water production	Remains low if pressure remains high	Down-dip wells produce water early and water production increases to appreciable amount	35-80% Avg. 50%	N calculated by material balance increases when water influx is neglected
5. Gravity drainage	Declines rapidly and continuously	Remains low in down-dip wells and high in up-dip wells	Absent or negligible	40-80% Avg. 60%	When k > 200 mD, formation dip > 10° and μ_o low (< 5 cP)

Table B-1: Differences in reservoir drive mechanisms and their impacts on oil production efficiency. Solution-gas drive mechanisms are most effectively waterflooded (Water Injection, 2014).

API#	Top	KB	Porosity (%)	Rw	Rt	m	n	a	Sw
20201 MS	4400	2316	0.2	0.299	360	2	2	1	0.1441
20182 MS	4409	2315	0.17	0.299	150	2	2	1	0.26263
148 MS	4386	2315	0.2	0.299	200	2	2	1	0.19333
20013 MS	4355	2294	0.3	0.299	110	2	2	1	0.17379
30243 MS	4408	2290	0.3	0.299	60	2	2	1	0.23531
30243 MS	4408	2290	0.2	0.299	30	2	2	1	0.49917
20161 MS	4386	2324	0.3	0.299	325	2	2	1	0.10111
23989 MS	4350	2287	0.3	0.299	325	2	2	1	0.10111
23989 MS	4350	2287	0.25	0.299	340	2	2	1	0.11862
00021 MS	4354	2277	0.23	0.299	50	2	2	1	0.33622
00021 MS	4354	2277	0.2	0.299	40	2	2	1	0.43229

Table B-2: Wells used to achieve data for entry into the reservoir model.