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Reservoir Study For Production Optimization By Water Flooding In The Gullfaks Field

[1]Berthelot Tamo Sop, [2]Rolande Tsapla Fotsa, [3]Dianorré Tokoue Ngatcha, [4]Alex Stephane Kemnang Tsafack, [5]Finalise Komofor Ngopuh,* and [6]Serge Gervais Ngueuteu Mbouna

[1] Department of Petroleum and Gas Engineering, School of Geology and Mining Engineering, University of Ngaoundere, P.O. BOX 115, Meiganga, Cameroon
[2] Department of Mechanical Engineering, College of Technology, University of Buea, P.O. BOX 63 Buea, Cameroon
[3] Department of Automotive and Mechatronics Engineering, National Higher Polytechnic School of Douala, University of Douala, P.O. Box 24, 2701, Douala, Cameroon

[4] Research unit of Condensed matter of electronics and signal processing. Dept. of Physics, Faculty of Science, University of Dschang, P.O. Box 67, Dschang, Cameroon
[5] Department of Physics, Faculty of Science, University of Bamenda, P.O. Box 39 Bamenda, Cameroon
[6] Laboratory of Modelling and Simulation in Engineering, Biomimetics and Prototypes, Faculty of Science, University of Yaoundé I, P.O. 812, Yaoundé, Cameroon

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Corresponding Author:
Finalise Komofor Ngopuh
ngopuhfk@gmail.com

Abstract

The Gullfaks field constitutes one of the largest hydrocarbon deposits in Norway. It is divided into several geological formations: Cook, Statfjord, Lunde, and the Brent group. It consists of several reservoirs, two of which are the subject of this paper: Tarbert and Ness reservoirs. This paper aims to re-pressurize the reservoir of the Gullfaks field through the implementation of a secondary oil recovery method by flooding the reservoir with water. Many methods have been employed for the estimation of hydrocarbons and the enhancement of oil recovery (EOR). This study utilises the water flooding method to optimize oil recovery in the Gullfak field. Based on data from the Gullfaks field provided by company X for security reasons, a 3-dimensional static model of the reservoir, created using Petrel, revealed a volume of 459 119 496,855 bbls of oil and 206 274 915 000 cf of gas. Subsequently, a 3-dimensional dynamic model was constructed through Eclipse simulation to predict a 20-year operation (2000-2020) of water injection into the reservoir over 20 years (2000-2020). The results indicated an oil recovery factor of 28.8%, representing a 19.7% increase over the primary recovery of 9.1%. Similarly, the gas recovery factor was determined to be 36.1%, representing a 24.6% increase over the primary recovery of 11.5%. This exponential increase in gas and oil production has led to economic growth, indicating that this method enhanced high-quality production in comparison to other oil recovery techniques.

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1. Introduction

The Gullfaks field represents one of the most substantial hydrocarbon deposits in Norway since its discovery in 1978. The field is composed of multiple geological formations, including Cook, Statfjord, Lunde, and the Brent groups. The Brent group comprises numerous reservoirs, with this paper focusing on two of these (Tarbert and Ness reservoirs). The Gullfaks field has been in production since 1986 [1-3], and a subsequent decrease in production was observed a few years later, with an oil recovery of 9.1% and a gas recovery of 11.5% [4-6]. The Gullfaks field is one of the most productive oil fields in Norway, to a consortium comprising Statoil (85%), Norsk Hydro (9%), and Saga Petroleum (6%), with Statoil designated as operator [7-9]. Statoil is a petroleum company in the Norwegian State, which was renamed to Equinor in 2018, indicating a broader shift from a purely oil and gas company to an integrated energy company. The Tarbert and Ness formations are prograding near-shore environment and fluvial respectively. These formations have distinct depositional environments and facies distributions, influencing their reservoir properties. The Tarbert and Ness reservoirs are characterised by a high degree of structural complexity, with approximately 200 faults identified within their respective models. It is subdivided into a domino system, an accommodation zone, and a horst complex [10-12].

In light of the Gullfaks field details literature exploitation, Solheim et al. [13] investigated the various Gullfaks field formations, such as Cook, Statfjord, Lunde, and Brent Groups. The present paper focuses on the Brent Group, which consists of several reservoirs, the most significant of which are Tarbert and Ness. The latter are reservoirs consisting primarily of sand and silt, with a significant hydrocarbon overflow [14-16]. The production history of these reservoirs (1986-2000) demonstrates a gradual decline until 2000, which followed a decrease in reservoir pressure. In light of these continuous decreases in oil and gas production from the Gullfaks field, several techniques have been employed to enhance production in accordance with the physicochemical properties of the reservoir [17-19]. Some of these techniques include: carbon dioxide (CO_2) injection, gas injection, thermal EOR, chemical EOR, well log data, and water flooding, just to name a few. Water flooding is a process used to inject water into an oil-bearing reservoir for pressure maintenance as well as for displacing and producing incremental oil. It is therefore crucial to ascertain the impact of water flooding on production. The implementation of this method is based on data from the Gullfaks field provided by company X. This will facilitate the design of a three-dimensional static model of the reservoir, which will then be used to generate a quantitative estimate of hydrocarbons in place with the Petrel software. A simulation case will be constructed based on the static models of the reservoir, integrating the production history and the water injection parameters to perform a simulation through the Eclipse software. To achieve this, it is essential to pursue the following objectives: The characterization of the reservoir, quantification of hydrocarbons, and simulations of water injection into the reservoir are essential for understanding the impact of water flooding on production and for identifying potential sources of uncertainty.

The objective of this paper is to re-pressurize the Tarbert and the Ness reservoir for production optimization in the Gullfaks field by flooding the reservoir with Water. The remaining parts of the paper are organized as follows: Section two outlines the study area, materials, and methods in Section three, Section four presents results and discussion, and the conclusion in section five.

2. Theoretical Part

The Gullfaks main field consists of the Brent Group and the underlying Cook, Statfjord, and Lunde Formations. The Brent Group represents the main reservoir containing more than 73% of the in-place volumes. The current recovery factor is approximately 60%. It consists of Broom, Rannoch, Etive, Ness, and Tarbert. Tarbert and Ness are collectively called Upper Brent, and the rest is called Lower Brent. The Gullfaks oil field is located within the Norwegian license PL 050 in block 34/10 at 610N 20E in the Norwegian sector of the North Sea, specifically in the central region of the East Shetland Basin on the western flank of the Viking Graben [20-22]. The Tarbert and Ness Formations are part of the Middle Jurassic Brent Group, a key hydrocarbon reservoir in the Northern North Sea. The Tarbert Formation, which is typified by a prograding nearshore environment, is situated on top of the Upper Ness, which is of a fluvial nature. These formations are of critical importance for the extraction of oil and gas in the region Fig. 1.

Figure 1: Location map of the Gullfaks field [23].

3. Experimental Procedure

The acquisition of data was made possible by company X for security reasons, which granted permission for work to be conducted on the Gullfaks field, where the main operator is Statoil. The data provided by company X was divided into two distinct data sets, which were subsequently utilized. The initial data set comprised a more recent 3D seismic cube along with a static model of the overlying Upper Brent Group accompanied by the following description: Seismic cube, interpreted horizons, fault,15 wells (A10, A15, A16, B1, B2, B4, B8, B9, C1, C2, C3, C4, C5, C6, and C7), isochores and Velocity model. The second data set consisted of a dynamic model of the reservoirs of the Gullfaks field, in Eclipse format, containing data for twelve years between December 1, 1986, and December 31, 1999. As previously stated, the reservoirs in question are those belonging to the Lower Brent.

Over the past decades, a variety of techniques have been utilized for the estimation of hydrocarbons and the enhancement of oil recovery. These techniques encompass carbon dioxide (CO_2) injection, gas injection, thermal EOR, chemical EOR, well log data, water flooding, and other methods. It is essential to recognize that each technique possesses both advantages and disadvantages. The selection of an optimal technique is contingent upon a comprehensive assessment of the specific circumstances. This paper employs the water flooding method to optimize oil production. The water flooding method is used to maintain reservoir pressure in oil and gas fields. It involves injecting water into the reservoir, which increases pressure and helps displace oil towards production wells. The tools utilized in this paper to achieve the stated objectives are Petrel and Eclipse software. The two methods selected are in accordance with the aforementioned data and tools, with the initial objective being the establishment of a volumetric reserve estimation via the modelling, as earlier investigated in the literature by Jassim et al. calculating value of the initial Oil in place using an equation [24], and the subsequent objective being the production of a dynamic reservoir model via simulation.

4. Results and Discussion

The data provided by company X was subjected to partitioning into two distinct data sets, which were then utilised for further analysis. The initial set comprises a 3D seismic cube, accompanied by a static model of the overlying Upper Brent Group, and is accompanied by the following description: Seismic cube, interpreted horizons, fault,15 wells (A10, A15, A16, B1, B2, B4, B8, B9, C1, C2, C3, C4, C5, C6, and C7), isochores, and Velocity model. The second data set consists of a dynamic model of the reservoirs of the Gullfaks field. The ensuing discussion will present the findings from these data sets.

Figure 2 presents the well correlations of B9, C1, C2, C3, and C4 wells.

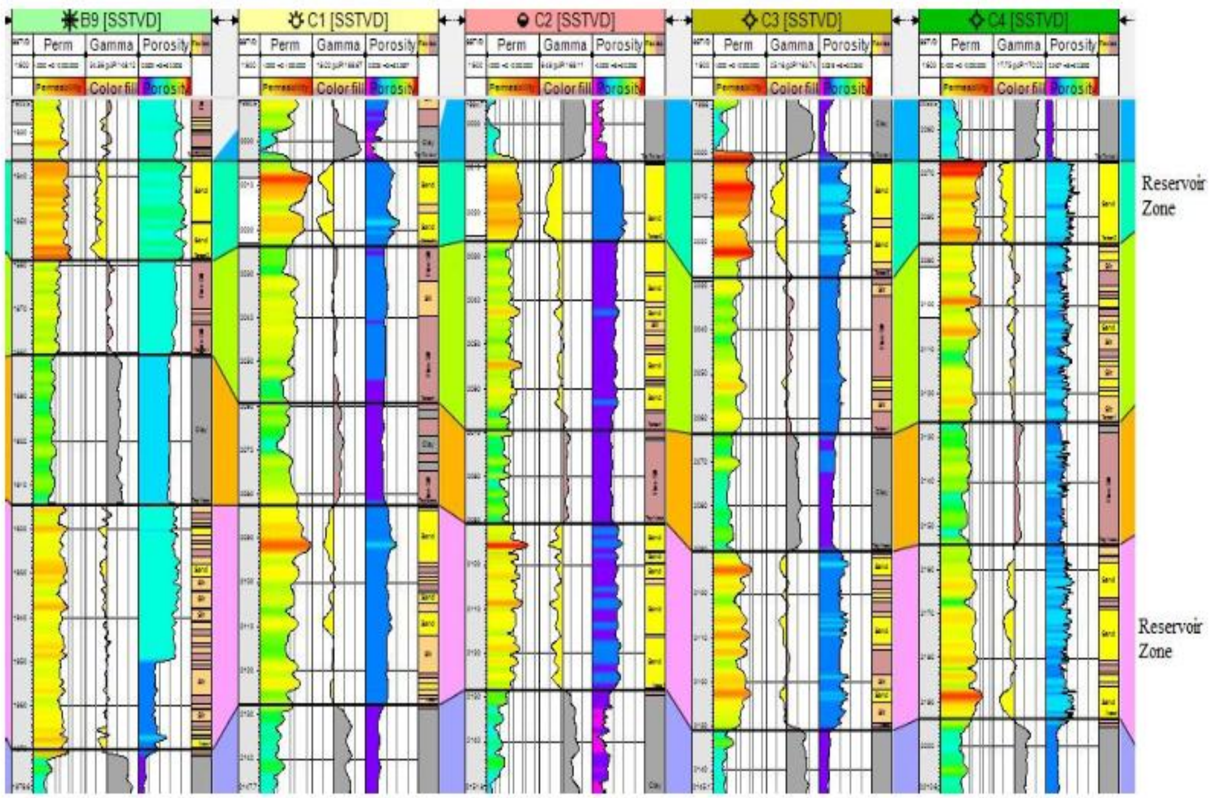

Figure 2: Well correlations of B9, C1, C2, C3, and C4 wells.

The well correlations illustrated in Fig. 2 are established through the determination of the lithofacies section, which is derived from the logs of gamma ray, porosity, and permeability logs. The heterogeneity of the subsurface enabled the identification and delineation of distinct zones of interest in each well. Figure 3 presents a model of 23 faults, delineated by varying colors, which indicate the depths of each fault in accordance with the accompanying legend.

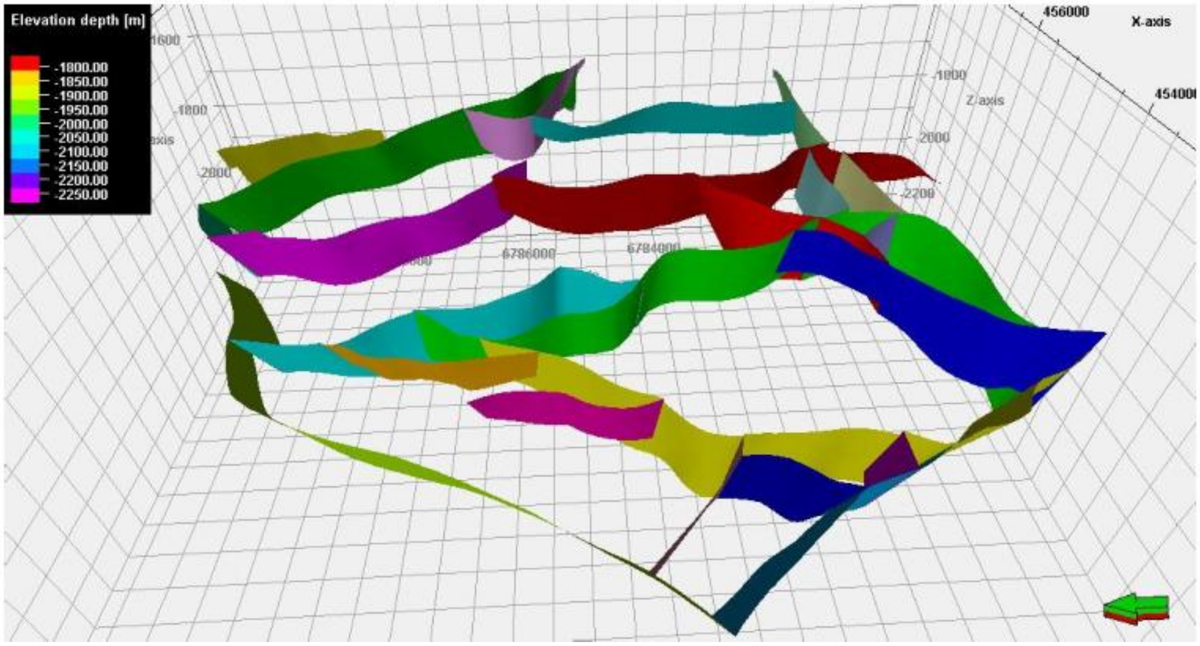

Figure 3: Model of 23 faults.

The fault model of Fig. 3 demonstrates the intricate structural complexity of the Brent reservoirs, including the Tarbert and Ness reservoirs. Such discontinuities may result in the subdivision of the tank into several blocks. The design of this model will contribute to the realization of the 3D grid. The pillar grid allows for the subdivision of the reservoir into small cells of coordinates dx and dy (100 * 100), to distribute the attribute (facies, porosity, permeability, net to gross, saturation) over the entire reservoir as shown in Fig. 4.

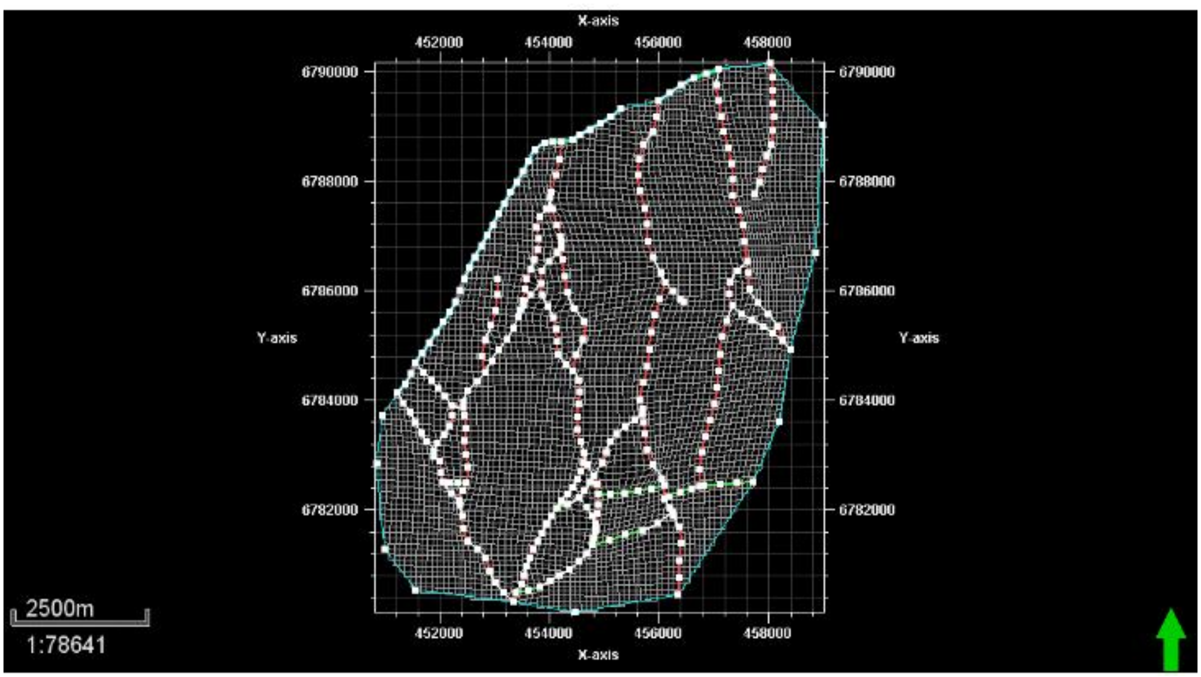

Figure 4: Pillar grid of the Gullfaks field reservoir.

The geometrical model of the Brent reservoir is depicted in Fig. 5.

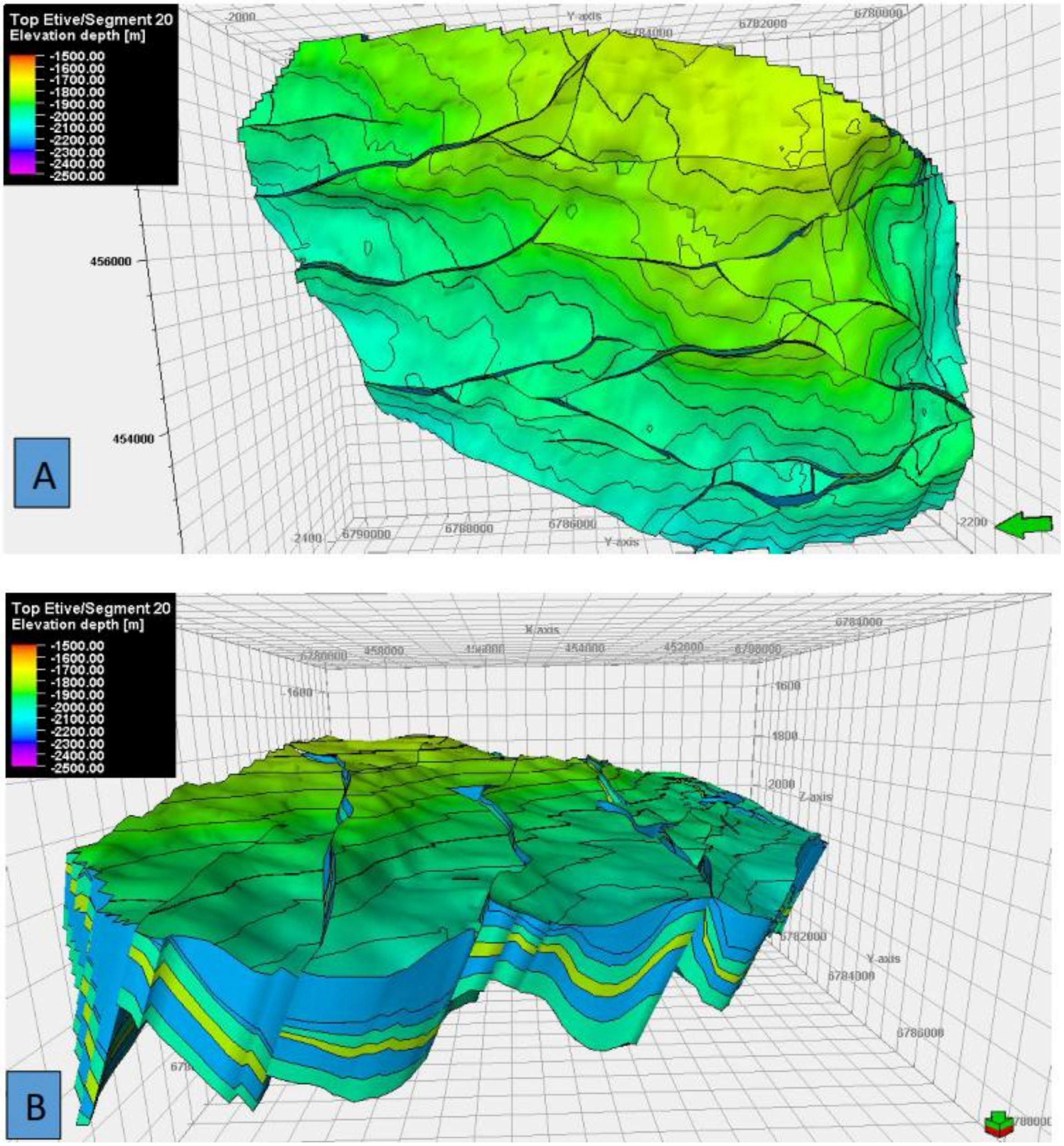

Figure 5: Geometrical model of Brent reservoir view from above (A) and from the north (B).

Figure 5 illustrates the various horizons and layers exhibiting discontinuities due to the fault model, as demonstrated by the models depicted in Figure 5. Subsequently, these horizons and layers are transformed from the time domain to depth using the velocity model derived from the data. Figure 6 illustrates the facies modeling of the Tarbet and Ness reservoirs.

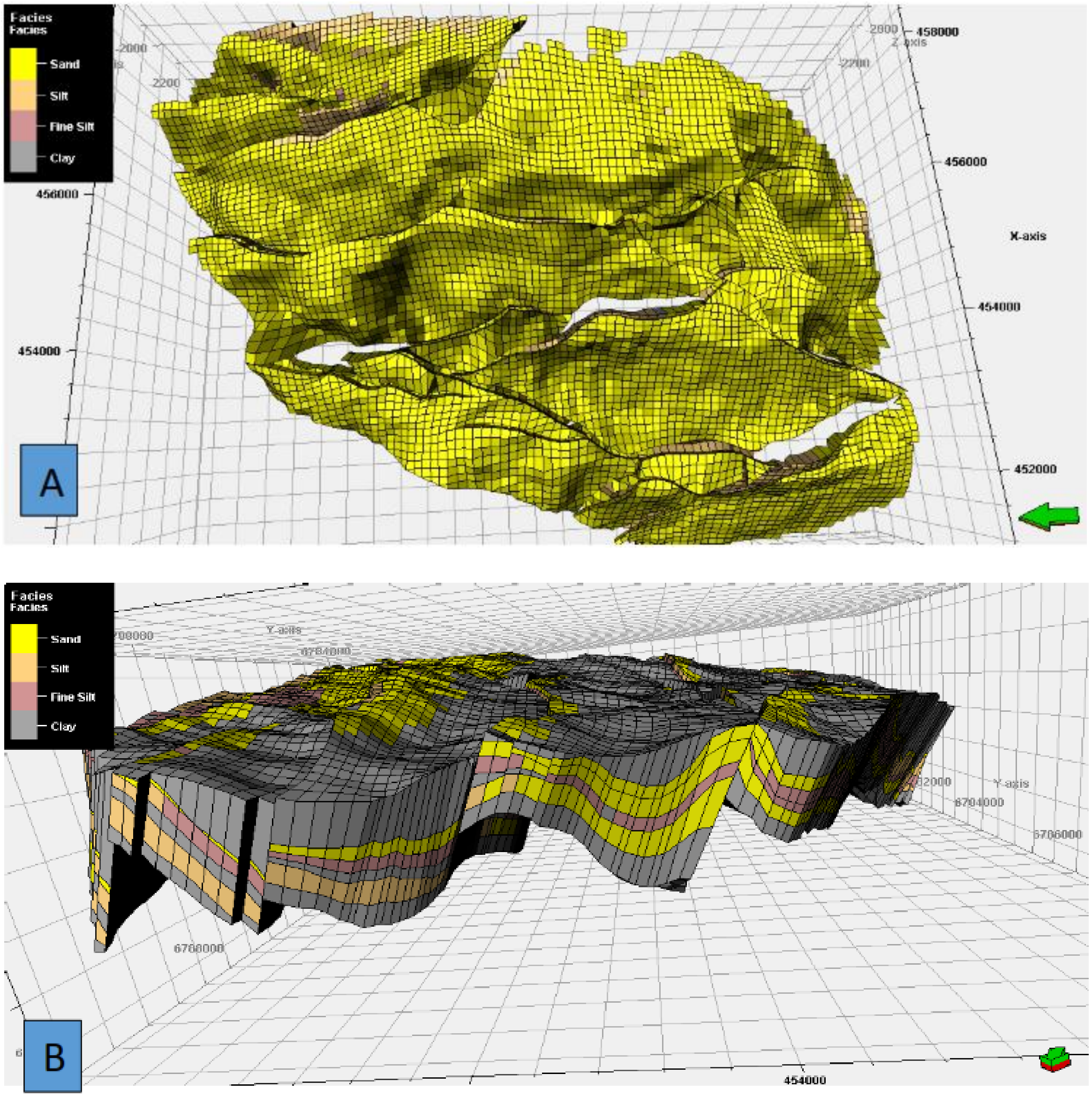

Figure 6: Brent facies model of Tarbet and Ness reservoirs, view from above (A) seen from the north (B).

Figure 6 shows the distribution of each facies (sand, silt, fine silt, clay) within each cell of the grid of our model. This is done to distinguish the clay zones (Cap) from the sandy zones (reservoirs). A summary of the distribution of facies per layer is provided in Table 1.

Table 1: Distribution of facies modeling and identification of cap and reservoir zones.

	Facies				
Zones	Sand (%)	Silt (%)	Fine Silt (%)	Clay (%)	Nature
Base Cretaceous-Top Tarbert	7.41	0	0	92.59	CAP
Top Tarbert-Tarbert3	92.42	7.58	0	0	RESERVOIR
Tarbert3-Tarbert2	15.18	46.91	37.91	0	CAP

Tarbert2-Tarbert1	0	0	71.71	28.29	CAP
Top Ness-Ness2	59.93	40.07	0	0	RESERVOIR
Ness2-Ness1	-	-	3.71	96.29	CAP

As illustrated in Table 1, the data clearly indicate that all the reservoir zones, as depicted in Fig. 6(A), are primarily composed of sand and silt (yellow color). In contrast, the cap zones, as depicted in Fig. 6(B), are predominantly made up of clay and fine silt (gray color). The yellow and gray colors represent, in alternation, the silt zones and the fine silt zones, which are the subject of a separate study. The cross-section of facies modelling is depicted in Fig. 7.

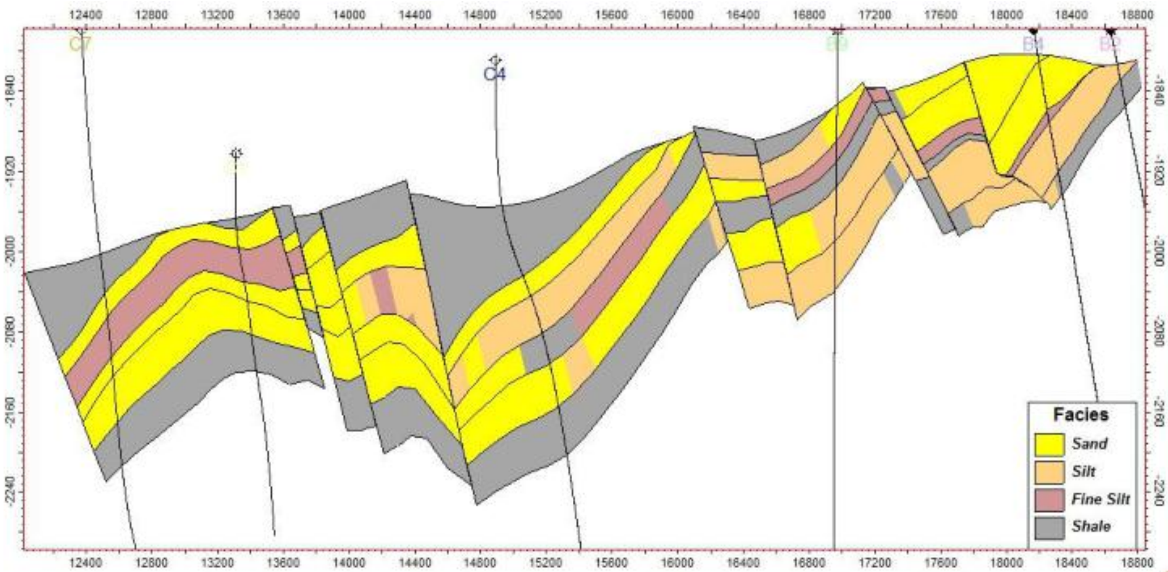

Figure 7: Cross-section of facies modelling.

The cross-section of facies modelling presented in Fig. 7 highlights a structural and stratigraphic correlation of the field from different facies. Nevertheless, concerning the Tarbert3-Tarbert2 zone, the majority of the material is composed of silt and fine silt, which is indicative of a cap zone. Once a grid has been constructed, it is essential to populate it with the requisite properties. In the model, each grid cell is assigned a single value for each property, including porosity, permeability, net to gross, and saturation. Figure 8 illustrates the distribution of porosity in the top Tarbert-Tarbert3 and top Ness-Ness2 reservoirs.

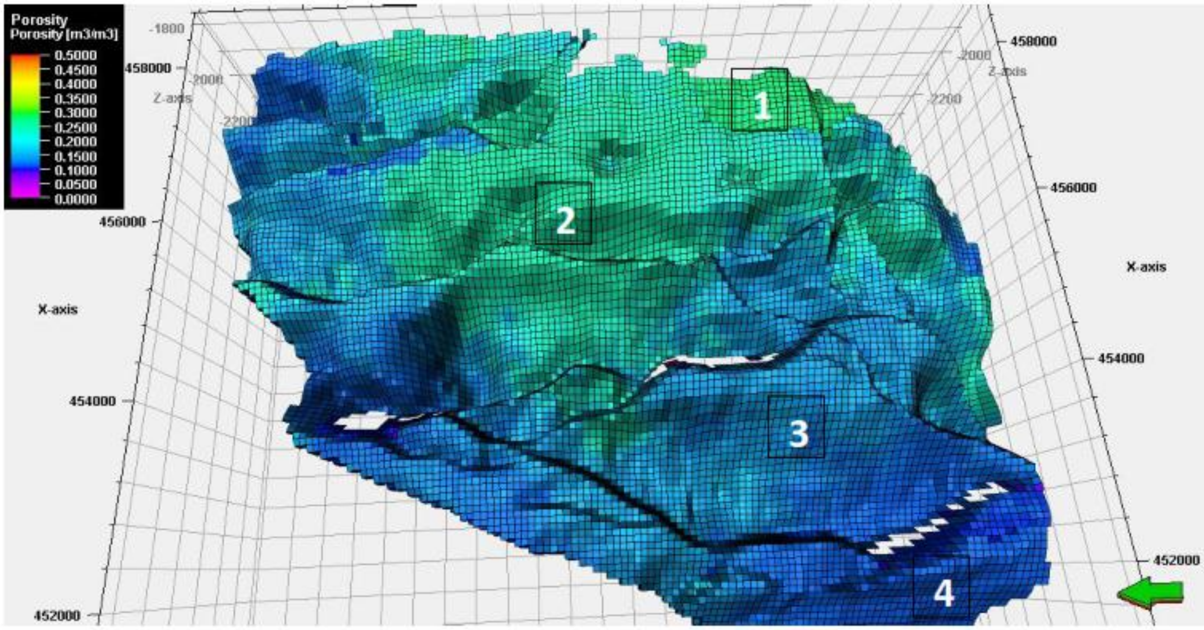

Figure 8: Model of distribution of porosity in the reservoirs.

Figure 8 illustrates that the porosity, expressed as a percentage, varies between zones in accordance with the degree of rock compaction. The zones corresponding to color "1" exhibit a porosity of 30%, those corresponding to color "2" display a porosity of 25%, those corresponding to color "3" demonstrate a porosity of 12%, and the zones corresponding to color "4" exhibit a porosity of 9%. The distribution of permeability in the Top Tarbert-Tarbert3 and Top Ness-Ness2 reservoirs is shown in Figure 9.

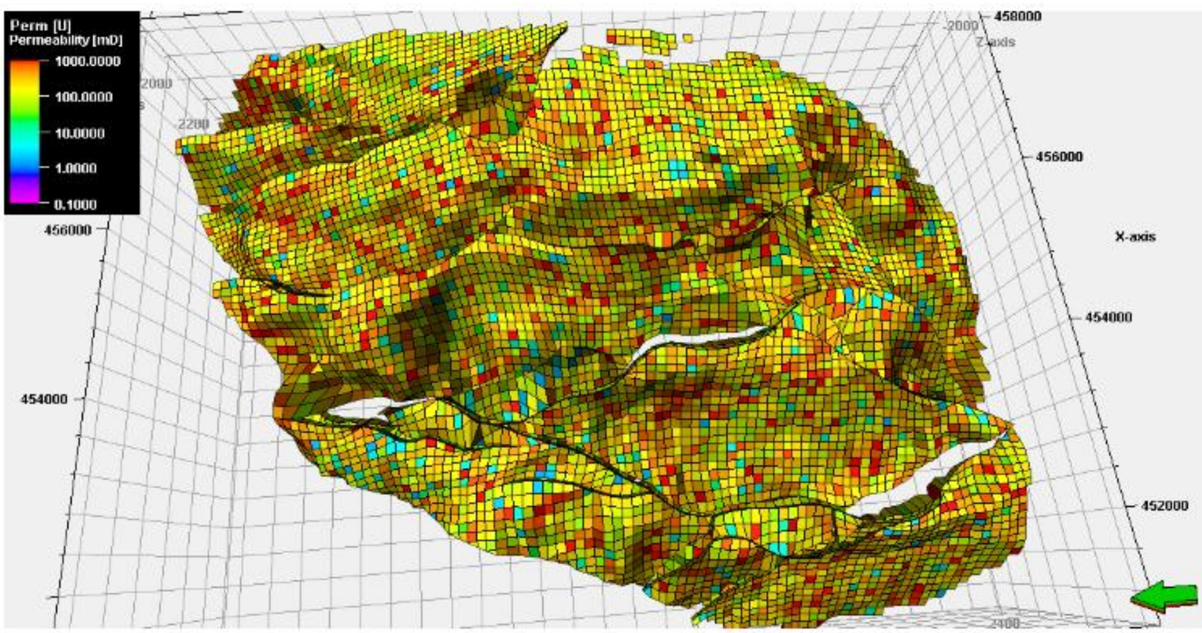

Figure 9: Model of distribution of permeability in the reservoirs.

As illustrated in Figure 9, the permeability exhibits a range of values, from 10 mD to 1000 mD, in accordance with the provided legend. In light of the reservoir's heterogeneous nature, it is crucial to acknowledge that the net-to-gross ratio is unique to each cell within the model grid, as shown in Figure 10.

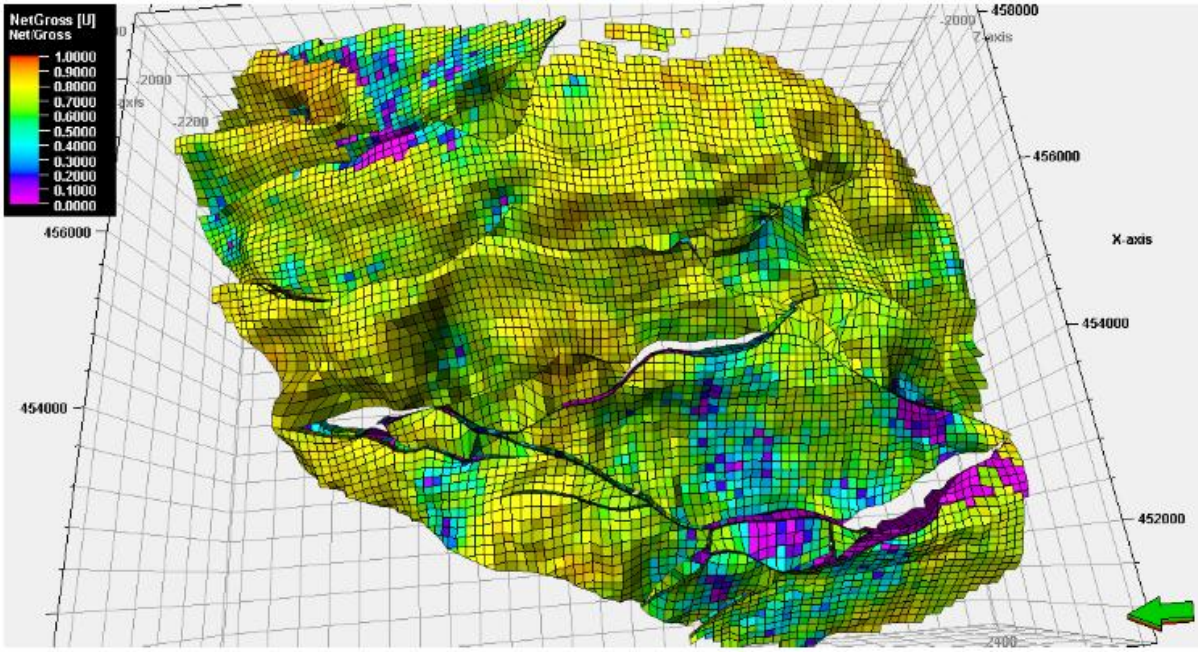

Figure 10: Model of the distribution of net to gross in the reservoirs.

In Figure 10, the specific values of all the cells in the grid are summed to produce a net-to-gross (NTG) model specific to the Tarbert and Ness reservoirs. A mixed fluid reservoir will stratify according to fluid density, with gas at the top, oil in the middle, and water as shown in Fig. **S1 in Supplementary Files.**

As illustrated in **Fig. S1**, the production of fluids frequently disrupts the fluid contacts within a reservoir. With regard to the Tarbert-Tarbert 3 and Top Ness-Ness 2 reservoirs of the Brent Group, it is crucial to acknowledge that the observed contacts are situated at different elevations, as shown in Fig. S2.

Figure S2 reveals that the gas-oil contact (GOC) is located at -1880 m and the oil-water contact is located at -2010 m. The results of the volume of initially hydrocarbons in place in the Tarbet and Ness reservoirs are presented in Table 2.

Table 2: Quantitative estimation of initially hydrocarbons in place.

	Quantitative Estimation	
UNITS	STOIIP	GIIP
m^3	73 000 000	5 841 000 000
L	73 000 000 000	5 841 000 000 000
bbls/cf	459119496.855	206 274 915 000

Following the design of the static 3D model, which has been subject to volume calculation constraints, it is essential to associate it with a dynamic model. This will facilitate the simulation of the reservoir and enable the prediction of the recovery rate following water injection.

Once the case simulation has been designed, integrating the petrophysical parameters of the reservoir and the history strategy, it is then executed and exported to the Eclipse simulator. This is where the simulation operation will take place. Once the simulation has concluded, the recovery factor for each fluid is calculated. Upon completion of the history strategy simulation, the recovery factor of the oil is determined to be 9.1%, while the recovery factor of the water is 13.5%. The recovery factor of the gas is approximately 11.5%. Figure S3 illustrates the initial fluid saturation in the reservoir in 1980 and the subsequent saturation after production in 2000.

Fig. S3(A) represents the reservoir in its initial conditions, specifically the pressure and contact of fluids, prior to the commencement of production in 1986. From the commencement of production in the reservoir in 1986 until 2000, there was no injection of water into the reservoir. This is illustrated in **Fig. S3 (B)**, which depicts the displacement of fluids from their initial contacts. The incorporation of water flooding prediction into the historical strategy within the simulation box has revealed the following: (1) The oil recovery factor is 28.8%, representing a 19.7% increase over the primary recovery of 9.1%. This improvement can be attributed to the implementation of water flooding, which enables the re-pressurization of the tank; and (2) the gas recovery factor is 36.1%, representing a 24.6% increase over the primary recovery of 11.5%. This exponential increase in gas and oil production, which is approximately double the primary production, demonstrates that water flooding can enhance production. This is why, in the saturation model of Fig. S4, there is an efficient flow of fluids in the reservoir compared to that of the primary recovery.

The impact of water injection into the reservoir is illustrated by the cumulative output of select wells, as depicted in **Fig. S5**.

Fig. S5 illustrates the production of oil (green curve), gas (red curve), and the combined production of water and BHP (blue and brown curves). The respective curves illustrate the production of water and the bottom hole pressure (BHP). It is noteworthy that in the year 2000, which marks the commencement of water injection, the curves representing gas and oil production exhibit a pronounced increase, indicative of an efficient and effective enhancement in oil production and production gas. The sharp decrease in the bottom hole pressure curve in 2000 can be explained by the fact that the injection of water into the tank increases the pressure in the tank and simultaneously causes the displacement of oil from the pores in the reservoir rock. The efficiency of this displacement is contingent upon the viscosity of the oil and the characteristics of the rock. Consequently, a reduction in pressure at the bottom of the well leads to an increase in production. This phenomenon occurs as a result of the movement of the fluid in question from an area of high pressure to one of low pressure.

Water flooding represents the most prevalent secondary recovery technique, whereby water is injected into the reservoir, displacing the oil to the production well. This process increases the reservoir energy of the system. The secondary recovery technique has been shown to possess a recovery factor of approximately 50% and above, as evidenced by the research conducted by Ahmed in 2006 [24]. The findings of company X indicate a substantial enhancement in hydrocarbon production through the implementation of water flooding, with the oil recovery factor rising from 9.1% to 25.01% (an increase of 15.91%), and the gas recovery factor increasing from 11.5% to 36.1% (an increase of 24.6%). These observations provide unequivocal evidence in support of the efficacy of hydrocarbon optimisation in comparison to conventional recovery methods, namely primary and tertiary recovery, which have recovery factors of approximately 30% and 12%, respectively, as stated by Ahmed in Ref [24].

5. Conclusions

This study was conducted in the upper Brent group, which encompasses the Tarbert and Ness reservoirs, the two principal reservoirs of the Brent field, where production commenced in 1986. The history of production indicates a decline in output between 1996 and 2000, which can be attributed to a pressure drop within the reservoir. This resulted in a recovery factor of 9.1% for oil and 11.5% for gas. To address this issue, a number of potential solutions exist.

However, for the purposes of this paper, water flooding was employed as a means of re-pressurizing the reservoir. The objective was to demonstrate the impact of water flooding on production. The implementation of this technique was made possible by data from a number of sources, including wells, surfaces, faults, isochores, velocity, and production, all of which were provided by company X. The data enabled the reservoir to be modelled in order to estimate the quantity of hydrocarbons in place through the use of the Petrel software.

Subsequently, the creation of a dynamic model was made possible through the simulation of approximately twenty years (2000-2020) using the Eclipse software, which integrated the parameters of water injection into the reservoir. The results of the simulation demonstrated a tangible increase in hydrocarbon production through the injection of water into the reservoir, with the oil recovery factor rising from 9.1% to 25.01% (an increase of 15.91%), and the gas recovery factor increasing from 11.5% to 36.1% (an increase of 24.6%).

Further improvements to this paper could be made by conducting additional research in other wells within specific blocks of the reservoir, taking into account the presence of water-proof faults that subdivide it.

Abbreviations

Bottom Hole Pressure	(BHP)
Enhancement of Oil Recovery	(EOR)
Gas-Oil Contact	(GOC)
Limited	(LTD)
Net-to-Gross	(NTG)

Conflict of Interest: The authors declare that they have no conflict of interest.

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