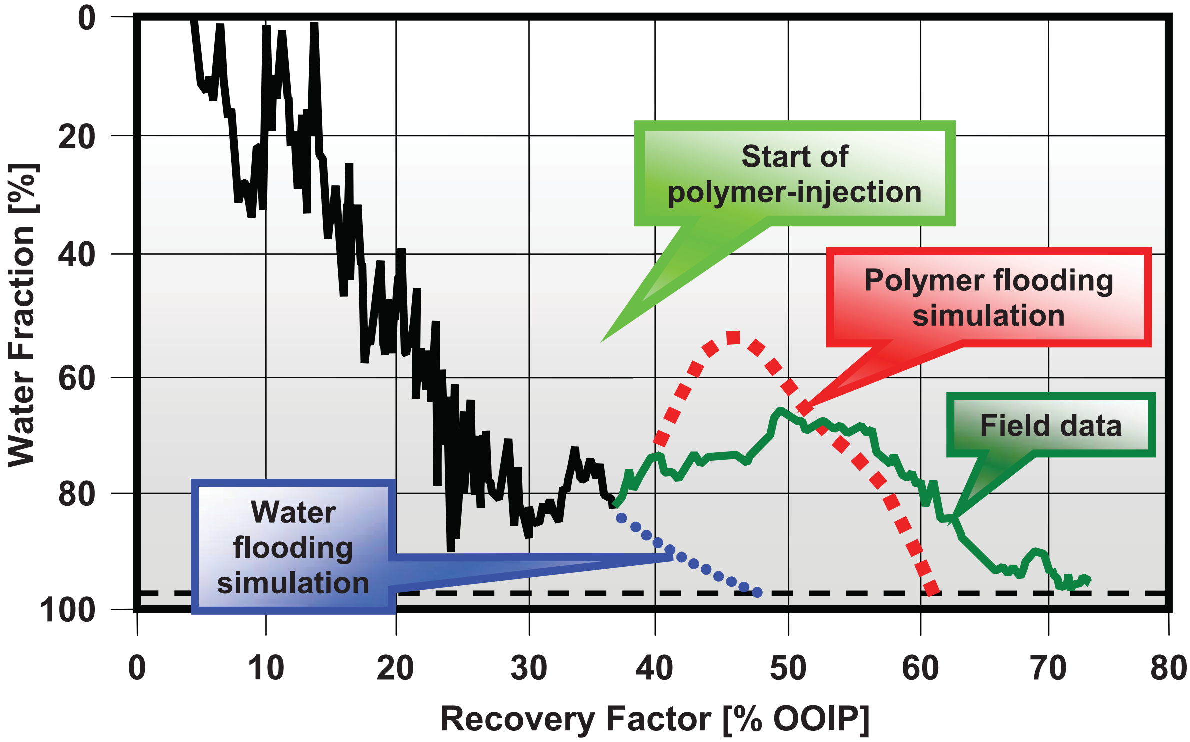
Oil Field “Mittelplate” – Assessment of EOR / IOR Possibilities in respect of Economical and Technical Boundary Conditions

Diploma Thesis



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Submitted to the

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December 2006

I declare in lieu of oath that I did this work by myself using only literature cited at the end of this volume.

Dominik Racher

Leoben, December 2006

Acknowledgements

I would like to thank O.Univ.Prof. Dipl.-Ing. Dr.mont Dr.h.c. Zoltán E. Heinemann for his help and guidance during the course of this work and the effort, commitment and enthusiasm he showed towards his students in the many years he was lecturing at the University of Leoben.

Furthermore, I would like to thank Dr. Curt-Albert Schwietzer, Dipl.-Ing Christian Jespersen, Dipl.-Ing. Thomas Kainer and all other members of the reservoir development oil department of the RWE Dea, for continuously supporting my work with enthusiasm and always having answers when I needed them.

Most of all, I want to thank my parents, my brother and my sister for their continuous encouragement throughout my years at the university.

Kurzfassung

Das Erdölfeld Mittelplate ist die sowohl bedeutendste als auch größte Erdöllagerstätte Deutschlands und befindet sich seit über 20 Jahren in Produktion. Aufgrund ihres Alters ist in den letzten Jahren das Interesse an einer Implementierung von „Enhanced“ und „Improved Oil Recovery“ (EOR und IOR) Methoden stetig gestiegen.

Das Ziel dieser Arbeit ist eine Evaluierung des EOR und IOR Potenzials unter der Berücksichtung von sowohl wirtschaftlichen als auch technischen Rahmenbedingungen, basierend auf den technischen Daten der Lagerstätte. Zu den Eckpunkten für diese Beurteilung zählen, auf anerkannte Literatur basierende, technische Selektionsverfahren und Studien technischer Schlüsselparameter wie dem minimalen Mischungsdruck.

Aufbauend auf den Resultaten der Selektionsverfahren wurde ein kommerzielles Programm benutzt, um mögliche EOR Methoden analytisch zu bewerten. Hierbei war das Ziel nicht nur die Anwendbarkeit, sondern auch die Potenziale möglicher Techniken beurteilen zu können.

Ein zusätzlicher Schwerpunkt der Arbeit war die ökonomische Bewertung eines Musterbeispiels für ein Chemisches EOR Verfahren, welches die größte technische Erfolgschance bietet. Hierbei wurde wiederum kommerzielle Software eingesetzt um den Firmenstandards des Feldbetreibers gerecht zu werden.

Basierend auf allen technischen und ökonomischen Bewertungen wurden Empfehlungen für eine Weiterführung des Projektes ausgesprochen, welche „Tracer“ Studien, Laboranalysen und Numerische Simulation für bestimmte Bereiche des Mittelplate Öl Feldes beinhalten.

Abstract

The Mittelplate field is the largest German oil reservoir and has been in production for more than 20 years. Due to its maturity there has been a rising interest from its operator to apply Enhanced and Improved Oil Recovery (EOR and IOR) techniques to the field.

The general objective of this thesis is the evaluation of EOR and IOR potential, considering technical boundary conditions implied through rock and fluid properties of the reservoir additionally to economical considerations. Corner points for this evaluation are technical screening studies, adapted from well known literature resources as Taber et al. or done through the application of commercially available software. To complement the screenings, different technical studies of key parameters, such as the minimum miscibility pressure, have been undertaken to improve the viability of the evaluation.

With the results from the screening processes a commercial software package was used to analyze possible EOR methods analytically, to judge not only the applicability but as well the performance potential of the different techniques.

Supplementary emphasis has been put into an economical analysis, based on a sample case, for a possible chemical project, which yielded the most promising technical results. Again commercial software was used to satisfy corporate standards.

Based on all economical and technical assessments, suggestions will be given on a continuative project plan including tracer studies, laboratory analysis and numerical simulations for a chemical injection project within certain areas of the Mittelplate oil field.

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Chapter 1

Introduction

1.1 Scope of Work

Interest in Enhanced and Improved Oil Recovery (in the course of this work abbreviated with "EOR" and "IOR") has been on a steady rise during the last couple of years. Due to the tremendous rise of the oil price, upstream companies in the whole world started to re-evaluate their assets in the hope for an increased oil production, to satisfy the demands of the open market. Germany's largest oil field, the "Mittelplate" field, has been as well a target of increased consideration from its operator. To clarify the possible applications of tertiary recovery methods, large literature surveys have been conducted to gasp the full range of possibilities for the different geological formations of the field. In the course of these researches, numerous meetings with young external scientists, laboratory and simulation personal as well as experienced members of the reservoir engineering departments took place, to question and discuss with them opinions, possible strategies and new developments. After the technical screenings, where raw data extracted from the simulation models and data sheets of the formations have been compared to key parameters of the different methods, supplementary calculations, as for the minimum miscibility pressures of CO_2 or N_2 miscible displacements, have been made and compared. Analytical pre simulations have been conducted afterwards to get a first feeling of the impact of the promising EOR methods and give base data for a detailed technical and economical evaluation of these techniques. The results of these studies have been used to suggest further tests and analysis for the continuing development of the project "EOR – Mittelplate".

The general objective of the thesis was the evaluation and screening for possible EOR / IOR mechanisms to apply on the "Mittelplate" oil filed. While an extensive literature research was conducted to scan for scientific developments and proven industrial screening criteria, the suggested methods have been examined and interpreted with analytical simulation tools and under geological, economical and technical aspects. Suggestions for further measurements and injection targets are made on the basis of these analyses.

1.2 Outline

Chapter 2 describes the results of the literature surveys. Traditional, specialized and unconventional EOR methods are presented and briefly discussed.

Chapter 3 gives an introduction about the general data of the Mittelplate oil field. Short overviews over the structural properties, the reservoir development up until today and the fluid and formation properties of all oil bearing horizons are presented.

Chapter 4 is a summary of the technical screening studies conducted during this thesis. Two different literature methods additionally to a software application have been used to evaluate the Mittelplate oil filed and their results are discussed.

Chapter 5 is comprised of analytical prediction evaluations. Commercial software capable of analytical simulation has been used to set up models for all Mittelplate horizons and judge possible additional recovery factors of different EOR methods.

Chapter 6 shows studies conducted for a detailed evaluation of the three promising EOR methods for the Mittelplate oil field. Geological, economical and technical studies are presented.

Chapter 7 gives a summary of this thesis work is presented and the main conclusions are drawn.

Chapter 8 gives an overview over abbreviations, conversion factors and the general nomenclature used in this work.

Finally, **Chapter 9** displays the list of the cited reference literature

Chapter 2

Literature Research on EOR / IOR Techniques

The literature research for this diploma thesis has been very extensive. Since the EOR / IOR market received a huge boost due to the increasing oil prices, many new projects are being reported in addition to many new scientific approaches. The following chapter tries to capture the multitude of techniques, definitions and mechanism and put them into a framework, giving a better overview on the current developments and provide a solid basis for the practical part of screening and evaluating.

2.1. Definitions

2.1.1. What is EOR / IOR and "tertiary recovery"

The definitions on what EOR exactly is, are various and very open to interpretation throughout the literature. This can be explained by the evolution of the term throughout its use during the last fifty years. After Green et al.[1], traditionally primary recovery can be regarded as production resulting from the natural displacement energy existing in the reservoir, where no measures to stabilize the pressure are necessary nor taken. Secondary recovery covers the use of water floods, pressure maintenance and hydrocarbon gas (re-) injection. Tertiary recovery introduces additional energy into the reservoir over chemical, thermal or physical means to further enhance oil recovery economically. Usually these mechanisms follow each other in a chronological sense. As mentioned by Green et al. and Taber et al.[2], traditional tertiary recovery made not always economical or technical sense to be applied last, as for example with extremely heavy oil reservoirs, and was thus applied already as secondary or even primary recovery method. Thus the term "Enhanced Oil Recovery" (EOR) got more accepted within the technical community for the application of advanced recovery mechanisms. Generally it can be said that EOR describes all processes formally named as tertiary or advanced secondary process, while in the more recent past the term "Improved Oil Recovery" has been introduced to describe an even broader spectrum, going from traditional secondary recovery to improved reservoir management or even infill drilling. As these methods are beyond the scope of this work, only traditional (mostly tertiary) EOR techniques will be taken into consideration.

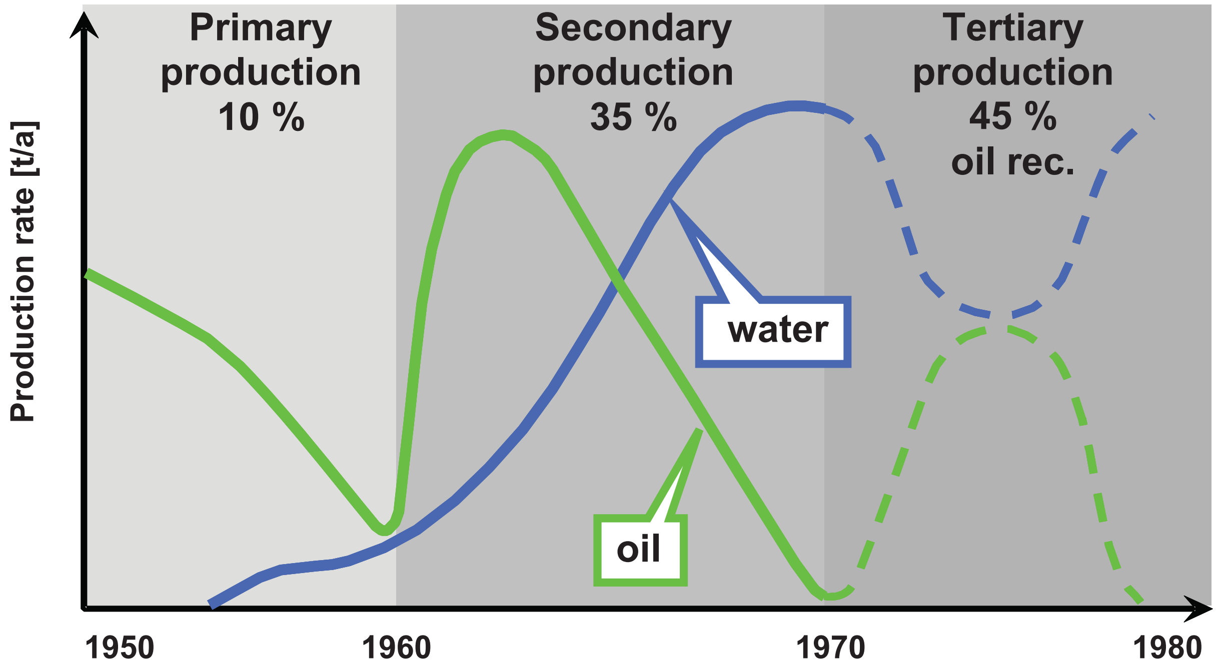

Figure 2.1.: Phases of Recovery[3]

2.1.2. Crude Oil Classifications, what is "heavy", "intermediate" and "light" Oil

The following definitions from the American Petroleum Institute (API) can be found, among others, in the literature[4,5]. For the course of this work this shall be the defining values:

Light crude oil is defined as having an API gravity higher than 31.1 °API
Intermediate crude oil is defined as having an API gravity between 22.3 °API and 31.1 °API
Heavy crude oil is defined as having an API gravity below 22.3 °API.

2.2. Mechanisms

All EOR techniques aim to overcome specific limitations in the reservoir to improve the oil recovery. Those can be either a very bad mobility ratio between the displacing and the displaced fluid due to high oil viscosity, a very heterogeneous reservoir (both in vertical and horizontal direction) or high interfacial tensions between the displacing phase and the oil phase. This chapter deals very briefly with the main mechanisms to improve or overcome the limitations named above.

2.2.1. Mobility Control

The mobility[1] of a fluid is based on the well known Darcy Equation. For calculation purposes the concept of the mobility ratio,

$$M = \lambda_D / \lambda_d \quad \text{………………………………………(1)}$$

is a very useful tool to evaluate the impact on the displacement process. It affects both areal and vertical sweep efficiencies, which decrease as M increases, as well as displacement efficiency. The displacement front becomes unstable once $M > 1$ which will lead to viscous fingering of the front. This situation is usually referred to as an “unfavorable mobility ratio” while $M < 1$ is “favorable”. Because of these aspects, control of the mobility ratio can be very beneficial for the displacement process, and can be achieved over different approaches like increasing the viscosity of water through the use of chemicals, or decreasing the viscosity of oil through thermal measures.

2.2.2. Alteration of Interfacial and Surface Tensions

Interfacial Tensions (IFT) between fluid – fluid or fluid – rock (so called surface tensions, ST) systems are key parameters for most EOR methods. IFT influence the capillary forces in the reservoir, which are key parameters (along with viscous forces) for the capillary number and thus have a major impact on the residual oil saturation or the entrapment of oil during a displacement process like water flooding.

The reduction of the IFT, or the enlargement of the dependent capillary number, between oil and water can considerably reduce the residual oil saturation and thus increase oil recovery. This mechanism is applied by chemical methods that use alkalis or surfactants ($\sigma_{OW} \approx 0.01$ dyne / cm) or by gas displacement methods which reduce the IFT to zero to achieve miscibility between the oil and the displacing gas phase (CO_2, LPG, N_2).

Another option is to alter the surface tensions between the reservoir fluids and the reservoir rock from an oil wet to a water wet system to mobilize the trapped residual oil through the application of chemical additives.

These techniques and their influences on the IFT’s of the fluid – fluid – rock systems are of a very complex nature and influence each other severely. These influences have been extensively discussed in the literature[1,6,7]. Recent advancements on the experimental side made IFT measurements between two fluids more practicable, and are helping a lot in the evaluation of these techniques[8,9].

2.3. Procedures

2.3.1. Chemical Methods

Chemical methods are based on the addition of chemicals into the injection water. They either enhance the viscosity of the drive water (and thus optimize the mobility ratio) or reduce the IFT. Multiple combinations of different chemicals are used to achieve these targets, which can be separated into the groups of alkalis, polymers and surfactants.

2.3.1.1. Polymer Flooding[10]

The addition of polymers into the injection water to enhance its viscosity and thus mobility is the prime target of this EOR method. Through the enhanced mobility ratio the volumetric sweep efficiency will be improved and oil from previously untouched parts of the reservoir will be produced. Although it must be mentioned that polymer flooding does not reduce the residual oil saturation, but accelerates the time necessary to reach the economic limit of a project (see analysis later in this work). The recovery mechanism is solely based on mobility control. Common practical application of this method is the injection of a slug (50 – 100 % of the pore volume) with a few hundred milligrams polymers, such as for example polyacrylamides or polysaccharides (biopolymers), per liter of injection water. The polymer concentration is slowly decreased over time to prohibit viscous fingering of the drive water.
Special care has to be taken with the degradation of polymers due to heat, reservoir brine salinity, chemical adsorption, stability over time, clay content or bio degradation. Injectivity of the solution can be a major problem due to its high viscosity and possible damage of the polymers through shear in the perforations. Generally a pressure drop in the reservoir can be assumed after the beginning of a polymer injection project due to the higher viscosity of the injection water. Values as the Residual Resistance Factor (RRF) and the Resistance Factor (RF) are as well key parameters of polymer floods which need to be checked by laboratory measurements.
Polymer Flooding is a proved EOR method since decades and thus plentiful literature exists that describes all major technical aspects, economics, and future outlooks[11]. Y. Du[12] and L. Guan recently published a paper about experiences gained from the last 40 years of polymer flooding, which offers a nice overview about this topic. B. K. Maitin offers an overview of all polymer floods conducted by RWE Dea[13]. The most prominent and successful international showcase for polymer injection is the Daqing oilfield in the Peoples Republic of China.

2.3.1.2. Chemical Combination Flooding[1]

Other chemicals aiding the recovery process are surface active agents (surfactants) and alkaline agents. They do not have an impact on the mobility ratio within the reservoir but improve recovery through the reduction of IFT. The main differences between these two chemicals are that alkaline agents have very high pH values (they react with the organic acids of the crude oil to form surfactants, while regular surfactants are injected with the displacing water) and the improved economics of alkalis due to their lower cost. The most common form of surfactants is made up of a hydrophilic and a lipophilic part, which connect themselves to the aqueous and oleic phases and thus reduce the IFT between oil and water. As well a reduction of the surface tensions between the reservoir fluids and the reservoir rock can be achieved, changing the wettability to a more favorable condition and reduce the residual oil saturation even further.

The injection procedure[6] consists of a preflush, which may include sacrificial chemicals and sweet water to compensate for possible salinity problems and adsorption, followed by the alkali slug, the actual surfactant slug, where co surfactants such as alcohols might be added to improve the efficiency even further, a polymer mobility buffer, a taper to reduce viscous fingering by the drive water and finally the injection water to drive the front through the reservoir.

Multiple setups of chemical combination floods are possible, examples might be alkaline – polymer floods, surfactant – polymer floods (also called micellar or low tension floods) or alkaline – surfactant – polymer floods (ASP Floods), as required by the reservoir or intended by the responsible engineers.

The necessary precautions which must be taken for chemical combination floods are very similar to those for polymer floods like injectivity, degradation and proper mixing of the chemicals.

2.3.2. Gas Injection Methods[1]

Gas injection methods for EOR purposes are all, so called, “miscible” processes. These techniques use special injection gases to reduce IFT with crude oils, under specific conditions, to zero and thus achieve miscibility. Generally two types of miscibility can be distinguished, one being “First Contact Miscibility (FCM)” and the other “Multiple Contact Miscibility (MCM)”. With FCM a single phase is established at the first contact between the displacing gas and the crude oil, while with MCM miscible conditions are generated by in situ composition upgrading of either the displaced or displacing phase. The reservoir pressure, at which miscibility is achieved, is referred to as the "Minimum Miscibility Pressure (MMP)". This pressure is largely dependent on the composition of the crude oil and the injection gas and the reservoir temperature. As experimental determination of the MMP is an unstandardized laboratory process, which is difficult and expensive to undertake (slim tube tests), a wide range of correlations exists to describe it approximately. Much care has to be taken with these calculations as they usually have only a very narrow range of applicability.

2.3.2.1. CO_2 Injection

CO_2 injection is the most productive gas injection EOR method applied world wide. Especially in the USA multiple large field projects are conducted due to the large availability of cheap CO_2. The recovery mechanisms of CO_2 are manifold. It has a very low IFT with crude oil (depending on oil composition), which even vanishes at most reservoir pressures and temperatures and subsequently forms MCM. Other recovery mechanisms include the swelling of crude oil due to CO_2 going in solution, which can increase the volume by 30 %, and the reduction of crude oil viscosity. The most important parameter is the MMP, for which a large number of correlations exist in the literature[14,15]. Special caution must be taken when the injected CO_2 contains impurities, such as methane, as these can have a considerable influence on the required pressure. The main problems of CO_2 injection are the possible asphaltene precipitation, corrosion problems during injection and production and gas reconditioning.

Injection strategies for CO_2 floods usually consist of the CO_2 injection (15% hydrocarbon pore volume or more[16]) followed by the chase water. Very often WAG strategies are applied to reduce viscous fingering and improve mobility of the injection process.

2.3.2.2. Hydrocarbon Gas Injection[2,15]

Three different methods of HC injections are practiced in the field[17]. Liquefied Petroleum Gas (LPG) uses the concept of FCM and is usually injected with dry gas and / or water in a WAG mode. Enriched or Condensing Gas Drive is natural gas enriched with higher components (such as ethane to hexane) which are transferred during the displacement process to the crude oil. The slug is as well followed by dry gas and / or water. High pressure or Vaporizing Gas Drive consists of dry gas (mostly methane) which is injected at a very high pressure to strip (or vaporize) the crude oil of its light and intermediate components. Both the High Pressure and the Enriched Gas Drives are MCM processes.

The recovery mechanisms are different for the three methods and range from the miscibility concept over oil swelling to viscosity optimization. The most critical parameters are the MMP, process economics due to injected hydrocarbon prices and mobility problems.

2.3.2.3. N_2 Injection

The biggest benefit of nitrogen injection is the price. Because of the low cost it is possible to inject large volumes for displacement, or even fill portions of the reservoir with it for pressure support. It recovers additional oil by vaporizing the lighter crude oil components (similar to the High Pressure Gas Drive) and can achieve miscibility. However, the needed MMP pressure is the highest within the traditional gas injection methods and thus very hard to achieve with heavier oils or shallower reservoirs.

2.3.3. Thermal Methods[1]

Thermal methods have been developed to produce heavy to extra heavy crude oils (bitumen) and usually apply the principle of mobility control. Introduction of thermal energy via combustion or steam injection into the reservoir decreases the viscosity of the oil and thus makes it more mobile and produceable. World wide four different thermal methods developed into economically feasible processes, namely Forward In Situ Combustion (ISC), Steam Cycling (also called Huff and Puff), Steam Flooding and Steam Assisted Gravity Drainage (SAGD) which will be discussed in the following chapter.

2.3.3.1. In-Situ Combustion (ISC)

In-Situ Combustion (also called Fire Flooding or Air Injection) can be divided between the forward and the reverse combustion (similar to Huff and Puff steam injection) processes, where only the forward combustion will be discussed in detail. The simplified principle is to inject oxygen or air (due to cost reasons) into the reservoir and ignite it. The reactions between the oxygen and the crude oil in place (usually around 10% of the OOIP will be burned, heavy hydrocarbons are preferred) form a very high temperature front which is propagated, depending on the injection rates, throughout the reservoir. The temperature ranges from 150 °C to 300 °C for High Pressure Air Injections (HPAI), which is predominantly used in light oil reservoirs, and 450 °C to 600 °C in heavy oil reservoirs. These high values are necessary to animate the, for the effective recovery important, “bond scission” reactions where oxygen breaks the hydrocarbon molecules and forms water and CO_2. Other recovery mechanisms include mobility control, due to increased crude oil temperature (reduced viscosity), oil swelling and near miscible displacement due to CO_2 in situ generation and pressure support due to the injected air. A variation of the classic dry forward combustion is the "combination of forward combustion and water flooding" (COFCAW) which has similar effects as the WAG technique.

Key parameters of the process include the process temperature for efficiency control, air injection rate to keep the combustion alive and control the advancement, air injection pressures and produced flue gas. A variety of laboratory measurements like flue gas analysis (CO and O_2 determination) exist which help to judge the effectiveness of this EOR method.

Currently several field applications are underway, as the very mature Suplacu de Barcau project in Romania[18] or several projects in the red river formation in North and South Dakota, USA[19].

2.3.3.2. Steam Injection

Steam injection is the most productive EOR method world wide with a production of more then 600,000 bbl oil per day (2004)[20]. There are three major techniques covering steam injection, which include Steam Cycling, Steam Flooding and SAGD.

The recovery mechanisms of these methods are the mobilization of the crude oil through the introduction of heat, steam distillation of the crude oil and pressure support. In general steam injection is only applied to heavy or extra heavy oil reservoirs which are shallow. The reason for this can be found in the phase diagram of water, since steam only exists physically at pressures of up to 221 bar with a temperature exceeding 374 °C[21] as shown in Figure 2.2.

Steam Cycling (also called Steam Stimulation, Huff and Puff or Steam Soak) is a technique applied to a single well. For a few weeks steam is injected into the well, which is then shut in to let the steam soak into the formation, followed by a production phase. With every conducted cycle the amount of oil recovered will be decreasing, until the economic limit is reach. Once that is the case, these producers are usually converted to full time injectors for a following steam field flood project. It has also been reported that producing wells of a steam flood project applied the huff and puff technique as well to maximize crude oil recovery.

SAGD is a special technique developed for the tar sands in Canada. It is based on the application of two horizontal wells, which are separated vertically by a few meters. The structural higher well injects steam into the reservoir, which heats the crude oil and displaces it via gravity drainage to the lower production well. The design of this technique is very similar to the VAPEX method.

Key parameters for steam injection projects are thermal conductivities of the well and the reservoir formation (to maximize heat transfer to the crude oil), reservoir temperature and pressure to ensure the existence of steam in situ and design appropriated injection conditions, the energy balance between crude oil required for steam generation in opposition to the amount produced additionally, water supplies, ecological parameters such as flue gas generation while steam production and possible environmental impact on the surface when operating in very shallow reservoirs.
Steam injection techniques have been applied since decades in the Californian Kern County heavy oil fields, but the most impressive and successful project until today is the Duri[22] Steam Flood in Indonesia with a production of over 200.000 bbl oil per day.

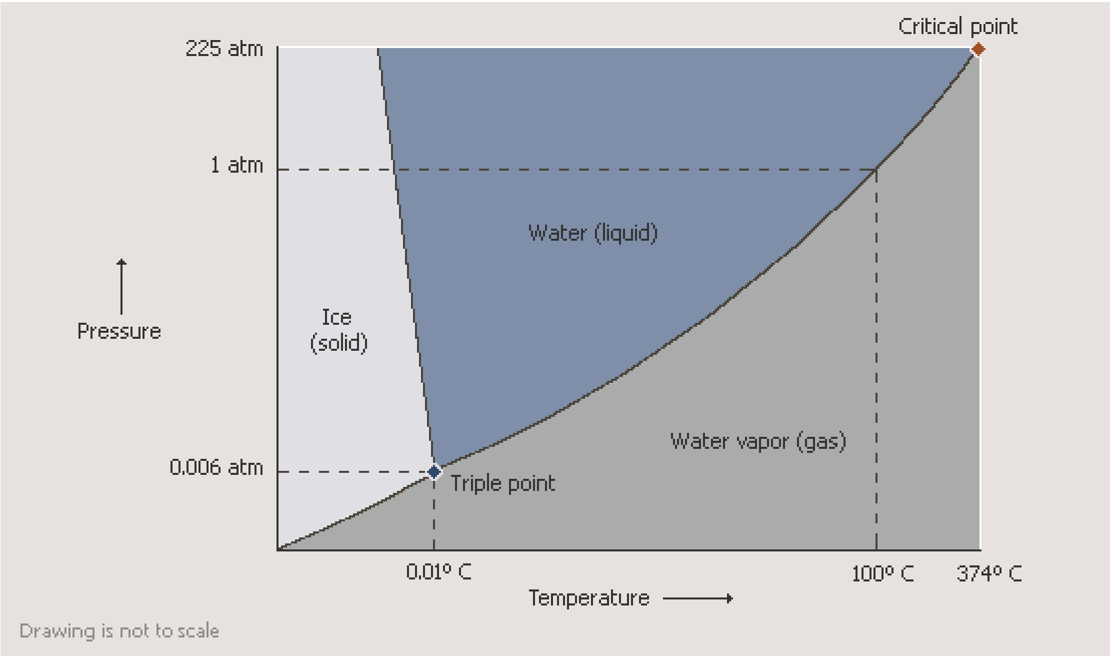

Figure 2.2.: Phase Diagram of Water[23]

2.3.4. Other Methods

Additionally to the traditional EOR methods named above, different specialized methods have been developed, such as VAPEX or CHOPS, for heavy oil recovery. Besides those specializations, major research initiatives from companies, universities or governments developed completely new EOR concepts such as MEOR or the application of microwave technology for enhanced oil recovery. A short overview over recent developments is presented in the following chapter.

2.3.4.1. Cold Heavy Oil Production with Sand (CHOPS)

CHOPS is a primary production technique developed for the extra heavy tar sands in Canada. Through the use of progressive cavity pumps the reservoir is produced from the beginning with big sand cuts of up to 50% in volume. Over the course of a year, the sand cuts slowly reduce to approximately 1 - 5% and stay at this levels for the ensuing years. Due to the large amount of sand production in the beginning, so called worm holes may form within the formation. They enhance the effective permeability and the well radius of the borehole and thus have a positive impact on production. Another possibility, depending on the reservoir pressure and the gas in solution, is the appearance of foamy oil. Foamy oil describes a special consistency of the crude oil, which occurs when gas is coming out of solution but stays trapped within the fluid phase due to the extreme viscosities. Due to this condition, the crude oil is improved in his flowing capability which benefits production of the reservoir.

Another positive effect of chops is the generation of flow paths for a possibly following steam injection project, as described in SPE paper 58773[20].

2.3.4.2. Low Salinity Enhanced Oil Recovery (LoSal)[24,25]

In a recent SPE paper, McGuire et al. suggested the use of LoSal EOR in oil fields with high salinity reservoir brines, like for Alaska’s North Slope. Instead of the produced reservoir brine sweet water with very low salinities (below 5000 ppm) are injected into the reservoir. The recovery mechanisms for this technique seem to be very similar to alkaline floods. Due to the very low salinity of the injection water and thus very high alkalinity or pH value, the injection water reduces the IFT between oil and water, increases the water wettability of the reservoir and generates surfactants due to saponifying of acid components in the crude oil. Experiments on Berea core samples show a considerable increase of recovery. Another possible mechanism is the detachment of mixed-wet clay particles from the pore walls.

However, the presence of a large sweet water supply with fitting parameters is imperative for this EOR method. Additionally it is unsure if conducted laboratory research can be scaled up to reservoir conditions, thus future work on this newly considered EOR method will be very important.

2.3.4.3. Microbial Enhanced Oil Recovery (MEOR)

In the last decade a lot of scientific work in regard to MEOR has been conducted worldwide, trying to advance this technique from the laboratory to successful field application. Bryant[26] and Lockhart published a study describing the reservoir engineering aspects of MEOR, incorporating an analysis of possible methods and reactions and suggesting formulas for analytical evaluation and process calculations.

MEOR is a technique developed in the 1970's to 1980's, seeking to recover additional oil by the application of microbes. There are several different ways to achieve this, and several possible recovery mechanisms which might be employed. The basic idea is to have the microbes generating chemicals or gases, such as surfactants or CO_2, in situ and thus achieve a cost optimization and easier designs due to the lack of surface equipment. An alternative option is the plugging of thieve zones due to biomass generation.

Key parameters for the application of microbes are the microbial reactor type, the carbon source, microbe provenance and reservoir conditions such as temperature, salinity and pressure.

The main issue with MEOR is the lack of descriptive field tests, which have not only been technical successful, but as well economical viable projects. The US Department of Energy recently conducted a study[27] to increase efficiency of MEOR projects, but more research has to be conducted until this method can be regarded as adequately described and commercially promising.

2.3.4.4. Microwave Enhanced Oil Recovery

A very new EOR approach, getting a reasonable amount of attention lately, is the possibility of applying microwave radiation in a reservoir. The mechanisms of this technique are not completely understood yet, but seem to be composed out of heating and cracking mechanisms, depending on the existence of a catalyzer within the formation. There already exist sample laboratory experiments, where crude oil was cracked and possible reactions, implied through plasma discharges, have been described[28]. The technique itself has a wide range of application, from thermal cracking mechanisms in oil refineries, cuttings upgrading in drilling engineering, heating oil for better pumping properties in pipeline engineering to possible in situ application for EOR in reservoir engineering. Due to these reasons, American research institutes, as the US Department of Energy in its "Cold Cracking Report"[29], have been picking up this topic. New start-up business companies formed to develop this technique even further, while bigger E&P companies are evaluating possible applications[30]. However, more fundamental research needs to be conducted to achieve commercial viability.

2.3.4.5. Sonic Enhanced Oil Recovery (SEOR)

SEOR, as microwave EOR, is another exotic idea being picked up again due to the large EOR potential deriving from the high crude oil prices. The basic mechanism is a mobilization of residual oil in the pore throats (so called ganglia) through the application of seismic waves. An U.S. Department of Energy project was conducted to formulate a theoretical background for SEOR and conduct field testing[31]. Application possibilities have been outlined to be reservoirs with shallow depth, water flooded with a water saturation of 90% percent or higher and low crude oil viscosity. Emphasize must be taken to select optimal resonant frequencies to maximize the mobilization effect. Furthermore there have been reports of experiments conducted in the former U.S.S.R., but the literature was, if reported, in Russian and very hard to find and thus not further tracked.

2.3.4.6. Vapor Extraction (VAPEX)[32]

VAPEX is an EOR method very similar to SAGD. It originates, as well, from the Canadian oil sand production and got developed as an alternative to SAGD. Main reason for the development is the increasing lack of fresh water supplies for steam projects, but large enough natural gas resources exist in the region allowing a different approach.

The concept behind VAPEX involves, as with SAGD, the drilling of two horizontal wells in close vertical distance. However, instead of injecting steam into the structural higher borehole to mobilize the heavy oil, hydrocarbon gas is used. After injection it diffuses into the crude oil, enhancing its viscosity and thus mobilizing it. The upgraded crude oil is then displaced by gravity drainage towards the structural lower well and produced.

One main design consideration of VAPEX is the fact that molecular diffusion works much slower then thermal, which is its main disadvantage compared to SAGD. However, it is possible to equalize this problem by drilling longer horizontal wells to maximize reservoir contact and enhance VAPEX production rates.

2.3.4.7. Gel Applications[1]

Reservoir heterogeneities are a major reason for low recovery factors. Special attention has to be given to high permeability layers, so called “thief zones”, which take most of the injected fluid. These zones can put every EOR / IOR technique in danger and reduce severely the volumetric sweep efficiencies. One solution technique to fight these zones is the injection of cross-linking polymer solutions, which form in situ gels of considerable strength and thus reduce the effective permeability and divert the injection stream towards the lesser flooded areas. An important parameter for the application of this method is the vertical permeability between the different layers in the reservoir, since they can considerably reduce the efficiency of the gel placement.

Different procedures, depending on the used polymer system, exist for gel placements. One option is to inject the chemicals (polymers and cross linking agents) as separated slugs into the reservoir. Another method is the mixing of the chemicals during the injection, effectively starting the gel formation in the reservoir, while for the last option (often used with biopolymers) the solution is already mixed in a surface tank. During this option the gel formation starts already in the tank, but the solution remains pumpable, until reaching the reservoir formation. Time management is of importance with this technique, similar as with cement placement.

2.3.4.8. Foam[1]

Foam offers a wide range of applications within IOR and EOR. It consists of a large volume of gas in a much smaller volume of liquid, generated usually through the use of a foaming agent (surfactant). It can be used for:

- Blocking or restricting flow of unwanted fluids such as water or gas during coning problems
- Profile modifications (plugging of thief zones, similar to gels, for a better propagation of injection fluids)
- Mobility control of an injected gas phase (similar benefits as WAG techniques)

Usually only a very small volume (a few percent) of the foaming agent is needed to achieve the desired effect. However, care must be taken with its application due to the large pressure losses over the occupied volume.

2.3.4.9. Combined Approaches

Another direction to maximize oil recovery even further has been the idea of combining traditional EOR techniques. Castanier and Kovscek[33] presented the idea of using a combination of solvents and in-situ combustion to increase heavy oil recovery in Canada and Venezuela in a cyclic injection process. Another publicized method is the combination of VAPEX and SAGD in a steam-propane trial for the well known Duri field in Indonesia[34], where pilot tests have been pretty successful.

Combined approaches of different EOR methods offer a wide range of possibilities and applications and their boundaries have yet to be determined.

Chapter 3

Mittelplate Data Overview

The following chapter will give a short overview over the known data of the Mittelplate oil field. Structural maps for geological information, a short overview of the already drilled wells and a summary of the formation fluid and formation rock data will be given.

3.1. Geological Overview

The Mittelplate oil field is situated about 100 km northwest of the city of Hamburg in the estuary mouth of the river Elbe. This location is a big challenge for the field development due to two reasons. First the Elbe serves as an important international shipping route to one of Europe's biggest commercial harbors located in Hamburg and secondly the area operated in belongs to the Wadden Sea National Park. These circumstances call for special care in environmental protection and make the placement of additional drilling rigs or pipelines for EOR projects extremely difficult.

Geologically the Mittelplate field is situated in the Westholstein Jurassic trough along the Büsum salt dome. The five oil bearing horizons range from the Lowest Cretaceous Wealden formation to the Jurassic Dogger formation where the beta, gamma, delta and epsilon horizons are being produced. Each of the horizons is composed out of different productive sands. The depth ranges from 1900 meter below sea level (Wealden) to about 3000 meter (Dogger beta), where the Dogger beta formation is, with an area of more than 60 km², by far the largest horizon.

3.1.1. Structural Overview

The following structural maps give a good overview over the Mittelplate field. Special note should be given to the south of the Dogger beta formation, where a large number of faults emerge from the Büsum salt dome. They start out at a 90 degree angle from the dome and slowly turn towards the south of the reservoir where they continue in an approximate parallel fashion to each other. Additionally the high reservoir dips of the gamma, delta and epsilon formations towards the salt dome should be highlighted.

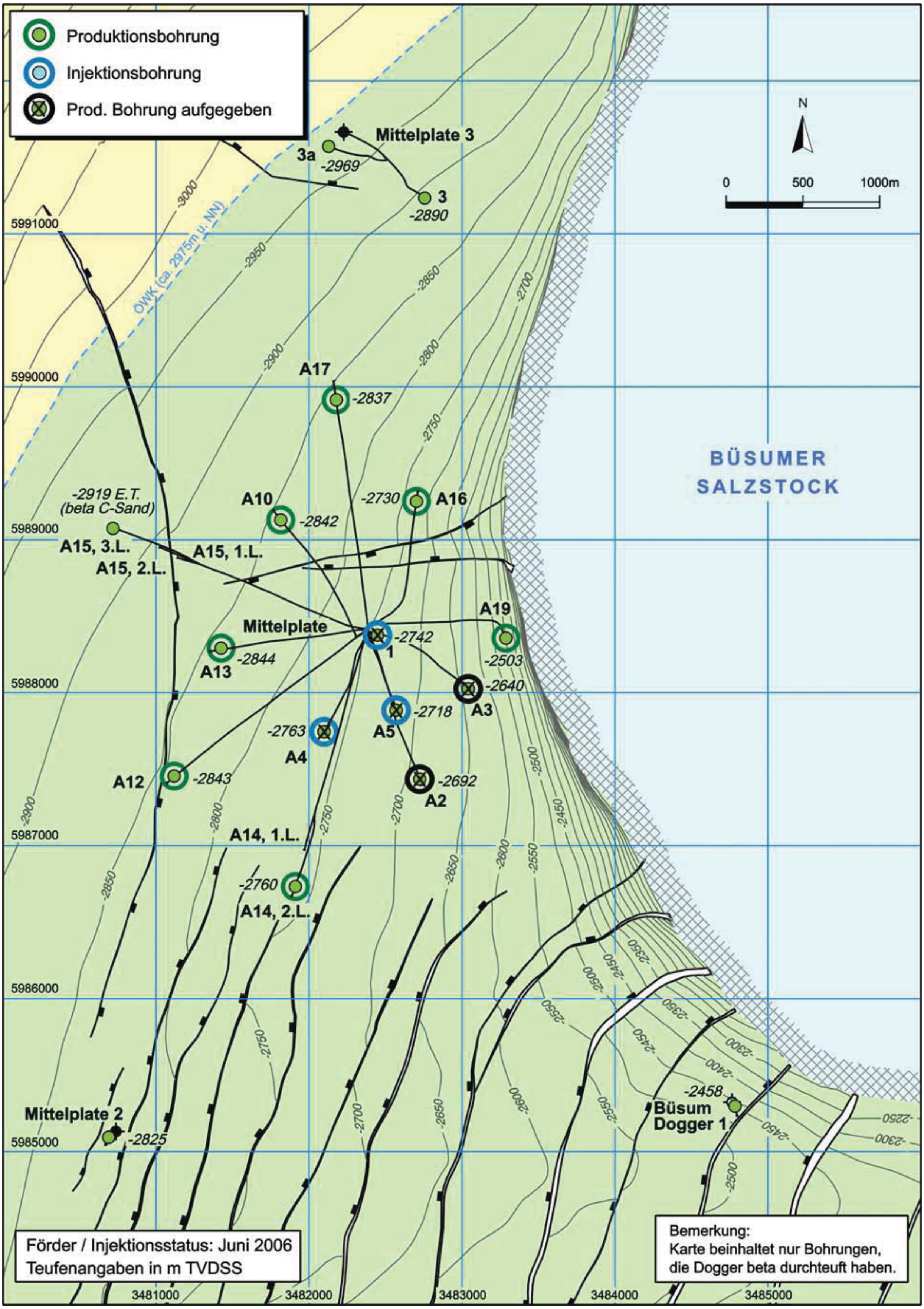

Figure 3.1.: Structural map of the Dogger beta formation

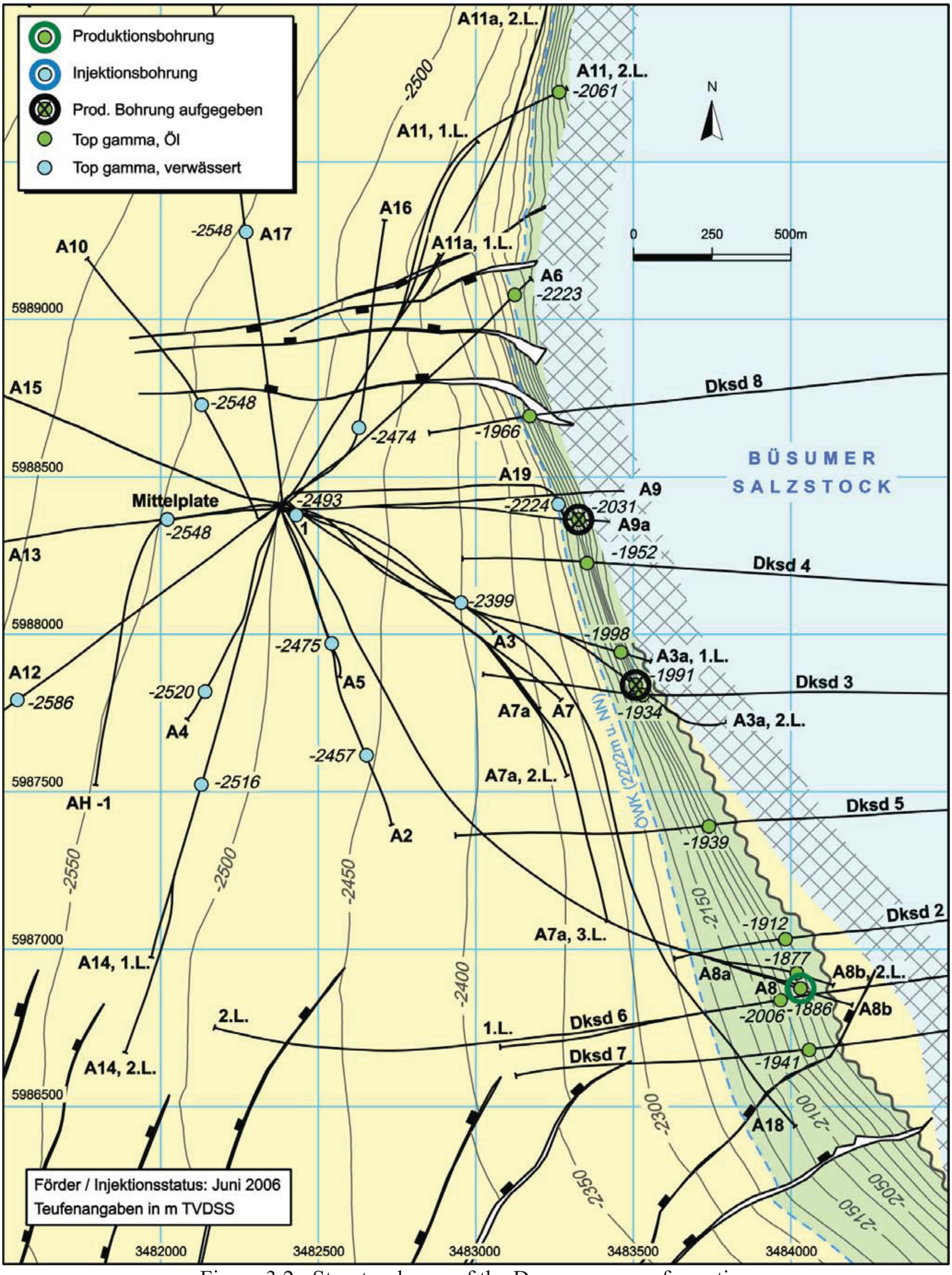

Figure 3.2.: Structural map of the Dogger gamma formation

Figure 3.3.: Structural map of the Dogger delta formation

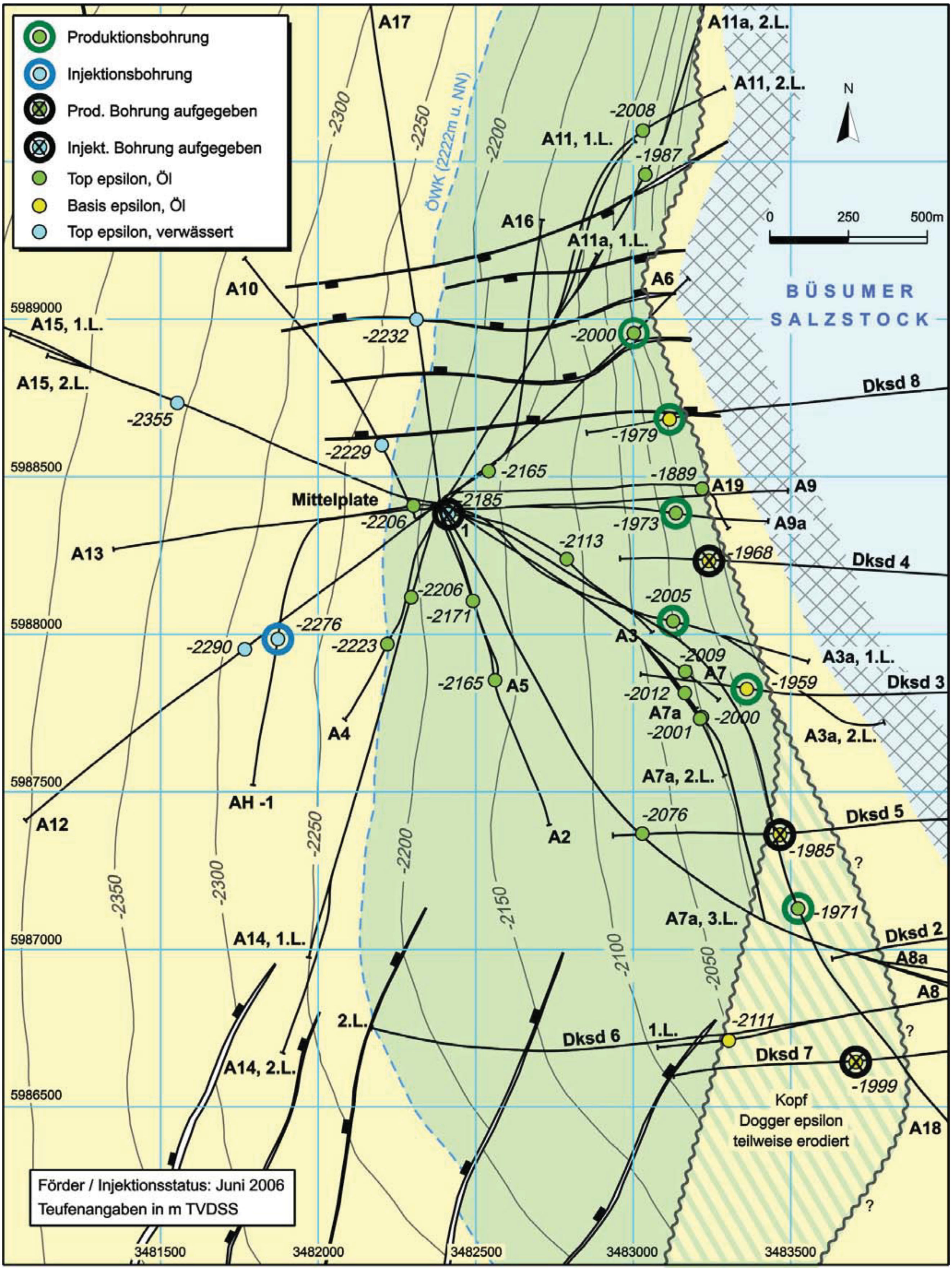

Figure 3.4.: Structural map of the Dogger epsilon formation

3.2. Technical Overview

3.2.1. Dogger Beta Formation

The initial development plan for the largest Mittelplate horizon, the Dogger beta formation, started with a 5 spot scheme in the central area around the Mittelplate 1 exploration well. Currently, as can be seen in the structural maps above, the wells 1, A4 and A5 serve as water injection wells for pressure support, while the wells A3 and A4 have been liquidated due to economic reasons. The general field development plan follows the intention to drill producers in a circular pattern around the initial 5 spot scheme, as can be seen by the producers A10 to A19. All producers are equipped with electric submersible pumps to enhance productivity.

3.2.2. Dogger Gamma Formation

The Dogger gamma formation is the smallest Mittelplate horizon and thus offers only very limited development possibilities. Currently only one well is producing from this formation, the well A8b, while pressure supply is provided by an active water aquifer. The production wells A9a and A3a have been liquidated. The main potential for development lies within the southern region of the horizon, which is separated from the north by a large fault. The production well is, analogues to the beta wells, equipped with an electric submersible pump.

3.2.3. Dogger Delta / Epsilon Formation

Due to the hydrodynamic contact between these two formations, they will be regarded as one horizon in the course of this study. They share the water oil contacts (WOC), initial reservoir pressures and their wells show pressure responses induced from water injectors of both horizons. A complete list of producers and injectors can be found in appendix A in tabular form. One of the most interesting aspects about these formations is that the production wells are mostly extended reach wells drilled from the onshore location Dieksand, while the injection wells are based out of the Mittelplate offshore platform. The horizontal well AH-1 serves as the main water injector and injects directly into the active aquifer to support the pressure and dispose produced formation water. The flow paths within the horizons are not yet fully understood, but are research targets of a tracer study, which is planned for the coming year. Possible flow paths will be discussed later in this study.

Analogue to the production wells in the other horizons, all Dieksand production wells have electrical submersible pumps installed.

3.3. Fluid and Formation Properties

Reservoir Parameter	Unit	Beta			Gamma			Delta			Epsilon		
		Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean
Anisotropy	-	0,76	0,76	0,76	0,0022	0,0022	0,0022	0,49	0,49	0,49	0,31	0,31	0,31
Clay Content	%	12	37	25	12	37	25	10	32	21	7	30	18
Current / Initial Oil S.	-	0,33	0,47	0,40	0,50	0,63	0,56	0,36	0,48	0,42	0,42	0,54	0,48
Current Oil Saturation	%	25 / 75	35 / 75	30 / 75	40 / 80	50 / 80	45 / 80	30 / 84	40 / 84	35 / 84	35 / 84	45 / 84	40 / 84
Depth	m	2400	2975	2750	1900	2222	2050	1900	2222	2050	1900	2222	2100
Formation Type	-	Sandstone			Sandstone			Sandstone			Sandstone		
High / Low Perm. Ratio	-	15	15	15	8,33	8,33	8,33	20	20	20	20	20	20
Oil Density @ R.C.	kg/m³	885	895	890	850	860	854	865	875	871	855	865	861
Oil Density @ S.C.	kg/m³	935	945	940	895	915	900	910	920	913	910	920	913
Oil Gravity	°API	18,24	19,84	19,03	23,14	26,60	25,72	22,30	23,99	23,48	22,30	23,99	23,48
Oil Viscosity @ R.C.	mPa.s	27	29	28	6	8	7	11	12	11,5	11	12	11,5
Oil Viscosity @ S.C.	mPa.s	1700	1900	1800	100	150	125	200	300	250	200	250	225
Permeability	mD	200	3000	390	60	500	375	500	10000	1572	500	10000	854
Porosity	%	15	24	20	22	25	24	17	27	24	22	25	24
Reservoir Pressure	Bar	215	245	235	175	210	200	150	180	170	150	180	170
Temperature @ R.C.	°C	82	82	82	69	69	69	69	69	69	69	69	69
Thickness	m	6	17	15	30	50	40	40	60	50	20	30	25
Water Salinity	g/l or kg/m³	115	125	120	225	235	230	220	230	225	220	230	225

Reservoir Parameter	Unit	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean	Min	Max	Mean
Anisotropy	-	0,76	0,76	0,76	0,0022	0,0022	0,0022	0,49	0,49	0,49	0,31	0,31	0,31
Clay Content	%	12	37	25	12	37	25	10	32	21	7	30	18
Current / Initial Oil S.	-	0,33	0,47	0,40	0,50	0,63	0,56	0,36	0,48	0,42	0,42	0,54	0,48
Current Oil Saturation	%	25 / 75	35 / 75	30 / 75	40 / 80	50 / 80	45 / 80	30 / 84	40 / 84	35 / 84	35 / 84	45 / 84	40 / 84
Depth	ft	7874	9760	9022	6234	7290	6726	6234	7290	6726	6234	7290	6890
Formation Type	-	Sandstone			Sandstone			Sandstone			Sandstone		
High / Low Perm. Ratio	-	15	15	15	8,33	8,33	8,33	20	20	20	20	20	20
Oil Density @ R.C.	lb/ft³	55,25	55,87	55,56	53,06	53,69	53,31	54,00	54,62	54,37	53,38	54,00	53,75
Oil Density @ S.C.	lb/ft³	58,37	58,99	58,68	55,87	57,12	56,19	56,81	57,43	57,00	56,81	57,43	57,00
Oil Gravity	°API	18,24	19,84	19,03	23,14	26,60	25,72	22,30	23,99	23,48	22,30	23,99	23,48
Oil Viscosity @ R.C.	cP	27	29	28	6	8	7	11	12	12	11	12	12
Oil Viscosity @ S.C.	cP	1700	1900	1800	100	150	125	200	300	250	200	250	225
Permeability	mD	200	3000	390	60	500	375	500	10000	1572	500	10000	854
Porosity	%	15	24	20	22	25	24	17	27	24	22	25	24
Reservoir Pressure	psi	3118	3553	3408	2538	3046	2901	2176	2611	2466	2176	2611	2466
Temperature @ R.C	°F	179,6	179,6	179,6	156,2	156,2	156,2	156,2	156,2	156,2	156,2	156,2	156,2
Thickness	ft	20	56	49	98	164	131	131	197	164	66	98	82
Water Salinity	ppm	115.000	125.000	120.000	225.000	235.000	230.000	220.000	230.000	225.000	220.000	230.000	225.000

Table 3.1.: Overview of Mittelplate Fluid and Rock Data

Table 3.1 shows an overview of averaged reservoir rock and fluid parameters for each of the Mittelplate horizons. The parameters chosen for this table represent all necessary data needed for the application of quick screening tools for EOR methods. Several of those tools have been applied to the Mittelplate field and will be described in detail in the next chapter.

The data has been compiled from different sources within the operating company, consisting mainly of the Eclipse models of the different formations, the data handbook for the Mittelplate field, several PVT Reports of the crude oils and analyses (such as formation water tests) from the E&P Laboratory.

The data represent here shows mean, low and high values for several parameters and is dated with **September 2006**. Obviously several parameters, such as the average reservoir pressure or saturations, are expected to change over time.

Table 3.2 gives and overview of other initial reservoir properties such as pressure or OWC. Diagrams for the formation volume factors and the viscosity of the crude oils are presented in appendix B.

	Beta	Gamma	Delta / Epsilon
Initial Pressure [bar]	304,5	233,5	233,5
Area [km²]	60	1	8
OWC [m]	2975	2222	2222

Table 3.2.: Various other important initial reservoir properties

Chapter 4

Technical Screenings for EOR Methods

The first step in the assessment of possible EOR methods for the Mittelplate oil field was the employment of technical screening studies. After an elaborate literature research and a survey of commercial software for this application, the guidelines of Taber et al.[2] and Al-Bahar[35] et al. have been chosen additionally to a software package, which features an applicability screening and the possibility of analytical simulation. Unconventional EOR methods are screened after various other literature sources. Additionally studies of critical parameters have been carried through to improve the viability of the assessment.

In general a color coding principle has been applied to all screening studies, marking data in the required reference interval green and data outside the interval red. Borderline cases have been marked yellow, N.C. stands for not critical. It must be said that all given applicability ranges for EOR methods are derived from published field cases, physical or chemical limitations and must be generally perceived as suggestion but not definite borders. The results of said screening methods are thus not of an absolute nature but can show trends and problematic parameters, thus, before excluding any specific EOR method, further research has to conducted on reservoir or fluid data, which are marked with a red tag.

Usually screening procedures are applied only to a certain area or pattern within a reservoir (as for example a 5 spot pattern) but the presented studies tried to cover the whole reservoir due to the small areal extensions of the Mittelplate gamma, delta and epsilon horizons.

4.1. Screening after Taber et al.[2]

Taber et al. described screening criteria for gas injection methods (nitrogen, CO_2 and hydrocarbon gas in miscible mode and a generalized immiscible gas injection method), enhanced water treatments (polymer flooding and chemical combination floods) and thermal – mechanical methods (in-situ combustion, steam flooding and surface mining) using a wide range of reservoir rock and fluid properties. Table 4.1 shows a sample layout for the screening after Taber et al. while the following sub chapters will give detailed studies for each of the Mittelplate horizon. Gel treatments have been neglected for the general applicability evaluations because they require more detailed information about water producing sands within each formation.

EOR Method	Oil Properties			Formation Properties						Results
	Gravity [°API]	Viscosity [cp @ R.C.]	Composition	Oil Saturation	Formation Type	Net thickness [ft]	Average Permeablity [md]	Depth [ft]	Temperature [°F]	
Gas Injection Methods (Miscible)										
Nitrogen (& Flue Gas)	>35	<0,4	High % of C1-C7	>40	Sandstone or Carbonate	Thin unless dipping	N.C.	>6.000	N.C.	
Hydrocarbon	>23	<3	High % of C2-C7	>30	Sandstone or Carbonate	Thin unless dipping	N.C.	>4.000	N.C.	
Carbon Dioxide	>22	<10	High % of C5-C12	>20	Sandstone or Carbonate	N.C.	N.C.	>2.500	N.C.	
Immiscible Gases	>12	<600	N.C.	>35	N.C.	dipping or good vertical perm.	N.C.	>1.800	N.C.	
[Enhanced] Waterflooding										
ASP & Alkaline	>20	<35	Light to Intermediate; some organic acids	>35	Sandstone preferred	N.C.	>10	<9.000	<200	
Polymer Flooding	>15	10-150	N.C.	>70	Sandstone preferred	N.C.	>10	<9.000	<200	
Thermal - Mechanical										
Combustion	>10	<5.000	Some asphaltic components	>50	High porosity sand / sandstone	>10	>50	<11.500	>100	
Steam	>8	<200.000	N.C.	>40	High porosity sand / sandstone	>20	>200	<4.500	N.C.	
Surface Mining	7-11	zero, cold flow	N.C.	>8% by wt of sand	mineable tar sand	>10	N.C.	<150	N.C.	

Table 4.1.: Sample layout for screening after Taber et al.

4.1.1. Dogger Beta Formation

EOR Method	Oil Properties			Formation Properties						Results		
	Gravity [°API]	Viscosity [cp @ R.C.]	Composition	Oil Saturation	Formation Type	Net thickness [ft]	Average Permeablity [md]	Depth [ft]	Temperature [°F]			
Gas Injection Methods (Miscible)												
Nitrogen (& Flue Gas)	>35	<0,4	High % of C1-C7	>40	Sandstone or Carbonate	Thin unless dipping	N.C.	>6.000	N.C.	3	2	4
Hydrocarbon	>23	<3	High % of C2-C7	>30	Sandstone or Carbonate	Thin unless dipping	N.C.	>4.000	N.C.	3	1	5
Carbon Dioxide	>22	<10	High % of C5-C12	>20	Sandstone or Carbonate	N.C.	N.C.	>2.500	N.C.	3	0	6
Immiscible Gases	>12	<600	N.C.	>35	N.C.	dipping or good vertical perm.	N.C.	>1.800	N.C.	0	2	7
[Enhanced] Waterflooding												
ASP & Alkaline	>20	<35	Light to Intermediate; some organic acids	>35	Sandstone preferred	N.C.	>10	<9.000	<200	0	4	5
Polymer Flooding	>15	10-150	N.C.	>70	Sandstone preferred	N.C.	>10	<9.000	<200	0	2	7
Thermal - Mechanical												
Combustion	>10	<5.000	Some asphaltic components	>50	High porosity sand / sandstone	>10	>50	<11.500	>100	0	2	7
Steam	>8	<200.000	N.C.	>40	High porosity sand / sandstone	>20	>200	<4.500	N.C.	1	2	6
Surface Mining	7-11	zero, cold flow	N.C.	>8% by wt of sand	mineable tar sand	>10	N.C.	<150	N.C.	4	0	5

Table 4.2.: Screening after Taber et al. for the Dogger beta formation

4.1.2. Dogger Gamma Formation

EOR Method	Oil Properties			Formation Properties						Results		
	Gravity [°API]	Viscosity [cp @ R.C.]	Composition	Oil Saturation	Formation Type	Net thickness [ft]	Average Permeablity [md]	Depth [ft]	Temperature [°F]			
Gas Injection Methods (Miscible)												
Nitrogen (& Flue Gas)	>35	<0,4	High % of C1-C7	>40	Sandstone or Carbonate	Thin unless dipping	N.C.	>6.000	N.C.	3	1	5
Hydrocarbon	>23	<3	High % of C2-C7	>30	Sandstone or Carbonate	Thin unless dipping	N.C.	>4.000	N.C.	2	1	6
Carbon Dioxide	>22	<10	High % of C5-C12	>20	Sandstone or Carbonate	N.C.	N.C.	>2.500	N.C.	1	1	7
Immiscible Gases	>12	<600	N.C.	>35	N.C.	dipping or good vertical perm.	N.C.	>1.800	N.C.	0	1	8
[Enhanced] Waterflooding												
ASP & Alkaline	>20	<35	Light to Intermediate; some organic acids	>35	Sandstone preferred	N.C.	>10	<9.000	<200	0	1	8
Polymer Flooding	>15	10-150	N.C.	>70	Sandstone preferred	N.C.	>10	<9.000	<200	0	2	7
Thermal - Mechanical												
Combustion	>10	<5.000	Some asphaltic components	>50	High porosity sand / sandstone	>10	>50	<11.500	>100	0	2	7
Steam	>8	<200.000	N.C.	>40	High porosity sand / sandstone	>20	>200	<4.500	N.C.	1	1	7
Surface Mining	7-11	zero, cold flow	N.C.	>8% by wt of sand	mineable tar sand	>10	N.C.	<150	N.C.	4	0	5

Table 4.3.: Screening after Taber et al. for the Dogger gamma formation

4.1.3. Dogger Delta / Epsilon Formation

EOR Method	Oil Properties			Formation Properties						Results		
	Gravity [°API]	Viscosity [cp @ R.C.]	Composition	Oil Saturation	Formation Type	Net thickness [ft]	Average Permeablity [md]	Depth [ft]	Temperature [°F]			
Gas Injection Methods (Miscible)												
Nitrogen (& Flue Gas)	>35	<0.4	High % of C1-C7	>40	Sandstone or Carbonate	Thin unless dipping	N.C.	>6.000	N.C.	3	2	4
Hydrocarbon	>23	<3	High % of C2-C7	>30	Sandstone or Carbonate	Thin unless dipping	N.C.	>4.000	N.C.	2	2	5
Carbon Dioxide	>22	<10	High % of C5-C12	>20	Sandstone or Carbonate	N.C.	N.C.	>2.500	N.C.	1	1	7
Immiscible Gases	>12	<600	N.C.	>35	N.C.	dipping or good vertical perm.	N.C.	>1.800	N.C.	0	0	9
[Enhanced] Waterflooding												
ASP & Alkaline	>20	<35	Light to Intermediate; some organic acids	>35	Sandstone preferred	N.C.	>10	<9.000	<200	0	1	8
Polymer Flooding	>15	10-150	N.C.	>70	Sandstone preferred	N.C.	>10	<9.000	<200	0	2	7
Thermal - Mechanical												
Combustion	>10	<5.000	Some asphaltic components	>50	High porosity sand / sandstone	>10	>50	<11.500	>100	0	2	7
Steam	>8	<200.000	N.C.	>40	High porosity sand / sandstone	>20	>200	<4.500	N.C.	1	2	6
Surface Mining	7-11	zero, cold flow	N.C.	>8% by wt of sand	mineable tar sand	>10	N.C.	<150	N.C.	4	0	5

Table 4.4.: Screening after Taber et al. for the Dogger delta / epsilon formation

4.1.4. Conclusions

4.1.4.1. Dogger Beta Formation

For the Dogger beta formation, Taber et al. yields immiscible gas displacements, enhanced water flooding and in-situ combustion as viable EOR mechanisms, all other methods have at least one parameter that fails the required range.

The only secondary recovery technique considered is immiscible gas displacement, while regular water injection is neglected in the screening process. As described in chapter 3, water injection has been chosen over gas injection already several years ago, due to the following reasons:

- Water injection is far more economical for the Mittelplate field, as produced water can be disposed again into the formation and thus saving water treatment costs.
- The GOR experienced from Mittelplate horizons is very low (around 10 sm^3 gas / sm^3 oil) and thus transportation of displacement gas to the offshore platform would to be required, which is not economically viable.
- All Mittelplate horizons are operated above the bubble point pressure and thus do not have a gas cap.
- If other gases apart from hydrocarbon gas would have been taken into consideration, additional technical problems as corrosion and precipitations (if applying CO_2) spoke as well against an application of an immiscible gas displacement.

Due to this reasons and water injection already in place, a further discussion about the secondary recovery mechanism can be regarded as redundant. As well water alternating gas (WAG) methods are, due to gas shortage reasons, not a viable technique for the Mittelplate oil field.

For tertiary recovery mechanisms Taber et al.'s results show that there are two crucial parameters, namely crude oil quality (API gravity, viscosity and molecular composition) and reservoir depth. All miscible gas displacements fail due to bad oil composition (all having three parameters outside the required interval), which implies that the required minimum miscibility pressure (MMP) cannot be reached. A more detailed study on this topic will follow later in this work. Steam injection techniques and surface mining methods fail (having one or more bad parameters) mainly due to the reservoir depth of more then 2500 meters. Steam can not exist physically at reservoir conditions found within the Dogger beta horizon and surface mining is not viable at such depths.

Due to these reasons the only viable EOR mechanisms, according to reservoir data and applying Taber et al.'s screening guidelines, for the Dogger beta horizon are enhanced water flooding techniques (polymer flooding and chemical combination flooding) and in-situ combustion. Special note has to be taken about the oil saturations within the horizon, as they differ throughout the field. The central region around the initial 5 spot scheme has already very high water saturations while the outer regions still have the initial oil saturations.

4.1.4.2. Dogger Gamma Formation

Generally speaking the results for the Dogger gamma formation are similar to the Dogger beta formation. According to Taber et al.'s screening procedure, again immiscible gas displacement, enhanced water flooding techniques and in-situ combustion remain the viable EOR methods.

The main difference to the Dogger beta formation in regard to secondary recovery is that the Dogger gamma formation does not have water injectors, but an active water aquifer which supplies the needed pressure for the production well, which is currently the only one in place. Due to these facts, there is no need to install additional pressure supply through the application of water or gas injectors, which would as well face the same limitations as for the Dogger beta formation.

From a screening for tertiary recovery methods perspective, the crude oil from the gamma formation is quite similar to the beta oil. The main difference lies within the better oil quality of the gamma crude oil, when looking at the API gravity and viscosity categories. CO_2 injection has only one parameter failing the required reference interval and thus might be eligible for further consideration if the MMP can be achieved without taking the risk of fracturing the formation. However, side effects as corrosion and asphaltene precipitation must be taken into consideration. Analogues to the Dogger beta formation, crude oil quality and reservoir depth are the limiting factors.

Nevertheless, the viable EOR methods resulting from the screening process are analogues to the Dogger beta results. Enhanced water flooding techniques and in-situ combustion remain the techniques of choice, while the oil saturation is still a parameter which needs to be taken care of.

4.1.4.3. Dogger Delta / Epsilon Formation

The results of the screening process for the Dogger delta / epsilon formation are analogues to the results of the other horizons, as the crude oil quality can be placed between Dogger beta quality (worst quality Mittelplate oil) and Dogger gamma quality (best quality Mittelplate oil).

As a secondary recovery mechanism water injection is already in place within this horizon, as can be seen from the technical description in chapter 3. Additionally the delta / epsilon formation is pressure supported by a very strong water aquifer, which makes a further discussion of a secondary gas injection redundant. It would, as well, face the same limitations named for the Dogger beta formation.

For the application of tertiary recovery mechanisms, the results for the Dogger delta / epsilon formation are more similar to the results of the beta formation than the gamma formation, which can be seen by the results for miscible gas displacement. Again crude oil quality and reservoir depth rule most EOR mechanisms out.

According to these reasons, the only possible EOR methods left are the application of enhanced water flooding or in-situ combustion, considering a screening point of view.

4.2. Screening after Al-Bahar et al.[35]

The screening guidelines of Al-Bahar et al. are based upon the suggestions of Taber et al., but take more data from published field cases into consideration and offer a more detailed analysis. Essentially Al-Bahar et al. used a wider range of reservoir rock and fluid data to describe the possible applicability of EOR methods, while differentiating those into more sub groups. He considered different chemical combination floods separately (there are separate data sets for alkali – polymer, surfactant – polymer and alkali – surfactant – polymer floods) and added water injection as a second secondary recovery method.

Table 4.5 shows a sample layout of Al-Bahar et al.'s analysis and the subsequent Tables 4.6 till 4.8 show the detailed studies for the Mittelplate formations.

	EOR Method	Water Based					Gas Immiscible	Gas Miscible			Thermal	
		Water	Polymer	AP	SP	ASP	Immiscible Gas	Carbon Dioxide	Hydrocarbon	Nitrogen	In Situ Comb.	Steam
Oil	Gravity (° API)	N.C.	N.C.	< 35	N.C.	< 35	> 13	> 22	> 24	> 35	N.C.	N.C.
	Mobility (md / mPa.s)	> 0,1	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
	Viscosity @ Pb (mPa.s)	< 2000	< 150	< 150	< 150	< 150	< 600	< 10	< 5	< 2	2 - 5000	50 - 5000
Reservoir	Clay Content	N.C.	N.C.	low	low	low	N.C.	N.C.	N.C.	N.C.	N.C.	low
	Depth (m)	N.C.	N.C.	N.C.	N.C.	N.C.	> 200	> 600	> 1200	> 1800	150 - 1800	< 1400
	Drive	no water	no water	no water	no water	no water	no water	N.C.	N.C.	N.C.	N.C.	N.C.
	Formation Type	N.C.	N.C.	Sandstone	N.C.	Sandstone	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
	Horizontal Perm. (md)	N.C.	> 50	> 50	> 50	> 50	N.C.	N.C.	N.C.	N.C.	> 50	> 200
	Net Pay Thickness (m)	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	> 3	> 6
	Oil Saturation (%)	> 50	> 60	> 50	> 35	> 35	> 50	> 25	> 30	> 35	> 35	> 30
	Porosity (%)	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	> 18	> 20
	Pressure (psi)	> 0,7	N.C.	N.C.	N.C.	N.C.	N.C.	MMP < Pi	N.C.	MMP < Pi	N.C.	< 1500
	Temperature (°C)	N.C.	< 70	< 70	< 70	< 70	N.C.	> 30	N.C.	N.C.	N.C.	N.C.
	Thickness	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
Other	Bottom Water	N.C.	local or no	local or no	local or no	local or no	local or no	N.C.	N.C.	N.C.	local or no	N.C.
	Current WOR (%)	< 90	< 90	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	< 90
	Gas Cap	N.C.	local or no	local or no	local or no	local or no	local or no	local or no	local or no	local or no	local or no	local or no
	Water Hardness (ppm)	N.C.	< 1.000	< 1.000	< 1.000	< 1.000	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
	Water Salinity (ppm)	N.C.	< 100.000	< 50.000	< 50.000	< 50.000	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
Special		(1 - Swr - So)^2 * µ < 0,5	N.C. = Not Critical								no fractures	

Results										

Table 4.5.: Sample layout for screening after Al-Bahar et al.

4.2.1. Dogger Beta Formation

EOR Method		Water Based					Gas Immiscible	Gas Miscible			Thermal	
		Water	Polymer	AP	SP	ASP	Immiscible Gas	Carbon Dioxide	Hydrocarbon	Nitrogen	In Situ Comb.	Steam
Oil	Gravity (° API)	N.C.	N.C.	< 35	N.C.	< 35	> 13	> 22	> 24	> 35	N.C.	N.C.
Oil	Mobility (md / mPa.s)	> 0,1	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
Oil	Viscosity @ Pb (mPa.s)	< 2000	< 150	< 150	< 150	< 150	< 600	< 10	< 5	< 2	2 - 5000	50 - 5000
Reservoir	Clay Content	N.C.	N.C.	low	low	low	N.C.	N.C.	N.C.	N.C.	N.C.	low
Reservoir	Depth (m)	N.C.	N.C.	N.C.	N.C.	N.C.	> 200	> 600	> 1200	> 1800	150 - 1800	< 1400
Reservoir	Drive	no water	no water	no water	no water	no water	no water	N.C.	N.C.	N.C.	N.C.	N.C.
Reservoir	Formation Type	N.C.	N.C.	Sandstone	N.C.	Sandstone	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
Reservoir	Horizontal Perm. (md)	N.C.	> 50	> 50	> 50	> 50	N.C.	N.C.	N.C.	N.C.	> 50	> 200
Reservoir	Net Pay Thickness (m)	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	> 3	> 6
Reservoir	Oil Saturation (%)	> 50	> 60	> 50	> 35	> 35	> 50	> 25	> 30	> 35	> 35	> 30
Reservoir	Porosity (%)	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	> 18	> 20
Reservoir	Pressure (psi)	> 0,7	N.C.	N.C.	N.C.	N.C.	N.C.	MMP < Pi	N.C.	MMP < Pi	N.C.	< 1500
Reservoir	Temperature (°C)	N.C.	< 70	< 70	< 70	< 70	N.C.	> 30	N.C.	N.C.	N.C.	N.C.
Reservoir	Thickness	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
Other	Bottom Water	N.C.	local or no	local or no	local or no	local or no	local or no	N.C.	N.C.	N.C.	local or no	N.C.
Other	Current WOR (%)	< 90	< 90	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	< 90
Other	Gas Cap	N.C.	local or no	local or no	local or no	local or no	local or no	local or no	local or no	local or no	local or no	local or no
Other	Water Hardness (ppm)	N.C.	< 1.000	< 1.000	< 1.000	< 1.000	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
Other	Water Salinity (ppm)	N.C.	< 100.000	< 50.000	< 50.000	< 50.000	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
Special		(1 - Swr - So)^2 * μ < 0,5	N.C. = Not Critical								no fractures	
Results		0	3	3	3	3	0	3	2	3	1	3
		0	1	2	2	2	1	0	0	1	1	2
		20	16	15	15	15	19	17	18	16	18	15

Table 4.6.: Screening after Al-Bahar et al. for the Dogger beta formation

4.2.2. Dogger Gamma Formation

EOR Method		Water Based					Gas Immiscible	Gas Miscible			Thermal	
		Water	Polymer	AP	SP	ASP	Immiscible Gas	Carbon Dioxide	Hydrocarbon	Nitrogen	In Situ Comb.	Steam
Oil	Gravity (° API)	N.C.	N.C.	< 35	N.C.	< 35	> 13	> 22	> 24	> 35	N.C.	N.C.
	Mobility (md / mPa.s)	> 0,1	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
	Viscosity @ Pb (mPa.s)	< 2000	< 150	< 150	< 150	< 150	< 600	< 10	< 5	< 2	2 - 5000	50 - 5000
Reservoir	Clay Content	N.C.	N.C.	low	low	low	N.C.	N.C.	N.C.	N.C.	N.C.	low
	Depth (m)	N.C.	N.C.	N.C.	N.C.	N.C.	> 200	> 600	> 1200	> 1800	150 - 1800	< 1400
	Drive	no water	no water	no water	no water	no water	no water	N.C.	N.C.	N.C.	N.C.	N.C.
	Formation Type	N.C.	N.C.	Sandstone	N.C.	Sandstone	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
	Horizontal Perm. (md)	N.C.	> 50	> 50	> 50	> 50	N.C.	N.C.	N.C.	N.C.	> 50	> 200
	Net Pay Thickness (m)	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	> 3	> 6
	Oil Saturation (%)	> 50	> 60	> 50	> 35	> 35	> 50	> 25	> 30	> 35	> 35	> 30
	Porosity (%)	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	> 18	> 20
	Pressure (psi)	> 0,7	N.C.	N.C.	N.C.	N.C.	N.C.	MMP < Pi	N.C.	MMP < Pi	N.C.	< 1500
	Temperature (°C)	N.C.	< 70	< 70	< 70	< 70	N.C.	> 30	N.C.	N.C.	N.C.	N.C.
	Thickness	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
Other	Bottom Water	N.C.	local or no	local or no	local or no	local or no	local or no	N.C.	N.C.	N.C.	local or no	N.C.
	Current WOR (%)	< 90	< 90	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	< 90
	Gas Cap	N.C.	local or no	local or no	local or no	local or no	local or no	local or no	local or no	local or no	local or no	local or no
	Water Hardness (ppm)	N.C.	< 1.000	< 1.000	< 1.000	< 1.000	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
	Water Salinity (ppm)	N.C.	< 100.000	< 50.000	< 50.000	< 50.000	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
Special		(1 - Swr - So)^2 * µ < 0,5	N.C. = Not Critical								no fractures	

Results										
1	3	3	3	3	1	1	1	3	1	3
0	1	2	1	1	1	0	0	0	0	1
19	16	15	16	16	18	19	19	17	19	16

Table 4.7.: Screening after Al-Bahar et al. for the Dogger gamma formation

4.2.3. Dogger Delta / Epsilon Formation

	EOR Method	Water Based					Gas Immiscible	Gas Miscible			Thermal	
		Water	Polymer	AP	SP	ASP	Immiscible Gas	Carbon Dioxide	Hydrocarbon	Nitrogen	In Situ Comb.	Steam
Oil	Gravity (° API)	N.C.	N.C.	< 35	N.C.	< 35	> 13	> 22	> 24	> 35	N.C.	N.C.
	Mobility (md / mPa.s)	> 0,1	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
	Viscosity @ Pb (mPa.s)	< 2000	< 150	< 150	< 150	< 150	< 600	< 10	< 5	< 2	2 - 5000	50 - 5000
Reservoir	Clay Content	N.C.	N.C.	low	low	low	N.C.	N.C.	N.C.	N.C.	N.C.	low
	Depth (m)	N.C.	N.C.	N.C.	N.C.	N.C.	> 200	> 600	> 1200	> 1800	150 - 1800	< 1400
	Drive	no water	no water	no water	no water	no water	no water	N.C.	N.C.	N.C.	N.C.	N.C.
	Formation Type	N.C.	N.C.	Sandstone	N.C.	Sandstone	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
	Horizontal Perm. (md)	N.C.	> 50	> 50	> 50	> 50	N.C.	N.C.	N.C.	N.C.	> 50	> 200
	Net Pay Thickness (m)	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	> 3	> 6
	Oil Saturation (%)	> 50	> 60	> 50	> 35	> 35	> 50	> 25	> 30	> 35	> 35	> 30
	Porosity (%)	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	> 18	> 20
	Pressure (psi)	> 0,7	N.C.	N.C.	N.C.	N.C.	N.C.	MMP < Pi	N.C.	MMP < Pi	N.C.	< 1500
	Temperature (°C)	N.C.	< 70	< 70	< 70	< 70	N.C.	> 30	N.C.	N.C.	N.C.	N.C.
	Thickness	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
Other	Bottom Water	N.C.	local or no	local or no	local or no	local or no	local or no	N.C.	N.C.	N.C.	local or no	N.C.
	Current WOR (%)	< 90	< 90	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.	< 90
	Gas Cap	N.C.	local or no	local or no	local or no	local or no	local or no	local or no	local or no	local or no	local or no	local or no
	Water Hardness (ppm)	N.C.	< 1.000	< 1.000	< 1.000	< 1.000	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
	Water Salinity (ppm)	N.C.	< 100.000	< 50.000	< 50.000	< 50.000	N.C.	N.C.	N.C.	N.C.	N.C.	N.C.
	Special	(1 - Swr - So)^2 * µ < 0,5	N.C. = Not Critical								no fractures	

Results										
1	3	3	3	3	1	2	1	3	1	3
0	1	2	1	1	1	0	1	0	0	1
19	16	15	16	16	18	18	18	17	19	16

Table 4.8.: Screening after Al-Bahar et al. for the Dogger delta / epsilon formation

4.2.4. Conclusions

4.2.4.1. Dogger Beta Formation

For the Dogger beta formation Al-Bahar et al. yields only secondary recovery methods as possible EOR techniques, namely water injection and immiscible gas displacement. All other methods have between one and three parameters outside the required reference interval and are thus marked red.

Al-Bahar gives both secondary recovery techniques excellent results. As explained earlier, a water injection program is already in place for the Dogger beta formation.

More interesting is the study for possible tertiary recovery mechanisms. Analogues to Taber et al., miscible gas displacement fails due to crude oil quality, which will be studied in more detail in a later chapter. However, an interesting point is that Al-Bahar et al. included directly the prerequisite of the MMP being lower than the initial pressure p_i. It can be however not explained, why this condition is missing for the application of a miscible hydrocarbon gas displacement, as miscibility is as well a requirement for this technique. Both thermal EOR methods fail because of the high reservoir depth, which is definite bad parameter for steam injection due to the physical properties of water. For in-situ combustion however, this requirement is likely to be derived from possible wellhead injection pressures, which needs to be evaluated separately to make a definite statement. The main differences between Taber et al. and Al-Bahar et al. are getting visible during the comparison of the results for water based EOR methods (chemical and chemical combination floods). Al-Bahar et al.'s screening guidelines include properties such as reservoir temperature, water hardness and water salinity, which are the main limitations for chemical additives, such as polyacrylamides. The parameter range applied even suggests that polyacrylamide limitations have been used to set the boundary conditions. There are of course alternative and more expensive additives, such as for example biopolymers or synthetic polymers, which can be applied at higher temperatures or salinities than the boundaries given by Al-Bahar et al. In conclusion there are five critical parameters for the Dogger beta formation when screening after Al-Bahar et al., reservoir depth, reservoir temperature, pressure (reservoir and MMP) crude oil quality and water salinity.

Due to the reasoning supplied, the screening study after Al-Bahar et al. suggests a more detailed evaluation of water based or enhanced water floods such as polymer floods or chemical combination floods and in-situ combustion. As noted already above, caution must be taken in regard to saturation values.

4.2.4.2. Dogger Gamma Formation

For the Dogger gamma formation Al-Bahar et al. yields no EOR method with a spotless result. All techniques have between one and three parameters outside the reference interval, which is a rather disappointing result. If we consider all methods with only one parameter failing, Al-Bahar et al. gives water injection, immiscible gas displacement, miscible CO_2 and hydrocarbon gas injection and in-situ combustion as viable methods.

For the purpose of secondary recovery, both available techniques fail the condition of having no active waterdrive. This however, is a very arguable limitation as an active water drive certainly must be taken into consideration when applying water injection or immiscible gas displacement for pressure support, but hardly rules it out. However, taking the small amount of producers of the Dogger gamma formation into consideration additionally to the active water aquifer, there is no further need to implant additional pressure support.

Considering tertiary recovery mechanisms, Al-Bahar et al. gives CO_2 injection, hydrocarbon gas injection and in-situ combustion as the best alternatives. The limiting factor for these methods are on the one side crude oil quality and the MMP necessary for the miscible displacements and on the other side reservoir depth for steam injection. A more detailed analysis for the MMP has to be made to either rule out or further study miscible displacements. For water based methods the same remarks as for the Dogger beta formation are valid. The limitations suggested by Al-Bahar et al. are only true for polyacrylamides, while better and more expensive chemical additives have a wider application range. Thus further research has to be conducted.

As a conclusion of the analysis made above, closer evaluation of chemical methods (salinity and reservoir temperature), miscible gas methods (MMP evaluation) and in-situ combustion (reservoir depth) have to be conducted.

4.2.4.3. Dogger Delta / Epsilon Formation

The results for the Dogger delta / epsilon formation are very similar to those of the gamma formation. No method passes all criteria, while water injection, immiscible gas displacement, miscible hydrocarbon gas displacement and in-situ combustion got one failed requirement.

Al-Bahar et al. yields for secondary recovery techniques the same results as for the Dogger gamma formation, while analogues to the reasons supplied in chapter 4.2.3.3. and the in place water injection program additionally to the active aquifer make a further discussion obsolete.

The results for tertiary recovery methods are similar to those of the Dogger gamma formation, with the exception of miscible CO_2 displacement, which fails two requirements. Besides this fact, the same conclusions as for the Dogger gamma horizon can be drawn.
Due to this thoughts, further evaluation of water based methods (salinity and reservoir temperature), miscible hydrocarbon gas injection (MMP evaluation) and in-situ combustion (reservoir depth) is suggested.

4.3. Screening with Commercial Software

Additionally to the two literature screening guides, a commercial software package was used to analyze possible EOR methods for the Mittelplate oil field. The tool itself worked basically analogues to the screening guides. Twelve key parameters are defined by the program, which need to be entered by the user. Afterwards the program checks if the entered values are within a certain reference interval, which has been defined by "experts from the EOR industry" according to the program description. If the entered value is outside the reference interval, it returns a violation for this parameter (analogues to a red marked value for the literature guides), if not, the entered value gets weighted towards the average of the reference interval with the help of a triangular distribution. Additionally it must be noted that the software screens only for the head categories, but not explicit EOR methods. The program has been used to analyze the data of all Mittelplate horizons. Table 4.9 shows the reference intervals given by the program, while the Tables 4.10 to 4.12 show detailed studies of the Dogger beta, gamma and delta / epsilon formations.

Reference intervals										
	Parameter	Unit	Water Flooding		Gas Injection		Thermal methods		Chemical methods	
			Min	Max	Min	Max	Min	Max	Min	Max
1	Depth	m	30	5000	150	5000	30	2000	30	2500
2	Permeability	md	100	5000	1	5000	20	5000	100	2000
3	Thickness	m	3	500	2	130	6	20	2	25
4	Temperature	Celsius	0	200	0	100	0	200	0	70
5	Oil viscosity	cp	0,2	25	0,2	10	1	1500	0,4	250
6	Pressure	bar	10	500	80	500	10	250	10	250
7	Oil density	kg/m3	650	930	650	950	750	1000	650	850
8	Anisotropy (kv/kh)	%	1	100	1	10	1	50	1	10
9	Clay content	%	0	20	0	30	0	20	0	5
10	Salinity	kg/m3	0	40	0	40	0	25	0	20
11	Curr/init oil saturation	%	70	100	40	100	40	100	30	100
12	High/low perm. ratio		1	100	1	20	1	50	1	200

Table 4.9.: Reference intervals used by the commercial software

4.3.1. Dogger Beta Formation

Field case input				
	Parameter	Unit	Min	Max
1	Depth	m	2400	2975
2	Permeability	md	200	3000
3	Thickness	m	6	17
4	Temperature	Celsius	80	85
5	Oil viscosity	cp	1700	1900
6	Pressure	bar	215	245
7	Oil density	kg/m3	940	945
8	Anisotropy (kv/kh)	%	70	80
9	Clay content	%	12	37
10	Salinity	kg/m3	115	125
11	Curr/init oil saturation	%	25	35
12	High/low perm. ratio		14	16

Applicability evaluation			
	Method	Score	Violations
1	Water flooding	0,429	4
2	Gas injection	0,410	4
3	Thermal methods	0,382	5
4	Chemical methods	0,174	6

Table 4.10.: Input values and results for the software screening of the Dogger beta formation

4.3.2. Dogger Gamma Formation

Field case input				
	Parameter	Unit	Min	Max
1	Depth	m	1900	2222
2	Permeability	md	60	500
3	Thickness	m	30	50
4	Temperature	Celsius	65	70
5	Oil viscosity	cp	100	150
6	Pressure	bar	175	210
7	Oil density	kg/m3	895	915
8	Anisotropy (kv/kh)	%	0,2	0,25
9	Clay content	%	12	37
10	Salinity	kg/m3	225	235
11	Curr/init oil saturation	%	50	60
12	High/low perm. ratio		8	8,5

Applicability evaluation			
	Method	Score	Violations
1	Gas injection	0,526	3
2	Thermal methods	0,37	3
3	Water flooding	0,326	4
4	Chemical methods	0,317	5

Table 4.11.: Input values and results for the software screening of the Dogger gamma formation

4.3.3. Dogger Delta / Epsilon Formation

Field case input				
	Parameter	Unit	Min	Max
1	Depth	m	1900	2222
2	Permeability	md	500	10000
3	Thickness	m	60	90
4	Temperature	Celsius	65	70
5	Oil viscosity	cp	200	300
6	Pressure	bar	150	180
7	Oil density	kg/m3	910	920
8	Anisotropy (kv/kh)	%	31	49
9	Clay content	%	7	32
10	Salinity	kg/m3	220	230
11	Curr/init oil saturation	%	40	50
12	High/low perm. ratio		19	21

Applicability evaluation			
	Method	Score	Violations
1	Thermal methods	0,476	2
2	Water flooding	0,466	3
3	Gas injection	0,439	3
4	Chemical methods	0,235	5

Table 4.12.: Input values and results for the software screening of the Dogger delta / epsilon formation

4.3.4. Conclusions

4.3.4.1. Dogger Beta Formation

For the Dogger beta formation the software applicability screening returns very bad results. None of the listed EOR methods passes the application with positive results, having at least four violations of the reference data set (similar to red marked values for the literature screening). Water flooding achieves the best results with a weighted score of 0.429 points.

The meaning of these results is the same for secondary and tertiary recovery methods. No method considered by the software is applicable for the Mittelplate oil field, including regular water injection. Of course these results are highly unsatisfying and can be considered highly unrealistic. The major reason for this outcome lies in the given reference intervals, which have been very poorly chosen by the software programmers.

4.3.4.2. Dogger Gamma Formation

The results of the software screening for the Dogger gamma formation are similar to those of the Dogger beta formation. All methods suffer from multiple violations and a bad scoring, suggesting no other recovery then primary. Gas injection and thermal methods receive even better marks then regular water injection, making the results highly doubtable from a reservoir engineering point of view.

The conclusion is identical to the one for the Dogger beta formation as there are no IOR or EOR possibilities for the Mittelplate Dogger gamma formation due to the same reasons.

4.3.4.3. Dogger Delta / Epsilon Formation

Going along with the results of the other two formations, the software applicability screening tool fails to return positive results for the Dogger delta / epsilon horizon. The best possibilities given by the program are thermal methods, which fail only two parameters and get a scoring of 0.476, while water flooding and gas injection methods receive even three violations.
The conclusion of these results is identical to the other two formations, as the program yields no possibility of secondary or tertiary recovery. The reasoning for that is as well identical.

4.4. Screening for unconventional EOR Methods

Additionally to the literature and software screenings for traditional EOR methods, other, more unconventional options have been considered as well. The literature review already gives an overview over these methods under chapter 2.3.4. However, it must be recognized that all of these methods are either very specialized approaches for extreme conditions (such as VAPEX or CHOPS for heavy oils) or are still in research or under evaluation to prove their economical or technical viability (MEOR, LoSal EOR, Microwave or Sonic EOR). As the conditions in the Mittelplate oil field are already rather difficult for implementation of EOR or IOR methods, these techniques have been neglected for closer studies to reduce the economic risk to a manageable minimum.

4.5. Evaluation of Key Parameters

To increase the viability of the technical screenings after Taber et al. and Al-Bahar et al. several follow up studies on critical parameters have been conducted. Parameters chosen for this evaluation have been reservoir depth in comparison to the phase diagram of water to check the suitability of steam injection, MMP versus initial reservoir pressure of all horizons to confirm or rule out a possible miscible gas injection and reservoir brine salinity in combination with reservoir temperature to study the applicability of different polymers.

4.5.1. Reservoir depth

Figure 2.2 shows the phase diagram of water, giving the particularly interesting vapor region, ice region and the liquid region as well as the triple point and the critical point. The comparison with Table 4.13, which shows the current reservoir conditions of all three Mittelplate horizons, makes it clear that no water vapor phase can exist at these conditions, thus rendering a possible steam injection project useless. The fluid would be either liquid or supercritical in the reservoir.

Horizon	Depth	Temperature	Pressure
	[m]	[°C]	[bar]
Beta	2750	82	200 - 250
Gamma	2000	69	150 - 200
Delta / Epsilon	2000	69	150 - 200

Table 4.13.: Current reservoir conditions of the Mittelplate horizons

4.5.2. Minimum Miscibility Pressure (MMP)

For the study of the MMP, only the pressure necessary for CO_2 injection has been evaluated. It is proven throughout the technical literature that the MMP for nitrogen injection is usually far larger then the pressures required by the other two miscible injection methods. The MMP for hydrocarbon gas injection however can be quite similar to the one required by CO_2 injection. To confirm this thesis, commercial software has been used to calculate all three minimum miscibility pressures for all Mittelplate horizons. The results of this evaluation can be seen in appendix C, where all input and output values of the software are documented. A short summary is shown in Table 4.14.

Additionally to the software evaluation, four correlations for the MMP of CO_2 have been applied to confirm or rule out the application of miscible EOR methods. Table 4.15 gives summary on these correlations.

EOR Method	Unit	Beta	Gamma	Delta / Epsilon
CO2	bar	553,0	379,8	405,8
Hydrocarbon Gas	bar	598,1	260,5	293,4
Nitrogen	bar	1435,6	1520,3	1342,4
Initial Pressure	bar	304,5	233,5	233,5

Table 4.14.: Summary of the results from the software application

Composition	Unit	Beta	Gamma	Delta	Epsilon
C_1	mol %	13,04	10,09	10,98	11,16
C_2 - C_6	mol %	13,38	10,82	12,80	13,69
C_5+	g / mol	354	309	328	328
C_7+	g / mol	386	323	349	343
Temperature	°F	179,6	156,2	156,2	156,2
Initial Pressure	bar	304,5	233,5	233,5	233,5
MMP (Yuan et al)[14]	psia	1507	3259	2887	2906
MMP (Yuan et al)[14]	bar	104	225	199	200
MMP (Yellig & Metcalfe)[15]	psia	2240	1959	1959	1959
MMP (Yellig & Metcalfe)[15]	bar	154	135	135	135
MMP (Glaso)[36]	psia	5759	4010	4235	4017
MMP (Glaso)[36]	bar	397	276	292	277
MMP (Cronquist)[37]	psia	6423	4147	4655	4661
MMP (Cronquist)[37]	bar	443	286	321	321

Table 4.15.: Summary of the applied correlations

The input data for all correlations and the software have been generated from internal operator PVT reports of the Mittelplate crude oil. The necessary calculations and correlations can be found as well in appendix C.

The four correlations applied have been publicized by Yuan et al.[14], Yellig and Metcalfe[15], Glaso[36] and Cronquist[37]. The correlation of Yuan et al. uses three parameters, mol% of the C_2-C_6 fraction, mole weight of the C_{7+} fraction and reservoir temperature, but fails to yield stable results for high gravity oils, which has been confirmed by its authors. The correlation of Yellig and Metcalfe is a lot simpler and requires only the reservoir temperature to calculate the MMP. Since this correlation does not use any crude oil data, its results are not very trustworthy. Glaso's correlation requires the same parameters as Yuan et al., but delivers much more reasonable results for high gravity oils. Cronquist's correlation applied the mol% of C_1, the molecular weight of the C_{5+} fraction and the reservoir temperature. His correlation seems to yield good results as well. Due to the factors named above, only the results of the correlations from Glaso and Cronquist have been taken, additionally to the software results, into consideration for the decision process.

The results from both studies are identical. None of the Mittelplate crude oils offer the required quality to reach the minimum miscibility pressure before the initial pressure for any miscible EOR method. Thus the application of these methods can be ruled out, as damage to the Mittelplate formations must be assumed.

4.5.3. Polymer Suitability

Figure 4.1 shows the different application intervals, in regard to salinity and reservoir temperature, for polyacrylamides, biopolymers and synthetic polymers additionally to Mittelplate reservoir conditions.

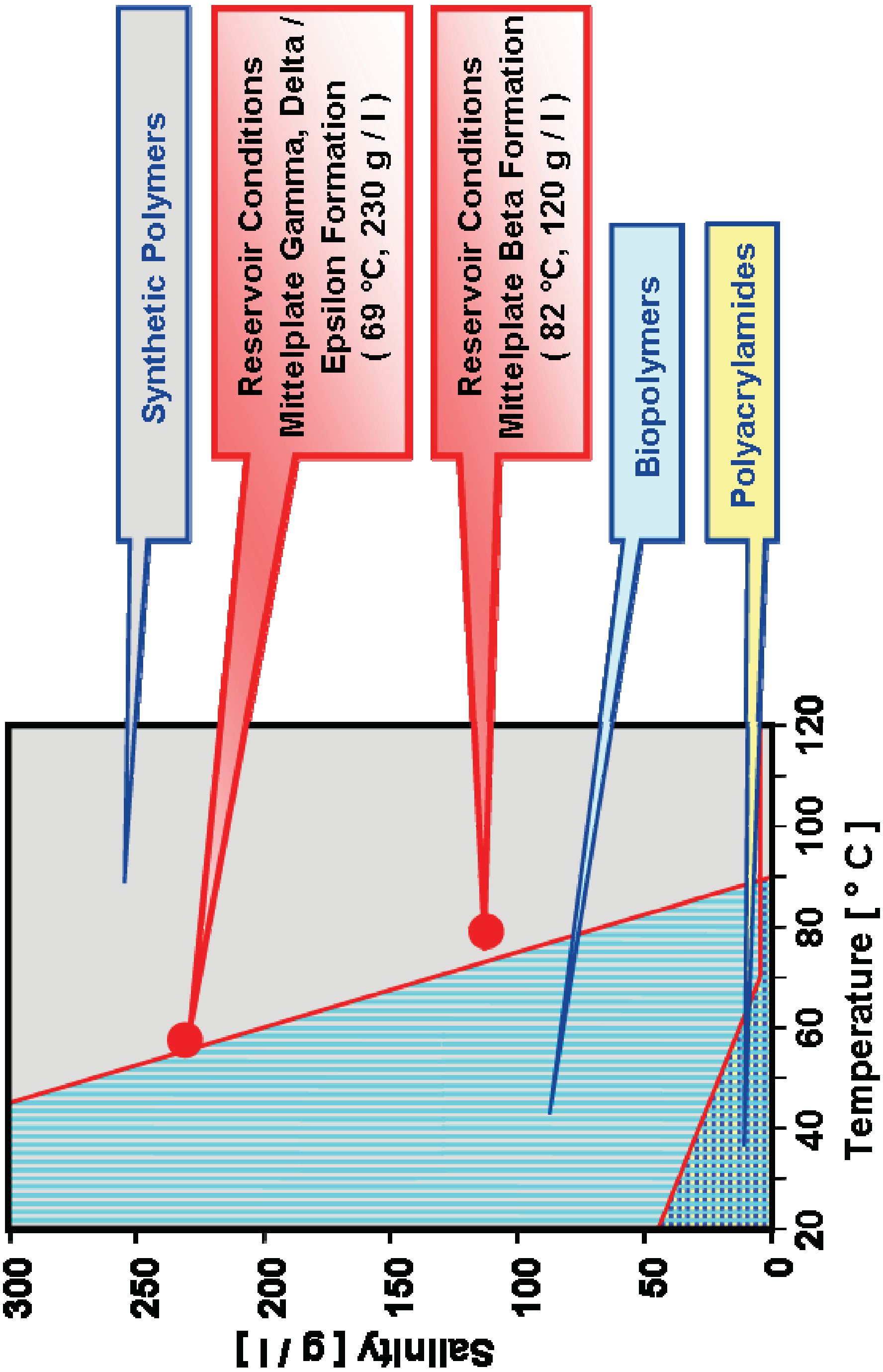

Figure 4.1.: Application interval of different polymers in regard to Mittelplate reservoir conditions

As can be seen by this figure, the application of polyacrylamides can be certainly ruled out because of the prevailing reservoir conditions in the Mittelplate field. However, synthetic polymers can be applied without any big restrictions, even biopolymers such as Xanthan are in the border area of applicability, providing positive laboratory testing. Earlier laboratory analysis of the Mittelplate operator company suggested that biopolymers might be stable enough to consider their application.

Due to theses reasons, the application of polymer or chemical combination floodings can be taken into consideration, but further laboratory research must be conducted.

4.6. Summary of the technical Screenings

The technical screening studies give a good overview over the possibilities for the Mittelplate oil field, in respect to the reservoir conditions. It has been proven that steam injection strategies are no viable alternative, because steam cannot exist at the prevailing conditions. Furthermore the required pressures to achieve miscibility during the application of CO_2, hydrocarbon gas or nitrogen injection are far higher then the initial reservoir pressures for all Mittelplate horizons, thus there would be an extremely high risk of fracturing the formation and destroy it. This risk cannot be taken. Unconventional EOR methods are either too specialized to be considered for the Mittelplate oil field (such as cold heavy oil production with sand or vapor extraction) or are still not mature enough, and thus economical proven, to be applied (such as microbial EOR, the application of microwaves for EOR purposes, low salinity EOR or sonic EOR).

Because of these reasons, only polymer flooding, chemical combination floodings and in-situ combustion should be considered as possible tertiary recovery methods.

Chapter 5

Analytical Performance Evaluation

The commercial software, which was used to perform the technical screenings, offers as well the option of analytically simulating multiple EOR methods. Since a performance evaluation for a test pattern is crucial to determine an EOR methods economical and technical viability, it was decided to incorporate such a study into this work. Of course this “pre simulation” can only serve as a guideline and its results must not be taken literally. However, it does show trends and gives a first approximation on the results to be expected from numerical simulation and laboratory analysis, which are far more resource intensive studies and would be beyond the scope of this work. The following chapter will give a short description of the software used, to show its possibilities, limitations and the reservoir engineering principles it is based on. Furthermore, models for each Mittelplate formation have been set up and computed. To obtain the best possible results, different steps have been undertaken. Firstly the data has been assembled from a multitude of sources to provide a good base for the calculations. A very detailed description of the data for all horizons can be found in appendix D. Secondly an evaluation of the possible calculation options and boundary conditions has been undertaken to judge which parameters fit the formation best. After the optimal settings have been evaluated, two different models for each formation have been set up, which will be used for further studies, depending on the test area geometry.

5.1. Program Description

The performance prediction module of the commercial software allows the user quantitative prediction of the performance of different EOR methods. It covers the possibility to compute water injection, immiscible gas injection, miscible gas injection (CO_2, hydrocarbon gas and nitrogen) and chemical EOR methods (surfactants, polymer and surfactant – polymer). However, it is not possible to analyze thermal EOR methods due to the extremely complicated physical and chemical processes which happen during their application.

The program offers the possibility to simulate the displacements either in a two dimensional cross section geometry or in an approximate three dimensional geometry (5 spot pattern). It applies the proven analytical solutions of Dykstra – Parsons (DP) and gravity dominated Vertical Equilibrium (VE) approximations, accounting either for a constant rate (CR) or a constant pressure loss (CP) boundary condition. These conditions can be freely selected by the user to fit the reservoir in the best possible way.

5.2. Evaluation of Calculation Options and Boundary Conditions

The main design parameters for all models have been the geometry, analytical solution method and boundary conditions. The studies incorporate an analysis of the recovery factor of all possible EOR methods against time, to verify the most descriptive solution in accordance with reservoir engineering comprehension. The results will be used to set up the base cases for further evaluation of the EOR methods.

5.2.1. Dogger Beta Formation

From a reservoir engineering point of view, a constant rate boundary, due to the unknown aquifer behavior, applying the Dykstra – Parsons solution method would be the best description of the Dogger beta horizon. An overview of the generated graphs to determine the best options can be found in appendix D.

The analytical simulation of the different Dogger beta models proved the description suggested by reservoir engineering comprehension. For both geometries the Vertical Equilibrium solutions had very unrealistic responses towards the use of a pure polymer injection, featuring for the 2D case a linear rise of the recovery factor accompanied by a sudden break of production. For the 3D case the recovery factor increased more smoothly, but still couldn't yield a realistic decline before breaking as well in an incomprehensive fashion. For both geometries surfactant injection yielded an unrealistic low recovery factor (about 17% - 18%) in comparison to pure water injection (recovery factor of about 68%). In the Dykstra – Parsons combined with constant pressure loss cases, polymer injection showed a slower rise in the recovery factor than water, which stands in contradiction with the technical principles of a polymer injection. As well surfactant injection showed an unrealistic response compared to a combined surfactant – polymer flood in the 2D case, while it responded in the anticipated fashion for the 3D case. Furthermore the 3D case required an unrealistic amount of time to reach ultimate recovery (2500 years in comparison to 50 years of all other models). Due to these reasons, the 2D, Dykstra – Parsons, constant rate model has been chosen to be the most descriptive solution for both geometries. Figures 5.1 and 5.2 show the computed graphs for these cases.

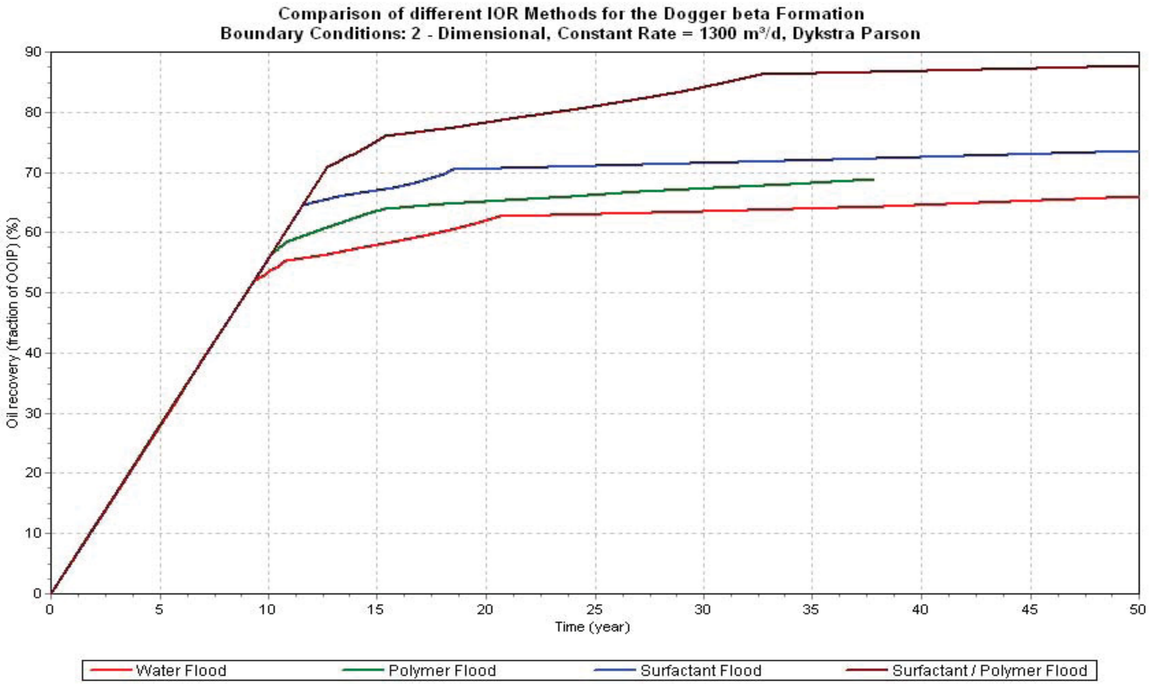

Figure 5.1.: 2D – Dykstra Parsons – constant rate case for the Dogger beta formation

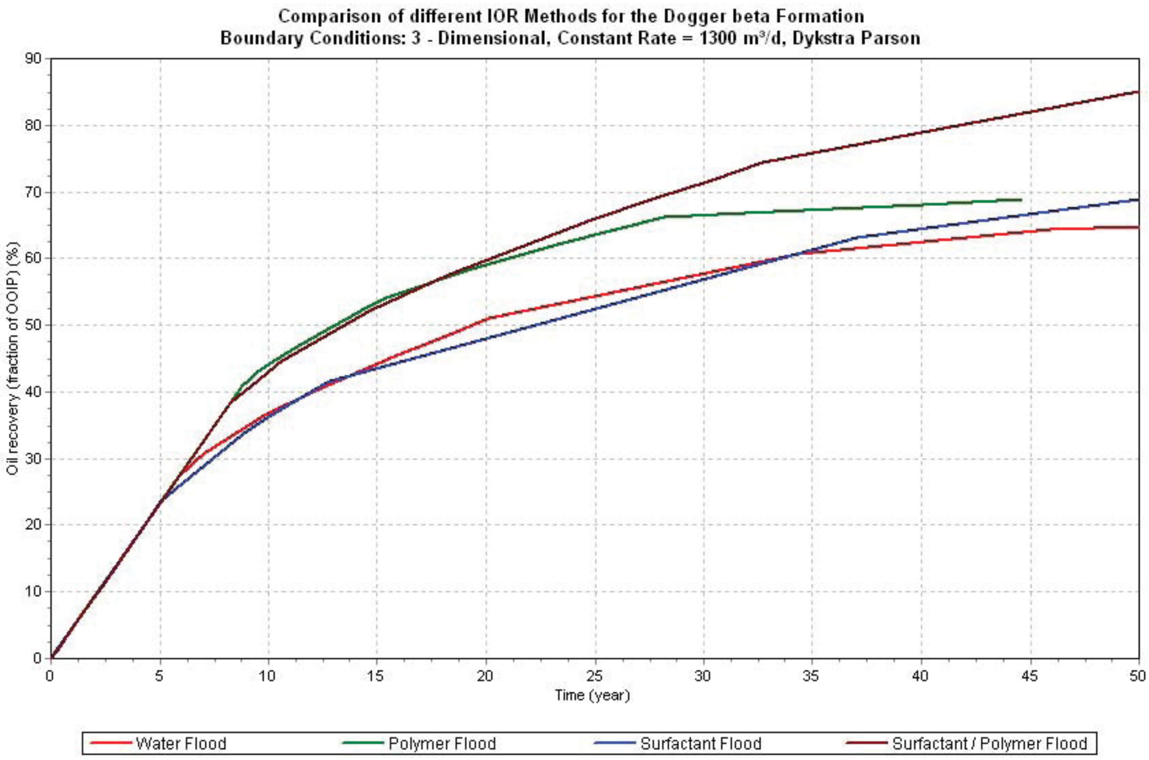

Figure 5.2.: 3D – Dykstra Parsons – constant rate case for the Dogger beta formation

5.2.2. Dogger Gamma Formation

The Dogger gamma formation is very different to the beta formation. The reservoir is know a lot better due to its smaller areal extension, thus it is known that the aquifer is supplying actively pressure. Due to the reservoir pressure being above the bubble point pressure and the supporting water aquifer, Dykstra – Parsons solution using the constant pressure loss boundary condition seems to be the best description of the horizon. All graphs generated to evaluate the different options can be found in appendix D.

However, the analytical simulation proved this thesis wrong. The Vertical Equilibrium theory was ruled out for both geometric cases due to its application needs. The Dogger gamma formation sands don't have the high vertical permeabilites, low oil viscosities or low layer thicknesses required by this theory. Furthermore the results of water injection have been better then those for polymer injection, while surfactant injection outperformed the combined polymer – surfactant treatment in both geometric cases for the constant pressure loss boundary. This behavior is strongly contradicted by the technical implication of its use and thus the results for Dykstra – Parsons applying a constant pressure loss boundary have been ruled out. The long times needed to reach ultimate recovery in all three graphs featuring a 3D case can be explained by the low production rates. The Figures 5.3 and 5.4 show the graphs for the chosen options (2D, Dykstra – Parsons, constant rate boundary) resulting from this study.

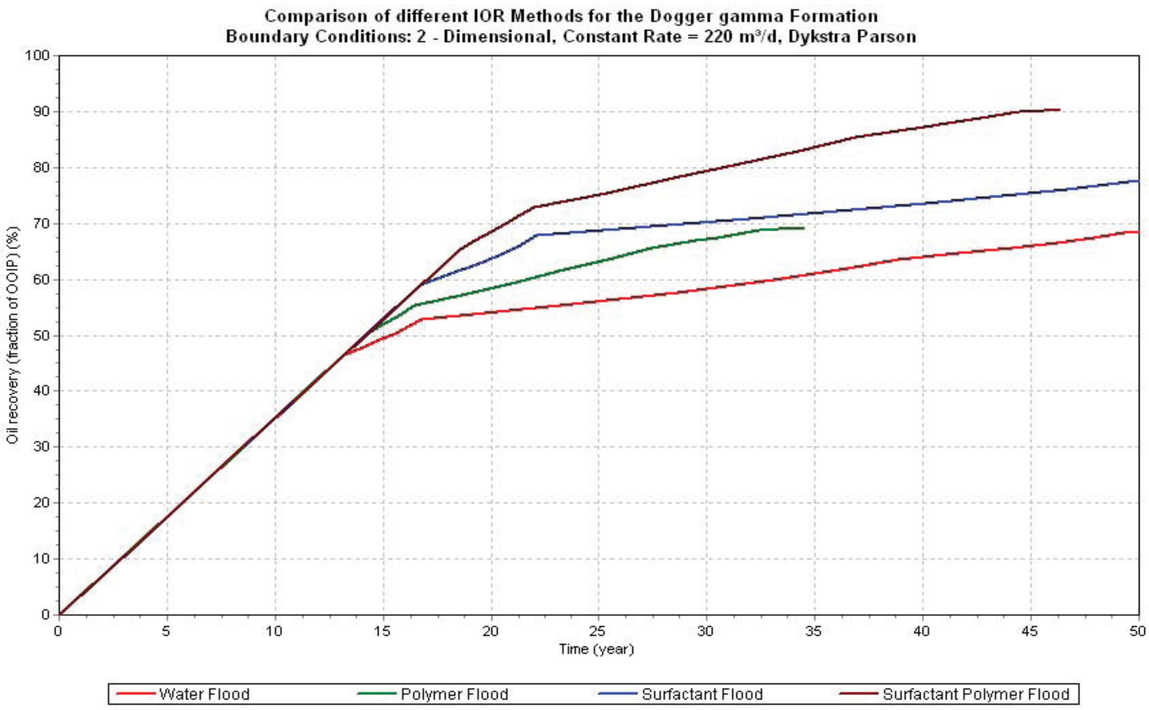

Figure 5.3.: 2D – Dykstra Parsons – constant rate case for the Dogger gamma formation

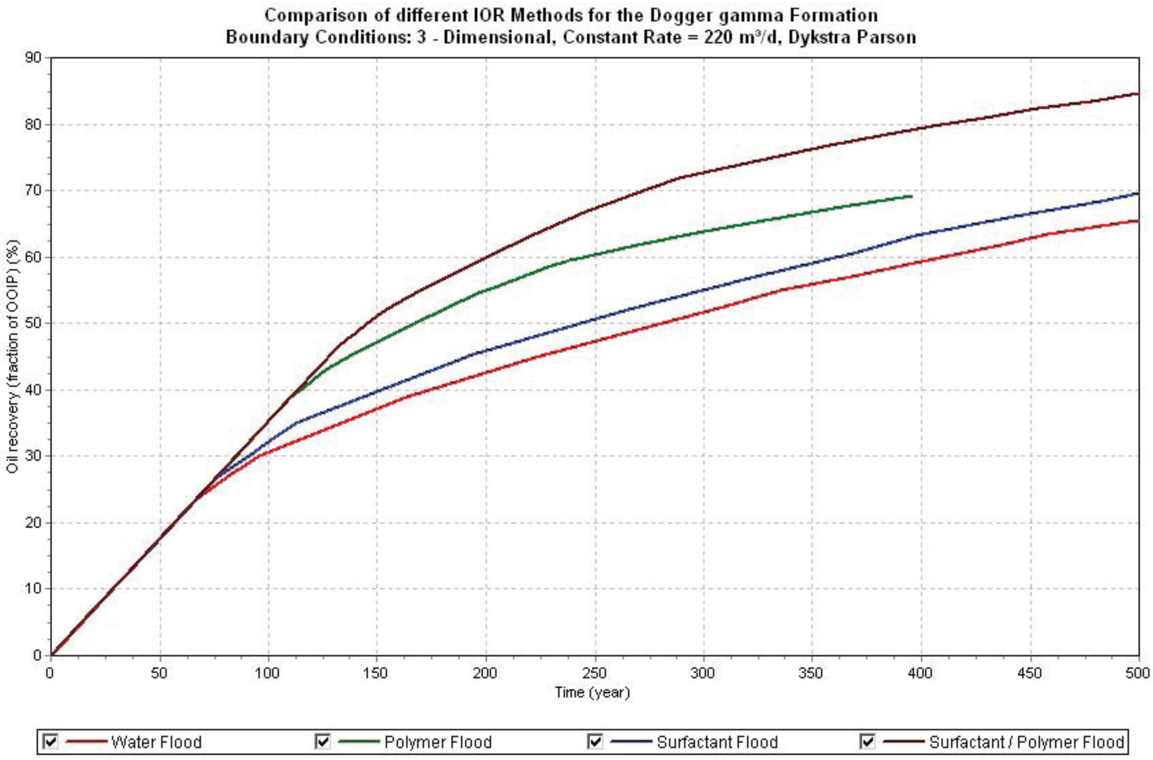

Figure 5.4.: 3D – Dykstra Parsons – constant rate case for the Dogger gamma formation

5.2.3. Dogger Delta / Epsilon Formation

The initial conditions for the Dogger delta / epsilon formation have been very similar to those of the Dogger gamma formation. An active water aquifer is known to support the reservoir with pressure and the reservoir pressure is higher then the bubble point pressure of the formation fluid. These conditions suggest the usage of the Dykstra – Parsons analytical solution, employing the constant pressure loss boundary condition. All graphs considered for the evaluation can be found in appendix D.

Again as for the Dogger gamma formation, the results of the study suggest the use of different options for the delta / epsilon horizon. Again the Vertical Equilibrium theory was ruled out as a possible analytical model due to the same regions as named for the Dogger gamma formation. Additionally in evaluation of the 2D case, the polymer and water injection curves break very soon without an apparent reason and show a very linear and thus unrealistic behavior. The 2D evaluation of the Dykstra – Parsons evaluation applying the constant pressure loss boundary shows again, as for the Dogger gamma case, a technically incomprehensive reversed behavior of the surfactant / surfactant – polymer and water / polymer injection pairs. Due to these reasons, the Dykstra – Parsons solution applying the constant rate boundary condition has been chosen to represent the Dogger delta / epsilon horizon best and was considered in more detail. The Figures 5.5 and 5.6 give the graphs for the chosen method.

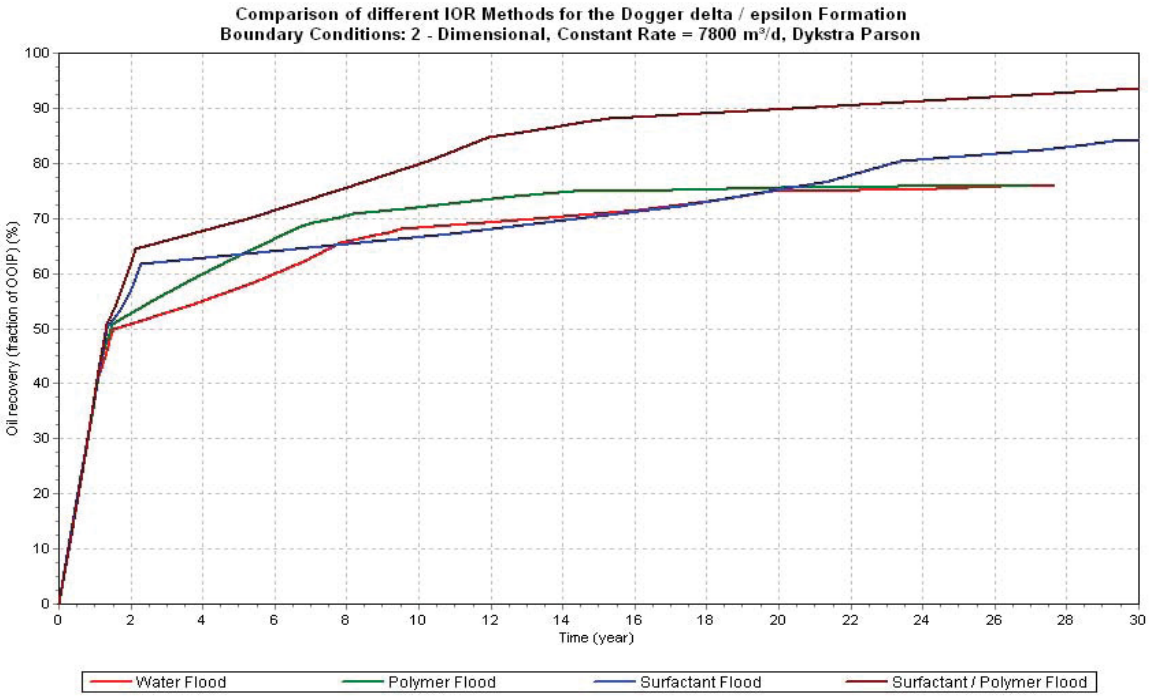

Figure 5.5.: 2D – Dykstra Parsons – constant rate case for the Dogger delta / epsilon formation

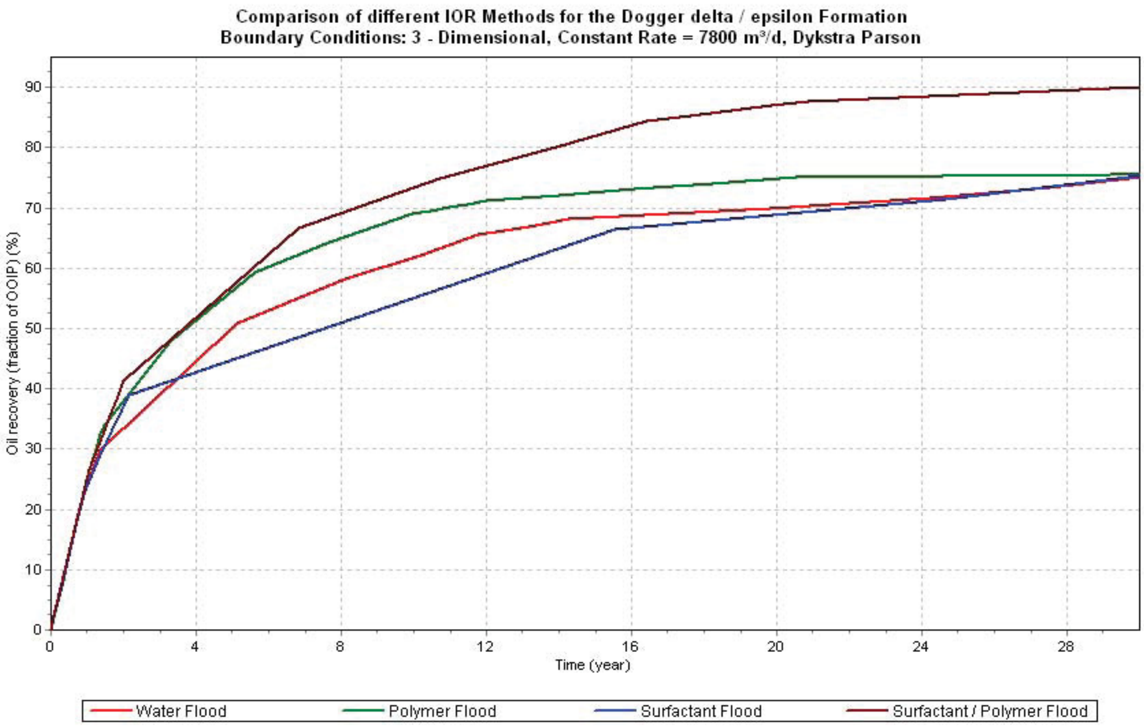

Figure 5.6.: 3D – Dykstra Parsons – constant rate case for the Dogger delta / epsilon formation

5.3. Predictions for the 2D Cross Sectional Cases

Based on the studies to find the optimal settings for the reservoir models, more detailed 2D analyses for these cases have been set up. All chose models used the 2D, Dykstra – Parsons and constant rate boundary condition settings. Graphical computations for the recovery factor, oil production rate, the water fraction of the produced fluid and pore injection volume have been made and are given in the following sub sections.

5.3.1. Dogger Beta Formation

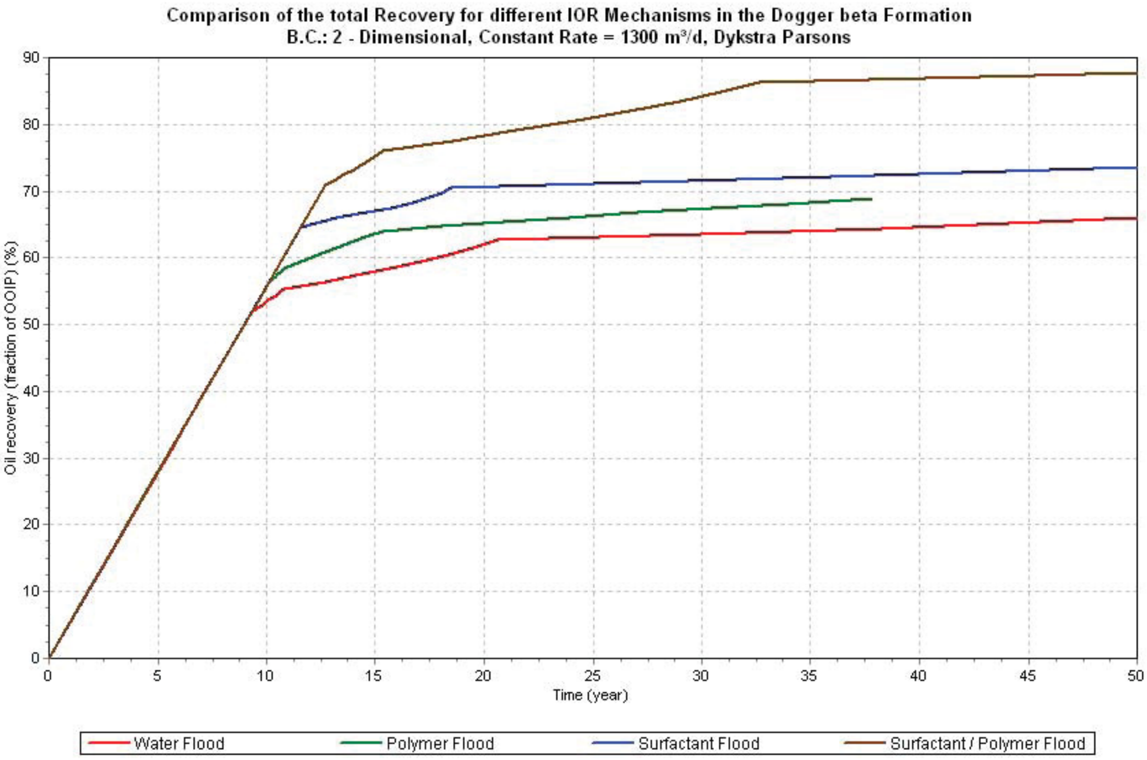

Figure 5.7.: Comparison of the recovery factor for the 2D Dogger beta case

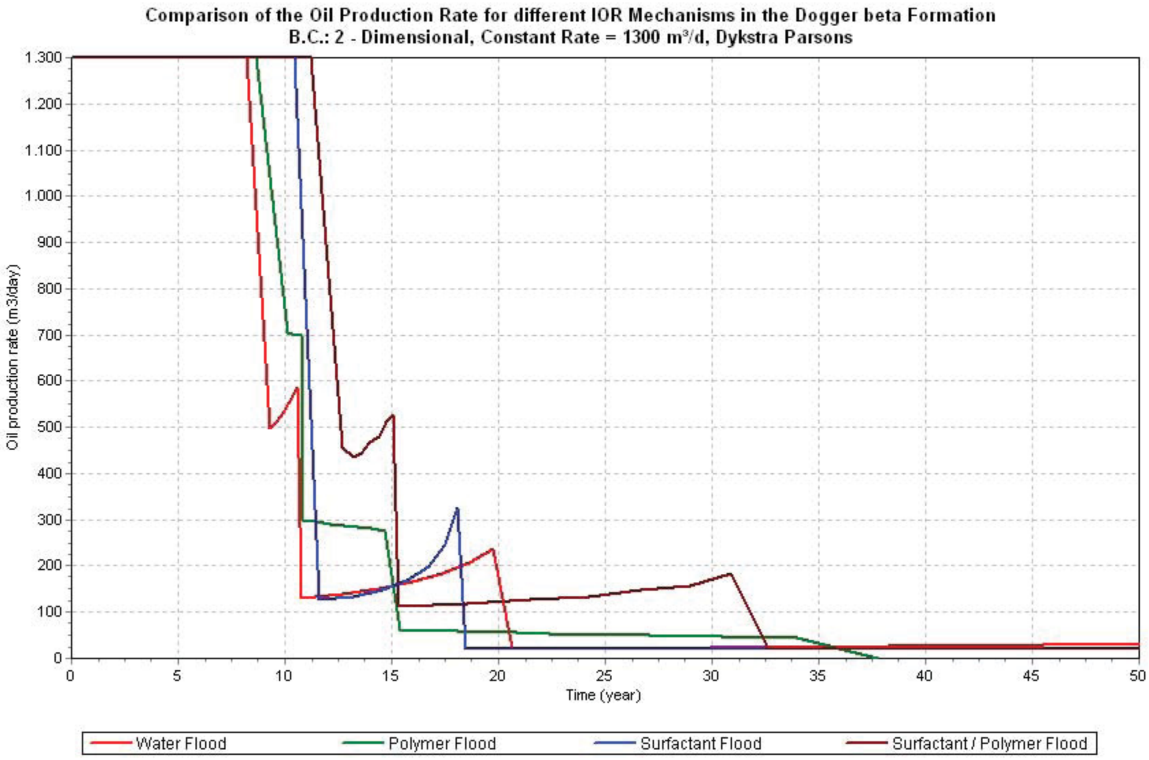

Figure 5.8.: Comparison of the oil production rate for the 2D Dogger beta case

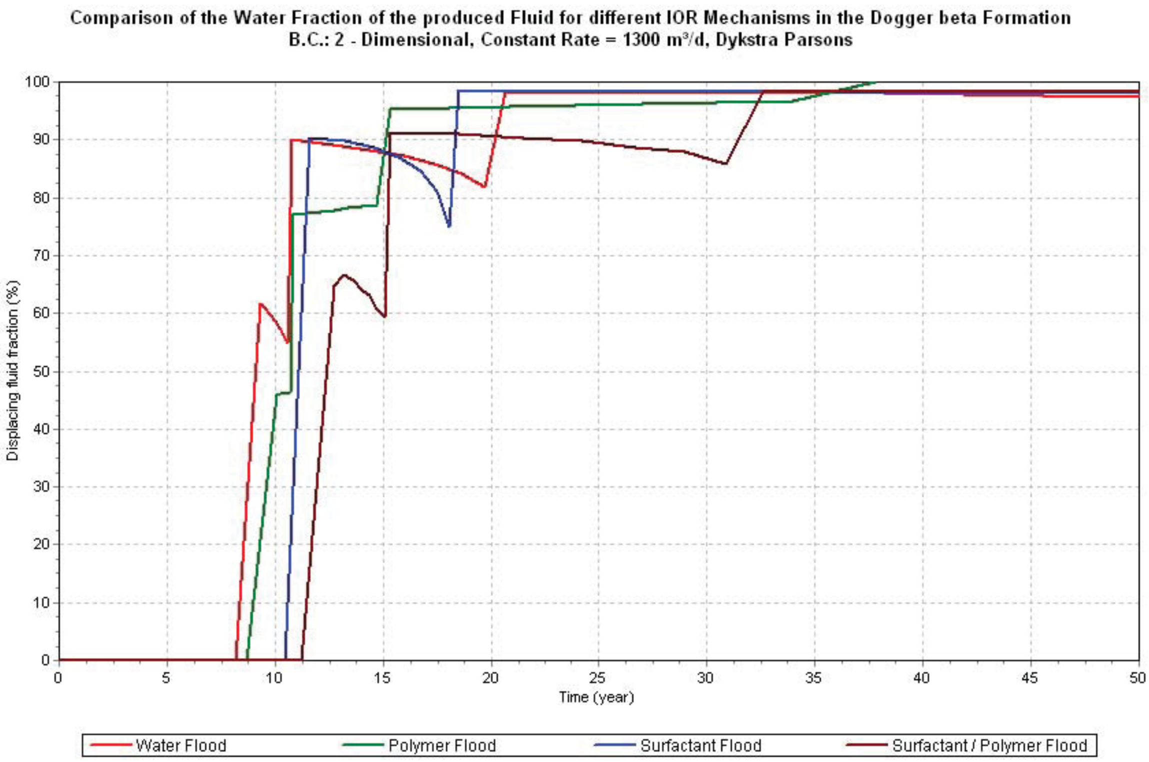

Figure 5.9.: Comparison of the water cut for the 2D Dogger beta case

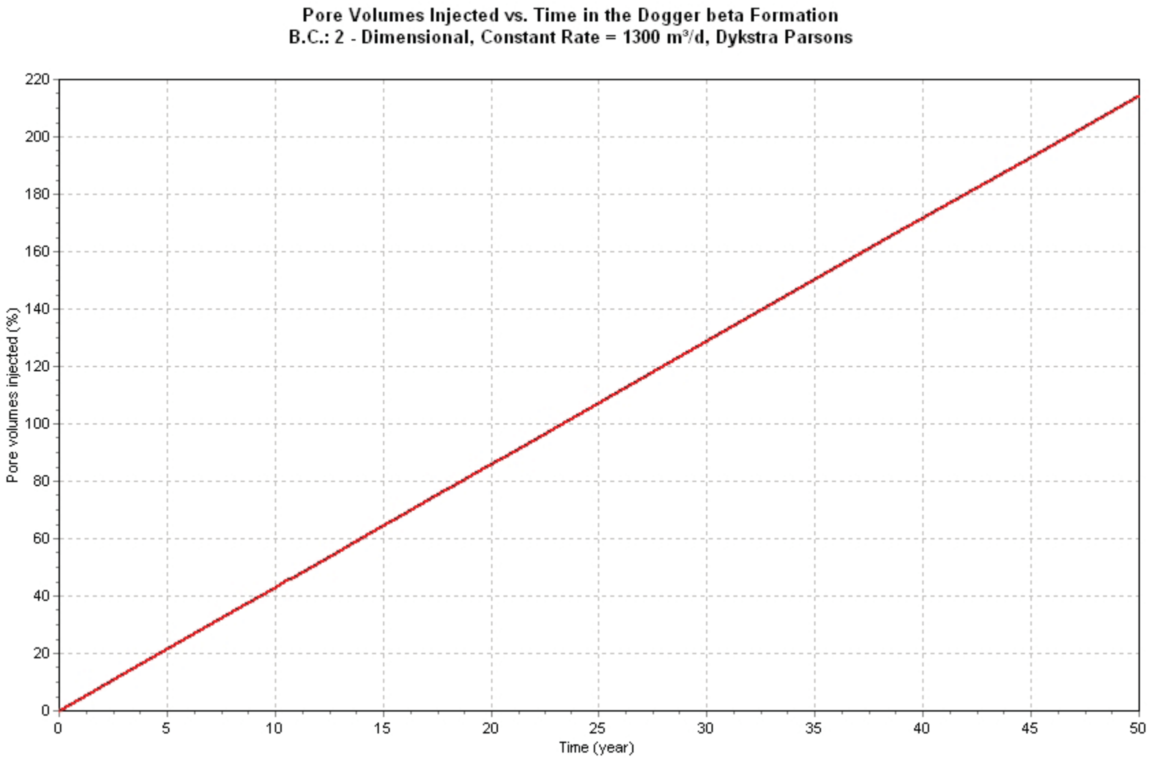

Figure 5.10.: Injected pore volume for the 2D Dogger beta case

Figure 5.7 shows a comparison of the recovery factor for the different calculated EOR methods. As can be seen in this graph, polymer injection speeds up the recovery of the crude oil by a significant amount of time in comparison to regular water injection. The additional amounts range between 3% and 8% of the OOIP at certain time points and could be even more if economic limits are considered. The reason for this effect can be found in the improved volumetric sweep efficiency, induced by the polymer enhanced water viscosity. The application of a surfactant or surfactant – polymer injection might even have a bigger benefit (the base case shows an increase in recovery of 8% - 20% over water injection), but must be taken with caution because of program limitations. The software is an analytical simulator and cannot capture the different physical or chemical processes caused by the application of surfactants. The Figures 5.8 and 5.9 show comparisons of the oil production rate and the water cut respectively. The results can be reasoned analogues to the recovery factor. A very steep increase in water cut accompanied by short plateaus can be observed after 8 to 12 years of production resulting from the water breakthrough in the different sands and the Dykstra – Parsons solution method. For all methods except polymer flooding, the oil production rate and water cut experience unrealistic spikes, which seem to be the result of problems in the analytical calculation. Figure 5.10 shows the injected pore volume over time, which follows a linear increase. This can be reasoned by the volumetric characteristic of the simulation in combination with the constant rate boundary. After about 23 years a pore volume has been injected.

5.3.2. Dogger Gamma Formation

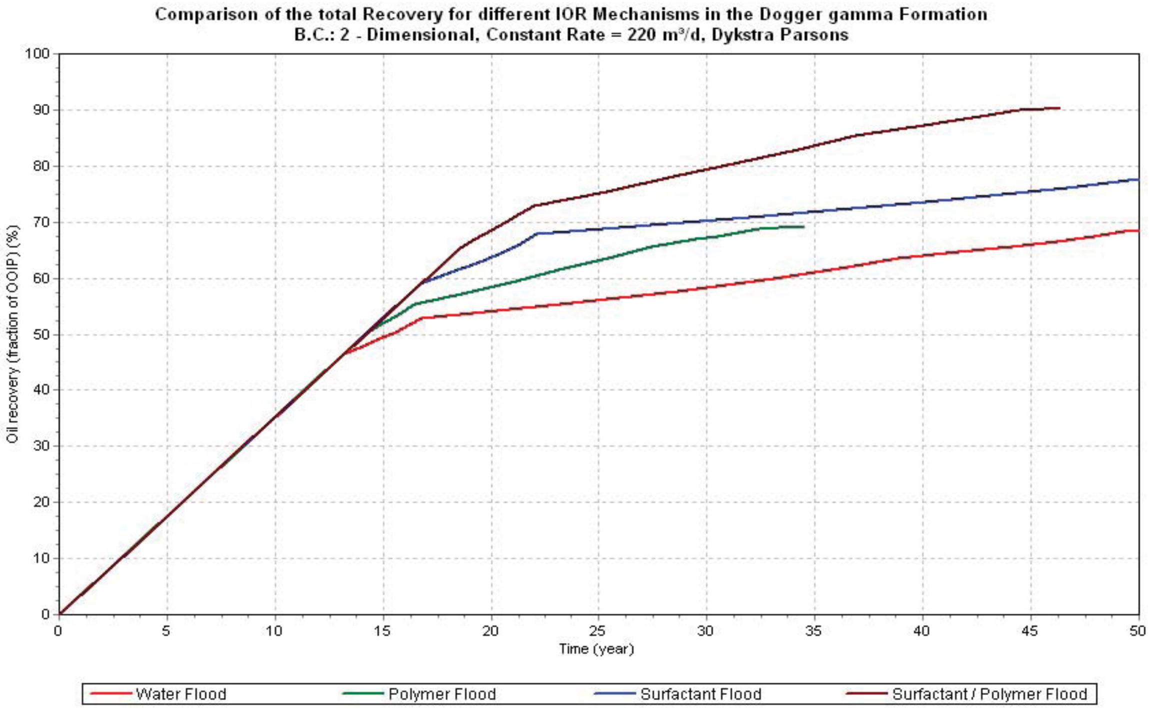

Figure 5.11.: Comparison of the recovery factor for the 2D Dogger gamma case

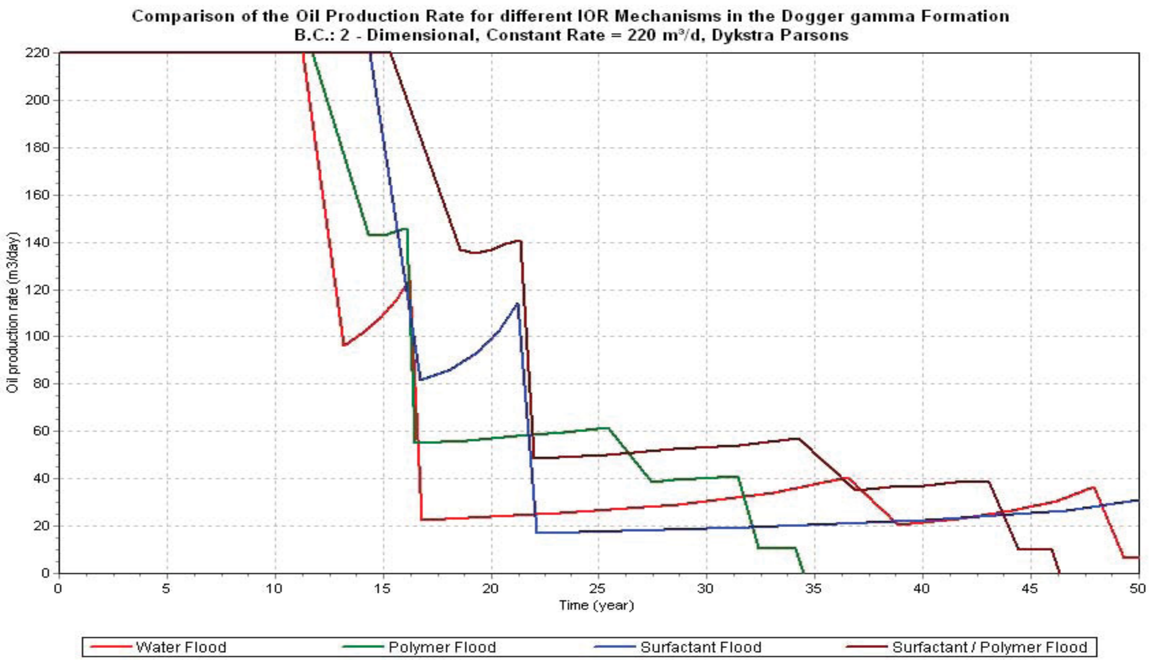

Figure 5.12.: Comparison of the oil production rate for the 2D Dogger gamma case

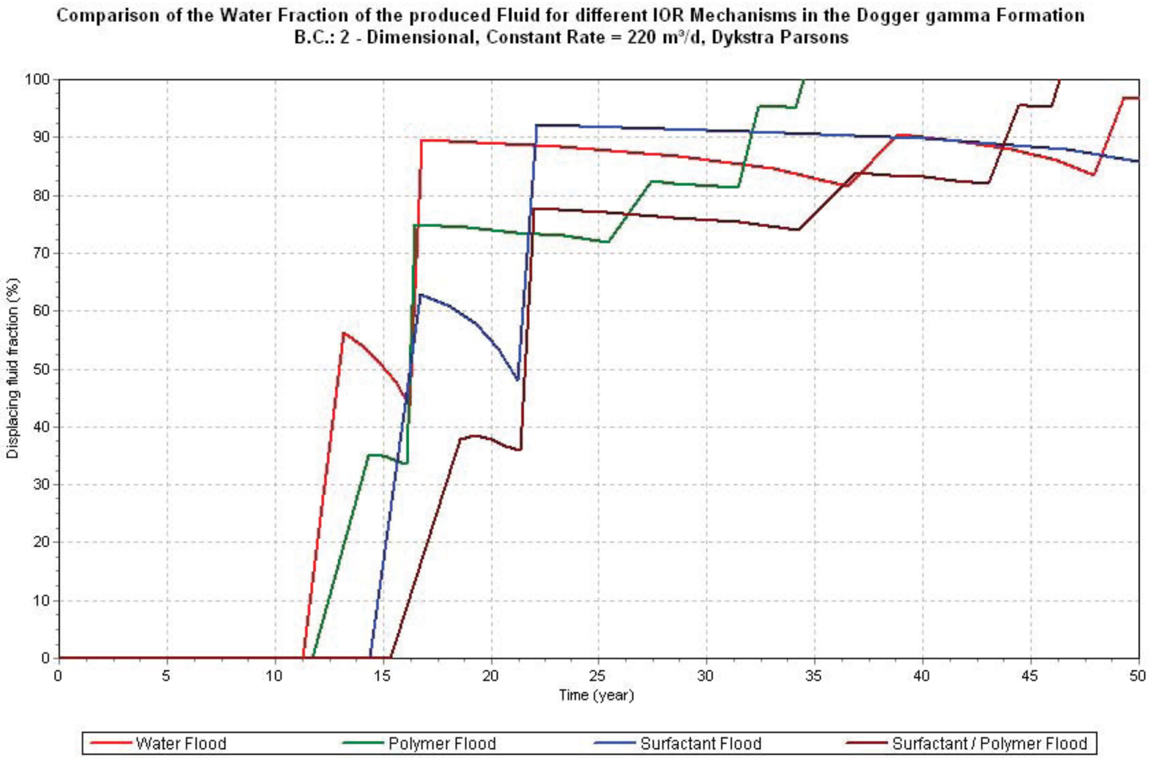

Figure 5.13.: Comparison of the water cut for the 2D Dogger gamma case

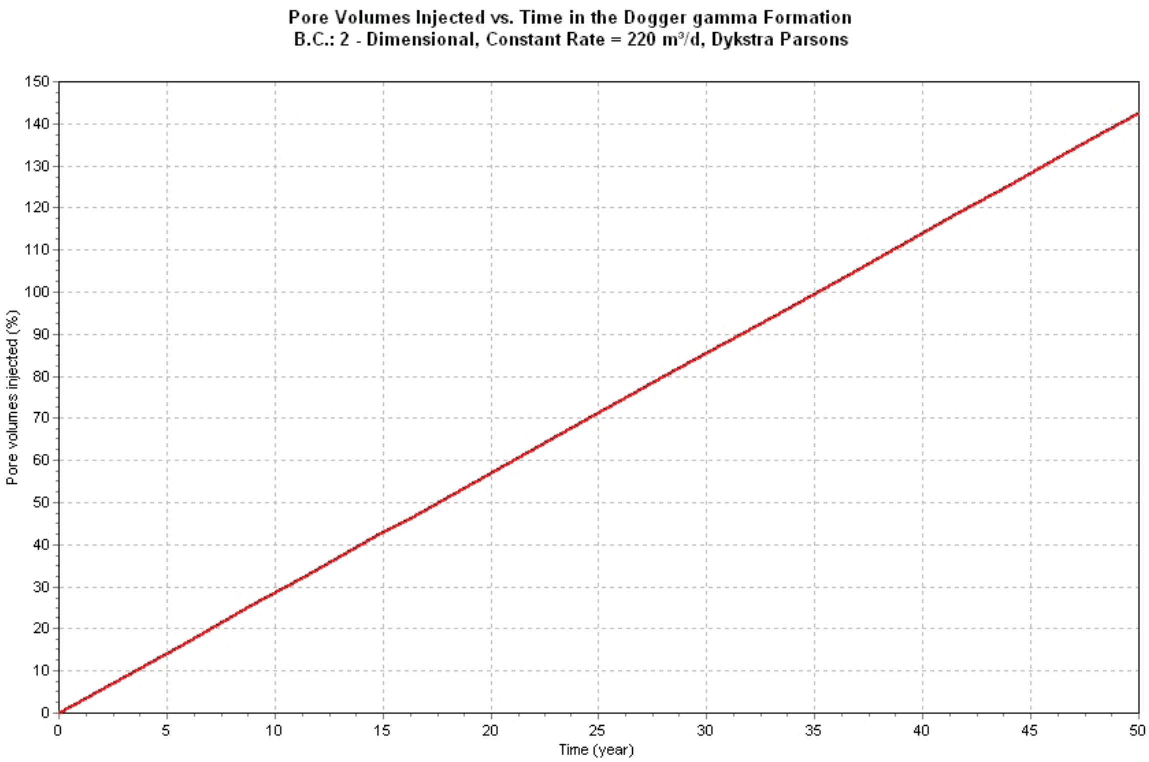

Figure 5.14.: Injected pore volume for the 2D Dogger gamma case

The results and reasoning of the 2D prediction case for the Dogger gamma formation are quite similar to those of the Dogger beta formation. After an initial production period of about 13 years where the recovery factor for all methods rises linearly, the benefits of the different methods can be seen. Polymer injection reaches a recovery increase over water injection of about 2% to 10% of OOIP, depending on the observation moment. Again economic limits could even increase these amounts. Surfactant and surfactant – polymer injection achieve even an increase of 10% to 25% of oil production. The same limitations considered for the Dogger beta formation apply as well to the Dogger gamma formation. Figures 5.12 and 5.13 show comparisons of the oil production rate and the water cut for each EOR method. Again rather steep increases in water cut can be observed, although they are a bit slower then for the Dogger beta formation. The accompanying plateaus hold themselves additionally for a longer time, which can be explain by the more heterogeneous sands of the Dogger gamma formation that cause a bigger difference in the breakthrough times. The decrease in oil production rate starts after 12 to 16 years of production. Again unrealistic spikes for water and surfactant injection can be observed, but they seem as well smoother then for the Dogger beta formation. Figure 5.14 shows the injected pore volume for the Dogger gamma formation, which features as in the Dogger beta formation a linear increase. After 35 years a 100% pore volume is injected.

5.3.3. Dogger Delta / Epsilon Formation

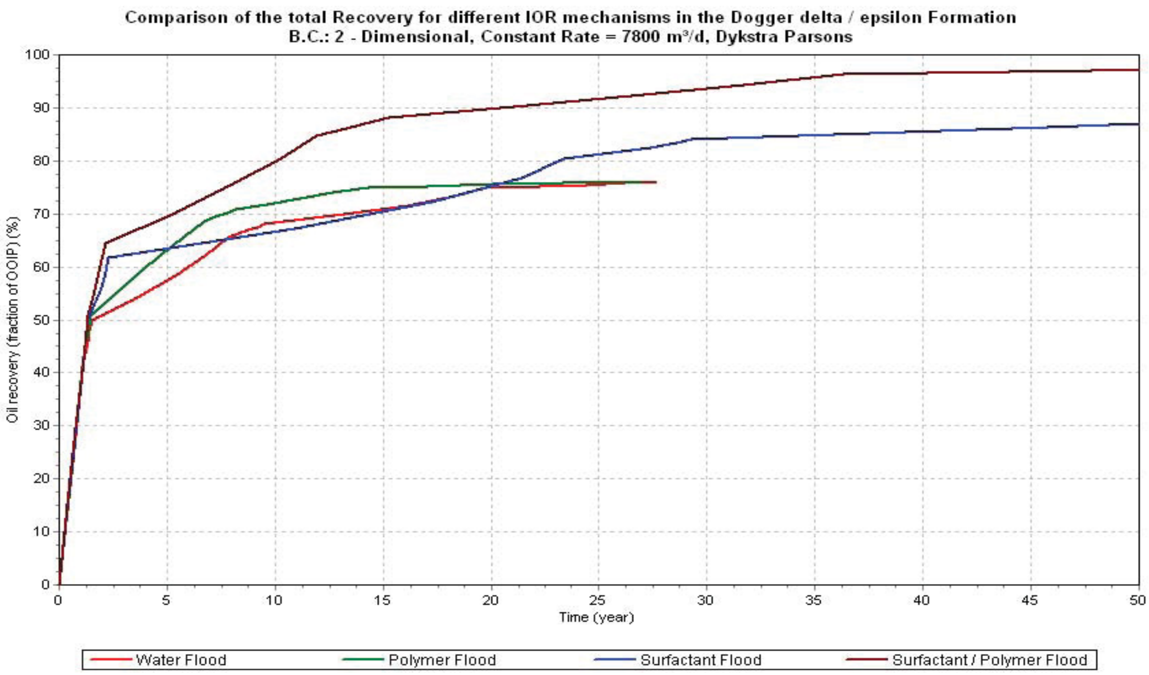

Figure 5.15.: Comparison of the recovery factor for the 2D Dogger delta / epsilon case

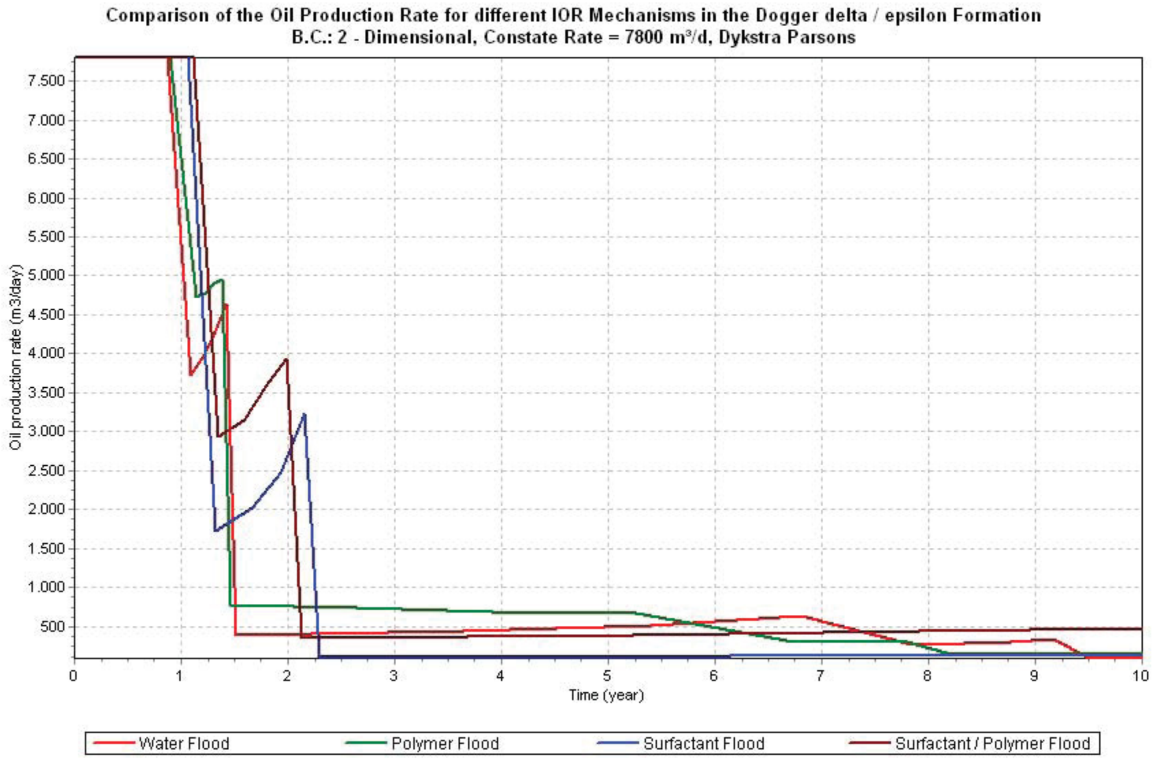

Figure 5.16.: Comparison of the oil production rate for the 2D Dogger delta / epsilon case

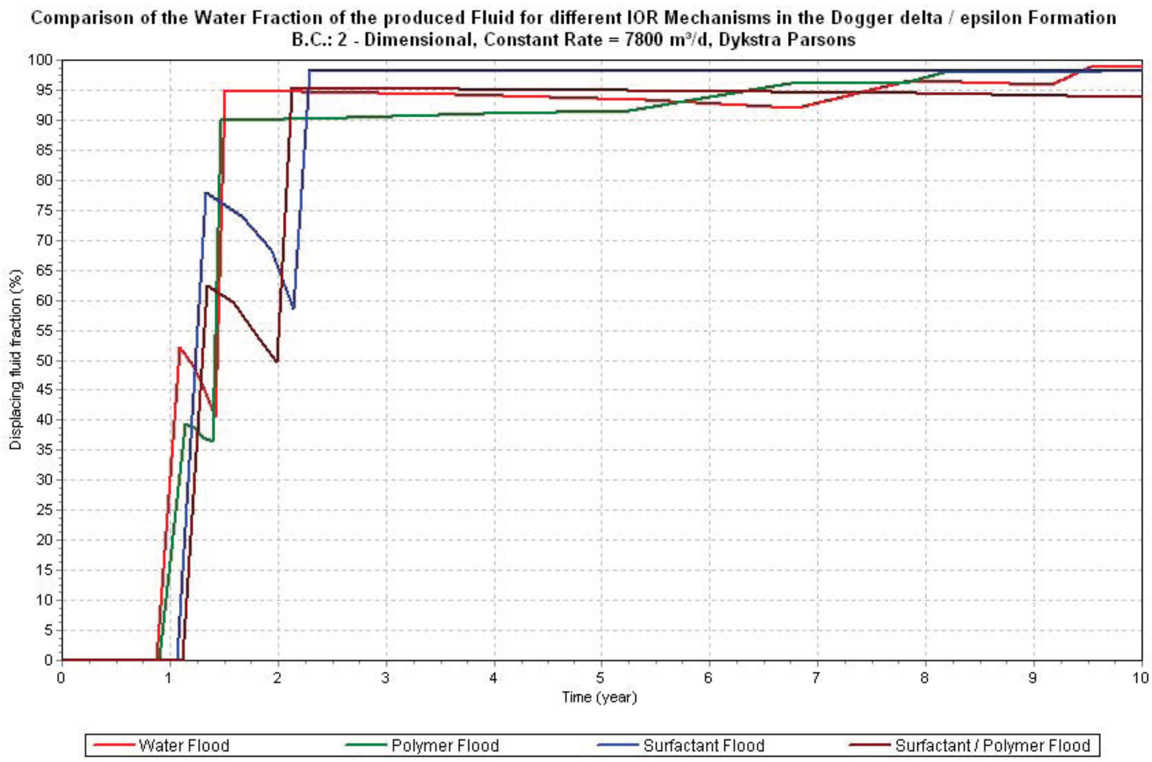

Figure 5.17.: Comparison of the water cut for the 2D Dogger delta / epsilon case

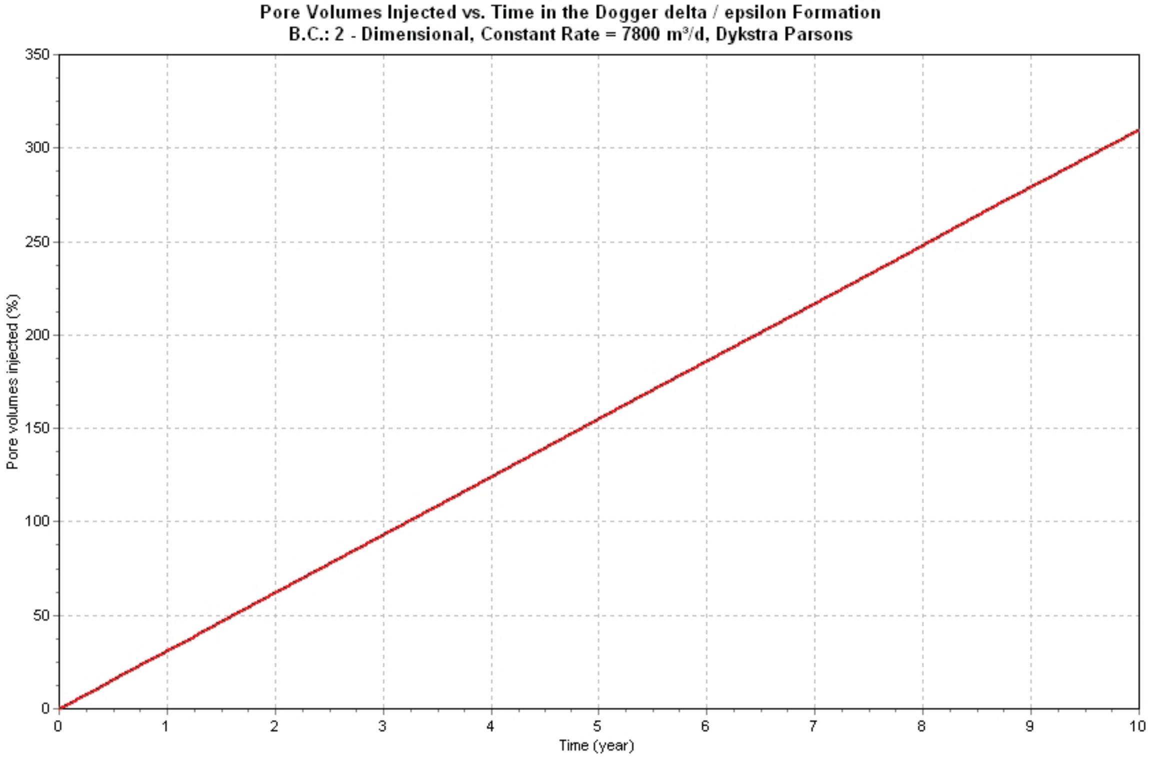

Figure 5.18.: Injected pore volume for the 2D Dogger delta / epsilon case

The results for the Dogger delta / epsilon 2D case go along with those of the other formations. Figure 5.15 shows excellently the scissor effect between polymer and water injection. After about 2 years of production, where the recovery factor rises linearly for all four methods, the increased benefit ob polymer injection starts, opening the "scissor" to a maximum of about 5% of OOIP until it closes again at the time of ultimate recovery. The benefits of surfactant flooding start for the Dogger delta / epsilon formation pretty late, but offering more then 10% of OOIP of additional ultimate recovery, not considering economic limits. The recovery factor of the combined surfactant – polymer flooding rises quickly to a 20% increase over water injection. The limitations for this study are identical to those of the other two formations. The Figures 5.16 and 5.17 show the results of the oil production rate and water cut evaluation. It can be seen that the plateaus are much smaller then those of the Dogger beta or gamma formation, additionally the spikes are more severe. Additionally to the reasoning supplied earlier, the very high permeability of the Dogger delta / epsilon sands seems to be enlarging these issues. Finally, Figure 5.18 shows the injected pore volume for this horizon, featuring an injected pore volume of 100% already after 3 years. Again, the high permeability appears to be the reason.

5.4. Predictions for the 3D Cases (5 Spot Pattern)

Additionally to the detailed 2D case, 3D analyses have been set up to have the possibility of evaluation economical studies on both possible geometric settings. All chose models used the 3D, Dykstra – Parsons and constant rate boundary condition settings. Graphical computations for the recovery factor, oil production rate, the water fraction of the produced fluid and pore injection volume have been made and are given in the following sub sections.

5.4.1. Dogger Beta Formation

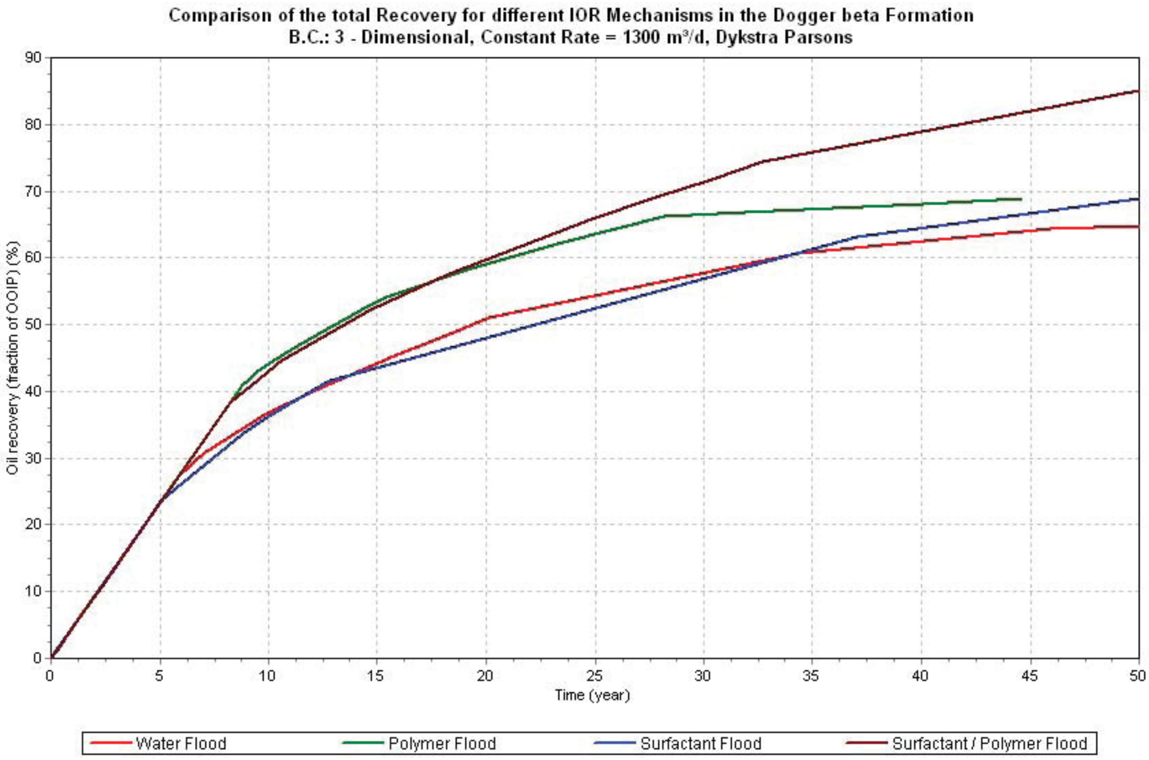

Figure 5.19: Comparison of the recovery factor for the 3D Dogger beta case

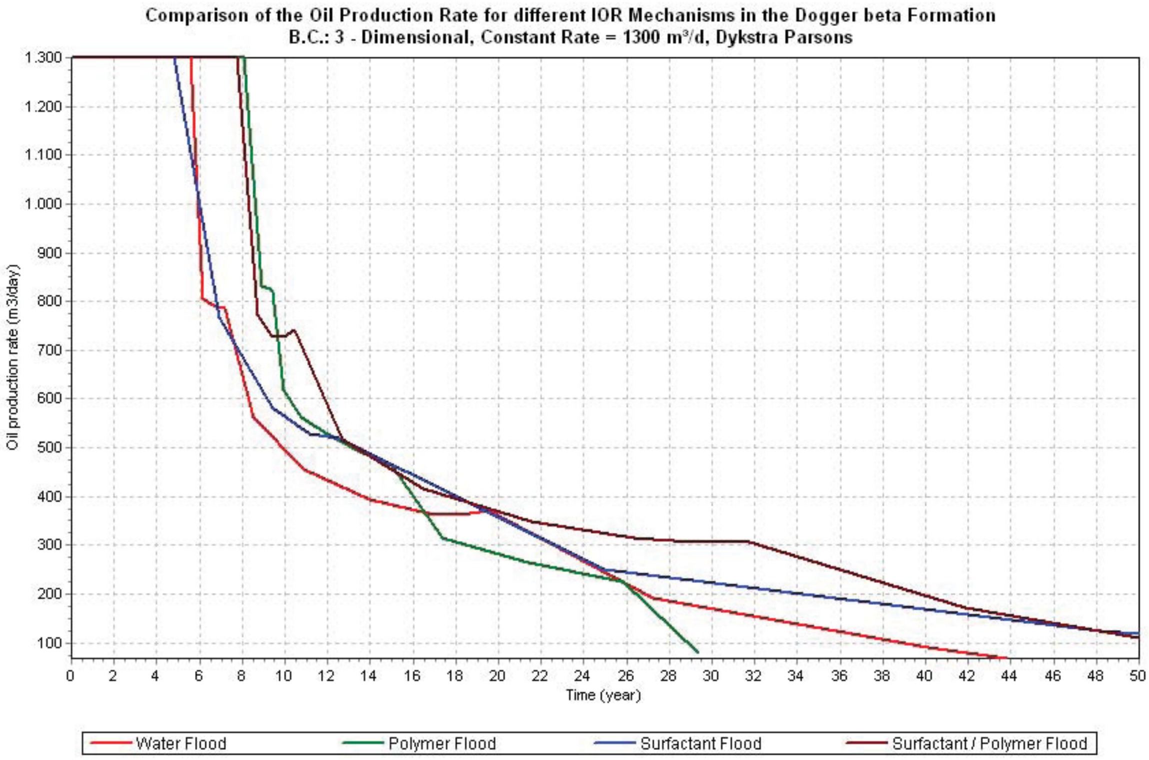

Figure 5.20.: Comparison of the oil production rate for the 3D Dogger beta case

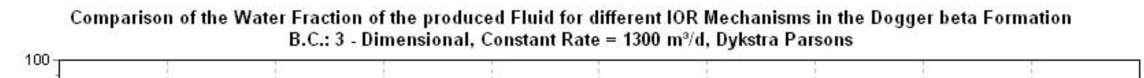

Figure 5.21.: Comparison of the water cut for the 3D Dogger beta case

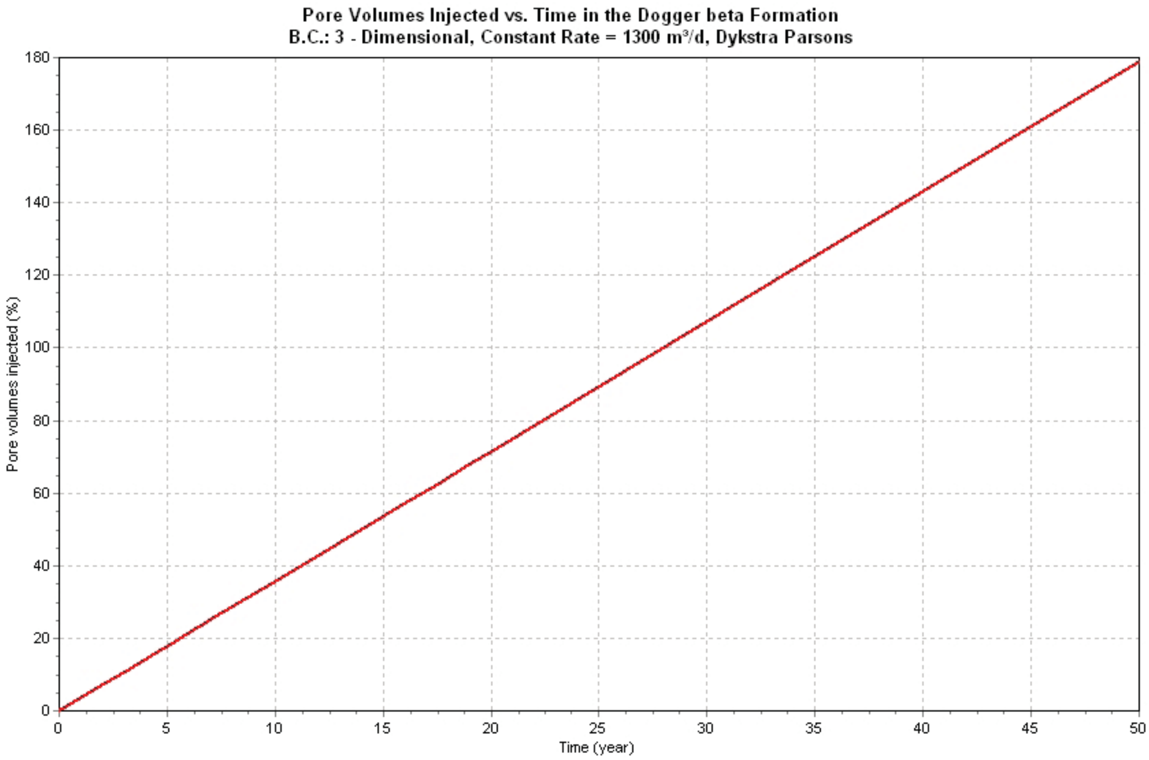

Figure 5.22.: Injected pore volume for the 3D Dogger beta case

In Figure 5.19 the results of the recovery factor comparison for the different mechanisms can be seen. They are analogues to those of the 2D comparison, featuring an increase of production for polymer injection of over 10% of OOIP in comparison to water injection. As well the beneficial impact of surfactants and the combined treatment are obvious on the first sight, with a maximum of 20% of OOIP of additional production after 50 years. The limitations named for the 2D prediction case count as well for the 3D case. The Figures 5.20 and 5.21 show the oil production rate and the water cut of the produced fluid. They are a lot more stable then in the 2D case, showing more or less smooth increases or decreases respectively and no plateaus. Water production starts after 5 – 8 years and rises sharply at first. These results can be explained by a reduced effect of the different layer breakthrough times due to the 3D geometry. Figure 5.22 features the injected pore volume over time, reaching 100% pore volume after about 28 years of injection.

5.4.2. Dogger Gamma Formation

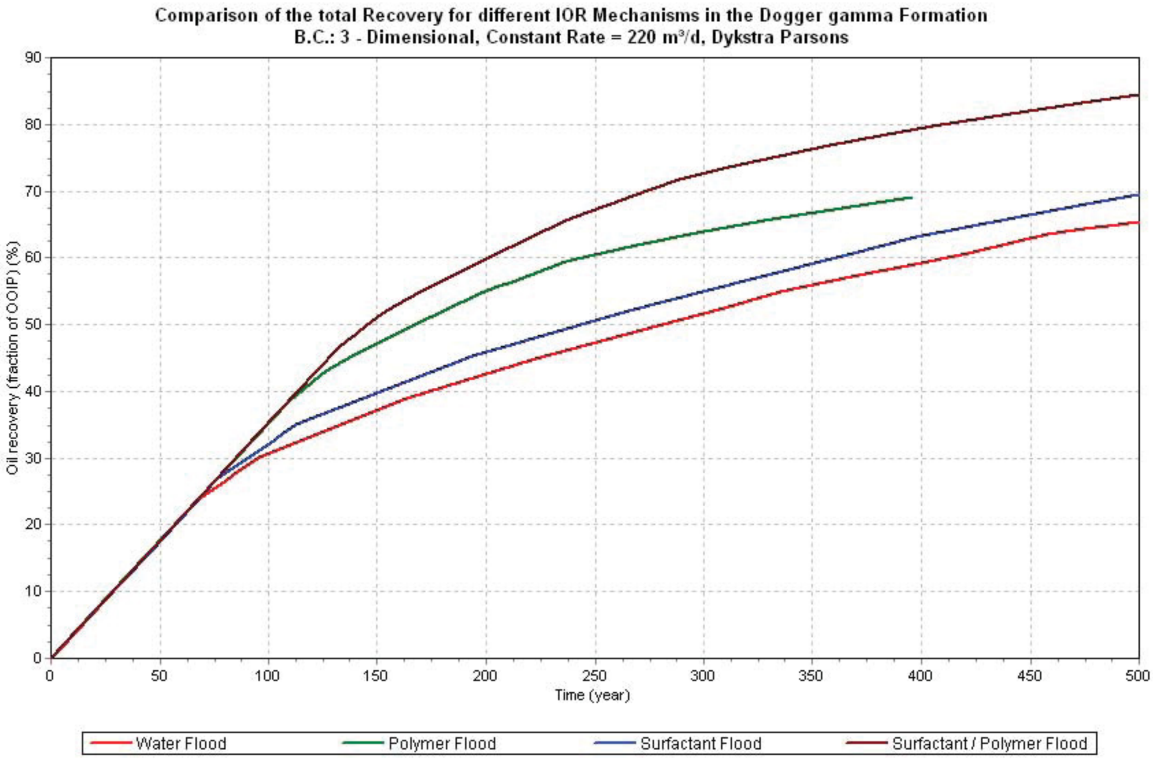

Figure 5.23.: Comparison of the recovery factor for the 3D Dogger gamma case

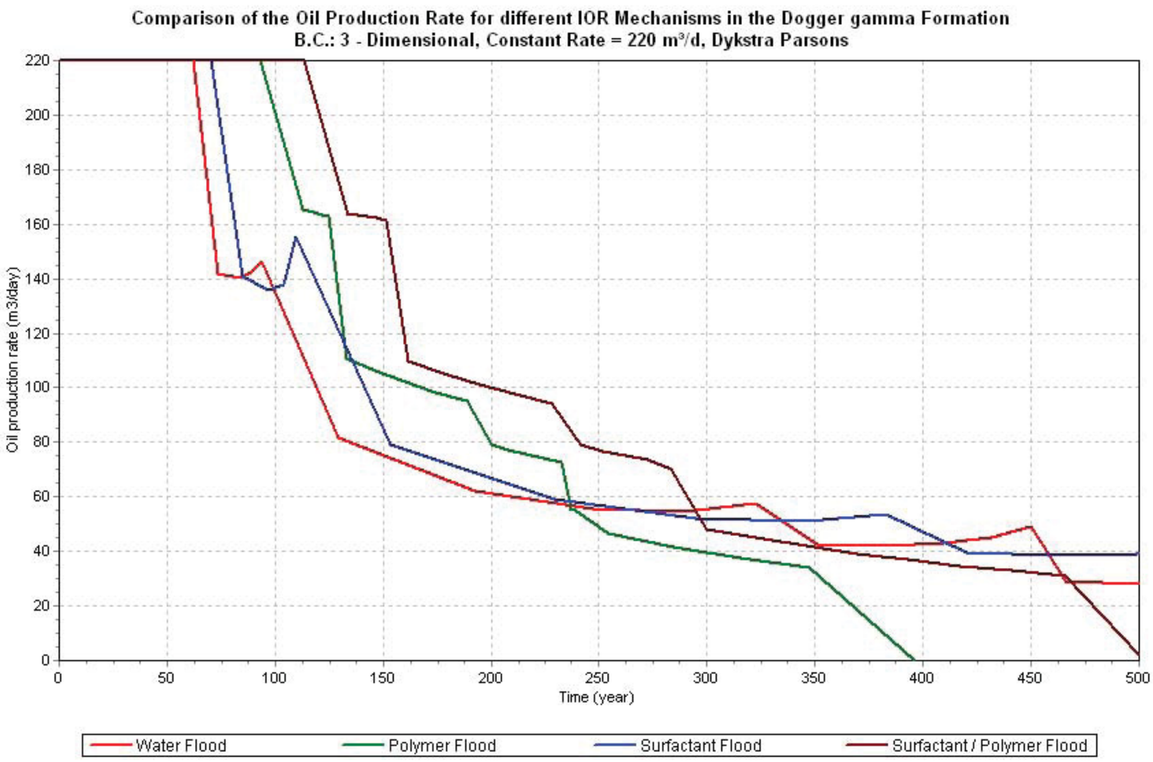

Figure 5.24.: Comparison of the oil production rate for the 3D Dogger gamma case

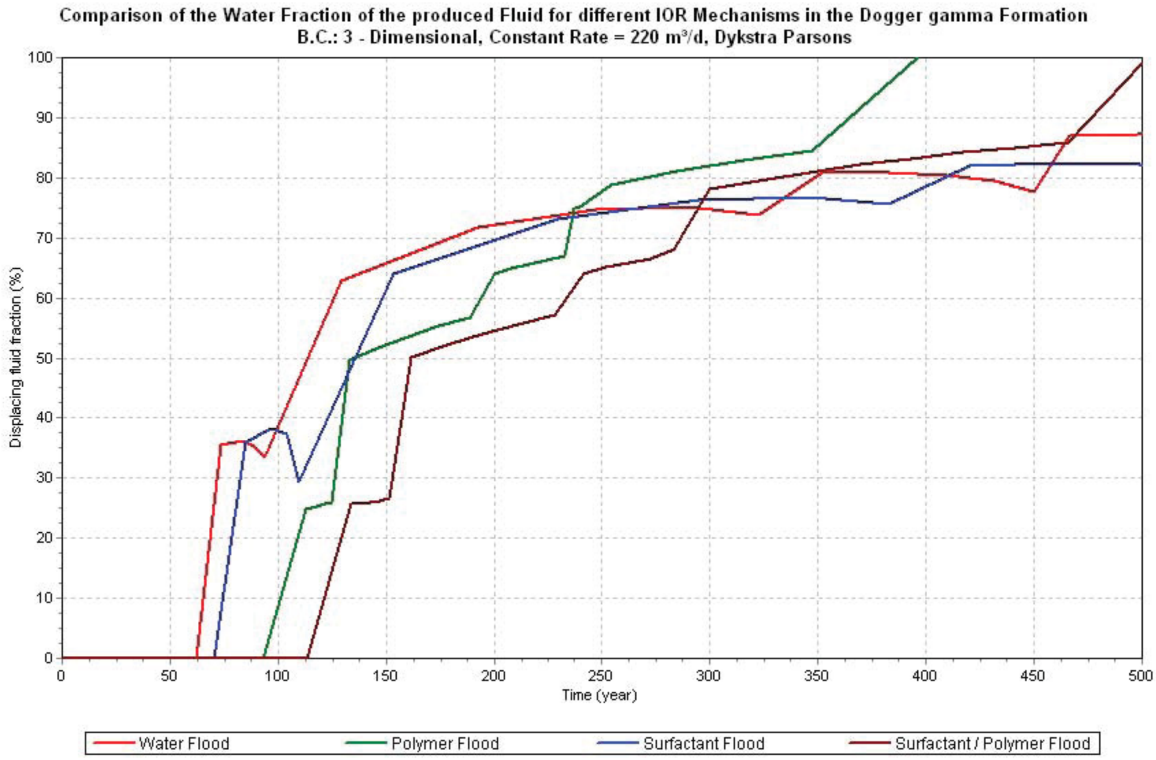

Figure 5.25.: Comparison of the water cut for the 3D Dogger gamma case

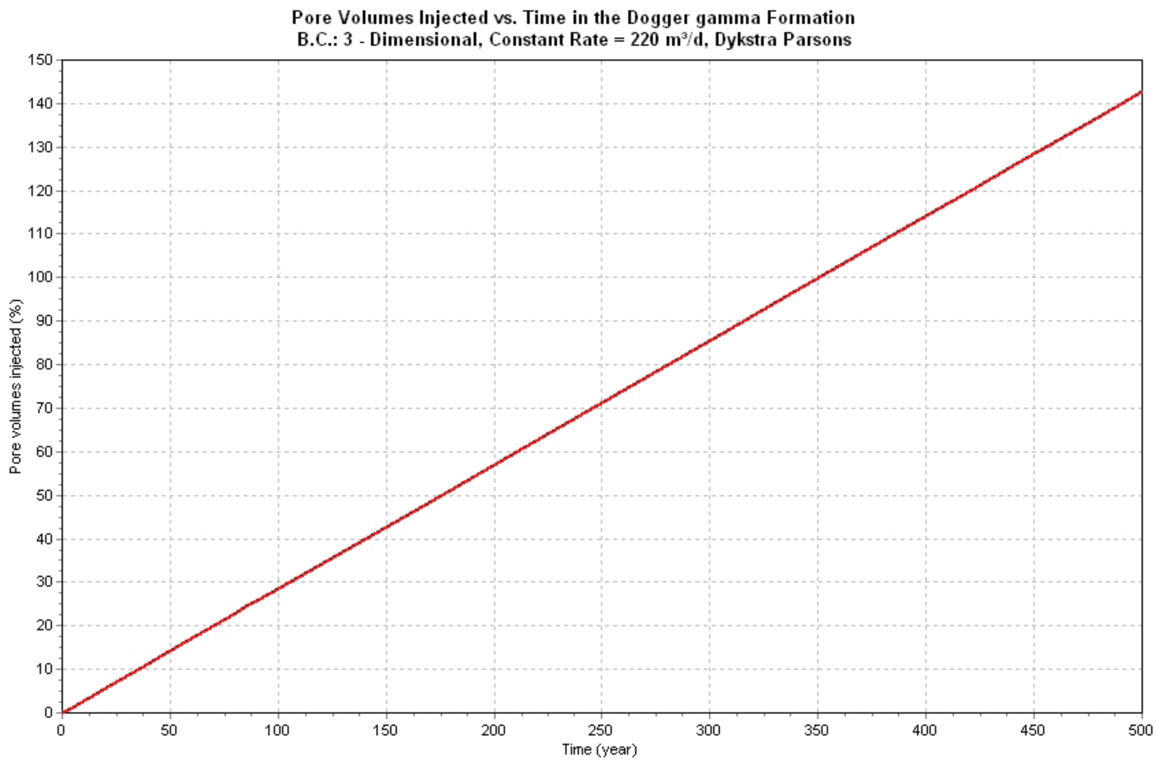

Figure 5.26.: Injected pore volume for the 3D Dogger gamma case

The results of the 3D case for the Dogger gamma formation are in line with the Dogger beta formation. Figure 5.23 gives the recovery factor comparison, showing very nicely the benefits of the EOR methods. An increase of up to 10% of OOIP for the polymer injection over water injection can be observed, while surfactant and surfactant – polymer injection gives a 4% - 20% increase. In general the different graphs rise very smoothly over a very long time. The reason for that can be found in the rather low oil production rate. Figures 5.24 and 5.25 give comparisons of the oil production rate and the water cut of the produced fluid for the 3D case of the Dogger gamma formation. The rate stays very long at the boundary condition of 220 m^3/d and starts falling finally after a production time of 50 to 100 years. The plateaus caused by the solution method can be seen more clearly here in opposition to the Dogger beta case and are generally technically reasonable. However, the water and surfactant injection methods have an incomprehensive spike shortly after the decline starts, which can be reasoned analogues to the other studies with problems in the analytical calculation. Figure 5.26 shows the injected pore volume over time, reaching 100% pore volume after about 350 years. In general all limitations and reasons named for the other study cases can be applied towards this case as well.

5.4.3. Dogger Delta / Epsilon Formation

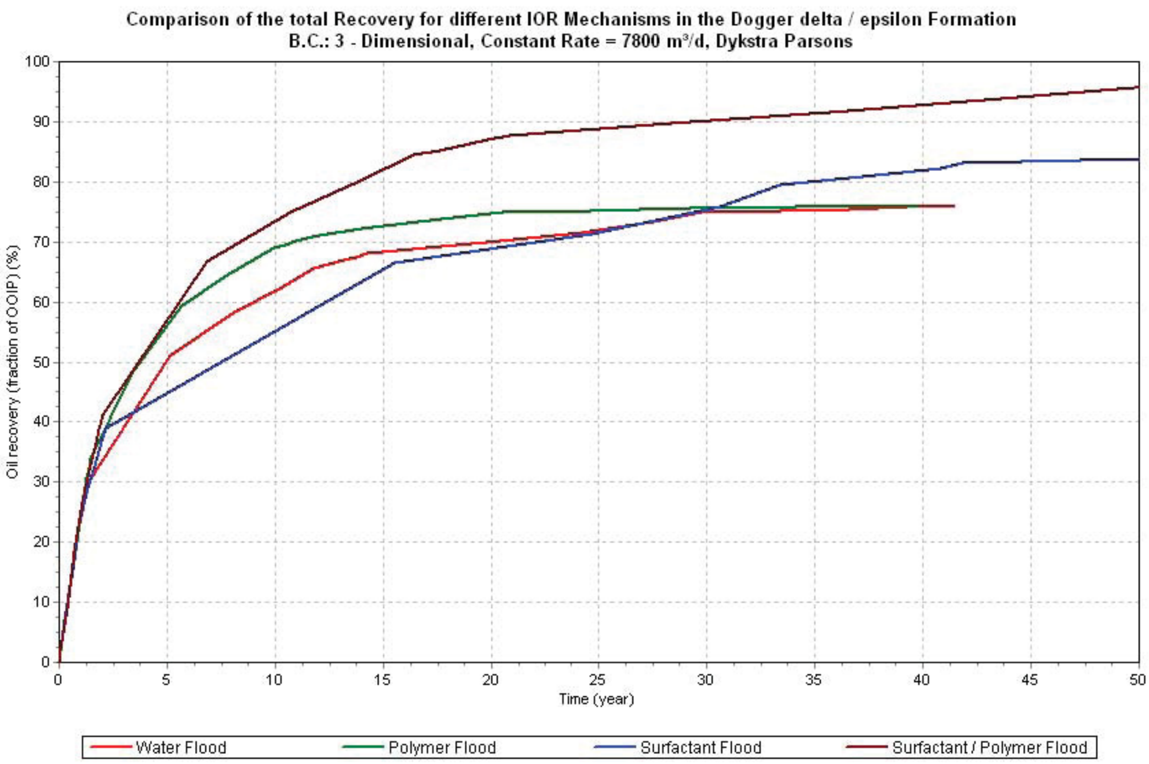

Figure 5.27.: Comparison of the recovery factor for the 3D Dogger delta / epsilon case

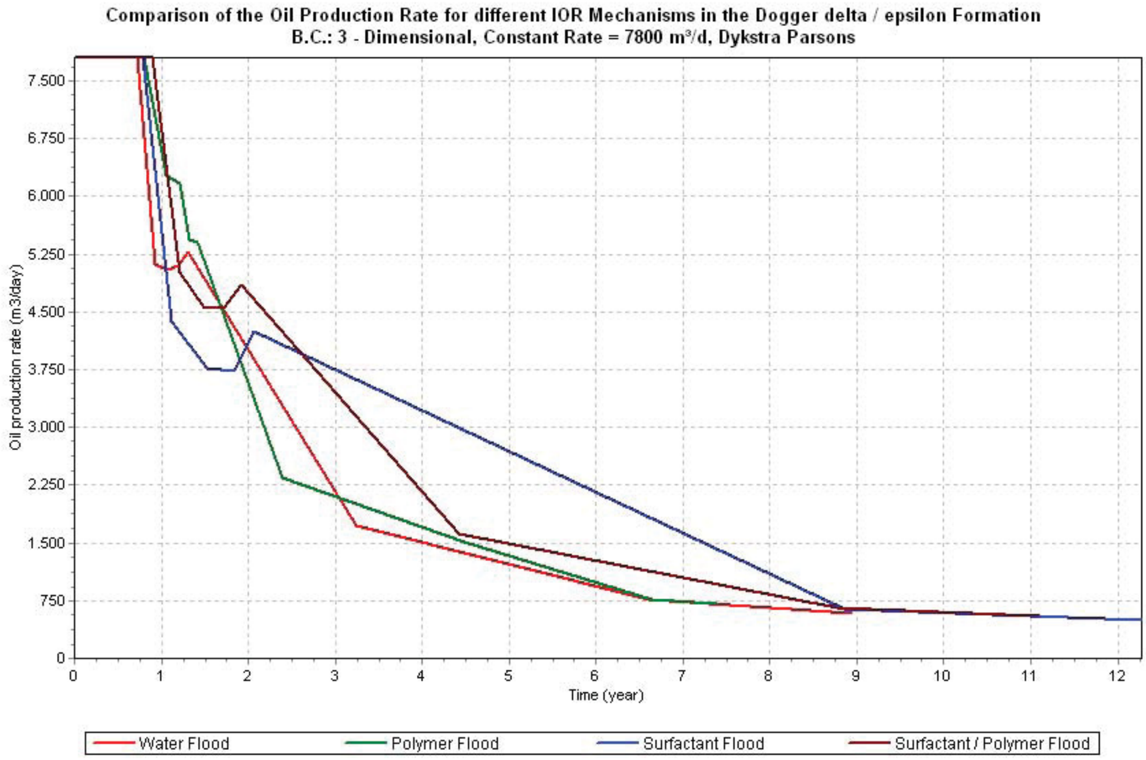

Figure 5.28.: Comparison of the oil production rate for the 3D Dogger delta / epsilon case

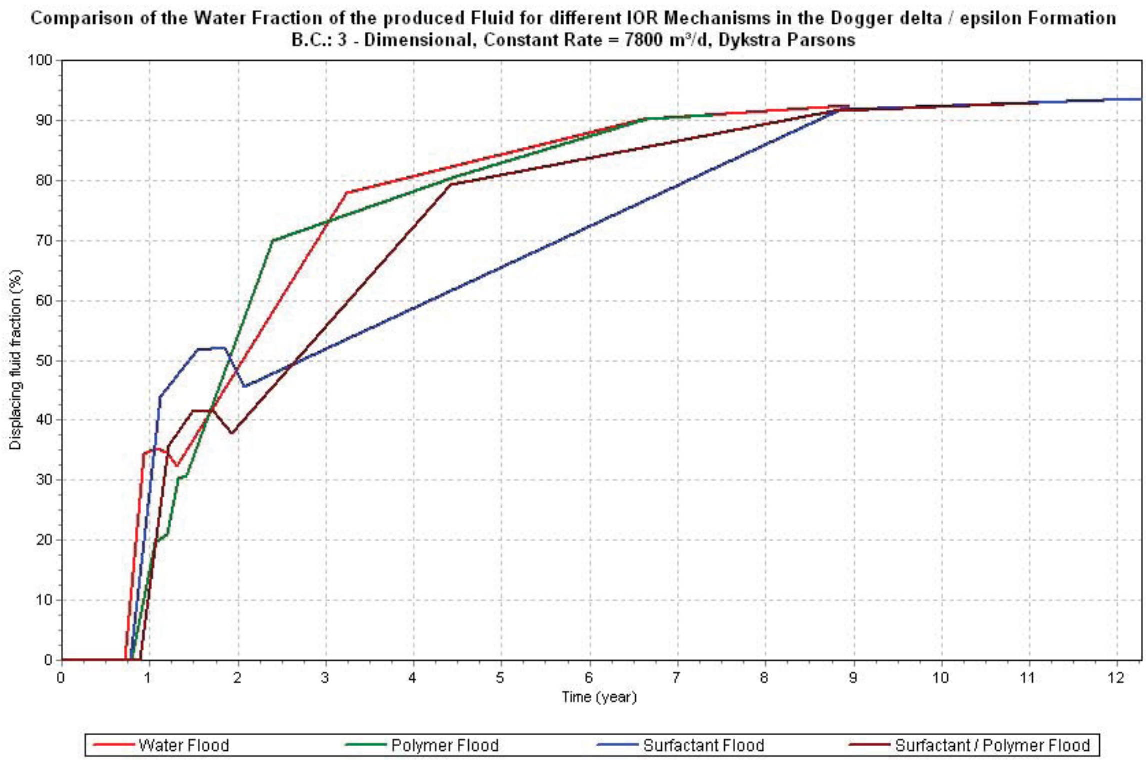

Figure 5.29.: Comparison of the water cut for the 3D Dogger delta / epsilon case

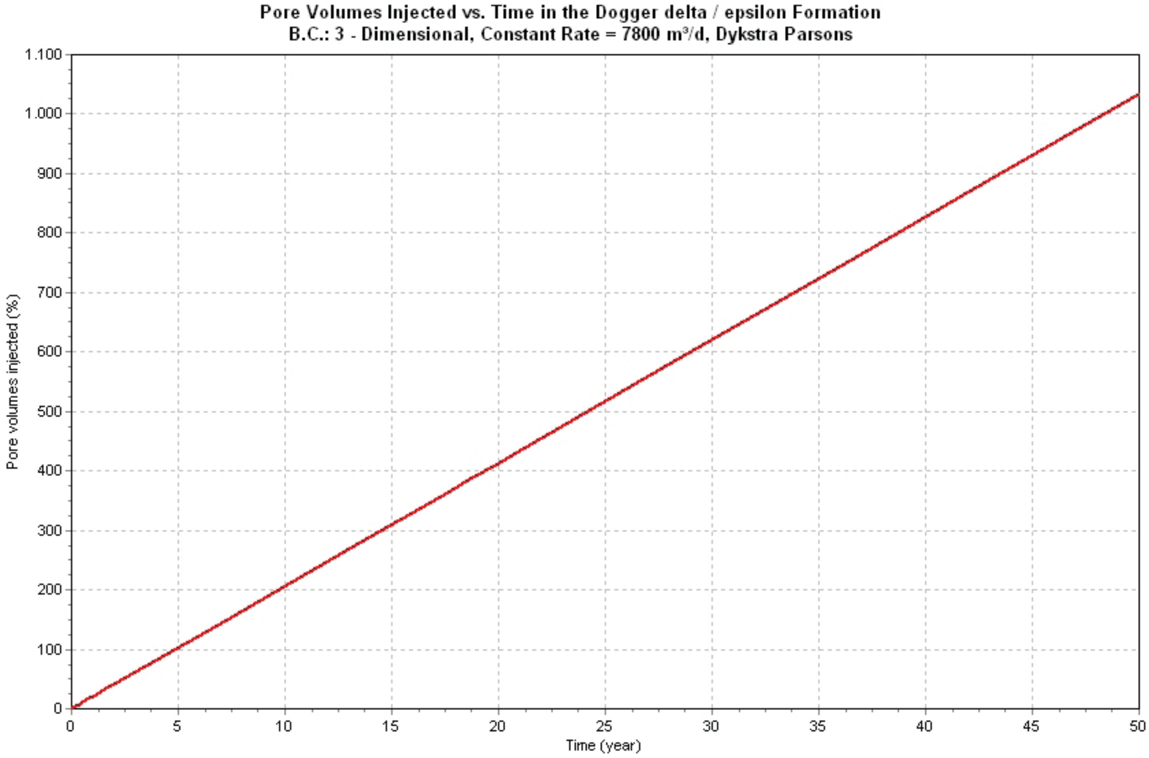

Figure 5.30.: Injected pore volume for the 3D Dogger delta / epsilon case

Figure 5.27 shows a comparison of the recovery factors for all applied methods. Analogues to the 2D case, the scissor effect of the polymer injection towards water injection can be nicely observed. The linear increase in recovery of all methods last only for a very short amount of time (1 year) until the positive effects of the EOR methods kick in. The scissor effect peaks at an extra recovery for the polymer injection of about 8% of OOIP, while surfactant and surfactant – polymer injection achieve an increase of 8% - 20% of OOIP in recovery, not taking economic limits into consideration. However, the benefits of the surfactant injection can only be seen at a very mature state of the test reservoir. Analogues to all other formations, the results of the two surfactant cases must be taken with caution due to the inability of the software to describe the complicated physical and chemical processes connected to them. The Figures 5.28 and 5.29 show the oil production rate and the water cut of the produced fluid for the 3D Dogger delta / epsilon case. As for the 3D Dogger beta case, production plateaus due to the Dykstra – Parsons solution cannot be seen, but all methods except polymer injection show spikes in the production and water cut, shortly after the decline of the reservoir kicks in. Again the very high permeability of the Dogger delta / epsilon sands might be a main reason for the stronger severity of the spikes in opposition to the other formations. Lastly, Figure

5.30 shows the injected pore volume over time, where already after 5 years of injected 100% pore volume is reached.

5.5. Summary of the Analytical Performance Evaluation

With the help of commercial software capable of analytical simulation, a multitude of models for the Mittelplate Dogger formations have been setup. The decision process for the optimal software settings yielded models using the Dykstra – Parsons solution method and a constant rate boundary condition as the best possibility for all horizons. Thus 2D and 3D models have been set up for each formation to have base cases available for both geometric conditions. Theses studies resulted in detailed performance evaluations of water injection, polymer injection, surfactant injection and polymer – surfactant injection for each formation. Generally the results have been positive throughout the board, confirming a reasonable EOR potential. However, the software has serious limitations which must be considered in the further application of its results. Firstly it is a strictly analytical simulator and thus cannot model the complicated physical and chemical processes of surfactant application. Thus the results of the two EOR methods using this chemical additive must be considered with caution. Secondly the software applied a volumetric condition (injection rate = production rate) which leads to an inaccurate description of formations with a strong water aquifer, since those cannot be properly accounted for. Furthermore it is only possible to simulate an EOR application from the time point t = 0, which will hardly happen in reality. Nevertheless the resulting models gave a good impression of the EOR possibilities within the Mittelplate oil field, without applying resource intensive numerical simulations or laboratory experiments. Although, those evaluations have to be the next step in a possible EOR project. The 2D base case of the Dogger beta formation was used for economical studies following in the next chapter.

Chapter 6

Evaluation of the Promising Methods

With the results of the technical screening procedures and the analytical performance evaluation it was possible to make a more in depth evaluation of the three promising methods. The following chapter gives an overview over the studies made to judge the best alternative for the Mittelplate formations, covering economical and engineering aspects. The methods in consideration are polymer injection, chemical combination flooding and in-situ combustion.

6.1. Polymer Injection

To judge a possible polymer injection project for the Mittelplate oil field, multiple considerations have been made. Firstly required surface equipment was analyzed and costs evaluated, to have enough data for an economic study. Secondly a geological survey based on the Mittelplate structural maps was conducted to find the best possible injection area. Furthermore a detailed technical analysis based on the analytical performance evaluation and the results of the geological survey has been made to calculate possible recovery factors and increased oil production rates over water injection. These data was then finally used to set up an economic model to judge the viability of a possible application, yielding enough information for a profound statement.

6.1.1. Surface Equipment

The operating company of the Mittelplate oil field spearheaded multiple polymer injection projects in the last 40 years[13]. Due to these experiences profound knowledge about the necessary surface equipment was available in the company. The surface installations used in Hankensbüttel polymer project[38] have been built into standard containers with the following properties:

- 20 feet long containers
- 1000 m^3/d maximum mixing capability of polymer slug
- Costs of 300.000 DM per unit

Since the Mittelplate oil field lies offshore in the North Sea, limited space is only available for the installation of special EOR facilities. Thus the application of standard containers which are capable of stacking, greatly ease the requirement of space. Furthermore, one standard container should be able to deliver enough mixing capacity to serve two dedicated injectors for a possible test pattern. If required, the capacities could be easily expanded by stacking another 20 feet container. The costs per unit are naturally subjected to change over the last decades due to vastly increased resource costs of steel and inflation. Economical calculations have been conducted with a price of 300.000 euros per unit, accounting for these changes.

6.1.2. Geological Survey

As the geological boundary conditions are a main parameter to guarantee or deny the successful application of an EOR project, a survey based on the Mittelplate structural maps has been conducted to set an optimal application area. The most advantageous region identified by this survey was the southern Mittelplate Dogger beta area shown in Figure 6.1. The advantage of this area lies in the large amount of parallel faults stratifying it. Under the precondition of the faults being sealing, a possible injected polymer solution could distribute itself perfectly along the faults, using a direct line drive. The possibility of using multilateral injectors and producers in this area could additionally vastly increase the project economics.

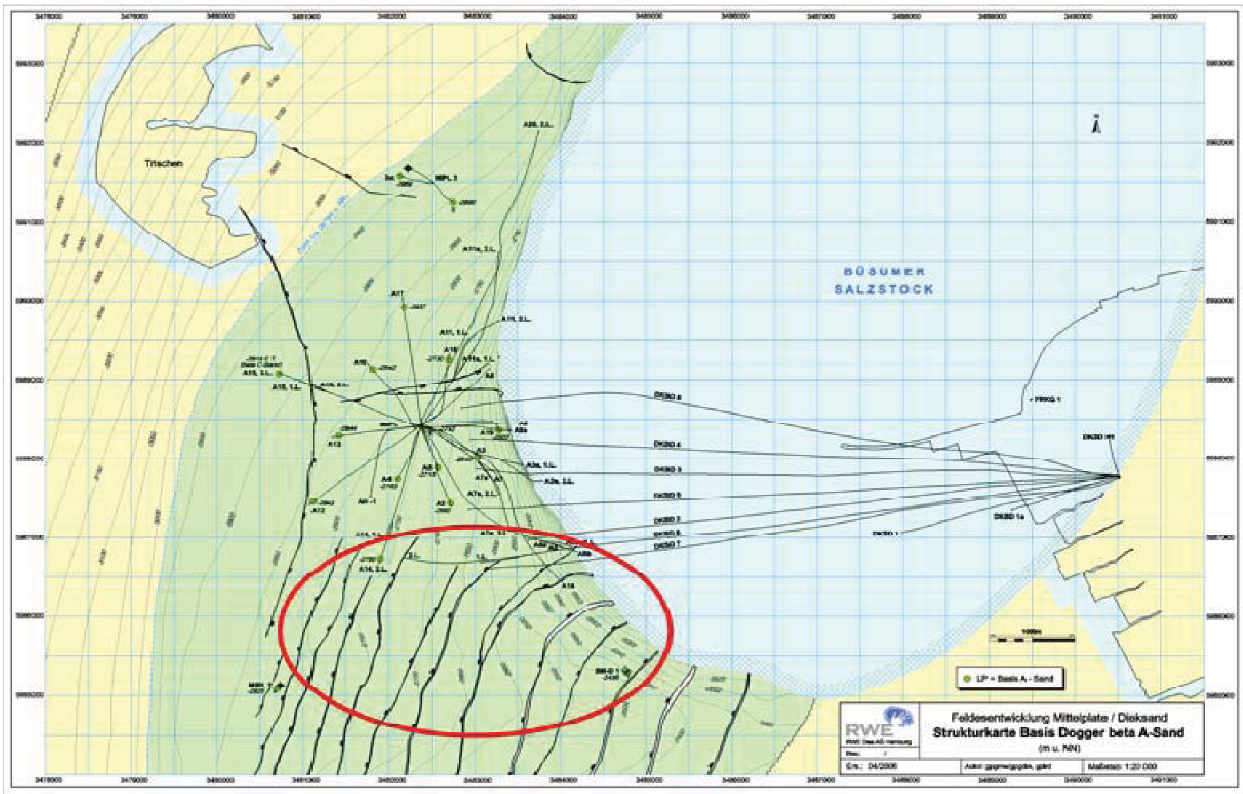

Figure 6.1.: Structural map of the Dogger beta formation

For the Dogger gamma and delta / epsilon formations, no favorable areas could be identified. However, the application of polymers gels to shut off specific sands is a geologically interesting option.

6.1.3. Technical Analysis

Based on the results of the Dogger beta 2D, Dykstra – Parsons, constant rate boundary study, a technical sample case for the southern Mittelplate region has been set up. Due to the different areal extensions assumed in the analytical prediction, in opposition to the target region, it was necessary to convert the results to fit the targets areal parameters and correlate it to fit the right time steps. The input parameters used for this study are presented in Table 6.1 and 6.2.

Polymer Data	Value	Unit
Polymer Costs	7	Euro / kg
Facility Costs	300.000	Euro
Required Density	1	kg/m³
Polymer Mixture Viscosity	30	mPa.s
Oil Sales Price	232,01	Euro / m³

Table 6.1.: Polymer data for the Dogger beta sample case

Example Line Drive	Value	Unit
Length	1.000	m
Width	100	m
Height	15	m
Porosity	0,2	
S_{wi}	0,23	
B_{oi}	1,062	
Pore Volume	300.000	m³
OOIP	217.514	m³
Economic Limit (Rate)	20	m³/d

Table 6.2.: Example line drive data for the Dogger beta sample case

Table 6.3 and Figure 6.2 show the results of evaluation of the sample case. The data conversions and correlations necessary for these computations can be found in appendix E.

Results	Value	Unit
Waterflood Recovery	62,72	%
Polymer Recovery	65,15	%
Difference	2,43	%
Limit reached for Water after	22	months
Limit reached for Polymers after	18	months
Difference	18,18	%
Polymer Slug fully injected after	14,75	months

Table 6.3.: Results of the evaluated sample case

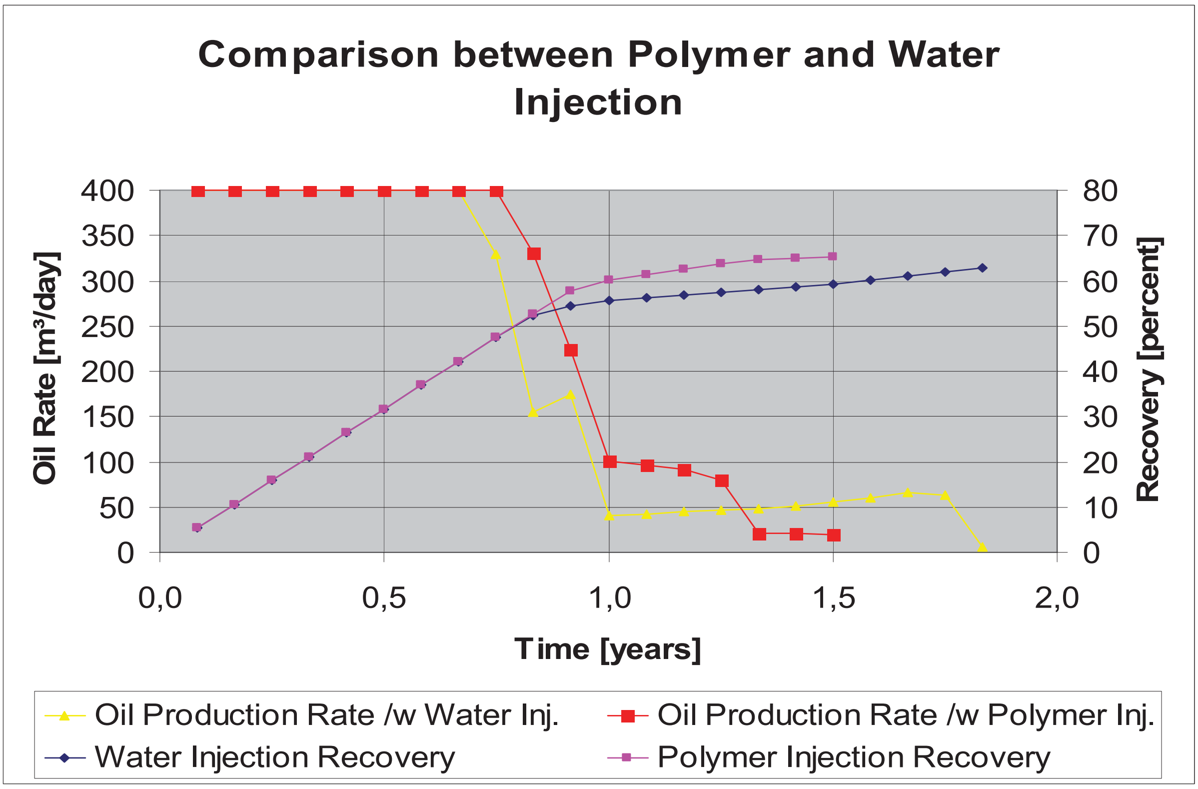

Figure 6.2.: Results of the evaluated sample case

The results of the analysis prove the technical viability of a possible polymer injection project. After reaching the economic production limit of 20 m³/d, there is an increase of 2.43 % in recovery factor of polymer injection over water injection. Additionally to the increase in production, the time required to reach the economic limit could be shortened by 18.18 % when applying polymer injection. The combination of these two facts can considerably improve the economics of a project. However, there are certain drawbacks of the presented analysis. Firstly, the production rate has not been optimized to fit the necessary reduced injection rate when applying polymers, which results from the increased solution viscosity and safety measurements to protect the chemical additives. Secondly, the analytical case used had the boundary condition of being volumetric, which is not a realistic assessment. Furthermore, a specially adapted software model for this technical evaluation would have been very beneficial to avoid the conversion and correlation, but another study could not be conducted due to licensing problems with the software.

6.1.4. Economical Evaluation

The economical study was based on the technical analysis presented above. To comply with the Mittelplate field operator corporation standards, commercial software was used to conduct this study. The input data for the base case consisted of economical project calculations for a production well in the southern Mittelplate Dogger beta region, which included the well costs, abandonment costs and standard Mittelplate operational costs. The polymer case additionally included the costs for surface installations (mixing facility) and increased operational costs to reflect the chemical additives required. The acceleration case only included the increased operational costs and those of the surface installation. Furthermore the operator company discounts the NPV with 15% to calculate project viability. Table 6.4 shows the results of the economical study, while Table 6.5 shows a comparison of the operational costs.

Base Case		Polymer Case		Acceleration	
Oil Price [$]	NPV [T€]	Oil Price [$]	NPV [T€]	Oil Price [$]	NPV [T€]
				20	32
				30	279
				40	526
50	-1.412	50	-1.621	50	774
60	920	60	824	60	1.021
70	3.251	70	3.269	70	1.268
80	5.583	80	5.714	80	1.515
90	7.915	90	8.159	90	1.762

Table 6.4.: Results of the economical evaluation

Case	Operational Costs in €
Base	20,63
Polymer	27,58
Acceleration	27,58

Table 6.5.: Comparison of operational costs

From the results of the study can be said that a polymer injection would improve the economics of the project once an oil price of 68.4 $/bbl is reached. However, it must be noted that this calculation includes surface facilities which could serve additionally another injection well. Furthermore the analytical prediction used for these cases reflects only a very small area, which would be smaller then the possible drainage area of the production well, as can be seen in the technical analysis. Due to these reasons there is a lot of potential to reduce the required oil price to make the polymer project viable. The third case studied, an acceleration case, assumed the production well to be already in place. Thus the required oil price to make the polymer injection economical viable drops to 18.7 $/bbl. Table 6.6 gives an analysis of the payout period and the rate of return for the base and the polymer case, considering different oil prices.

	Base Case		Polymer Case	
Oil Price	Payout Period	ROR	Payout Period	ROR
$	months	%	months	%
50,00	22,00	0,90	0,00	0,00
60,00	21,40	25,90	17,50	25,80
70,00	18,50	61,70	15,80	66,70
80,00	10,40	114,60	10,20	126,30
90,00	8,40	195,60	5,90	215,10

Table 6.6.: Comparison of payout period and ROR

6.2. Chemical Combination Flooding

The second possible EOR method after the technical screenings and backed up by analytical prediction is chemical combination flooding. The most interesting possibility of the variety of available techniques poses certainly the combination of alkalis and surfactants with polymers. As it is a very similar method to polymer injection, the studies and arguments covering surface facilities and geological considerations for polymer injection are viable for this technique as well.

A technical and economic analysis for such an EOR project however, was beyond the scope of this work. As already pointed out in chapter 5, the very complex chemical and physical processes induced by the alkalis and surfactants in the reservoir cannot be properly described by analytical simulation. Thus descriptive technical evaluations require either detailed numerical simulation or a series of core tests in the laboratory to measure the response of the reservoir and estimate necessary slug sizes. However, such studies about the Mittelplate oil field have not been available at the time of this work.

6.3. In-Situ Combustion

Based on the technical screening guidelines, the third possible EOR method is in-situ combustion. However, the processes applied by this technique are still hardly known. Due to this fact, there is only very limited literature available giving empirical calculation options to describe the possible performance. Those calculations available, such as Nelson and McNeil[39] and Brigham et al.[40], require extensive laboratory work with combustion tube experiments. Having these reasons in mind, the primary consideration in the detailed evaluation of this technique has been the calculation of possible well head pressures and the associated injection rates. The first step has been the computation of the phase behavior of pure oxygen with a chemical process simulation software. This data was required to calculate the pressure losses in the annulus during the oxygen injection. Usually only air is compressed and injected into the reservoir to keep the combustion process alive, but due to the large well spacing used in offshore field development, larger amounts of oxygen are required. Due to this reason it was decided to conduct the calculations with pure oxygen. The next step has been the actual calculation of the well head pressure using commercial software. Figure 6.3 shows the results of this study.

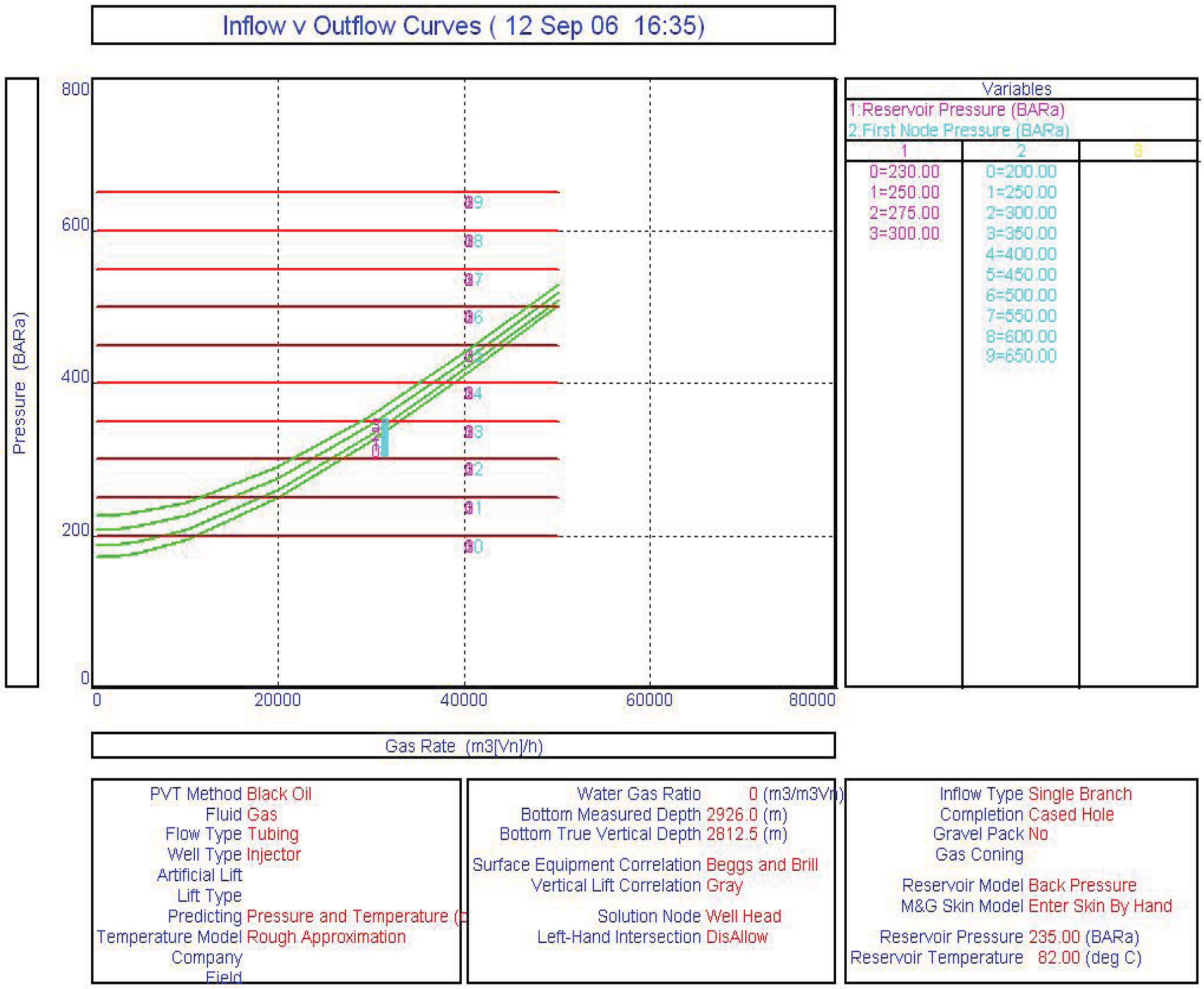

Figure 6.3.: Computation results of the wellhead pressure for in-situ combustion

The data input for Figure 6.3 can be found in appendix F. According to this figure, it would be possible to inject 50000 sm^3 of oxygen per hour, at a wellhead pressure of 530 bar and a reservoir pressure of 300 bar. It is questionable however, if this injection rate would be sufficient to supply enough oxygen for the combustion, considering for example the large well spacing of the central 5 spot pattern of the Mittelplate oil field. As mentioned already above, combustion tube experiments would be necessary for an accurate evaluation. Additionally the in-situ combustion damages due to corrosion and the high temperatures the subsurface well equipment, resulting in considerably rising well workover costs.

Due to these facts, a technical and economical successful in-situ combustion project is at best questionable for the Mittelplate oil field.

6.4. Results of the Detailed Evaluations

In the detailed evaluations of the three promising methods, it became obvious that chemical treatments are the way to go for the Mittelplate oil field. The technical and economical evaluation of polymer flooding proved that a successful application in the southern region of the Dogger beta formation is possible and should be further tracked. Laboratory measurements, numerical simulation and a tracer project are however required to confirm the studies of this work. As well chemical combination treatments seem to be promising, but no definite statement in respect to its performance can be made without appropriated core flooding analyses in the laboratory. In-situ combustion on the other side was confirmed to be theoretically viable in regard to the reservoir parameters, but this could not be confirmed in a practical evaluation. Eventually combustion tube experiments could back up the theoretical recommendation, but the studies shown in this chapter reduce this possibility to a minimum. Additionally a much closer well spacing would be favorable for its application, to have more possibilities of supervising the hardly known process.

Chapter 7

Conclusion and Suggestions

The target of this work was the identification of EOR methods applicable to the Mittelplate oil field. The first step in this direction was an extensive literature survey to summarize traditional EOR methods and new developments on the one hand and find up to date technical screening guidelines on the other hand. After this research multiple technical screenings have been conducted to check upon traditional EOR techniques, resulting in the identification of polymer flooding, chemical combination flooding and in-situ combustion as possible methods. Miscible floodings and steam injection failed the screenings due to unfavorable reservoir parameters, while new or specialized techniques like MEOR or CHOPS have not been considered for further evaluation. Afterwards analytical simulation was applied and confirmed a good response of the reservoir towards the chemical treatments. During the following detailed analyses of the three potential EOR methods, in-situ combustion could be ruled out as possible EOR method, since practical considerations of the well head pressure and the well spacing would considerably complicate its application. Polymer flooding on the other side showed excellent results in practical considerations. A technical and economical successful application, in dependency of the oil price, was proven for the southern region of the Dogger beta formation. For the Dogger gamma and delta / epsilon formations however, no geologically favorable region could be identified. Chemical combination flooding seems to have potential as well, but more detailed laboratory analysis on the impact of surfactants on the reservoir needs to be conducted.

To confirm the results of this work, it is suggested to perform additional laboratory analysis in respect to polymer and chemical combination flooding (such as retention tests, core flooding tests and injection tests) and numerical simulation of a possible polymer project in the southern Dogger beta region. If the results of possible follow up studies deliver the same conclusions as this work, the implementation of a test project should be considered. Furthermore tracer studies of all Mittelplate horizons are suggested to evaluate the possibility of larger field applications. For the Dogger delta / epsilon formation, the application of polymers shut off high permeability layers should be evaluated. Furthermore it is suggested to follow studies of new EOR methods, such as microwave application, and support those.

Chapter 8

Nomenclature

Abbreviations

EOR	- Enhanced Oil Recovery
IOR	- Improved Oil Recovery
API	- American Petroleum Institute
IFT	- Interfacial Tension
ST	- Surface Tension
LPG	- Liquefied Petroleum Gas
RF	- Resistance Factor
RRF	- Residual Resistance Factor
ASP	- Alkali / Surfactant / Polymer
FCM	- First Contact Miscibility
MCM	- Multiple Contact Miscibility
MMP	- Minimum Miscibility Pressure
WAG	- Water Alternating Gas
HC	- Hydrocarbon
ISC	- In-Situ Combustion
SAGD	- Steam Assisted Gravity Drainage
OOIP	- Original Oil in Place
HPAI	- High Pressure Air Injection
COFCAW	- Combination of Forward Combustion and Water Flooding
VAPEX	- Vapor Extraction
CHOPS	- Cold Heavy Oil Production with Sand
MEOR	- Microbial Enhanced Oil Recovery
LoSal	- Low Salinity Enhanced Oil Recovery
SEOR	- Sonic Enhanced Oil Recovery
WOC	- Water Oil Contact
PVT	- Pressure / Volume / Temperature
E&P	- Exploration and Production

N.C.	- Not Critical
GOR	- Gas Oil Ratio
DP	- Dykstra – Parsons
VE	- Vertical Equilibrium
CR	- Constant Rate
CP	- Constant Pressure Loss
2D	- Two Dimensional
3D	- Three Dimensional
DM	- Deutsche Mark (Old German Currency)
bbl	- Barrel

Symbols

M	- Mobility Ratio [-]
t	- Time [years]
$	- Dollar
€	- Euro
P	- Pressure [bar]
S_{wi}	- Initial Water Saturation [-]
B_{oi}	- Initial Oil Formation Volume Factor [m^3/sm^3]

Greek Symbols

λ	- Mobility [1/cP]
σ	- Interfacial Tension [dyne/cm]

Subscripts

D	- Displacing Fluid
d	- Displaced Fluid
O	- Oil
W	- Water
I	- Initial
r	- Reservoir

Conversion Factors

°API $= \dfrac{141.5}{SpecificGravity} - 131.5$

m = ft · 0.3480

kg/m³ = lb/ft³ · 1.601846e+1

mPa·s = cP

bar = psia · 6.894757e-2

°C $= \dfrac{(°F - 32)}{1.8}$

Chapter 9

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Appendix A

Mittelplate Well Overview

Bohrungsübersicht Mittelplate / Dieksand						
		Notizen	Dogger Beta	Dogger Gamma	Dogger Delta	Dogger Epsilon
Büsum Dogger 1			Exploration			
Mittelplate 1	MIPL1		I			A
Mittelplate 2			Exploration			
Mittelplate 3			Exploration			
Mittelplate 3a			Exploration			
Mittelplate A2	MIPLA2				I	
Mittelplate A3	MIPLA3		A		A	
Mittelplate A3a	MIPLA3a			A	P	P
Mittelplate A4	MIPLA4		I			
Mittelplate A5	MIPLA5		I			
Mittelplate A6	MIPLA6				A	P
Mittelplate A7a	MIPLA7a				P	
Mittelplate A8b	MIPLA8b			P		
Mittelplate A9a	MIPLA9a			A		P
Mittelplate A10	MIPLA10		P			
Mittelplate A11a	MIPLA11a				P	
Mittelplate A12	MIPLA12		P			
Mittelplate A13	MIPLA13		P			
Mittelplate A14	MIPLA14		P			
Mittelplate A15	MIPLA15		nicht in betrieb			
Mittelplate A16	MIPLA16		P			
Mittelplate A17	MIPLA17		P			
Mittelplate A18	MIPLA18				P	P
Mittelplate A19	MIPLA19		P			
Mittelplate A20	MIPLA20		wird gebohrt			
Mittelplate AH1	MIPLAH1				I	I
Dieksand 2	DKSD2				P	
Dieksand 3	DKSD3					P
Dieksand 4	DKSD4				P	A
Dieksand 5	DKSD5				P	A
Dieksand 6	DKSD6				P	
Dieksand 7	DKSD7				P	A
Dieksand 8	DKSD8				P	P

Aufgegeben	A
Injiziert	I
Produziert	P

Table A.1.: Tabular overview of the Mittelplate wells

Appendix B

Mittelplate Formation Volume Factors and Oil Viscosities

B.1. Dogger beta formation

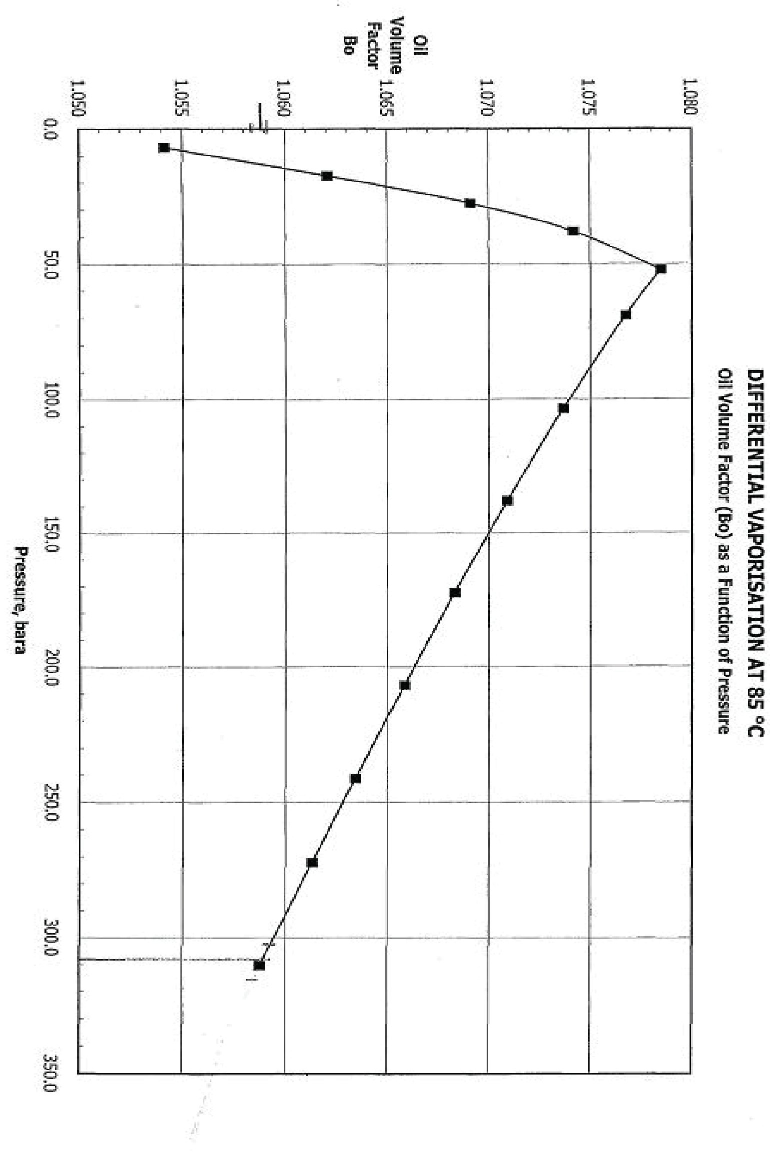


Figure B.1.: FVF against pressure of Dogger beta crude oil

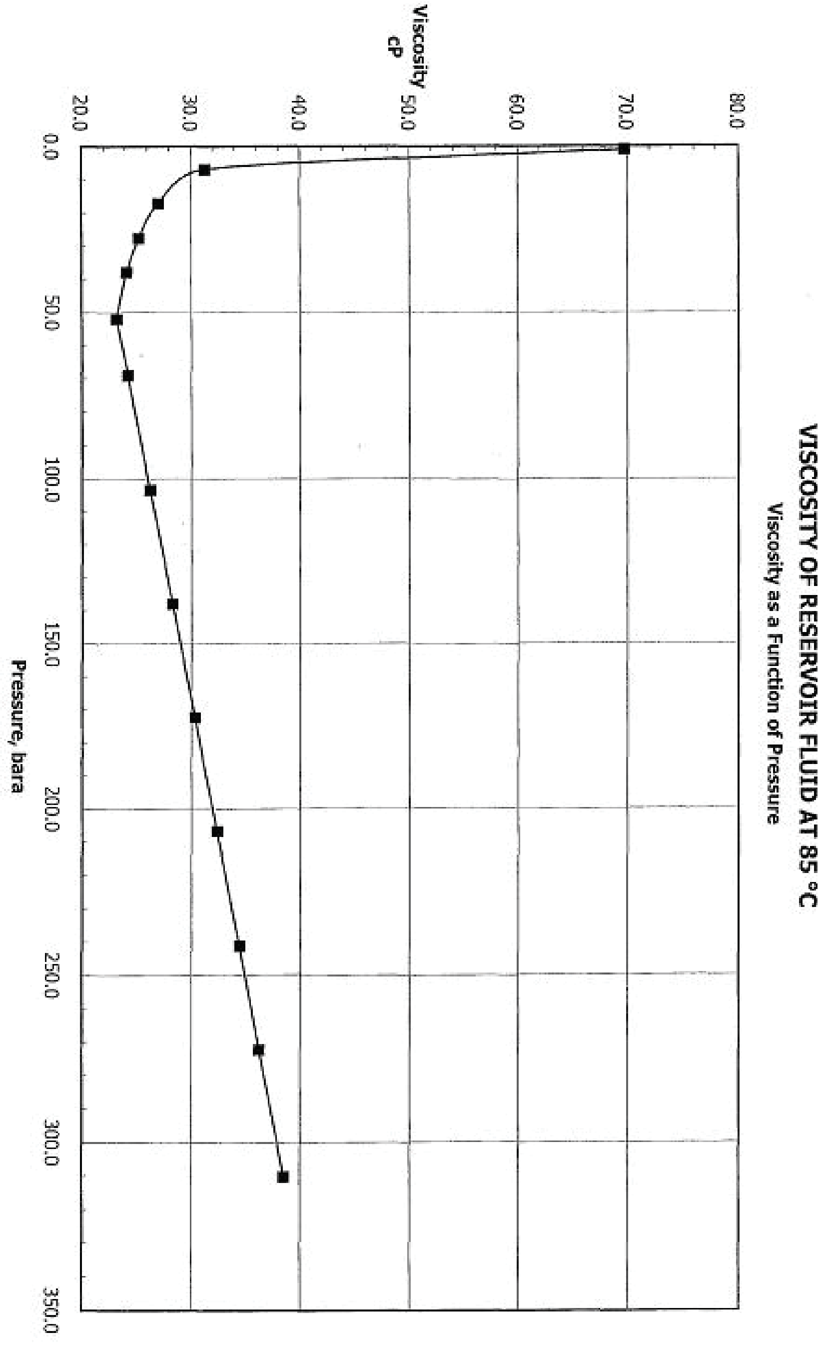


Figure B.2.: Viscosity against pressure of Dogger beta crude oil

B.2. Dogger gamma formation

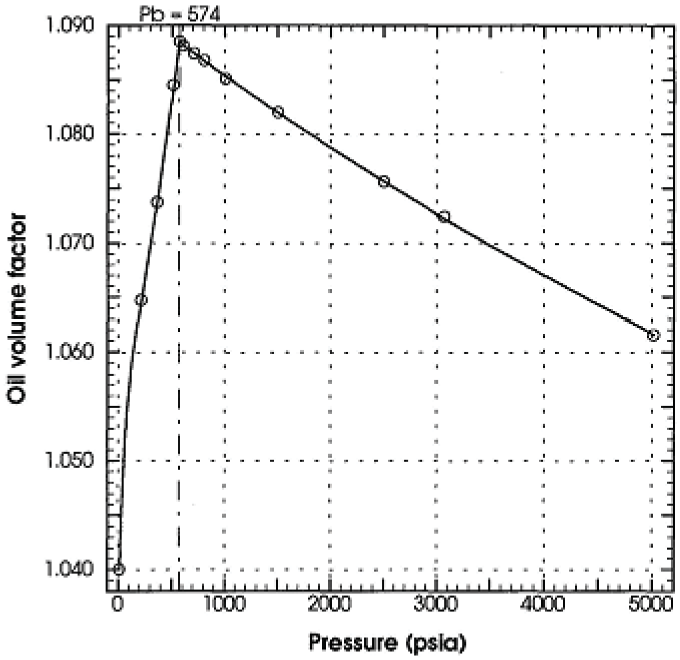


Figure B.3.: FVF against pressure of Dogger gamma crude oil

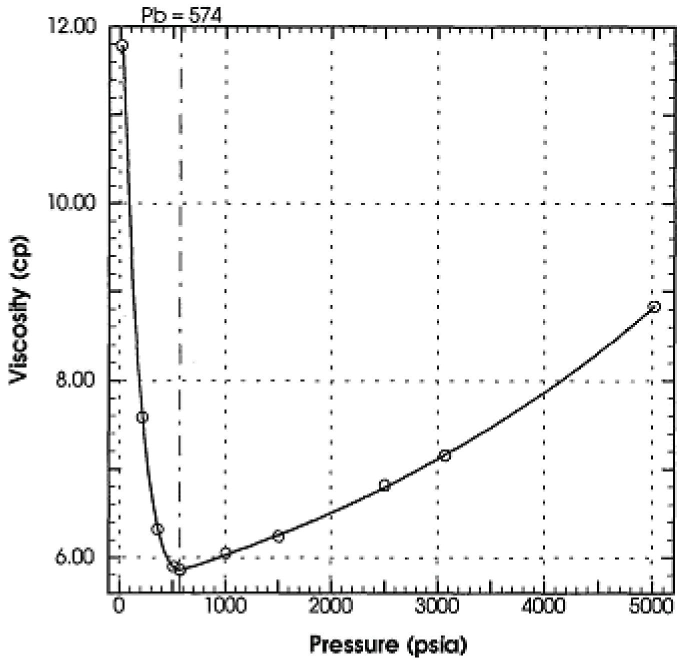


Figure B.4.: Viscosity against pressure of Dogger gamma crude oil

B.3. Dogger delta formation

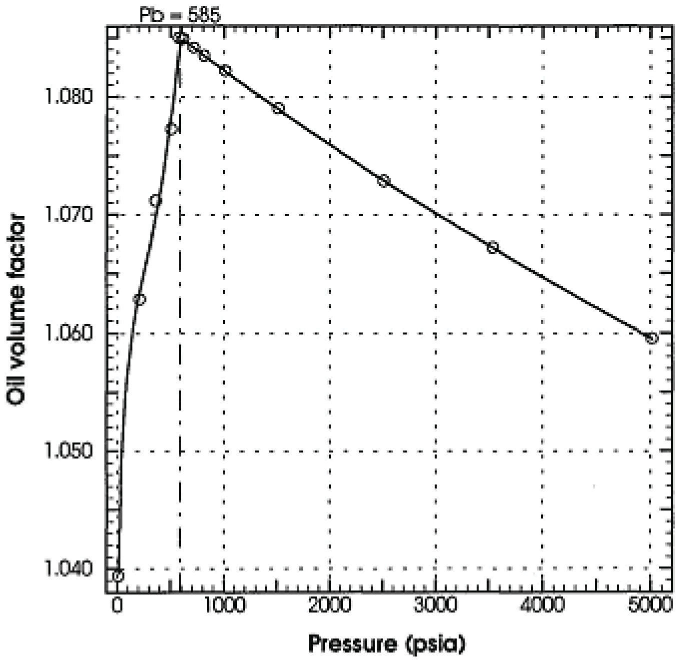


Figure B.5.: FVF against pressure of Dogger delta crude oil

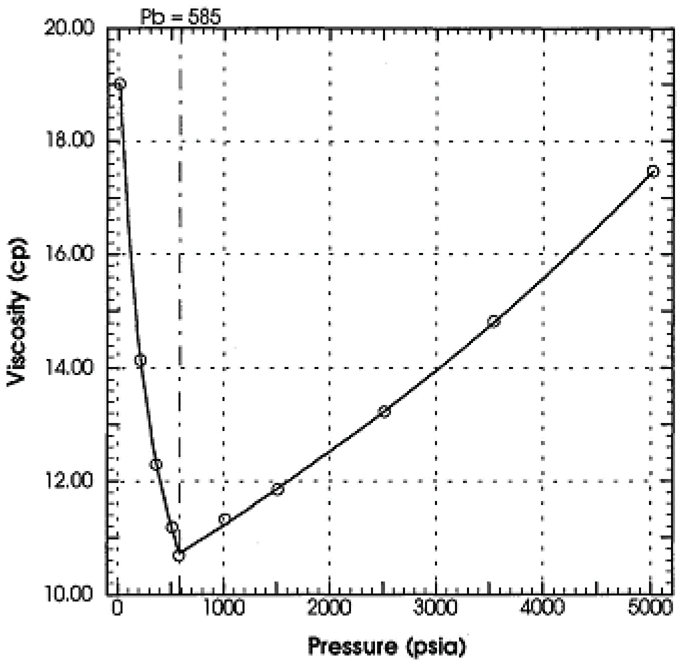


Figure B.6.: Viscosity against pressure of Dogger delta crude oil

B.4. Dogger epsilon formation

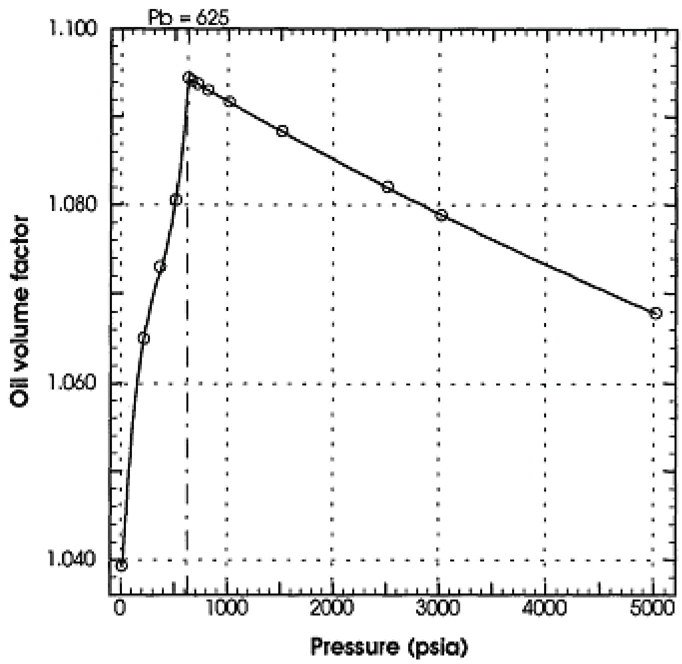


Figure B.7.: FVF against pressure of Dogger epsilon crude oil

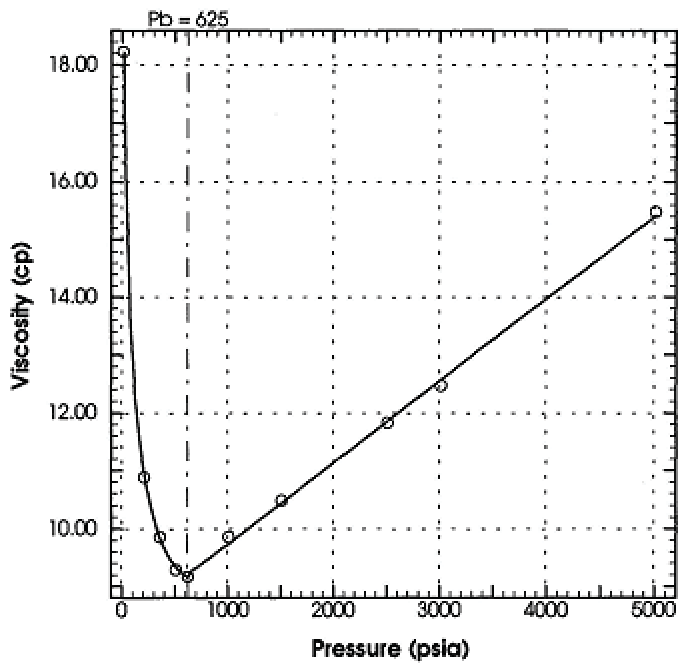


Figure B.8.: Viscosity against pressure of Dogger epsilon crude oil

Appendix C

Minimum Miscibility Pressure

C.1. Calculations with Commercial Software

C.1.1 Dogger Beta Formation

C.1.1.1. Carbon Dioxide Injection

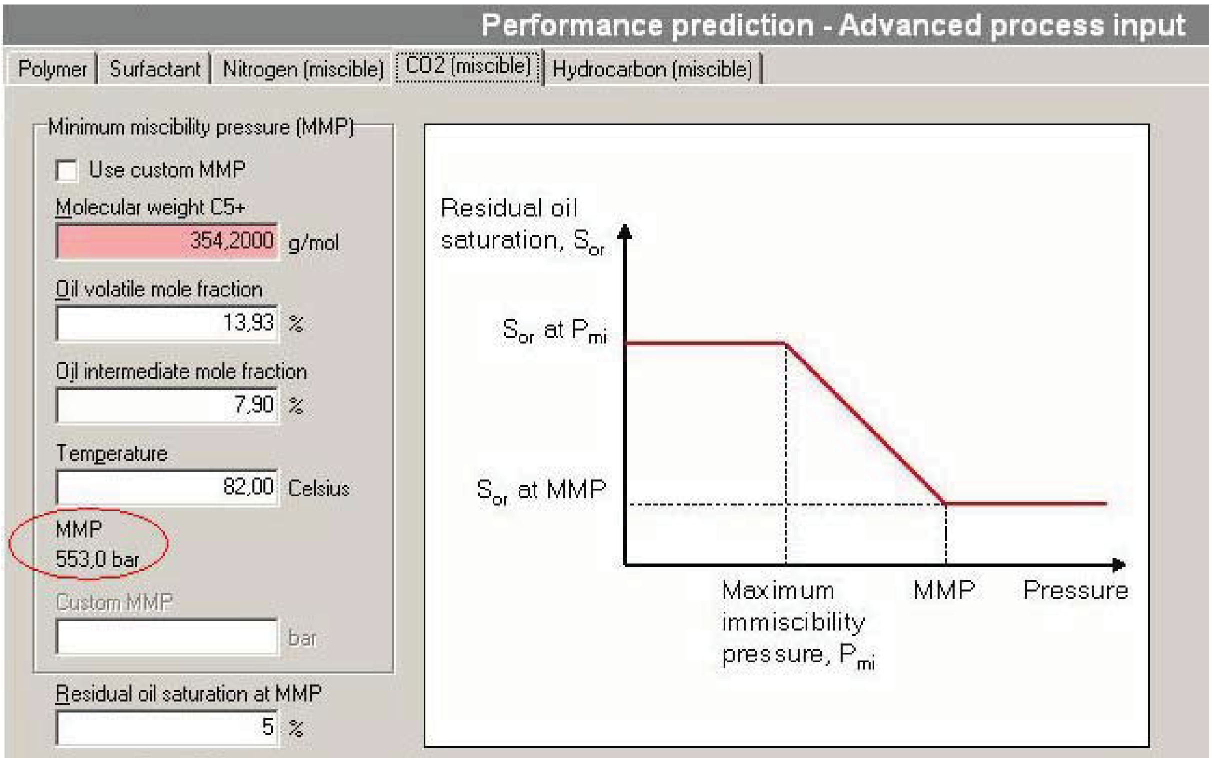


Figure C.1.: MMP for CO_2 injection in the Dogger beta formation

C.1.1.2. Hydrocarbon Gas Injection

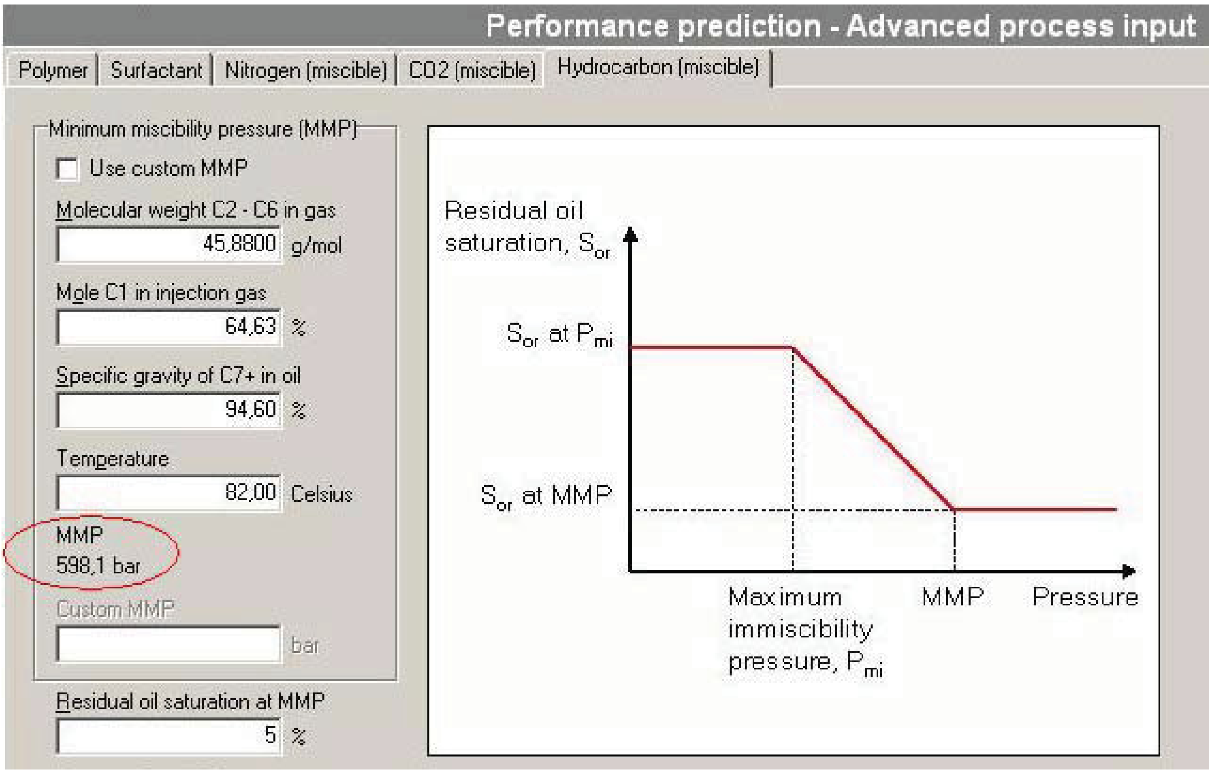


Figure C.2.: MMP for hydrocarbon gas injection in the Dogger beta formation

C.1.1.3. Nitrogen Injection

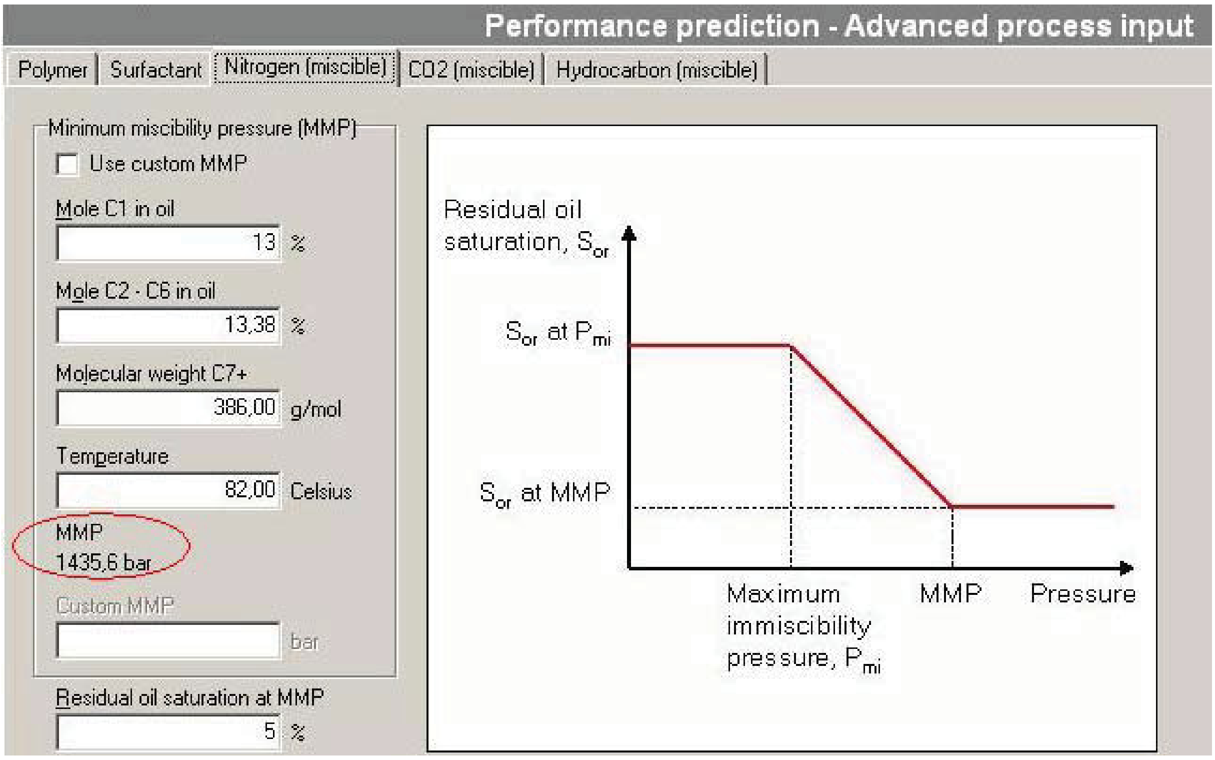


Figure C.3.: MMP for nitrogen injection in the Dogger beta formation

C.1.2 Dogger Gamma Formation

C.1.2.1. Carbon Dioxide Injection

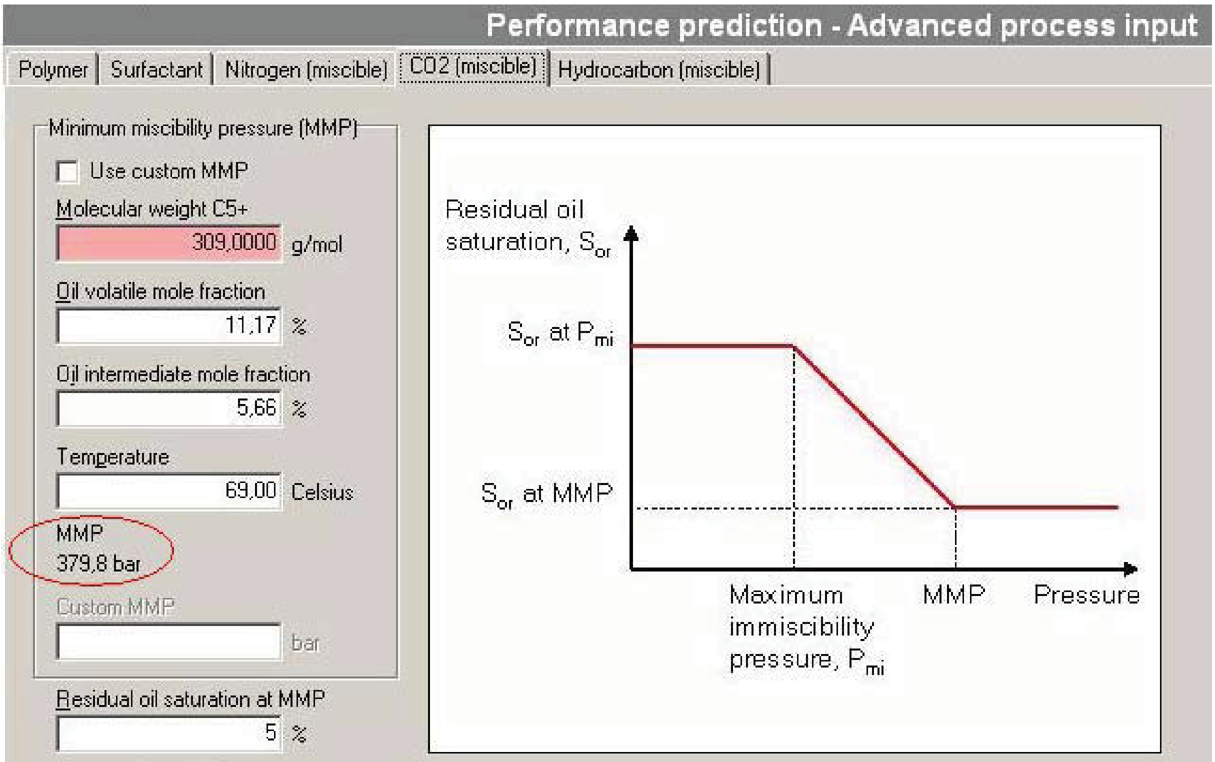


Figure C.4.: MMP for CO_2 injection in the Dogger gamma formation

C.1.2.2. Hydrocarbon Gas Injection

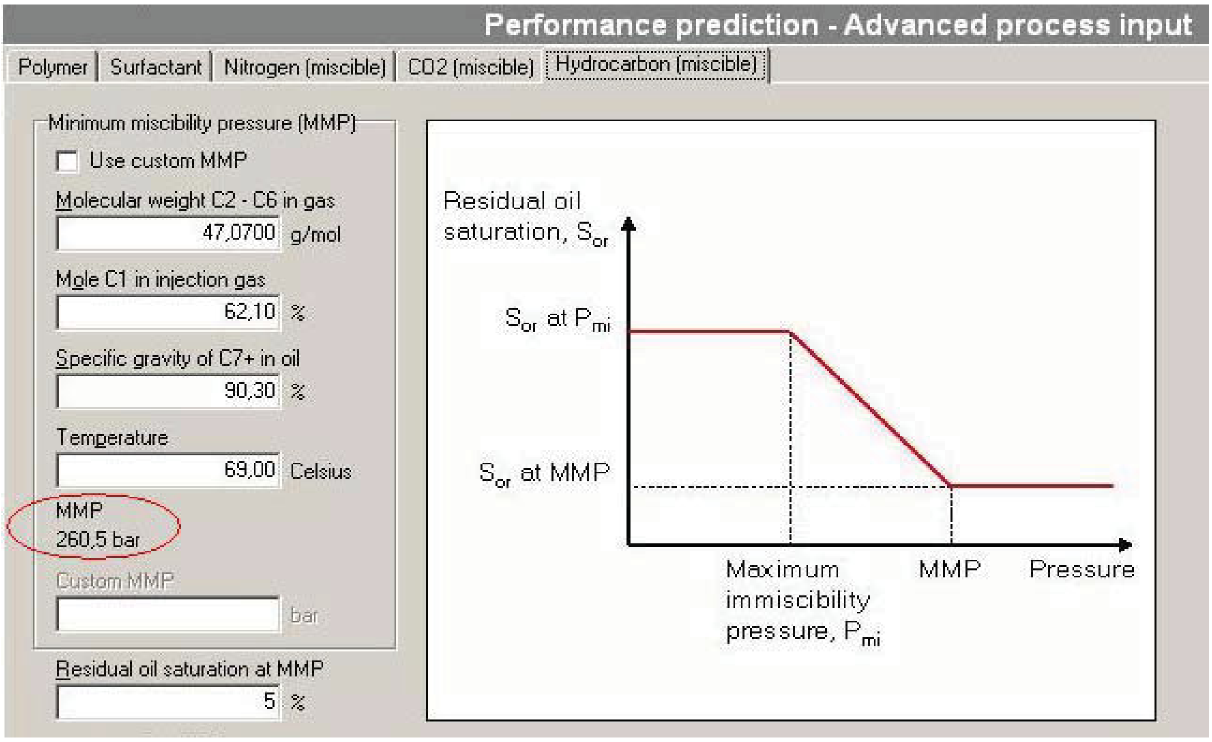


Figure C.5.: MMP for hydrocarbon gas injection in the Dogger gamma formation

C.1.2.3. Nitrogen Injection

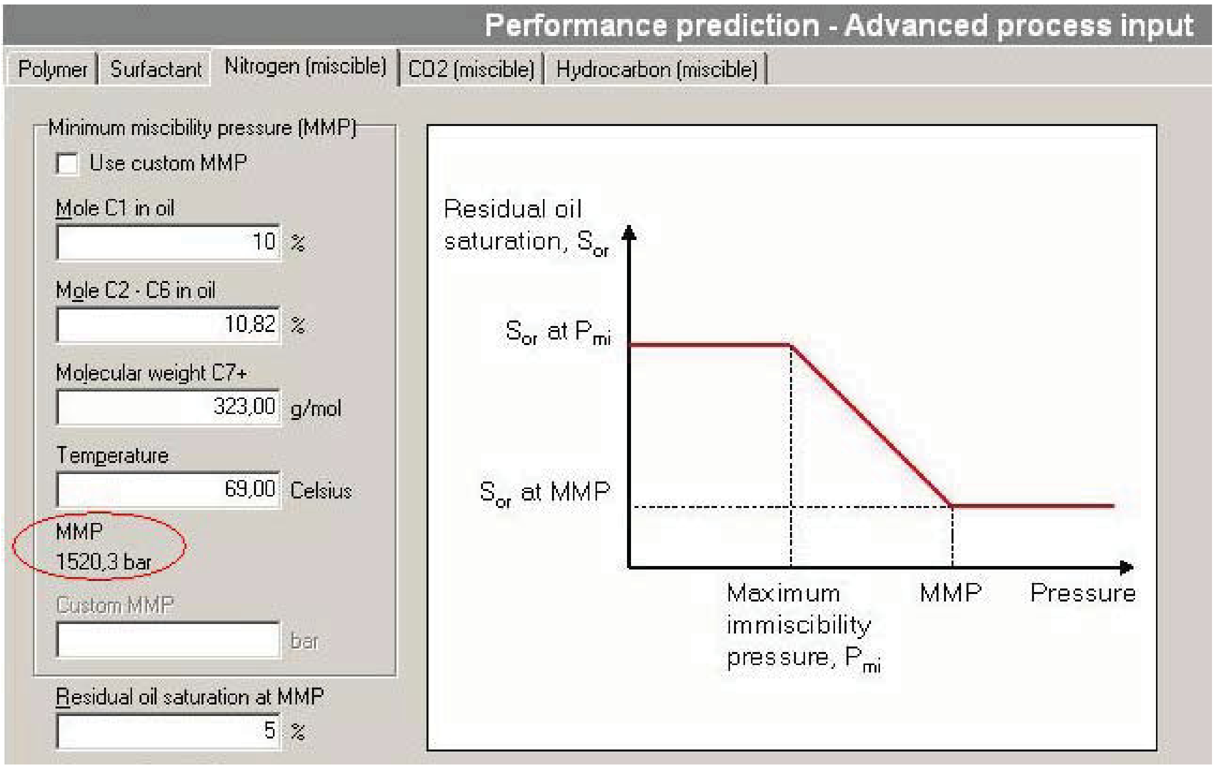


Figure C.6.: MMP for nitrogen injection in the Dogger gamma formation

C.1.3 Dogger Delta / Epsilon Formation

C.1.3.1. Carbon Dioxide Injection

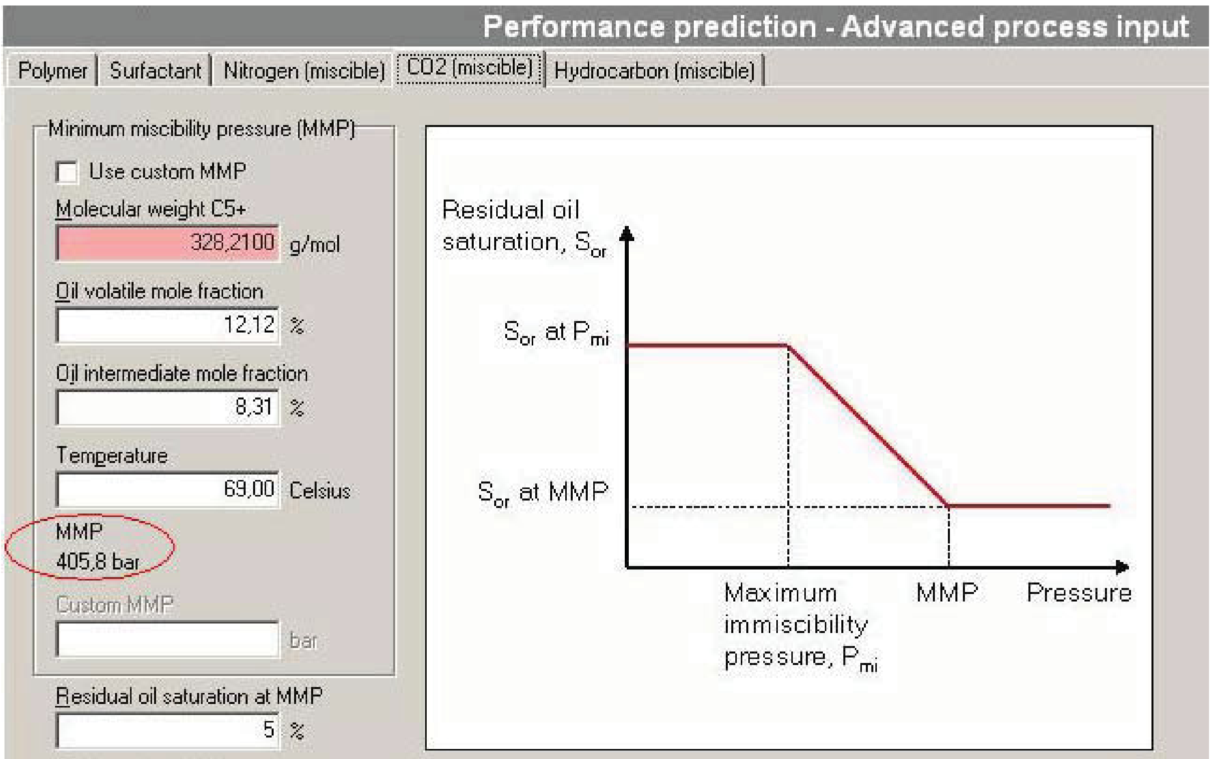


Figure C.7.: MMP for CO_2 injection in the Dogger delta / epsilon formation

C.1.3.2. Hydrocarbon Gas Injection

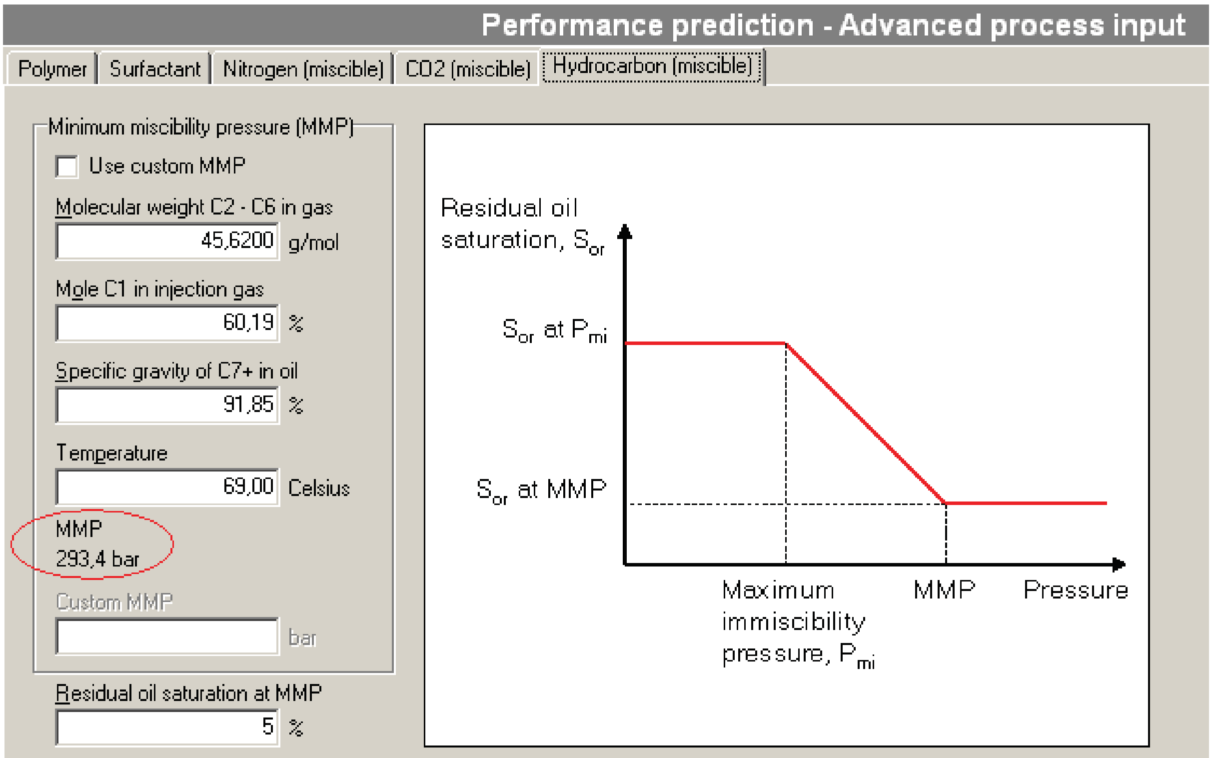


Figure C.8.: MMP for hydrocarbon gas injection in the Dogger delta / epsilon formation

C.1.3.3. Nitrogen Injection

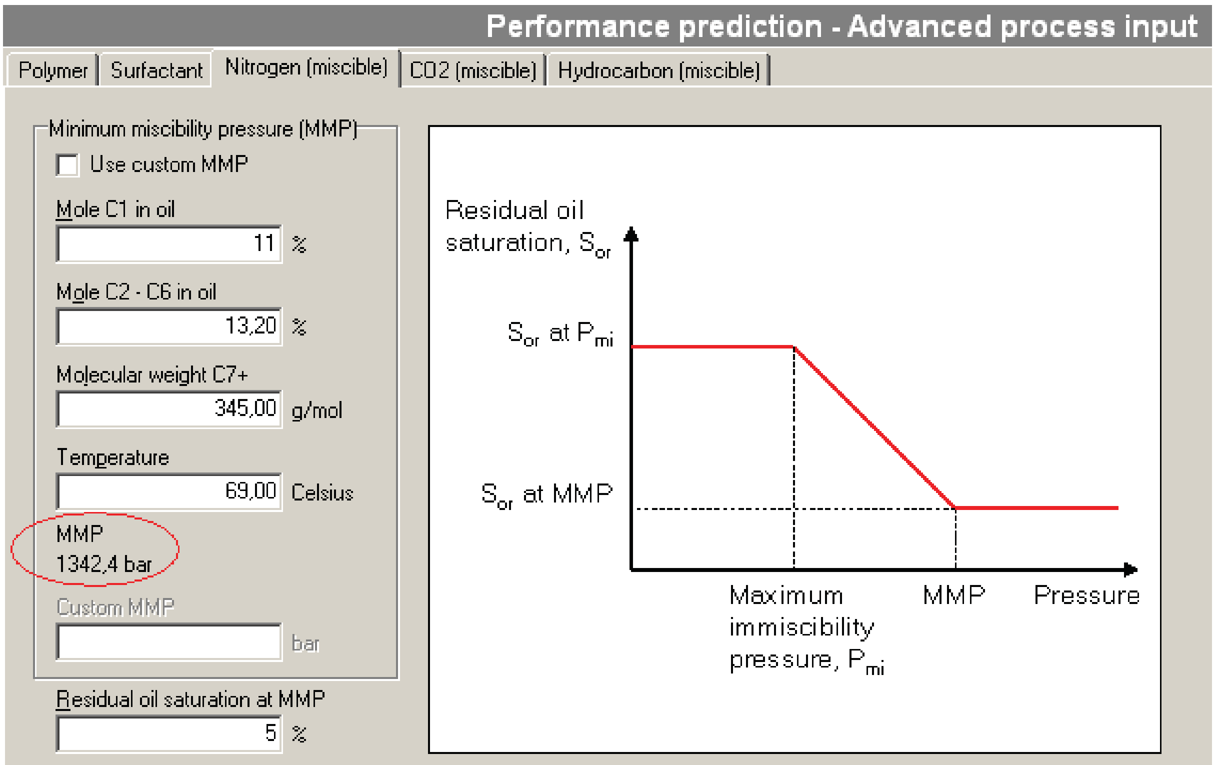


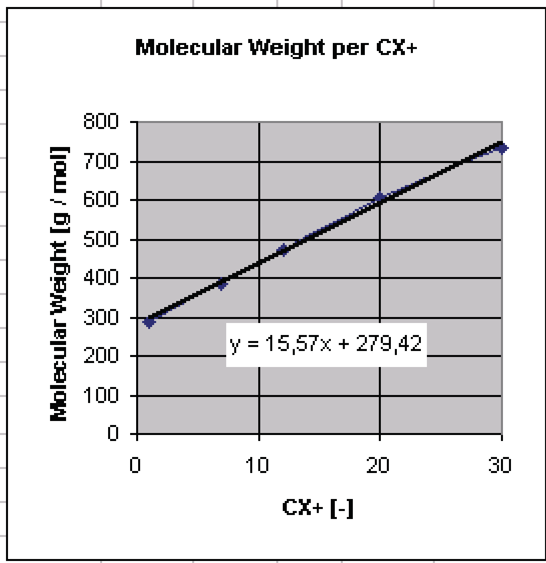
Figure C.9.: MMP for nitrogen injection in the Dogger delta / epsilon formation

C.2. Calculation of Input Data for MMP Evaluation

C.2.1 Dogger Beta Formation

Oil

Daily Rates		Molecular Weight S.C.	
Injection	Production	CX+	g / mol
438	197	1	289
531	240	7	386
246	220	12	470
1215	166	20	607
	276	30	735
	212		
	99	5	354
	1410		



Oil_{med} mole Fraction		Correlation		
Ethane	1,84	1	289	287
Propane	2,92	2		304
Isobutane	0,72	3		321
N-Butane	2,18	4		337
CO2	0,24	5		354
H2S	0	6		371
Summe	**7,9**	7	386	388
		8		404
		9		421
		10		438
		11		455
		12	470	472
		13		488
		14		505
		15		522
		16		539
		17		555
		18		572
		19		589
		20	607	606
		21		622
		22		639
		23		656
		24		673
		25		689
		26		706
		27		723
		28		740
		29		756
		30	735	773

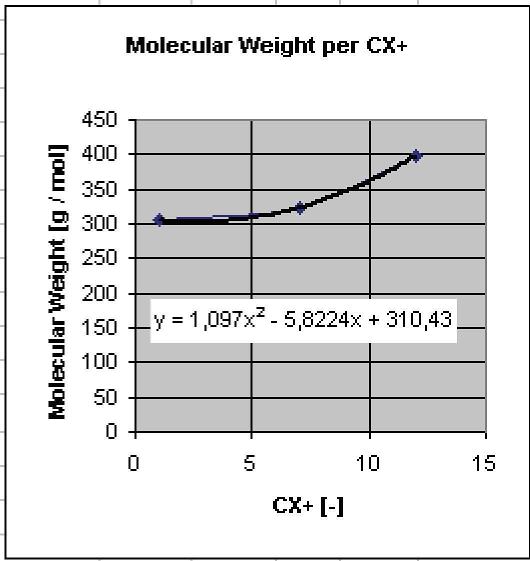
Gas

Molecular Weight C2 - C6				
	MW	Mol%		
C7	96,00	0,59	0,62	59,62
C8	107,00	0,35	0,37	39,42
C9	121,00	0,01	0,01	1,27
		0,95	1	**100,32**
C2	30,07	8,69	0,30	9,14
C3	44,10	10,98	0,38	16,93
C4	58,12	6,21	0,22	12,62
C5	72,15	1,93	0,07	4,87
C6	84,00	0,79	0,03	2,32
C2 - C6		28,60	1	**45,88**

Table C.1.: Calculation of input data for MMP evaluation for the Dogger beta formation

C.2.2 Dogger Gamma Formation

Oil				
Daily Rates		Molecular Weight S.C.		
Injection	Production	CX+	g / mol	
	218	1	306	
		7	323	
		12	399	
		5	309	
Oil$_{med}$ mole Fraction		**Correlation**		
Ethane	2,05	1	306	306
Propane	3,24	2		303
Isobutane	0,70	3		303
N-Butane	2,02	4		305
CO2	0,3	5		309
H2S	0	6		315
Summe	**8,31**	7	323	323
		8		334
		9		347
		10		362
		11		379
		12	399	399

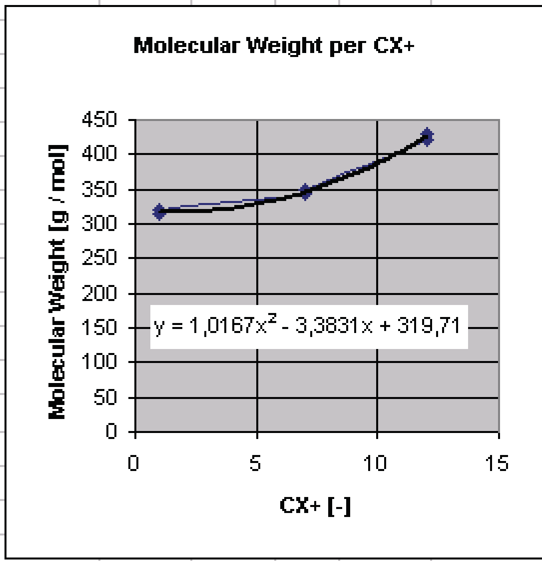


Gas				
Molecular Weight C2 - C6				
	MW	Mol%		
C7	96,00	0,27	0,82	78,55
C8	107,00	0,06	0,18	19,45
C9	121,00	0	0,00	0,00
		0,33	1	**98,00**
C2	30,07	7,62	0,25	7,65
C3	44,10	12,12	0,40	17,85
C4	58,12	7,10	0,24	13,78
C5	72,15	2,42	0,08	5,83
C6	84,00	0,69	0,02	1,94
C2 - C6		29,95	1	**47,04**

Table C.2.: Calculation of input data for MMP evaluation for the Dogger gamma formation

C.2.3 Dogger Delta / Epsilon Formation

Oil					
Daily Rates			**Molecular Weight S.C.**		
Injection	Production		CX+	g / mol	
2327	DKS	MPA	1	313	
1568	1160	261	1	321	
3895	520	271	7	343	
	832	414	7	349	
	868	296	12	423	
	633	1051	12	428	
	752	270			
	467		5	328	
	7795				
Oil$_{med}$ mole Fraction			**Correlation**		
Ethane	1,84		1	318	317,34
Propane	2,92		2		317,01
Isobutane	0,72		3		318,71
N-Butane	2,18		4		322,44
CO2	0,24		5		328,21
H2S	0		6		336,01
Summe	**7,9**		7	345	345,85
			8		357,71
			9		371,61
			10		387,55
			11		405,52
			12	425	425,52



Gas				
Molecular Weight C2 - C6				
	MW	Mol%		
C7	96,00	0,24	0,86	82,29
C8	107,00	0,04	0,14	15,29
C9	121,00	0,00	0,00	0,00
		0,28	1	**97,57**
C2	30,07	9,83	0,30	9,07
C3	44,10	12,88	0,40	17,42
C4	58,12	6,94	0,21	12,37
C5	72,15	2,33	0,07	5,16
C6	84,00	0,62	0,02	1,60
C2 - C6		32,60	1	**45,62**

Table C.3.: Calculation of input data for MMP evaluation for the Dogger delta / epsilon formation

Appendix D

Performance Prediction Evaluation

D.1. Input Data Overview and Origin

D.1.1 Dogger Beta Formation

Reservoir		
Injection to production well distance	**[m]**	1500,000
Pressure drop from injection to production well	**[bar]**	200,0
Production well bottomhole pressure	**[bar]**	100,0
Injection and production rate	**[m3/day]**	1300,00
Injection and production well radius	**[m]**	0,500
Reservoir width	**[m]**	2500,000
Oil viscosity	**[cp]**	28,00
Oil density	**[kg/m3]**	890
Dip	**[deg]**	-7,0

Table D.1.: General reservoir data of the Mittelplate Dogger beta formation

- **Injection to production well distance**

1500 m - Approximated distance between wells (producers and injectors) in the Mittelplate beta central area. Information was taken from the Mittelplate structural map of the Dogger beta formation.

- **Pressure drop from injection to production well**

200 bar - Approximated Value. P_{wf} is about 100 bar (much lower is not possible due to the P_b being around 50 bar. The pressure at the electric submersible pumps must be above the P_b to guarantee their operation), the wellhead pressure of the injectors is 150 bar, the hydrostatic pressure in the annulus 280 bar, while the pressure losses in the injectors are unknown. Thus the P_{wf} of the injectors is assumed to be around the initial reservoir pressure P_i of 305 bar, resulting in about 200 bar pressure drop.

- **Production well bottom hole pressure**

100 bar - Averaged Value from the daily report of the Mittelplate beta production wells. Report date: 15.08.2006

- **Injection and production rate**

1300 m³/day - Calculated from the daily report of the Mittelplate wells, averaged value (the software assumes a volumetric model, but in reality the numbers differ around 200 m³). Report date: 15.08.2006

- **Injection and production well radius**

0,5 m - The description of this parameter was unclear in the software manual, thus the recommended value was taken.

- **Reservoir width**

2500 m – Approximate width of the central area. Information was taken from the Mittelplate structural map of the Dogger beta formation.

- **Oil viscosity and density at reservoir conditions**

28 cp or 890 kg/m³ - Taken from the Eclipse model of the Dogger beta formation (viscosity), or directly from the PVT reports (density).

- **Dip**

-7 deg - Averaged value calculated between the height differences and horizontal distances of the wells within the reservoir. Extreme values go from -5 to -10 degrees. Negative values result from the fact that the injectors are structurally higher due to reservoir development. Information was taken from the Mittelplate structural map of the Dogger beta formation.

Reservoir layers							
	Vertical permeability, kv	Horizontal permeability, kh	Anisotropy, kv/kh	Porosity	Thickness	Initial water saturation	Initial gas saturation
	[md]	[md]		[%]	[m]	[%]	[%]
1	368,00	507,00	0,726	18	6,000	23	0
2	367,00	464,00	0,791	17	4,500	23	0
3	0,05	84,00	0,001	9	4,500	23	0
4	193,00	256,00	0,754	13	5,000	23	0

Table D.2.: Data of the Dogger beta sands

- **Reservoir layer data**

Taken from the Eclipse model and the Petrel model (thickness) of the Mittelplate beta formation

Gas		
Gas viscosity	[cp]	0,01
Gas density	[gas gravity]	0,710

Table D.3.: Data of the hydrocarbon gas in the Dogger beta formation

- **Gas data**

There is no hydrocarbon gas in the reservoir due to the P_b being below the current P_r. The listed values have been taken from PVT analysis of the Mittelplate crude oil.

Reservoir layers			
	Residual oil saturation	Endpoint relative permeability, oil	Endpoint relative permeability, gas
	[%]	[%]	[%]
1	24	100	0
2	24	100	0
3	24	100	0
4	24	100	0

Table D.4.: Relative permeability data of oil and gas in the Dogger beta formation

- **Reservoir layer data**

Reservoir layer data has been taken from the relative permeability curves of the Eclipse model.

Water		
Water viscosity	[cp]	0,51
Water density	[kg/m3]	1055

Table D.5.: Data of the reservoir brine in the Dogger beta formation

- **Water data**

All water data comes from the current Eclipse model for the Dogger beta formation.

Reservoir layers			
	Residual oil saturation	Endpoint relative permeability, oil	Endpoint relative permeability, water
	[%]	[%]	[%]
1	24	100	9
2	24	100	9
3	24	100	9
4	24	100	9

Table D.6.: Relative permeability data of oil and water in the Dogger beta formation

- **Reservoir layer data**

Reservoir layer data has been taken from the relative permeability curves of the Eclipse model.

Polymer		
Polymer viscosity (Newtonian limit)	[cp]	30,00
Shear thinning index		0,5
Relaxation time	[s]	1
Shear rate correction factor		5
Proportionality factor		-0,33
Limiting permeability	[md]	3000,00

Table D.7.: Polymer data for application in the Dogger beta formation

- **Polymer data**

At the time of the study, no laboratory data was available. The polymer applied in case of the Mittelplate beta formation would be most likely a biopolymer. Polymer viscosity can be assumed, in reference to the oil viscosity, around 30 cp. The other data used was taken from reference values suggested by the software.

Surfactant		
Interfacial tension	[dyne/cm]	0,01
Critical capillary number		0
Total capillary number		0,05

Table D.8.: Surfactant data for application in the Dogger beta formation

- **Surfactant data**

The surfactant data has been assumed accordingly to literature and reference values by the software. No laboratory test data was available at the time of the study.

Nitrogen (miscible)		
Use custom MMP		No
Custom MMP	[bar]	
Mole C1 in oil	[%]	13
Mole C2 - C6 in oil	[%]	13
Molecular weight C7+	[g/mol]	386,0000
Temperature	[Celsius]	82,00
Residual oil saturation at MMP	[%]	5
Maximum immiscibility pressure	[bar]	250,0

Table D.9.: Miscible nitrogen injection data for application in the Dogger beta formation

CO_2 (miscible)		
Use custom MMP		No
Custom MMP	[bar]	
Molecular weight C5+	[g/mol]	354,2000
Oil volatile mole fraction	[%]	14
Oil intermediate mole fraction	[%]	8
Temperature	[Celsius]	82,00
Residual oil saturation at MMP	[%]	5
Maximum immiscibility pressure	[bar]	250,0

Table D.10.: Miscible CO_2 injection data for application in the Dogger beta formation

Hydrocarbon (miscible)		
Use custom MMP		No
Custom MMP	[bar]	
Molecular weight C2 - C6 in gas	[g/mol]	45,8800
Mole C1 in injection gas	[%]	65
Specific gravity of C7+ in oil	[%]	95
Temperature	[Celsius]	82,00
Residual oil saturation at MMP	[%]	5
Maximum immiscibility pressure	[bar]	250,0

Table D.11.: Miscible hydrocarbon gas injection data for application in the Dogger beta formation

- **Nitrogen (miscible), CO_2 (miscible) and hydrocarbon gas (miscible) injection data**

The compositional data of the Mittelplate beta crude oil and gas has been calculated or taken from the PVT reports of the production wells. Residual oil saturation at MMP and MIP can only be estimated with the help of literature and correlations, since they need closer laboratory evaluation to be accurately measured.

D.1.2 Dogger Gamma Formation

Reservoir		
Injection to production well distance	[m]	1500,000
Pressure drop from injection to production well	[bar]	150,0
Production well bottomhole pressure	[bar]	80,0
Injection and production rate	[m3/day]	220,00
Injection and production well radius	[m]	0,500
Reservoir width	[m]	300,000
Oil viscosity	[cp]	7,00
Oil density	[kg/m3]	854
Dip	[deg]	45,0

Table D.12.: General reservoir data of the Mittelplate Dogger beta formation

- **Injection to production well distance**

1500 m – Assumed valued for the Dogger gamma formation, due to no injectors being currently present in addition to the only producer. Information was taken from the Mittelplate structural map of the Dogger gamma formation.

- **Pressure drop from injection to production well**

150 bar - Approximated Value. P_{wf} is about 80 bar (much lower is not possible due to the P_b being around 50 bar. The pressure at the electric submersible pump must be above the P_b to guarantee its operation). As there is currently no injection well in the Dogger gamma formation, the value was assumed analogues to the data of the other Mittelplate horizons in addition to an initial pressure P_i of 233 bar

- **Production well bottom hole pressure**

80 bar - Value from the daily report of the Mittelplate MPA8b production well. Report date: 15.08.2006

- **Injection and production rate**

220 m³/day – Value from the daily report of the Mittelplate MPA8b production well. Report date: 15.08.2006

- **Injection and production well radius**

0,5 m - The description of this parameter was unclear in the software manual, thus the recommended value was taken.

- **Reservoir width**

300 m – Average width of the Dogger gamma formation. Information was taken from the Mittelplate structural map of the Dogger gamma formation.

- **Oil viscosity and density at reservoir conditions**

7 cp or 854 kg/m³ - Taken from the Eclipse model of the Dogger gamma formation (viscosity), or directly from the PVT reports (density).

- **Dip**

29 deg - Averaged value calculated between the height differences and horizontal distances within the reservoir. Extreme values go from 15 to 45 degrees. Information was taken from the Mittelplate structural map of the Dogger gamma formation.

Reservoir layers							
	Vertical permeability, kv	Horizontal permeability, kh	Anisotropy, kv/kh	Porosity	Thickness	Initial water saturation	Initial gas saturation
	[md]	[md]		[%]	[m]	[%]	[%]
1	0,75	164,00	0,005	10	5,000	19	0
2	0,87	520,00	0,002	20	10,000	19	0
3	0,86	481,00	0,002	17	8,000	19	0
4	0,82	247,00	0,003	13	7,000	19	0
5	0,74	240,00	0,003	14	10,000	19	0

Table D.13.: Data of the Dogger gamma sands

- **Reservoir layer data**

Taken from the Eclipse model and the Petrel model (thickness) of the Mittelplate beta formation

Gas		
Gas viscosity	[cp]	0,01
Gas density	[gas gravity]	0,705

Table D.14.: Data of the hydrocarbon gas in the Dogger gamma formation

- **Gas data**

There is no hydrocarbon gas in the reservoir due to the P_b being below the current P_r. The listed values have been taken from PVT analysis of the Mittelplate crude oil.

Reservoir layers			
	Residual oil saturation	Endpoint relative permeability, oil	Endpoint relative permeability, gas
	[%]	[%]	[%]
1	25	100	0
2	25	100	0
3	25	100	0
4	25	100	0
5	25	100	0

Table D.15.: Relative permeability data of oil and gas in the Dogger gamma formation

- **Reservoir layer data**

Reservoir layer data has been taken from the relative permeability curves of the Eclipse model.

Water		
Water viscosity	[cp]	0,51
Water density	[kg/m3]	1055

Table D.16.: Data of the reservoir brine in the Dogger gamma formation

- **Water data**

All water data comes from the current Eclipse model for the Dogger beta formation.

Reservoir layers			
	Residual oil saturation	Endpoint relative permeability, oil	Endpoint relative permeability, water
	[%]	[%]	[%]
1	25	100	60
2	25	100	60
3	25	100	60
4	25	100	60
5	25	100	60

Table D.17.: Relative permeability data of oil and water in the Dogger beta formation

- **Reservoir layer data**

Reservoir layer data has been taken from the relative permeability curves of the Eclipse model.

Polymer		
Polymer viscosity (Newtonian limit)	[cp]	10,00
Shear thinning index		0,5
Relaxation time	[s]	1
Shear rate correction factor		5
Proportionality factor		-0,3
Limiting permeability	[md]	3000,00

Table D.18.: Polymer data for application in the Dogger beta formation

- **Polymer data**

At the time of the study, no laboratory data was available. The polymer applied in case of the Mittelplate gamma formation would be most likely a biopolymer. Polymer viscosity can be assumed, in reference to the oil viscosity, around 10 cp. The other data used was taken from reference values suggested by the software.

Surfactant		
Interfacial tension	[dyne/cm]	0,01
Critical capillary number		0
Total capillary number		0,05

Table D.19.: Surfactant data for application in the Dogger beta formation

- **Surfactant data**

The surfactant data has been assumed accordingly to literature and reference values by the software. No laboratory test data was available at the time of the study.

Nitrogen (miscible)		
Use custom MMP		No
Custom MMP	[bar]	
Mole C1 in oil	[%]	10
Mole C2 - C6 in oil	[%]	11
Molecular weight C7+	[g/mol]	323,0000
Temperature	[Celsius]	69,00
Residual oil saturation at MMP	[%]	5
Maximum immiscibility pressure	[bar]	200,0

Table D.20.: Miscible nitrogen injection data for application in the Dogger gamma formation

CO_2 (miscible)		
Use custom MMP		No
Custom MMP	[bar]	
Molecular weight C5+	[g/mol]	309,0000
Oil volatile mole fraction	[%]	11
Oil intermediate mole fraction	[%]	6
Temperature	[Celsius]	69,00
Residual oil saturation at MMP	[%]	5
Maximum immiscibility pressure	[bar]	200,0

Table D.21.: Miscible CO_2 injection data for application in the Dogger beta formation

Hydrocarbon (miscible)		
Use custom MMP		No
Custom MMP	[bar]	
Molecular weight C2 - C6 in gas	[g/mol]	47,0700
Mole C1 in injection gas	[%]	62
Specific gravity of C7+ in oil	[%]	90
Temperature	[Celsius]	69,00
Residual oil saturation at MMP	[%]	5
Maximum immiscibility pressure	[bar]	200,0

Table D.22.: Miscible hydrocarbon gas injection data for application in the Dogger beta formation

- **Nitrogen (miscible), CO_2 (miscible) and hydrocarbon gas (miscible) injection data**

The compositional data of the Mittelplate gamma crude oil and gas has been calculated or taken from the PVT report of the production well. Residual oil saturation at MMP and MIP can only be estimated with the help of literature and correlations, since they need closer laboratory evaluation to be accurately measured.

D.1.3 Dogger Delta / Epsilon Formation

Reservoir		
Injection to production well distance	[m]	750,000
Pressure drop from injection to production well	[bar]	50,0
Production well bottomhole pressure	[bar]	100,0
Injection and production rate	[m3/day]	7800,00
Injection and production well radius	[m]	0,500
Reservoir width	[m]	1000,000
Oil viscosity	[cp]	11,50
Oil density	[kg/m3]	866
Dip	[deg]	14,5

Table D.23.: General reservoir data of the Mittelplate Dogger delta / epsilon formation

- **Injection to production well distance**

750 m - Approximated distance between wells (producers and injectors) in the Mittelplate delta / epsilon central area. Information was taken from the Mittelplate structural map of the Dogger delta / epsilon formation.

- **Pressure drop from injection to production well**

50 bar - Approximated Value. P_{wf} is about 100 bar (much lower is not possible due to the P_b being around 50 bar. The pressure at the electric submersible pumps must be above the P_b to guarantee their operation), the wellhead pressure of the injectors is 150 bar, the hydrostatic pressure in the annulus 200 bar, while the pressure losses in the injectors are unknown. Thus the P_{wf} of the injectors is assumed to be around the initial reservoir pressure P_i of 233 bar, resulting in about 50 bar pressure drop.

- **Production well bottom hole pressure**

100 bar - Averaged Value from the daily report of the Mittelplate and Dieksand delta / epsilon production wells. Report date: 15.08.2006

- **Injection and production rate**

7800 m³/day - Calculated from the daily report of the Mittelplate and Dieksand production wells, averaged value (the software assumes a volumetric model, but in reality the numbers differ a lot due to the strong aquifer). Report date: 15.08.2006

- **Injection and production well radius**

0,5 m - The description of this parameter was unclear in the software manual, thus the recommended value was taken.

- **Reservoir width**

1000 m – Approximate width of the central area. Information was taken from the Mittelplate structural map of the Dogger delta / epsilon formation.

- **Oil viscosity and density at reservoir conditions**

11,5 cp or 866 kg/m³ - Taken from the Eclipse model of the Dogger delta / epsilon formation (viscosity), or directly from the PVT reports (density).

- **Dip**

14,5 deg - Averaged value calculated between the height differences and horizontal distances of the wells within the reservoir. Extreme values go from -10 to 40 degrees. Information was taken from the Mittelplate structural map of the Dogger delta / epsilon formation.

Reservoir layers							
	Vertical permeability, kv	Horizontal permeability, kh	Anisotropy, kv/kh	Porosity	Thickness	Initial water saturation	Initial gas saturation
	[md]	[md]		[%]	[m]	[%]	[%]
1	813,00	6000,00	0,136	18	25,000	18	0
2	1611,00	5744,00	0,28	15	15,000	18	0
3	227,00	647,00	0,351	10	15,000	18	0
4	425,00	2384,00	0,178	17	12,500	18	0
5	211,00	1950,00	0,108	16	7,500	18	0
6	95,00	511,00	0,186	10	5,000	18	0

Table D.24.: Data of the Dogger beta sands

- **Reservoir layer data**

Taken from the Eclipse model and the Petrel model (thickness) of the Mittelplate delta / epsilon formation

Gas		
Gas viscosity	[cp]	0,01
Gas density	[gas gravity]	0,710

Table D.25.: Data of the hydrocarbon gas in the Dogger delta / epsilon formation

- **Gas data**

There is no hydrocarbon gas in the reservoir due to the P_b being below the current P_r. The listed values have been taken from PVT analysis of the Mittelplate crude oil.

Reservoir layers			
	Residual oil saturation	Endpoint relative permeability, oil	Endpoint relative permeability, gas
	[%]	[%]	[%]
1	19	100	0
2	19	100	0
3	19	100	0
4	21	100	0
5	21	100	0
6	21	100	0

Table D.26.: Relative permeability data of oil and gas in the Dogger delta / epsilon formation

- **Reservoir layer data**

Reservoir layer data has been taken from the relative permeability curves of the Eclipse model.

Water		
Water viscosity	[cp]	0,51
Water density	[kg/m3]	1055

Table D.27.: Data of the reservoir brine in the Dogger delta / epsilon formation

- **Water data**

All water data comes from the current Eclipse model for the Dogger delta / epsilon formation.

Reservoir layers			
	Residual oil saturation	Endpoint relative permeability, oil	Endpoint relative permeability, water
	[%]	[%]	[%]
1	19	100	25
2	19	100	25
3	19	100	25
4	21	100	16
5	21	100	16
6	21	100	16

Table D.28.: Relative permeability data of oil and water in the Dogger delta / epsilon formation

- **Reservoir layer data**

Reservoir layer data has been taken from the relative permeability curves of the Eclipse model.

Polymer		
Polymer viscosity (Newtonian limit)	**[cp]**	15,00
Shear thinning index		0,5
Relaxation time	**[s]**	1
Shear rate correction factor		5
Proportionality factor		-0,3
Limiting permeability	**[md]**	10000,00

Table D.29.: Polymer data for application in the Dogger delta / epsilon formation

- **Polymer data**

At the time of the study, no laboratory data was available. The polymer applied in case of the Mittelplate delta / epsilon formation would be most likely a biopolymer. Polymer viscosity can be assumed, in reference to the oil viscosity, around 15 cp. The other data used was taken from reference values suggested by the software.

Surfactant		
Interfacial tension	**[dyne/cm]**	0,01
Critical capillary number		0
Total capillary number		0,05

Table D.30.: Surfactant data for application in the Dogger beta formation

- **Surfactant data**

The surfactant data has been assumed accordingly to literature and reference values by the software. No laboratory test data was available at the time of the study.

Nitrogen (miscible)		
Use custom MMP		No
Custom MMP	**[bar]**	
Mole C1 in oil	**[%]**	11
Mole C2 - C6 in oil	**[%]**	13
Molecular weight C7+	**[g/mol]**	345,0000
Temperature	**[Celsius]**	69,00
Residual oil saturation at MMP	**[%]**	5
Maximum immiscibility pressure	**[bar]**	200,0

Table D.31.: Miscible nitrogen injection data for application in the Dogger delta / epsilon formation

CO2 (miscible)		
Use custom MMP		No
Custom MMP	[bar]	
Molecular weight C5+	[g/mol]	328,2100
Oil volatile mole fraction	[%]	12
Oil intermediate mole fraction	[%]	8
Temperature	[Celsius]	69,00
Residual oil saturation at MMP	[%]	5
Maximum immiscibility pressure	[bar]	200,0

Table D.32.: Miscible CO_2 injection data for application in the Dogger delta / epsilon formation

Hydrocarbon (miscible)		
Use custom MMP		No
Custom MMP	[bar]	
Molecular weight C2 - C6 in gas	[g/mol]	45,6200
Mole C1 in injection gas	[%]	60
Specific gravity of C7+ in oil	[%]	92
Temperature	[Celsius]	69,00
Residual oil saturation at MMP	[%]	5
Maximum immiscibility pressure	[bar]	200,0

Table D.33.: Miscible hydrocarbon gas injection data for application in the Dogger beta formation

- **Nitrogen (miscible), CO_2 (miscible) and hydrocarbon gas (miscible) injection data**

The compositional data of the Mittelplate delta / epsilon crude oil and gas has been calculated or taken from the PVT reports of the production wells. Residual oil saturation at MMP and MIP can only be estimated with the help of literature and correlations, since they need closer laboratory evaluation to be accurately measured.

D.2. Evaluation of Calculation Options and Boundary Conditions

D.2.1 Dogger Beta Formation

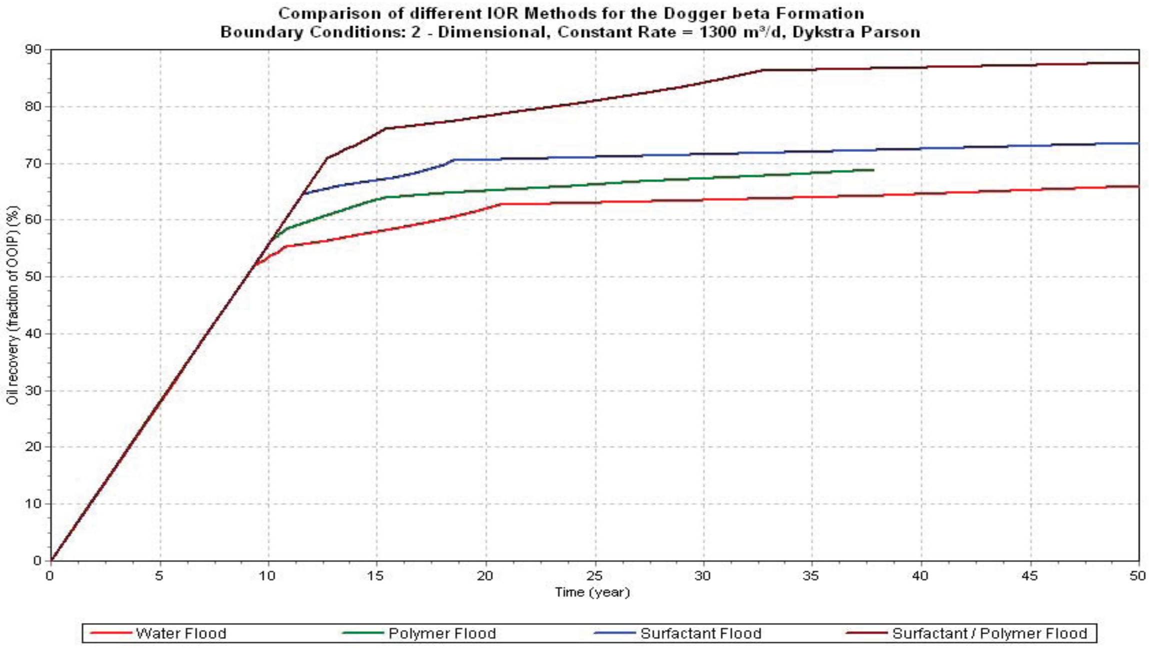


Figure D.1.: Comparison of the calculation options for the Dogger beta formation, 2D – Dykstra Parsons – constant rate

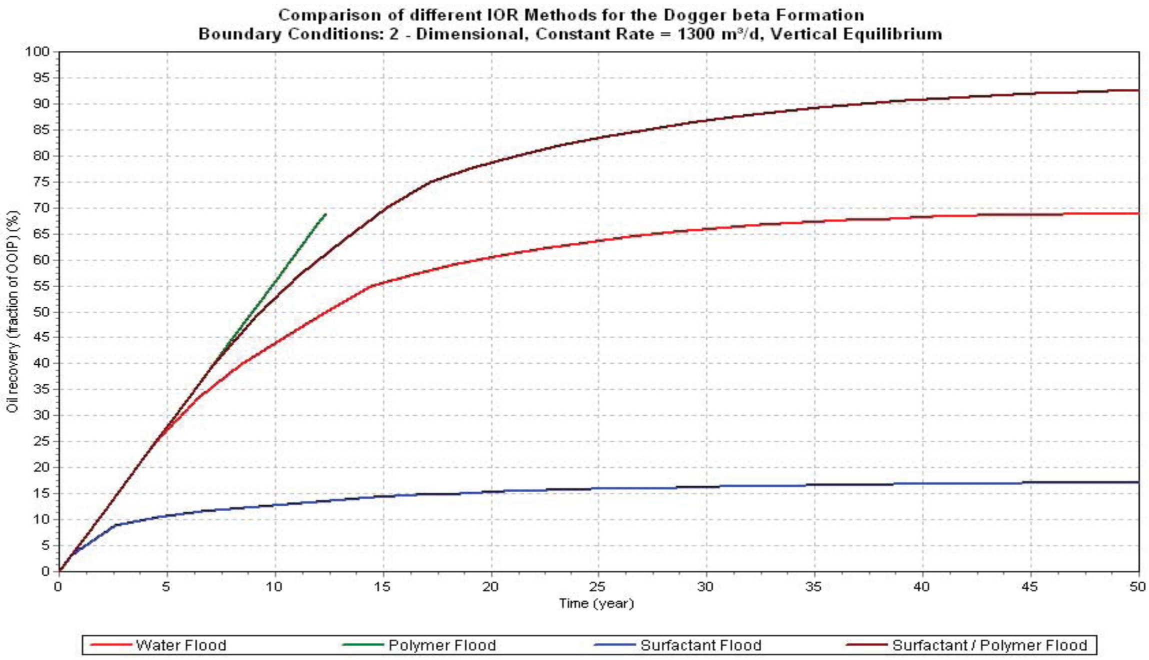


Figure D.2.: Comparison of the calculation options for the Dogger beta formation, 2D – Vertical Equilibrium – constant rate

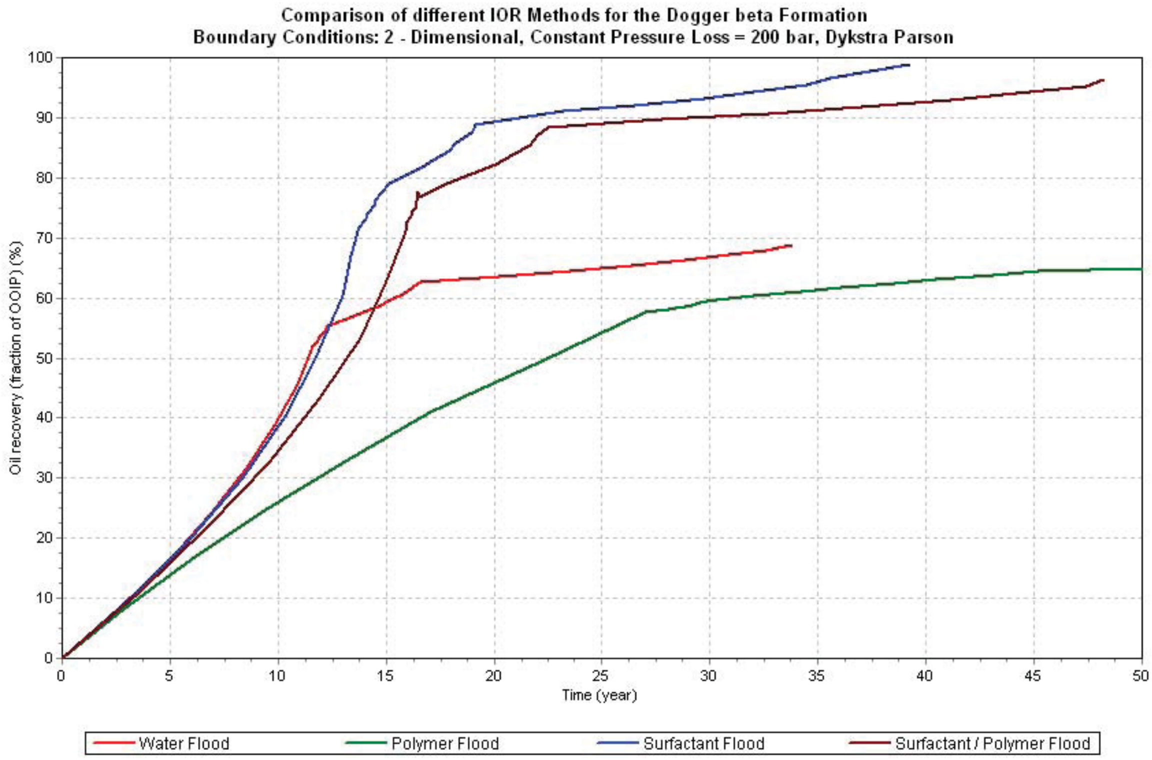


Figure D.3.: Comparison of the calculation options for the Dogger beta formation, 2D – Dykstra Parsons – constant pressure loss

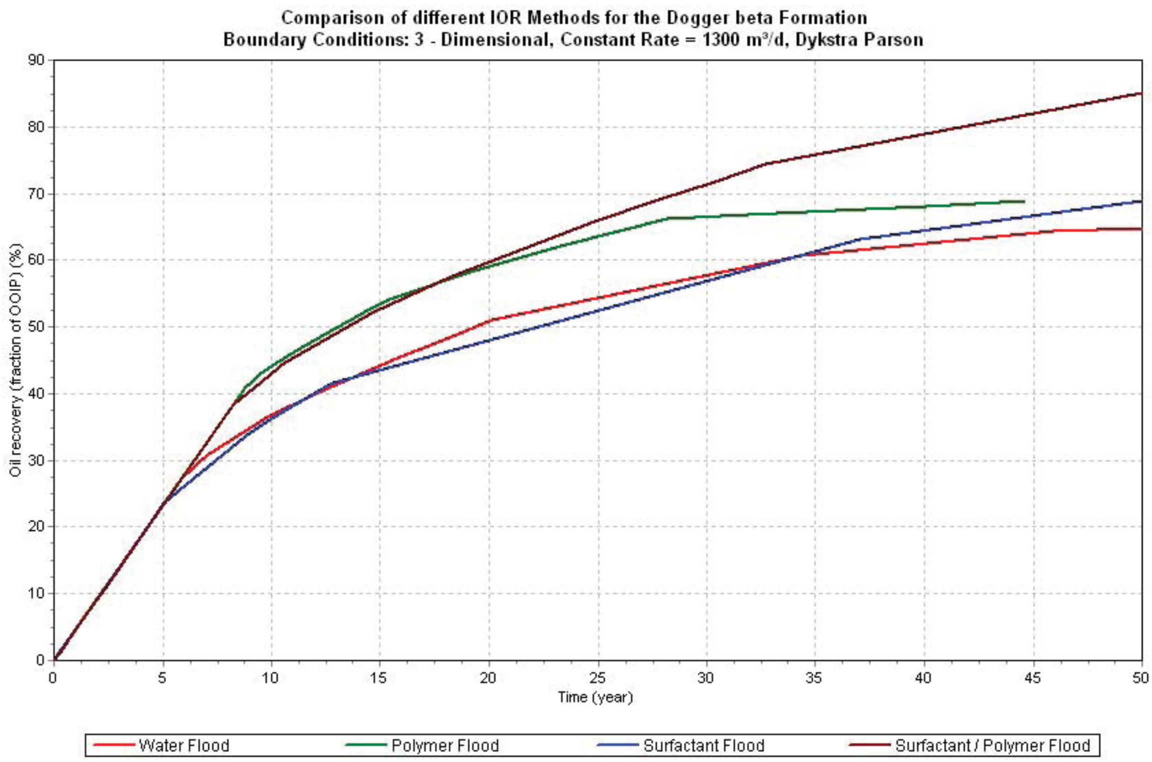


Figure D.4.: Comparison of the calculation options for the Dogger beta formation, 3D – Dykstra Parsons – constant rate

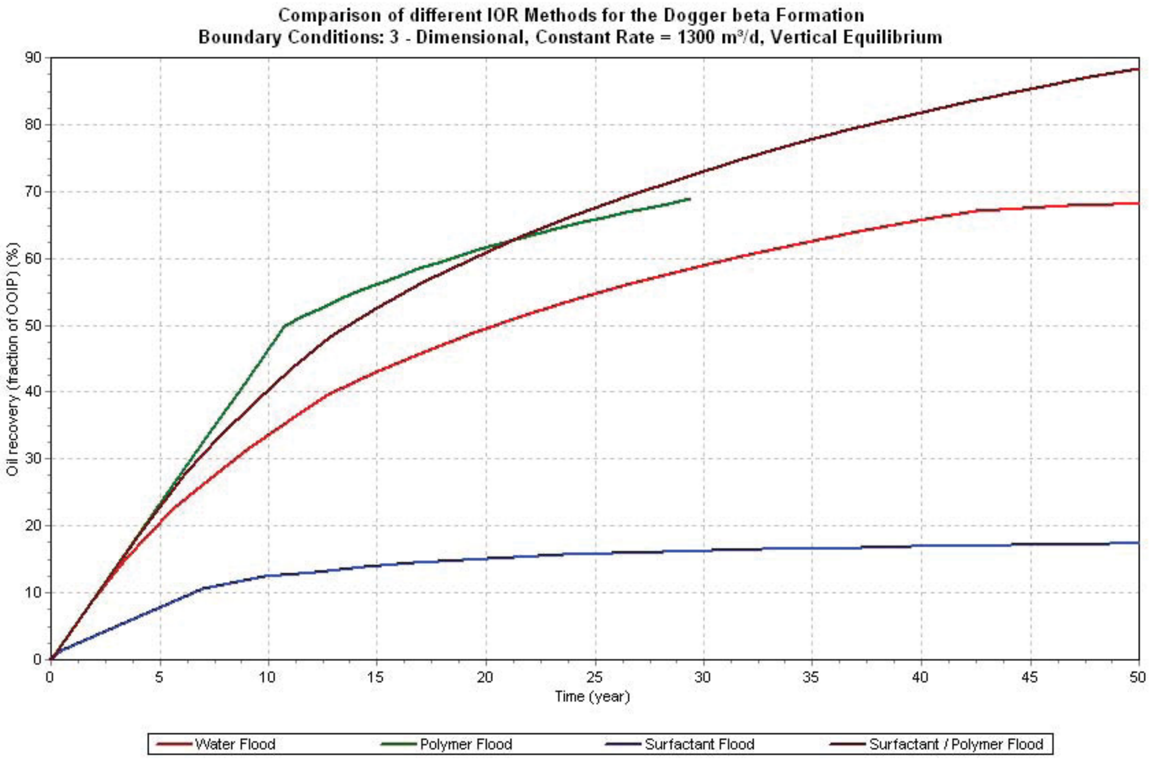


Figure D.5.: Comparison of the calculation options for the Dogger beta formation, 3D – Vertical Equilibrium – constant rate

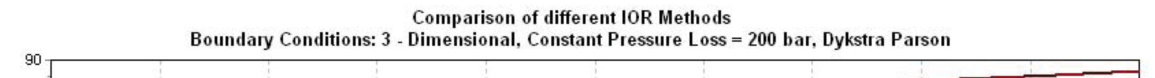


Figure D.6.: Comparison of the calculation options for the Dogger beta formation, 3D – Dykstra Parsons – constant pressure loss

D.2.2 Dogger Gamma Formation

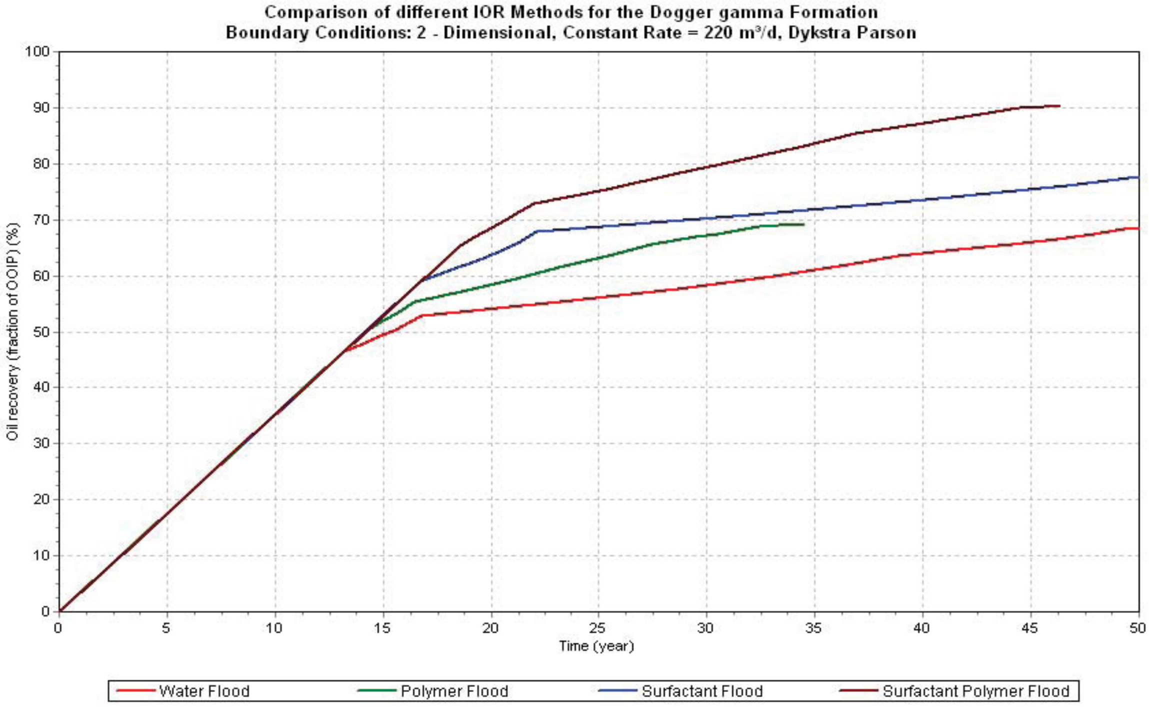


Figure D.7.: Comparison of the calculation options for the Dogger gamma formation, 2D – Dykstra Parsons – constant rate

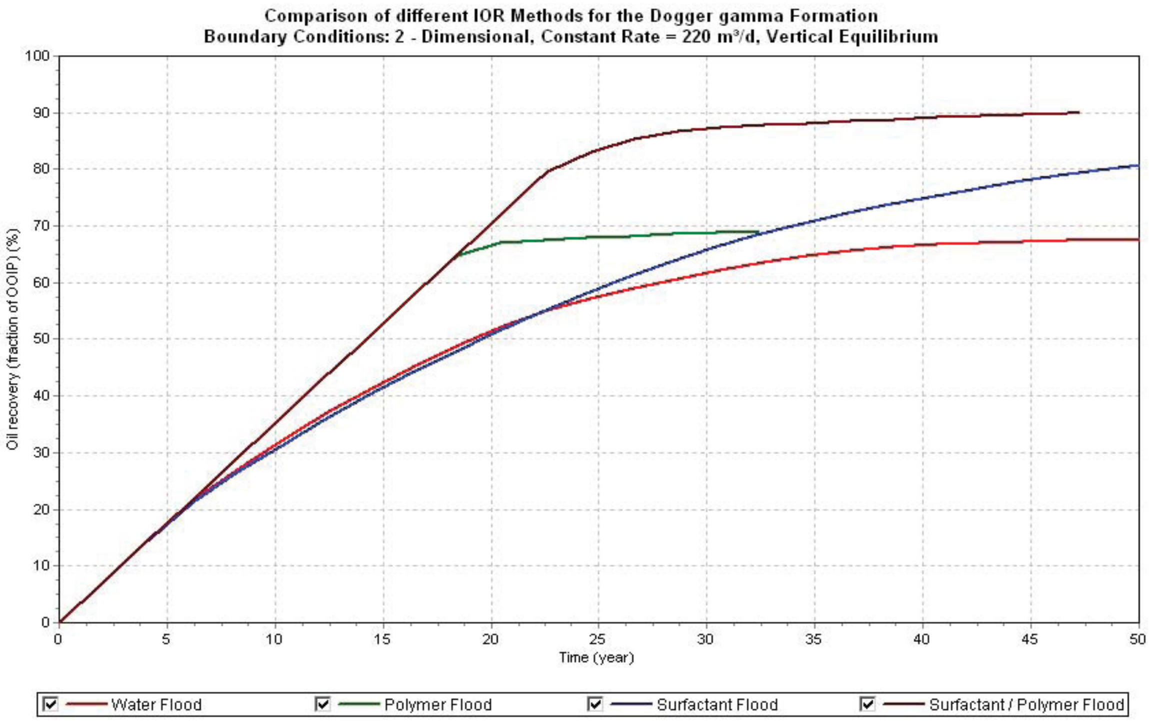


Figure D.8.: Comparison of the calculation options for the Dogger gamma formation, 2D – Vertical Equilibrium – constant rate

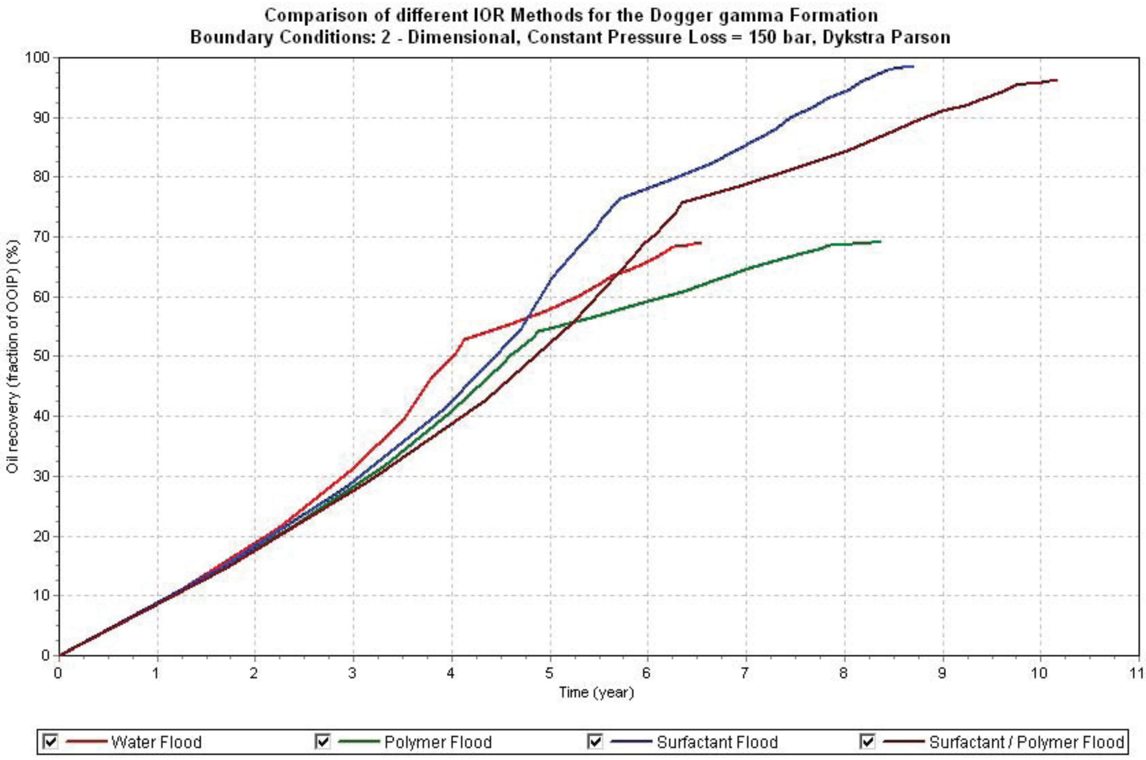


Figure D.9.: Comparison of the calculation options for the Dogger gamma formation, 2D – Dykstra Parsons – constant pressure loss

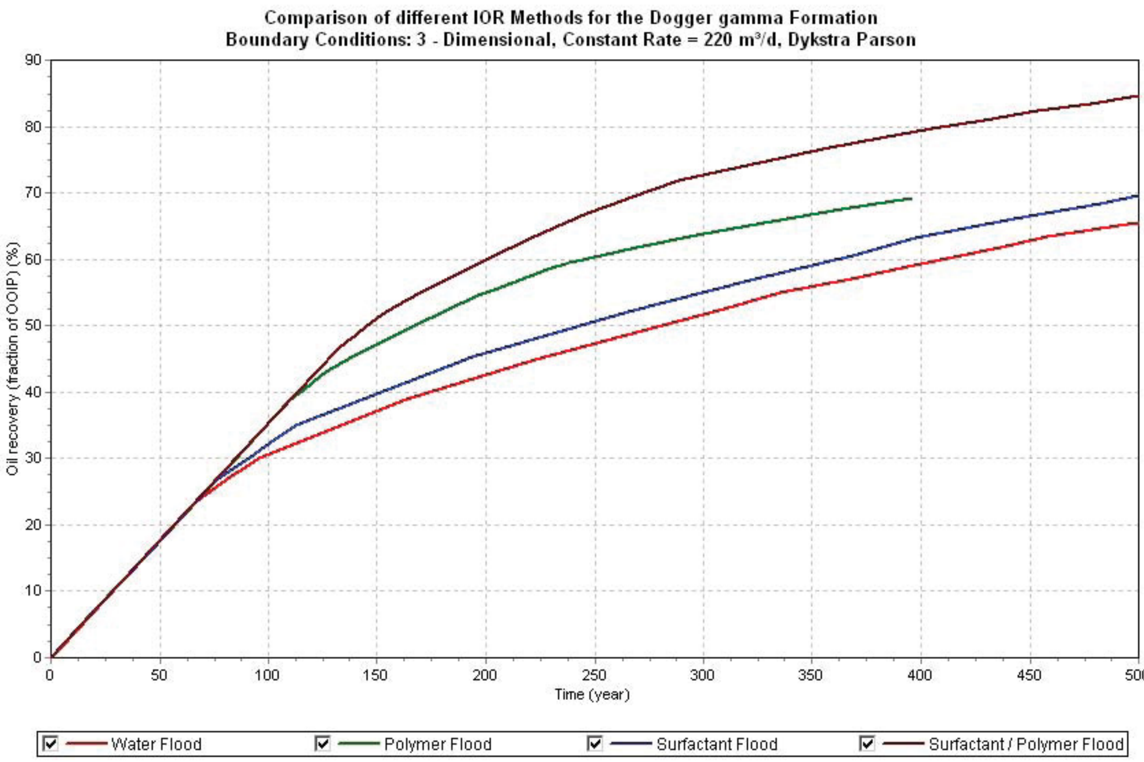


Figure D.10.: Comparison of the calculation options for the Dogger gamma formation, 3D – Dykstra Parsons – constant rate

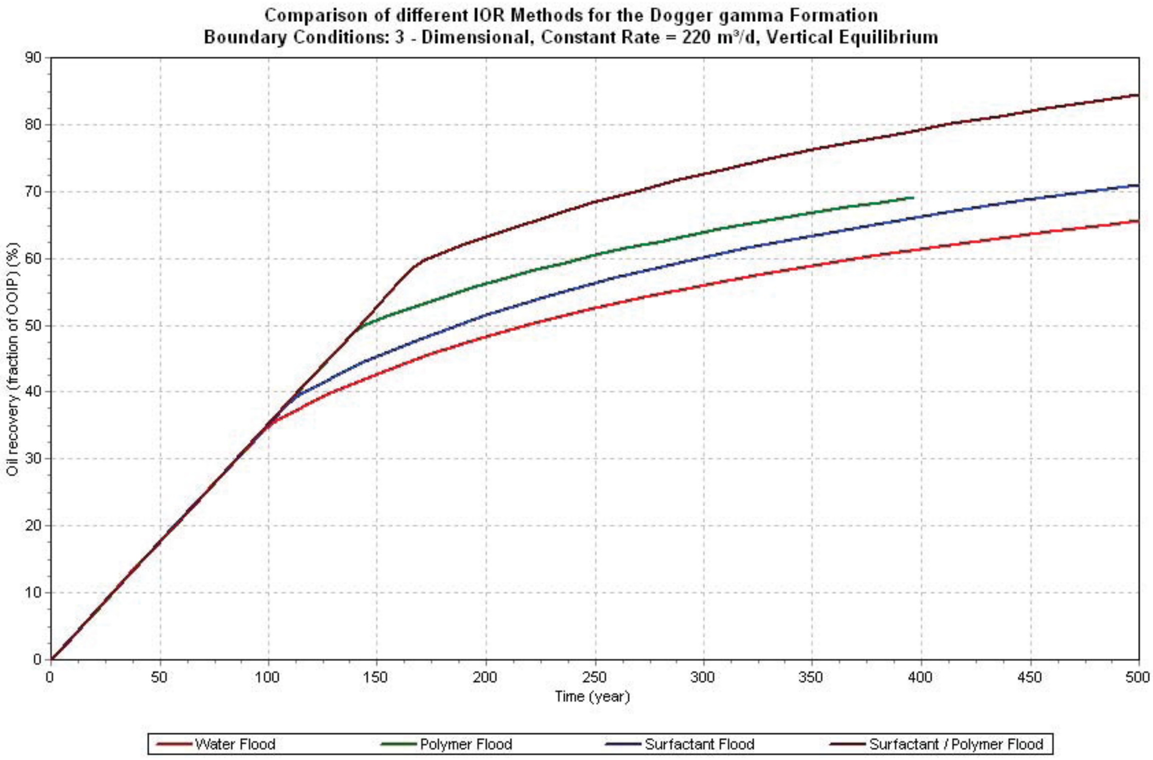


Figure D.11.: Comparison of the calculation options for the Dogger gamma formation, 3D – Vertical Equilibrium – constant rate

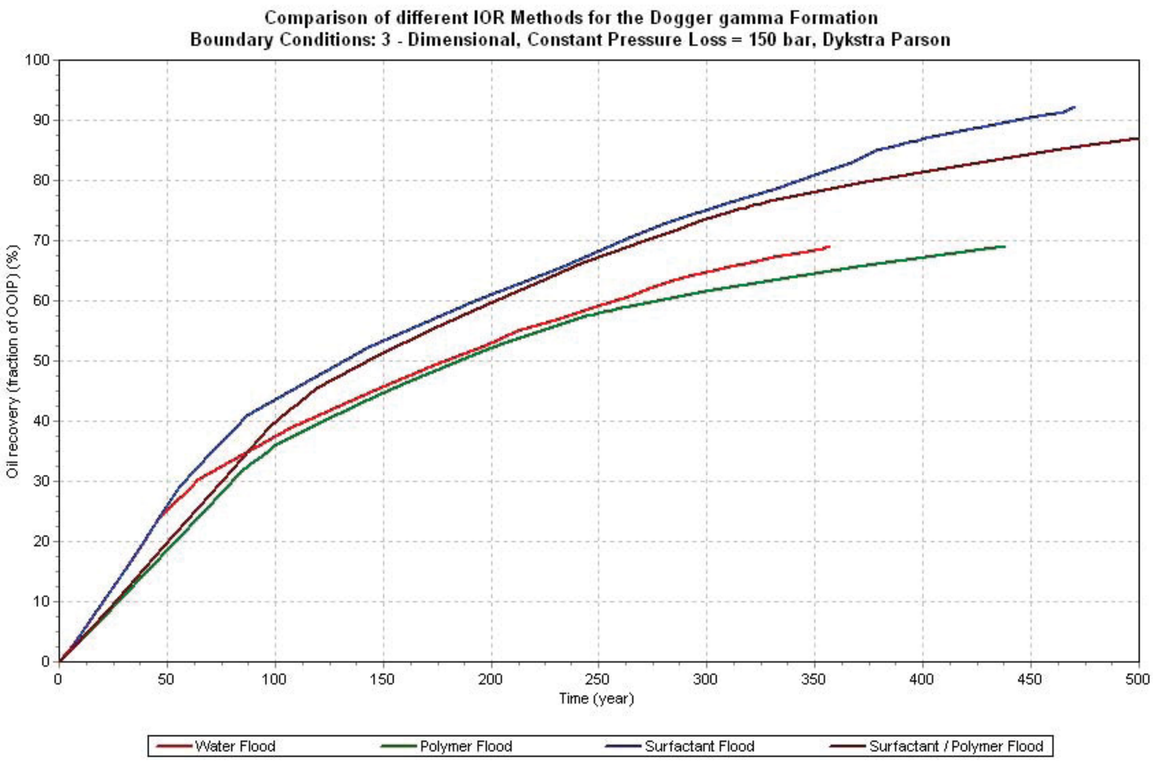


Figure D.12.: Comparison of the calculation options for the Dogger gamma formation, 3D – Dykstra Parsons – constant pressure loss

D.2.3 Dogger Delta / Epsilon Formation

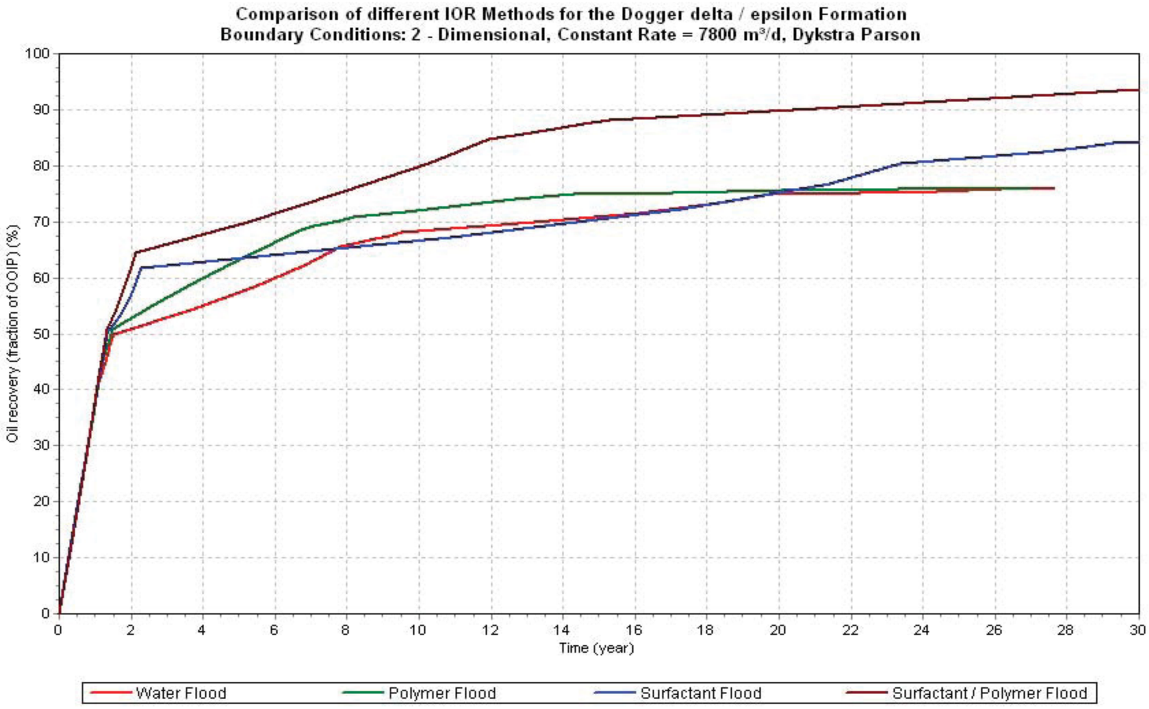


Figure D.13.: Comparison of the calculation options for the Dogger delta / epsilon formation, 2D – Dykstra Parsons – constant rate

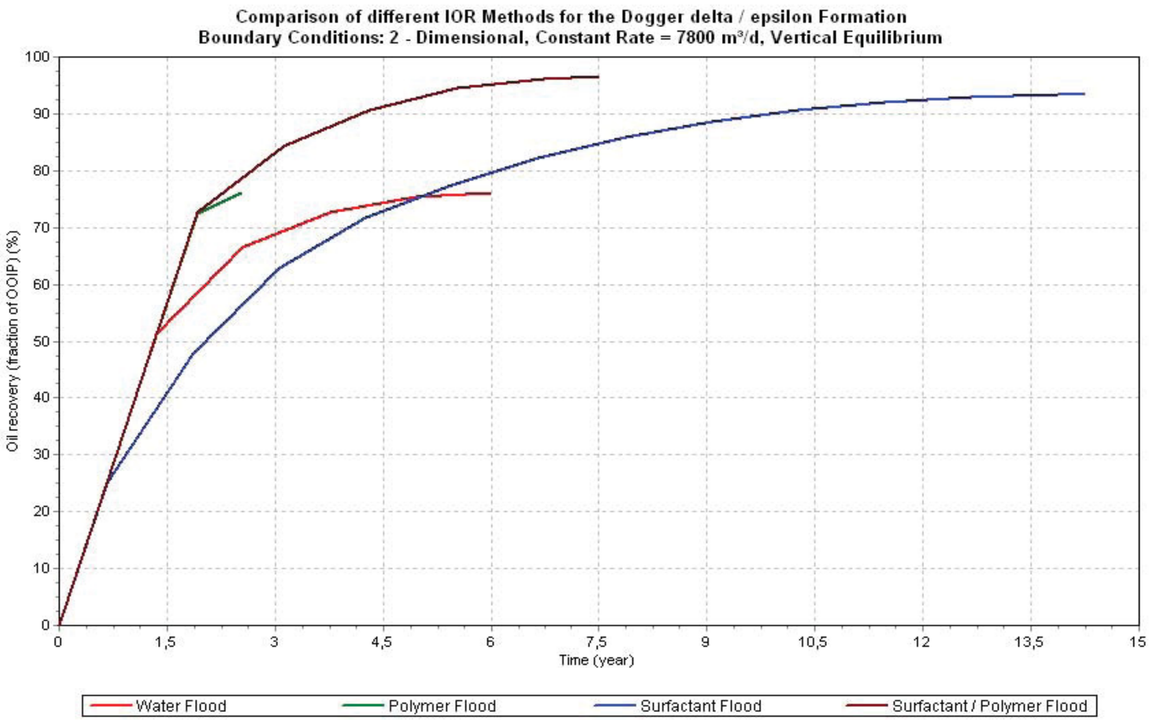


Figure D.14.: Comparison of the calculation options for the Dogger gamma formation, 2D – Vertical Equilibrium – constant rate

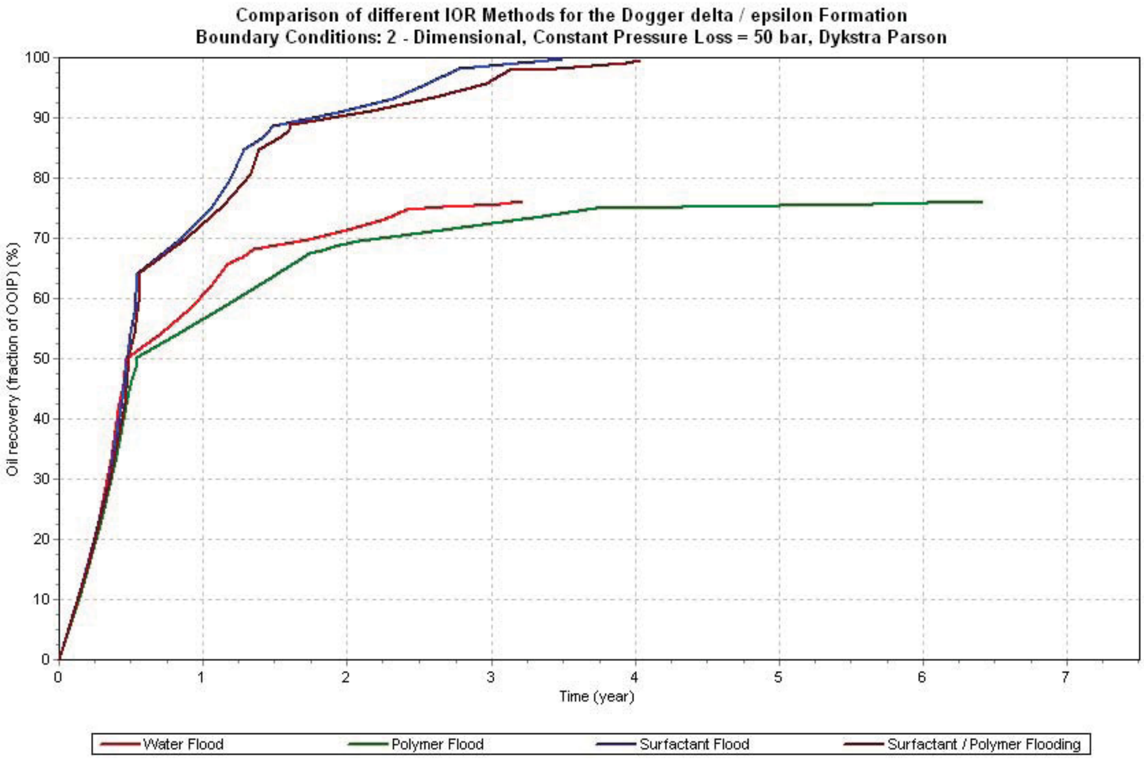


Figure D.15.: Comparison of the calculation options for the Dogger delta / epsilon formation, 2D – Dykstra Parsons – constant pressure loss

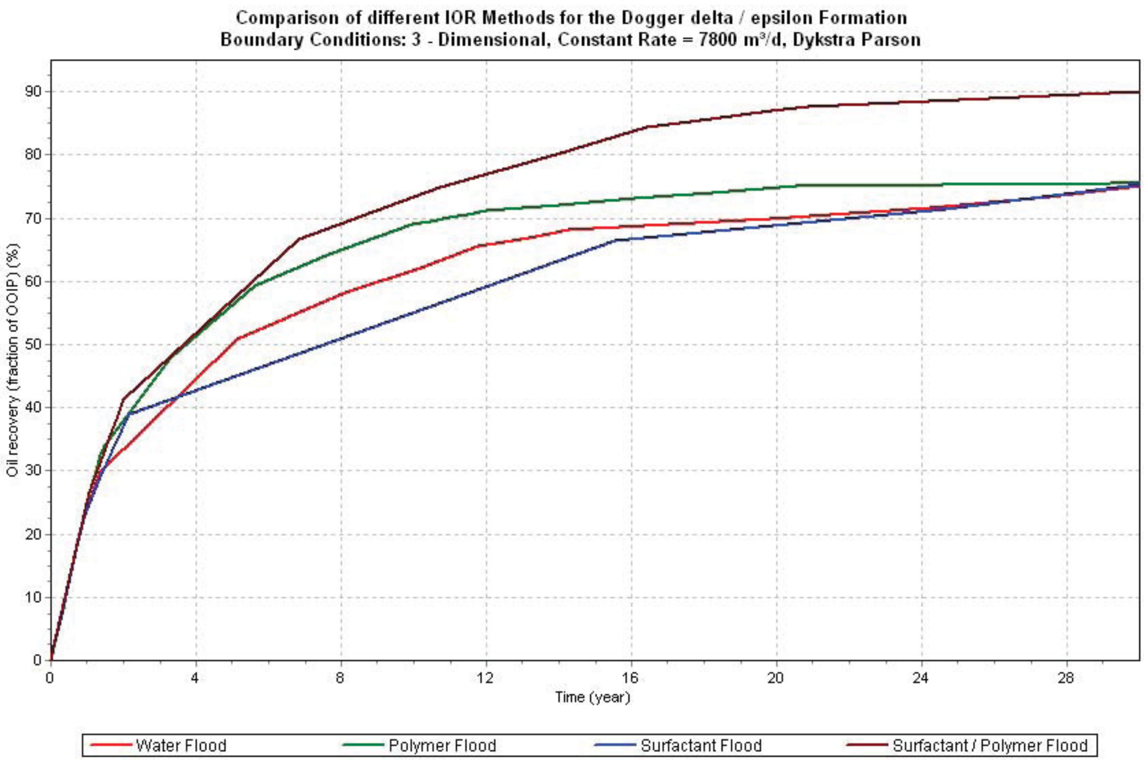


Figure D.16.: Comparison of the calculation options for the Dogger delta / epsilon formation, 3D – Dykstra Parsons – constant rate

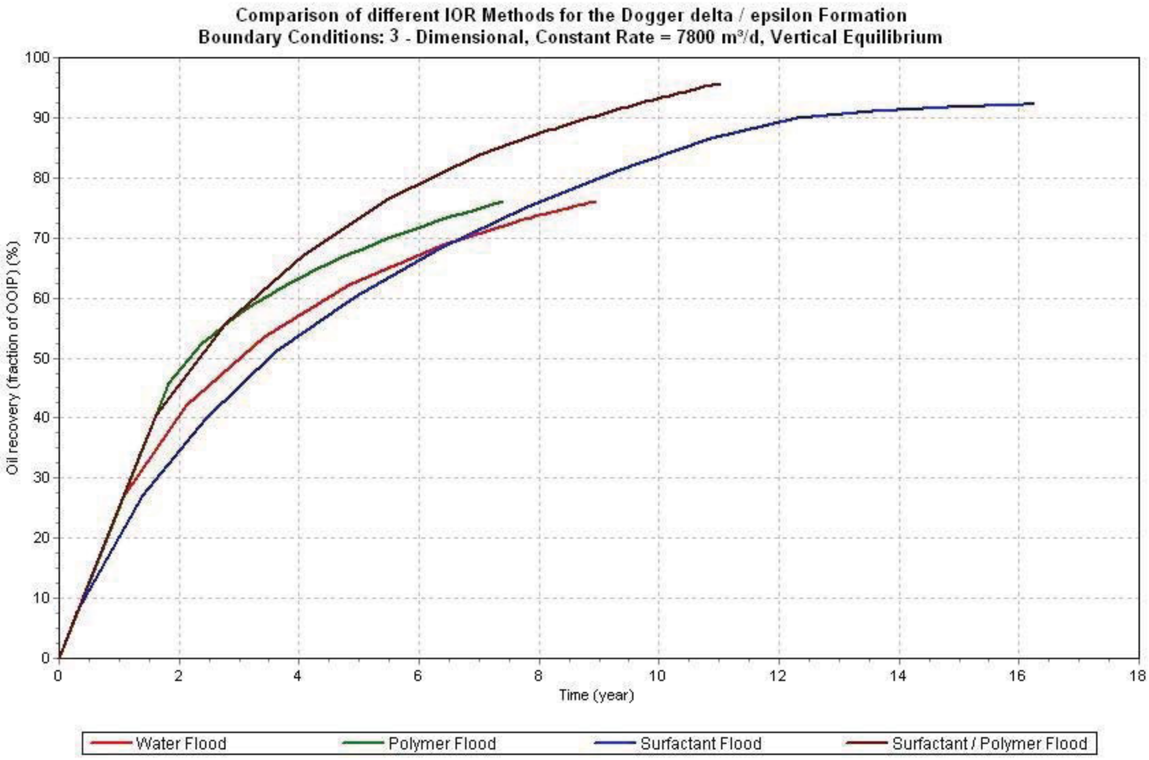


Figure D.17.: Comparison of the calculation options for the Dogger delta / epsilon formation, 3D – Vertical Equilibrium – constant rate

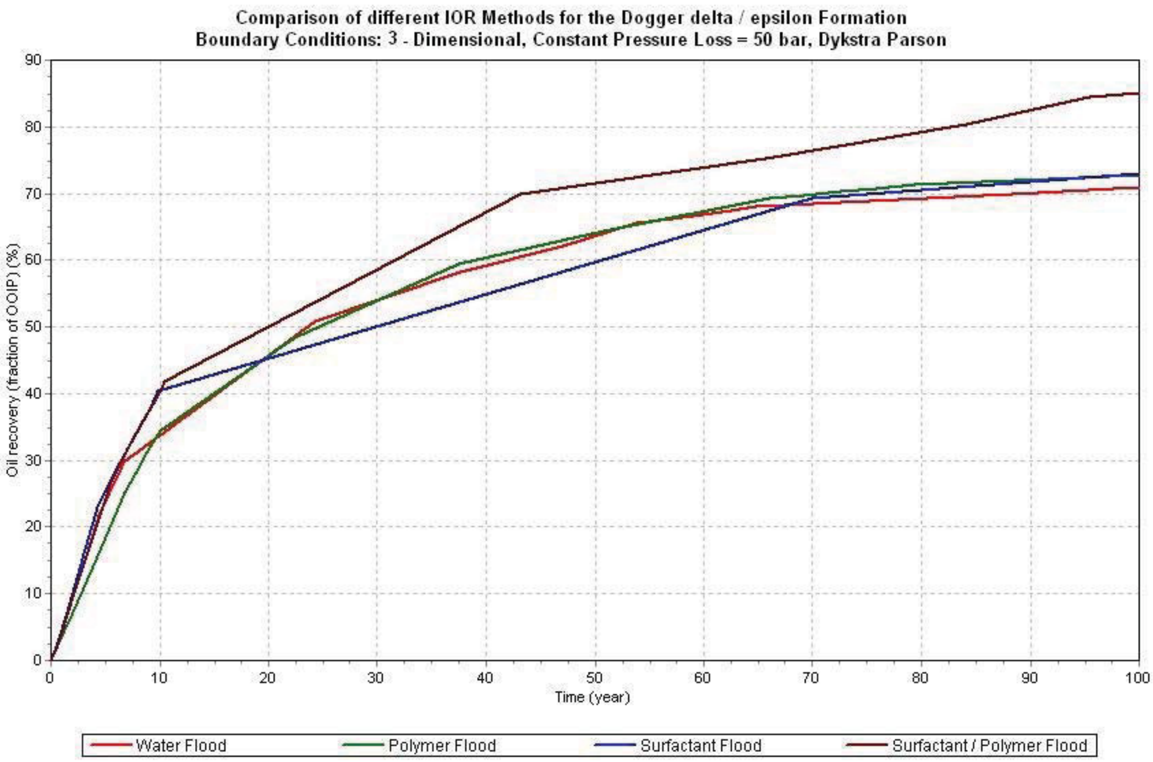


Figure D.18.: Comparison of the calculation options for the Dogger delta / epsilon formation, 3D – Dykstra Parsons – constant pressure loss

Appendix E

Data Correlations for the Dogger Beta Sample Case

Water (old model)			Water (new model)		
Time	Recovery	Rate	Time	Recovery	Rate
0,000	0,000	400,000	0,000	0,000	400,000
4,719	8,090	400,000	0,128	8,090	400,000
9,363	16,051	400,000	0,254	16,051	400,000
13,910	23,846	400,000	0,377	23,846	400,000
18,331	31,426	400,000	0,497	31,426	400,000
22,586	38,720	400,000	0,613	38,720	400,000
26,607	45,614	400,000	0,722	45,614	400,000
30,285	51,918	153,130	0,821	51,918	153,130
31,053	52,429	156,930	0,842	52,429	156,930
31,794	52,933	160,991	0,862	52,933	160,991
32,507	53,432	165,347	0,882	53,432	165,347
33,191	53,923	170,036	0,900	53,923	170,036
33,847	54,408	175,106	0,918	54,408	175,106
34,474	54,886	180,613	0,935	54,886	180,613
35,073	55,357	40,166	0,951	55,357	40,166
41,216	56,453	43,219	1,118	56,453	43,219
46,837	57,536	46,840	1,270	57,536	46,840
51,934	58,605	51,214	1,409	58,605	51,214
56,506	59,658	56,618	1,533	59,658	56,618
60,555	60,696	63,484	1,642	60,696	63,484
64,079	61,718	72,522	1,738	61,718	72,522
67,078	62,724	6,393	1,819	62,724	6,393
97,300	63,596	7,118	2,639	63,596	7,118
100,000	63,683	7,209	2,712	63,683	7,209

Table E.1.: Water data conversion

Polymer (old model)			Polymer (new model)		
Time	Recovery	Rate	Time	Recovery	Rate
0,000	0,000	400,000	0,000	0,000	400,000
4,761	8,162	400,000	0,129	8,162	400,000
9,541	16,357	400,000	0,259	16,357	400,000
14,334	24,573	400,000	0,389	24,573	400,000
19,148	32,827	400,000	0,519	32,827	400,000
23,965	41,084	400,000	0,650	41,084	400,000
28,806	49,384	400,000	0,781	49,384	400,000
33,642	57,673	223,945	0,912	57,673	223,945
33,940	57,966	223,422	0,921	57,966	223,422
34,230	58,243	223,055	0,928	58,243	223,055
34,525	58,527	222,220	0,936	58,527	222,220
34,816	58,805	221,854	0,944	58,805	221,854
35,113	59,089	221,019	0,952	59,089	221,019
35,406	59,367	220,654	0,960	59,367	220,654
35,705	59,651	101,043	0,968	59,651	101,043
37,289	60,333	99,632	1,011	60,333	99,632
38,932	61,029	96,734	1,056	61,029	96,734
40,591	61,712	95,388	1,101	61,712	95,388
42,312	62,412	92,548	1,148	62,412	92,548
44,049	63,096	91,267	1,195	63,096	91,267
45,855	63,800	88,490	1,244	63,800	88,490
47,675	64,486	21,779	1,293	64,486	21,779
54,726	65,107	19,972	1,484	65,107	19,972
62,180	65,727	18,920	1,687	65,727	18,920
70,483	66,348	16,989	1,912	66,348	16,989
79,231	66,969	16,146	2,149	66,969	16,146
88,988	67,590	14,482	2,414	67,590	14,482
99,234	68,210	13,806	2,692	68,210	13,806
100,000	68,252	12,881	2,712	68,252	12,881

Table E.2.: Polymer data conversion

Water (new model)				Differences		Polymer (new model)			
Timestep	Time	Recovery	Rate	delta Er	delta qo	Timestep	Time	Recovery	Rate
1	0,083	5,267	400,000	0	0	1	0,083	5,267	400,000
2	0,167	10,534	400,000	0	0	2	0,167	10,534	400,000
3	0,250	15,801	400,000	0	0	3	0,250	15,801	400,000
4	0,333	21,068	400,000	0	0	4	0,333	21,068	400,000
5	0,417	26,335	400,000	0	0	5	0,417	26,335	400,000
6	0,500	31,602	400,000	0	0	6	0,500	31,602	400,000
7	0,583	36,870	400,000	0	0	7	0,583	36,870	400,000
8	0,667	42,137	400,000	0	0	8	0,667	42,137	400,000
9	0,750	47,404	329,904	0	70,096	9	0,750	47,404	400,000
10	0,833	52,210	155,300	0,461	174,889	10	0,833	52,671	330,189
11	0,917	54,371	174,713	3,454	48,961	11	0,917	57,825	223,674
12	1,000	55,678	41,058	4,474	58,949	12	1,000	60,152	100,007
13	1,083	56,226	42,585	5,219	53,331	13	1,083	61,444	95,916
14	1,167	56,799	44,377	5,889	47,655	14	1,167	62,688	92,031
15	1,250	57,391	46,356	6,496	33,676	15	1,250	63,887	80,032
16	1,333	58,023	48,832	6,594	-27,433	16	1,333	64,616	21,399
17	1,417	58,673	51,565	6,214	-30,953	17	1,417	64,887	20,612
18	1,500	59,381	55,195	5,774	-35,305	18	1,500	65,155	19,891
19	1,583	60,137	59,787	5,017		19	1,583	abandoned	
20	1,667	60,955	65,773	4,199		20	1,667	abandoned	
21	1,750	61,866	62,800	3,288		21	1,750	abandoned	
22	1,833	62,738	6,405	2,416		22	1,833	abandoned	
23	1,917	abandoned				23	1,917	abandoned	
24	2,000	abandoned				24	2,000	abandoned	

Table E.3.: Resulting data after conversion and correlation

Appendix F

Data Input for the Wellhead Pressure Calculations

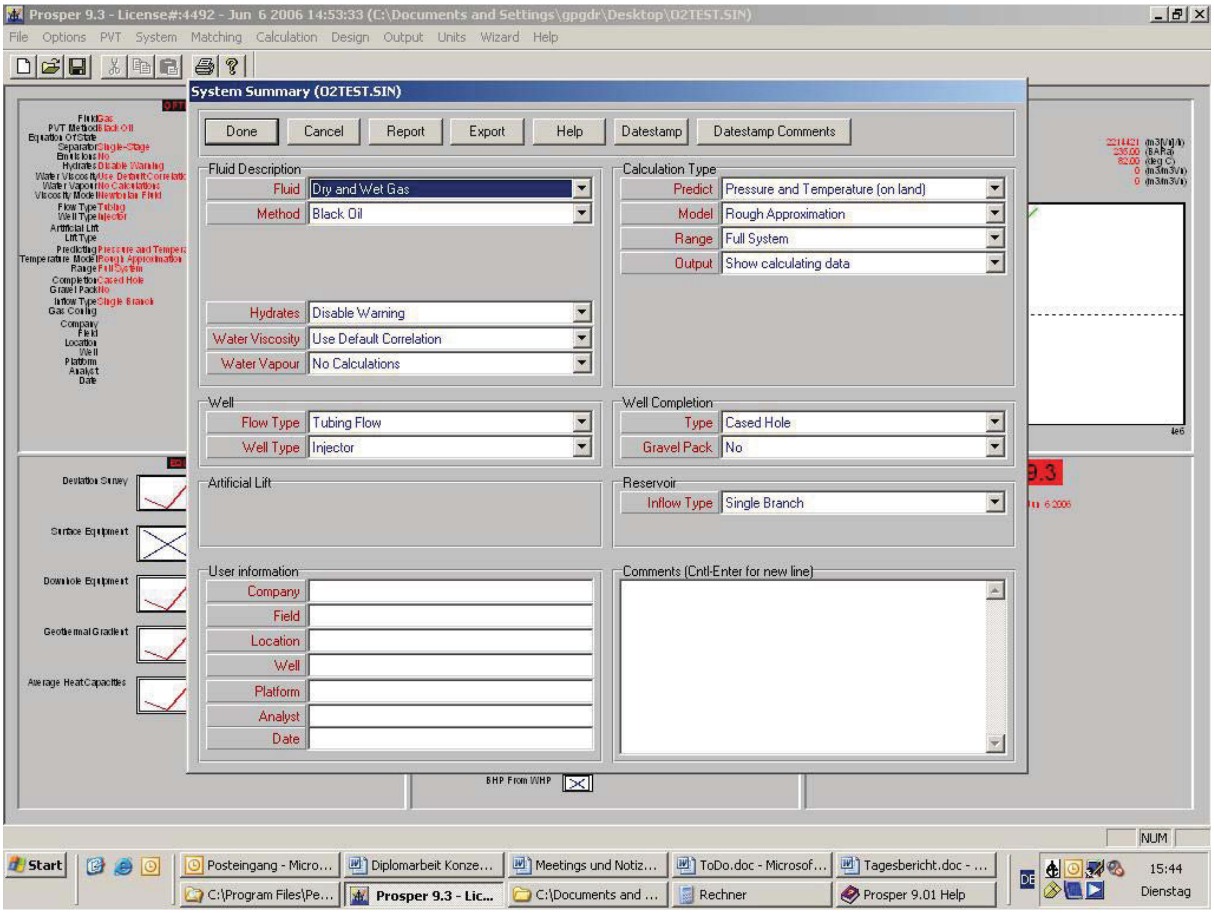


Figure F.1.: Data input overview

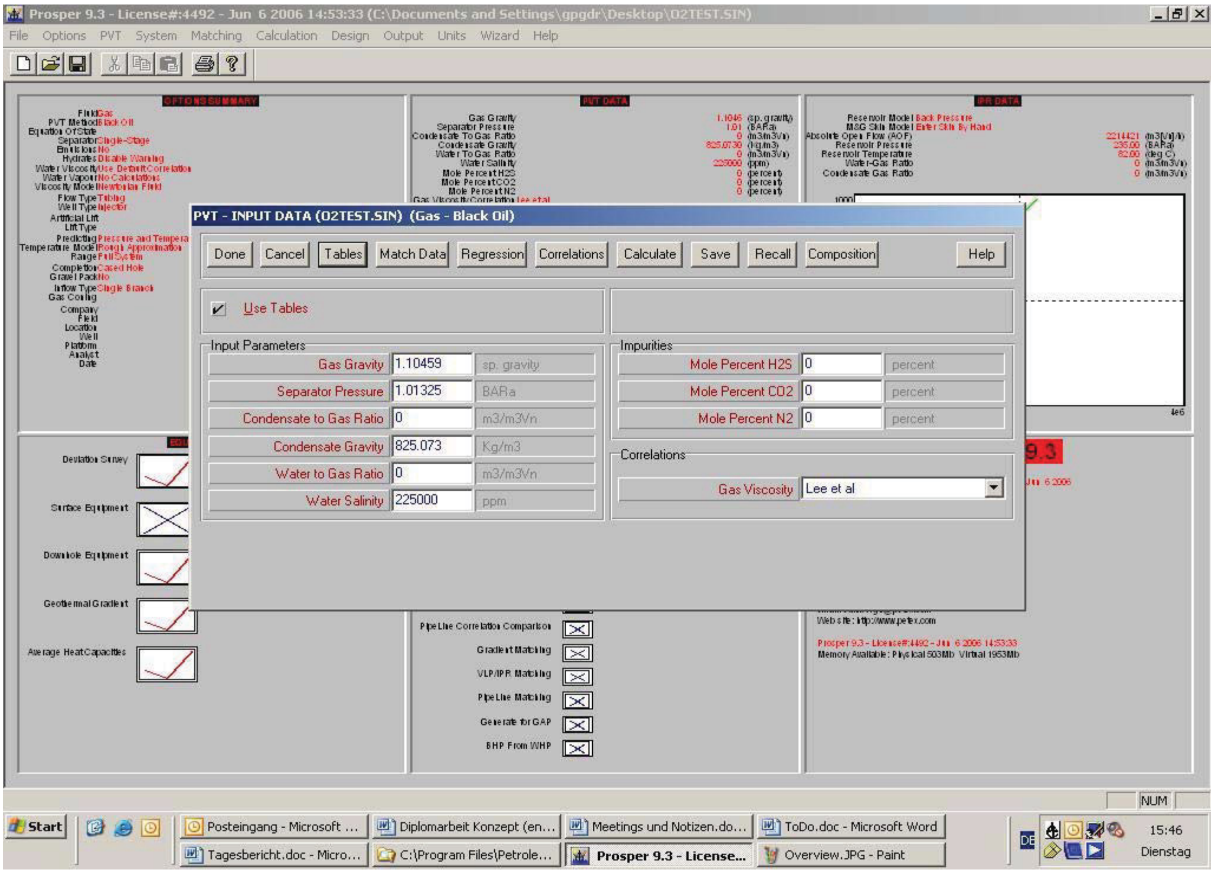


Figure F.2.: PVT data input

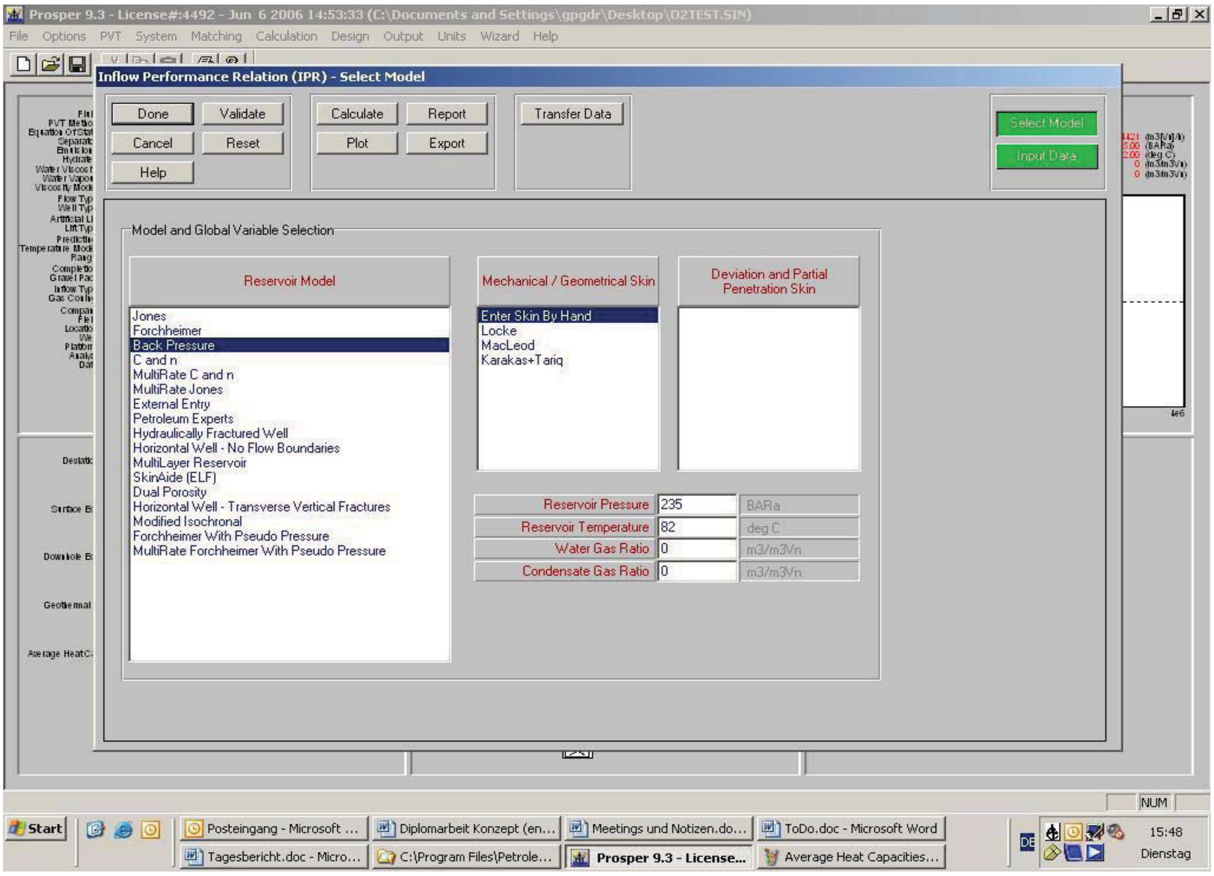


Figure F.3.: IPR model selection (1)

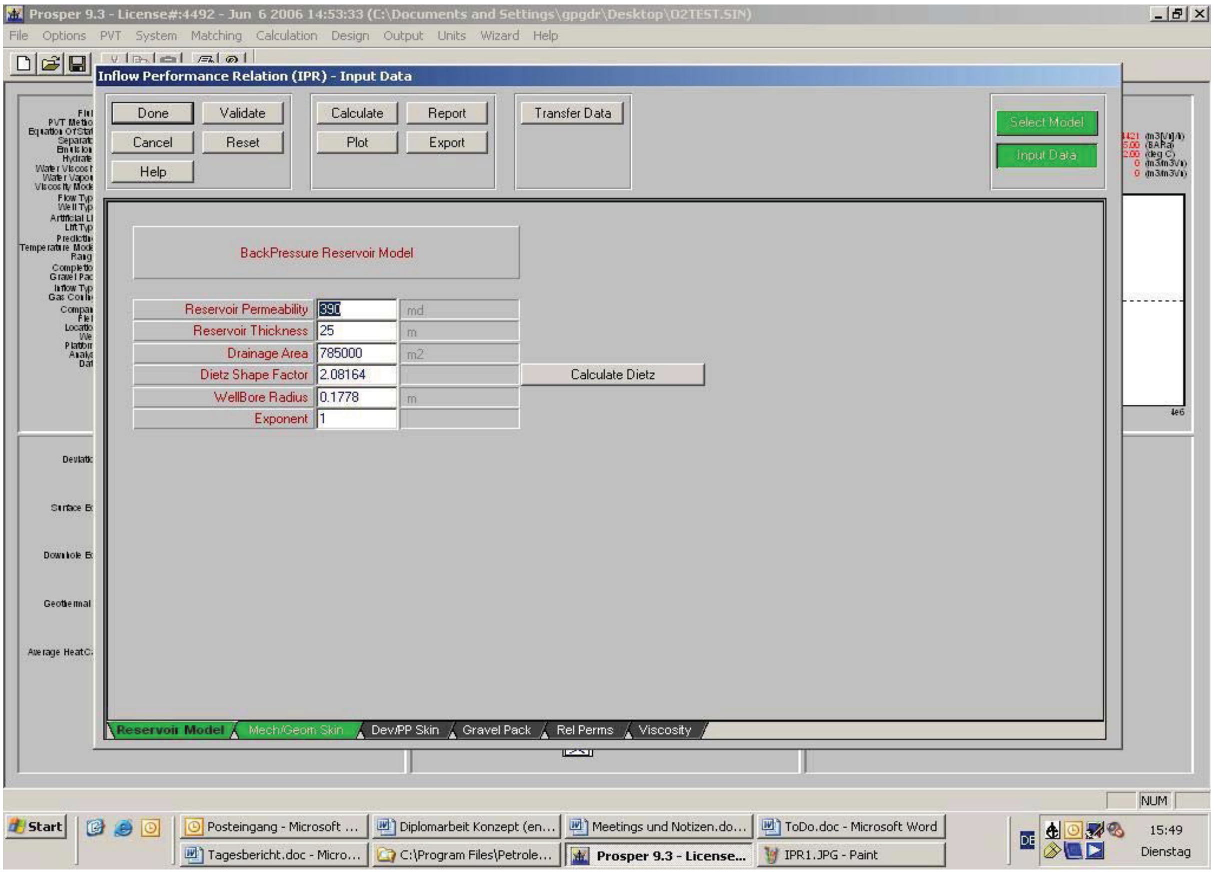


Figure F.4.: IPR model selection (2)

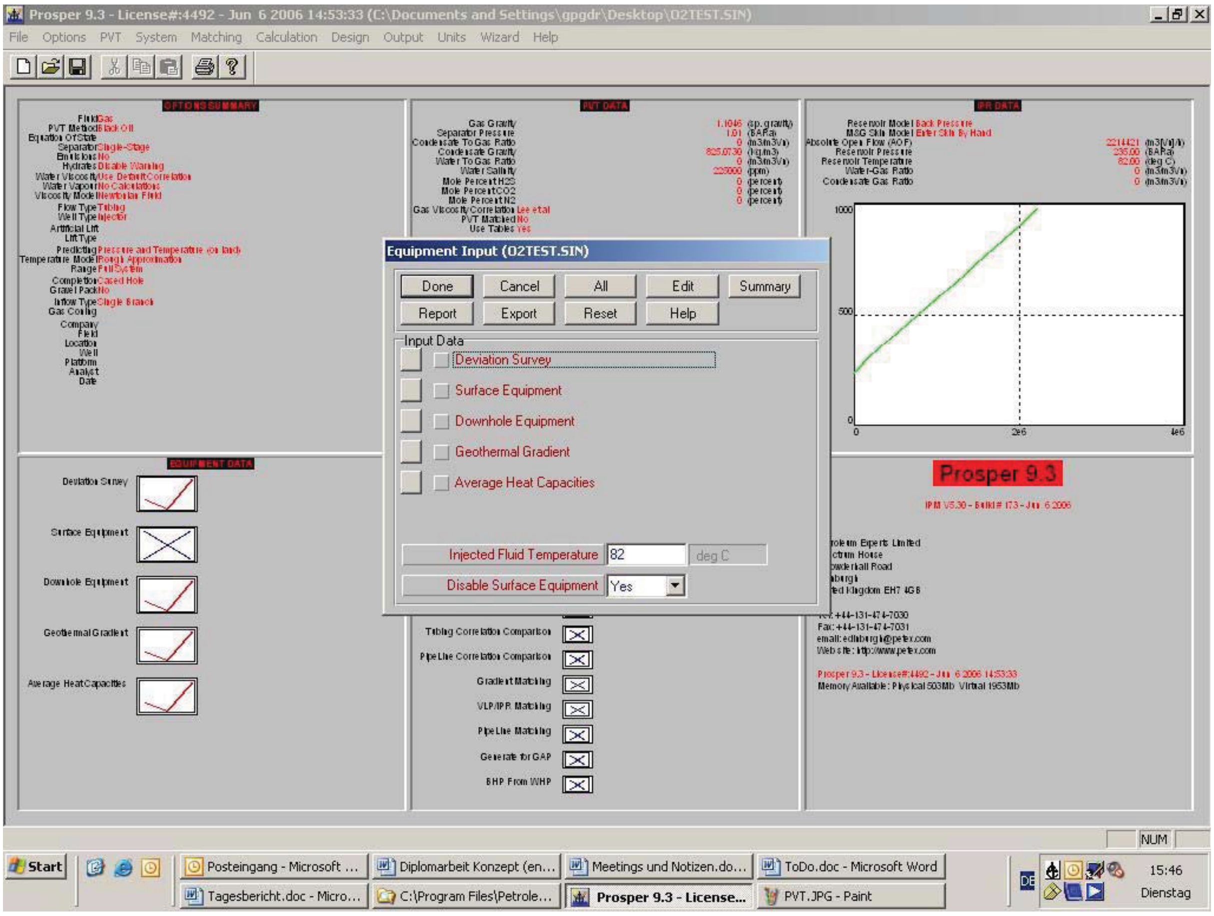


Figure F.5.: Equipment input overview

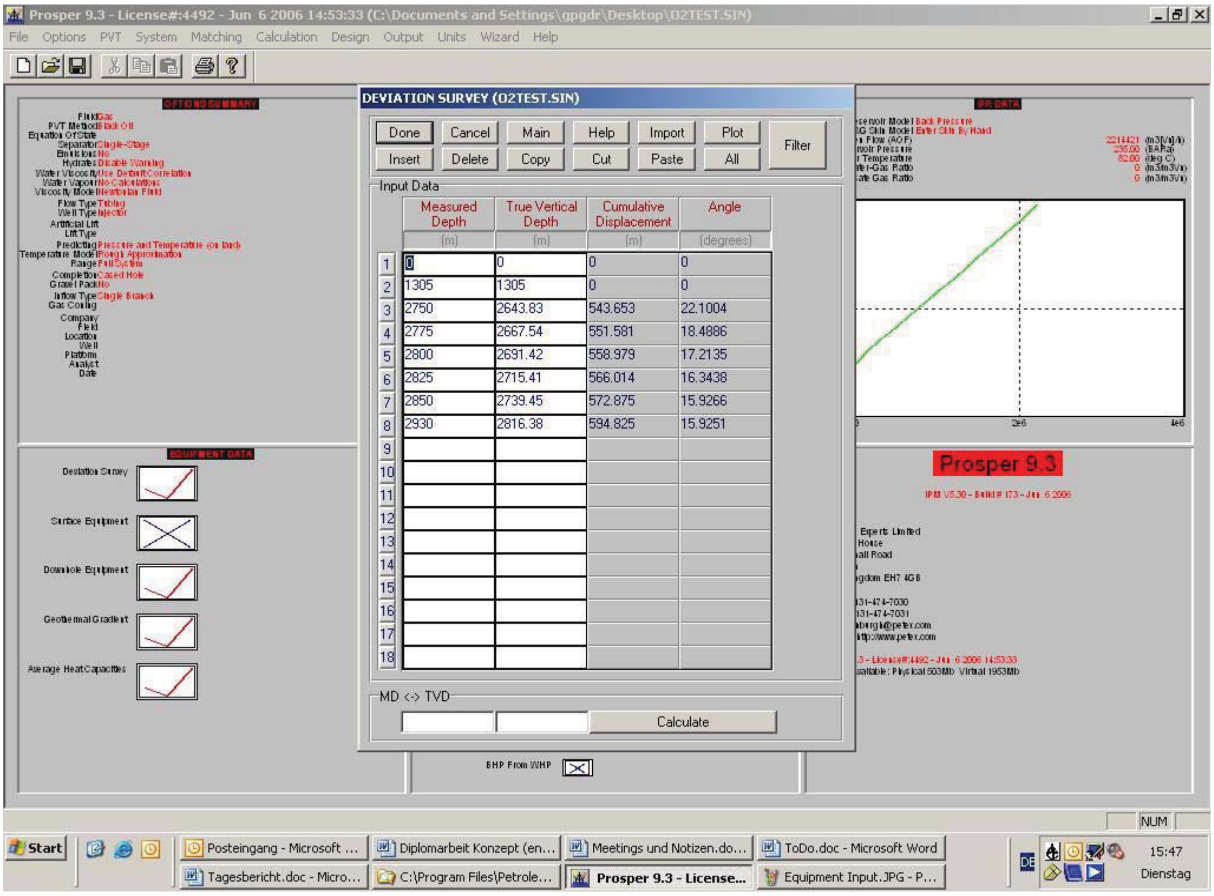


Figure F.6.: Deviation survey

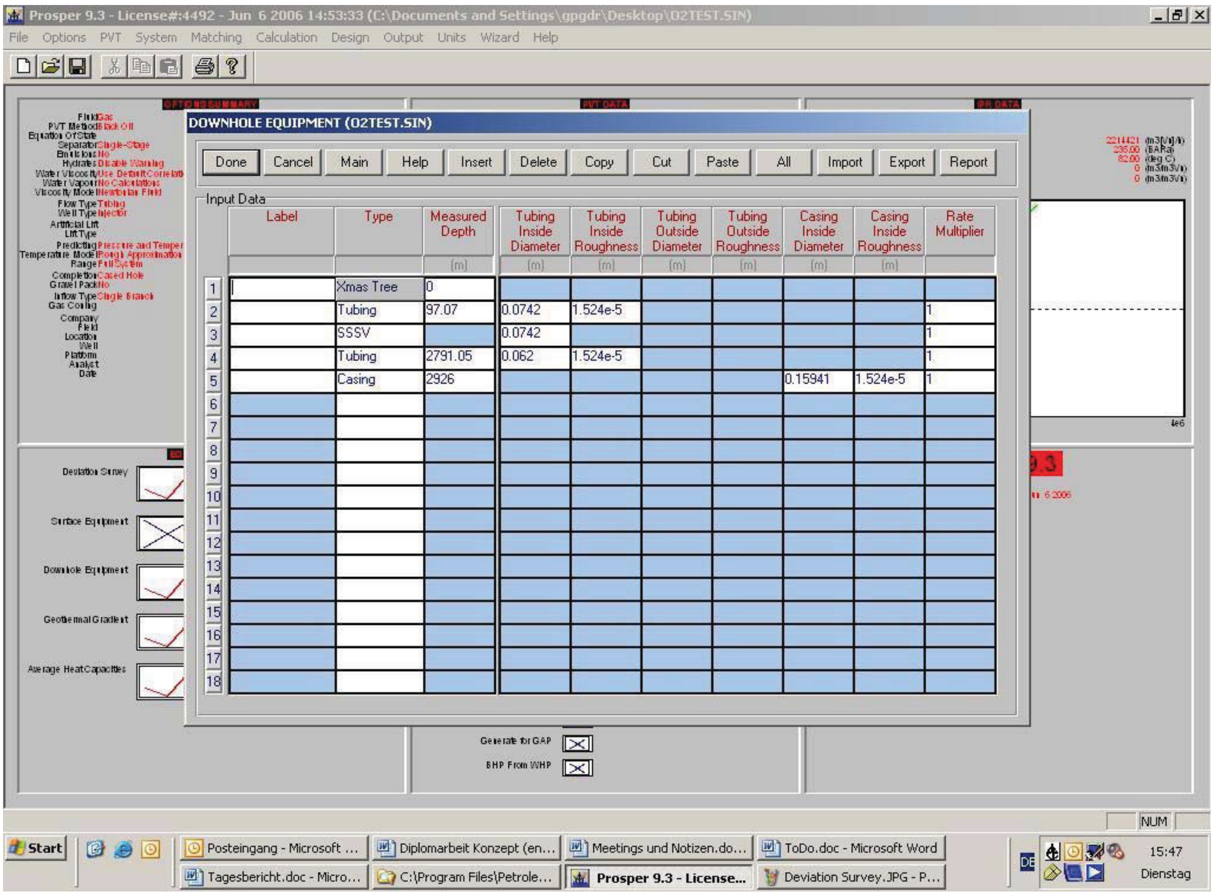


Figure F.7.: Downhole equipment

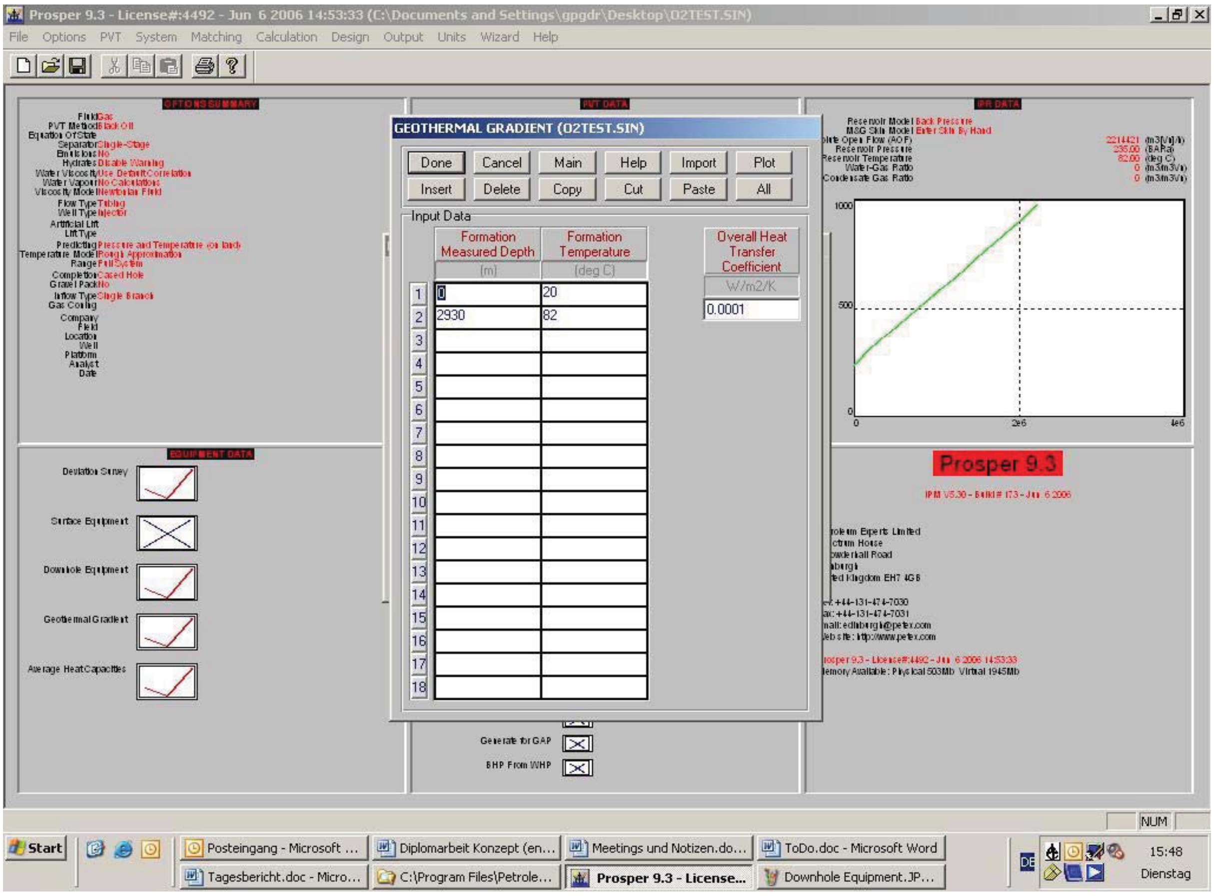


Figure F.8.: Geothermal gradient

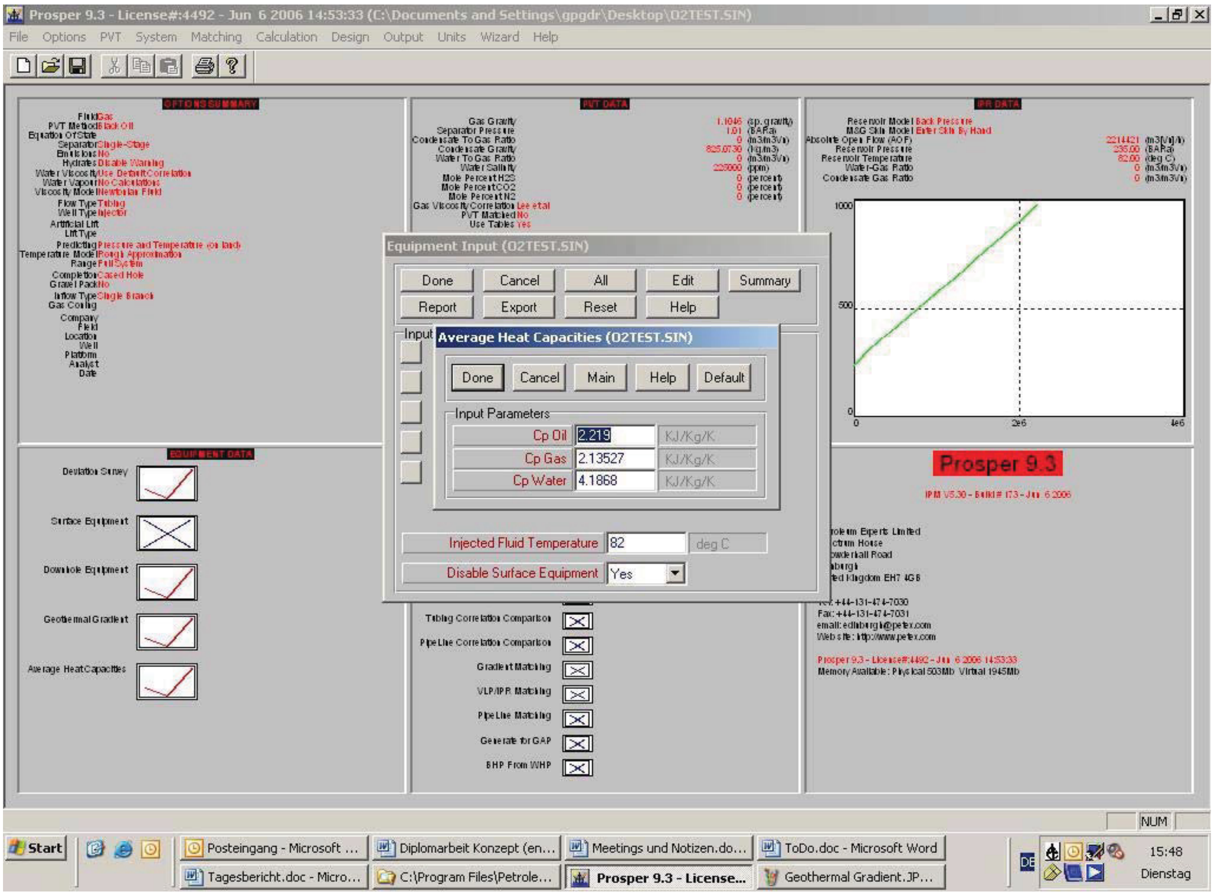


Figure F.9.: Average heat capacities