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Decline Curve Analysis of Shale Oil Production

The Case of Eagle Ford

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Abstract

Decline Curve Analysis of Shale Oil Production: The Case of Eagle Ford

Linnea Lund

Production of oil and gas from shale is often described as a revolution to energy production in North America. Since the beginning of this century the shale oil production has increased from practically zero to currently supply almost half of the U.S. oil production. This development is made possible by the technology of horizontal drilling and hydraulic fracturing. Since the production has not been ongoing for that long, production data is still fairly limited in length and there are still large uncertainties in many parameters, for instance production decline, lifespan, drainage area, geographical extent and future technological development. More research is needed to be able to estimate future production and resources with more certainty.

At the moment shale oil is extracted only in North America but around the world investigations are starting to assess if the conditions are suitable from shale oil extraction elsewhere. The global technically recoverable resource has been estimated to 345 Gb, 10% of all global technically recoverable resources. Health and environmental aspects of shale oil and gas production have not yet been investigated thoroughly and there is a risk that these parameters may slow down or limit the spreading of shale development.

This report aims to examine production patterns of shale oil wells by applying decline curve analysis. This analysis comprises of analyzing historical production data to investigate how the future production may develop. The area of the study is the Eagle Ford shale play in Texas, U.S. The goal is to fit decline curves to production data and then use them for making estimates of future production in the Eagle Ford.

The production in the shale oil wells included in the study reach their peak already within a few months after production starts. After this point, production is declining. After one year, production has decreased by 75% and after two years the production is 87% of the peak production. The hyperbolic decline curve has a good fit to production data and in many cases the curve is close to harmonic. It is too early to determine whether the alternative decline curve that is tested, the scaling decline curve, has a better fit in the long term.

The report also investigates how the density of the petroleum affects the decline curve. The result is that lighter products decline faster than heavier.

A sensitivity analysis is performed to illustrate how different parameters affect the future production development. In addition to the wells' decline rate, the assumptions on the maximum number of wells, the maximal production and the rate at which new wells are added affect the ultimately recoverable resource. These parameters all have large uncertainties and makes resource estimations more difficult.

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SAMMANFATTNING

Sedan början av 2000-talet har man börjat utvinna alltmer så kallad skifferolja i Nordamerika. Det som skiljer skifferoljan från konventionell olja är geologin. Skifferoljan är instängd i skifferformationer eller andra trånga bergsformationer, vilket innebär att oljan har mindre möjlighet att förflytta sig i berget och utvinningen försvåras. Utvinningen har möjliggjorts tack vare teknikutveckling när det gäller borrning och så kallad hydraulisk spräckning av berget, där man skapar nya frakturer för att skapa vägar för oljan att flöda från berget till brunnen. Dessa två tekniker har lett till att produktionen av skifferolja i USA har stigit från nästan noll år 2000 till 3,5 miljoner fat per dag år 2013 och nu står för nästan hälften av USA:s oljeproduktion. Utvinningen av olja och gas från skifferformationer kallas ofta en revolution för Nordamerikansk energiproduktion på grund av den stora produktionsökningen som skett under en väldigt kort tid.

Volymen olja och gas som har utvunnits har varit större och ökat snabbare än de flesta förutspått och har fått följder som ett minskat gaspris och importberoende i Nordamerika. Då geologin skiljer sig från konventionella oljefält och utvinningen inte pågått så länge finns det stora osäkerheter när det gäller framtida produktivitet och utbredningsmöjligheter för skifferoljeproduktion. Bland de rapporter som publicerats är få akademiska, expertgranskade studier.

Denna rapport syftar till att undersöka produktionsmönster hos skifferoljebrunnar och utifrån den historiska produktionen bedöma framtida produktionspotential. Området för studien är skifferformationen Eagle Ford i Texas, USA.

Produktionen i en skifferoljebrunn avtar snabbare än i en konventionell oljebrunn vilket leder till att nya brunnar måste borras i hög takt för att uppehålla produktionen. Produktionen i de skifferoljebrunnar som studerats når sin topp redan inom några månader efter att produktionen startar. Därefter avklingar produktionstakten snabbt. Efter ett år har produktionstakten sjunkit med 75 % och efter två år har den sjunkit med 87 % jämfört med den högst uppmätta produktionen.

Rapporten undersöker även hur oljans densitet påverkar produktionen med resultatet att lättare olja har en snabbare avklingningstakt.

En känslighetsanalys har gjorts för att illustrera hur olika parametrar påverkar den framtida produktionsutvecklingen. Utöver osäkerheten i brunnarnas avklingningstakt (decline rate) påverkas den framtida produktionen av antaganden om maximalt antal brunnar, maximal produktion hos en brunn och i vilken takt brunnarna kan borras. Alla dessa parametrar har fortfarande stora osäkerheter och försvårar resursuppskattningen.

ACKNOWLEDGMENTS

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Contents

1 Introduction

Oil and gas production from shale formations is a relatively new phenomenon. Production started only this century and large-scale production is so far restricted to plays in the United States and in Canada. Since the extraction of oil and gas from shale formations has increased a lot in a short period of time it is often called a revolution for North American energy production, the 'shale revolution'. From being almost nonexistent by the turn of the century, oil production from tight formations in the U.S. reached 3.5 million barrels of oil per day (mb/d) in 2013[1]. This is almost half of the total U.S. oil production (Eggleston, 2014; U.S. Energy Information Administration, 2014a).

The access to the large volumes of oil from shale and tight formations that were previously uneconomic to produce is enabled by the technologies of horizontal drilling and hydraulic fracturing. The increasing domestic production of oil and gas is important to the U.S. since it decreases the dependence on energy imports. Shale oil production has reversed the oil production trend in the U.S. that was previously declining since the 1980's, which is illustrated in Figure 1 (U.S. Energy Information Administration, 2014a). Without the 3.5 mb/d added from shale formations the U.S. crude oil production would be around 5 mb/d, around the level of 2008 average annual production.

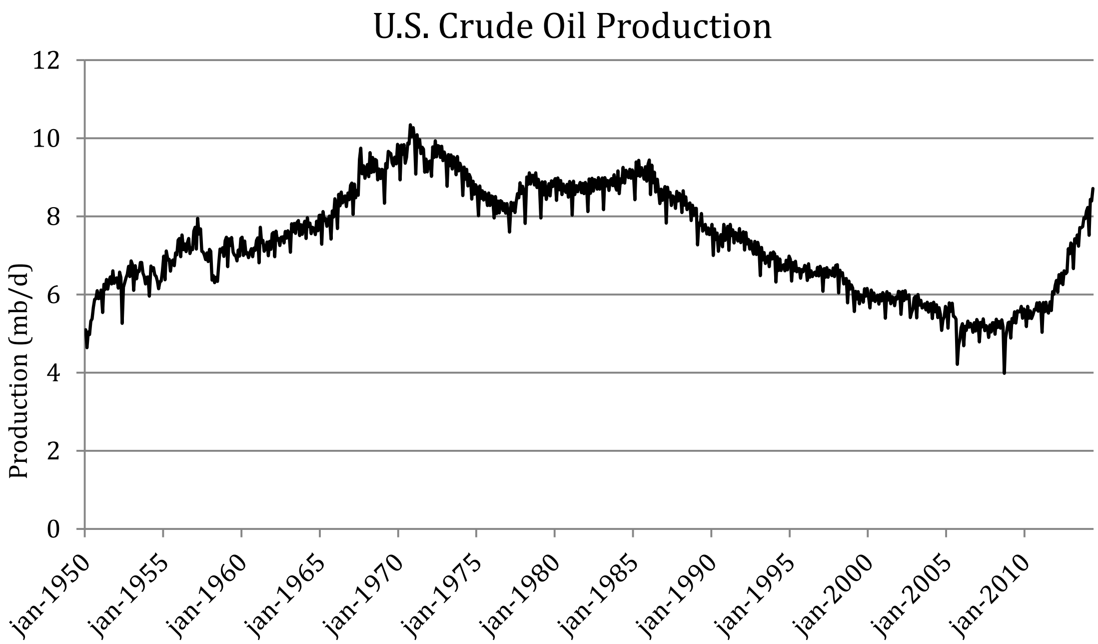
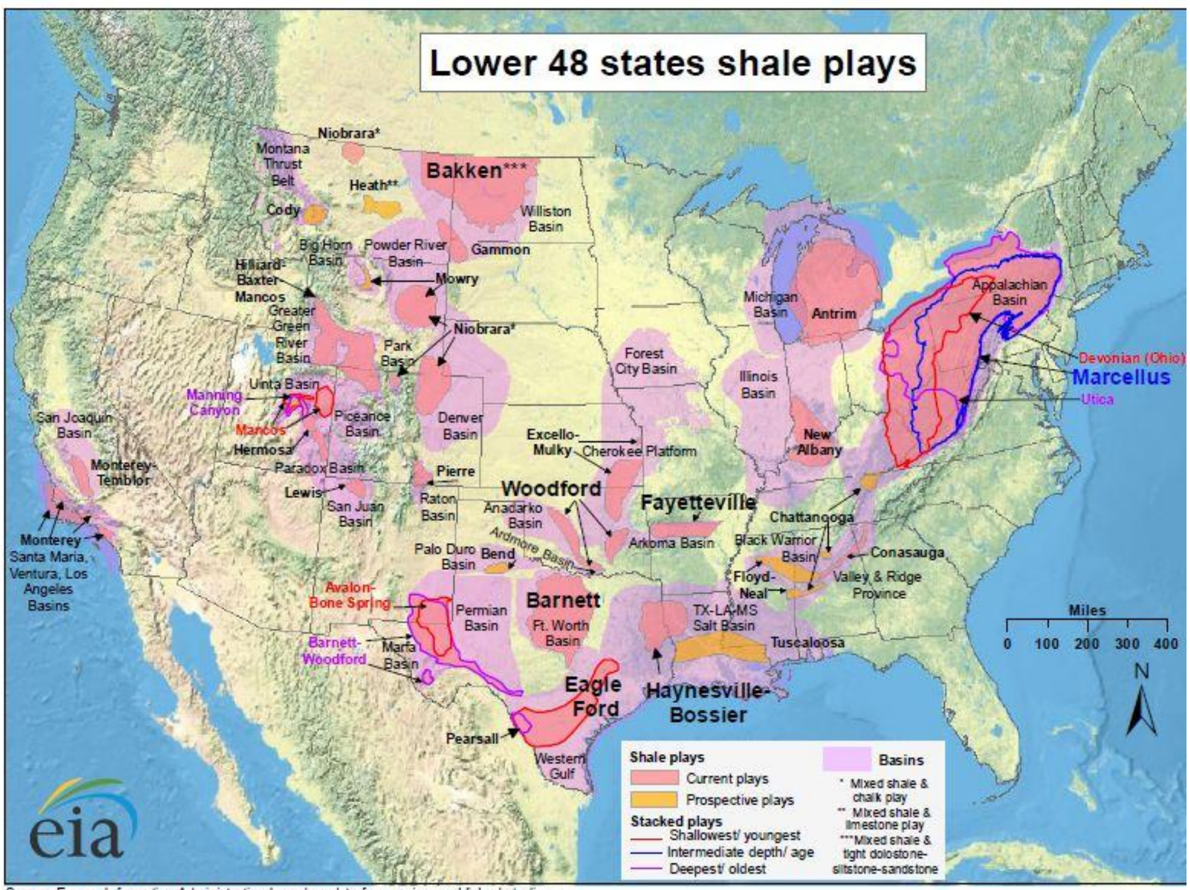


Figure 1. Production of crude oil in the U.S. from 1950 until today. Conventional oil production has been declining since the early 1970's with exception of the temporarily increase in production in the 1980's due to new production added from Alaska. The current increase ongoing since around 2005 is entirely due to the unconventional shale oil production. Based on data from the U.S. Energy Information Administration (2014b).

[1] The 3.5 mb/d include crude oil and condensate from the following low permeability reservoirs: Bakken/Three Forks/Sanish, Eagle Ford, Woodford, Austin Chalk, Spraberry, Niobrara, Avalon/Bone Springs and Monterey.

The United States Geological Survey's estimates of shale oil endowments cover 20 plays in the United States (U.S. Geological Survey Oil and Gas Assessment Team, 2012). Six of these are regarded key formations since they accounted for 95% of the growth in U.S. oil production and all growth in natural gas production during 2011-2013 (U.S. Energy Information Administration, 2014c). These six plays are Bakken, Eagle Ford, Haynesville, Marcellus, Niobrara and Permian. Figure 2 shows the shale oil and gas plays in the U.S.

The shale revolution started with gas extraction around the year 2000 but decreasing gas prices became a driver for the development of tight oil. The first shale oil play to be exploited for oil extraction through modern horizontal drilling and hydraulic fracturing was the Bakken formation in the states of North Dakota and Montana. According to Maugeri (2013) successful test drillings were performed in the early 2000's and exploration took off in 2006. Since 2010 the Eagle Ford formation in south Texas has been developed and Eagle Ford together with Bakken currently account for approximately 65% of U.S. shale oil production (U.S. Energy Information Administration, 2014a, 2014c). Eagle Ford passed Bakken production in 2012 and is currently the formation with the highest shale oil production. Shale oil extraction from the Permian basin in west Texas is increasing and is expected to exceed production in both Bakken and Eagle Ford around 2020 (Rystad Energy, 2014a).



Source: Energy Information Administration based on data from various published studies.
Updated: May 9, 2011

Figure 2. Map of shale plays in the lower 48 states of the U.S. Key formations are Bakken (MT, ND), Eagle Ford (TX), Haynesville (TX, LA), Marcellus (NY, PA, WV), Niobrara (WY, CO) and Permian (TX).

Other countries are now looking into the possibilities to repeat the successful shale oil development in the U.S., wells being drilled in China, Russia and the U.K. during 2014 (Swint and Bakhsh, 2013). The shale resources in other parts of the world are being examined to assess whether the 'revolution' can be repeated elsewhere (Kuuskraa et al., 2011; Pearson et al., 2012). At the same time the limitations in production potential for individual shale oil wells are discussed. Low production flow and high decline rates will limit the maximal potential for shale oil extraction and a production plateau at 4.3 mb/d is expected to be reached by the U.S. around 2025-2030 (International Energy Agency, 2013). Other limiting factors of the shale development are the potential environmental and health risks.

Despite the drawbacks, some are more positive in estimating future production of shale oil in North America. Kopits (2014) estimates the production in four U.S. shale plays; Bakken, Eagle Ford, Niobrara and Permian. The total production of these four plays is estimated to peak in 2018 at 6 mb/d (oil and condensate). Nysveen (2014) estimates the total production in all North American shale plays to reach 8 mb/d (oil and condensate) or 10 m/b/b (oil, condensate and NGL) in 2020. Figure 3 shows the historical development in shale oil production in the U.S. until early 2014.

Since oil and gas production from shale formations started quite recently the production data series cover only around 8 years for Bakken and 4 years for Eagle Ford. Hence, the limited length of the data series is a constraint to the analysis of long term production behavior of wells. There are still large uncertainties in factors such as well production decline, lifespan, drainage area, geographical extent and future technological improvement, both in developed areas and areas yet to be developed. As illustrated by the U.S. Energy Information Administration (2014b) different assumptions in future shale oil production will have significant implications for the dependence on oil imports for the U.S., ranging from almost total oil independence to a 40% dependence on oil imports in 2040.

More research in the field is needed to provide more detailed information, which is crucial when evaluating the future possibilities of shale oil and gas production and the role it may play in future energy supply. So far, most studies and reports on the subject are released by the industry while there is a lack of independent, peer-reviewed academic studies.

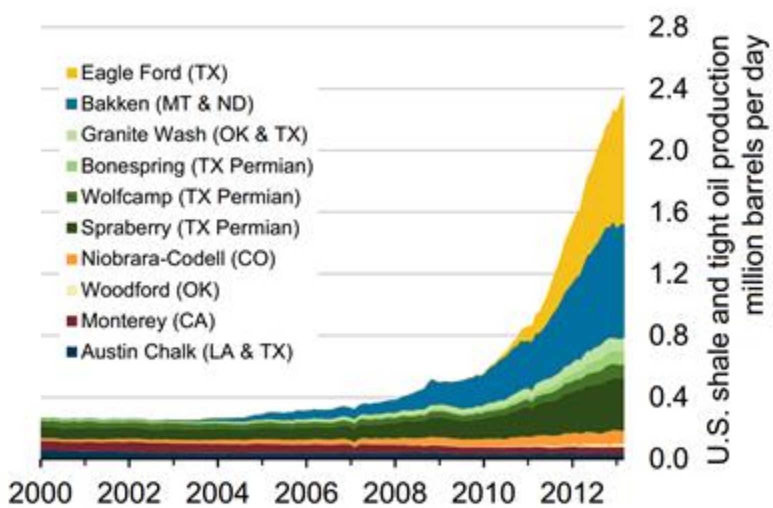


Figure 3. Historical production of shale oil in the U.S., showing the contributions from different plays.

Source: Sieminski, 2014.

1.1 Purpose and goal

The aim of the study is to analyze production behavior of shale oil wells by developing and implementing decline curve analysis. The purpose is to identify a representative production profile for wells in the Eagle Ford, Texas, U.S. Decline curve analysis will be applied on production data both on single well and multiple well levels with the purpose to examine whether the production of a single well is applicable to describe the production of a whole formation.

A production profile that describes production in the region may be used to make projections for future shale oil production rate in the Eagle Ford and to make estimates of the Ultimately Recoverable Resources (URR) of shale oil in this particular play. A statistical analysis of characteristic production parameters of individual wells will be conducted to find statistical distributions of certain production parameters. The geology of the Eagle Ford shale play has led to varying API gravity of the petroleum products, ranging from natural gas (dry gas) to condensate (wet gas) and crude oil. An additional aim of the study is to investigate whether the API gravity affects the rate of decline. Production data from the Drillinginfo database will be used.

1.2 Limitations of study

The analysis is limited to cover only the shale play Eagle Ford in the south east of Texas, U.S. (See Figure 2). The Eagle Ford is currently the shale formation with the highest oil production and is one of the shale plays with the longest data sets, after the Bakken in North Dakota and Montana, U.S. For this reason many previous studies have been on the Bakken while the Eagle Ford is just starting to generate production data long enough to analyze. The purpose of limiting the study to this one shale play is to be able to distinguish potential differences between the different plays to add to the knowledge of shale oil production. Because of the potential difference between plays the resulting decline curves are only applied to model future production in the Eagle Ford. If used on other shale plays there is a risk of errors due to different decline patterns.

The scope of the study is limited to the technical and geological aspects of shale oil production. The economic aspects of shale oil and gas production are extensive enough to provide a separate field of study and are omitted in this report.

2 Petroleum background

Petroleum is the collective name for naturally occurring hydrocarbon mixtures including crude oil, condensate, dry gas, tar, and bitumen (Satter et al., 2008). As the name indicates, the compounds consist mainly of hydrogen and carbon. Their composition as well as the pressure and temperature determine whether the hydrocarbons occur as liquid or gas (Satter et al., 2008).

In the first subsection of this chapter (2.1) it is described how the hydrocarbons were formed and some important geological concepts are explained. The following section (2.2) describes how hydrocarbons may be classified according to certain properties. Section (2.3) describes the mathematical expression derived for fluid flow and its implications in oil production while section (2.4) introduces the concept of decline rates and explains the methodological foundation of decline rate analysis.

2.1 The origin and accumulation of oil and natural gas

The formation of hydrocarbons is described by Grace (2007). The carbon and the hydrogen originate from organic matter, primarily plankton and bacteria, which has been deposited on the seabed. The organic matter has then become buried in sediments and formed a so called sedimentary rock. Under heat and pressure the organic matter has turned into oil and natural gas, a process that goes on during millions of years. The forming of oil and gas is temperature dependent. Oil is formed at lower temperatures than natural gas whereas too high temperatures destroy the energy-containing hydrocarbons.

The first crucial step for the formation of oil and gas is the sedimentary rock, which is also called the source rock. The sedimentary rocks contain small voids called pores, necessary for the formation of oil and gas (Grace, 2007). The share of pore space is called the *porosity*, which is the property that determines how much of a fluid the rock can contain (Satter et al., 2008). Apart from the sedimentary rocks there exist two other types of rocks, categorized from their formation processes. Igneous rocks are solidified from volcanic magma and metamorphic rocks are recrystallized from existing rocks due to heat (Grace, 2007). Both these rock types have lower porosity than the sedimentary rocks and cannot serve as the source rock for petroleum products.

Another important property for the formation of an oil reservoir mentioned by Grace (2007) is the rock *permeability*. This is the rock’s ability to transmit fluids. The porosity and the permeability are somewhat correlated but a high porosity does not necessarily mean that the permeability is also high. For the permeability to be good the pores need to be interconnected and large enough not to inhibit the flow of fluids.

Once the oil has formed it is pressed out of the source rock and it starts migrating towards the surface, according to Archimedes’ principle (Grace, 2007). For oil reservoirs to be built up there needs to be a reservoir rock of high porosity and permeability. A so called seal or trap is also needed, which is a layer of rock with low permeability that hinders the petroleum to migrate all the way to the surface where it will be broken down by oxidation and micro-organisms. If any of the above steps of the formation process is missing, no oil reservoir will be formed.

2.2 Classifying oil

2.2.1 Conventional and unconventional resources of oil

There is no unique definition to distinguish between conventional and unconventional resources. The International Energy Agency (IEA) uses a classification in the World Energy Outlook 2013 (International Energy Agency, 2013) where the conventional resources are considered to be found in the typical formation described in section 2.1 with a source rock, a reservoir rock and a trap. The unconventional resources are fossil resources where one or several of the components of the conventional resources are missing. If the trap is missing the oil continues migrating to the surface where it is degraded to *Extra Heavy Oil* or *Oil Sands*.

If the porosity and/or permeability are/is low the oil products can either stay in the source rock or migrate into other low permeability rocks. The permeability is usually not identical in all directions. For example, the horizontal permeability may be high, but if the vertical permeability is low no reservoir can be built up. The oil trapped in such formations is regular crude oil which is called *tight oil* or *shale oil* due to the way it is trapped or the formation it is trapped in. As explained by the U.S. Energy Information Administration (2013) shale formations are a sub-category of low permeability tight formations, the latter including sandstones and carbonates along with shale. For this reason, the term tight oil is more suitable and is also the term used by U.S. oil and gas industry. In this report, however, the term shale oil will be used referring to all tight resources, since commonly used in the public debate.

Not to be confused with shale oil is *oil shale*. Oil shale is shale rich in kerogen which is the solid pre-stage of crude oil and natural gas (International Energy Agency, 2013), and is sometimes also called kerogen shale. Liquid hydrocarbons can be extracted from the oil shale if it is heated at a controlled rate. The petroleum in the oil shale is of less quality than the shale oil, which is high quality light oil. Other resources classified as unconventional by the IEA are coal-to-liquids and gas-to-liquids.

2.2.2 API gravity

API gravity is a measure of petroleum density developed by the American Petroleum Institute (Britannica Online Encyclopedia, 2014). The API gravity is calculated using the specific gravity of the petroleum product, i.e. the ratio between the density of the petroleum product and the density of water. The measuring scale is calibrated according to Equation 1 and measured in degrees API (U.S. Energy Information Administration, n.d.).

$$API\ gravity = (141.5/Specific\ Gravity\ at\ 60\,^{\circ}\ Farenheit) - 131.5 \qquad (1).$$

The specific gravity of water is 1 and thus the API gravity is 10°. Liquids lighter than water have API gravities greater than 10°. Crude oil is usually referred to as light, intermediate or heavy. The API gravity ranges for the different classes are approximate and different intervals may be used. Britannica Online Encyclopedia classifies crude oil with API gravities less than 20° as heavy oil, API gravities between 20° and 25° as medium and API gravities greater than 25° as light (Britannica Online Encyclopedia, 2014). Satter et al., (2008) use the API gravity for classifying reservoirs and are considering reservoirs with API gravities less than 22.3° to be heavy oil reservoirs. Furthermore light oil is divided into two classes; Black Oil Reservoirs with API gravity 22.3°-38° and Volatile Oil Reservoirs with API gravity 38°-45°. Condensates are defined by the IEA as hydrocarbons of five or more carbon atoms and with API gravity between 50 and 85 (International Energy Agency, 2013).

2.3 Oil production

The units commonly used in the oil industry are barrels (b or bbl) for fluid volume and barrels per day (b/d or bbl/d) for flow rate. One U.S. barrel of oil equals 159 liters.

2.3.1 Fluid flow equation

As explained in Chapter 2.1 the hydrocarbons' ability to move within the rock depends on the porosity and the permeability of the rock. The physical properties of the fluids are also important for the fluid transmission (Höök et al., 2014). In 1856 the French hydraulics engineer Henry Darcy derived an expression for fluids' flow which is now known as Darcy's law (Darcy, 1856):

$$q = -\frac{kA}{\mu}\frac{\partial P}{\partial L} \qquad (2)$$

where q is the volumetric flow rate (cm^3/s), k is the permeability (darcy), A is the cross-sectional area of the flow (cm^2), μ is the viscosity (centipoise), and $\partial P/\partial L$ is the pressure gradient over the length of the flow path (atm/cm).[2]

Equation 2 describes a unidirectional flow, where the fluid is transmitted straight in one single direction. In reality, however, the flow within the rock is far more complicated. Despite this, Darcy's law is important when studying fluid flow in oil reservoirs since it gives the physical limits to the production rate (Höök et al., 2014) and indicates in what manner the different parameters affect the flow-rate. The negative sign shows that the fluid flows from high pressure to low pressure. There needs to be a pressure gradient for the fluid to flow and the greater the pressure gradient, the greater the flow rate. When recovering oil or gas from a reservoir, the pressure gradient decreases along with the extraction. When the pressure in the reservoir has decreased to a level too low to drive the flow any longer the pressure can be maintained by feeding additional energy into the reservoir by injecting water and/or gas (Höök, 2014).

A lower permeability needs to be compensated for with a greater pressure to obtain the same flow rate as for a higher permeability reservoir. The permeability may differ in different directions in the rock, usually with a greater horizontal than vertical permeability (Höök, 2014). The viscosity is inversely proportional to the flow rate, meaning that fluids of lower viscosity, such as gas, flow easier (faster) than fluids of greater viscosity, such as oil - given the other parameters are identical.

2.3.2 Recoverable resources and depletion

The process of formation of petroleum products is explained in chapter 2.1. The time required for the process is extensive and with the high rate the fossil fuels are currently extracted they are subject to depletion. The concept of depletion is described mathematically by Höök (2014).The first important parameter in depletion analysis is the remaining resource, R_r. It is expressed by an estimate of the Ultimately Recoverable Resources, *URR*, at time t, and the amount of the resource that has already been extracted at the time, the cumulative production Q_t, as shown in Equation 3. The URR is an estimate of the total amount of oil that will ever be extracted from a formation or a region. It is sometimes referred to as Estimated Ultimate Recovery, EUR.

$$R_r = URR_t - Q_t \qquad (3).$$

[2] The units darcy and centipoise are commonly used in the oil and gas industry. 1 darcy = 9.869233×10^{-13} m², 1 centipoise = 0.001 kg m^{-1} s^{-1}, 1 atm = 101,325 kg m^{-1} s^{-2} (Satter et al., 2008).

The URR is a parameter of great importance since it has vast economic significance. The URR together with the extraction rate determines the economic yield of the production. The production rate is usually connected to how much of the resources that are extracted, i.e. the depletion level. The depletion level, D_t , is defined by Höök et al. (2014) as the fraction of the URR that has been extracted at time *t*;

$$D_t = \frac{Q_t}{URR_t} \quad (4).$$

From Equation 4 follows that the depletion rate of URR, d_{URRt}, is the time derivative of the depletion level:

$$d_{URR_t} = \frac{q_t}{URR_t} \quad (5).$$

The URR is an estimate of the resources that are technically and economically recoverable. Consequently, it may vary in time depending on improved technology, changing market conditions, better geological knowledge etc. (Höök et al., 2014). Advanced methodologies such as geological surveys and reservoir simulations are used to make accurate estimates of the URR of different petroleum containing formations. A simpler, less data intensive methodology is the one of decline curve analysis, explained in the next section.

2.4 Decline rates and decline curve analysis

When estimating future production in an oil field or an oil well the concept of decline rate is fundamental. The decline rate is the reduction in production-rate from an individual field or a group of fields, after the production has peaked (Höök et al., 2014). The decline rate is defined in Equation 6:

$$Decline\ rate_{\ n} = \frac{Production_{\ n} - Production_{\ n-1}}{Production_{\ n-1}} \quad (6)$$

where *n* is usually month or year, to calculate monthly or annual decline.

The concepts and foundation of decline curve analysis is explained by Höök et al. (2014, 2009) and Höök (2014). The methodology has been used in analyses of conventional oil production for several decades and can also be applied on shale oil wells. The methodology comprises analyzing historical production and fitting certain type curves to the production data. The type curves can then be extrapolated to predict future production behavior. The great advantage of the methodology is that little data is required. Only production data of sufficient length to cover the behavior is needed. A weakness is that production data may also reflect non-physical factors such as underinvestment, politics and production quotas and one needs to be careful when extrapolating production trends into the future (Höök et al., 2014).

McGlade et al. (2013a) compares different approaches to resource assessment. Extrapolation together with geological approaches are concluded to be equally robust in the early stage while extrapolation gains more reliability with longer production data series, and therefore becomes more preferable in the medium and long term. The drawbacks of the extrapolation methodology that McGlade et al. (2013a) highlight are that the resource estimate is much dependent on the choice of decline curve and that the productivity can vary widely both within a play and between plays, why analogues should be used with prudence. Extrapolation is preferably used together with bottom-up modeling of geological parameters (McGlade et al., 2013a).

In 1945, J.J. Arps (1945) published a work where he presented a decline curve that is still the foundation for decline curve analysis. The suggested curve is a hyperbolic decline curve, with the exponential and harmonic curves as special cases. Arps based his work on empirical studies but the connection to physics has later been proved for the exponential decline curve, which represent the solution to the flow equation for constant pressure (Höök, 2014).

The general decline curve is described, as by Satter et al. (2008), by Equation 7:

$$\lambda_t = -\frac{dq/dt}{q} = Cq^{\beta} \tag{7}$$

where λ is the decline rate, q is the production rate, t is the time, C is a constant and β is the exponent. The decline can be of constant percentage (β = 0, exponential decline), directly proportional to the production rate (β = 1, harmonic decline) or proportional to a fraction of the production rate ($0 < \beta < 1$, hyperbolic decline) (Satter et al., 2008). The equations for some important properties for the different cases are expressed in Table 1, from Höök et al. (2014) and Satter et al. (2008).

The production rate at time t, $q(t)$, is a function of the initial production rate q_0, the decline parameters λ and β, and the initial time t_0, the time when the decline starts. $Q(t)$ is the cumulative production at time t. It is the sum of two terms; the cumulative production up until the decline starts, Q_0, and the cumulative production of the decline phase.

When a decline curve that describes the production has been found and extrapolated to predict future production the URR of the field or well of the analysis can easily be calculated. The integral of the production over the lifetime of the well gives the URR given the current technology. As explained in section 2.3.2, the URR is an estimate of the technically and economically recoverable resources and may therefore change in time with changing market conditions and technology developments.

The impact of the β-parameter on Arps' curves is discussed by Pearson et al. (2012). In theory, the hyperbolic decline is valid assuming a boundary-dominated flow, i.e. a flow that is affected by the reservoir boundaries. However, this is not the case in reality. According to Pearson et al. (2012), a β greater than 1 may be used for compensation, at least in the case of gas production.

Table 1. Arps' decline curves

	exponential	hyperbolic	harmonic
β	$\beta = 0$	$0 < \beta < 1$	$\beta = 1$
q(t)	$q_0 e^{-\lambda(t-t_0)}$	$q_0[1+\lambda_0\beta(t-t_0)]^{-1/\beta}$	$\frac{q_0}{1+\lambda_0(t-t_0)}$
Q(t)	$Q_0 + \frac{q_0}{\lambda_0}\left(1-e^{-\lambda_0(t-t_0)}\right)$	$Q_0 + \frac{q_0}{\lambda_0(1-\beta)}\left[1-\left(1+\lambda_0\beta(t-t_0)^{-1-1/\beta}\right)\right]$	$Q_0 + \frac{q_0}{\lambda_0} ln\left(1+\lambda_0(t-t_0)\right)$
URR	$Q_0 + (q_0/\lambda_0)$	$Q_0 + (q_0/\lambda_0(1-\beta))$	∞

The impact on the hyperbolic curve from the β ranging from 0.01 to 0.99 is illustrated in Figure 4. Since the URR is the integral of the curve, only small changes in the β-parameter have large impacts on the URR. The higher the β-parameter, the greater the URR estimate. The case of harmonic decline, where β equals one, gives a decline curve that approaches an asymptote of a fix production rate greater than zero in the long run. In other words, the harmonic curve results in an infinite URR, which is not possible in reality.

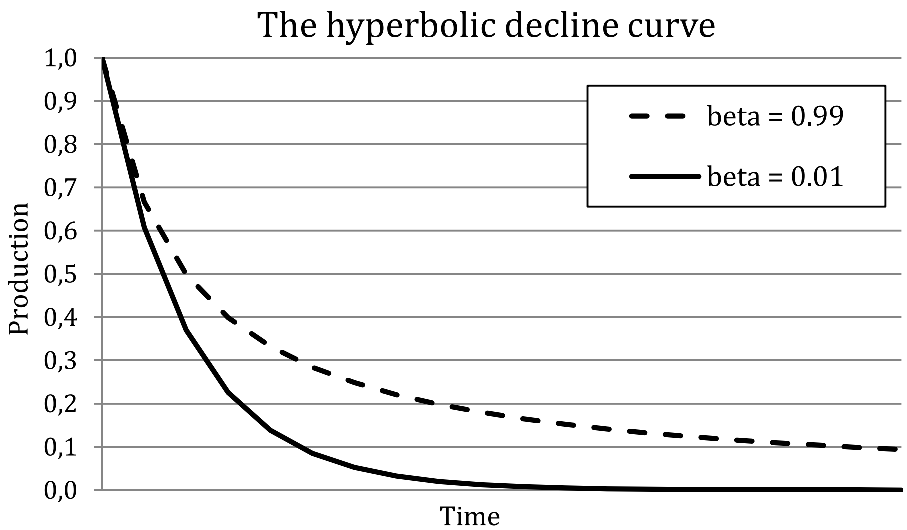


Figure 4. Illustration of how different β-parameters affect the hyperbolic curve. A β closer to zero gives a curve closer to the exponential curve, the special case of β=0. A β closer to one gives a curve closer to the other special case, the harmonic curve with β=1.

The exponential decline curve is the special case of the hyperbolic decline where β=0, thus close to the lower curve in Figure 4. When using the hyperbolic decline curve there is a risk to overestimate the URR and consequently the economic yield of a project, an argument to abandon the hyperbolic curve for one that is less optimistic regarding the late production ("tail production"). The exponential curve however is often not flexible enough to cover the tail production behavior.

Jakobsson et al. (2012) investigate the optimal production profile with regards to economics. In reality, production is disrupted and a well is decommissioned at the point where the operating costs are no longer covered by revenues. This means that the tail production is cut off at some stage, limiting the URR.

Other types of decline curves than the Arps' curves have been suggested, for instance by Patzek et al. (2013) and Ilk et al. (2008). As pointed out by Patzek et al. (2013), the exponential and hyperbolic curves where introduced when all wells were vertical, either un-fractured or with only vertical fractures that do not interfere. Further, these curves are suitable only under certain physical conditions. Ilk et al. (2008) highlight the fact that the hyperbolic curve is only suitable for cases of boundary-dominated flow behavior, which is the case only for late-time flow in a well. It is also stated that the hyperbolic decline leads to a great overestimate of the URR when used for future production estimates. Patzek et al. (2013) studied a set of shale gas wells while Ilk et al. (2008) base the analysis on production data of tight gas sands.

The strength of the work of Patzek et al. (2013) lies in the fact that the suggested decline curve is derived from physics, based on the diffusion of gas within the rock. The scaling curve production rate suggested by Patzek et al. (2013) declines as one over the square root of time ($1/\sqrt{t}$) early on, thereafter it transitions to an exponential decline. The wells produce at a rate of one over the square root of time as long as the initial pressure is kept in the reservoir. When the pressure drops below the original reservoir pressure the production rate is decreased. This point is referred to as the interference time. Eventually, the produced amount of gas is proportional to the remaining gas, which is the definition for the exponential decline.

3 Shale oil

3.1 Global shale resources

Shale oil and gas resources are present on all continents. Until recently, the shale resources have not been economically or technically available for production and therefore resource estimates have focused on the conventional resources. Rogner (1997) made an attempt to assess unconventional resources. However, the study does not include estimates on shale oil/tight oil but only lower quality unconventional oil such as oil shales, tar sands/bitumen, heavy and extra heavy crude oils, and deep-sea oil occurrences. In the unconventional gas estimates, gas in shale formations or other tight formations are included.

The U.S. Energy Information Administration (2013) assessed shale oil and gas resources in 137 shale formations in 41 countries. The global technically recoverable shale oil resources, estimated by the EIA, are 345 Gb. Technically recoverable means that the resources are estimated to be recoverable with current technology, regardless of economics. The estimated technically recoverable shale oil resource would cover 10.9 years of the 2013 global oil consumption of 86.8 Mb/d (BP, 2014). It also corresponds to around 10% of all global technically recoverable resources of oil (conventional and unconventional) as estimated by the U.S. Energy Information Administration (2013).

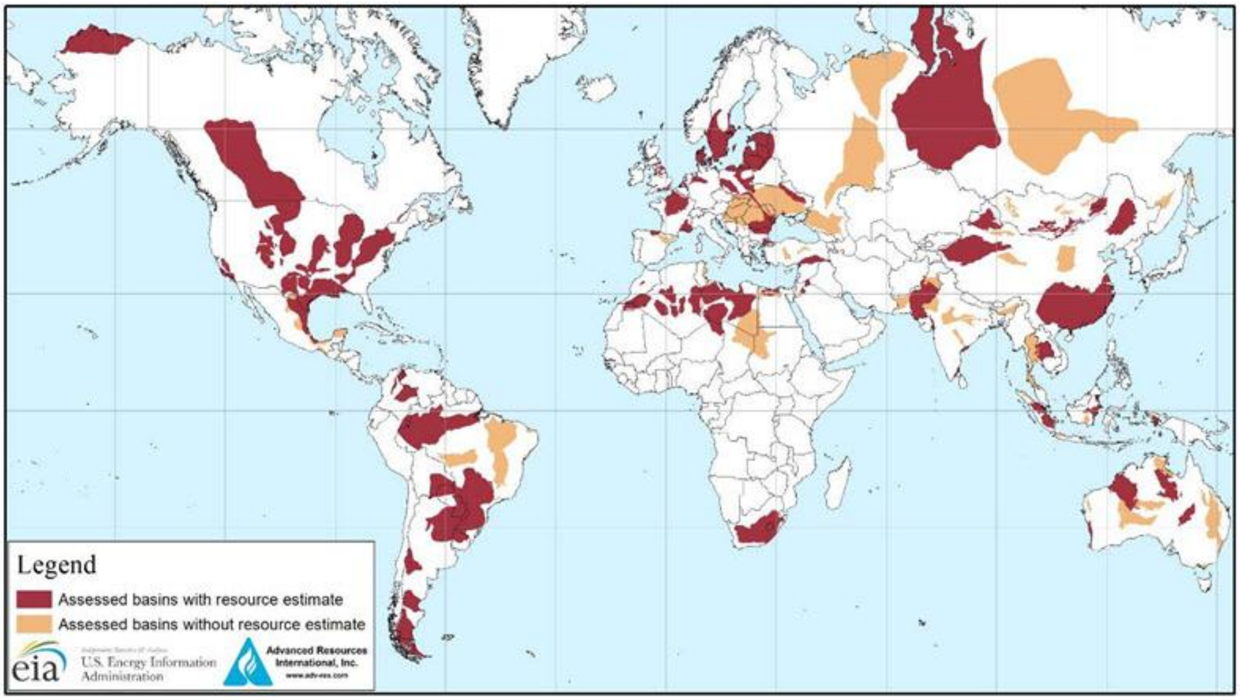
Figure 5 shows the shale oil and gas formations that are included in the EIA study. For the red areas, the U.S. Energy Information Administration (2013) have estimated the resources. Tan areas are included in the study but resource estimates are not available. The white areas are not assessed in the report. Thus, there are large areas that are omitted in the estimate figures.

The figures are estimates and hold some uncertainties and weaknesses in methodology approach. McGlade et al. (2013) review studies of unconventional gas estimates and some of the findings may also apply for shale oil estimate studies. Of the reviewed unconventional gas studies the majority is from commercial sources, thus not peer-reviewed. Other weaknesses that are mentioned are that the underlying data and assumptions are not clearly stated and the estimates are point estimates rather than ranges. The review further shows that there are still great uncertainties in the shale resource estimates. McGlade (2012) present a central estimate of global technically recoverable shale oil resources of 278 Gb, with a high estimate of 508 Gb and a low estimate of 151 Gb.

The shale resources were not considered technically recoverable until recently. When technology develops further and more knowledge is gained about the shale formations the technically recoverable resources are likely to change. Also, it is important to distinguish between technically recoverable resources and economically recoverable resources. A technically recoverable resource means that there is technology available to extract the resource. To be economically recoverable the resource can be recovered at economic profitability under prevailing market conditions (U.S. Energy Information Administration, 2013).

The technically recoverable resources per region are shown in Table 2 (U.S. Energy Information Administration, 2013). North America and the Former Soviet Union together hold almost half of the world’s unproven technically recoverable resources with 80.0 Gb and 77.2 Gb respectively.

Table 3 shows the top 10 shale oil resources on country level (U.S. Energy Information Administration, 2013). The ten countries with the largest shale oil resources have over 80% of the total global resources.



Source: United States basins from U.S. Energy Information Administration and United States Geological Survey; other basins from ARI based on data from various published studies.

Figure 5. Global shale basins with resource estimates (red) and without resource estimates (tan). Source: U.S. Energy Information Administration (2013)

Table 2. Shale oil unproven technically recoverable resource estimates by region.

Region	Unproven shale oil technically recoverable resources (Gb)
Europe	12.9
Former Soviet Union	77.2
North America	80.0
Asia and Pacific	61.0
South Asia	12.9
Middle East and North Africa	42.9
Sub-Saharan Africa	0.10
South America and Caribbean	59.7

Table 3. Top 10 countries with technically recoverable shale oil resource estimates.

Country	Unproven shale oil technically recoverable resources (Gb)
Russia	75
U.S.	58
China	32
Argentina	27
Libya	26
Australia	18
Venezuela	13
Mexico	13
Pakistan	9
Canada	9

3.1.1 Shale oil and gas in Europe

The countries with the largest technically recoverable shale oil resources in Europe are France and the Netherlands with 4.7 Gb and 3.0 Gb respectively (U.S. Energy Information Administration, 2013). Poland has a shale oil resource of 1.8 Gb and is one of the countries that also have large shale gas resources. The Baltic Basin below Lithuania and Kaliningrad has a resource estimate of 1.4 Gb and Ukraine, Romania and Bulgaria have a common resource of 1.6 Gb. The UK, Germany and Spain have resource estimates less than 1 Gb each. The Scandinavia Region basin below Sweden and Denmark contains some shale gas but no technically recoverable shale oil resources according to the U.S. Energy Information Administration (2013).

In Europe, research on energy extraction from shales has focused more on gas than on oil (Pearson et al., 2012). According to Söderbergh et al. (2010), the gas demand in the EU is expected to increase due to climate goals – both directly by driving power generation towards gas instead of coal, and indirectly by an increased need of regulating power with an increased share of intermittent power. Söderbergh et al. (2010) also highlight the fact that conventional gas production within the EU peaked in 1996, which together with the increasing gas demand potentially increases the European dependency on Russian gas. In a recent report from the European Commission (2014) the strong dependency on Russian gas in the EU is called the "most pressing energy security of supply issue" of the union. The security of supply is a strong motive to investigate the potential of exploring the shale resources within the EU.

Large volumes of shale gas have been estimated within the EU (McGlade et al., 2013b; U.S. Energy Information Administration, 2013) but there are some important differences between Europe and North America that might hinder a replication of the U.S. shale revolution in Europe. Spencer et al. (2014) point out a number of reasons why the shale revolution in North America will not easily be repeated in Europe. Firstly, the U.S. shale revolution did not come out of nowhere – decades of geological exploration preceded the boom of the first decade of the 2000's. Between 2000 and 2010 a total of 17,268 exploratory gas wells were drilled in the U.S. as compared to about 50 exploratory wells drilled in the EU. Other important factors that differ between the U.S. and the EU and that are slowing down the shale development in the EU are the more difficult conditions for land access, the stricter environmental regulations, lack of public support and instead local oppositions (Johnson and Boersma, 2013; Spencer et al., 2014). For instance, hydraulic fracturing is banned in France, Bulgaria and Czech Republic while in the Netherlands and in the German federal state of Nordrhein-Westfalen there is moratoria pending further research and better knowledge about the potential environmental consequences of hydraulic fracturing (Johnson and Boersma, 2013).

The Geological Survey of Sweden has assessed the shale gas resource in Sweden and deems it not available for extraction due to the small amount of gas, small amount of shale and the fact that it underlies densely populated areas (Erlström, 2014).

3.2 Shale oil extraction

The technology of hydraulic fracturing (fracking) has enabled extraction of oil and gas from geological structures that used to be considered impossible or uneconomic to produce. The technology, which means that new fractures are induced into the rock, can also extend the production and lifetime of older conventional fields. The technique of hydraulic fracking has been used since the 1940's but what has changed recently is the advance in more complex wellbores such as horizontal boreholes and vertical boreholes with horizontal wells at multiple levels (America's Oil and Natural Gas Industry, 2014).

3.2.1 Drilling

To protect the ground water and aquifers during the drilling and usage phases of a well casing and cement are used. Casing is hollow steel pipe that is used to line the inside of the wellbore. The casing is applied successively and is cemented into place (King, n.d.). The first string of casing is the conductor casing and is inserted after drilling through the unconsolidated material at the surface (Canadian Society for Unconventional Gas, n.d.). The second step is to drill to a depth that has been determined to be below the ground water protection level and to have sufficient mechanical strength for further drilling and fracturing (Canadian Society for Unconventional Gas, n.d.). The second string of casing is called the surface casing. The cementing is crucial to prevent vertical fluid movements into the groundwater from deeper zones. The cement sealing quality may be controlled by geophysical logs where sound waves are used to measure the bond between the casing, the cement and the formation (King, n.d.).

After assuring the sealing quality of the surface casing the drilling continues to the target zone. An intermediate casing may be inserted, or the production casing is inserted directly, depending on the depth and the orientation of the well (Canadian Society for Unconventional Gas, n.d.). The final casings are also cemented into place.

Most horizontal wells start as vertical wells at the surface. When the drill bit reaches a depth of about 30-100 meters above the target rock the drill pipe is pulled out and a hydraulic motor is inserted between the drill pipe and the drill bit (King, n.d.). This enables the drill bit to rotate without the whole pipe rotating which means that the direction of the drilling path can be steered in a different direction than the initial vertical direction. The hydraulic motor is powered by drilling mud and steers the wellbore from vertical to horizontal over another 30-100 meters.

When the well has achieved the desired angle the straight-ahead drilling can continue and the horizontal well follows the target rock. Especially in thin rock the drill has to be steered carefully and instruments determining azimuth and orientation are used down the hole to aid steering (King, n.d.). The horizontal lengths of gas wells are on average 1,000-2,000 meters in the U.S., with lengths up to 6,000 meters reported (Pearson et al., 2012).

The so-called pad drilling is another measure to increase the operational efficiency and to reduce costs and surface footprint (Pearson et al., 2012), meaning that several wells are drilled in different directions from the same pad. Figure 6 shows how several horizontal wells may be drilled from the same pad on the surface.

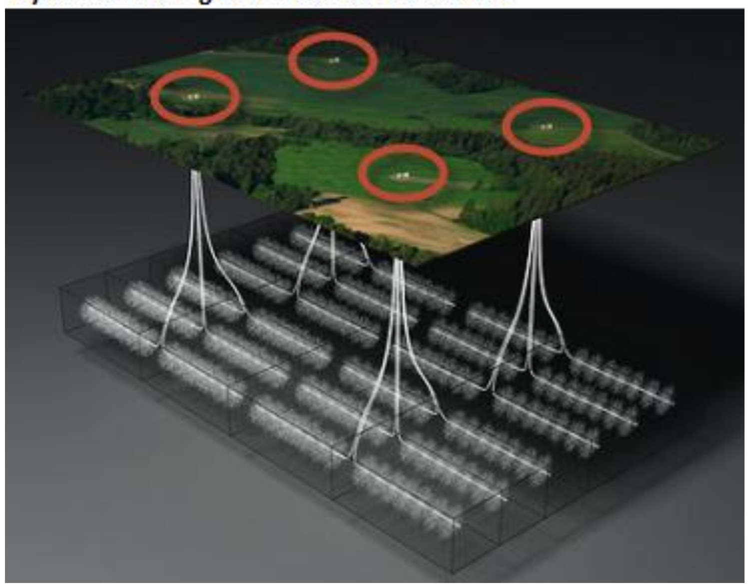


Figure 6. Pad-drilling is used to reduce surface foot-prints and costs. Several wells are drilled from the same pad, this case shows four drilling pads, each with six horizontally drilled and fractured wells. *Source: U.S. Energy Information Administration (2012).*

3.2.2 Hydraulic fracturing

Hydraulic fracturing increases the permeability of tight reservoirs by creating new fractures in the rock. The technology simply means that a mix of water, sand and chemicals are pumped down the wellbore into the target rock where the pressure creates new cracks in the rock and the sand keep the new fractures open.

The production casing is perforated in certain places to allow the fracking fluid and proppant (sand or other material) to enter the target zone, and later for the oil and gas to be transferred in the opposite direction, from the rock to the well (Canadian Society for Unconventional Gas, n.d.). The hydraulic fracturing process can be divided into four steps, explained by the Canadian Society for Unconventional Gas (n.d.). The first step is to pump a fluid into the reservoir rock at a high pressure to induce cracks and fractures. The second step is to make the fractures grow by pumping more fluids into the rock. Thirdly, proppant materials are added to the fluid, and are pumped down the wellbore in the form of slurry. The fourth and final step is to recover the fluids while the proppant materials are left in the induced fractures and keep them open. Because of the length of several thousand meters of horizontal well to fracture, the four steps of the hydraulic fracturing is conducted in several stages, starting from the tip moving towards the vertical wellbore (Zoback et al., 2010). In the Bakken formation the average number of frac stages has increased from 22 to 30 between 2010 and 2013. Several wells with 50-70 stages were drilled in 2013 (Rystad Energy, 2014b). The hydrofractures are typically designed to propagate horizontally around 150-250 m from the well (Zoback et al., 2010).

The water required for fracturing a shale gas well is between 8,700 and 14,500 m^3 and another 2,300-4,000 m^3 are needed for the drilling (Pearson et al., 2012). For the Marcellus shale 13,000-19,000 m^3 of water is typically used for the fracturing of a gas well (Osborn et al., 2011). The New York State Department of Environmental Conservation (2011) estimates 9,000-30,000 m^3 of water to accomplish a multi-stage hydraulic fracturing procedure while Johnson and Boersma (2013) reproduce the water need of 15,000-23,000 m^3 per well reported by the U.S. Environmental Protection Agency. Since the procedure of the fracturing is similar in gas and oil wells the amount of water required for an oil well should lie in the same range. According to Walls and Sinclair (2011) the porosity of the Eagle Ford ranges from 2 to 15% which explains the varying need of water to perform the hydro-fracturing.

Water and sand make up 98-99.5% of the fracturing fluid, whereof around 90% is water (New York State Department of Environmental Conservation, 2011; Pearson et al., 2012). The remaining 0.5-2% consist of different additives to give the fluid desired properties such as decreased friction, resistance to bacterial growth and corrosion and a certain pH value and viscosity. Lists covering the different additives and their purpose and properties are given for instance by the New York State Department of Environmental Conservation (2011) and Pearson et al. (2012). The exact compositions of additives in different projects are company secrets and vary depending on the formations' properties. Some argue that the chemicals added to the fracturing fluids are mostly non-toxic, with common applications in food, cosmetics, pharmaceutical products and detergents and disinfectants (ExxonMobil, n.d.; Pearson et al., 2012; Rahm, 2011). Others claim that many of the substances are hazardous and carcinogen, potentially causing rare cancers, disorders in the central nervous system and miscarriages (Rahm, 2011; U.S. Environmental Protection Agency, 2004).

3.3 Environmental and health aspects of shale oil extraction

Like all industrial activities the extraction of fossil hydrocarbons from shale formations has an effect on the surrounding environment. Emissions to water and air as well as changes in land and water use are effects of the increased production of oil and gas in new regions. The environmental effects from the consumption phase being the same as for conventional hydrocarbons, this chapter focuses on the environmental and health aspects of the extraction of shale oil.

3.3.1 Water and air related impacts

Public concern about drinking-water contamination by fracturing fluids, saline brine from deep geological formations or by the hydrocarbon themselves has risen and has been studied by Osborn et al. (2011), Vidic et al. (2013) and by the U.S. Environmental Protection Agency (2012), among others. The focus for many current studies is the extraction of natural gas from shale but since the process of drilling and hydraulic fracturing is similar for gas and oil wells the results may apply for both kinds of wells.

Osborn et al. (2011) found that methane is present in water wells both within and beyond a distance of 1 km from an active gas well site, but the concentration of methane was on average 17 times higher in the water wells within the 1 km distance from gas extraction. Since thermogenic methane from deep geological formations differs from biogenic methane of shallow origin, Osborne et al. (2011) could also show that the methane in the water wells located close to gas wells originated from deep formations. The methane in wells further away from gas wells had a more biogenic or mixed source. Three possible explanations to the increased methane in drinking-water aquifers close to gas extraction are presented in the study. The first is that the gas migrates from the source rock itself 1-2 km below ground, the second is leaking casings a couple of hundred meters below the surface and the third is that the fracturing activity creates new fractures not only in the source formation but also in the formations above, leading to an enhanced conductivity of gas. Considering the fact that no traces of migration of fracturing fluids or brine from the source rock have been found, it is unlikely that the gas would migrate from this deep formation. According to Osborne et al. the migration of methane through the formations above the source formation is not impossible but it is less likely as a source of the methane than leaky casings. Several studies, e.g. Zoback et al. (2010), point out the unlikeliness of hydro-fractures directly connecting the source rock with groundwater aquifers due to the great vertical distance that separate them. Vengosh et al. (2014) also express the risk of leakages due to improperly constructed wells rather than extensive induced fractures.

Most of the water injected in the fracturing process stay in the formation, which may lead to a displacement of the water originally in place (formation water). Studies from gas wells in Pennsylvania show that the average of the injected water that is recovered from the wellbore before the gas production starts is 10% (Vidic et al., 2013). Thus, much of the injected water stays in the formation and it is not known exactly how this affects the original formation water. The formation water contains a high concentration of dissolved solids such as toxic trace elements and radioactive material and according to Osborne et al. (2011) this water may migrate to shallower aquifers after the fracturing. However, their result when analyzing the water wells for contamination by fracturing fluid or deep formation brines show no evidence of such contamination.

Another issue of the fracturing fluid is the wastewater handling. Waste fluids that are produced during the drilling and fracturing activities include drilling muds and produced water or brine (Rahm and Riha, 2014). The alternatives for wastewater disposal are reinjection is so-called injection wells/disposal wells, surface water body disposal (after treatment) and disposal to the land (Rahm, 2011). In the U.S., 90% of the produced brine is injected but the regional variations are large (Rahm and Riha, 2014). For instance, there are tens of thousands injection wells in Texas while in the Marcellus shale they are much rarer due to political and geological constraints (Zoback et al., 2010). The wastewater contains hazardous elements such as chloride, bromide, calcium, barium, strontium, radium, and iron (Rahm and Riha, 2014), as well as radioactive material and arsenic, benzene and mercury (Zoback et al., 2010). Hence, the fluids require treatment before reuse, disposal or discharge. The wastewater handling process is important to take into consideration in new shale gas projects, in an early stage of the project. For example, the current municipal wastewater treatment facilities in the Marcellus shale will not be enough to handle an increase in wastewater from shale gas (Zoback et al., 2010) so alternatives need to be found.

Many argue that the surface handling of wastewater and chemicals is of more concern, due to higher potential damage, than the injection of water and chemicals in the deep formations (Johnson and Boersma, 2013; Rahm, 2011). The produced water is often stored in open evaporation pits that may cause contamination if they overflow (Zoback et al., 2010).

The vast water requirements for the fracturing may affect other water users in the region. The U.S. Environmental Protection Agency (2011) studied the potential impacts on drinking water resources and found that the impacts vary a lot with several factors, such as geographic area and quantity, quality and sources of the water. The water is taken from either surface water or ground water depending on availability. Trucks are generally used for transportation and storage of the needed water. The U.S. Environmental Protection Agency (2011) further emphasizes the importance of well substantiated water management strategies as the intensity of hydraulic fracturing activities increases, to avoid effects on the water quality by changing the water level within aquifers or surface resources.

The World Resource Institute addresses the issue of freshwater availability for hydraulic fracturing activity in the report *Global Shale Gas Development: Water Availability and Business*

Risk (Reig et al., 2014). One of the key findings is that of the top 20 countries with the largest shale oil resources, eight countries face arid conditions or high to extremely high baseline water stress in the shale resource areas. The eight countries are the following: China, Libya, Mexico, Pakistan, Algeria, Egypt, India, and Mongolia. The situation is the same for the top 20 countries with the largest shale gas resources though the list of countries differs slightly. In total, 38% of the global shale resources are located in arid areas or areas of high to extremely high water stress. Not only is the water resource scarce in large parts of shale regions but there are many competing interests in the water use. According to Reig et al. (2014) there are 386 million people living in these regions and in 40% of the shale plays the currently largest water user is irrigation. Over 40% of the water supplies in shale regions are currently used for agriculture or for municipal or industrial purposes.

One possibility to reduce the amount of fresh water needed for fracturing and to reduce the wastewater is to reuse the produced water for new fracturing activities. However, the content of dissolved components in the flow-back water complicates the reuse (U.S. Environmental Protection Agency, 2011). A potential development of the fracturing to decrease water use is the so called Dry Frac that uses liquid CO_2 in place of water and chemical additives (Rahm, 2011). This process is still costly but considering the recent fast development and decreasing costs of hydraulic fracturing one can hope that the technology development continues at a fast pace.

Methane leakages from production of shale gas or shale oil are not only a problem for water and soil, but also for the air. Methane works as a potent greenhouse gas in the in the atmosphere. The shale gas extraction is estimated to give larger methane emissions than conventional gas wells, 3.6-7.9% of the gas leaking compared to 1.7-6.0% (Johnson and Boersma, 2013). This is important to take into account when rating natural gas as a more climate friendly energy source than for instance oil and coal. Burnham et al. (2012) highlights that it is important to limit methane leakages during production to not reduce the advantage of gas over coal and oil when it comes to greenhouse gas emissions. Other possible air pollutants from shale oil production are volatile organic compounds that may evaporate from wells and the open evaporation pits and contaminate the air (Zoback et al., 2010).

The shale oil and gas industry has led to an increase in truck traffic for transports of equipment, fracturing fluid ingredients, drilling equipment, compressors and pumps resulting in larger emissions and effects on the local air quality from CO_2, NO_x, SO_x and particulate matter (Zoback et al., 2010).

Manda et al. (2014) have compared single wells pads and multiple well pads with the result that the multiple wells pads have lower environmental impact and higher volumes of recycled water per well than the single well pads. Vengosh et al. (2014) conclude that many of the risks identified in literature are possible to mitigate or reduce with proper management and engineering.

3.3.2 Enhanced seismicity

Frohlich and Brunt (2013) studied the correlation between fluid injection or extraction and seismic events in the region of Eagle Ford. They found that extraction rather than injection of fluids may induce seismicity in the region. The majority of the events occurred in regions where the injection or extraction had increased significantly during the years prior to the increase or the beginning of seismic activity. Frohlich and Brunt (2013) notice a difference in the correlation between petroleum production activities and seismicity between Eagle Ford and Barnett and state that the seismic coverage needs to be extended to better understand the correlations.

The U.S. Geological Survey mean that there are no evidence that the hydraulic fracturing itself induces seismicity while some locations of increased seismicity are those where wastewater from fracturing activities are injected in deep disposal wells (Hayes, 2012).

3.3.3 Infrastructure issues

Increased truck traffic due to transportation of equipment, materials and products is not only causing air pollution. The increased heavy traffic leads to need of reinforcing and widening roads as well as construction of new ones. This activity means increased land use and may cause disturbances to humans and animals through noise, disturbed views or disrupted access to certain areas. There is also an increase in rail traffic due to the great transportation need of sand, pipes, chemicals as well as oil and gas. By increasing the number of wells drilled from the same pad the land disturbance can be reduced, both from pads and from access roads.

Another transportation issue is that of the extracted products. The most efficient way of transportation would be through pipelines but with the fast development of production in new areas in the U.S. the pipeline network has not been extended at the same pace. From production sites that do not have existing pipelines oil and gas is transported by road and rail. The construction of pipeline grids are costly and time-consuming (PwC, 2013). In some areas the investment in pipelines cannot be justified due to the short well lifetime and problems to provide the production commitment in the long run (Batson, 2012). Also, oil and gas pipelines can be an issue in densely populated areas, due to safety reasons (Rahm, 2011).

3.3.4 Health

The effects on human health from hydraulic fracturing are not well documented and more research is needed. The secrecy surrounding the substances used for hydraulic fracturing complicates the investigations of health practitioners in cases with hydraulic fracturing activities being the suspected cause of illness (Rafferty and Limonik, 2013).

Rabinowitz et al. (2014) found that skin and upper respiratory symptoms were more frequent among residents closer (<1km) to active gas wells than farther away (>2km), after adjustments for parameters such as age, gender and lifestyle. Also, the number of experienced symptoms is greater in households closer to the gas wells. The study also includes gastrointestinal, cardiovascular, and neurological symptoms but in these categories no difference is reported between the occurrence among residents close and farther away from the gas wells. The geographic area of the study is the Marcellus basin.

Bamberger and Oswald (2014) review studies on health impacts on animals and humans from shale oil and gas activities. Respiratory problems have been found in calves exposed in proximity to dams containing sulfur dioxide and volatile organic compounds. Further, animals exposed to drilling chemicals experienced reproduction failures, stillbirths, and sudden death to a larger extent than usual. When it comes to human health Bamberger and Oswald (2014) review several studies showing correlations between low birth weight, and some birth deficiencies.

All studies agree that more research is needed in the area of health impacts of shale oil and gas development to identify effects with more certainty.

4 The Eagle Ford shale play

The region of interest in this study is the Eagle Ford shale play in south Texas, U.S. The map in Figure 7 shows the geographic extent of the play, the currently petroleum producing part covering around twenty counties in Texas and stretching into Mexico. The formation is about 80 km wide and 650 km long with varying depth (Texas RRC, 2014).

4.1 Geology

The shale formation of Eagle Ford is of the late Cretaceous era, roughly 90 million years old. It has a high carbonate content, up to 70%, which makes it brittle and facilitates hydraulic fracturing (Texas RRC, 2014). During the Cretaceous time the tectonic movements caused the land masses in the south-east, in the direction of the Mexican gulf, to be pressed down. These movements caused a steep slope in the geological layers and brought once submerged areas, rich in organic matter, onshore. For this reason the depth of the oil and gas findings in the Eagle Ford varies from approximately 1.2 to 4.3 km, with an average thickness of 75 meters (Texas RRC, 2014). West of Dallas, Texas, the Eagle Ford formation can be seen on the surface. The geological layers of Texas are shown in Figure 8.

The fact that the Eagle Ford shale occurs at different depths is the reason for the occurrence of oil, wet gas/condensate and dry gas in different regions, which is shown in Figure 7. This is a classification based on the fluid properties (Satter et al., 2008) and it is connected to the API gravity of the hydrocarbons. The classifications of dry and wet gas are given by Satter et al. (2008) as follows. Dry gas reservoirs are categorized as reservoirs with hydrocarbons in the gas phase alone, remaining in the gas phase during production. In wet gas reservoirs the hydrocarbons are initially all in the gas phase. During production, however, some of the extracted gas condenses to the liquid phase because they are heavier (having lower API gravity). Further, the hydrocarbons in the oil reservoirs have yet lower API gravities, meaning they are in the liquid phase already within the reservoir.

Comparing Figure 7 and Figure 8 one can see that the dry gas window is deeper underground than the wet gas window, which is in turn deeper than the oil window. The higher temperature and pressure that occur at the larger depth have led to the formation of light hydrocarbons, i.e. dry gas, while the lower temperatures and pressures led to formation of heavier hydrocarbons, i.e. crude oil.

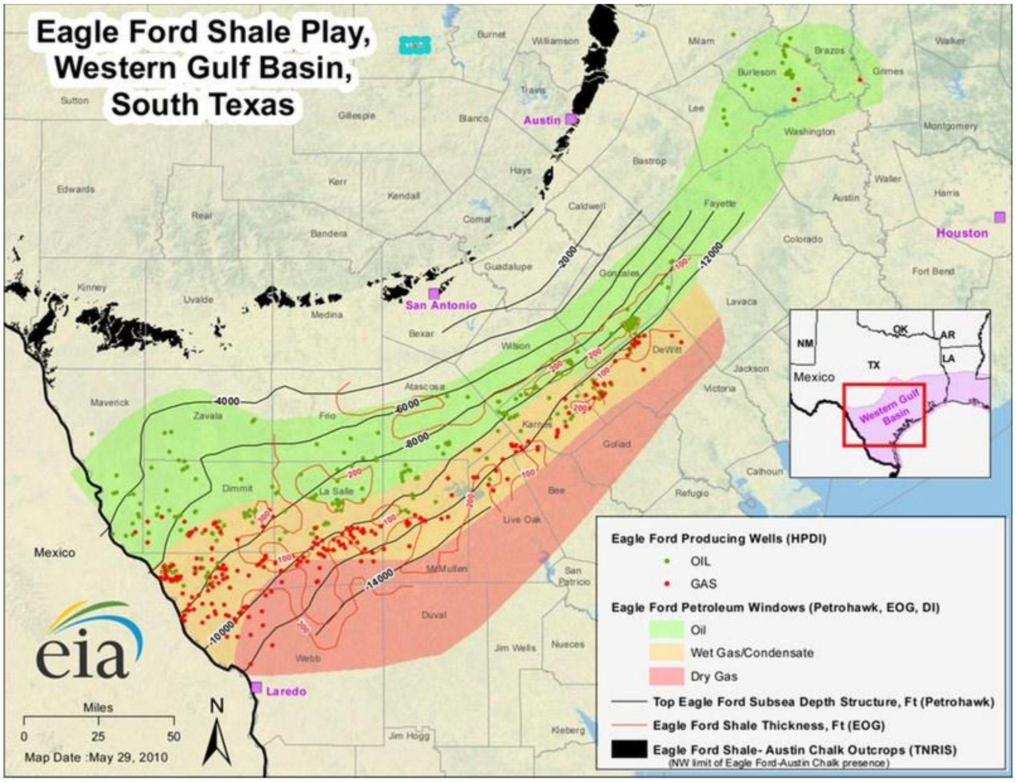


Figure 7. Geographic extent of the Eagle Ford shale play, covering about 20 counties in the state of Texas, U.S. The green, yellow and red fields represent the occurrence of oil, wet gas and dry gas respectively. Oil and gas wells, as of May 2010, are marked with dots. *Source: U.S. Energy Information Administration (2010)*

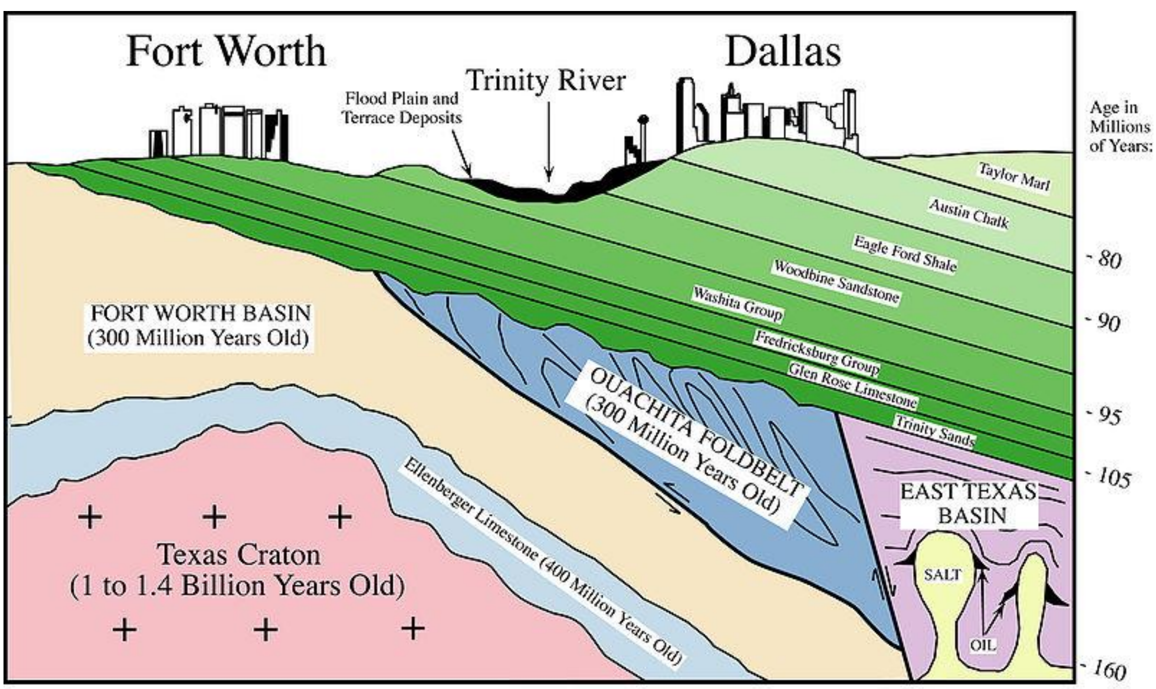


Figure 8. Underground slope of the geological layers in Texas. The depth of the Eagle Ford Shale varies from the surface to more than 4 km underground. *Source: eagleford.org (2014)*

4.2 Oil and gas production

Oil and gas have been produced from the Eagle Ford since 2007 but what really speeded up the production was the introduction of the technologies of horizontal drilling and hydraulic fracturing. In 2007 there were only vertical wells in the Eagle Ford and the total production of crude oil and condensate was less than 21 kb/d (U.S. Energy Information Administration, 2011). In 2010 the production took off and almost tripled from 55 kb/d in January to 142 kb/d in December, virtually all production from horizontal wells (U.S. Energy Information Administration, 2014c, 2011). Since then production has increased another tenfold to 1,429 kb/d in July 2014 (U.S. Energy Information Administration, 2014c).

The gas production has also seen an increase, yet not as steep as oil production. From producing at a fairly constant level of around 1,600,000 Mcf/d in 2007-2009 the gas production has increased since the start of 2010 and reached 6,400,000 Mcf/d in July 2014[3] (U.S. Energy Information Administration, 2014c). The development in oil and gas production is shown in Figure 9.

The relatively high oil prices and low natural gas prices have driven drilling of new wells towards oil-rich areas. The number of drilling rigs in the Eagle Ford has been quite steady around 300 since late 2011 (U.S. Energy Information Administration, 2014c) which makes the formation the most active shale play in the world (KED Interests, LLC, Houston TX, n.d.).

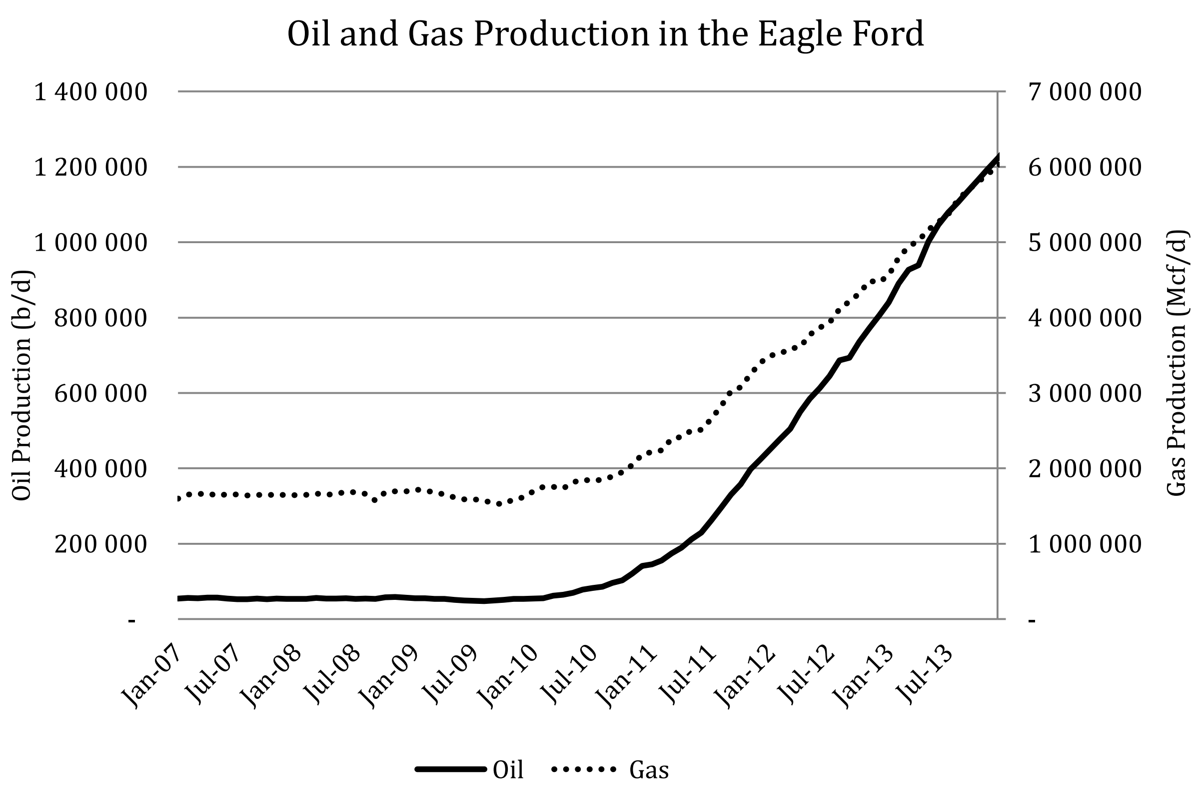


Figure 9. Production of oil (crude oil and condensate) and gas in the Eagle Ford shale play, from 2007 to present. Based on data from U.S. Energy Information Administration (2014a).

[3] Mcf/d = million cubic feet per day. 1 cf = 0.0283168 m^3.

5 Analysis of oil production in the Eagle Ford

5.1 Methodology

In section 5, shale oil production in the Eagle Ford is analyzed. Individual wells that were completed in the years 2010-2013 are studied to determine initial production, peak production, first year's production and second year's production. Monthly production data from the Drillinginfo database (Drillinginfo, 2014) are used. The software used for data processing and analysis are Matlab and Microsoft Excel. For the statistical distributions analysis the distribution fitting Excel add-in EasyFit is used.

The methodology of decline curve analysis is applied to production data from individual wells and aggregate production data from all wells in the data set. When adding data from several wells fluctuations in production are smoothed out. The individual well production data are analyzed to determine whether the aggregate decline curve can be applied also for individual wells.

Decline curve analysis as a methodology is widely used in the oil and gas industry and academic studies, for example Höök et al. (2014), Ilk et al. (2008), International Energy Agency (2013), Patzek et al. (2013) and Pearson et al. (2012). The theory of decline curve analysis is explained further in the chapter 2.4. The advantage of the method is that it is not as data-intensive as alternatives such as full reservoir models. The production characteristics of historic well production data are used to model future production given different assumptions.

5.2 Data

A major difficulty in shale oil studies is the lack of available production data. Since the production data are the foundation of the decline rate analysis data are crucial for the accuracy of a study. Production data are known to producers but little data is publically available which complicates external and independent analyses.

The analysis in this report is based on monthly production data from the Drillinginfo database, one of the world's largest oil and gas databases. Drillinginfo is an industry database requiring a subscription, which is the reason it is usually not available for academic studies. The access to the Drillinginfo data adds a greater reliability and accuracy to this study compared with many studies of poorer data access.

The data set used includes Eagle Ford wells that started oil production between January 2010 and December 2013. Only horizontal wells whose production is reported separately are included in the set. The production patterns sought in the study are those generated by the physical conditions only, such as the size of the resource, the geology of the rock and the physical flow constraints. When production is reported from several wells together these production decline patterns does not show. This is illustrated in Figure 10. The production curve of the multiple wells has a large and steep increase when a new well is put into production in April 2012. After this point the decline observed is the decline from two wells that are in different stages of the decline phase and therefore cannot be included when analyzing the typical decline in the formation. The production curve of a well that is reported individually is included for comparison.

Further, only wells with a cumulative production exceeding 20,000 barrels are included. This is a measure to sort out wells that have not produced successfully early in the analysis process.

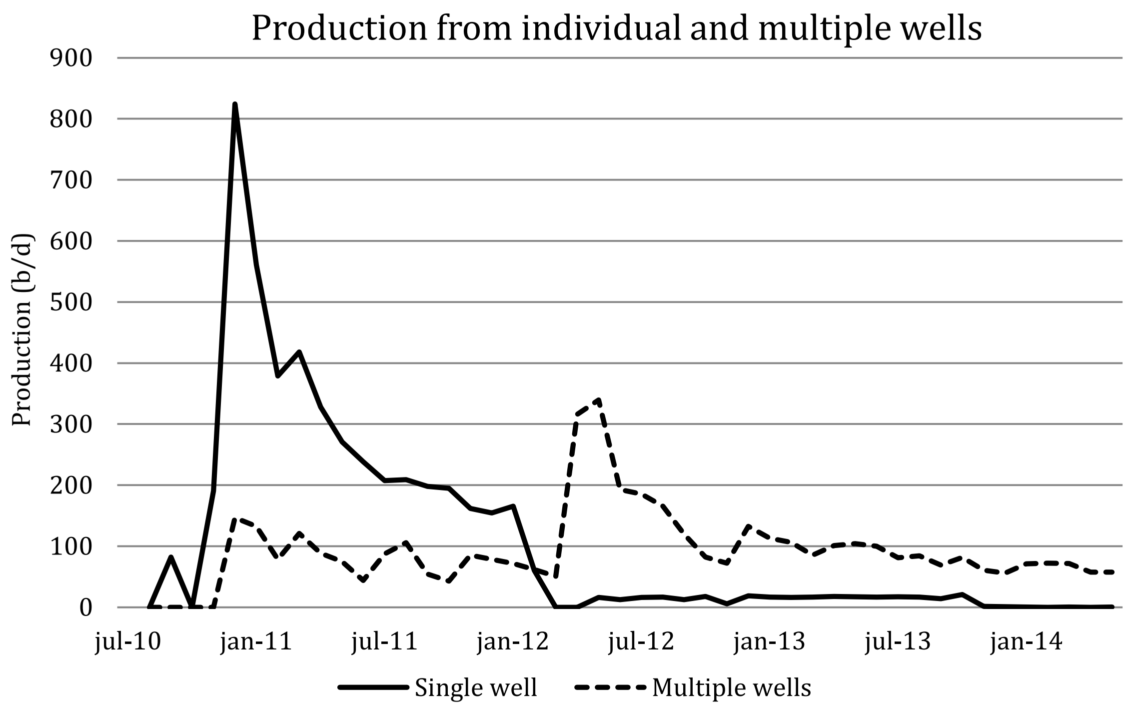


Figure 10. Illustration of production profiles for a well reported individually and multiple wells reported together.

5.3 Aggregate well decline curve

The "aggregate well decline curve" is a decline curve that is fitted to the average production curve of several wells. The advantage in taking the average of several wells' monthly production is that fluctuations are flattened out.

A different number of wells are used for different sections of the average production curve. The reason is the limited time series of production data. The first shale oil well production was reported in 2010 and thus the maximum number of months of production data through 2013 is 48. A total of 54 new wells are reported that started in 2010 (Drillinginfo, 2014), however none of these have a data series of 48 months. Only 7 wells have production data exceeding 31 months. The tail of the production curve thus holds more uncertainty than the other sections based on more extensive data. Also, the fluctuations between different months' production is more visible the fewer the wells.

When extending the data set to include all wells with production data exceeding 24 months the set expands to cover 53 wells. In this manner the data set is extended to cover more wells but shorter time periods.

When assessing the earliest production of the wells (month 1 to 6) the data set includes almost 1,000 wells, thus fairly extensive. When estimating the long term productivity of oil wells longer data series are needed to determine at what level the production stagnates after the initially steep decline diminishes. The available data set does not cover enough months to determine for sure the level of stagnation.

Table 4 shows the number of wells used for different sections of the average production curve. The average production for the number of wells of the different sections is used and the data is adjusted so the transitions between the sections are smooth. The number of wells decreases from 964 wells for the first six months from peak production to 7 wells month 31 to 36 after peak production.

Table 4. The number of wells used for different sections to construct the "aggregate production curve".

Month	Number of wells
1 - 6	964
7 - 12	599
13 - 18	357
19 - 24	181
25 - 30	53
31 - 36	7

The production of a well usually peaks within a few months after the initial production and the data set is limited to include only the decline phase (after the peak). Thus, what will be referred to as the "first month's production" is the highest production reached, before decline takes off (peak production). The conceptual production curve is illustrated in Figure 11, where the initial production/first oil, the peak production and the decline phase are marked.

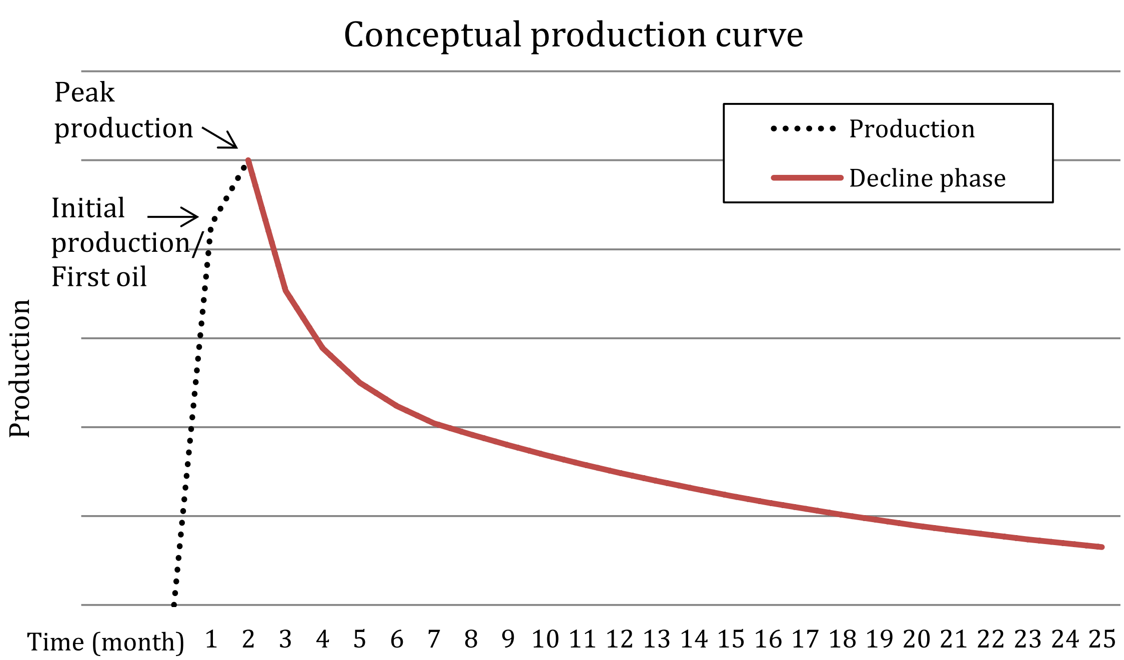


Figure 11. Conceptual decline curve showing the points of initial production/first oil and peak production, and the decline phase.

The production data is normalized in the sense that the first month's production is set to 1 to which the following months' productions are displayed in relation.

The decline curves fitted to the aggregate production curve is displayed in Figure 12. The parameters for the hyperbolic decline curve are λ=0.28 and β=1. The scaling decline curve follows one over the square root of the time for the first 8 months and thereafter is has an exponential decline of 6.2% per month. The interference time is found by plotting the cumulative production versus the square root of time (Patzek et al., 2013). The interference time occurs when this curve deviates from a straight line, which has been found by inspection of Figure 13. This method is arbitrary and not very precise.

The textbox in Figure 12 shows the decline in production over the first year and over the first two years of production. After one year production has decreased with 75.2% and after two years with 86.6%. The text box also displays the decline over the second year relative to the production after one year. The decline over the second year is 46.0%. The coefficients of determination (R^2 values) for the hyperbolic fit and for the scaling curve fit are 99.6% and 99.0% respectively.

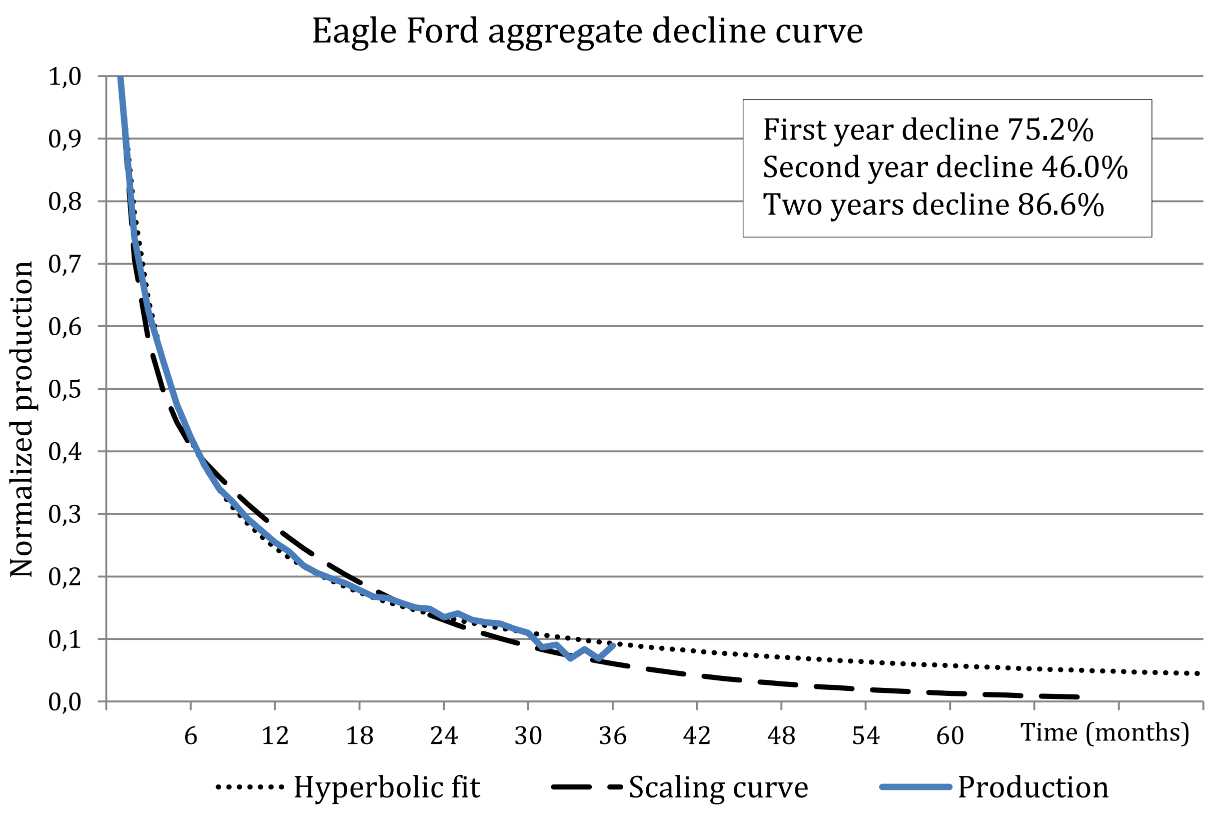


Figure 12. Actual production (blue), hyperbolic fit (dotted) and scaling curve fit (dashed).

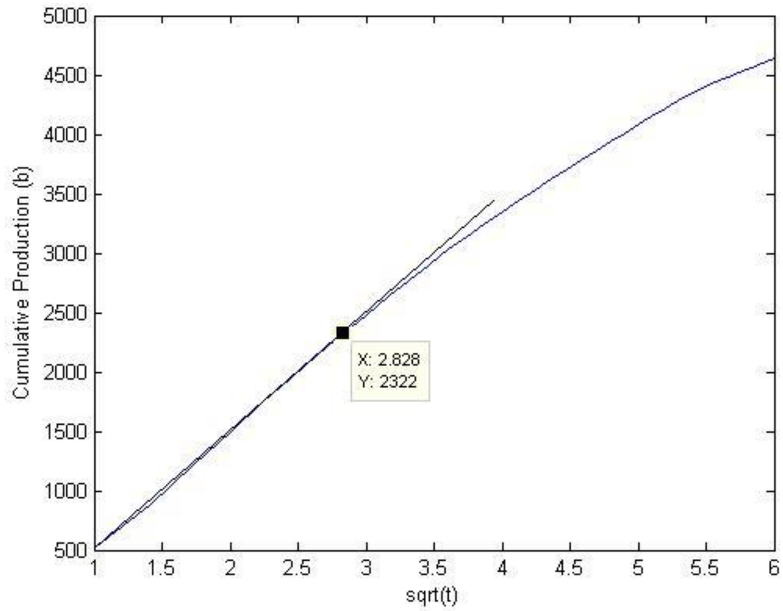


Figure 13. The interference time, i.e. when the decline transitions from $\mathbf{1/\sqrt{t}}$ to exponential, is found by plotting the cumulative production versus the square root of time.

5.4 Individual well decline curves

Hyperbolic decline curves are fitted to each well's production data. The length of the data series affects the shape of the fitted curve and the longer data series, the better the well behavior is covered. However, the larger the data set, the more accurate is the result. Therefore, a balancing is needed when determining the shortest production series to be included to cover well behavior and also have a data set of adequate size.

Table 5 displays the mean and the median of the individual decline curves λ and β parameters, for wells with more than 30 months' data (53 wells), 24 months' data (181 wells) and wells with more than 18 months' data (357 wells). The median values for the λ and β parameters for the data sets >24 months and >18 months are very close to the parameters of the aggregate decline curve (Figure 12). Figure 14 shows how the differences in the β and the λ parameters affect the shape of the decline curve. The mean values of β and λ result in a steeper decline curve that reaches a lower production level than the resulting decline curve using the median values.

Table 5. Mean and median values of λ and β parameters of the individual well decline curves

	mean				median			
months	>30	>24	>18	>12	>30	>24	>18	>12
λ	0.343	0.341	0.332	0.317	0.255	0.297	0.293	0.277
β	0.840	0.781	0.782	0.743	0.984	1.00	1.00	0.990

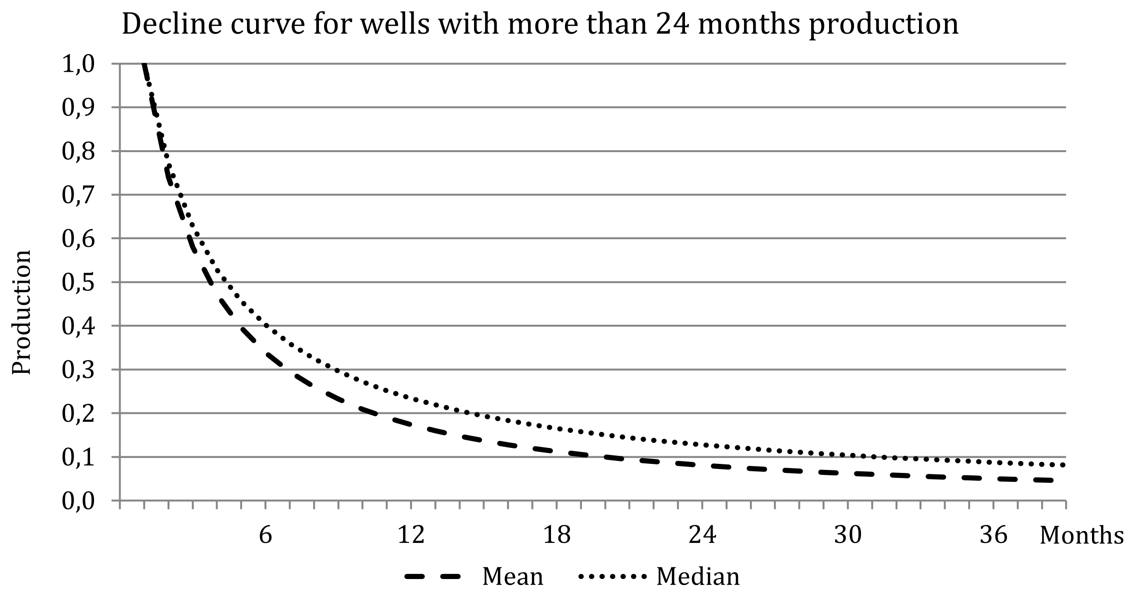


Figure 14. Example of decline curves for the data set including wells with more than 24 months of production. The difference in decline using mean and median values for the β and λ parameters is illustrated.

The distributions for the β and the λ parameters are displayed in Figure 15 and Figure 16 respectively. Only wells with production exceeding 12 months are included in this analysis. The limitation is set to exclude wells that does not yet show the patterns of specific curves and could be fitted to basically any hyperbolic curve, β ranging from 0 to 1. As shown in Figure 15 there is over a 50% probability that the β value is between 0.9 and 1, which means the hyperbolic curve is close to harmonic or harmonic. There is also about a 10% probability that the β parameter is between 0 and 0.1, which means exponential. The probability of a β between 0.1 and 0.9 is fairly constant, between 3 and 6%. In Figure 15 the best distribution fits according to the Anderson-Darling test (Beta distribution) and the Kolmogorov-Smirnov (Generalized Pareto distribution) are shown.

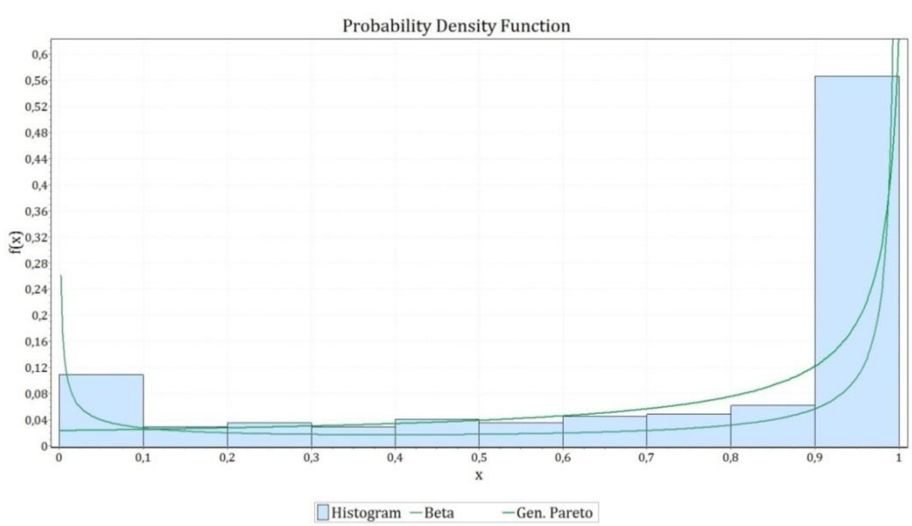


Figure 15. Distribution of β and probability functions with best fit according to A-D (Beta probability distribution with the U-shape) and according to K-S (Gen. Pareto probability distribution).

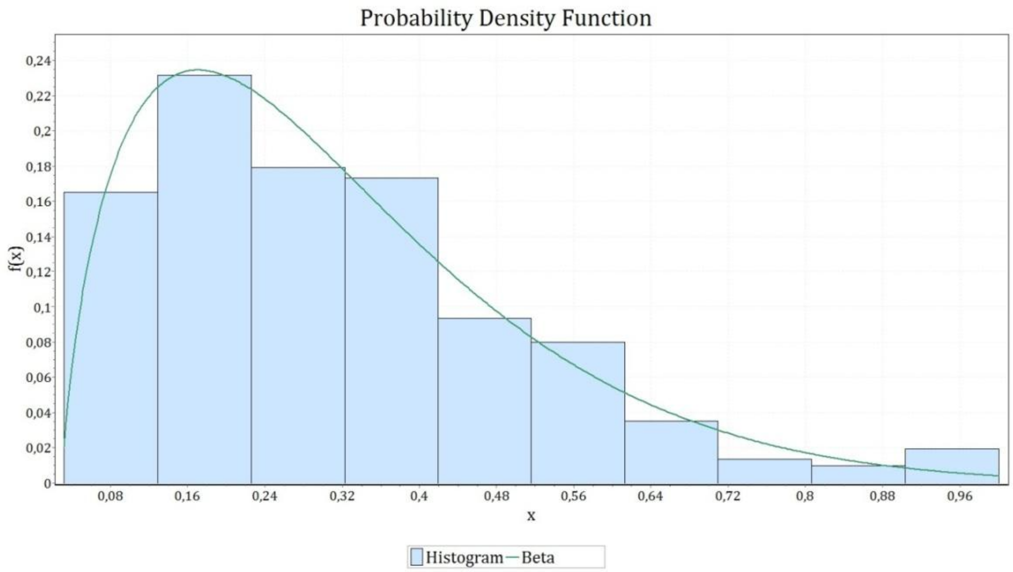


Figure 16. Distribution of λ and probability distribution with best fit according to A-D and K-S tests.

The set of λ values is spread out between 0 and 1 with emphasis of λ values between 0.10 and 0.30. There are several probability distribution functions with shapes fitting the set. The best fit according to both the Anderson-Darling test and the Kolmogorov-Smirnov is the Beta distribution shown in Figure 16.

The distributions of the first years decline and the decline over the first two years are displayed in Figure 17 and Figure 18 respectively. The average first year decline for wells started in 2010-2012 is 74.9%. For the respective years the average first year decline is 71.5%, 76.5% and 74.1%. Only wells that started in 2010 and 2011 have data to calculate two years decline. The 2010 average two years decline is 85.2% and for 2011 86.0%, giving an average for all wells of 85.9%.

The parameters and functions for the probability distribution functions are listed in Appendix B2.

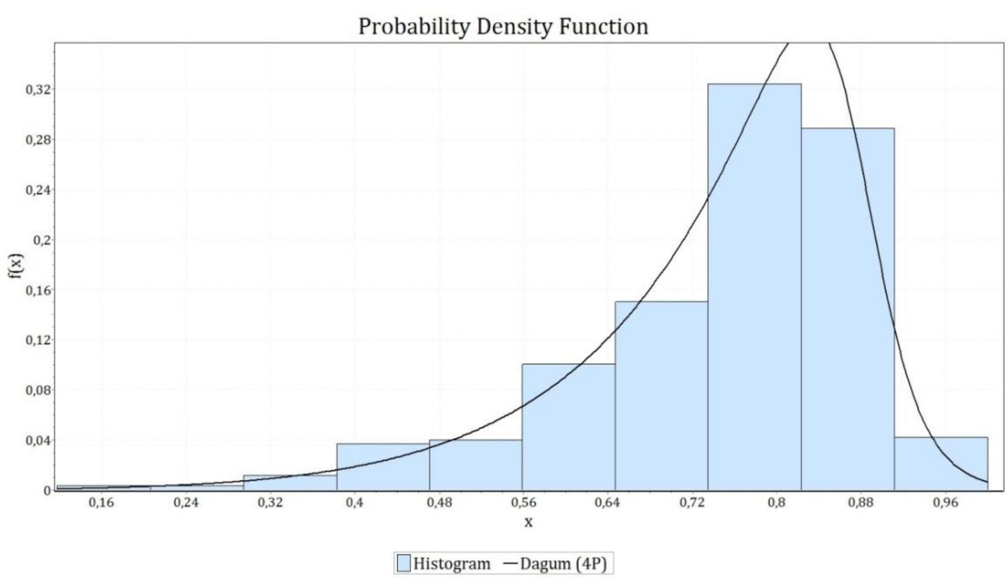


Figure 17. First year decline distribution, average decline is 74.9%. Probability distribution function with best fit according to both A-D and K-S tests.

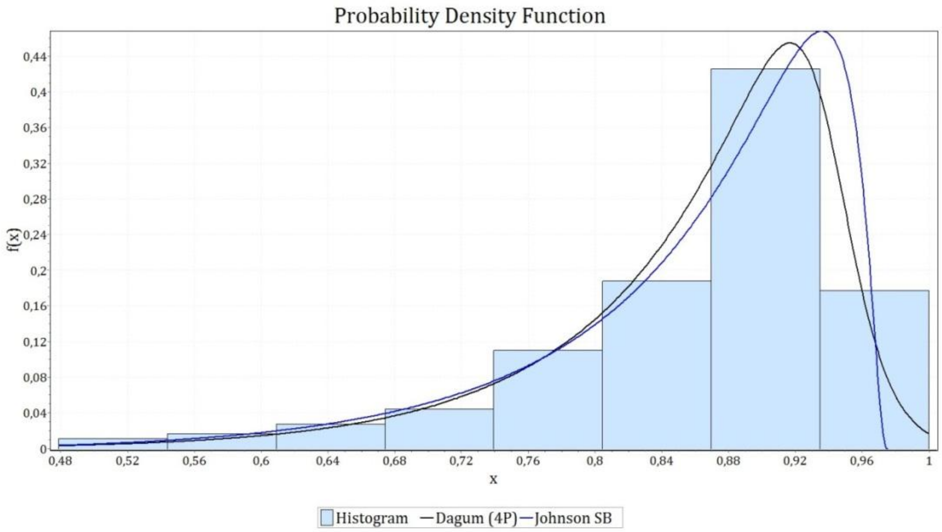


Figure 18. Decline over the first two years of production, average decline is 85.9%. Best probability density function fit according to A-D (Dagum, black) and K-S (Johnson SB, blue).

Variations in initial production and peak productionTable 6 shows the mean and median values for first oil and peak production for wells staring in 2010 through 2013, and reported with individual production data (Figure 11 shows the difference between first oil and peak production). For 2014, wells that were added to the Drillinginfo database up until July 2014 are included.

The development over the years of the parameters first oil and the peak production is shown in Figure 19. The first oil is fairly constant over the time period while the peak production has increased, with exception for a decrease in 2013.

Table 6. Variations in the parameters First oil, Peak production, First year's production and Second year's production.

Year		2010	2011	2012	2013	2014	2010-2013
Number of wells included in analysis (single wells)		54	229	478	531	86	1292
Total number of new wells		n.a.	486*	1860	2456	n.a.	4802*
Share off all wells in analysis (%)		n.a.	47*	26	22	n.a.	-
First oil (b/d)	Mean	252	238	212	244	392	232
	Median	124	173	159	206	292	177
Peak production (b/d)	Mean	371	529	521	484	833	501
	Median	246	507	479	447	669	460

*For 2011 new wells are reported only from April to December. The real number of new wells is therefore higher than 486 and the share is less than 47%.

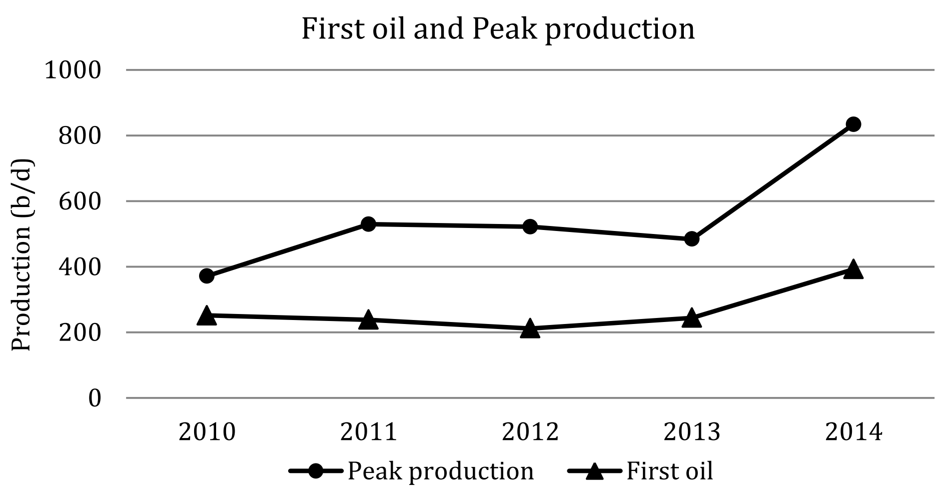


Figure 19. Yearly average of First oil and Peak production over the years 2010-2014. For 2014 only the first six months are included.

Figure 20 illustrates the variations in peak production and in the early decline (first 20 months) from year to year. Between 2010 and 2011 the peak production increased to stay about the same between 2011 and 2012. In 2013 the peak production decreased again. It is too early to determine whether this is an ongoing trend or if it is a temporary decline. Studying the wells started in the first half of 2014, the average peak production rises to a level significantly higher than those in 2011 and 2012.

In Figure 20 the wells with more than 20 months production data are included for the years 2010-2012. The number of wells included is 17, 207, and 57 for the respective years. The number of wells with more than 10 months production data included in the 2013 curve is 23. Thus, for all annual curves the number of wells included is only a small share of the total amount of wells. Therefore, if including all wells the result may be different and the result from the share of wells should be used with caution. However, Figure 20 reflects the results from the whole data set listed in Table 6 with increasing peak production between 2010 and 2011 and thereafter decreasing.

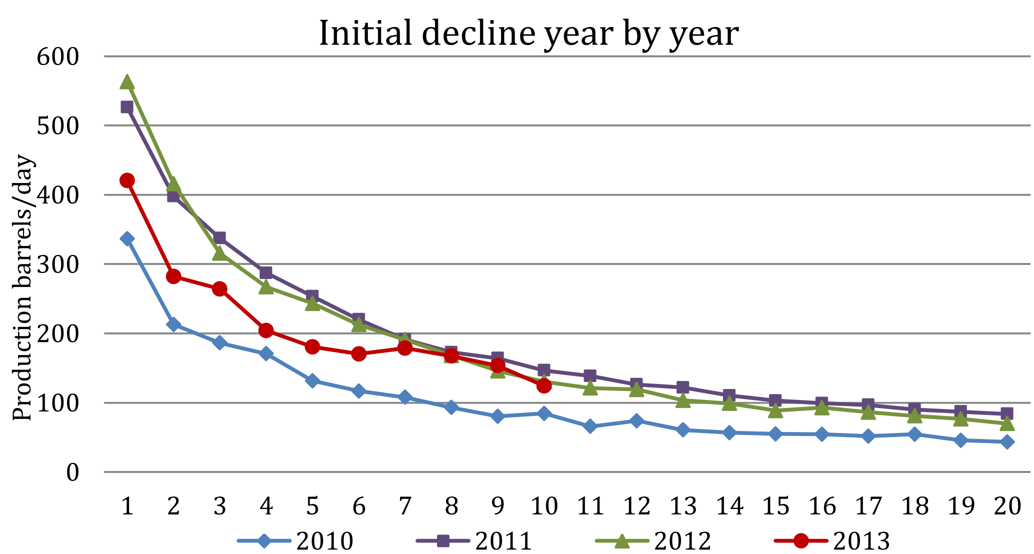


Figure 20. Variations in decline over the first 20 months of production. Wells started in 2013 only show the first 10 months of production.

The distributions for the first oil and the peak production from all wells starting in 2010-2013 are displayed in Figure 21 and Figure 22. With increasing volume of initial production (first oil) the probability decreases. In Figure 21 the Generalized Pareto distribution is used to describe the individual wells' first oil production. The first oil is expressed in barrels per day which is an average of the first month's production.

In Figure 22 the distribution of peak production is shown, also average values of barrels per day derived from the monthly production data. The data set is described by the Three-Parameter Log-Logistic distribution with emphasis on wells peaking at 300-600 b/d.

The development of the mean and median peak production values over time is shown in Table 6. There is an increase in peak production between 2010 and 2011. The following year the peak production remains similar to decrease again in 2013.

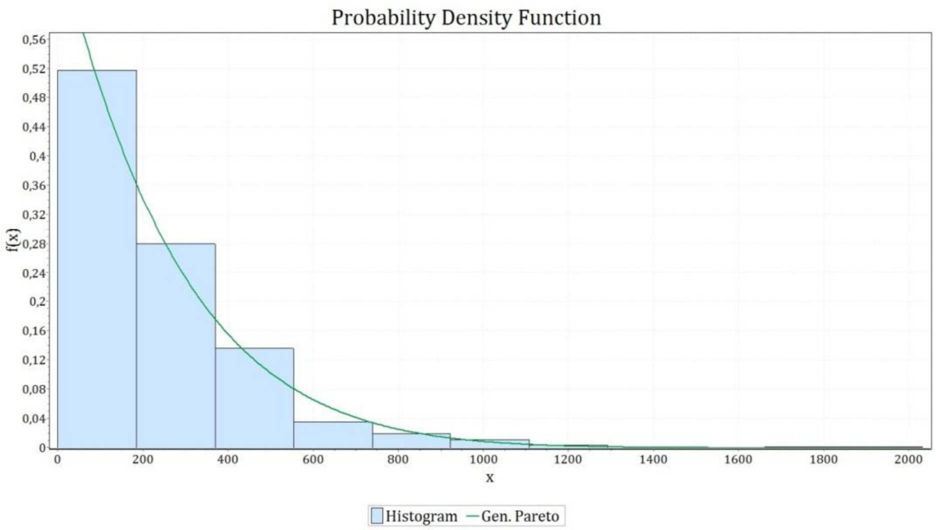


Figure 21. Probability distribution for first oil. The Generalized Pareto probability density function is the best fit according to A-D and K-S.

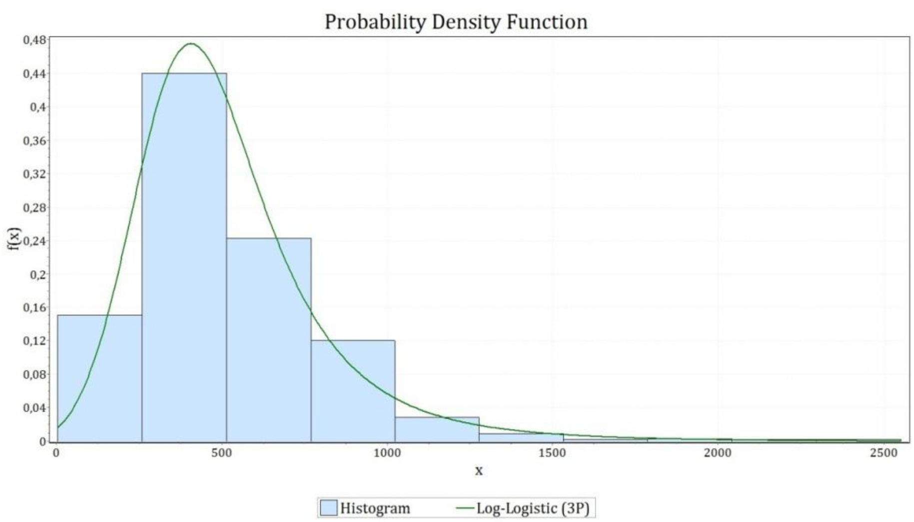


Figure 22. Peak production of all wells staring in 2010-2013. The Log-Logistic probability distribution is the best fit according to both A-D and K-S tests.

5.5 API gravity influence on decline

As explained in chapter 4.1 the geology of the Eagle Ford formation has led to different hydrocarbons in different parts of the formation, ranging from natural gas to condensate to light oil. Even though most of the oil is in the light oil category the API gravity of the oil spans from just below 31.1° (which is the lower boundary for light oil) to above 50° (the boundary for condensate).

Figure 23 shows the decline for wells in the counties McMullen and Wilson. The median values for the λ and β parameters of the individual decline curves are used, since shown closer to the aggregate decline curve than the mean vales (see Section 5.4).

It can be seen in Figure 7 that county McMullen covers mostly the wet gas/condensate window with some oil in the north-western corner while county Wilson covers mostly the oil window with some wet gas/condensate. Subsequently, the API gravity of the McMullen wells range from 30° to 50° while the API gravity of the Wilson wells range from 30° to 40°. The average API gravity of the wells included in the analysis is 45.6° for county McMullen (62 wells) and 35.2° for county Wilson (32 wells).

Figure 23 shows that the decline curve is steeper for the McMullen wells, which have lighter petroleum products (higher API) than for the Wilson wells with heavier products (lower API). The textbox in the diagram shows the first year and two years decline for the two counties.

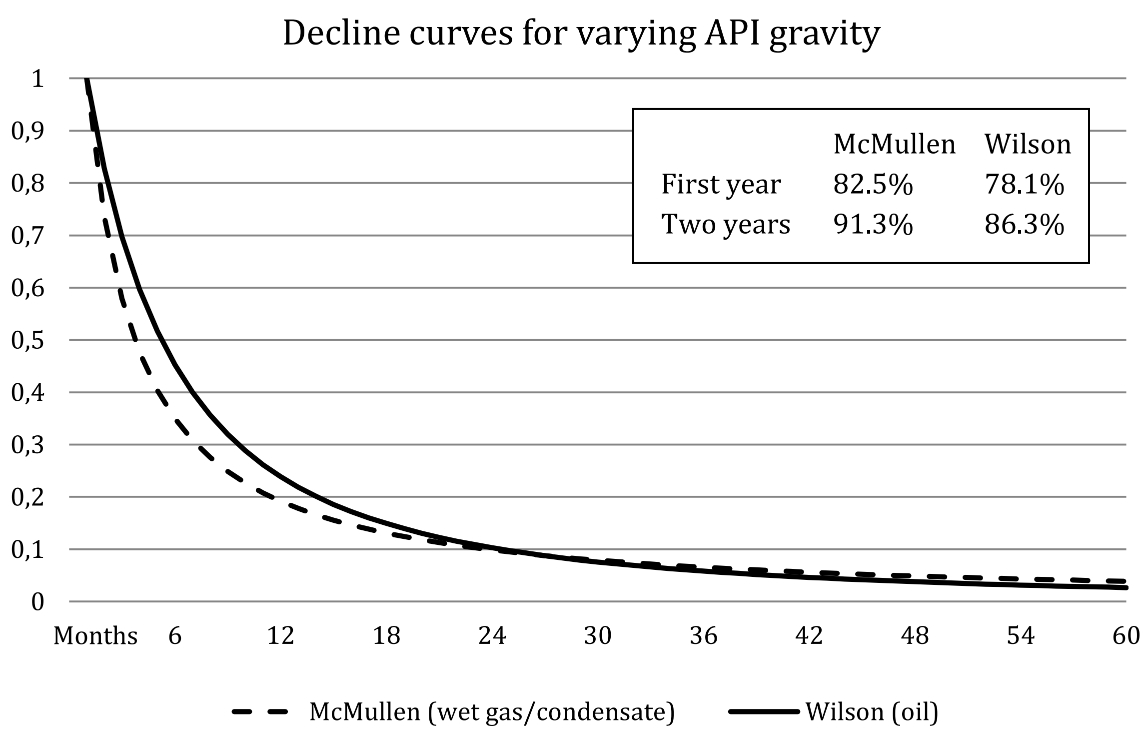


Figure 23. Decline curves for McMullen and Wilson counties. Wells with lighter oil (McMullen) have a steeper decline than wells with heavier oil (Wilson).

5.6 Discussion on the results

The fact that the β-parameters of the hyperbolic fits are often close to one indicates that the wells would stabilize at a production level that could be kept forever. This could not be the behavior in reality since the resource is finite. With the data available so far it is too early to get a good picture of how the production looks like at the late stage of a well's lifetime and also impossible to determine for how long the wells typically produce.

There is no clear trend in the development of first oil and peak production over time. The annual mean values of the first oil vary with less than 10% from the mean over the whole period. Studying the median values an increase can be seen from the first year (2010) to the last (2014), however not steady over the years in-between.

The peak production sees a decrease in mean and median values after the first increase from 2010 to 2011. However, in the first half of 2014 the peak production increases again. If the mean peak production stays this high for the second half of 2014, there will be an increase of 82% compared to 2013's mean peak production. Compared to the mean of all wells between 2010 and 2013, the 2014 mean peak production will be increased by 76%. Since the down-going trend in peak production in 2011-2013 is interrupted by the high peak productions in 2014 it is unlikely that the decrease was due to running out of sweet spots. The increase in 2014 could instead be a result of newly defined sweet spots since the shale oil extraction in the Eagle Ford is still in a quite early stage. Also, the increase could be a result of technology advances such as increased horizontal lengths of wells and increased number of fracturing stages. Another explanation to why it is difficult to distinguish a clear trend is that the data set might not reflect the features of all Eagle Ford wells properly.

The connection between the API gravity and the decline rate should be treated with caution since only a small number of wells are included in this analysis. The wells are located in two counties in different parts of the Eagle Ford region and there is big chance other parameters than the API gravity differ between the counties. Such parameters could be permeability, porosity, brittleness (ability to induce fractures) and other geological parameters. If the porosity is higher more water will be used in the hydro-fracturing and more of fracturing water would stay in the reservoir. The water affects production and therefore the decline.

6 Future oil production in the Eagle Ford

Based on the results in Chapter 5 projections for the future oil production in the Eagle Ford are made. The input parameters to the model are the following:

- Number of new wells per month
- Maximum number of wells
- Peak production of wells
- Well decline curve
- Production from already existing wells
- Field decline (decline in already existing wells).

The output is the future production curve and the URR.

6.1 Model validation on historical data

The model used for forecasting future production from the Eagle Ford is validated on historical production data. The model's results are compared to production data from the U.S. Energy Information Administration (2014b). The EIA report the production of crude oil and condensate without separation. The Railroad Commission of Texas reports the annual production of crude oil and condensate from 2008 to April 2014 (Texas RRC, 2014). Based on this information the crude oil production is calculated as a share of the monthly production reported by the EIA.

The hyperbolic decline curve fitted to the aggregate data (see Figure 12) is used for well decline. Every nine months a production of zero is added to cover time for maintenance. This means that the decline curve is shifted forward one month every nine months. The scaling curve is also tested in the model with a result very similar to the hyperbolic curve. The two different approaches to well decline are similar for the early production of a well. Due to the short production data set that is available for validation the result from the models are very similar. The difference appears only later in the wells' production. The results of both decline curves are shown in Figure 24.

The number of new oil wells per month is achieved from the Texas Railroad Commission (Texas RRC, 2014), starting from April 2011. The actual production reported by the EIA, for March 2011, is used as the first value for the model. This production is corrected downwards with a factor of 0.9246 per month to represent the field decline (the decline in pre-2011 production).

The production generated by the model is slightly less than the real production. The deviation of the cumulative production over the 33 months between April 2011 and December 2014 is 6.1% using the hyperbolic decline. When using the scaling decline curve the deviation is 7.5%.

As can be seen in Figure 24 the real production is increasing almost along a straight line while the production generated by the model is oscillating. The figure also shows the number of new wells drilled each month throughout 2012 and 2013. The monthly number of new wells has large variations, for example the variation within the year of 2012 is almost 450% (between April and December). The periods when fewest new wells are drilled are generally late summer (August and September) and December due to vacation[4]. This trend is somewhat visible in the diagram in Figure 24 where the top months are April and bottom months are December.

[4] Tad Patzek, personal communication 2014-03-24.

In reality, new wells are not put into operation directly when completed. Thus, the number of wells put into operation each month may be more constant, smoothing out the oscillations in Figure 24 and consequently giving a smoother production curve.

Figure 24 also shows that the model gives an overestimation of production during the years' first half and an underestimation during the second half. If this trend is to be continued, the production would again increase in the first months of 2014. Analyzing the real production and the simulated production for December of 2011, 2012 and 2013 the simulated production is falling behind by 21%, 15% and 18% respectively.

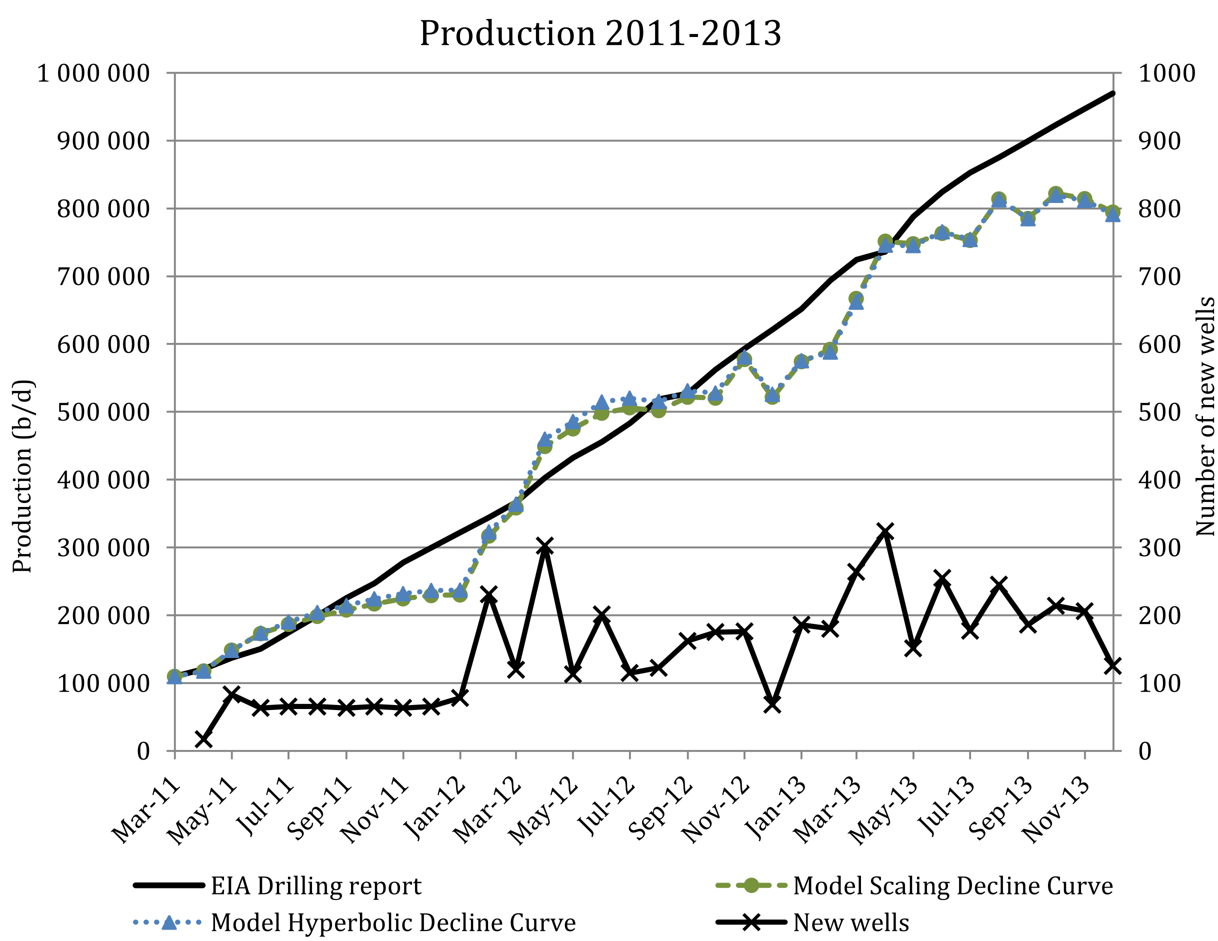


Figure 24. Actual production (as reported by the EIA) and calculated production of shale oil from the Eagle Ford.

6.2 Sensitivity analysis

The effect of different values on the different input parameters to the model are tested in different scenarios. The different scenarios are the following:

A. Hyperbolic vs. Scaling decline
B. Number of wells per month
C. Well peak production
D. Maximum number of wells

6.2.1 Scenario A – Hyperbolic vs. Scaling decline

In Scenario A the effect of the chosen decline curve is illustrated. The hyperbolic decline curve and the scaling decline curve as fitted to the data in section 5.3 are used. Like in previous section 6.1 a production of zero is added every nine months to represent maintenance. The scaling curve reaches a production of less than 1% of the peak production after 72 months (6 years). After this point the wells are assumed to stop producing (scaling curve is set to zero). The hyperbolic curve decreases slower than the scaling and only after 357 months (almost 30 years) the production is reduces to less than 1% of the peak production. However, production is assumed to stop already after 20 years when it has reduced to 1.5% of the peak production. The point of abandonment of a well depends on the economic limit, the point where the operating costs are no longer covered by the revenue. Kaiser and Yu (2010) have studied the economic limits of oil and gas wells in Louisiana. The average production the year before abandonment is 1,000 barrels of oil equivalents (boe) per year in the north part and 2,800 boe per year in the south part. Since the initial production is assumed to decrease over the period, the production of the last year before abandonment varies from the earliest wells to the later ones. The wells staring at a production of 830 b/d reaches a final year production of 4,750 barrels while the last wells have a final year production of only 913 barrels. The point where production stops is fixed due to simplicity and in a more detailed model the economic limit would be dynamic.

The input parameters to Scenario A are listed in Table 7. The number of wells added each month is 210, which is the average of new wells per month in 2013 (Texas RRC, 2014). The same amount of new wells is added each month for 190 months (almost 16 years) until the total number of wells is 45,000. The maximum of 45,000 wells is an estimation based on the well spacing span reported by New York State Department of Environmental Conservation (2011) and assuming 50-75% of the oil window in Eagle Ford is covered with wells. After 45,000 wells are drilled the drilling stops abruptly. The peak production of the wells is assumed to be 830 barrels per day for the first month, the average peak production of the new wells introduced in the first half of 2014. The peak production decreases with 10% per year to represent that the most productive sites, sweet spots, are drilled first leaving less productive sites for later exploitation.

The production from existing wells (pre-2014 wells) is taken directly from the U.S. Energy Information Administration (2014b), the condensate as reported by the Texas Railroad Commission (Texas RRC, 2014) is subtracted, and the field decline is the calculated mean value for the period of 2010-2013, based on the EIA's data.

Table 7. Input parameters to Scenario A.

Parameter	Value	
Number of new wells per month	210	constant
Maximum number of wells	45,000	
Peak production of wells (b/d)	830	annual decrease 10%
Well decline curve	hyperbolic + scaling	
Production from already existing wells (b/d)	969,726	
Field decline	0.9246	constant

Figure 25 shows the future production given the assumptions listed Table 7. For the first three years (Jan 14 – Jan 17) the different decline curves yield similar results. The hyperbolic decline curve gives a peak in total production rate sometime in 2014 or 2015 while the scaling decline curve peaks somewhat later, in 2015-2016. Both decline curves reach a maximum production of 1.4 Mb/d. After peaking, the scaling case decreases production faster than the hyperbolic case, yielding a URR of 5.5 Gb compared to 8.4 Gb for the hyperbolic curve. Thus the hyperbolic decline curve leads to a URR 1.5 times the URR from the scaling decline curve. When the introduction of new wells terminates in late 2029, both production curves decrease even more rapidly.

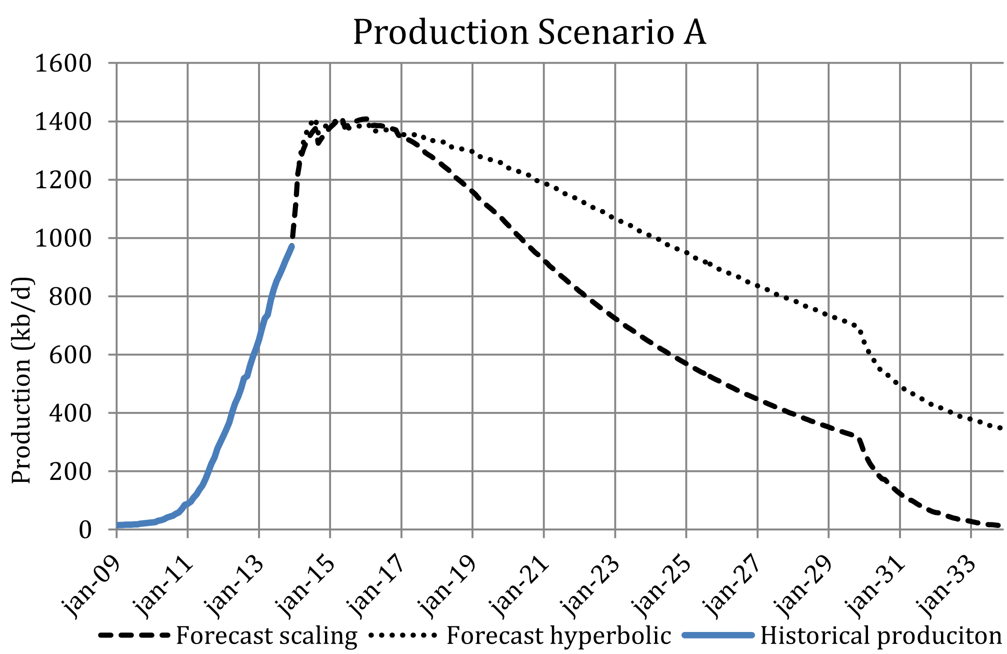


Figure 25. Production forecasts using a hyperbolic decline curve and a scaling decline curve. For the first three months, the two decline curves yield very similar results. After the first three months, the scaling decline curve results in a faster decline in total production from the Eagle Ford oil wells. The interruptions in the production curves that can be observed during 2014 and 2015 are effects of the months of zero production that are introduced. In late 2029 the maximum number of wells is reached and no new wells are introduced. This results in the increased decline just before January 2030.

6.2.2 Scenario B – Number of new wells per month

In Scenario B the number of wells per month is varied. The hyperbolic decline curve is used in all cases. Also common for all cases are the maximum number of wells set to 45,000, the peak production starting off at 830 b/d and decreasing 10% per year, the production from pre-2014 wells, and the field decline. Table 8 lists all input parameters to Scenario B.

The number of new wells per month starts at 206 wells the first month since this was the number of new wells in December 2013, the last month prior to the start of the period of the simulation. In the three cases illustrated in Figure 26 the maximum number of wells per month and the rate at which they are drilled vary. In the first case, 'Max 250 wells per month', the number of new wells increases with 5% annually until the maximum rate of 250 wells/ m is reached. This rate is then kept until the maximum number of wells of 45,000 is reached. In the cases 'Max 300 wells/m' and 'Max 300 wells/m (2)' the maximum rate of new wells is 300 wells/ m. The number increases with 10% and 5% respectively until the maximum rate is reached. The assumption about the possible number of new wells per month is based on the historical number of wells (see Figure 24) and the number of available drilling rigs (Baker Hughes, 2014). The maximum rate of introduction of new wells is then kept until the maximum number of 45,000 wells is reached.

Figure 26 displays the production forecasts for the three cases. The most restrictive case reaches a peak in production at 1.5 Mb/d in early/mid-2018. The most explorative case reaches a production of 1.7 Mb/d around the same time. The middle scenario has more of a plateau in production stretching over more than five years, from mid-2016 to the beginning of 2022. The maximum production is 1.5 Mb/d.

The cumulative maximum number of wells is the same in all three cases. Due to the differences in drilling rate the cumulative maximum is reached at different points in the three cases, with a span over two years. Common for the three cases is that as soon as the introduction of new wells terminates the production decreases faster than earlier.

The URR in the three cases are 8.3 Gb (Max 250), 8.9 Gb (Max 300) and 8.5 Gb (Max 300 (2)) respectively.

Table 8. Input parameters to Scenario B.

Parameter	Value	
Number of new wells per month	206	increasing at different rate and with different maximum number (see text)
Maximum number of wells	45,000	
Peak production of wells (b/d)	830	annual decrease 10%
Well decline curve	hyperbolic	
Production from already existing wells (b/d)	969,726	
Field decline	0.9246	constant

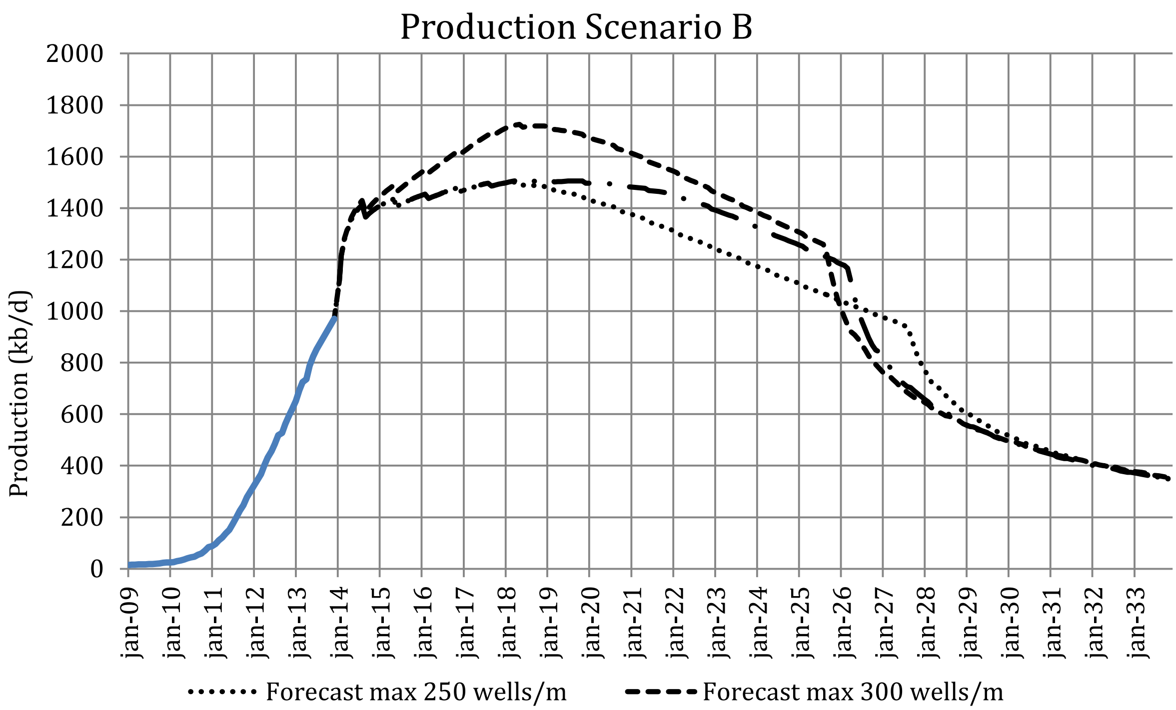


Figure 26. Production forecast for different assumptions regarding new wells. The most restrictive scenario with a maximum of 250 wells/m reaches peak production already in 2018. The most positive case, 300 wells/m, also reaches peak production in 2018, but at a higher level than the case of 250 wells/m. The middle case, also with a maximum of 300 wells/m (300 wells/m (2)) shows more of a plateau in production with a slower decline than the other two cases. For all cases, production decreases more rapidly when the introduction of new wells stops. This occurs at different points in time, late 2025 (300), early 2026 (300(2)) and late 2027 (250) for the respective cases.

6.2.3 Scenario C – Well peak production

Scenario C investigates the effect of the assumed peak production of wells. The number of new wells each month is held constant at 210 new wells per month. The maximum number of wells is 45,000 and the decline curve, pre-2014 production and field decline are all the same as in previous scenarios. Three different peak productions of the wells are assumed; 520 b/d (constant), 830 b/d (constant) and 830 b/d decreasing by 10% per year. The figures are the average peak production of the period of 2010-2014 (520 b/d) and the average peak production only during 2014 (830 b/d). The parameters for Scenario C are listed in Table 9.

Figure 27 shows the production in the different cases. In the most positive case where the peak production of the wells stays at 830 b/d during the whole period the production is continuously increasing all the time until new wells stops to be introduced. The maximum production of 2.7 Mb/d is reached the last month with new wells. Decline takes off only after no new wells are added. In the case with a decreasing peak production of wells, the peak of the total production is reached already during 2014 at 1.4 Mb/d.

In the third case the number of new wells is constant at 520 b/d. The production is falling by about 3% from August 2014 to June 2015, before it increases again until the starting of new wells is terminated in late 2029. The reason for the decrease in 2014-2015 is that the new wells are not fully compensating for the drop in production from pre-2014 wells. The maximum production reached is 1.7 Mb/d.

The URR differs with more than 100% in the most positive case and the most restrictive one. The case with a constant peak production of 830 b/d reaches a URR of 16.8 Gb while the case with decreasing peak production only results in a URR of 7.7 Gb. The case with 520 b/d yields a URR of 10.7 Gb.

Table 9. Input parameters to scenario C.

Parameter	Value	
Number of new wells per month	210	constant
Maximum number of wells	45,000	
Peak production of wells (b/d)	520, 830	constant
	830	annual decrease 10%
Well decline curve	hyperbolic	
Production from already existing wells (b/d)	969,726	
Field decline	0.9246	constant

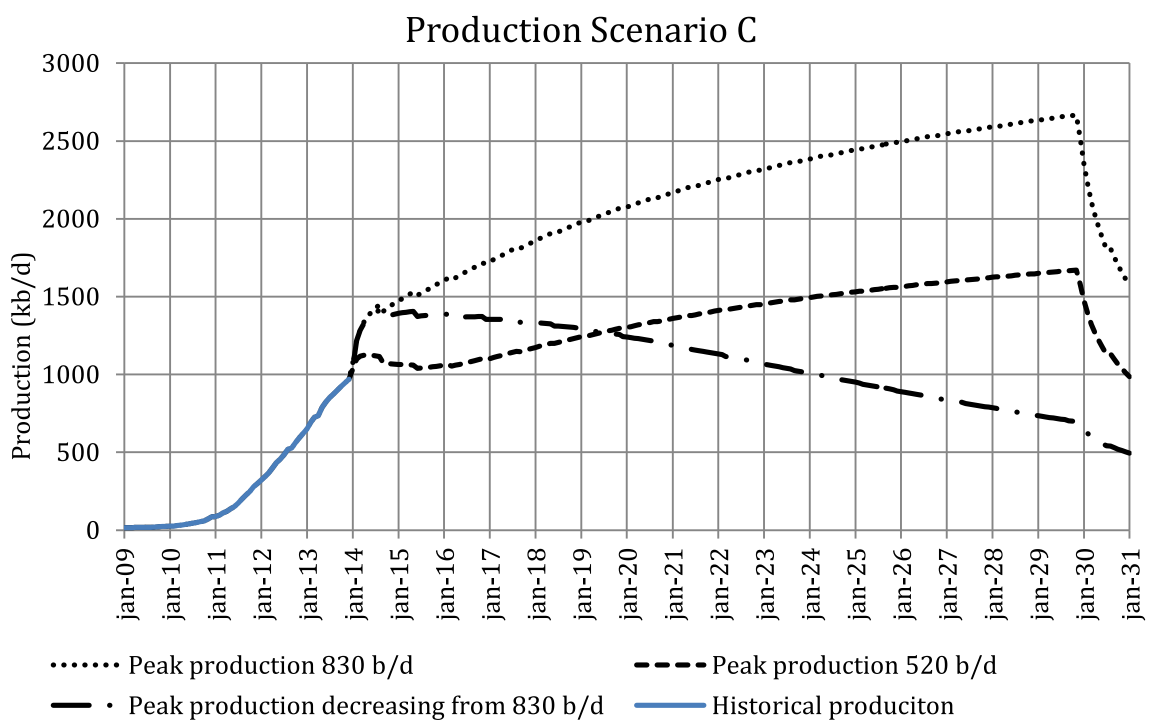


Figure 27. Production forecast given different assumptions of the peak production of the individual wells. The mean values for peak production for 2010-2014 (520 b/d) and for 2014 (830 b/d) are used. In the cases where the peak production stays constant for the whole period, the production rate continues to increase until no new wells are introduced (late 2029). In the case where the peak production in assumed to decrease over the years a peak total in production is reached already in 2014-2015.

6.2.4 Scenario D – Maximum number of wells

This scenario illustrates how the maximum number of wells in the Eagle Ford will affect the future production. The hyperbolic decline, pre-2014 production and field decline are the same as in previous scenarios (see Table 10). The maximum number of wells in the Eagle Ford is set to 20,000, 40,000 and 60,000 in the respective cases, covering the range of wells given by the well spacing reported by New York State Department of Environmental Conservation (2011).

The number of new wells per month is starting at 210 wells per month and increases with 5 wells per month until the rate of 300 wells per month is reached. The reason that this parameter is not kept constant while investigating another parameter is that it is assumed that the rate of 210 wells per month will need to be increased to reach the greater numbers of total amount of wells.

All three cases reach a maximum production of 1.9 Mb/d during 2017, as can be seen in Figure 28. The productions from the three cases follow each other until the point where the maximum number of wells is reached. For 20,000 wells this point is in May 2018 and for 40,000 in December 2023. 60,000 wells are reached in June 2029.

The URR in the three cases are 5.06 Gb, 8.64 Gb and 10.4 Gb respectively.

Table 10. Input parameters to Scenario D

Parameter	Value	
Number of new wells per month	210	Increasing to 300
Maximum number of wells	20,000	
	40,000	
	60,000	
Peak production of wells (b/d)	830	annual decrease 10%
Well decline curve	hyperbolic	
Production from already existing wells (b/d)	969,726	
Field decline	0.9246	constant

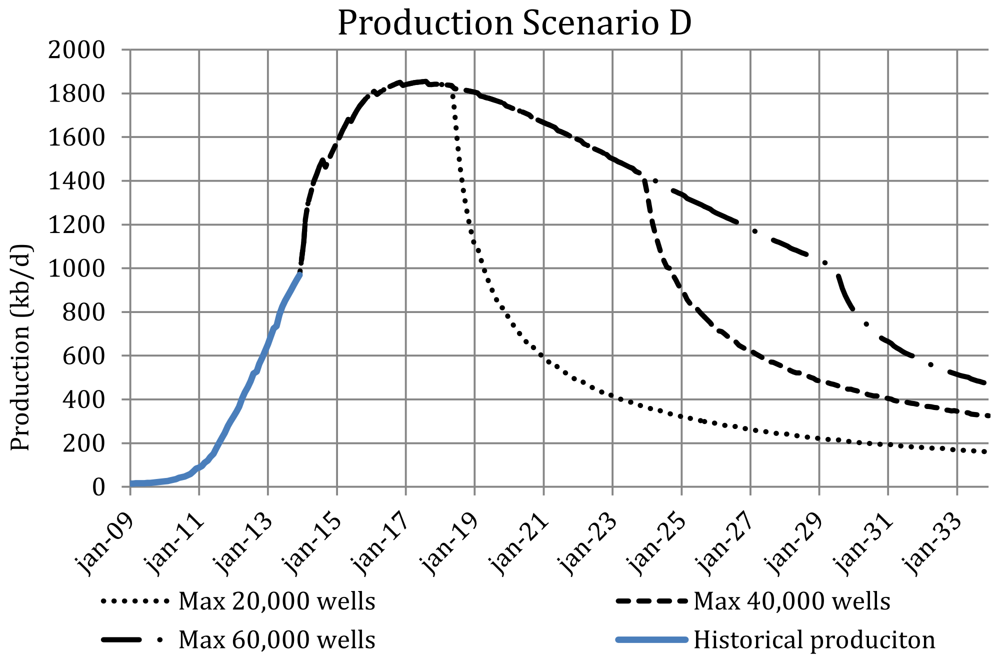


Figure 28. Forecast of production given different assumptions of the maximum number of wells. All cases follow the same production curve until the points where the maximum amount of wells is reached for the respective cases. When no new wells are introduced anymore production decreases fast. The maximum amount of wells are reached in 2018 (20,000 wells), 2023 (40,000 wells) and 2029 (60,000 wells) respectively.

6.2.5 Summary of sensitivity analysis

The output parameters of the different scenarios are summarized in Table 11.

Table 11. Summary of the scenarios.

Scenario	Case	Peak production (Mb/d)	Peak month	URR (Gb)	URR/well (kb)
A	Hyperbolic	1.44	Feb 2016	8.37	186
	Scaling	1.42	May 2015	5.52	123
B	Max 250	1.50	Apr 2018	8.27	184
	Max 300	1.73	May 2018	8.87	197
	Max 300(2)	1.51	Feb 2019	8.50	189
C	830 constant	2.67	Nov 2029	16.8	373
	520 constant	1.67	Nov 2029	10.7	237
	830 decreasing	1.41	Aug 2014	7.71	171
D	20,000	1.86	Aug 2017	5.13	257
	40,000	1.86	Aug 2017	8.64	216
	60,000	1.86	Aug 2017	10.4	174

7 Discussion

7.1 Evaluation of forecasting methodologies

The overall aim of the study is to analyze the production patterns of the Eagle Ford shale play, to eventually contribute to the knowledge of the shale oil resources and the potential future production. The early production data of wells is extensive and high accuracy can be given the analyses. When it comes to production at later stages of the wells' lifetime more uncertainty is introduced, due to the less extensive data. This is the main drawback to the methodology.

The decline curve analysis as a methodology has been used widely during several decades and the methodology has been tested and proved to be robust and reliable. However, it has some drawbacks, such as the high dependence on the choice of decline curve and the risk of using inappropriate analogues within or between plays (McGlade et al., 2013a). The result in this study shows that both the hyperbolic and the scaling decline curve fit well to the available production data. It is too early to determine which of the alternatives that is more accurate in the longer run and another few years of production is needed before a distinction will be apparent.

The hyperbolic decline curve has some advantages compared to the scaling decline curve. It has been used for a long time and has been proved to be accurate in conventional oil wells, for example by Höök and Aleklett (2008). The fact that it has one single mathematical expression describing the whole decline phase facilitates the usage. The scaling decline curve on the other hand is composed of two different mathematical expressions and the interference point needs to be found manually before the two curves can be applied. This adds more work to the analysis process.

An important but challenging factor to cover in the production analysis is the variations in geology and hence in production throughout a reservoir (McGlade et al., 2013a). Production patterns of wells in one part of a play may not be valid in another play or not even in another part of the same play. For this reason one must be careful when applying production patterns from one region on other regions. In this study the statistical distribution of different production parameters has been examined in an attempt to cover the inhomogeneous production. Still, more research is needed on the geology of shale plays to enable more accurate analogues between regions and plays.

7.2 Data

The data this study is based on is very detailed with monthly production on well basis reported. It is a great advantage to have access to production data of individual wells and without it this kind of study would not be possible.

One important uncertainty in the analysis is the limited number of wells that are included. Due to the way that production data is reported in the Drillinginfo database only a share of all wells in the Eagle Ford formation have production data that might be used. Only roughly 25% of all wells that started in 2012 and 2013 where included in the analysis. The assumption is made that these wells are representative for all wells in the region but if this assumption is not valid an error is introduced. Since the wells included in the analysis are wells reported individually there is a risk that this category of wells differ from wells reported together in parameters such as peak production or first oil. For instance, unusually large or small wells could be overrepresented in the set of individually reported wells.

A difficulty in the study is the variation in how the production data is reported in different sources and the fact that it is not always clearly stated what is included in different figures. The main issue is what is included in reported ‘oil production’. Some sources include both oil and condensate in the reported oil production while others distinguish between the two.

7.3 Future production

When it comes to making projections for future production, many other parameters in addition to the decline rate also have great uncertainties. Different estimates of URR per well are reported in literature; the greatest more than 10 times the smallest, which makes it difficult to exclude some of the scenarios only because they exceed the figures reported in literature. In the sensitivity analysis scenarios the URR per well in all scenarios except one lie within the somewhat narrower range of URR per well reported by the U.S. Energy Information Administration (2014a). On the other hand, the total URR generated in the sensitivity analysis scenarios are 1.5-4.7 times the estimated total URR reported by the EIA. If the total URR estimate by the EIA is assumed to be accurate, the number of wells is highly overestimated in the scenarios of this report. A study by Hughes (2013a) have URR estimates more in the same range as calculated in the scenarios is this study.

Regardless the size of the resource, future shale resource development need to take the environmental and health risks into consideration. The potential risks are large and more research is needed to gain better knowledge on the effects on humans, animals and environment from shale activities. Even though there is a potentially large resource available globally the aspects of health and environment may reduce the amount that will be available in reality.

The fact that a large share of the shale resources is located in regions with conventional production of oil and gas could facilitate the development of the unconventional resources meaning that much of the infrastructure may already be in place. Also, the acceptance might be greater in regions with conventional oil and gas production than in regions with no previous production.

7.4 Comparison to other studies

Several studies try to estimate the future production rates and the URR of the Eagle Ford and other shale plays in the U.S. Commonly, a peak in production rate is expected sometime before 2030. However, when the peak will be reached, at what level and the estimated ultimate recovery/ultimately recoverable resource differ.

According to Sandrea (2012) the original oil in place in the Eagle Ford formation was 300 Gb. However, the U.S. Energy Information Administration (2014a) estimates the technically recoverable resources to much less, 3.35 Gb.

In 2012, Swindell (2012) estimated the URR of individual wells in the Eagle Ford to 115,282 barrels of oil. Maugeri (2013) criticizes the estimation for being low and states that some companies estimate over 600,000 barrels of oil and gas combined per well. Hughes (2013a) also reports high industry estimates of 430,000-460,000 barrels per well. Maugeri (2013) estimates further that the peak production rate in the Eagle Ford will be reached at 1.5 Mb/d in 2017. The two references are both published some years ago and the estimations have generally been more positive lately. Figure 29 illustrates how the U.S. Energy Information Administration (2014a) changed its forecast between the Annual Energy Outlook of 2013 and 2014. This is one example of how great uncertainties about the resource still are and that estimations are subject to change.

As seen in Figure 29, the latest forecast of the U.S. Energy Information Administration (2014a) is a maximum production rate of just over 1.5 Mb/d, plateauing during 2015-2020. In the Annual Energy Outlook of 2014 the mean URR per well is reported for different counties in the Eagle Ford. The range is quite wide, from 80,000 barrels in county Webb to 334,000 barrels in county DeWitt. Also, the average URR is estimated depending on the year the wells started. The average for all wells that started between 2008 and 2013 is 168,000 barrels.

In a forecast from Rystad Energy (2014a), Figure 30, the peak production in Eagle Ford is expected to be reached in 2018-2019 at 1.7-1.8 Mb/d. The figure shows the expected production in all shale plays that are probable to produce shale oil in the U.S.

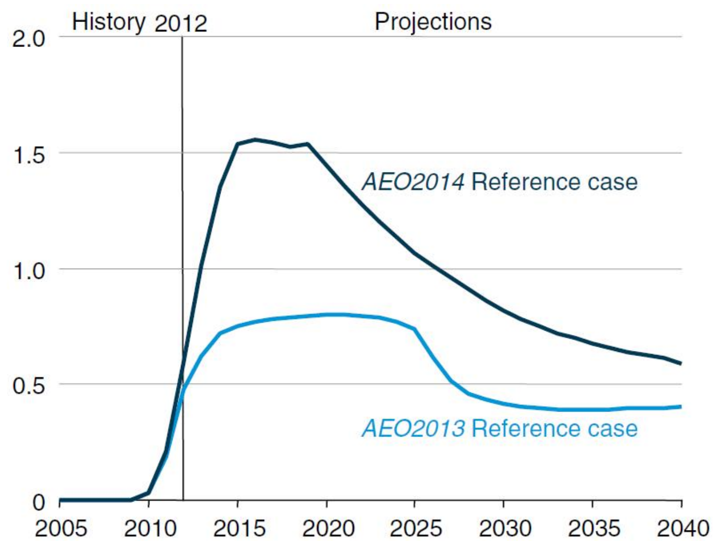


Figure 29. U.S. Energy Information Administration forecasts of production rates (million barrels per day) in the Eagle Ford 2013 and 2014. The forecast of 2014 is a lot more optimistic than the one from the previous year. *Source: U.S. Energy Information Administration (2014a)*

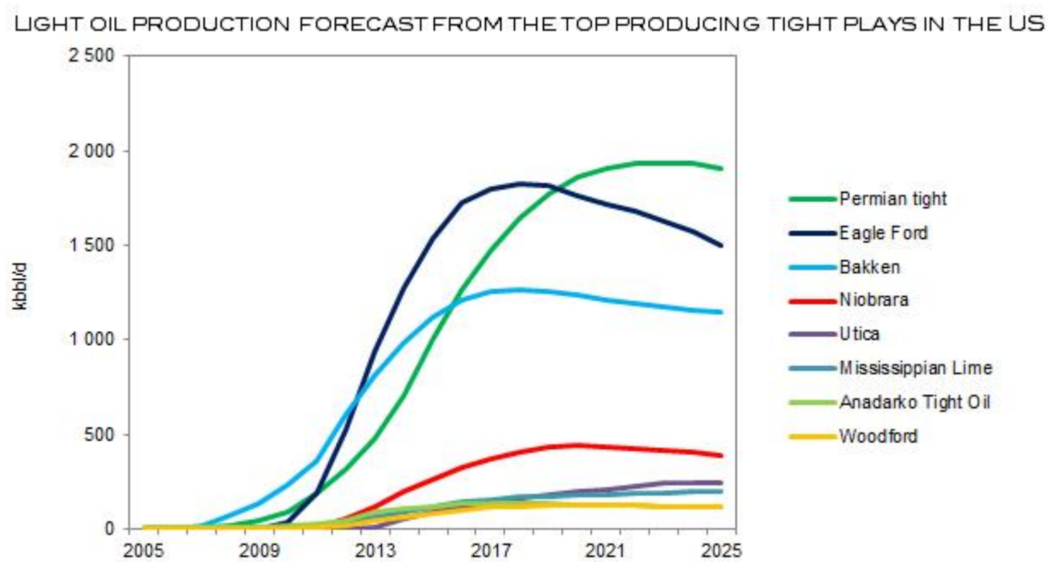


Figure 30. Production forecast of different shale oil plays in the U.S. Eagle Ford production is estimated to peak in 2017-2018 and thereafter the Permian basin will take over as the largest shale oil producing basin in the U.S. *Source: Rystad Energy (2014a)*

In the latest World Energy Outlook (International Energy Agency, 2013) shale oil estimates are made only on country level. The forecast for the U.S is a peak in 2025-2027, somewhat later than the Eagle Ford studies. The maximum production rate is predicted to 4 Mb/d, a level that the U.S. Energy Information Administration (2014a) expects already in 2014, i.e. more than 10 years earlier than the International Energy Agency forecast.

An estimate from the U.S. Geological Survey Oil and Gas Assessment Team (2012) is a lot more restrictive for the URR in the Eagle Ford with only 55,000 barrels of oil per well.

Hughes (2013a) calculates the decline of shale oil wells in the Eagle Ford. He is more positive in the wells' productivity, compared to the results in this study, with a first year's decline of only 60%. During the second year however, the decline is greater than found in this study and after two years the production has reduces with 86-89% of the initial production. The estimated URR for the Eagle Ford is 7.1-7.3 Gb and the production rate is expected to reach its peak in 2017 or 2018 at 1.3-1.5 Gb (Hughes, 2013b). The data that the study is based on are not well documented and the cause of the different results is therefore difficult to analyze.

The Bakken play has been used as an analogue to estimate production in Eagle Ford. According to Hughes (2013a) the decline of the Bakken play is 69% the first year and 39% the second year (about 72% over the first two years) North Dakota Department of Mineral Resources (2012) states even lower first year decline for the Bakken, 53%. The decline over two years, however, is 84%.

Table 12 shows a summary of the studies and compares the other studies with the results in this report (also shown in Table 11). The most extreme cases are omitted in Table 12 since regarded too exploratory and not very realistic.

Table 12. Summary of Eagle Ford shale oil production studies.

Reference	Peak production (Mb/d)	Peak year	URR (Gb)	URR/well (kb)
U.S. EIA (2014a)	1.5	2015-2020	3.35	80 - 334
Swindell (2012)				115
Maugeri (2013)	1.5	2017		< 600
Hughes (2013a), (2013b)	1.3-1.5	2017-2018	7.1-7.3	< 460
Rystad Energy (2014a)	1.7-1.8	2018-2019		
USGS (2012)				55
This report	1.4-1.9	2014-2019	5.13-10.4	123-257

7.5 Limitations of the study

The main constraint to the study is, as already mentioned, the limited length of the data set available. The first horizontal wells were drilled in the Eagle Ford in 2010 and for this reason the maximum length of production data sets is 4 years (48 months). This is too short to get a proper idea of production at later stages of the wells' lifetimes and how well the mathematical curves fit actually fit production at this later stage. Along with continued production long term production analysis will gain more accuracy.

The data set is further limited to include only wells that are reported individually. Production is commonly reported from several wells together. To be able to identify the production pattern of the formation, however, only production data from individually reported wells can be used. This constraint could be even more problematic in the future if it turns out that a larger share of the wells is reported together. The fact that an increasing amount of wells are drilled using pad-drilling, meaning that several wells are drilled from the same area at the surface, is a reason to suspect that production data for several wells together will be more common in the future.

8 Conclusion

The wells in the Eagle Ford shale play show a production pattern of peaking within a few months after initial production and declining steeply after the peak is reached. During the first year of production the decline is 75% and after two years production has decreased with 87% compared to the peak production, using the average decline curve. When taking the average of the individual decline curves the figures are similar, 75% decline the first year and 86% over the first two years.

Both the hyperbolic decline curve and the scaling curve fit well to the average production curve. The two curves generate similar results for the first years of decline and the data set in this study is too short to determine which of the curves that fits better in the long term. For the average decline curve the scaling curve reaches the interference time after eight months and is thereafter following an exponential decline of 6.2%.

Analysis of individual well decline shows that the hyperbolic fit is often harmonic or close to harmonic. The median values for beta and lambda of individual decline curves reflects aggregate decline better than the mean values.

Annual variations in first oil and peak production between 2010 and 2011 may be explained by improvements in technology and knowledge of the geology at the early stage of exploitation in the Eagle Ford. The decrease between 2012 and 2013 seems to be temporary and not caused by running out of sweet spots since there is and increase again in 2014.

The API gravity seems to affect decline, where wells with hydrocarbons of higher API gravity show a steeper decline than wells with lower API. However, another explanation for the variations in decline between different geographic areas may be variations in geology.

As expected, the scaling decline curve yields a lower estimate of URR than the hyperbolic decline curve. In addition to the decline, there are many parameters that are uncertain that affect the future projections of production rate and URR.

Potential health and environmental aspects are important to research further and may affect the spreading of shale oil and gas production outside of North America.

8.1 Scope for future work

This study is just a brief introduction to the analysis of oil production in the Eagle Ford. More research is needed in the area and there are many possibilities for deepening the study in the future. One aspect that has been omitted in this study is the economics. The results of the study will have implications on profitability of future production. If the resource and the productivity of wells are overestimated the revenue of the wells will be less than expected. An interesting research question to investigate is the historical profitability of shale oil wells in the Eagle Ford.

More in-depth analysis of the data set is also a field for future research. The data available in the Drillinginfo database is very extensive and a detailed coverage of the individual wells could reveal relations between variations in production pattern and location, geology, depth, etc.

Another development to the study is to implement more dynamics to the production projections by using the probability distributions of various parameters, from peak production to the λ and β decline curve parameters. This is a way to develop the complexity of the model to better cover variations within the play. In this study the variations were omitted for simplicity.

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Appendix A List of abbreviations

API	American Petroleum Institute
b/d, bbl/d	barrels per day
EIA	Energy Information Administration
IEA	International Energy Agency
mb, mbbl	million barrels
Mcf	thousand cubic feet
NGL	Natural Gas Liquids
URR	Ultimately Recoverable Resource

Appendix B Statistical distributions

B1 Statistical Distributions

Name of distribution	Parameters	Probability density function
Beta	α1 α2 a b	$f(x) = \frac{1}{B(\alpha_1, \alpha_2)} \frac{(x-a)^{\alpha_1 - 1}(b-x)^{\alpha_2 - 1}}{(b-a)^{\alpha_1 + \alpha_2 - 1}}$
Dagum	k α β γ	$f(x) = \frac{\alpha k \left(\frac{x-\gamma}{\beta}\right)^{\alpha k - 1}}{\beta \left(1 + \left(\frac{x-\gamma}{\beta}\right)^{\alpha}\right)^{k+1}}$
Gen. Pareto	k σ μ	$f(x) = \begin{cases} \frac{1}{\sigma}\left(1 + k\frac{(x-\mu)}{\sigma}\right)^{-1-1/k} & k \neq 0 \\ \frac{1}{\sigma}\exp\left(-\frac{(x-\mu)}{\sigma}\right) & k = 0 \end{cases}$
Log-logistic	α β γ	$f(x) = \frac{\alpha}{\beta}\left(\frac{x-\gamma}{\beta}\right)^{\alpha-1}\left(1 + \left(\frac{x-\gamma}{\beta}\right)^{\alpha}\right)^{-2}$

B2 Values of the Distribution Parameters Used in Chapter 5

Variable	Distribution	Parameter	Value
β	Beta	α_1	0.40126
		α_2	0.07171
		a	1.6823E-11
		b	1.0
	Gen. Pareto	k	-3.8792
		σ	5.1062
		μ	-0.30434
λ	Beta	α_1	1.7191
		α_2	11.835
		a	0.03055
		b	2.2842
First oil	Gen. Pareto	k	-0.10462
		σ	260.22
		μ	-4.0262
Peak production	Log-logistic	α	4.3539
		β	615.23
		γ	-145.94
First year decline	Dagum	k	0.17887
		α	68.687
		β	1.8165
		γ	-0.93735
Two years decline	Dagum (4P)	k	0.17116
		α	69198
		β	1042.1
		γ	-1041.1