PRODUCTION FORECAST, ANALYSIS AND SIMULATION OF EAGLE FORD SHALE OIL

A Thesis

by

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ABSTRACT

In previous works and published literature, production forecast and production decline of unconventional reservoirs were done on a single-well basis. The main objective of previous works was to estimate the ultimate recovery of wells or to forecast the decline of wells in order to estimate how many years a well could produce and what the abandonment rate was. Other studies targeted production data analysis to evaluate the completion (hydraulic fracturing) of shale wells.

The purpose of this research is to generate field-wide production forecast of the Eagle Ford Shale (EFS). This study considered oil production of the EFS only. More than 6 thousand oil wells were put online in the EFS basin between 2008 and December 2013. The method started by generating type curves of producing wells to understand their performance. Based on the type curves, a program was prepared to forecast the oil production of EFS based on different drilling schedules; drilling requirements can be calculated based on the desired production rate. To complement the research, analysis of daily production data from the basin was performed. Moreover, single-well simulations were done to compare results with the analyzed data.

Findings of this study depended on the proposed drilling and developing scenario of EFS. The field showed potential of producing high oil production rate for a long period of time. The three presented forecasted cases gave and indications of the expected field-wide rate that can be witnessed in the near future in EFS.

The method generated by this study is useful for predicting the performance of various unconventional reservoirs for both oil and gas. It can be used as a quick-look tool that can help if numerical reservoir simulations of the whole basin are not yet prepared. In conclusion, this tool can be used to prepare an optimized drilling schedule to reach the required rate of the whole basin.

DEDICATION

I would like to dedicate my work to my parents for their encouragement, and I dedicate this to my wife for her support and patience and to my sons. Also, I dedicate this to all my friends and colleagues who helped me throughout my study and research. Last, but not least, a special dedication to my late advisor, Dr. R.A. Wattenbarger for his supervision, kindness and support.

ACKNOWLEDGEMENTS

First of all, I thank Allah the Almighty for His blessing and guidance to accomplish this thesis.

Also, I would like to thank my late advisor, Dr. R.A Wattenbarger for his inspiration and help. In addition, I would like to express deep gratitude to the chair of my committee, Dr. David Schechter for his support and encouragement, especially after the sad demise of my previous advisor. Special thanks to my committee members, Dr. Bryan Maggard and Dr. Yuefeng Sun for their advice and feedback.

I am grateful to my colleagues, Dr. Ahmad Alkouh, Mohammad Kanfar, Sinurat Pahala, Hussain AlDaif and Mohit Dholi for their help during my research and study at Texas A&M University. They have made it easier for me than I thought it would be.

I would like take the opportunity to express my sincere thanks to Kuwait Oil Company, which gave me this opportunity by supporting me in my pursuit of the Master of Science degree.

TABLE OF CONTENTS

LIST OF FIGURES

Page

Page

Page

LIST OF TABLES

Page

CHAPTER I

INTRODUCTION

Oil Production in Unconventional Reservoirs

In the last decade, US oil production has dramatically increased through the continuous drilling of unconventional resources (shale reservoirs) coupled with hydraulic fracturing to liberate the recoverable hydrocarbon reserves. Thousands of wells that have been drilled in the major oil shale formations: Bakken, Permian Basin and Eagle Ford, where oil production peaked in the first few weeks and then showed a sharp decline. The industry is continuing efforts to overcome the problem of the fast production decline by increasing the number of wells drilled to sustain the production plateau. Figure 1 emphasizes the impact of unconventional reservoirs on the overall production of the United States.

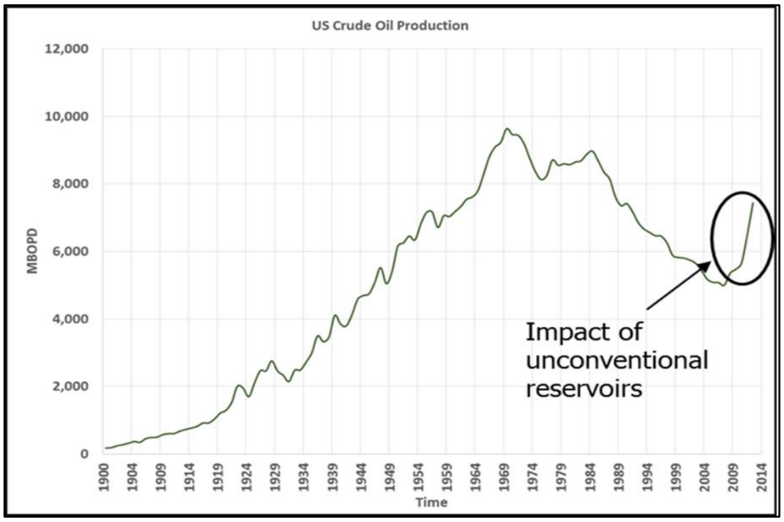

Figure 1: US Oil Production

Objective and Motivation

In this study, a method of predicting the performance of the Eagle Ford Shale (EFS) oil basin is presented. The objectives are to provide a pragmatic rather than theoretical method for general use as well as to generate different production forecast scenarios for various drilling schedules. In addition, production data analysis was added to the research to allow calculation of different parameters such as fracture half-length, area of matrix drainage, and oil-in-place. Single-well simulation runs on several of the nine available wells were done. Data input such as rock and fluid properties were obtained from papers published on EFS oil.

CHAPTER II

LITERATURE REVIEW

Eagle Ford Shale Geology and Reservoir Description

The Eagle Ford Shale (EFS) reservoir is 400 miles long and 50 miles wide. Located in the south and central part of the state of Texas, this unconventional reservoirs made of carbonate and cretaceous mudstone. Above EFS is the Austin Chalk formation and the Buda formation is below it. Its depth varies between 2,000 ft and 15,000 ft. The maximum thickness of the reservoir is 350 ft, and its minimum thickness is 70 ft. (Gong et al. 2013). The reservoir is brittle due to the high carbonate content, which facilitates stimulating the wells by hydraulic fracturing (Pope, Palisch, and Saldungaray 2012). Figure 2 shows a structure map of the EFS.

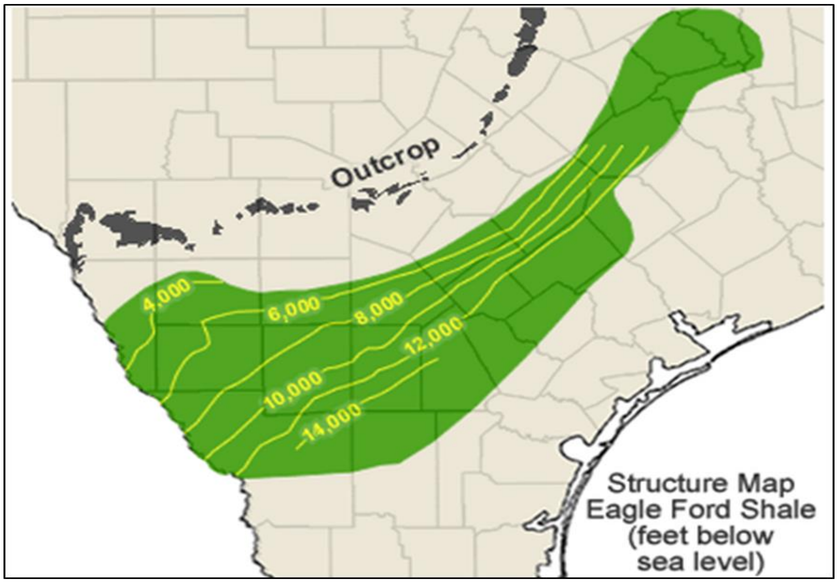

Figure 2: Structure Map of EFS

From its outcrop, the EFS extends to a depth of greater than 14,000 ft ss. However, the zone of production ranges between 3,000 and 13,000 ft ss. The burial depth is the cause of the existence of the hydrocarbon in EFS. At shallow depths, oil is present because heat and pressure affected organic material, which formed oil. At greater depths, gas is present because of the higher temperature and pressure.

There are two productive zones in the EFS, upper and lower. The lower is dark shale, and it is rich in organic materials. The upper layer contains calcareous shale, limestone and quartz siltstone (Martin et al. 2011). Figure 3 shows the layers of the EFS.

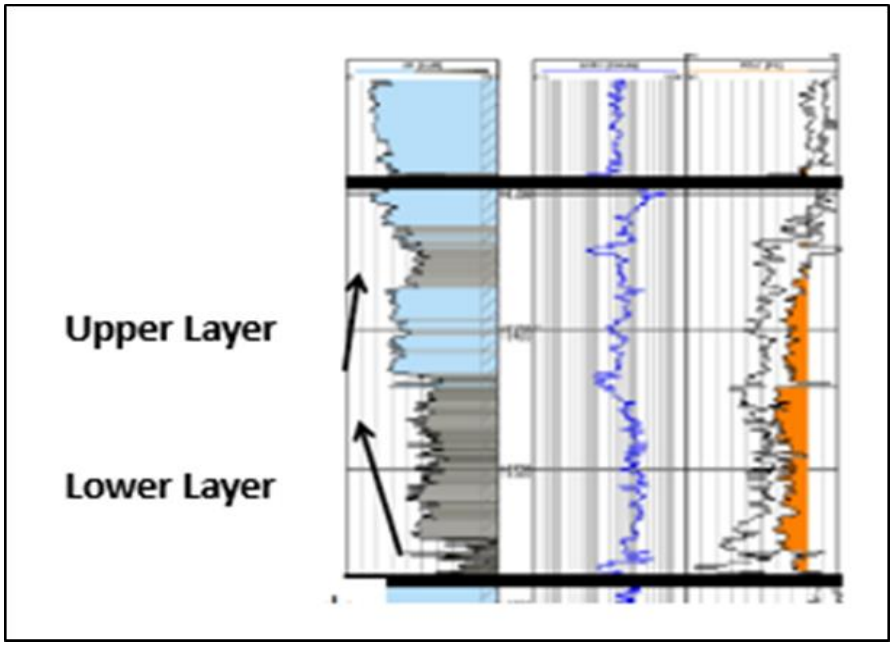

Figure 3: EFS Layers (Martin et al. 2011)

According to Mullen, Lowry, and Nwabuoku (2010), the EFS varies in petrophysical characteristics such as thickness, mineralogy and hydrocarbon saturation. The permeability of the EFS core is on the order of nanoDarcies and varies from 1 to 800 nd. This is the reason it must be hydraulically fractured. Moreover, the core porosity varies from 8% to 18%. The minimum water saturation is 7% and the maximum is 31%. Table 1 summarizes the petrophysical properties of the EFS.

Table 1: Core Date Petrophysics Analysis of EFS (Mullen, Lowry, and Nwabuoku 2010)

–	Minimum	Maximum
TOC, %	2	6
Porosity, %	8	18
Water saturation, %	7	31
Permeability, nanoDarcies	1	800
Young's Modulus, psi	$1.00e10^6$	$2.00e+10^6$
Poisson's ratio	0.25	0.27

Core mineralogy data for the oil window of the EFS is summarized in Figure 4. The same figure also summarizes the different types of clays found in the EFS. Knowing the mineralogy and clay types helps in designing the stimulation fluids.

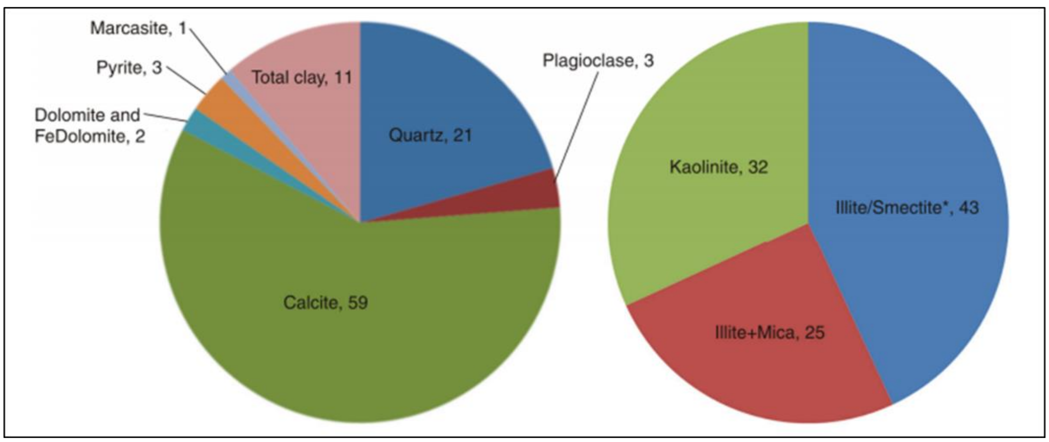

Figure 4: Mineralogy and Clay Types of EFS (Mullen, Lowry, and Nwabuoku 2010)

Fluid Properties of the EFS

Tian, Ayers, and McCain (2013) have studied thousands of wells throughout the EFS basin. They have studied the peak rates as well as the fluid properties. According to the second month gas-oil ratio, they divided the basin into different regions based on fluid types. Figure 5 displays a map of the different fluid types in EFS.

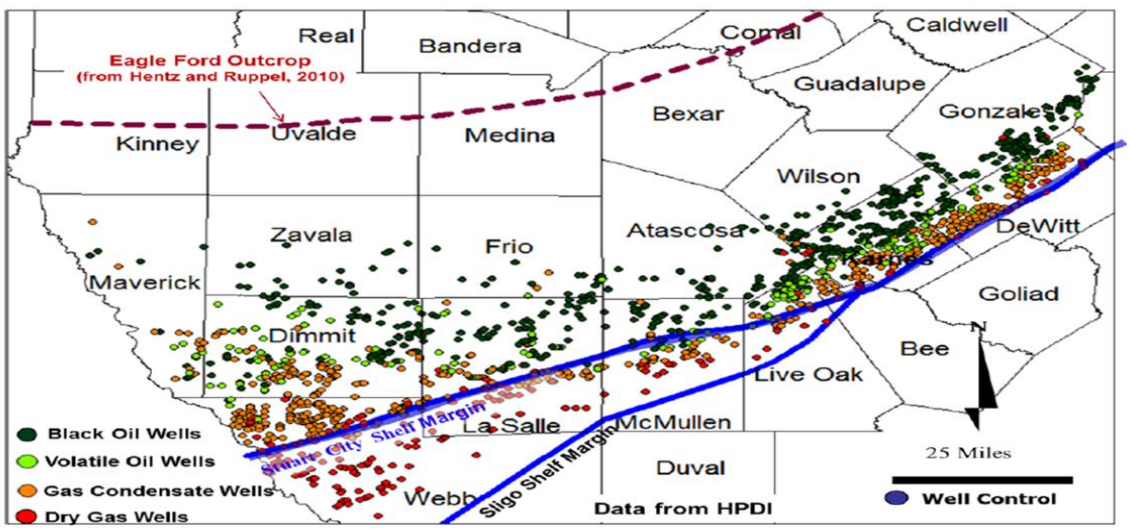

Figure 5: Fluid Types in EFS (Tian, Ayers, and McCain 2013)

Tian, Ayers and McCain (2013), prepared maps of oil API gravity and gas specific gravity. The maps were based on a public database, DrillingInfo.com (DrillingInfo 2014). The mapped data were used for better understanding of well production and to prepare data input for reservoir simulation studies. Figures 6 and 7 show the oil gravity and gas specific gravity maps of EFS, respectively.

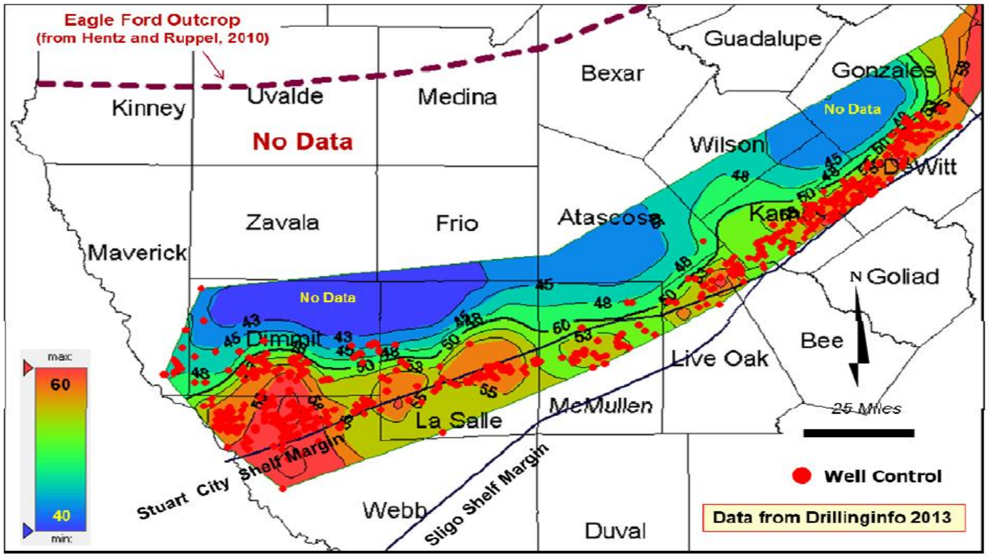

Figure 6: Oil API Gravity of EFS (Tian, Ayers, and McCain 2013)

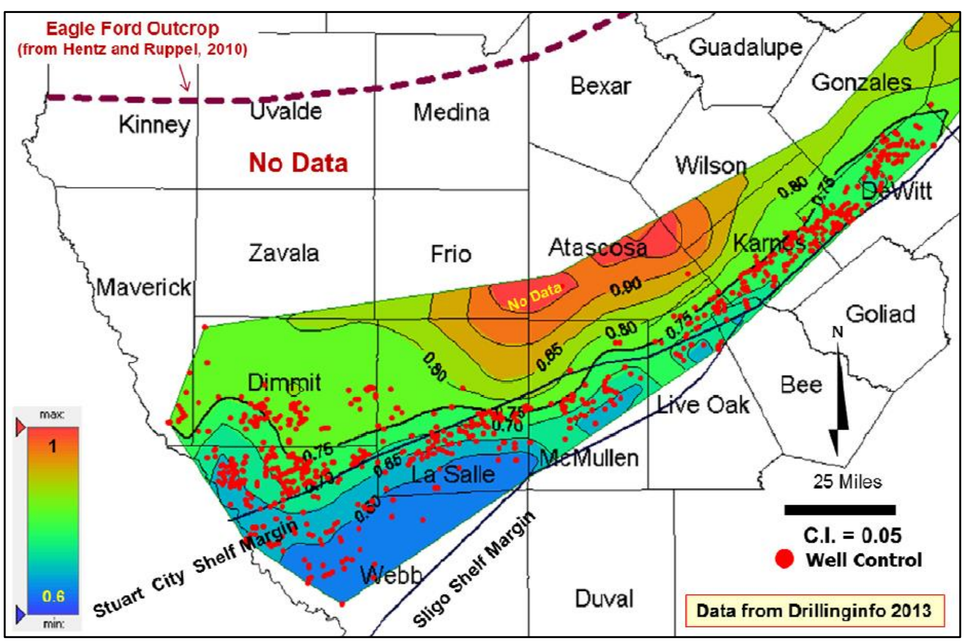

Figure 7: Gas Specific Gravity of EFS (Tian, Ayers, and McCain 2013)

Gong et al. (2013), divided the EFS into eight regions based on fluid types, formation and vertical depth, and calculated the area of each region. The purpose of the division was to estimate the reserves, as will be discussed later. Table 2 details the gas-oil ratio (GOR) values used to determine the fluid types, while Table 3 illustrates the criteria of the different regions.

Table 2: Fluid Types Based on GOR (Gong et al. 2013)

Fluid Type	Initial GOR, SCF/STB
Black Oil	0-1,500
Volatile Oil	3,200-10,000
Condensate	10,000-100,000
Dry Gas	>100,000

Table 3: Different Regions of EFS (Gong et al. 2013)

Production Region	Fluid Type	Initial Oil Rate	Formation	True Vertical Depth, ft	Area, acres
PR1	Black Oil	Low	Upper and Lower	4,056	799,836
PR2	Condensate/Volatile Oil	Medium-Low	Upper and Lower	6,505	942,734
PR3	Black Oil	Medium	Upper and Lower	7,719	1,617,410
PR4	Condensate	Medium-Low	Upper and Lower	10,874	584,070
PR5	Black Oil	Medium-High	Lower	9,450	977,484
PR6	Volatile Oil	High	Lower	12,286	338,000
PR7	Condensate	Medium	Lower	13,470	478,888
PR8	Dry Gas	None	Upper and Lower	10,532	1,201,185

Reserves and Ultimate Recovery of EFS

Different reserve estimates were done in the last few years for EFS tight oil and gas. The Energy Information and Administration (EIA) publishes updated reserves estimates every year as well as the cumulative production from each year. Due to increased activity in unconventional resources and their encouraging results, the reserves estimates are increasing. Table 4 gives the latest available estimates for the tight oil reservoirs. Stopped here.

Table 4: Reserves Estimate for Tight Oil Reservoirs (Energy Information Administration 2014)

Basin	Play	States	2011 Production (million barrels)	2011 Reserves (million barrels)	2012 Production (million barrels)	2012 Reserves (million barrels)
Western Gulf	Eagle Ford	TX	71	1,251	209	3,372
Williston	Bakken	ND, SD, MT	123	1,998	213	3,166
Fort Worth	Barnett	TX	8	118	10	66
Appalachian	Marcellus	PA, WV	-	-	4	72
Denver-Julesberg	Niobrara	CO, KS, NE, WY	2	8	3	14
Subtotal			**204**	**3,375**	**439**	**6,690**
Other tight oil			24	253	41	648
All U.S. tight oil plays			**228**	**3,628**	**480**	**7,338**

Gong et al. (2013) forecasted the oil and gas reserves and resources of the EFS basin based on probabilistic decline curves using a Markov Chain Monte Carlo algorithm. Simulation runs were also performed to forecast production for single wells and regions. The results were compared to the EIA estimates. Gong et al. divided the

EFS into regions based on fluid properties. Table 5 compares the work of Gong et al. to the EIA estimates:

Table 5: Comparison of Gong et al. Reserves Estimates vs. EIA Estimate

	Oil Region		Condensate Region		Gas Region	
	EIA	This Work	EIA	This Work	EIA	This Work
Area (Million Acres)	1.43	3.73	0.57	2.01	0.13	1.20
No. of wells/section	5	8.6	8	8	4	2
Mean EUR/well (MSTB, BCF)	300	319 & 1.45	4.5	192 & 3.78	5.5	3.25
P_{50} Total (BBO, TCF)	3.35	7.81 & 30.34	16.43	3.93 & 79.93	4.38	11.51
		EIA			This Work	
P_{50} Total All (BBO, TCF)		3.35 & 21			11.74 & 122	

In addition to estimating the reserves of the total basin, Gong et al. calculated the area of each region for each fluid (oil, gas and condensates), and then performed probabilistic calculations to estimate the reserves. They used different parameters in the probabilistic calculations, such as well count, well spacing and drilling efficiency. Table 6 gives a summary of their work.

Table 6: Probabilistic Reserves Estimate of Gong et al. (2013)

Production Region	PR1	PR2	PR3	PR4	PR5	PR6	PR7	PR8	Total
Area (Acres)	799,836	942,734	1,617,410	584,070	977,484	338,000	478,888	1,201,185	6,939,607
Reserves/Contingent Area (Acres)	173,590	550,944	1,017,488	414,105	675,539	318,336	370,863	565,281	4,086,146
Prospective Area (Acres)	626,246	391,790	599,922	169,965	301,945	19,664	108,025	635,904	2,853,461
Current Well Spacing (Acres/Well)	206	57	160	96	57	61	106	320	
Drilling Efficiency Factor	0.7875	0.7875	0.7875	0.7875	0.7875	0.7875	0.7875	0.7875	
Existing Well Count	102	839	913	428	1020	561	310	229	4,402
Reserves Well Count	235	2,035	2,710	965	2,710	1,545	730	365	11,295
Contingent Well Count	327	4,738	1,385	2,004	5,603	2,004	1,715	797	18,572
Prospective Well Count	2,394	5,413	2,953	1,394	4,172	254	803	1,565	18,947
Total Well Count	3,058	13,025	7,961	4,813	13,505	4,364	3,558	2,956	53,216

Swindell (2012) discussed the estimated ultimate recovery (EUR) of EFS oil and gas wells. Decline curves were normalized for each county and the distribution of EUR was generated. Swindell also correlated the EUR for some wells with various parameters such as peak rate, fracture size and first production date. Figure 8 shows an example of correlating EUR to the peak rate.

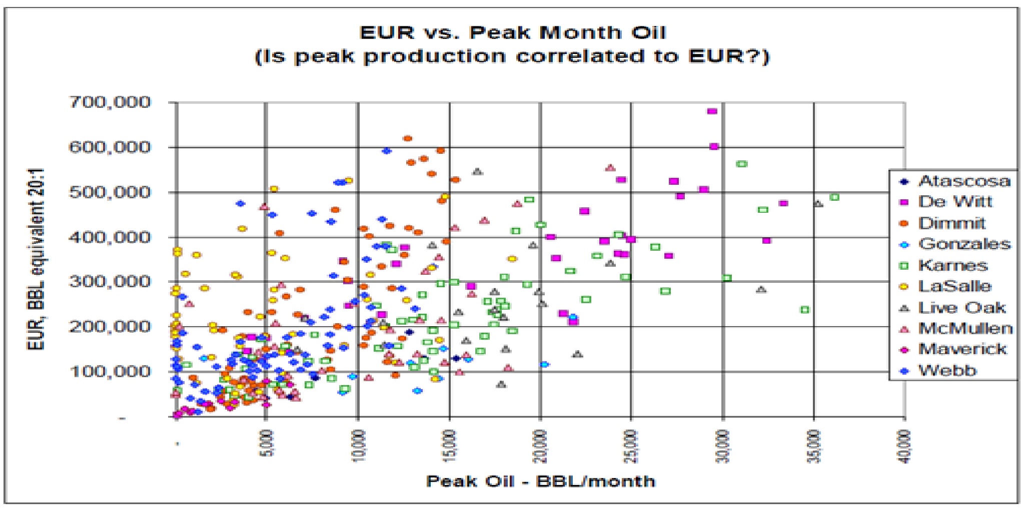

Figure 8: Swindell's Correlation of EUR to Peak Rate

Moreover, Swindell summarized the EUR of different counties in the EFS. The calculations were done on more than 1,000 wells. Each county was examined separately in terms of oil gravity, peak oil- and gas- production, and fracturing sands volume. Table 7 provides a summary of some of the counties in the EFS.

Table 7: Swindell's Summary of Eagle Ford Wells

County	Number of wells in study	Avg. Frac sand - Th. Pounds	Avg. oil gravity	Avg. peak oil production - BBL/month	Avg. peak gas production - MCF/month	Avg. EUR oil - BBL per well	Avg. EUR gas - MMCF per well	Avg. EUR - BOE per well
ATASCOSA	23	3,509	36.3	8,390	9,689	80,117	67	86,864
DEWITT	89	4,576	55.5	21,551	123,873	261,326	1,338	403,715
DIMMIT	182	3,450	49.3	7,430	37,772	114,644	638	180,870
GONZALES	83	3,280	41.3	13,457	10,635	121,795	135	135,102
KARNES	194	4,156	48.3	14,329	66,037	156,782	508	210,801
LA SALLE	173	4,649	50.9	5,195	128,891	64,157	1,331	194,991
LIVE OAK	28	3,538	51.7	17,184	107,657	136,136	963	248,818
MAVERICK	21	2,839	42.7	2,567	9,192	17,380	159	31,356
MCMULLEN	65	3,194	50.1	9,363	86,218	90,503	832	172,237
WEBB	178	3,646	59.3	5,721	119,458	70,104	1,925	192,697
Total	**1,041**					**115,282**	**1,044**	**206,779**

Production Data Analysis of EFS

Xu et al. (2012) were one of the first to publish production data analysis for the EFS. They used a linear, dual-porosity model to perform their analysis. Linear flow analysis parameters, such as stimulated reservoir volume, gas in place and fracture half-length were calculated. The analyses were done on gas rates only, as there was not much data available for oil production at that time. Figure 9 shows an example of their analysis plots.

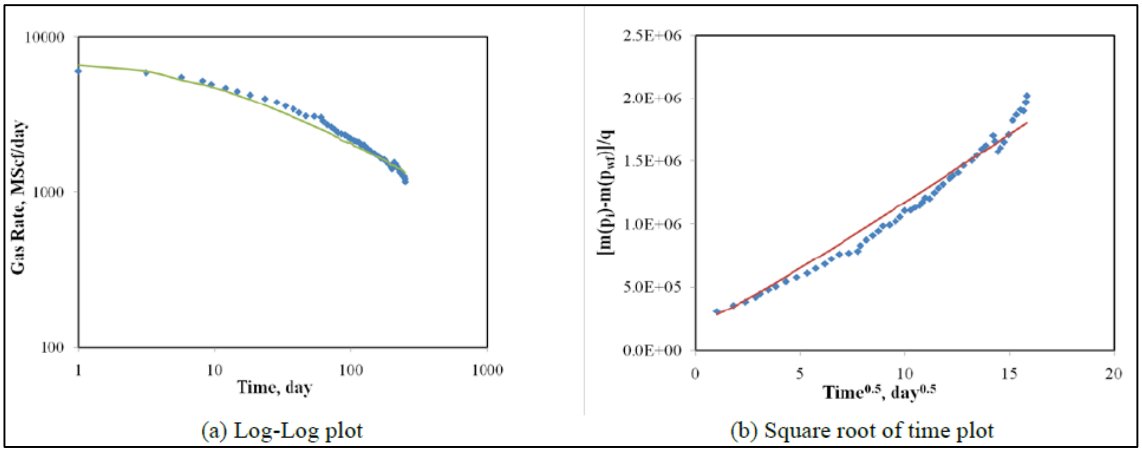

Figure 9: Example Plots of Linear Flow Analysis (Xu et al. 2012)

Following the same dual-porosity linear flow model, production forecasting of several gas wells were made also. The authors had to assume some unknown parameters in making the forecast, which, according to them, led to uncertain results. The production forecast took into account gas desorption using the isotherms of the Barnett and Woodford shale. Figure 10 shows an example of their production forecast.

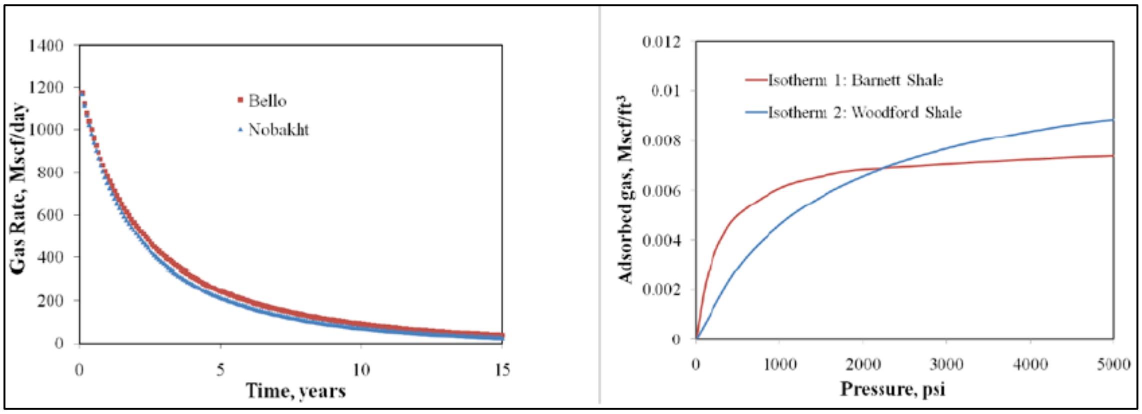

Figure 10: Production Forecasting (Left) and Gas Desorption Plot (Right) (Xu et al. 2012)

Agboada and Ahmadi (2013) analyzed production data as well as forecasting production on a single-well basis for EFS oil wells. They used Arp's Decline Curve Analysis (DCA) and Logistic Growth Analysis (LGA) of cumulative production. They performed DCA on several wells in each county in the basin. The purpose of using DCA was to get an idea about the initial decline of the wells in addition to discovering the exponent of the decline. In the forecast, abandonment rates were varied to estimate the remaining reserves for each case. Figure 11 gives an example of the DCA work done and the LGA.

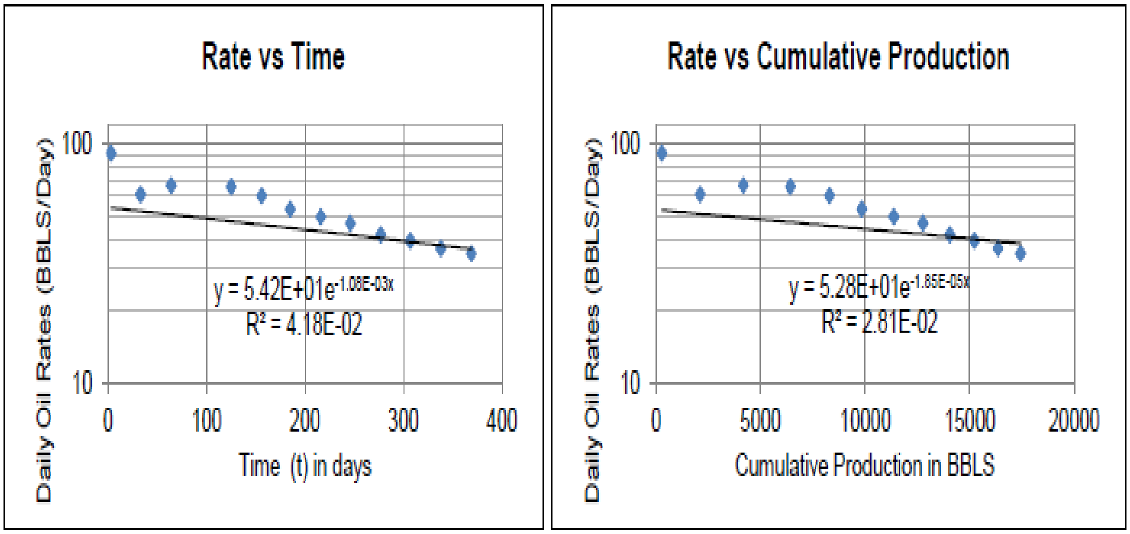

Figure 11: Examples of DCA (Left) and LGA (Right) (Agboada and Ahmadi 2013)

Moreover, Agboada and Ahmadi performed detailed DCA on selected oil wells in some of the counties in the EFS. They have performed exponential and harmonic decline analysis with sensitivity of abandonment rates yielded in getting different parameters such as oil cumulative, time to reach abandonment rate etc. This can be seen in detail in the example in Table 8.

Table 8: Results of Detailed DCA on one EFS Oil Well (Agboada and Ahmadi 2013)

	Exponential Decline (Log of Rates versus Time)	Exponential Decline (Log of Rates versus Time)	Harmonic Decline (Log of Rates versus. Cum. Production)	Harmonic Decline (Log of Rates versus. Cum. Production)
Abandonment rate q_l (barrels/day)	2	5	2	5
qi (barrels/day)	70	70	75	75
D & Di (1/days)	2.66E-03	2.66E-03	4.44E-03	4.44E-03
Time to reach abandonment, t (days)	1334	990	8207	3148
Np @ abandonment (STBs)	25414	24286	61096	45644
Cumulative days of production	274	274	274	274
Remaining Life (days)	1060	716	7933	2874
Current cumulative production	13061	13061	13061	13061
Remaining Reserve (bbls)	12353	11225	48035	32583

Reservoir Simulation of the EFS

In the published literature, several authors report attempts to perform well and reservoir simulation. They had different purposes, such as evaluating the completion of wells, validating analytical solutions and suggesting new ways to enhance production performance. Different reservoir simulation packages were used.

Wang and Liu (2011) constructed a dual-porosity, dual-permeability model to match the performance of EFS oil wells. A refinement of the previous model was built to discover whether the simpler coarse-grid model would produce similar results. After confirming the reliability of the coarse model, it was used on other shale oil wells in the field. The objective was to evaluate the design of stimulation treatments. Figure 12 is the result of oil rate match from the simulation model.

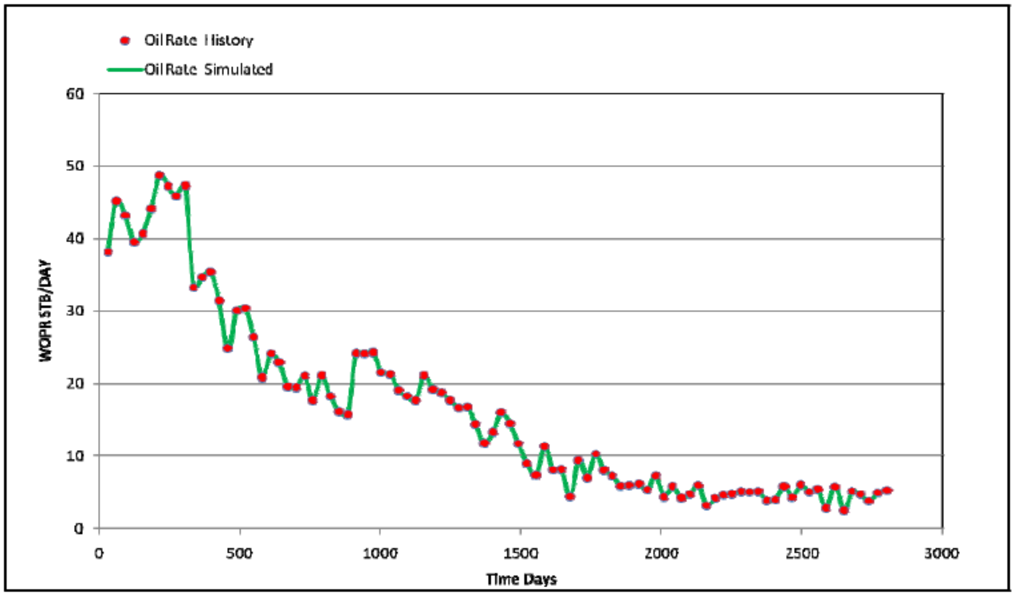

Figure 12: Oil Rate Simulation Results (Wang and Liu 2011)

Sensitivities on different parameters were performed to discover which had the maximum or minimum impact on well performance. They tested the sensitivity of the parameters by examining their effects on cumulative oil production. There are several parameters to evaluate, such as natural fractures spacing, porosity, reservoir thickness, etc. A summary of the effect of each parameter is provided in Figure 13.

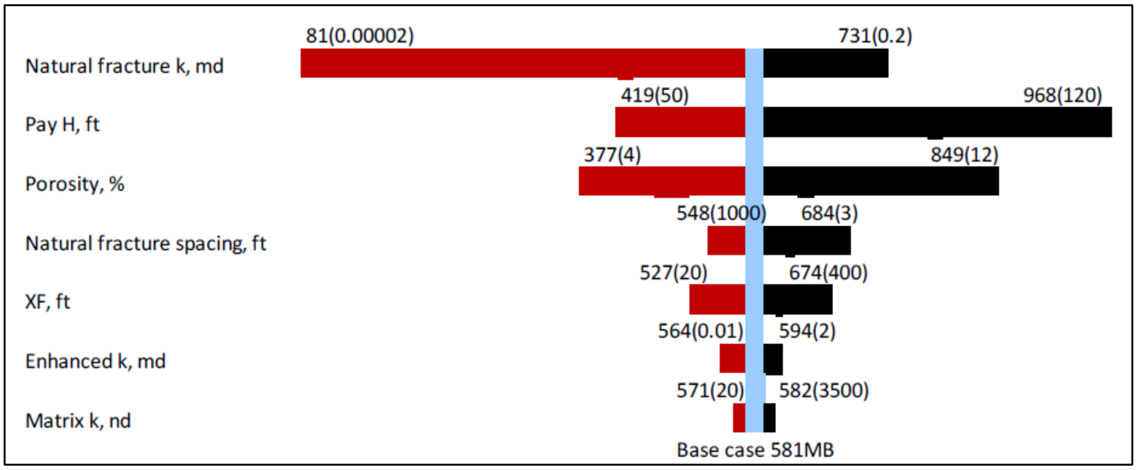

Figure 13: Impact of Different Parameters on Shale Oil Wells in the Basin (Wang and Liu 2011)

Agboada and Ahmadi (2013) complemented their production data analysis with a numerical simulation model for single shale oil wells. It was a dual-permeability model built in CMG software. The input data were taken from the literature. The objective of the numerical simulation model (NSM) was to compare results with their DCA and LGA findings. Comparison of the cumulative production results can be found in Figure 14.

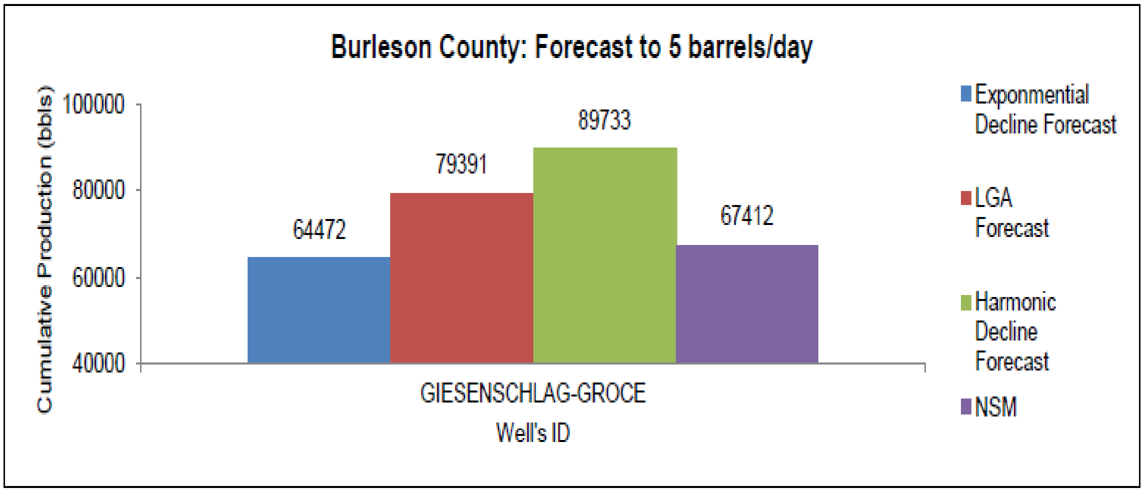

Figure 14: Comparison of Simulation, DCA and LGA Results (Agboada and Ahmadi 2013)

CHAPTER III

DATABASES USED

In this research, different types of data were required to achieve the objectives. Detailed production, completion, fluid and rock properties, and rig capability and efficiency data are not made easily available by operators to common users. The search for reliable databases was an essential part of this research. Authentic public databases and papers in the literature were used to extract the necessary information. The databases used in the study are:

- Energy Information Administration (EIA)
- Railroad Commission of Texas (RRC)
- Baker Hughes Rig Count (BHI)
- Drilling Info (Website and DI Desktop Software)
- Operators' Reports

Energy Information Administration (EIA)

EIA is a US government agency responsible for gathering the data related to all types of energy in the country. EIA keeps track of both production and reserves of oil and gas basins. Many researchers depended heavily on EIA data to accomplish their objectives. In this research, EIA data were used to compare results and to validate values found in previous work.

EIA updates production and reserves data on a regular basis. There are many tables for various unconventional resources that summarize their performance as can be seen in Table 9. Moreover, maps of basins are available that show the activities in recent years, such as drilling, completion and production. Figure 15 is a map of EFS with the locations of drilled wells as well as zones of the various fluid types.

Table 9: Production Summary of Unconventional Reservoirs (Energy Information Administration 2014)

	Oil production thousand barrels/day			Gas production million cubic feet/day		
Region	September 2014	October 2014	change	September 2014	October 2014	change
Bakken	1,152	1,179	27	1,390	1,418	28
Eagle Ford	1,551	1,582	31	6,823	6,920	97
Haynesville	56	56	-	6,728	6,757	29
Marcellus	51	52	1	15,842	16,064	222
Niobrara	356	362	6	4,573	4,624	51
Permian	1,718	1,757	39	5,709	5,776	67
Utica*	40	43	3	1,385	1,462	77
Total	4,924	5,031	107	42,450	43,021	571

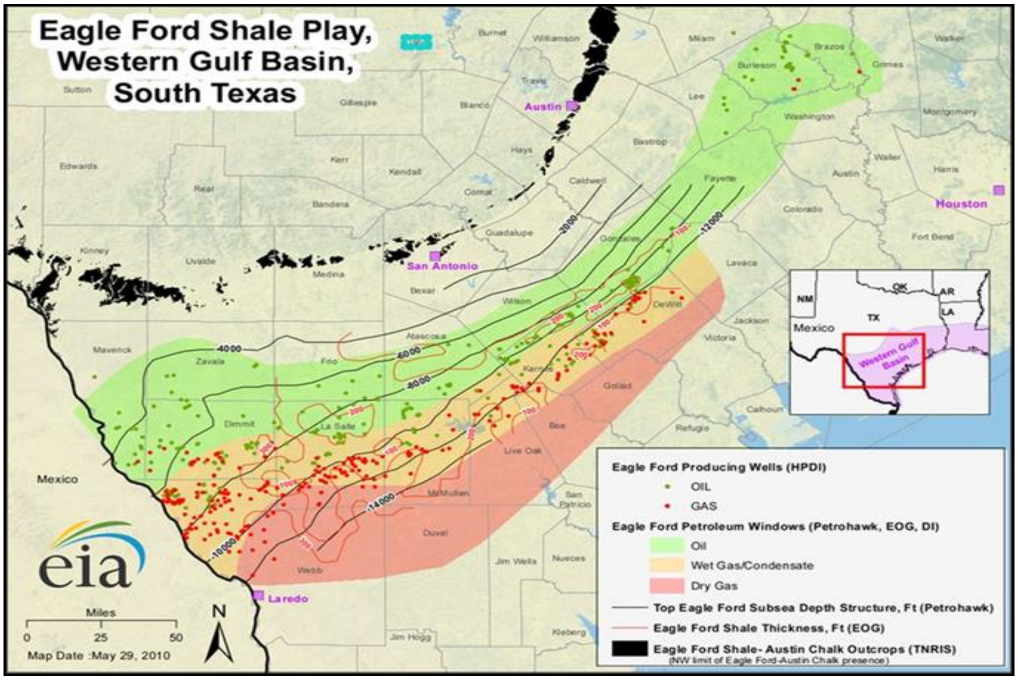

Figure 15: EFS Fluid Types and Drilled Wells (Energy Information Administration 2014)

Railroad Commission of Texas (RRC)

The Railroad Commission of Texas is a state agency that regulates the oil and gas industry within the state. Similarly to EIA, the RRC provides tables and plots of all gas and oil fields in Texas. The RRC can provide data for specific counties including the number of permits issued with detailed lease information. The RRC updates its databases faster than the EIA because it focused on Texas oil fields.

In this research, field-wide production data of the EFS were cross-checked with the RRC database. Figure 16 shows the annual oil production data for the EFS according to the RRC.

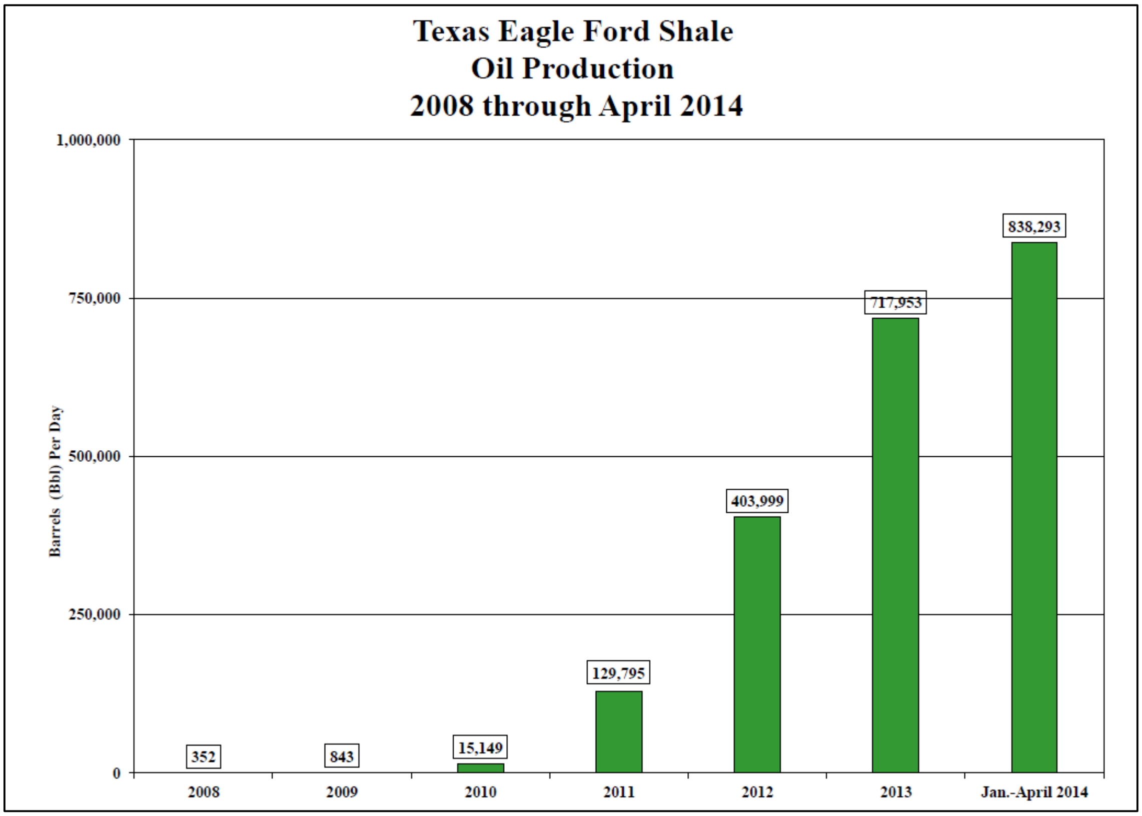

Figure 16: EFS Annual Oil Production (Railroad Commission of Texas 2014)

Moreover, it is possible to query several reports in the RRC database. Well records, well logs and surface permits can be extracted from the database. It is possible to filter required data by API number, lease name, well type etc. Figure 17 shows how flexible it is for generating reports based on different queries.

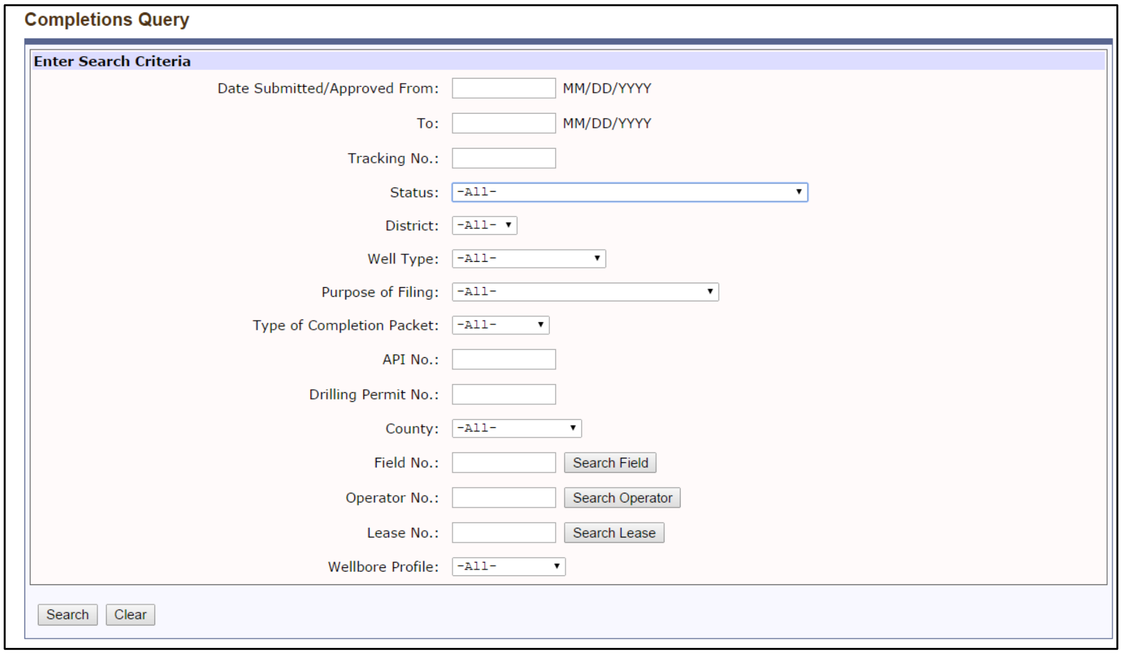

Figure 17: Completion Query Available in RRC Database (Railroad Commission of Texas 2014)

Baker Hughes Rig Count (BHI)

Baker Hughes, a service company for the oil and gas industry, issues drilling rig counts for both the US and the world. The count is an important tool for everyone involved in the industry, including investors and economists. The rig count is updated on a weekly basis for the U.S and on a monthly basis for the rest of the world. Table 10 summarizes the monthly count of rigs worldwide.

Table 10: Worldwide Monthly Rig Count (BHI 2014)

BAKER HUGHES INCORPORATED WORLDWIDE RIG COUNT									
2014	Latin America	Europe	Africa	Middle East	Asia Pacific	Total Intl.	Canada	U.S.	Total World
Jan	401	126	139	403	256	1,325	504	1,769	3,598
Feb	400	132	154	396	259	1,341	626	1,769	3,736
Mar	406	148	132	401	258	1,345	449	1,803	3,597
Apr	403	151	136	407	252	1,349	204	1,835	3,388
May	404	149	140	414	243	1,350	162	1,859	3,371
Jun	398	147	123	425	251	1,344	240	1,861	3,445
Jul	407	153	137	432	253	1,382	350	1,876	3,608
Aug	410	143	125	406	255	1,339	399	1,904	3,642
Sep									
Oct									
Nov									
Dec									
Avg.	404	144	136	411	253	1,347	367	1,835	3,548

In this research, it was necessary to know rig counts, rig capability and drilling efficiency to perform the production forecast. The BHI rig count tool was the main source of such data. The tool can track both oil and gas rigs separately for each field and also gives an average of the number of days for the rigs to finish drilling the wells. A map can also be generated to show the locations of the rigs. Figure 18 displays the interactive map of EFS wells.

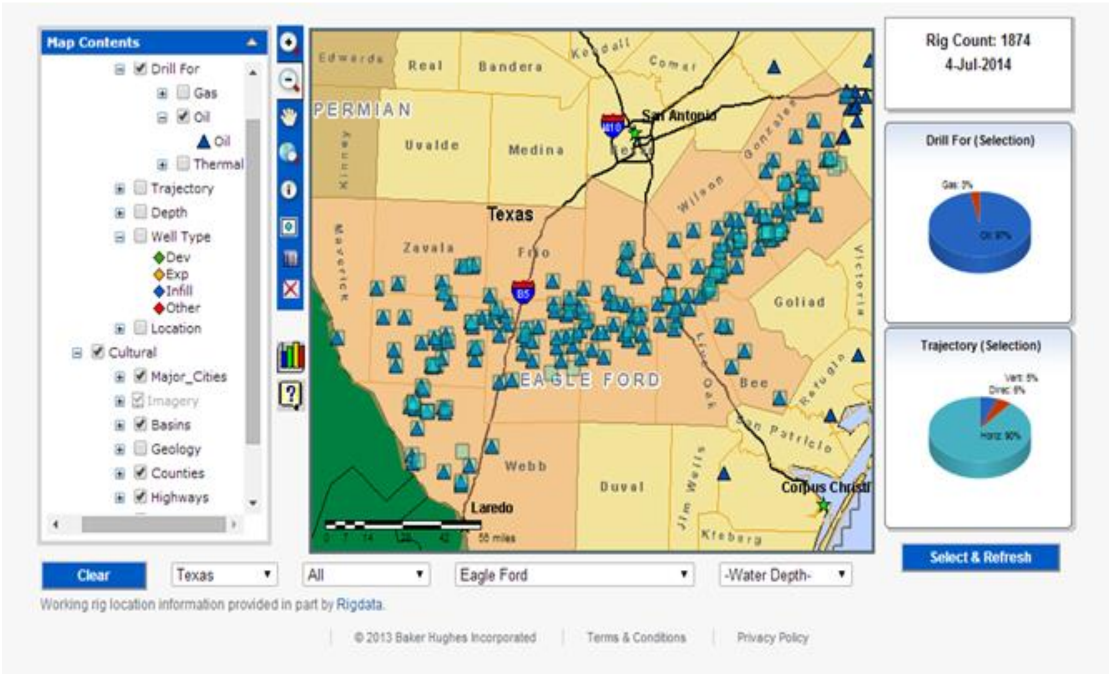

Figure 18: Map of Rigs in EFS (BHI 2014)

DrillingInfo Database

DrillingInfo is a private company that generates different types of data for oil and gas industry clients. Recently, publishers and operators have used DrillingInfo tools heavily. The DrillingInfo database contains an enormous amount of data, which are updated regularly. Maps, tables and graphs can be generated easily to track the progress of wells and fields. Both the Drillinginfo website and its various analysis tools, such DI Desktop, DI Engineering and DI Geology are good starting points in searching for the data. Figure 19 is an extracted map from the database showing the operators in the basin.

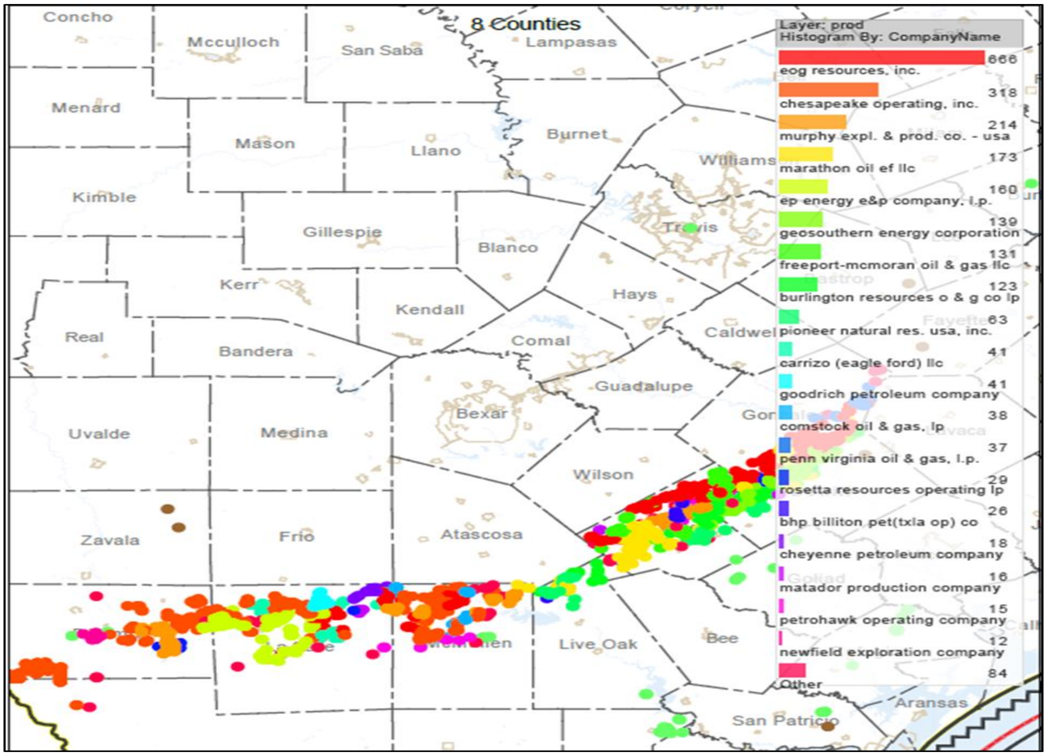

Figure 19: Map of Eagle Ford Wells Sorted by Operators (DrillingInfo 2014)

DrillingInfo was the main source that this research relied on. Its flexibility in navigating the database and tools helped a lot in achieving the objectives. Thousands of wells were filtered by the required criteria to obtain the correct data. The DI Desktop tool and the website were used to accelerate the work process. Figure 20 illustrates an example of an oil production plot of the EFS extracted from the DI Desktop tool.

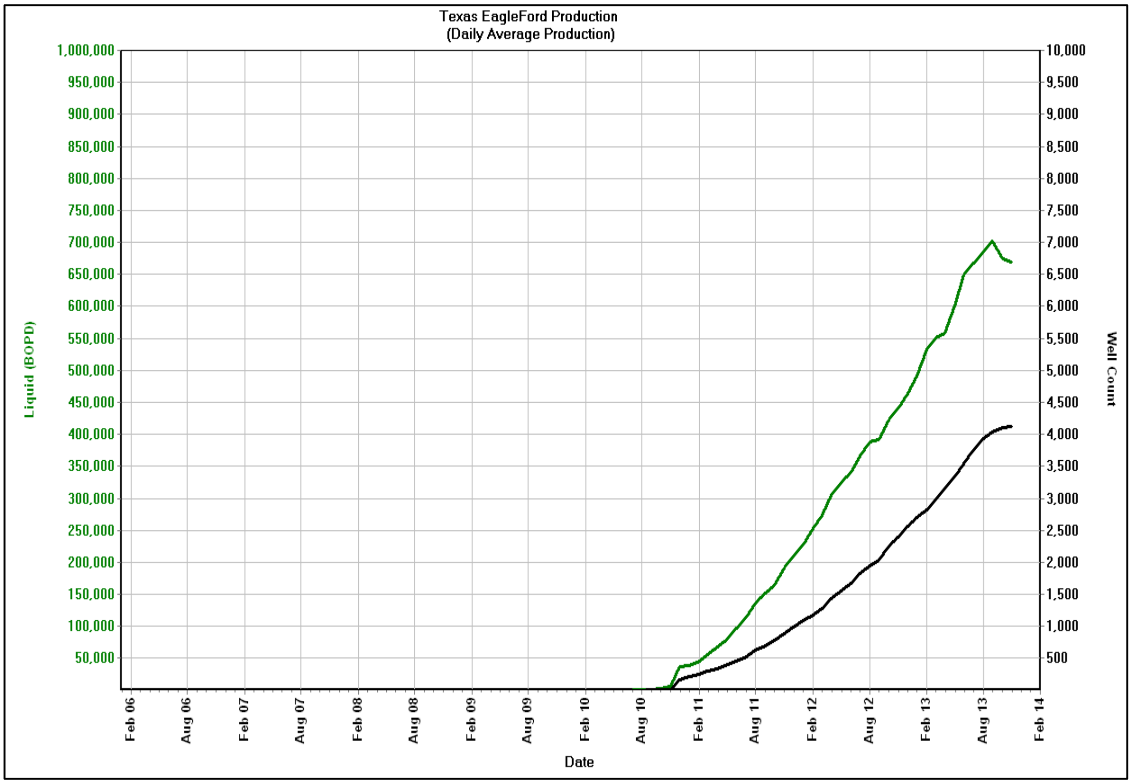

Figure 20: EFS Oil Production (DI Desktop 1998-2011)

Operators Reports

There are many operators working in EFS basin. Operators publish their reports (quarterly or annually) on their websites to attract investors. They mention the success of their activities and future development plans. The reports include performance of the wells, completion strategy, future drilling schedules and projects to be implemented.

In this study, the reports helped to explain and validate the data acquired from previous databases. For example, analyses of production data are published in the reports, which helps validate production data extracted from other databases. Other data, such as future well spacing, number of days to complete wells etc. were used for the forecast. Figure 21 shows production data of two wells from an EOG Resources operator report.

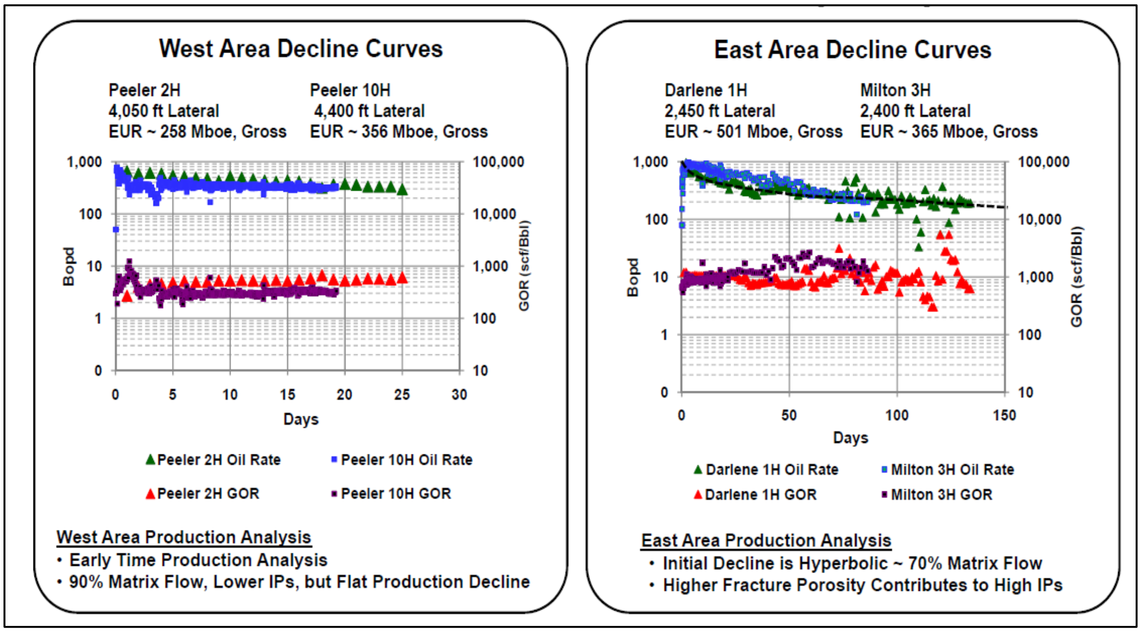

Figure 21: Two Oil wells Production Data Analysis (EOG Resources)

CHAPTER IV

PRODUCTION FORECAST

Introduction of Production Forecast

Forcasting production was the main objective of this research. As shown in the literature review, all previous work related to production forecasts was based on single-well data. So far, no attempt has been made to perform a field forecast of oil production for the EFS.

In this research, various scenarios of field-wide oil production forecast were achieved. In order to accomplish this task, the main database (DrilingInfo) was used to generate production data, which were filtered to oil wells (black and volatile), based on the initial gas/oil ratios (GOR) and included all wells with second GOR less than 3200 scf/stb. Figure 22 displays the DI Desktop interface used in filtering and generating the production data.

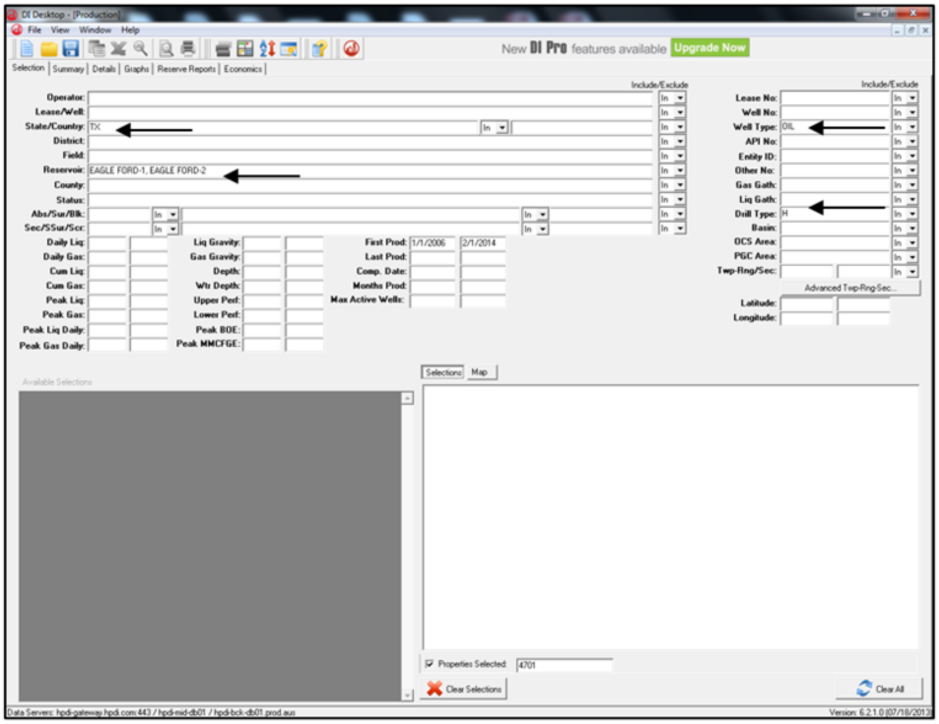

Figure 22: DI Desktop Interface for Filtering the Database

Once the data were generated and filtered, they were validated by comparing them to the RRC database. A very good match of the annual oil production data was achieved. This was considered a good starting point for the production forecast. Figure 23 is a column chart of the generated data compared to the data of the RRC report.

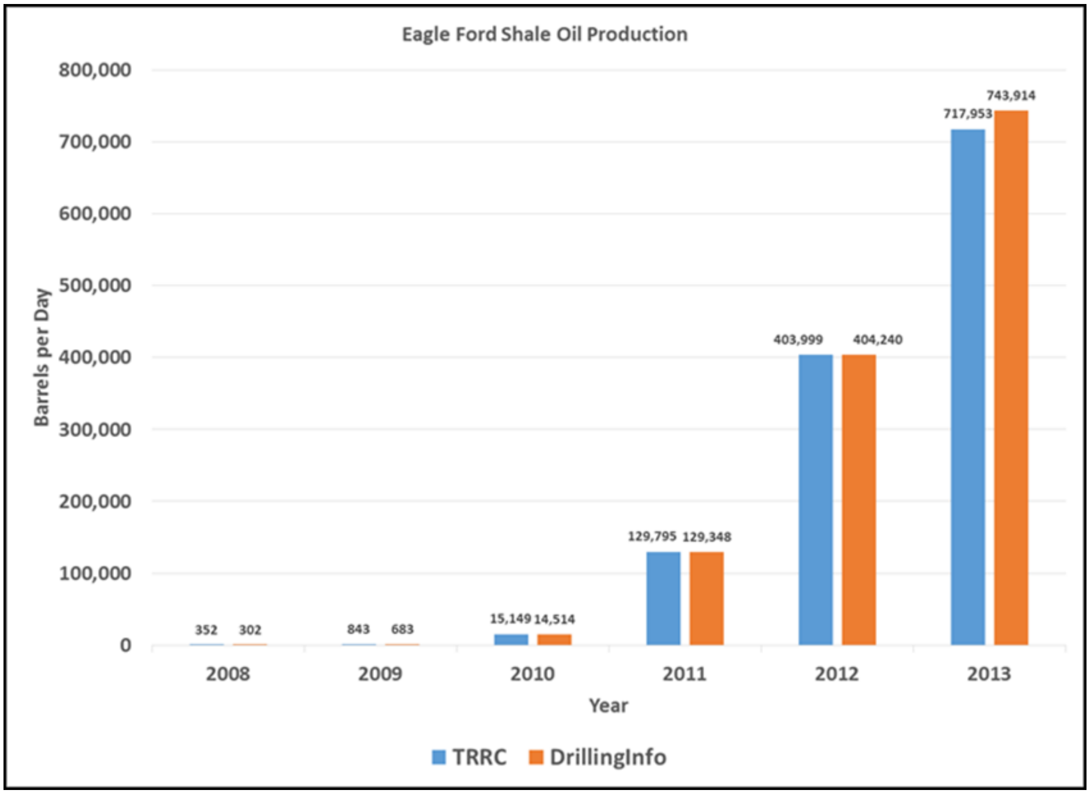

Figure 23: Comparison of the Generated Production Data to the RRC Report

Constraints on the production forecast should be taken into account. Oil reserves and resources, the area of the oil zone of the EFS, and well spacing were all limiting factors for the production forecast. These constraints are discussed in detail in the following sections of this chapter.

Type Curves of Oil Wells

More than 6,000 wells in the EFS have been put into production since 2008. All of those wells were horizontally drilled and hydraulically fractured. Wells with scattered data points and discontinuous production have not been included in generating the type curves for typical oil wells in the field. In this section, the type curve is calculated by normalizing the wells in the selection, summing their production, and dividing by the number of wells that contributed to the summed volume for the month. It is illustrated by the following equation:

$$Type\_Curve = \frac{\sum_i^n q_i}{\#\ of\ wells} \tag{1}$$

It is essential to understand the type curve data, as they explain how the well produced initially and how production declined in later years. Starting in 2008 and ending in 2013, it can be observed that every year the type curve increases, which indicates the improved performance of wells drilled in the recent years. Figure 24 shows improvement of the type curves of EFS oil wells, and Table 11 summarizes the peak oil rate for each type curve.

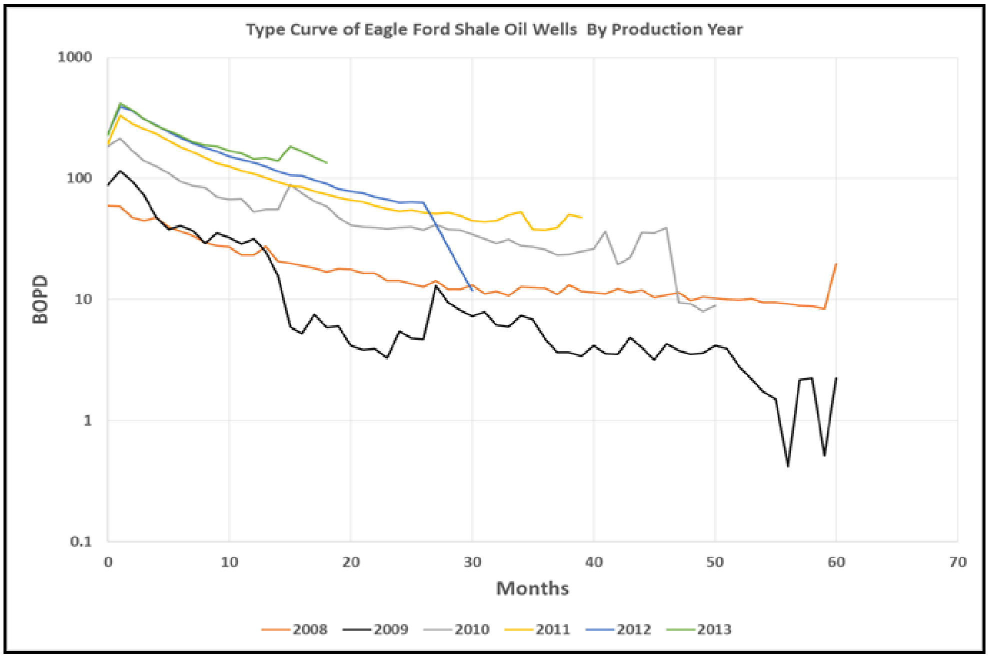

Figure 24: Type Curve of EFS Oil Wells.

Table 11: Maximum Oil Rate of the Type Curves for Each Year.

Year	Maximum Oil Rate , BOPD
2008	59
2009	116
2010	215
2011	333
2012	392
2013	420

It is believed that wells improved due to enhanced techniques of drilling and completion, rather than because of the reservoir properties where the wells were drilled. Every year, wells were drilled in different locations in the field, not focusing in any particular area. Figure 25 is a map of the locations of wells in each year.

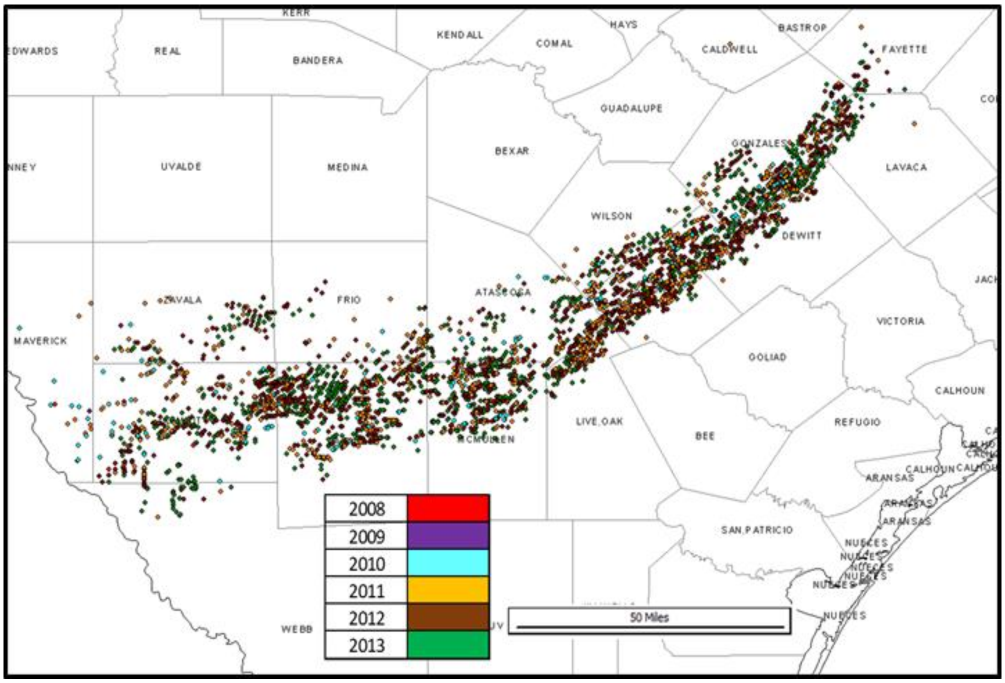

Figure 25: Map of EFS Oil Wells by Year of Production

Method of Forecasting Production

The generated type curves were converted to annual type curves because the target was an annual production forecast. Since most of the wells last for 5 years in production before reaching abandonment, the annual type curves were done for 5 years only. The method to generate the production forecast profile by simply specifying a certain drilling schedule and then multiplying the number of wells by the type curve. The following equation illustrates the calculation in matrix multiplication form.

$$\begin{array}{cccc}
\text{Type_Curve} & \text{\# of wells} & & \\
\begin{vmatrix}
q_1 & 0 & 0 & 0 & 0 \\
q_2 & q_1 & 0 & 0 & 0 \\
q_3 & q_2 & q_1 & 0 & 0 \\
q_4 & q_3 & q_2 & q_1 & 0 \\
q_5 & q_4 & q_3 & q_2 & q_1 \\
0 & q_5 & q_4 & q_3 & q_2 \\
0 & 0 & q_5 & q_4 & q_3 \\
0 & 0 & 0 & q_5 & q_4 \\
0 & 0 & 0 & 0 & q_5
\end{vmatrix}
&
\begin{vmatrix}
n_1 \\ \\ n_2 \\ \\ n_3 \\ \\ n_4 \\ \\ n_5
\end{vmatrix}
& = &
\begin{vmatrix}
q_1n_1 & 0 & 0 & 0 & 0 \\
q_2n_1 & q_1n_2 & 0 & 0 & 0 \\
q_3n_1 & q_2n_2 & q_1n_3 & 0 & 0 \\
q_4n_1 & q_3n_2 & q_2n_3 & q_1n_4 & 0 \\
q_5n_1 & q_4n_2 & q_3n_3 & q_2n_4 & q_1n_5 \\
0 & q_5n_2 & q_4n_3 & q_3n_4 & q_2n_5 \\
0 & 0 & q_5n_3 & q_4n_4 & q_3n_5 \\
0 & 0 & 0 & q_5n_4 & q_4n_5 \\
0 & 0 & 0 & 0 & q_5n_5
\end{vmatrix}
\end{array} \qquad (2)$$

Confirming the method followed in forecasting is essential and was accomplished by matching the annual historical production data for the 5 years (2008-2013). A visual basic (VBA) program was written to generate the forecast. The program can be used to forecast production based on a given drilling schedule, or it can calculate the drilling requirement based on a desired rate.

A generalized type curve of the EFS was used as well as annual type curves to match the historical data. Figure 26 is the generalized type curve, and Figure 27 is the historical matching using both the general type curve and the annual one.

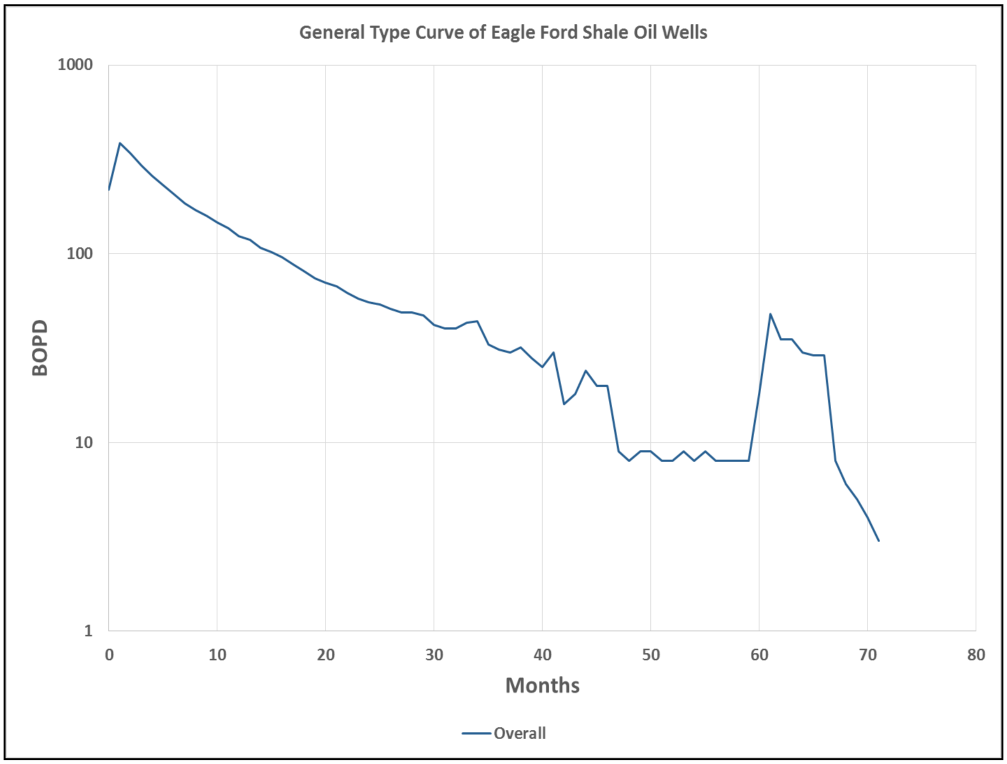

Figure 26: General Type Curve of EFS Oil Wells from DrillingInfo Database

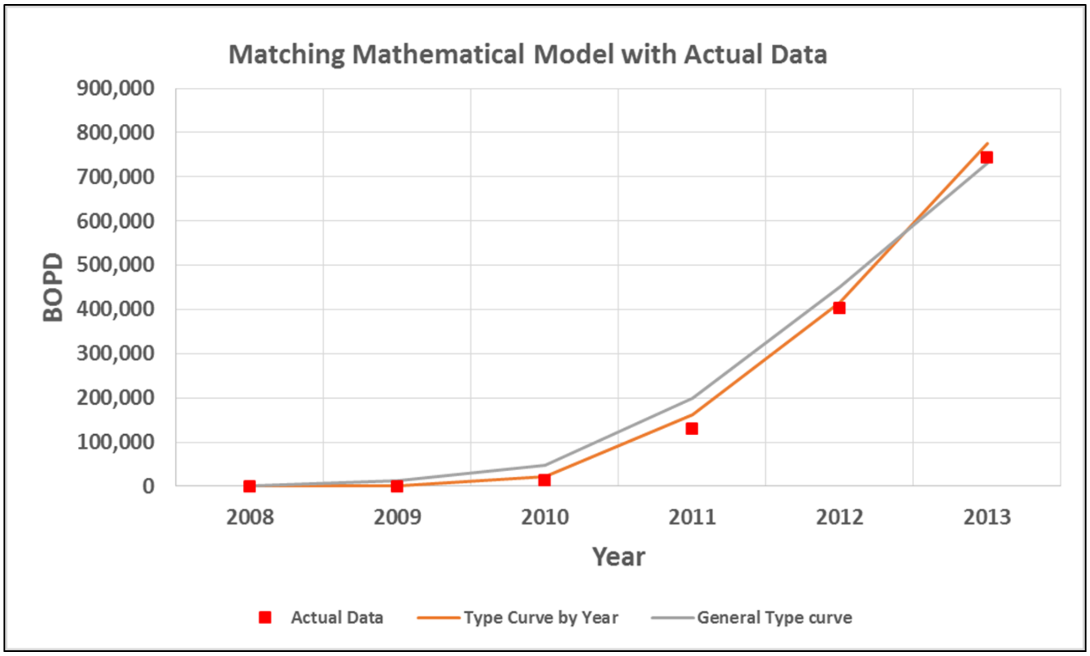

Figure 27: Matching the Production History of EFS Oil.

As seen in Figure 27, the annual type curves gave a closer match to the observed data than the generalized type curve. This assures that the approach followed is good for making the production forecast. The challenge comes in deciding which type curve should be used for the forecast. The type curves are improving as seen in Figure 24, and it is not possible to forecast the future type curves. Therefore, the latest curve from 2013 was selected for the different scenarios in the forecast.

Several scenarios can be generated using desired rates or drilling schedules. It is necessary to know the maximum number of wells that can be drilled in the oil zone of EFS. The history of the well spacing as was followed in the field is summarized in Table12.

Table 12: Spacing of EFS Oil Wells

Year	Acres/Well	Source
2011	130	Drilling Info
2012	65	Drilling Info
2013	45-65	Drilling Info
2014	40	EOG Report

Gong et al. (2013) states that the area of the oil zone in the EFS is 3.39 million acres, and the estimated P50 resources is 5.87 billion barrels of oil. It can be simply calculated now that the total number of wells that can be drilled in the oil zone is 45,263. After subtracting the number of wells drilled up to December 2013, the number of wells remaining is 39,451. Drilling trends and rig capabilities were taken into account before generating the scenarios for the production forecast. Moreover, the number of days to put wells online was estimated from the reports of operators in the basin.

The production forecast scenarios were now constrained by the number of remaining wells as well as the total oil resources. The number of scenarios can be endless. However, three scenarios thought to be practical will be discussed in detail in the next section. Production profiles, total cumulative oil as well as number of drilled wells will be mentioned.

Scenarios of the Production Forecast

Recently, oil production in the EFS has increased dramatically through the continuously increasing activity of the operators, especially after the discovery of the oil zone in the field, which caused the industry to focus its efforts more on oil and less on the gas zone. The currently high price of oil is also a main factor encouraging companies to participate in developing the field. The number of rigs and wells drilled is evidence of the high competition in the EFS.

In this study, several production scenarios were targeted. Practicality of the scenarios was an important factor in deciding on the details of each one. The three main scenarios were constrained by the total number of wells as well as the total amount of the oil resources, as mentioned above. Table 13 details the three main scenarios.

Table 13: Main Scenarios of the Production Forecast

Scenario	Target
1	To continue drilling trends of recent years
2	To achieve a 1 million barrel plateau as long as possible
3	To drill according to the recent rig numbers and capability

Drilling in the EFS started slowly, and then in the last 4 years it increased sharply because the oil wells were very productive. Figure 28 shows the recent drilling rate in the field. It is possible that the number of wells will continue to increase.

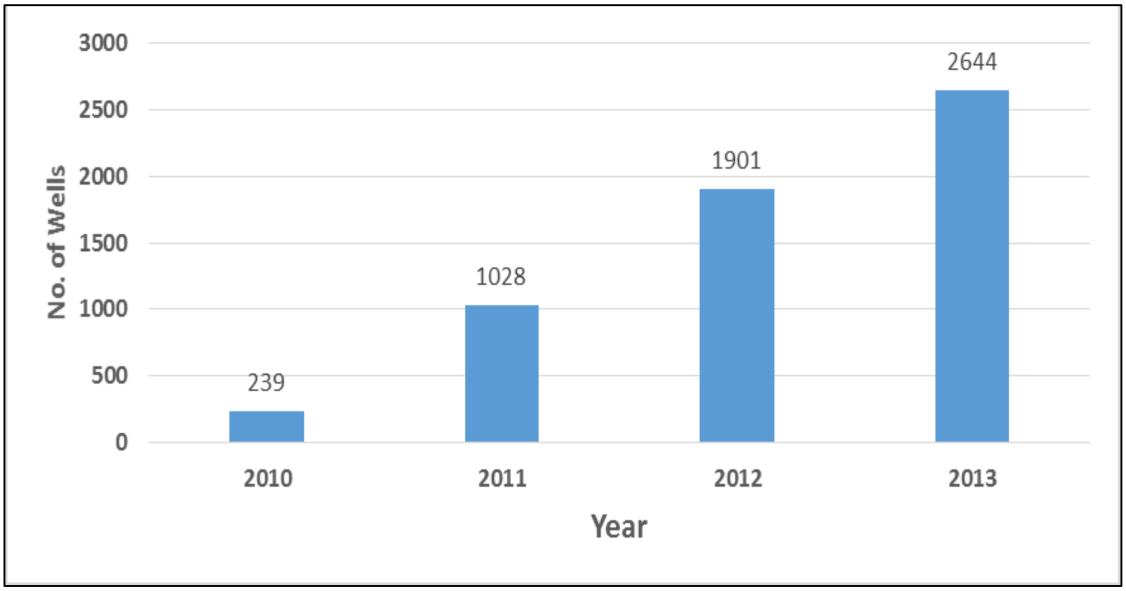

Figure 28: Oil Wells in Production in the EFS

The first production forecast scenario followed the same trend of drilling. For each year, the number of wells to be drilled was the input in the VBA program. This operation was repeated until either the total number of wells or the total resources was reached.

Production rates were generated and summed, taking into account the current year's contribution as well as the declining rate from previous years. Figure 29 illustrates the production profile of the first scenario, and Figure 30 shows the drilling schedule for the same scenario.

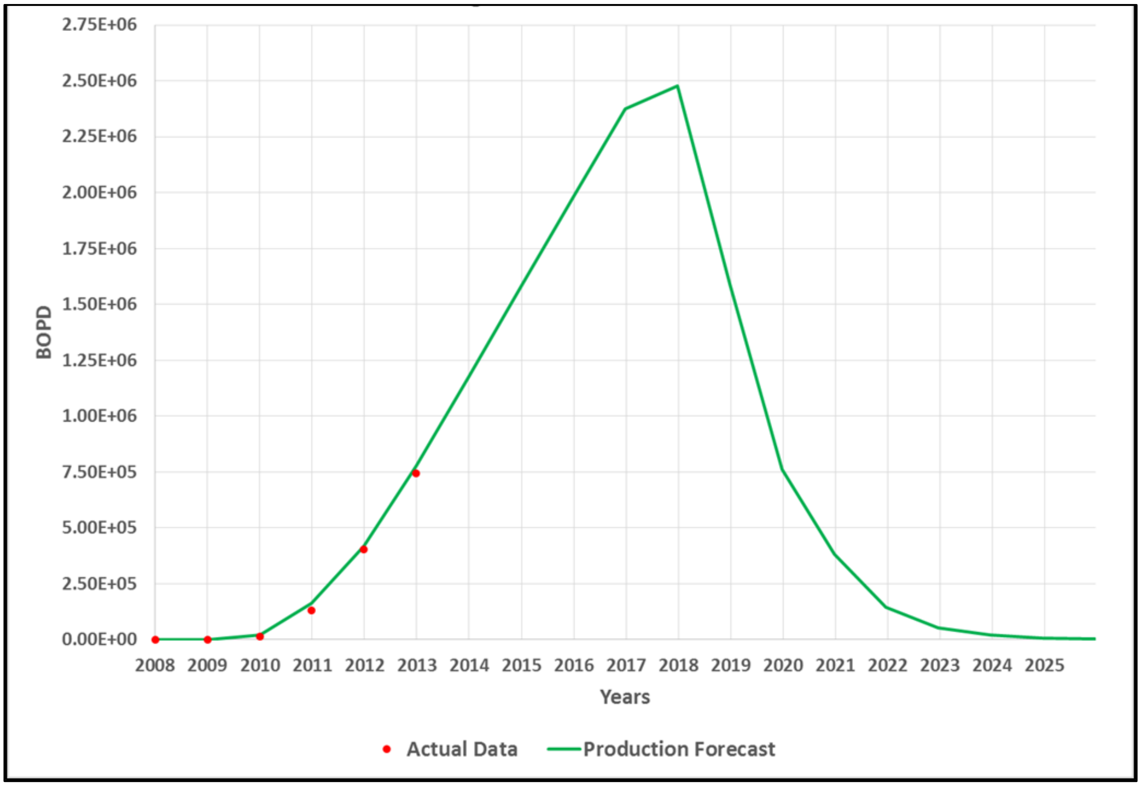

Figure 29: Production Profile of the First Scenario

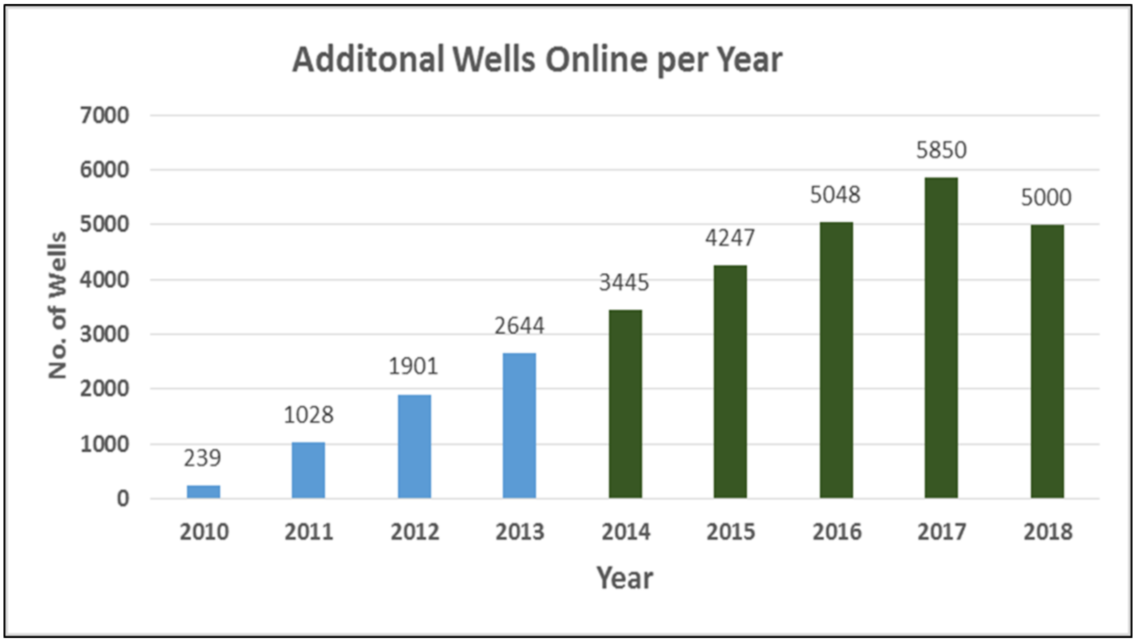

Figure 30: Drilling Schedule for the First Scenario

Figure 30 shows the forecasted drilling requirement if the historical drilling trend continued. The number of wells for the year 2018 does not continue the trend, as it is the remaining balance of the total wells. The total number of wells in the forecast was 23,590.

The production profile shown in Figure 29 exhibits the increasing trend of production. Peak production was forecasted to occur in 2018, and it is nearly 2.5 million barrels of oil per day. The cumulative production of oil reached by the year 2026 is 5.08 billion barrels.

The second scenario of the production forecast has as its goal a production of 1 million barrels of oil per day for as long as possible. The 1–million-barrel plateau was selected because this can be expected to occur in the EFS soon. The annual production of the field is approaching to 1 million barrels per day. Figure 31 from RRC reports summarizes the oil production of the field in the last few years.

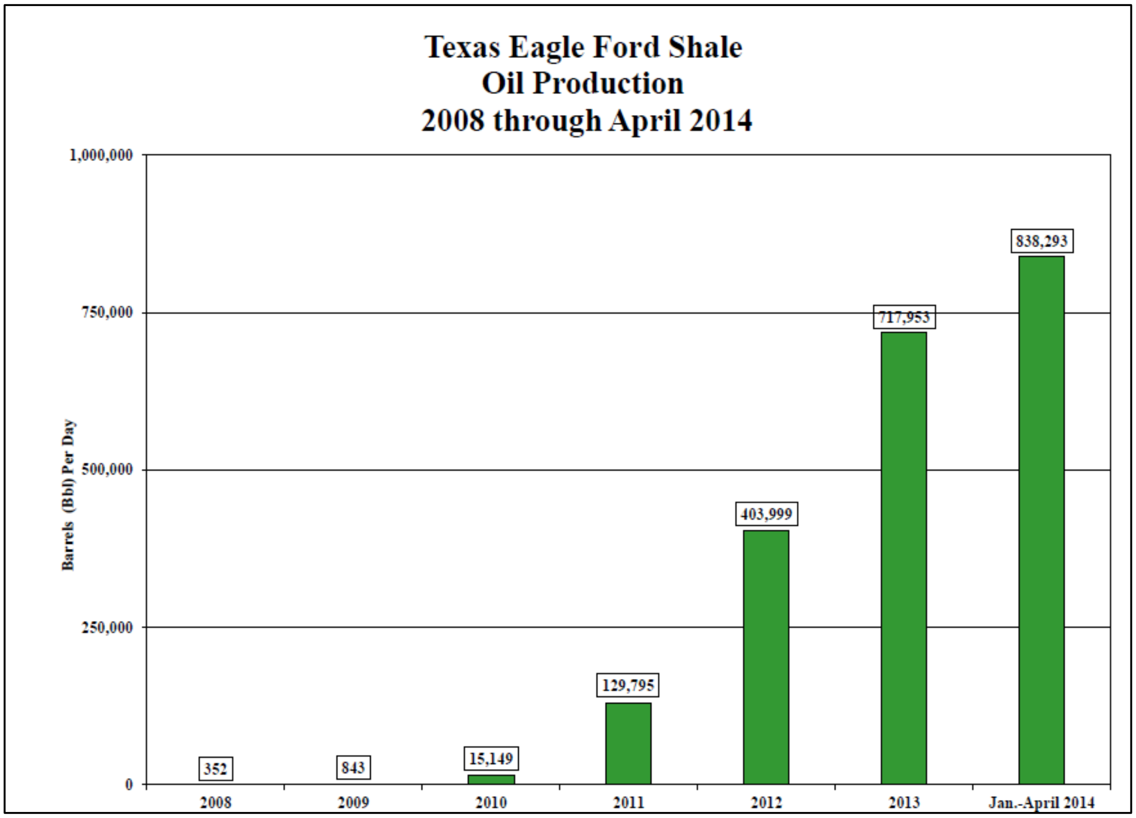

Figure 31: Eagle Ford Annual Oil Production (Railroad Commission of Texas 2014)

Beginning in 2014, the drilling requirements to meet the desired plateau of 1 million barrels per day were calculated using the VBA program. This was reiterated for several years until constraints were met. The resulting production profile is illustrated in Figure 32.

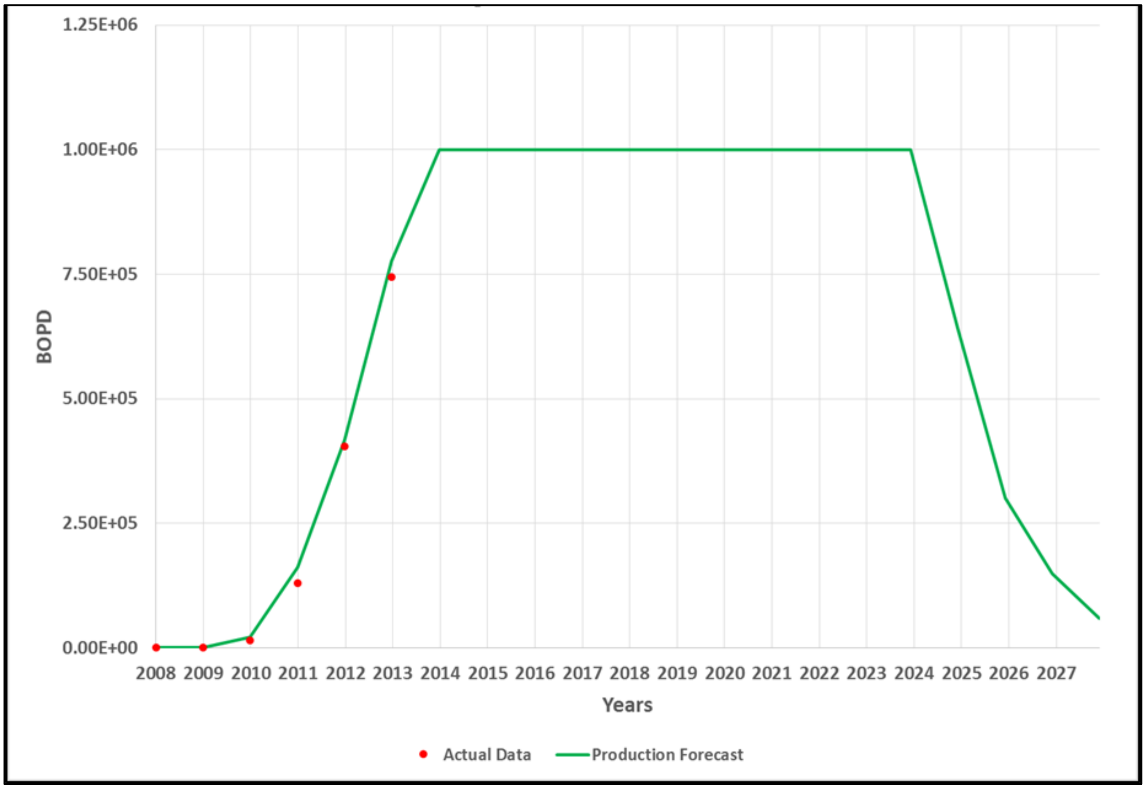

Figure 32: Production Profile of the Second Forecast Scenario

As shown in the preceding figure, the second scenario produces 1 million barrels of oil per day until 2024. The plateau is long enough to sustain the production in the field. The cumulative oil production until the year 2027 is 4.95 billion barrels of oil.

The drilling requirement for the second scenario was accomplished during the year 2013. The future drilling schedules seem very practical. Every year will require almost 2,000 wells to reach and maintain the production plateau. The total number of wells drilled in this case is 22,957. Figure 33 shows the future drilling requirement of this scenario starting with 2014.

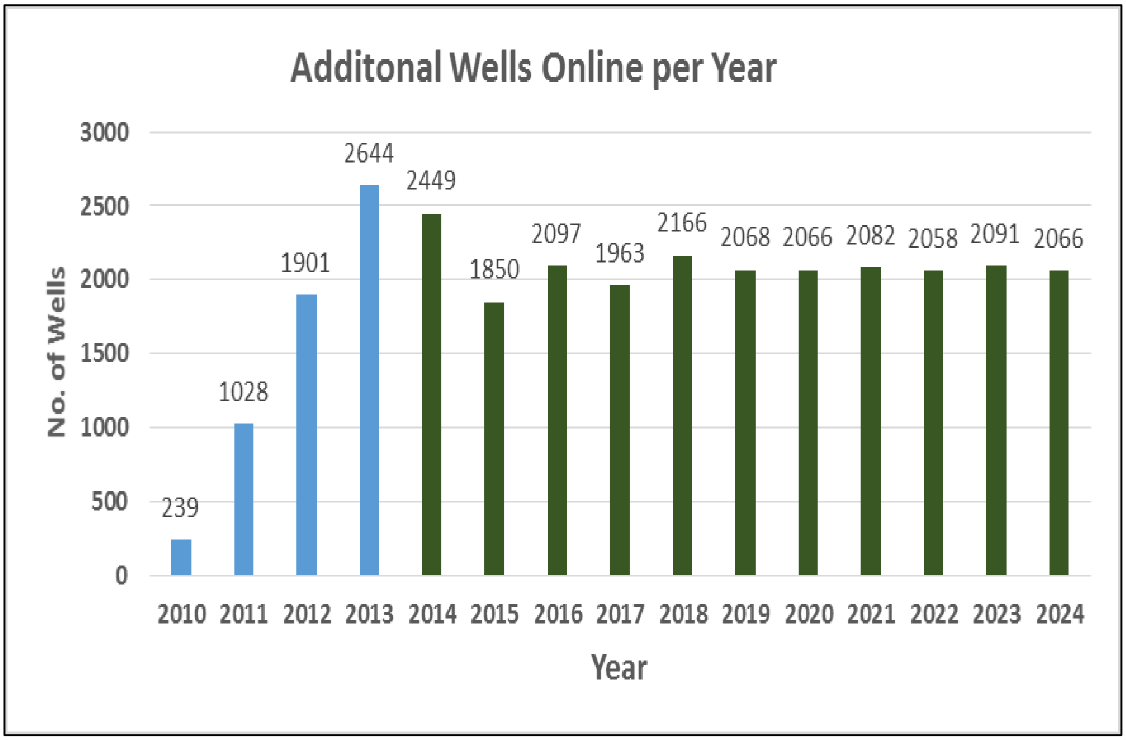

Figure 33: New Well Requirement of the Second Forecast Scenario

Recently, the number of drilling rigs in the EFS has been increasing. In particular, the number of oil rigs is increasing more than the number of gas rigs. The BHI database provides updated data on the number of rigs on each field, as shown in Figure 34.

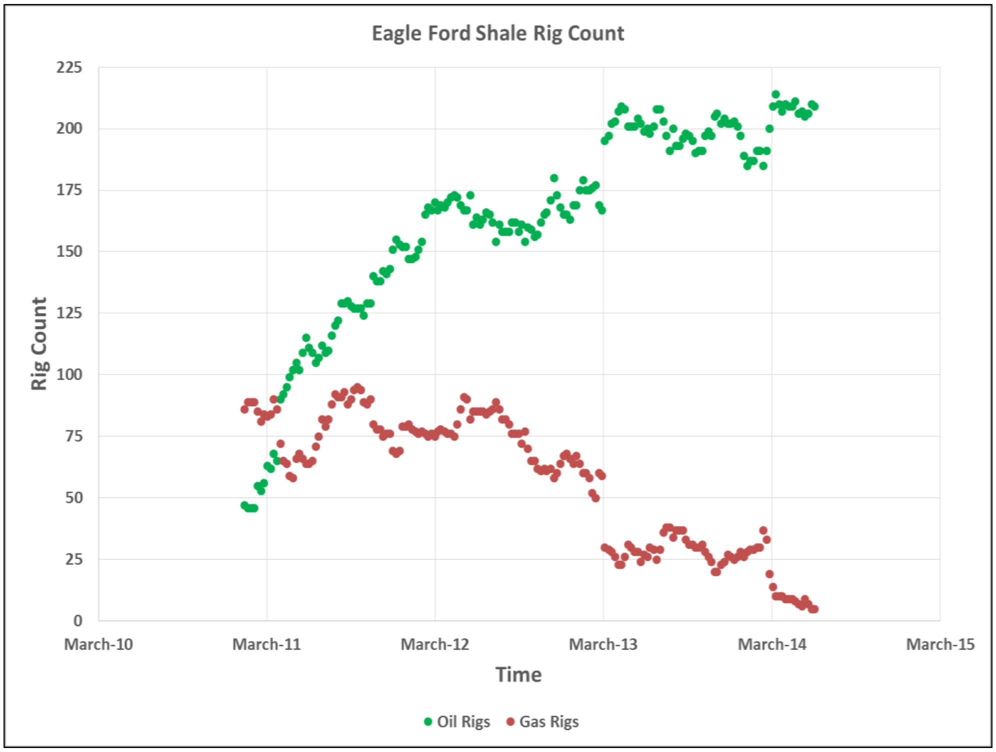

Figure 34: Oil and Gas Rig Counts for EFS (Baker Hughes International)

The goal of the third forecast scenario is to drill a constant number of wells each year, based on rig count and capability. The remaining values to be determined were the number of days it takes to drill and complete the well and put it online. Table 14 summarizes how long it takes to drill the wells. The number of days to finish the well to completion, including hydraulic fracturing is uncertain, yet most of the data suggests that it takes about 14 days for completion.

Table 14: Number of Days to Drill the Oil Well in EFS

Year	Wells/Rig	Days to Drill a Well	Source
2012	16	22.8	BHI
2013	19	19.2	BHI
2014	30	12	EOG Report

The rig count for the year 2014 was selected (214 rigs) with the data for completion and drilling days. A well can be drilled and completed in a 26 days. Therefore, the total number of wells that can be put online each year is 2,996. This number was used to generate the production profile for this scenario, and it is shown in Figure 35.

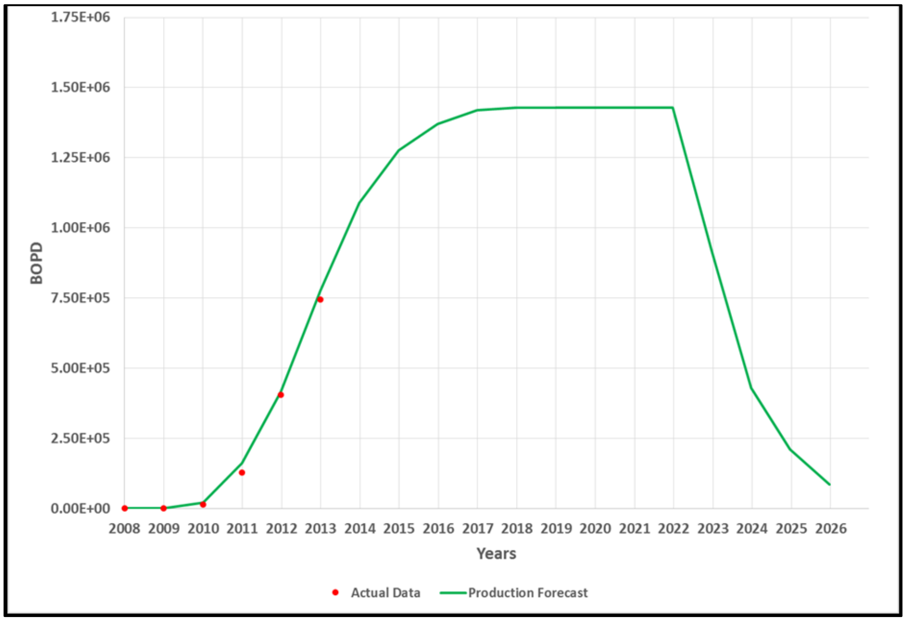

Figure 35: Production Profile for the Third Scenario

The production plateau was sustained from 2018 to 2022 at 1.42 million barrels per day. The total cumulative oil production is 5.6 billion barrels. The total number of wells required to meet this production is 26,694. The drilling schedule for this scenario is illustrated in Figure 36.

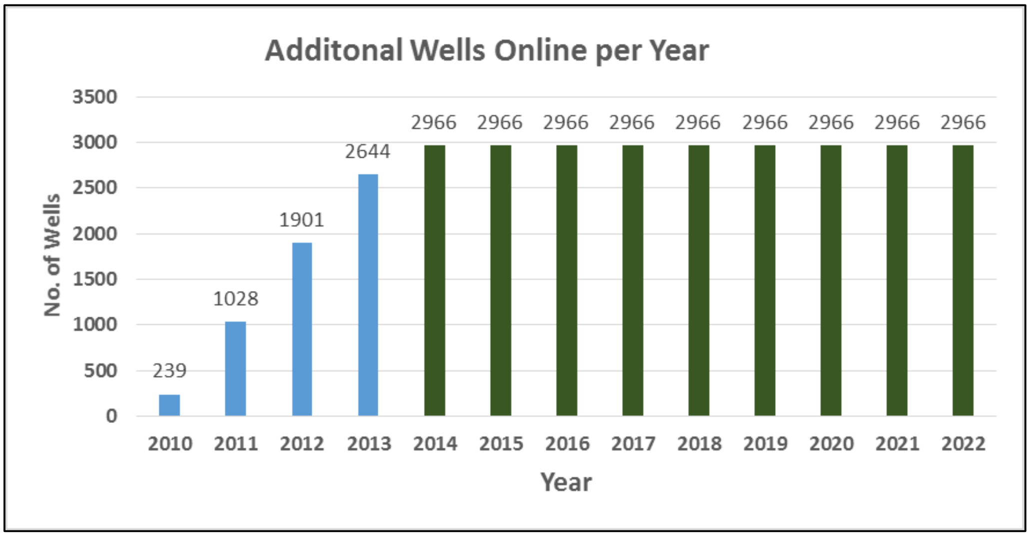

Figure 36: Drilling Schedule for the Third Scenario

The three scenarios detailed above show how the production forecast method is used. There can be countless scenarios depending on the desired rate, drilling schedule and other constraints. Moreover, the method can be applied to other unconventional oil and gas fields.

CHAPTER V

PRODUCTION DATA ANALYSIS

Data Analysis Introduction

In this chapter, oil production data analysis is performed on several wells in the EFS. As mentioned in the literature review, several authors have attempted to look at the daily production data and make forecasts in various ways. The method used in this analysis is transient linear-flow analysis based on the dual-porosity model.

EFS wells are drilled horizontally and completed with transverse hydraulic fractures. Natural fractures intersect with hydraulic fractures in the matrix. Therefore, the dual-porosity model is suitable for performing the analysis.

The dual-porosity model was first introduced by Warren and Root (1962). They introduced it in a well test analysis using a cube of matrix with naturally fractured intersections. Since it was a cube, the fracture spacing was uniform in all directions. Figure 37 illustrates the model.

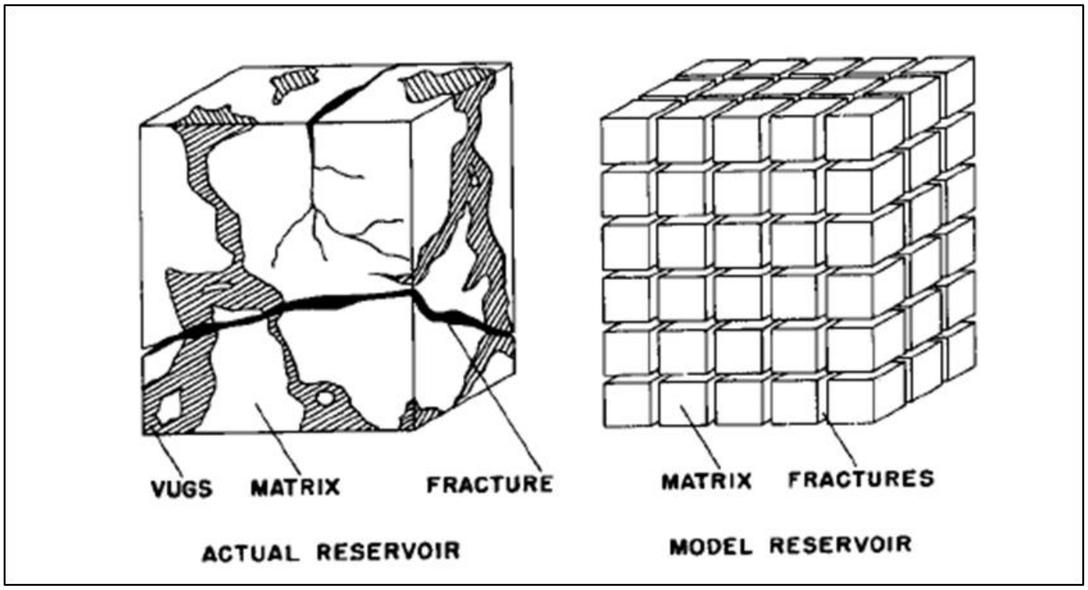

Figure 37 : Warren and Root Dual-Porosity Model (Warren and Root 1962)

Moreover, solution of linear flow reservoirs by the transient dual-porosity model was introduced by El-Banbi (1998). The solution was developed with constant bottom-hole pressure or with a constant rate. El-Banbi concludes that no radial flow can be observed during production and that linear flow is dominant. Table 15 and Table 16, taken from El-Banbi's dissertation, detail the equations used for further development of production data analysis in unconventional reservoirs.

Table 15: El-Banbi's Constant Bottom-Hole Pressure Solution (1998)

Constant p_{wf} (Oil Production)	$\sqrt{k}A_c = \frac{125.1\,B\mu}{(p_i - p_{wf})\sqrt{\phi\,\mu\,c_t}\,m_{CPL}}$ $V_p = 19.91\frac{B}{(p_i - p_{wf})c_t}\frac{\sqrt{t_{ehs}}}{m_{CPL}}$
Constant p_{wf} (Gas Production)	$\sqrt{k}A_c = \frac{1262\,T}{[m(p_i) - m(p_{wf})]\sqrt{(\phi\,\mu\,c_t)_i}\,m_{CPL}}$ $V_p = 2008\frac{T}{[m(p_i) - m(p_{wf})](\mu c_t)_i}\frac{\sqrt{t_{ehs}}}{m_{CPL}}$

Table 16: El-Banbi's Constant Rate Solution (1998)

Constant Rate (Oil Production)	$\sqrt{k}A_c = \frac{79.65\, qB\mu}{\sqrt{\phi\,\mu\, c_t}\, m_{CRL}}$ $V_p = 8.962 \frac{qB}{c_t}\frac{\sqrt{t_{ehs}}}{m_{CRL}}$
Constant Rate (Gas Production)	$\sqrt{k}A_c = \frac{803.2\, q_g T}{\sqrt{(\phi\,\mu\, c_t)_i}\, m_{CRL}}$ $V_p = 90.36 \frac{q_g T}{(\mu c_t)_i}\frac{\sqrt{t_{ehs}}}{m_{CRL}}$

Well Completion and Stimulation in the EFS

Because the EFS is an unconventional reservoir where permeability is extremely low compared to conventional reservoirs, the only way to access reserves is to drill long horizontal wells and stimulating them by hydraulic fracturing. The hydrocarbon will then flow from the matrix to the fractures and into the wellbore.

The lateral length of EFS wells ranges from 4,000 to 5,000 ft; the spacing between stages ranges from 200 to 250 ft. Usually, there are four perforation clusters per stage, according to Pope, Palisch, and Saldungaray (2012). Figure 38 is a typical schematic of an EFS well.

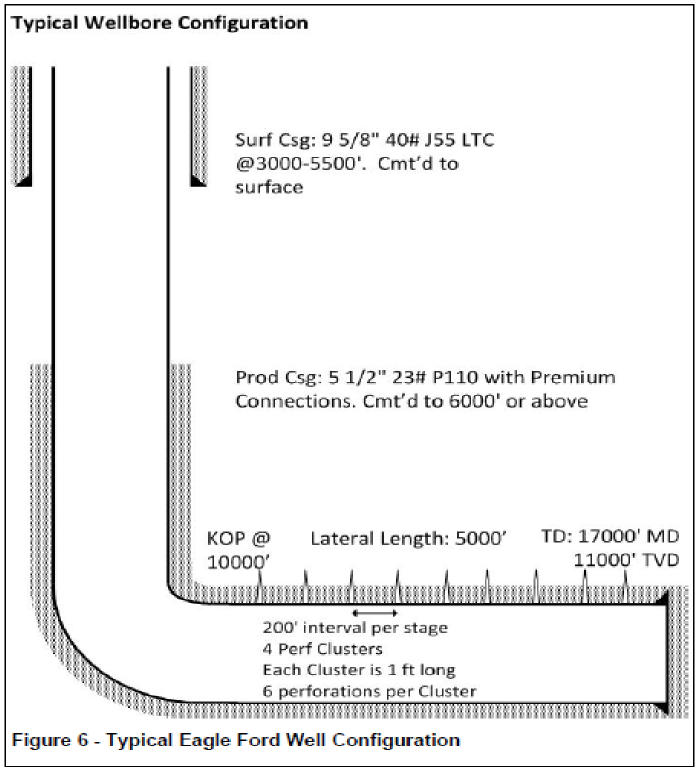

Figure 38: Typical Well Configuration of the EFS (Pope, Palisch, and Saldungaray 2012)

The way to enhance production from nano-darcy permeability reservoirs like the EFS is by the massive stimulation of hydraulic fracturing. Selecting the appropriate fracturing fluid is essential in designing a successful stimulation job. In the EFS, cross-linked fluids have been used to carry away the large-diameter proppant into the formation. The advantage of using this kind of fluid is that it requires less water (Pope, Palisch, and Saldungaray 2012). Table 17 gives the ranges for different parameters used in designing hydraulic fractures in the EFS.

Table 17: Ranges of Hydraulic Fracturing Parameters in EFS (Centurion 2011)

	MINIMUM	MAXIMUM	AVERAGE
Total Vertical Depth (ft).	5,660	12,775	8,195
Measured Depth (ft).	9,943	17,322	14,016
Number of Stages.	9	26	17
Total Perforated Length (ft).	2,869	7,939	5,301
Perforated Length, per Stage (ft).	151	609	326
Number of Clusters per Stage.	3	10	6
Average Treating Pressure (psi).	5,469	10,115	7,593
Average Treating Rate (bpm).	42.49	99.71	81.78
Average Treating HHP.	6,317	23,285	15,284
Average Treating Rate per Cluster (psi).	8.98	23.58	13.92
Average Treating HHP per Cluster (psi).	1,532	4,692	2,568
Average Treating Fluid, per Well (1,000 bbls).	39.2	247.4	104.5
Average Proppant Volume, per Well (1,000 lbs).	1,869.5	8,160.4	4,906.3
Average Treating Fluid, per Stage (1,000 bbls).	2.54	19.03	6.30
Average Proppant Volume, per Stage (1,000 lbs).	138.87	473.36	290.28
Average Treating Fluid per Cluster (1,000 bbls).	0.58	4.76	1.11
Average Proppant Volume per Cluster (1,000 lbs).	25.07	97.19	50.01

One of the main methods used for evaluating hydraulic fracturing was to run a microseismic survey along the lateral length of the well. This tool helps in visualizing the propagation of fractures and whether it meets expectation. One more benefit of this tool is in simulating the stimulated reservoir volume for better planning of future designs. This tool has been used in EFS wells as activity in drilling and completions have increased. Figure 39 displays the evaluation of EFS stimulation by microseismic survey.

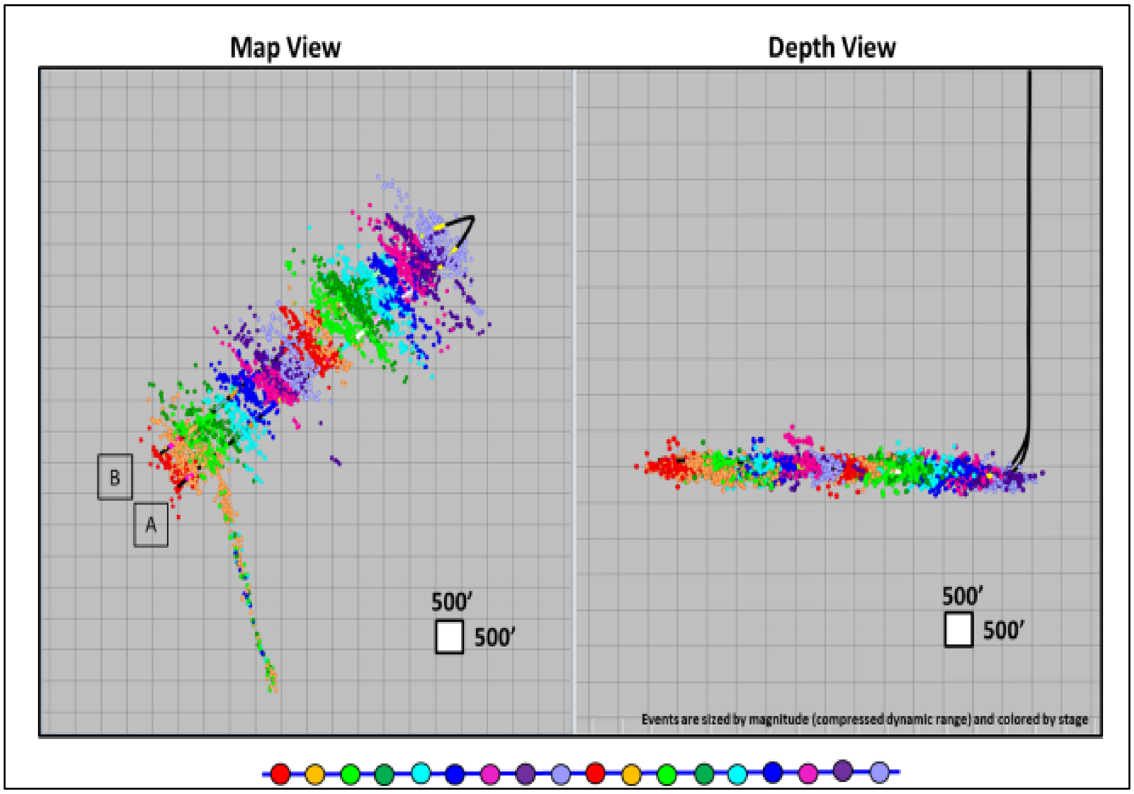

Figure 39: Evaluating EFS Fracturing Jobs by Microseismic Survey (Neuhaus and Zeynal 2014)

Analysis Method

The linear dual porosity model was used to analyze production data . Methods presented by Al-Ahmadi, Almarzooq, and Wattenbarger (2010) and Tran, Sinurat, and Wattenbarger (2011) will be applied in this chapter. As mentioned above, wells in the field are horizontal and completed with hydraulic fractures. This allows following the dual-porosity slab matrix 1 from Al-Ahmadi, Almarzooq, and Wattenbarger (2010). Figure 40 illustrates this model.

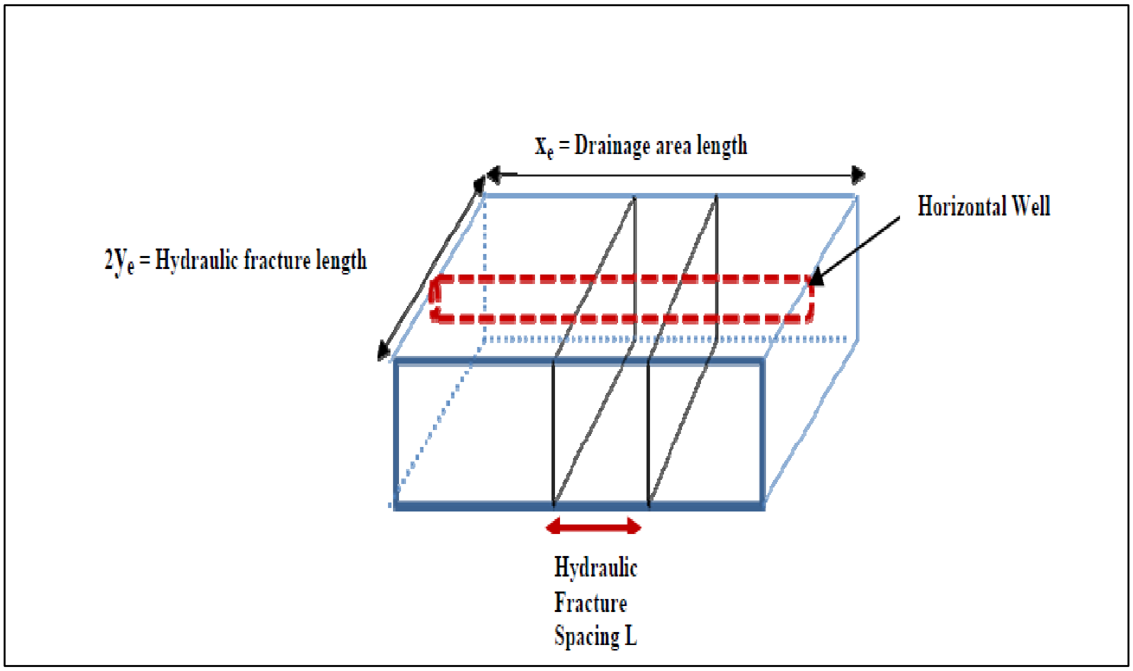

Figure 40: Dual-Porosity Slab Matrix Model 1 (Al-Ahmadi, Almarzooq, and Wattenbarger 2010)

Tran, Sinurat, and Wattenbarger (2011) used different plots for the analysis. Parameters for calculations were acquired from Tran, Sinurat, and Wattenbarger, as will be detailed in this chapter. Figure 41 is an example plot used in their method of analysis.

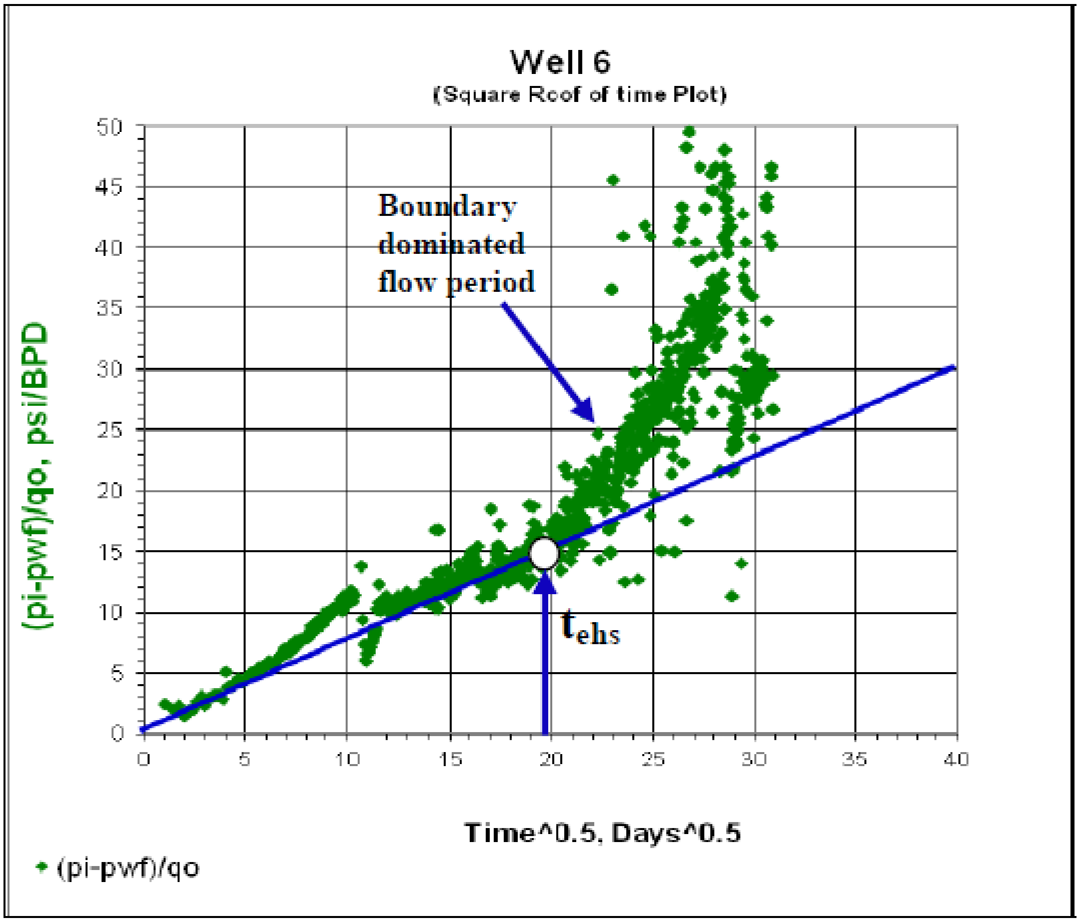

Figure 41: Square Root of Time plot (Tran, Sinurat, and Wattenbarger 2011)

Three main parameters are the results of the Tran, Sinurat, and Wattenbarger analysis; they are oil-in-place (OIIP), fracture half-length and area of drainage matrix. El-Banbi's (1998) equations for this model are used, and they as follows:

$$\sqrt{k_m}\, A_{cm} = 125.1 \frac{B\mu}{\sqrt{\Phi \mu c_t}} \frac{1}{m_4} \qquad (3)$$

$$\text{OOIP} = \frac{19.91\sqrt{t_{esr}}(1 - S_w)}{c_t m_4} \tag{4}$$

$$y_e = 0.1591\sqrt{\frac{k_m t_{esr}}{\Phi \mu c_t}} \tag{5}$$

The output from the analysis aids in understanding well performance as well as in evaluating stimulation designs. Input parameters are related to both rock and reservoir properties. Well completion data are also essential to accomplish this task. If data are not available from operators, published data are used or an initial estimate is made.

Available Data for Analysis

In order to perform the production data analysis, daily oil production data were required. Daily data cannot be acquired through public databases. Currently, daily production data are available for nine wells from one of the main operators in the EFS field. Some of the wells produce longer than others. Figure 42 is the log-log plot of those nine wells.

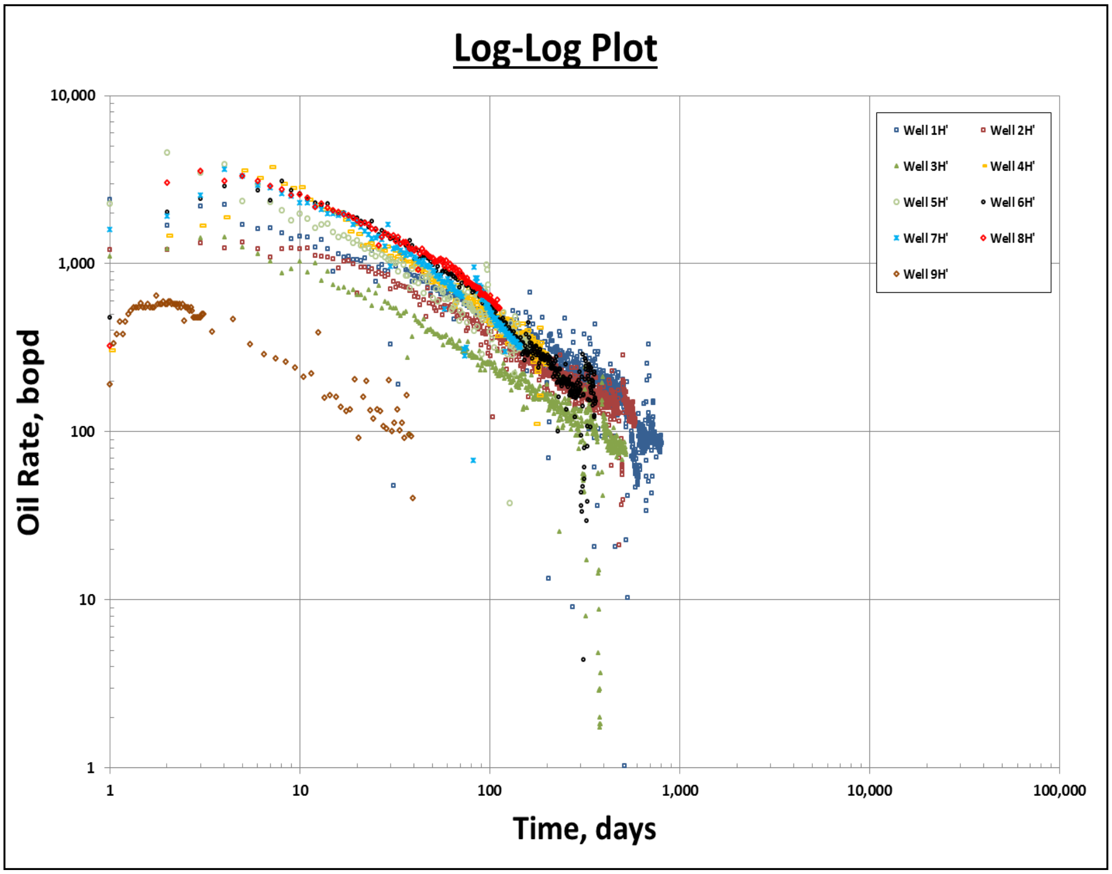

Figure 42: Log-log Plots of Daily Production Data of Nine Wells

In order to complete the set of data, fluid properties, rock properties and completion data are required. Unfortunately, most of those data are not available. However some data were obtained by searching for those nine wells in the databases using their operator names, production data and lateral number as indicated in Figure 42 above. Furthermore, whatever was available from the operators is shown in Table 18.

Table 18: Available Completion Data for the Nine Wells

Well Name	Lateral, ft	Lb/ft	Original Well Spacing, ft	Current Spacing, ft
Well 1H	5,538	762	2,000	800
Well 2H	4,055	800	1,200	800
Well 3H	4,294	773	750	750
Well 4H	6,024	974	750	750
Well 5H	5,373	864	750	750
Well 6H	4,829	1,988	500	500
Well 7H	3,276	2,169	500	500
Well 8H	5,594	1,518	340	300
Well 9H	3,801	1,968	200	200

Results of Analysis

As discussed in the previous sections, the method of Tran, Sinurat, and Wattenbarger (2011) was followed to carry out the analysis on the nine available wells. First, individual log-log plots of each well were generated to select the wells that exhibited a slope of one-half, which can indicate a linear flow. Figures 43 through 46 are the log-log plots of the wells with a slope of one-half and with sufficient time of production.

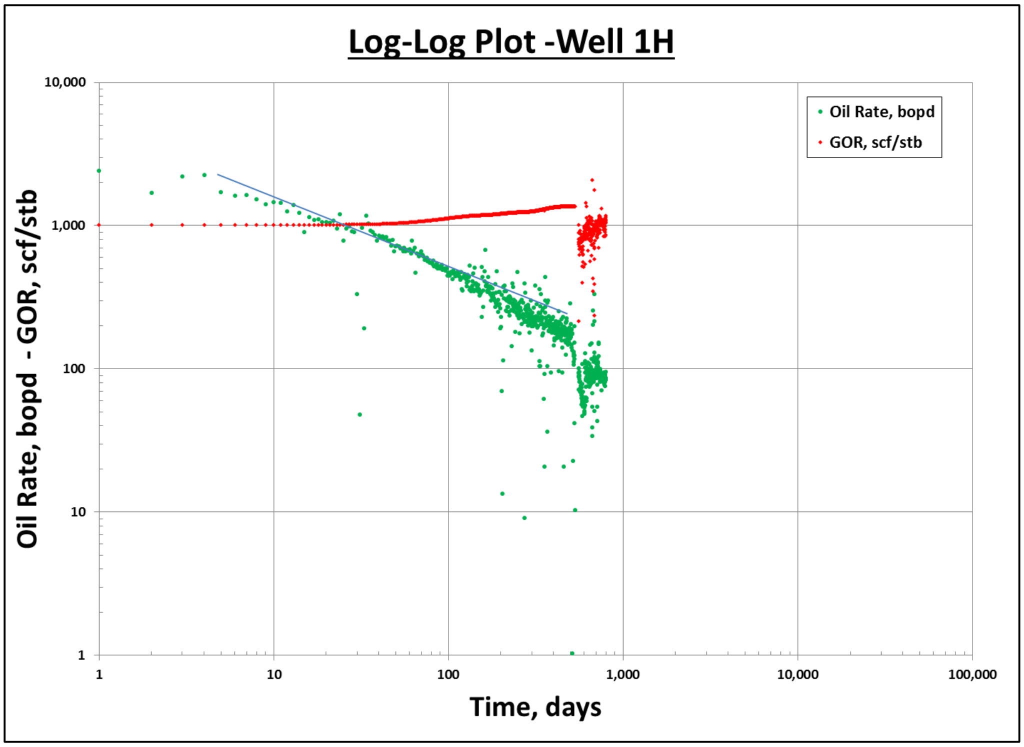

Figure 43: Log-log Plot of Well 1-H

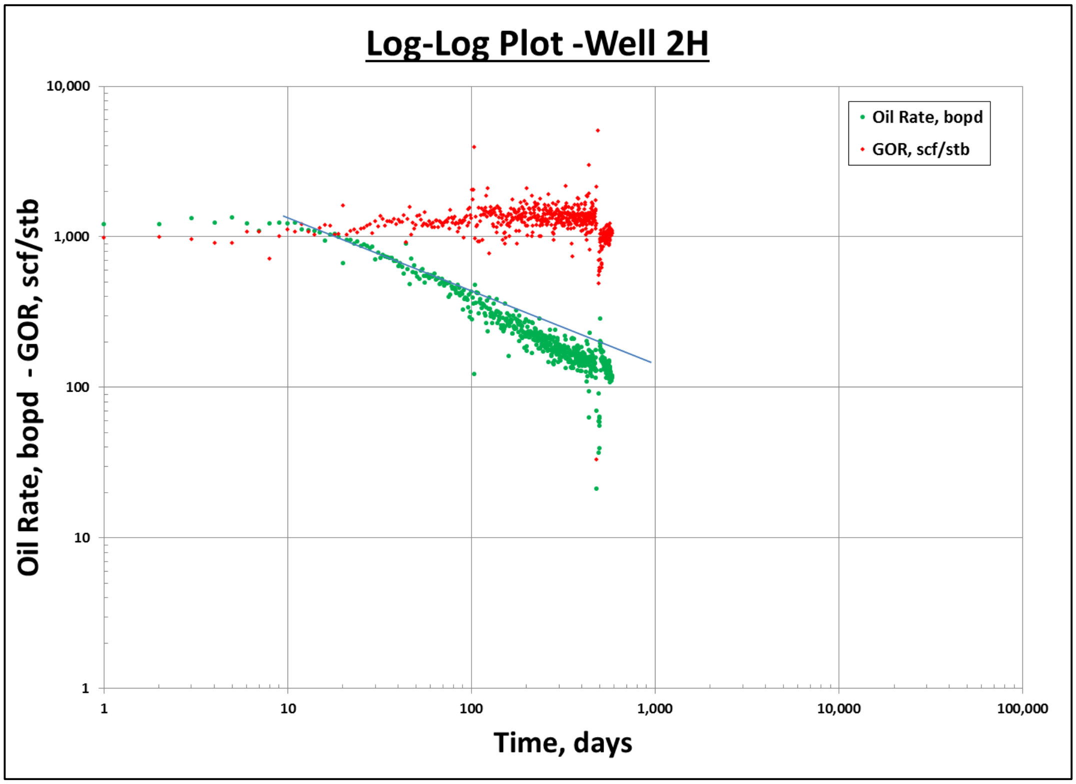

Figure 44: Log-log Plot of Well 2-H

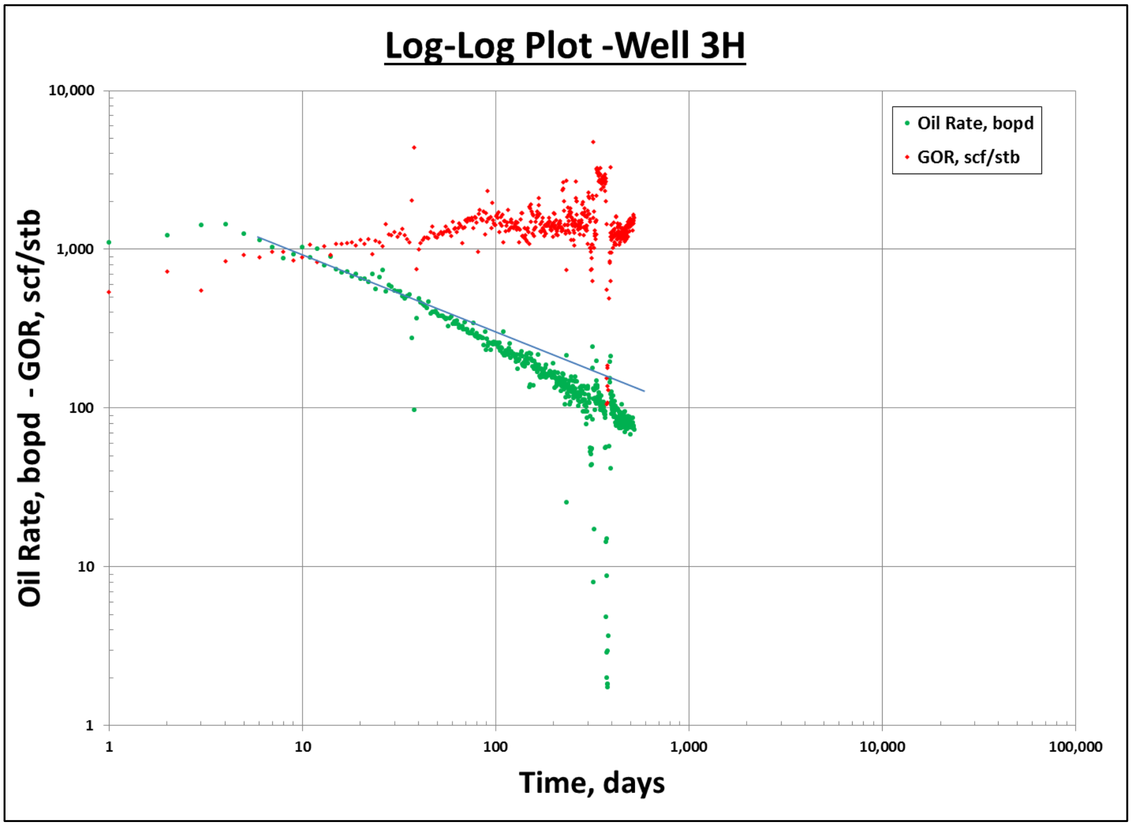

Figure 45: Log-log Plot of Well 3-H

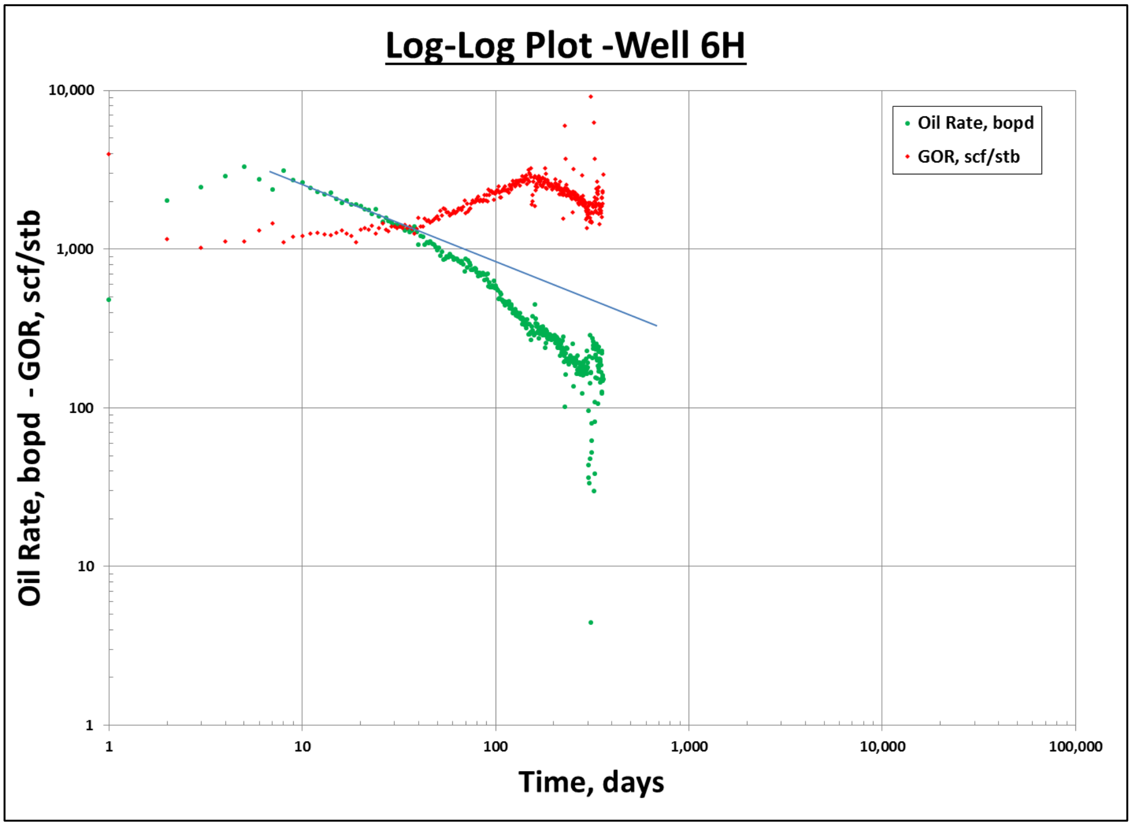

Figure 46: Log-log Plot of Well 6-H

Next, plots of rate-normalized pressure vs. the square root of time were generated. Since initial pressure and flowing bottom-hole pressure data were not available, an initial pressure of 8,000 psi and a constant 1,000 psi of bottom-hole pressure was assumed. The value of the initial pressure was obtained from a completion report for Well 6-H. This type of plot is important for determining the slope as well as the time at which linear flow ends. Figures 47 through 52 are the plots of rate-normalized pressures vs. square root of time.

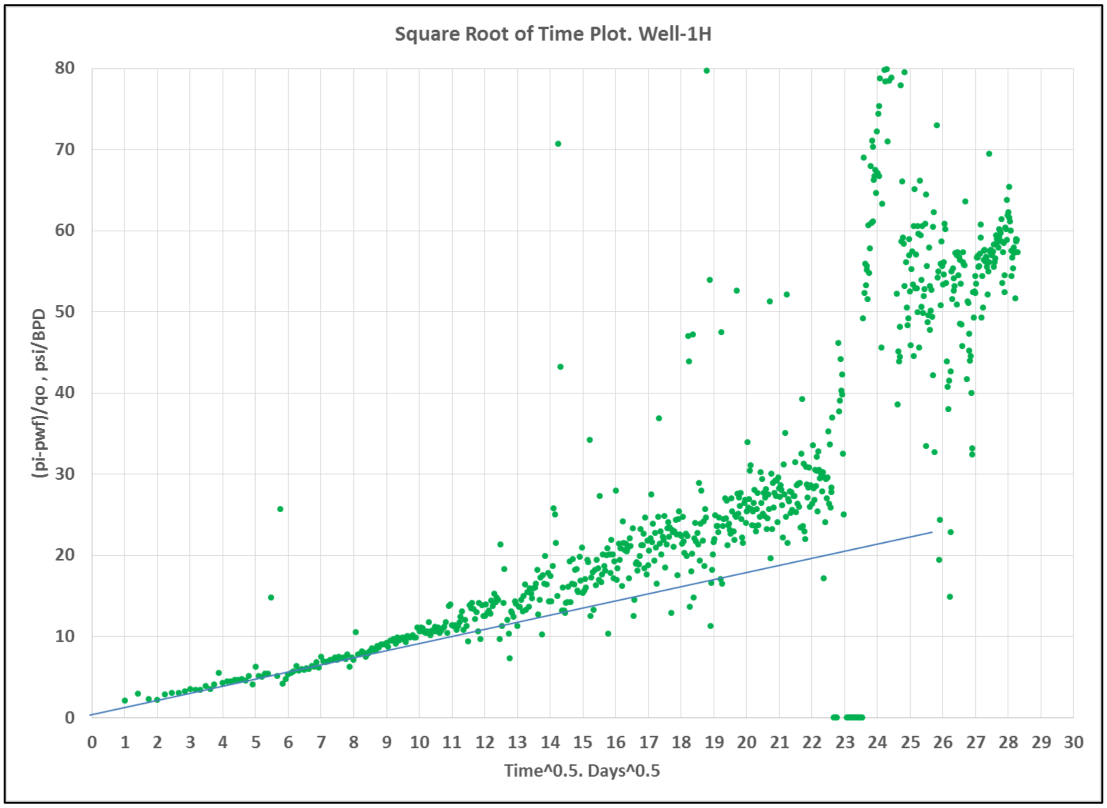

Figure 47: Rate-Normalized Pressure vs. Square Root of Time, Well-1H

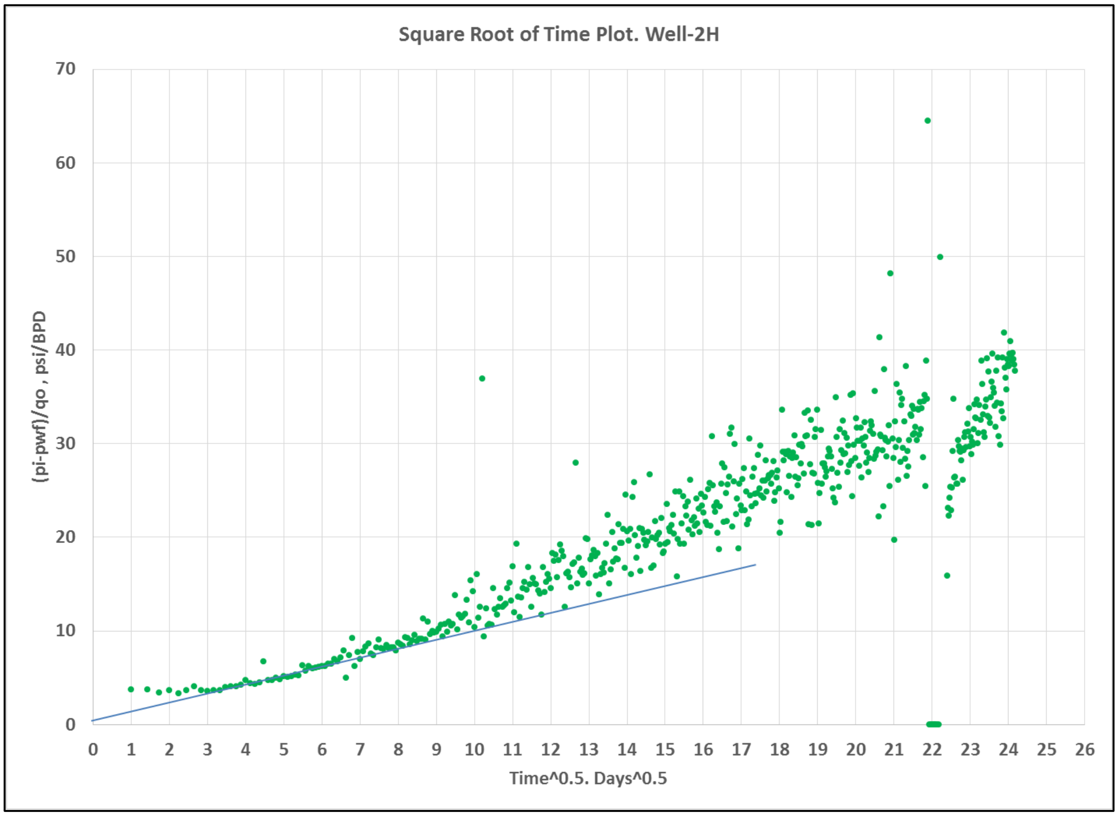

Figure 48: Rate-Normalized Pressure vs. Square Root of Time, Well-2H

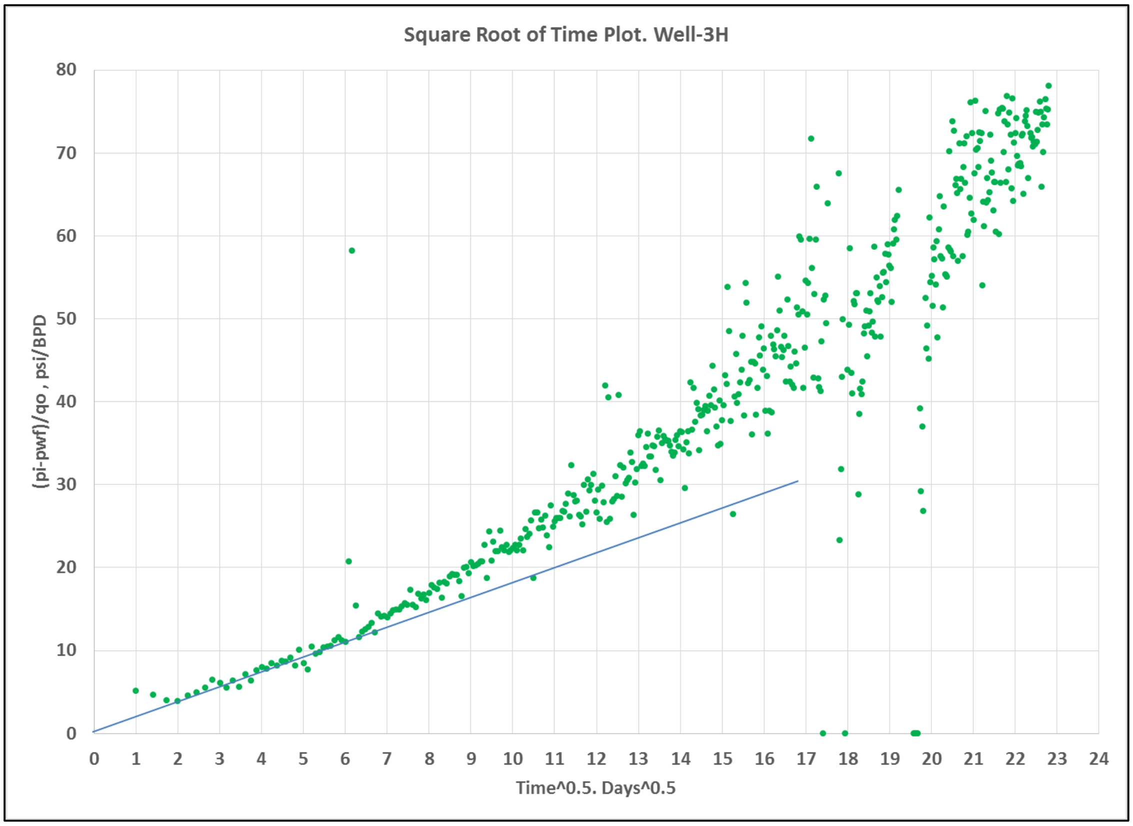

Figure 49: Rate-Normalized Pressure vs. Square Root of Time, Well-3H

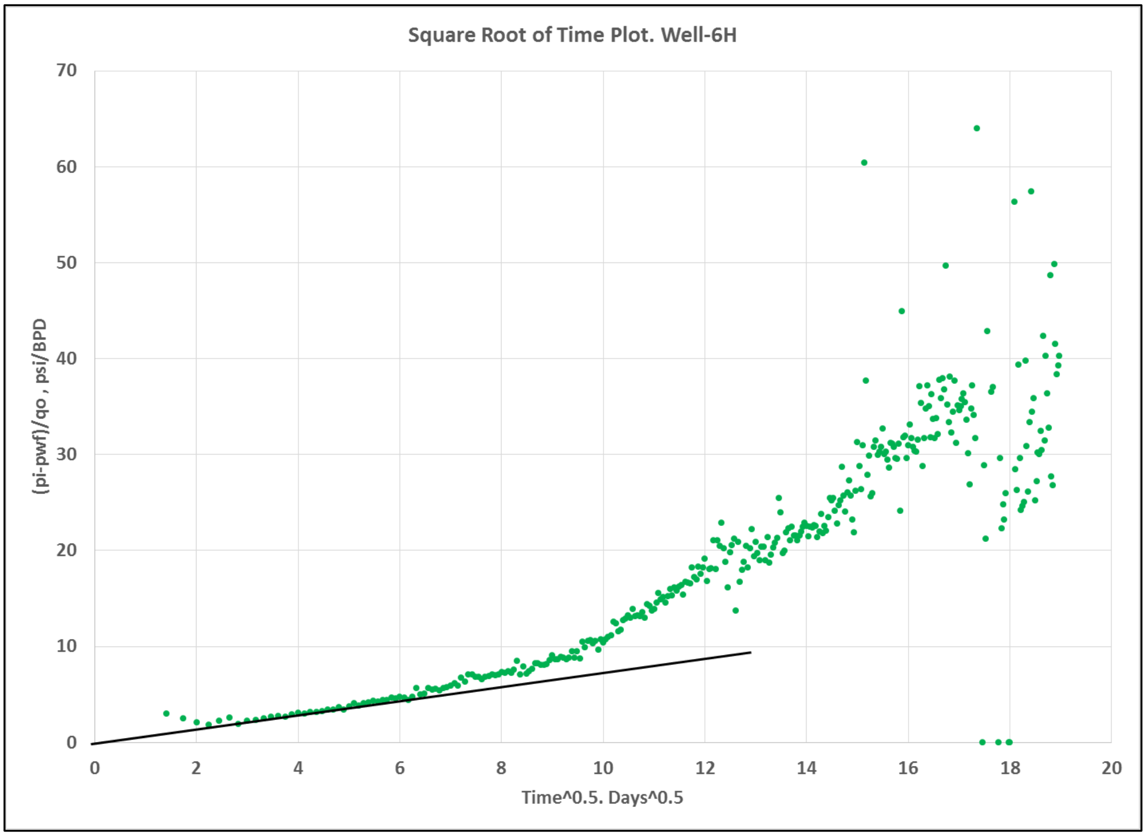

Figure 50: Rate-Normalized Pressure vs. Square Root of Time, Well-6H

Equations 3, 4 and 5 were applied to get the required three parameters, oil-in-place (OIIP), fracture half-length and area of drainage matrix. Tables 19 through 22 summarize the input and output of the analyzed wells.

Table 19: Input Data and Analysis Output of Well-1H

Matrix Permeability, km (md)	0.08
Porosity, fraction	0.09
Oil Compressibility, 1/psi	1.02E-05
Water Compressibility, 1/psi	4.00E-06
Oil viscosity, cp	4.00E-01
Formation Compressibility, 1/psi	3.00E-06
Total Compressibility, 1/psi	1.14E-05
Initial oil formation volume factor, rb/stb	1.4
Number of perforation cluster, nf	12
lateral well length, xe, ft.	5,538
Hydraulic fracture spacing, L, ft.	461.5
Water saturation, fraction	0.3
tehs, days	9
m, slope	0.258
OOIP, MMbbls	42.802
Acm, md^0.5 ft^2	1.50E+06
ye, ft.	211.144

Table 20: Input Data and Analysis Output of Well-2H

Matrix Permeability, km (md)	0.08
Porosity, fraction	0.09
Oil Compressibility, 1/psi	1.02E-05
Water Compressibility, 1/psi	4.00E-06
Oil viscosity, cp	4.00E-01
Formation Compressibility, 1/psi	3.00E-06
Total Compressibility, 1/psi	1.14E-05
Initial oil formation volume factor, rb/stb	1.4
Number of perforation cluster, nf	12
lateral well length, xe, ft.	4,055
Hydraulic fracture spacing, L, ft.	337.9167
Water saturation, fraction	0.3
tehs, days	9
m, slope	0.732
OOIP, MMbbls	15.073
Acm, md^0.5 ft^2	5.29E+05
ye,ft	211.144

Table 21: Input Data and Analysis Output of Well-3H

Matrix Permeability, km (md)	0.08
Porosity, fraction	0.09
Oil Compressibility, 1/psi	1.02E-05
Water Compressibility, 1/psi	4.00E-06
Oil viscosity, cp	4.00E-01
Formation Compressibility, 1/psi	3.00E-06
Total Compressibility, 1/psi	1.14E-05
Initial oil formation volume factor, rb/stb	1.4
Number of perforation cluster, nf	12
lateral well length, xe, ft.	4,294
Hydraulic fracture spacing, L, ft.	357.83
Water saturation, fraction	0.3
tehs, days	7
m, slope	1.637
OOIP, MMbbls	5.247
Acm, md^0.5 ft^2	2.37E+05
ye, ft.	186.211

Table 22: Input Data and Analysis Output of Well-6H

Matrix Permeability, km (md)	0.08
Porosity, fraction	0.09
Oil Compressibility, 1/psi	1.02E-05
Water Compressibility, 1/psi	4.00E-06
Oil viscosity, cp	4.00E-01
Formation Compressibility, 1/psi	3.00E-06
Total Compressibility, 1/psi	1.14E-05
Initial oil formation volume factor, rb/stb	1.4
Number of perforation cluster, nf	12
lateral well length, xe, ft.	4,829
Hydraulic fracture spacing, L, ft.	402
Water saturation, fraction	0.3
tehs, days	6
m, slope	0.818
OOIP, MMbbls	8.998
Acm, md^0.5 ft^2	4.74E+05
ye, ft.	172.398

CHAPTER VI

SIMULATION OF EAGLE FORD SHALE OIL WELLS

Introduction of Simulation Work

The last part of this research work is to perform single-well analysis of EFS oil wells. The objective of this part is to match the performance of the oil wells, which in turn, can help in understanding the reservoir and fluid properties of those wells and how to improve the completion and stimulation design. The nine wells for which data were available used in the previous chapter will be examples for the simulation work.

The approach of Alkouh et al. (2012) of simulating wells in unconventional reservoirs was followed. The approach initially focused on matching the transient linear flow of gas wells. In the paper, different sequences of flow were presented going through hydraulic fracture (HF), matrix (M) and natural fractures. Figure 50 is the different grid systems for these elements.

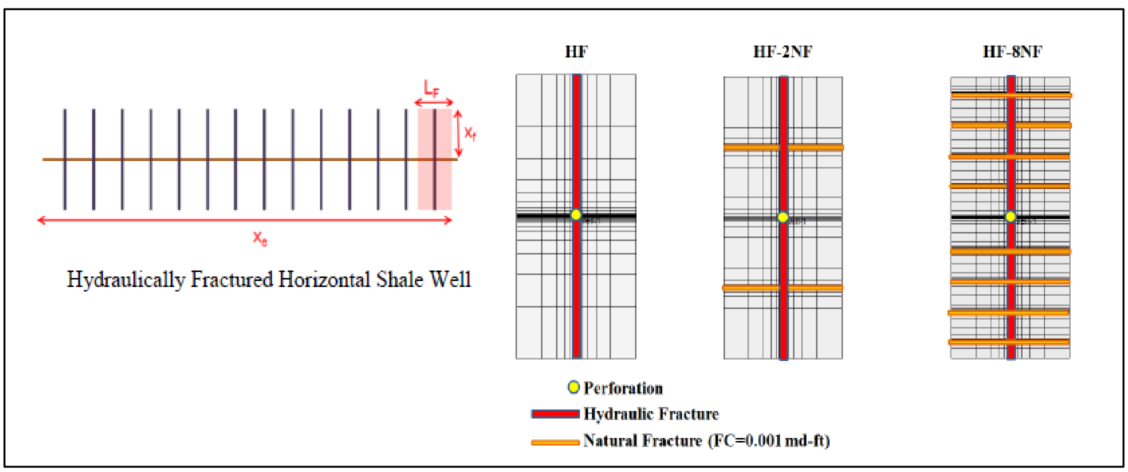

Figure 51: Simulation Grids Showing M, HF and NF. (Alkouh et al. 2012)

The gridding of the model was done explicitly (not using dual porosity model) to avoid the difficulty of having to calculate the shape factor. The permeability required for the hydraulic fracture cell in the model as well as its modified porosity can be calculated using equations 6, 7 and 8. Figure 51 illustrates the hydraulic fracture modification as presented in the mentioned paper.

$$k_{eff} = \frac{9.87\varphi\mu c_t L_F^2}{t_{esr}} \tag{6}$$

$$k_{f,eff} = \frac{k_m L_f + k_{f,in} w_f}{L_f} \tag{7}$$

$$\varphi_{PF} = \varphi_F \frac{w_F}{w_{PF}} \tag{8}$$

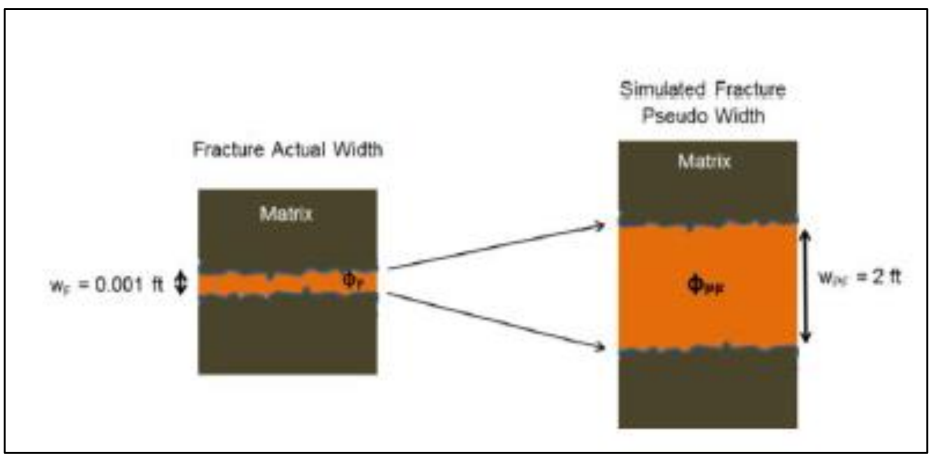

Figure 52: Hydraulic Fracture Cell Modification (Alkouh et al. 2012)

Results of Simulation

Wells with available daily production data from the previous chapter were targeted for use in the simulation. Of the four wells that were valid for analysis, Well 6-H was used to perform the analysis first. This well was selected because it was possible to it in the DrillingInfo database. Therefore, some data regarding initial pressure and completion were found. The well produced for almost a year. Figure 53 shows that the well had a linear flow (slope of ½) for almost 40 days. The linear flow could have resulted from the matrix flow to hydraulic fracture or natural fracture to hydraulic fracture. The period of time of the linear flow could be longer, but the increase of the gas-oil ratio at ~40 days impacted its continuation.

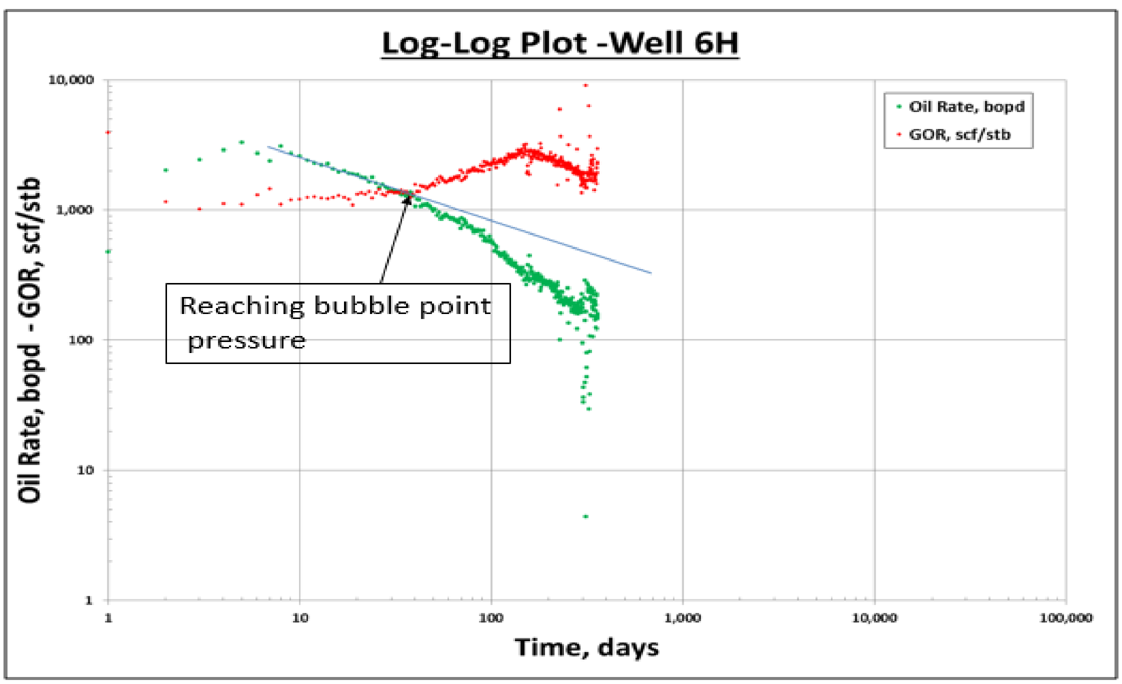

Figure 53: Well 6-H Production vs. Time

The simulation model then was constructed using CMG simulator for well 6-H. Logarithmic gridding was used to represent the fracture half-length and the lateral length of the well. Only one hydraulic fracture was simulated due to the limited number of grids allowed in the available CMG license. The initial input data were taken from the results of the production data analysis and from published data. Table 23 summarizes the input of the well simulation model while Figures 54 through 59 illustrate the rock and fluid properties of the model.

Table 23: Well 6-H Simulation Input

Grid dimension	21 X29X 1
Matrix porosity, fraction	0.06
Thickness, ft.	70
Matrix permeability, md	0.08
Hydraulic fracture Spacing, ft.	402
Fracture half-length, ft.	172
Initial Pressure, psi	8000
Flowing BH Pressure, psi	2000

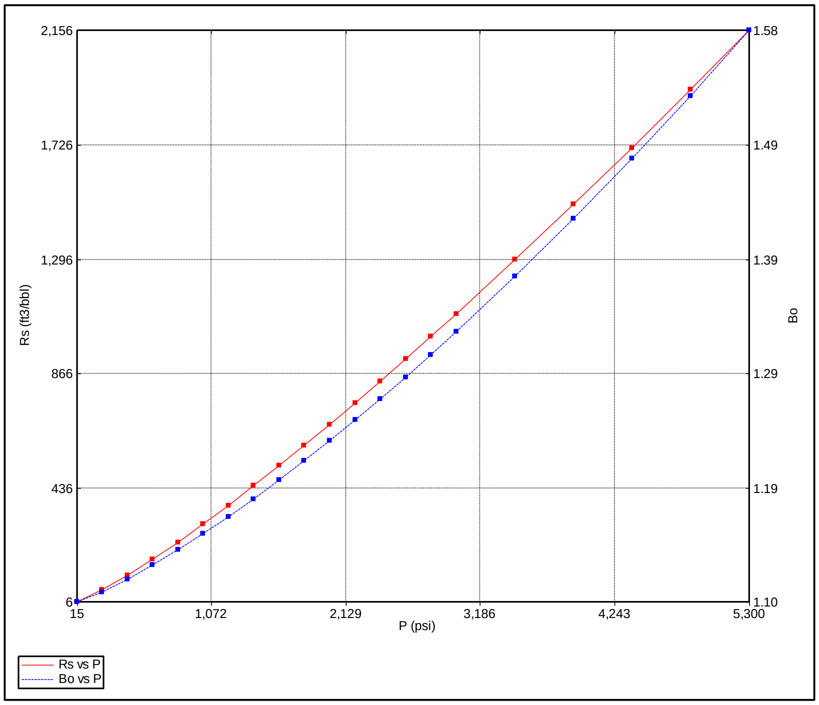

Figure 54: Rs and Bo vs. Pressure as Model Input

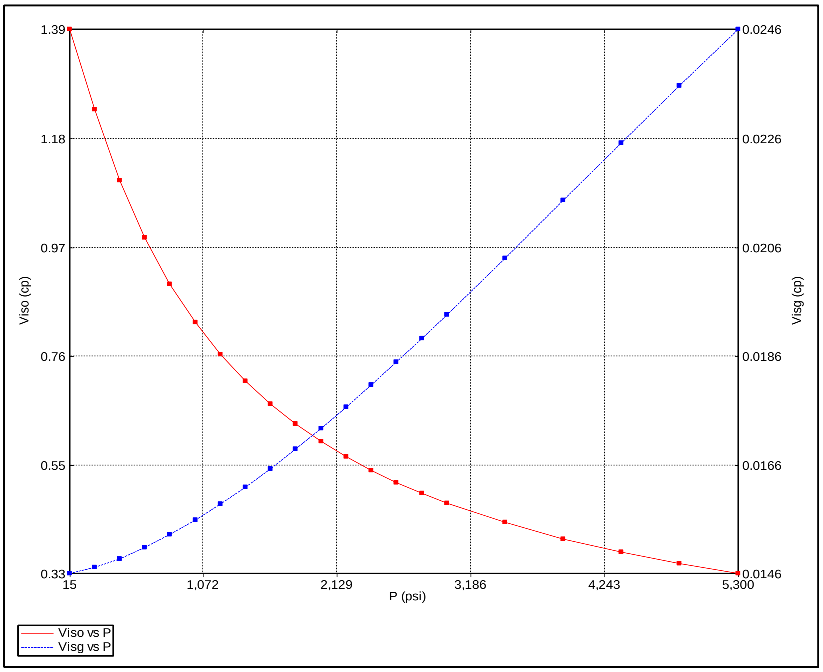

Figure 55: Oil and Gas Viscosities in Model

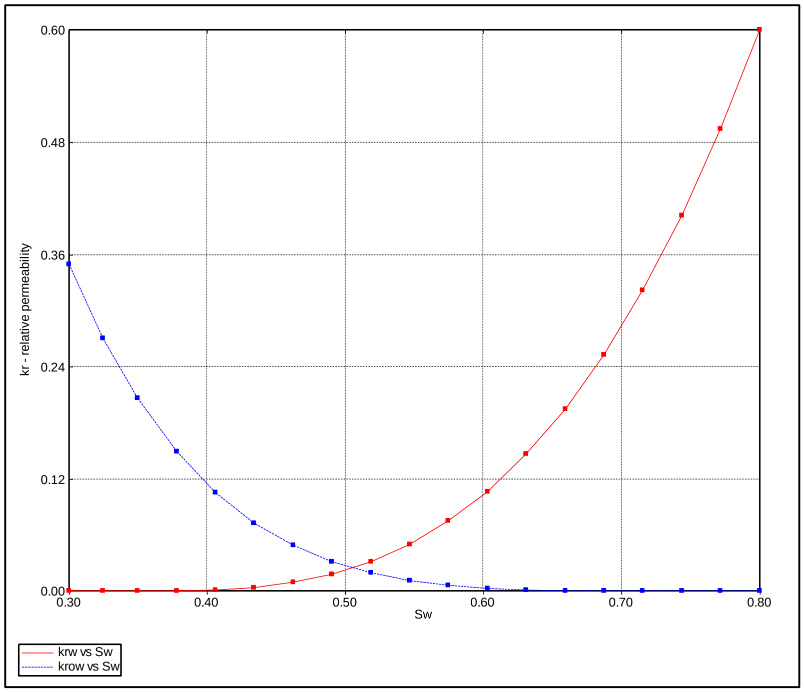

Figure 56: Model Oil-Water Relative Permeability for Matrix

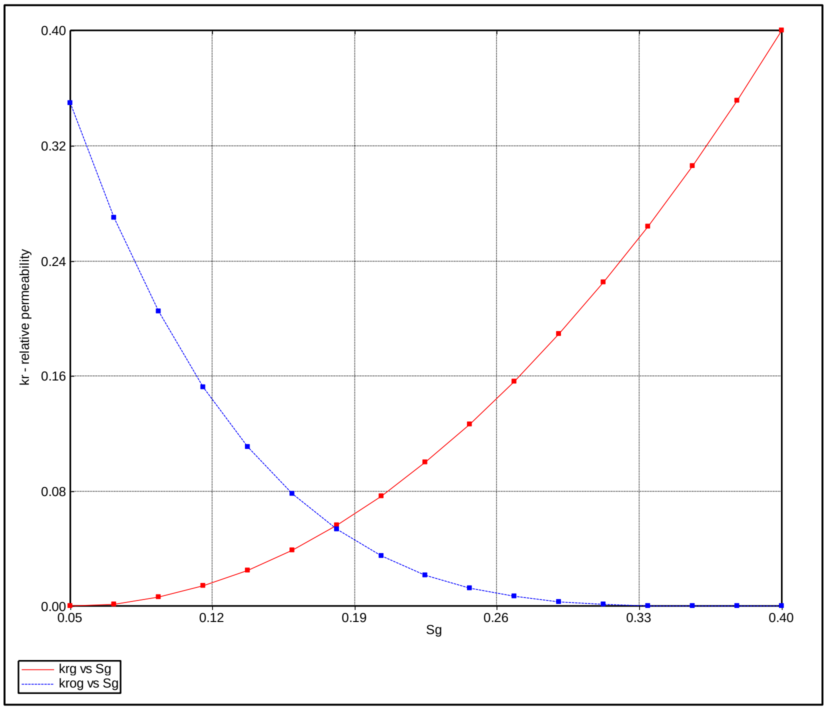

Figure 57: Model Gas-Oil Relative Permeability for Matrix

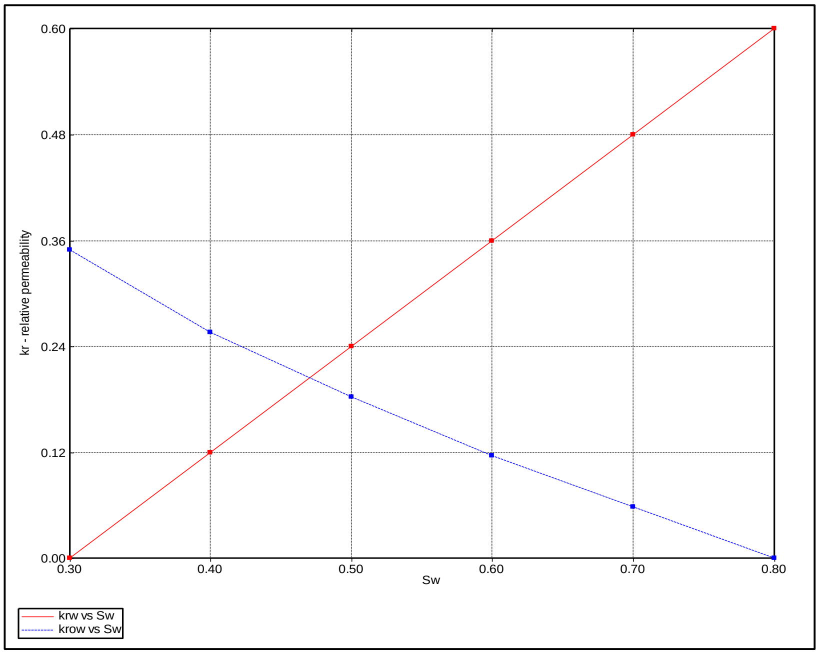

Figure 58: Model Oil-Water Relative Permeability for Fracture

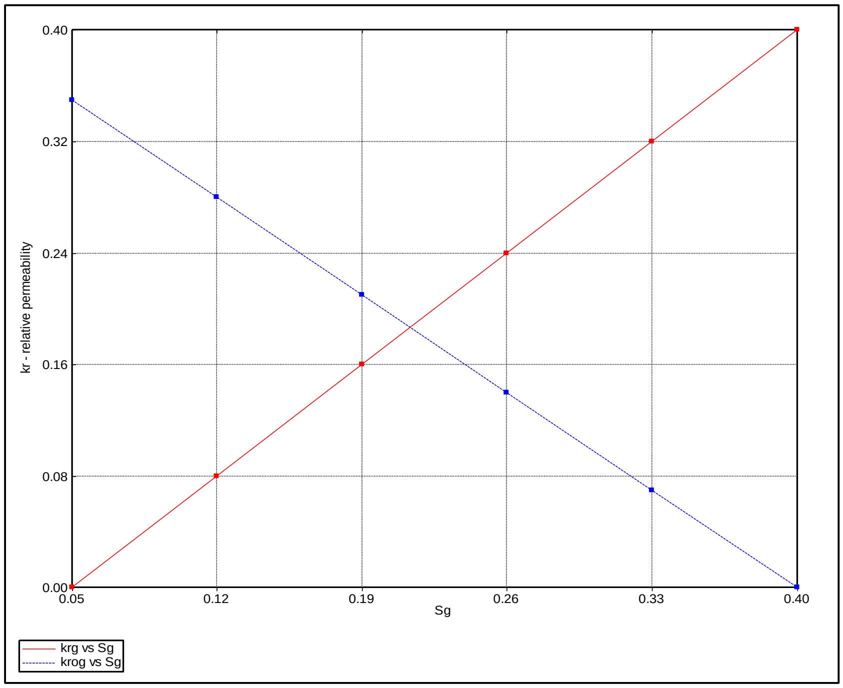

Figure 59: Model Gas-Oil Relative Permeability for Fracture

The above-mentioned model input was the final input after achieving an acceptable match in oil rate and gas/oil ratio. The natural fractures were ignored because including them caused a very quick and sharp decline rate. If better data became available for that specific well, a better match could be reached. Figures 60 and 61 show the final result of simulating well 6-H in both log-log and linear scales, respectively.

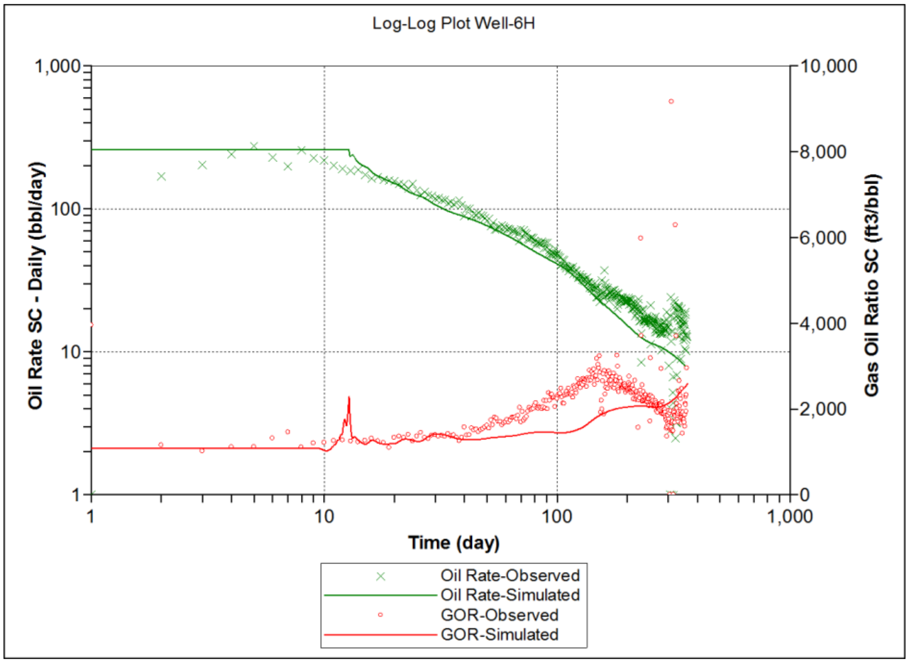

Figure 60: Log-log Plot of Oil Rate and Gas/Oil Ratio Match

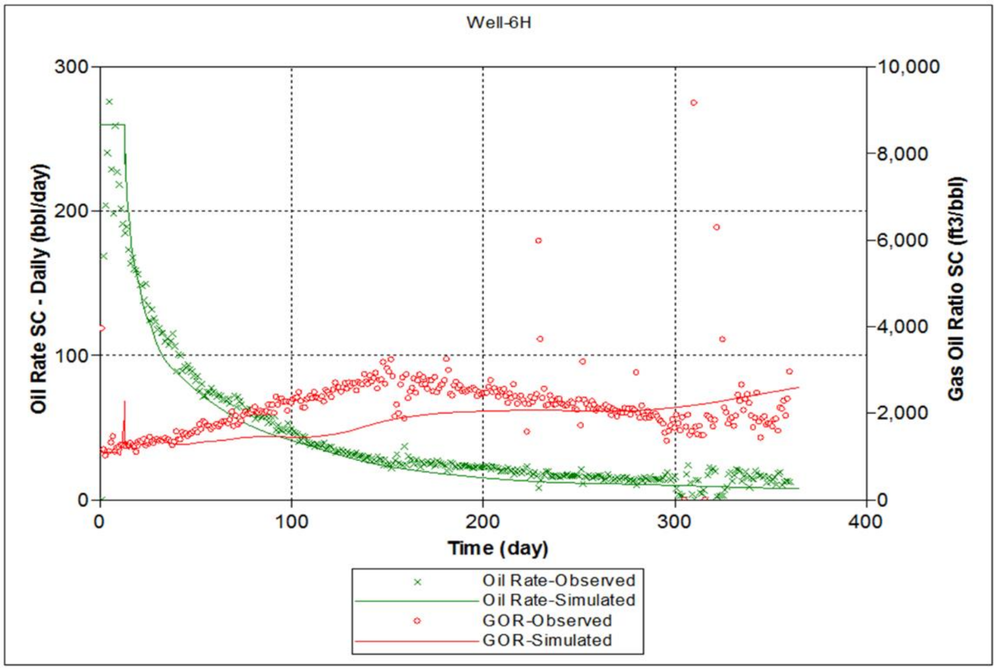

Figure 61: Plot of Oil Rate and Gas/Oil Ratio Match (Linear Scale)

CHAPTER VII

CONCLUSION AND DISCUSSION

The main focus of this research was to find a practical way to generate production forecast scenarios for the EFS. This method can be applied to any unconventional reservoir for both oil and gas. The public databases were adequate for the data required for this study. A simple VBA code was prepared to obtain the desired rate and drilling requirement.

The importance of the production forecast in this research can be demonstrated by performing a field-wide forecast instead of single-well forecasts, as has been done by various authors in the published literature. The simplicity of calculating the field rates adds value to the method presented. A generalized North American forecast of unconventional resources could be accomplished easily following the approach presented here. This will definitely be useful to industry operators, investors and economists.

Working on production data analysis and simulating oil wells of the EFS allowed this study to cover all aspects of the oil wells in the basin. The steps of the production data analysis were presented step-by-step with examples and the data used for several wells. Moreover, an example of simulation oil wells in the field was presented to aid in understanding the performance of wells and compare results to actual data.

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