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Implementation of chemical injection with WJSTP in the Gullfaks field attributed to reservoir permeability

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Abstract

The Gullfaks field is a complex field and it's divided into several formations, which have reservoirs in several stratigraphic layers and fragments of numerous faults. With current technological advancement techniques used in the Gullfaks field, the WJSTP is one of the solution-testing platforms that focuses on treating produced water for re-injection back into the reservoir to increase oil production. The implementation of chemical injection with WJSTP in the Gullfaks field, attributed to reservoir permeability to increase oil production, is the aim of this paper. To attest to the set aimed, a three-dimensional static model of the reservoir is constructed using data provided by NGB Geosciences Consulting LTD. With credit to the Petrel software simulation tool, an in-place volume estimate of 2,748,727,672.95 Bbls of oil and 970,264,150,943.39 SCF of gas was reviewed. Subsequently, a dynamic model is constructed on the foundation of the static model and the specified water injection parameters, and simulated with the use of the Eclipse software. The reduction in permeability of the reservoir's high-permeability zones through chemical injection of WJSTP resulted in 70% oil recovery, representing a 44.99% increase, and 74% gas recovery, representing a 37.9% increase. The sensitivity analysis conducted on oil price, oil production, and investment demonstrates that the viability of the project is highly contingent on the oil price. The findings of this study indicate that chemical injection of WJSTP represents a technically feasible and economically profitable method of enhancing oil production in the Gullfaks field.

Keywords: Gullfaks field; static and dynamic model; permeability; WJSTP; Petrel; Eclipse; profitability.

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1- Introduction

The Gullfaks field, discovered in 1978, represents a substantial Norwegian field situated within the Tampen region of the northern North Sea. It can be found within Norwegian license PL 050 in block 34/10 at 61°N and 2°E, within the Norwegian sector of the North Sea [1-3]. The field contains oil, gas, and condensate (light oil) and several surrounding satellite fields [4-6]. The main field contains 78% of the total oil-in-place volumes and 88% of the recoverable reserves [7-10]. The structure of this deposit, which has reservoirs in several stratigraphic layers, is complex and fragmented by numerous faults [10-12]. The field commenced production on December 22, 1986, reaching a peak output of 180,000 barrels per day in 2001. This field is situated in Lower and Middle Jurassic sandstones at a depth of 1,800 to 4,000 meters below sea level [13-15]. The field is structurally complex and can be divided into several formations. The upper Brent sequence contains approximately 80% of the reserves, with the deeper Cook and Statfjord formations contributing the remainder. Consequently, this study focuses on the Brent group, which consists of several reservoirs, the main ones being Tarbert and Ness. These reservoirs are primarily composed of sand and silt, and are characterized by the presence of significant quantities of hydrocarbons [16-18]. As the Gullfaks field has matured, production has exhibited a gradual decline due to a reduction in reservoir pressure. In response to this challenge, numerous enhanced oil recovery (EOR) techniques have been assessed for their potential to enhance ultimate oil recovery [19-21]. EOR entails the deployment of a range of techniques to augment the quantity of crude oil that can be extracted from an oil reservoir [22, 23]. EOR techniques have the potential to extract 30% to 60% or more of the oil originally present in the reservoir, whereas this ratio reaches 20% to 40% when solely relying on primary and secondary recovery techniques [24, 25]. In a recent study, the authors of [19] conducted a brief evaluation of water alternating gas

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injection in lower Brent injectors at the Gullfaks field, with a joint estimated increase in oil recovery of 0.7 mill Sm^3. In addition, the authors of [21] provide a comprehensive summary of five EOR technologies that were initiated in the North Sea between 1975 and the beginning of 2005. These EOR technologies include: Hydrocarbon miscible gas injection, water-alternating-gas injection [26], simultaneous water-and-gas injection [27, 28], foam-assisted water-alternating-gas injection, and microbial EOR.

The chemical injection of WJSTP usually results in the formation of micro-particles when it contacts with divalent cations present in the formation or injection water. The cations will adhere to the reservoir rock over time, forming a rigid layer of biogel. This layer should, in effect, reduce the permeability of the zone in question [29]. The objective of this paper is to ascertain whether the chemical injection EOR method, based on WJSTP, can extract the maximum amount of hydrocarbons from the Gullfaks field. The implementation of the EOR method based on the chemical injection of WJSTP using data provided by NGB Geosciences Consulting LTD enables the creation of a three-dimensional static model of the reservoir, which facilitates the quantitative estimation of the hydrocarbons in place with the Petrel software. To achieve this, the reservoir will first be characterised, after which the hydrocarbons will be quantified and the chemical injection of WJSTP into the reservoir will be simulated to ascertain its effect on production. The remaining part of the manuscript is organized as follows: Section 2 presents the data, methods, and results. And the conclusion in Section 3.

2- Materials, methods, and results

The data provided by NGB Geosciences Consulting LTD is limited to two different datasets: 3D seismic cube with a static model of the Upper Brent Group and a dynamic model including Seismic data, horizon interpretation, faults, the 14 drilled wells (A10, A15, A16, B2, B4, B8, B9, C1, C2, C3, C4, C5, C6 and C7 with their wellheads), isochores (divided into two main groups: Tarbert divided into Tarbert 1, Tarbert 2 and Tarbert 3 and Ness divided into Ness 1 and Ness 2) and the velocity model.

2.1. Estimating hydrocarbons through reservoir modeling

Hydrocarbon estimation is conducted through reservoir modeling, utilizing data from the Gullfaks field with Petrel software. EOR will be implemented through depth profile reduction and Eclipse flood prediction, enabling a production simulation. The correlation of wells in the Gullfaks reservoir is illustrated in Fig. 1.

The correlation of the wells is part of the larger correlation encompassing all 14 wells, including both the 07 producers and the 07 injectors, as illustrated in Fig. 1. The correlation made in the Gullfaks field underscores the significance and progressive evolution of erosion, which is a consequence of the structural uplift observed in the same direction. Fig. 2 depicts a model of 23 faults, represented by different colors, indicating the depth of each fault in accordance with the accompanying legend.

Fig. 2 illustrates the utilization of fault modeling within the 3D geological model, which serves as the fundamental basis for the generation of grids or meshes. The outcome of this process is referred to as "fault sticks. Fig. 3 depicts the integration of all fault models within the skeletal pillar grid.

Fig. 3 depicts the construction of a grid of layers, which will form the skeleton of the model and likely contain all the reservoir levels of the Gullfacks field. This grid is based on the fault plane. Fig. 4 illustrates the various horizons and layers, demonstrating the impact of the fault model on the formation of discontinuities.

Based on the results of the well and seismic interpretation, four horizons were created in accordance with the correct stratigraphic sequence, as illustrated in Fig. 4. The well vertices were employed to define the horizon vertices, with the horizon surfaces serving as inputs. A domain conversion of the 3D grid and fault model was conducted using a velocity model to bridge the gap between time and depth. This was achieved by utilizing the seismic datum to create a time-independent representation of the subsurface. The conceptual geological model illustrated in Fig. 5 demonstrates the realistic distribution of each facies: sand, silt, fine silt, and clay.

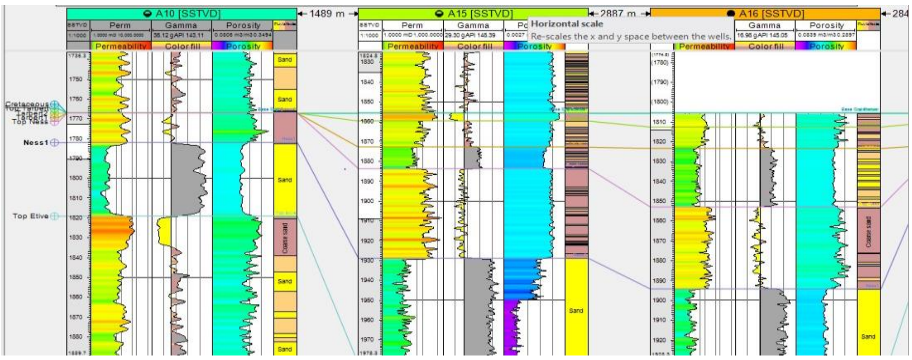

Fig. 1. Correlation of Gullfaks reservoir wells

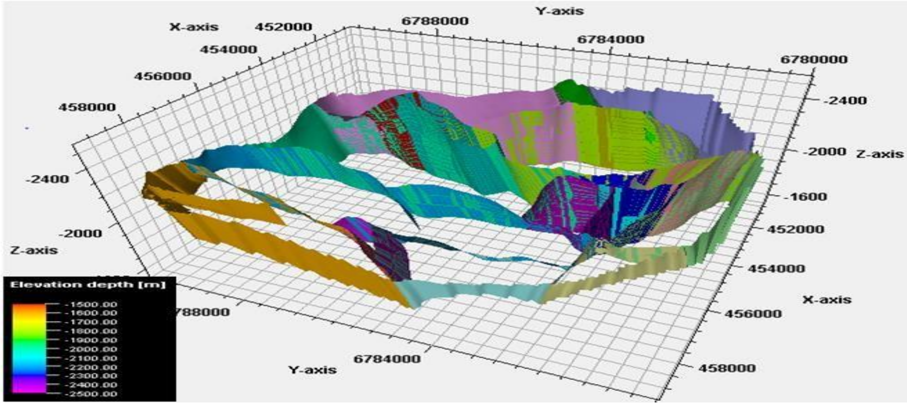

Fig. 2. Modeling reservoir faults in the Gullfaks field

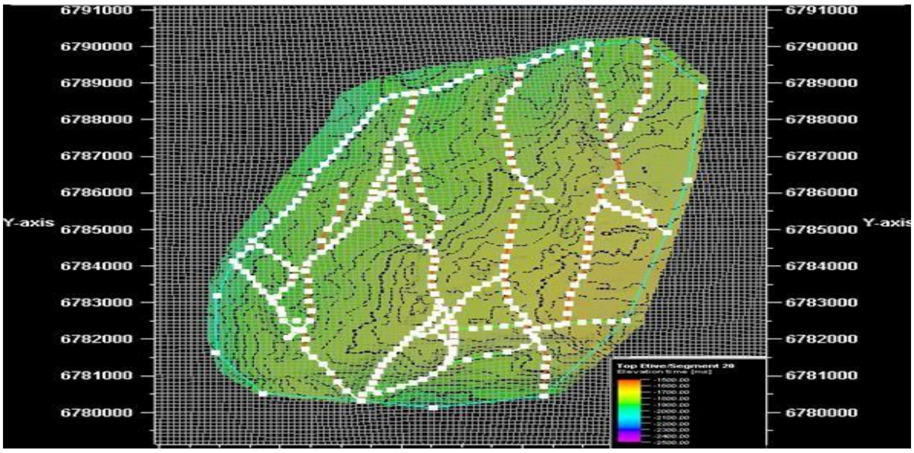

Fig. 3. Pillar gridding of the Gullfacks field reservoir

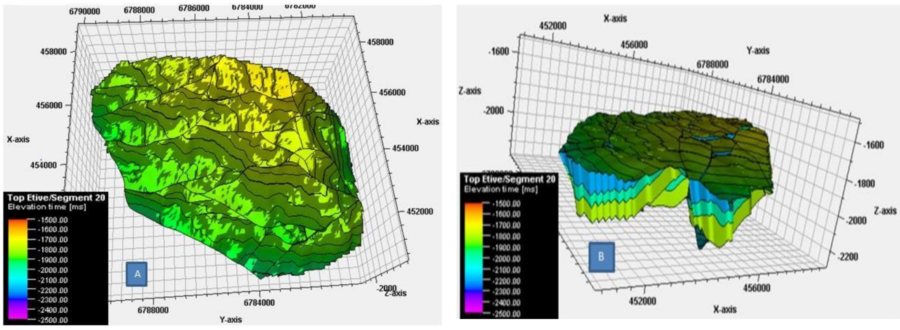

Fig. 4. Geometric model of Brent seen from above (A) and from the north (B)

Fig. 6 illustrates the synchronic and geometric configuration of facies, as well as their interrelationship. The geographical pattern is contingent upon the facies variability within the reservoir, exhibiting a multidimensional flow pattern as illustrated in Fig. 5 A. The model depicted in Fig. 5 B exemplifies the favorable lateral continuity of the Tarbert zone and the moderate connectivity of the sand channels within the Ness zone. Additionally, it accurately identifies clay barriers within the reservoir zones. Table 1 delineates the facies distribution and the delineation of CAP and reservoir zones.

Fig. 6 shows a structural and stratigraphic correlation of the Gullfaks field based on different facies.

As illustrated in Fig. 6, areas predominantly composed of sand and silt (as indicated by the low yellow coloration) are identified as reservoir zones. Areas predominantly composed of diurnal and fine silts (gray) are designated as cap zones, while yellow and brown represent alternating silty and fine silty zones. The Tarbert 3-Tarbert 2 zone is characterised by the dominance of silts and fine silts, which are situated in close proximity to a cap zone. The final porosity model is obtained by combining the models of the six layers. The porosity values typically span a range of 30% to 9%, as depicted in Fig. 7.

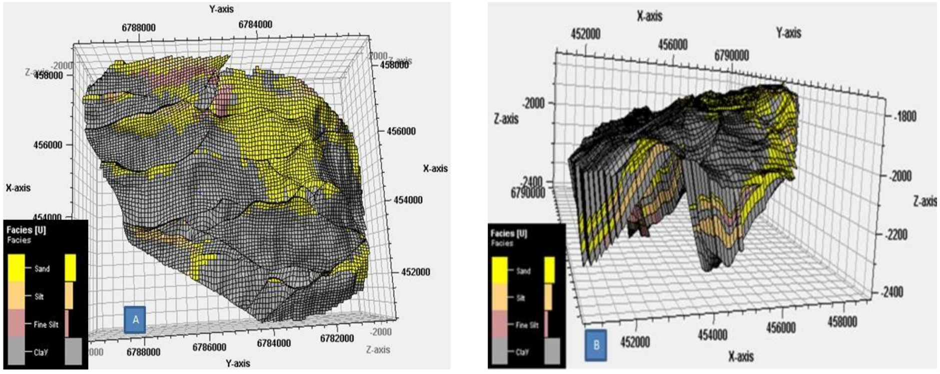

Fig. 5. Brent facies model of the Gullfaks field reservoir seen from above (A) seen from the north (B)

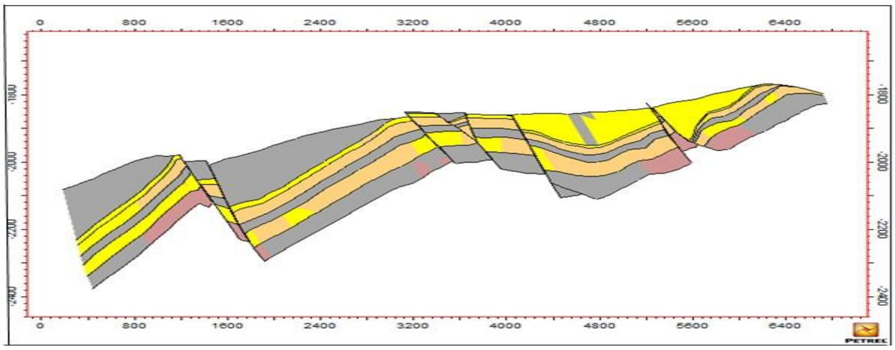

Fig. 6. Structural correlation of the facies model

Table 1. Facies distribution 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

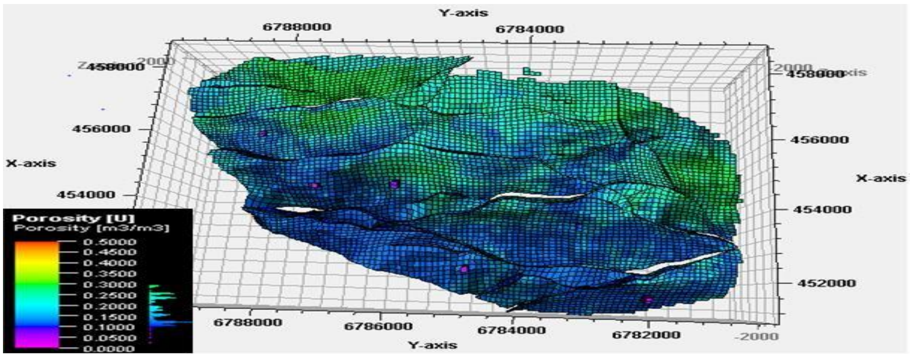

Fig. 7. Gullfaks reservoir porosity distribution model

The distribution of permeability appears to be more complex than that of porosity, due to the high degree of variability observed between 10 and 1000 mD, as illustrated in Fig. 8.

Fig. 8 depicts the fraction of the reservoir volume occupied by hydrocarbon-bearing rocks, which is a global attribute. Consequently, no replica of this attribute can be found on the reservoir. Fig. 9 illustrates a Petrel estimate that sums all the grid cells of the Tarbert and Ness reservoirs.

In a hydrocarbon reservoir, the oil is located in the middle of the gas upstream and the water downstream, as shown in Fig. 10.

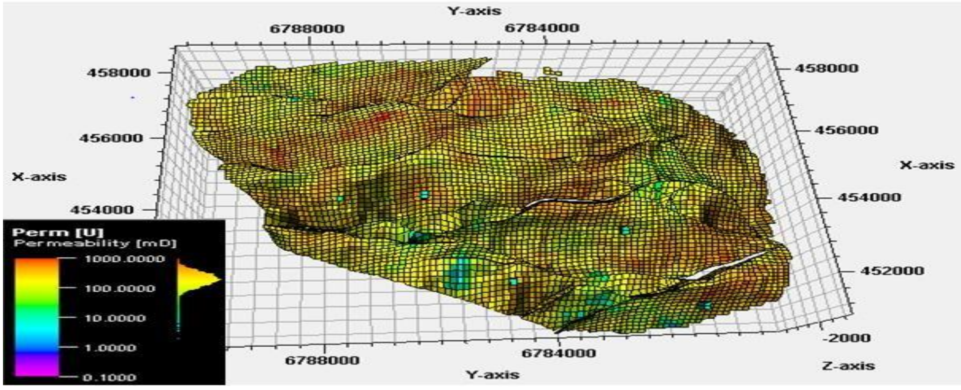

Fig. 8. Gullfaks reservoir permeability distribution model

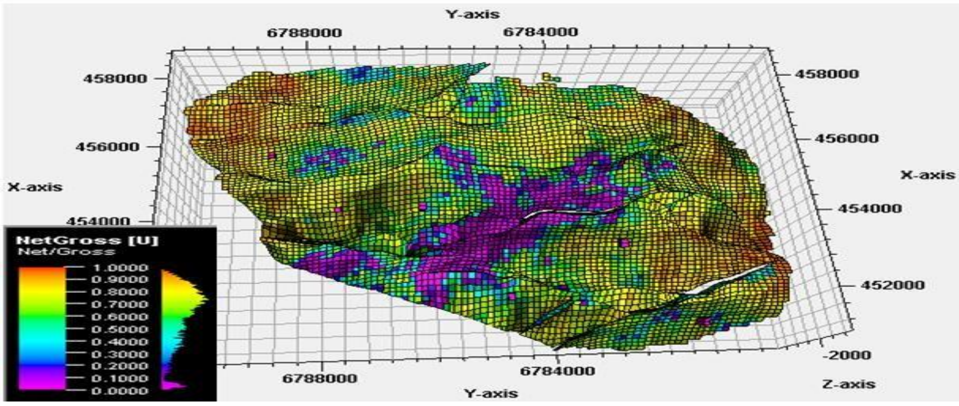

Fig. 9. NetGross distribution model of the Gullfaks reservoir

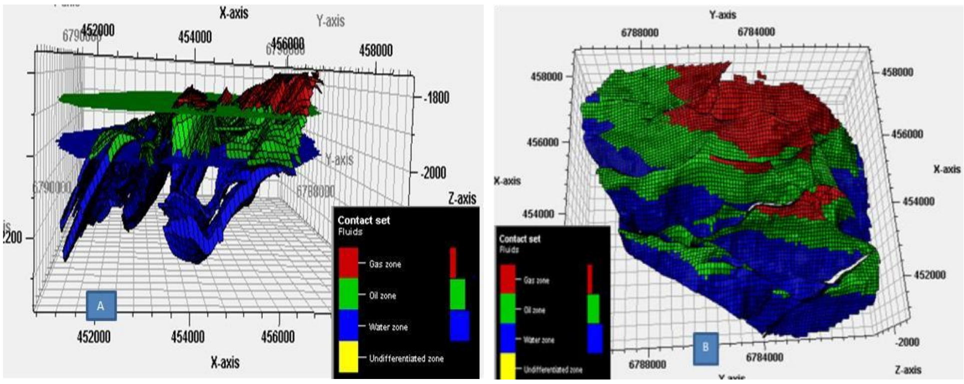

Fig. 10. Property of contacts with contact set seen from the south (A) and without contact set seen from above (B)

Fluid contacts are very often disturbed by their production, as shown in Fig. 10. For the Tarbert-Tarbert-3 and Top Ness-Ness-2 reservoirs of the Brent group, the gas-oil contact is located at -1880 m and the oil-water contact at -2010 m. It is worth noting that the observed contacts are located at the various peaks, as shown in Fig. 11.

The 3D dynamic model is developed with the objective of simulating productive behavior. In order to optimize reservoir characterization, changes in reservoir saturation are estimated, and the net-to-gross ratio of each compartment is calculated. In the area of the Gullfaks reservoir model, calculations are conducted using Petrel software, which integrates the hydrocarbons in place in the Tarbert3 and Ness2 reservoirs. The results of these calculations are presented in two ways: First, as a total stock of oil from the reservoir initially in place; second, as a total sum of gases initially in place obtained by the total sum of oils contained in the two reservoirs. These results are illustrated in Table 2.

The quantitative estimate of hydrocarbons in place is presented in Table 3.

The classification results are integrated with reservoir structural data for reservoir volume analysis. The results of this analysis are presented in Fig. 12.

Fig. 12 illustrates the extent to which the fluid distribution figures in the classification align with the tank structure. Furthermore, the reservoir volume up to the oil-water contact or at the base of the reservoir is also calculated. Fig. 13 demonstrates the implementation of a simple completion configuration for the B2, B8, and A10 wells.

Fig. 13 is divided into hydrocarbon production and water injection zones. The initial model of fluid saturation in 1980 and after production in 2000 are shown in Fig. 14.

The initial fluid saturation model, depicted in Fig. 14 A, illustrates the reservoir under its initial conditions (pressure and fluid contact) during production in 1980. The reservoir saturation model for the Gullfaks field without water injection is presented in Fig. 14 B for the production interval between 1986 and 2000. The initial fluid saturation model, subsequent to production in 2000, is illustrated in Fig. 14 B.

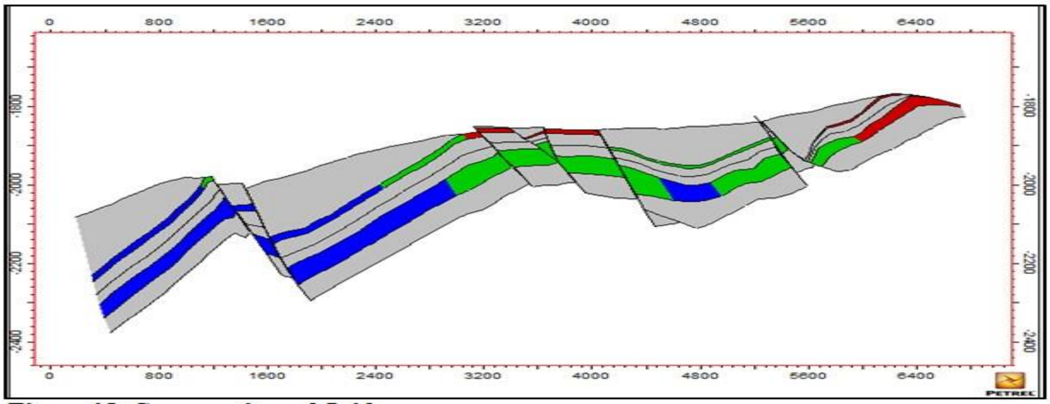

Fig. 11. Cross-section of fluid contact section

Table 2. Quantitative estimation of the hydrocarbon reserves in each zone

Case	Bulk volume [10^6 m^3]	Net volume [10^6 m^3]	STOIIP [10^6 m^3]	GIIP [10^6m^3]
case	1078	755	437	154 272
Zones	-	-	-	-
Base Createaceous-Top Tarbert	0	0	0	0
Tarbert-3	363	254	140	62 108
Tarbert-2	0	0	0	0
Tarbert-1	0	0	0	0
Ness-2	715	501	297	92 164
Ness-1	0	0	0	0

Table 3. Quantitative estimation of hydrocarbons in place

	Estimation quantitative	
UNITS	**STOIIP**	**GIIP**
m^3	437 000 000	154 272 000 000
L	437 000 000 000	154 272 000 000 000
Bbls/Scf	2 748 727 672.95	970 264 150 943.39

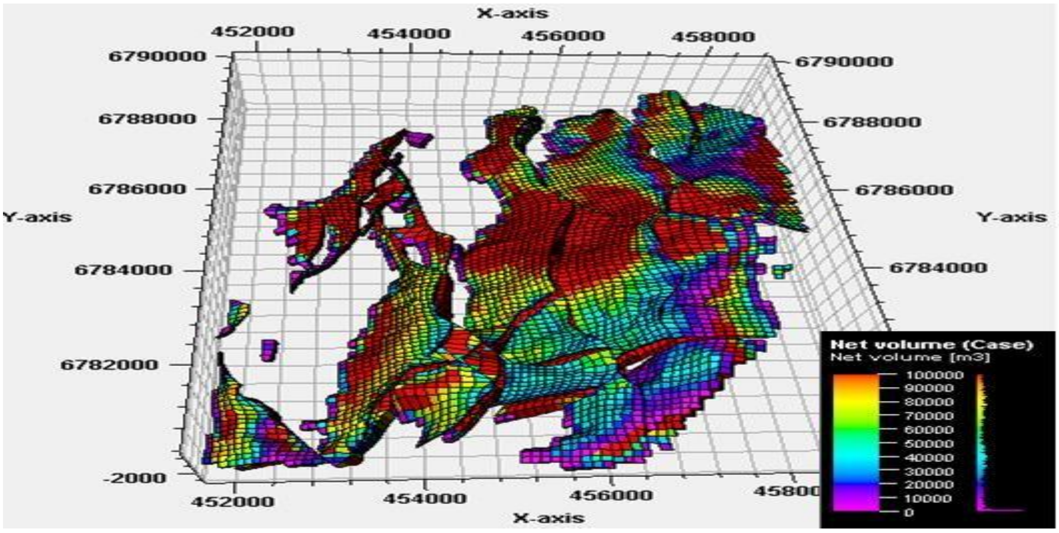

Fig. 12. Gullfaks field net reservoir volume

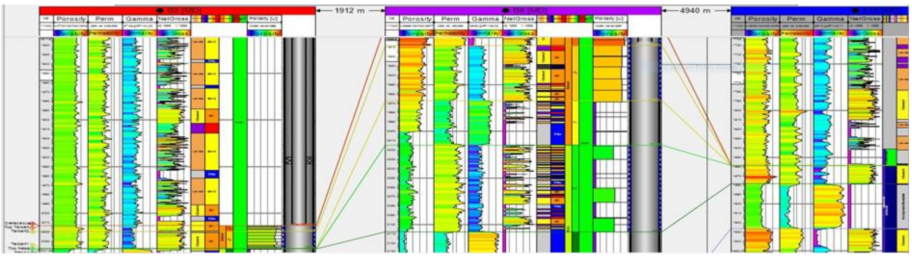

Fig. 13. Completion of wells B2, B8, and A10

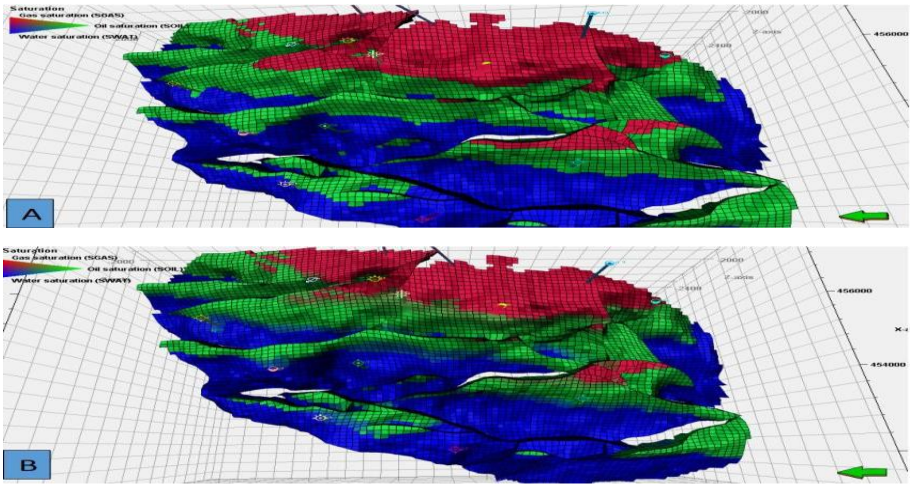

Fig. 14. Initial fluid saturation model in 1980 (A) and after production in 2000 (B)

2.2. Results obtained after chemical injection of WJSTP

WJSTP is introduced into the water injection well via injection with water. Its function is to coat the rock grain, thereby reducing permeability. The water injection path of the basic model is analyzed, as it is necessary to know the zone where the permeability modifier will be applied. A tracer is applied to the water injection path of the base case model to observe the water path. The fluid saturation models from 2011, before the use of WJSTP, to 2011, after the use of WJSTP, and to 2025, after the use of WJSTP are shown in Fig. 15.

The colors red, green, and blue are used to represent the three main types of resources: gas, oil, and water, respectively. The remaining oil is located in low-permeability zones, and its extraction was not feasible due to the low reservoir pressure, as illustrated in Fig. 15 A. The fluid saturation pattern in 2011 subsequent to the implementation of the WJSTP is illustrated in Fig. 15 B. The Abio-gel is now adhered to the tank walls, resulting in a considerable quantity of oil dispersed within the water, as illustrated in Fig. 15 C.

The application of WJSTP as a permeability modifier should result in a reduction in permeability within the high-permeability zone. Consequently, the injected water may result in a sweeping effect through the low-permeability zone. Upon running the updated model with the new permeability in Eclipse, the impact of the permeability modifier was validated by opening the GRID result in Floviz, as illustrated in Fig. 16.

As depicted in Fig. 16, the reduction in water cut-off is evident immediately following the chemical injection of WJSTP. The most substantial reduction in water cut occurs during the initial six-month period. Subsequently, the reduction in water cut-off levels off and begins to increase once more. It remains at a consistent level of approximately 2.8% below the base case for the 250 mg/L scenario and approximately 3.5% below the base case for the 150 mg/L scenario. The analysis of the results for varying tracer concentrations indicates that the optimal scenario is 80-60% reduction in permeability with a tracer concentration of 150%. A reduction in permeability of 40-20% in both 150 and 250 tracer concentrations has no discernible impact on total production. Fig. 17 illustrates the oil production rate in the field and the water cut for the 80-60% permeability reduction case (best case).

Fig. 17 illustrates the chemical injection of WJSTP in June 2012, indicated by the red line. Subsequent to the chemical injection in June 2012, a pronounced decline in the water cut and an augmentation in the oil production rate were observed. This evidence demonstrates the efficacy of the measure, indicating that the objective of reducing water cut and oil production, previously established, has been attained. Following the completion of simulations for a variety of scenarios involving permeability reduction, as well as plug size and placement, the total increase in recovery factor relative to total base case production was calculated and identified as the primary indicator of production performance. This is due to the project's objective of enhancing segment oil recovery. It can be observed that a reduction in permeability from 80% to 60%, coupled with the lowest permeability threshold, results in a notable increase in the recovery factor for the H1 segment of the Gullfaks field, exceeding 2%.

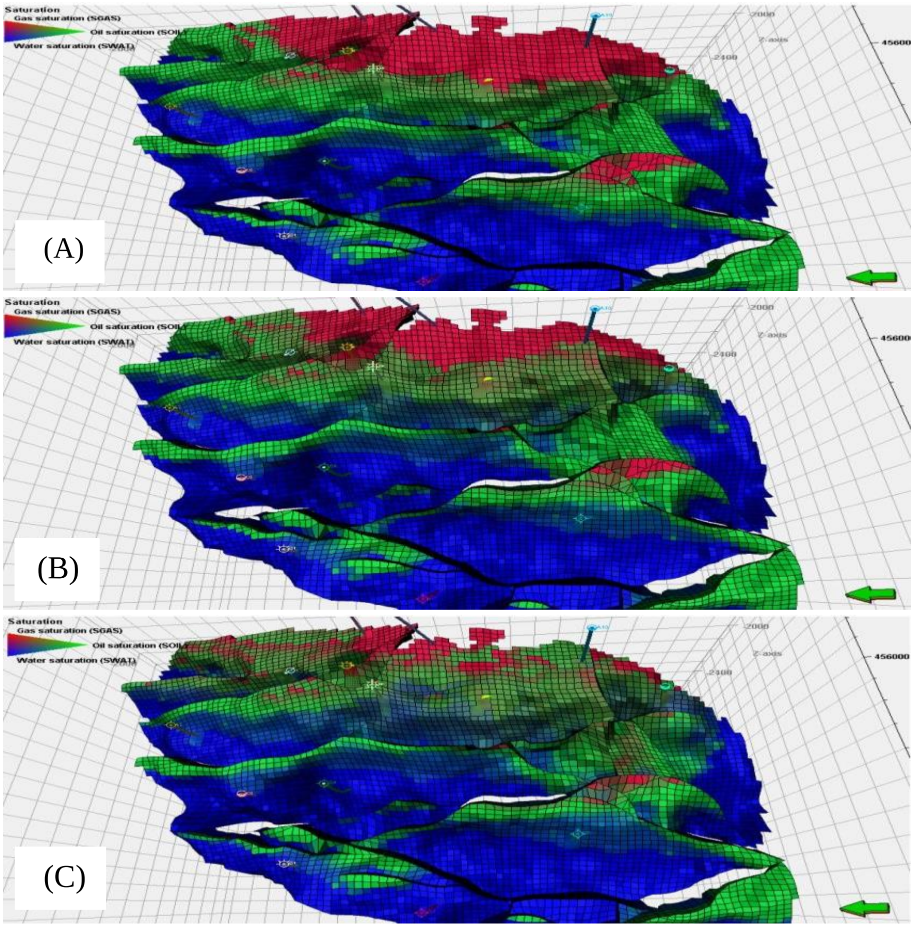

Fig. 15. Fluid saturation models in 2011 before WJSTP (A), in 2011 after WJSTP (B), and in 2025 after WJSTP (C)

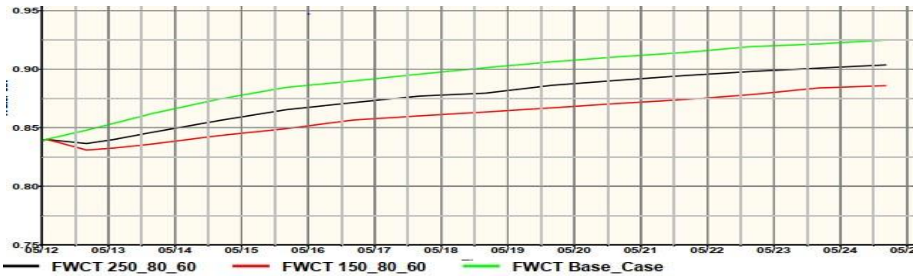

Fig. 16. A reduction in water content was achieved by reducing permeability from 80% to 60%. This was accomplished through the use of tracer concentrations of 150 mg/L and 250 mg/L, in comparison to the base case from 2012 to 2025

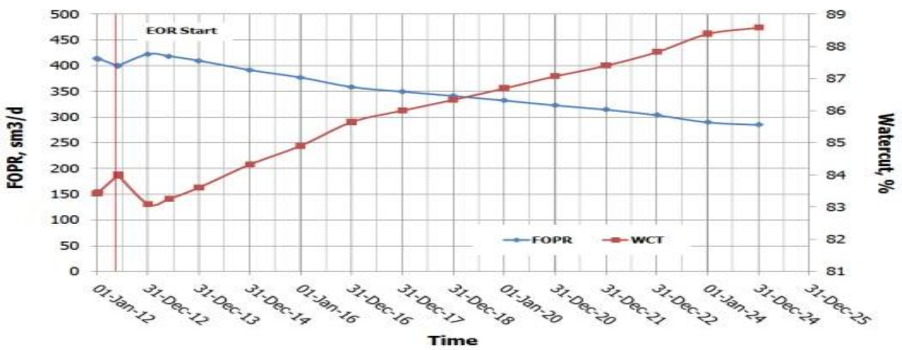

Fig. 17. Oil production rate and water cut of the field with a concentration of 150 and a reduction in permeability from 80 to 60% as a function of time

2.3. Project profitability and sensitivity analysis

In order to ascertain the viability of the three selected cases, it is necessary to calculate the net present value (NPV) of each case, as illustrated in Table 4.

Table 4. NPV of selected cases

Number of cases	NPV from 2025 (MUSD)
Basic case	357.148
Case 16-P90	355.377
Case 16-P50	3523.8
Case 12-P10	387.618

First, the net present value (NPV) of the base case and the three other cases selected without any sensitivity analysis, that is, without any change in oil price, oil production, or investment, was calculated. The oil price was set at \$100/bbl, with oil production dependent on each of the cases. Furthermore, investment was set at 7.7×10^6 USD. The investment price is a function of the injected WJSTP price of 2.2 $\times10^6$ USD and the WJSTP operating costs of 5.5 $\times10^6$ USD. This is the sole expense to be considered in this study, as the costs associated with drilling a well for gel injection should not be included, given that the well has already been constructed and the gel is injected with water into the water injection well. It should be noted that this expense should not be included in the base case analysis, as no WJSTP is injected. Subsequently, the cash flow must be calculated, defined as the difference between the sum of revenues and the sum of expenses. This net cash flow is discounted using a discount rate of 8%. Two tracer concentrations are employed: 250 mg/l and 150 mg/l, as illustrated in Table 5.

Table 5. Increased recovery factor for different cases of reduced permeability and CAP size

Concentration, mg/l	Permeability reduction, %	RF increase
	40-20	< 0.5
150	60-40	1 %
	70-50	1,25 %
	80-60	2 %
	40-20	< 0,5
250	60-40	< 0,5
	70-50	1.1 %
	80-60	1.4 %

At each tracer concentration, the observed permeability reductions are classified into four distinct cases, as delineated in Table 5. These cases encompass reductions ranging from 80-60% to 40-20%. For the purposes of establishing a baseline, the following assumptions have been made regarding the cost of oil, the cost of abio-freezing and the cost of chemical injection of WJSTP into the reservoir: oil is assumed to cost USD 100/barrel; abio-freezing costs are assumed to be USD 2,235,385.62; and chemical injection costs are assumed to be USD 5,588,464.06. It is assumed that the oil price will remain constant throughout the duration of the project, excluding the effects of inflation. Fig. 18 illustrates the incremental NPV of alternative measures in comparison to the original case, which represents the baseline scenario without chemical injection of WJSTP.

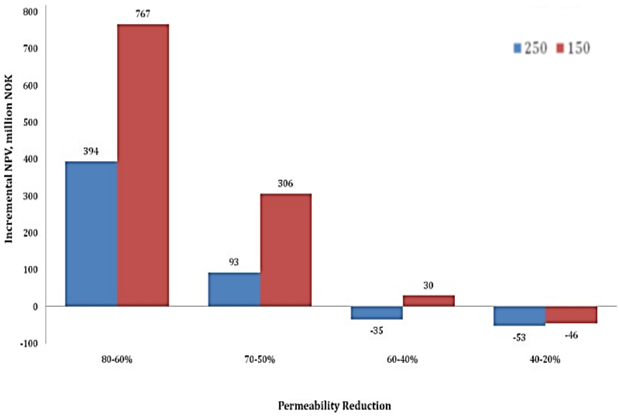

Fig. 18. Incremental NPV of the project at various permeability reductions and tracer concentrations

As illustrated in Fig. 18, a reduction in permeability from 60% to 40% at the 250 mg/L concentration level results in a negative incremental NPV. Therefore, the project is only viable when the permeability reduction is from 70% to 50% or above. Conversely, for the 150 mg/l concentration, a reduction in permeability from 60% to 40% yields a positive incremental net present value (NPV), thereby rendering the project always feasible. A sensitivity analysis was conducted on three distinct input parameters. The variables under consideration are the price of oil, the volume of oil produced, and the level of investment. In general, the acceptance of a project is contingent upon the attainment of a positive net present value (NPV). In order to ascertain whether WJSTP can be incorporated into the project, it is necessary to compare the NPV of all cases with that of the base case. In the event that the NPV of the case is less than that of the base case, it is not a viable proposition to utilise WJSTP, as this will result in additional expenditure for the company rather than increased profitability.

2.3.1. Oil price sensitivity analysis

Given the inherent volatility of the price of a barrel of oil, it was necessary to calculate the net present value (NPV) under two distinct scenarios: an annual increase of 5% and an annual decrease of 3%. The aforementioned sensitivity was applied to the base case and the three other cases, as illustrated in Table 6.

By employing the NPV calculation illustrated in Table 6 and by comparing each of the three cases with the base case where WJSTP has not been utilized, it is feasible to ascertain the viability of the case in question. As the sensitivity analysis was conducted with respect to the oil price, this demonstrates that the scenario of high probability and low anticipation is not a viable option in both the rising and falling oil price scenarios. The project exhibits a negative net present value, indicating that its costs exceed its future earnings. As in the other two cases, the chemical injection of WJSTP is always a viable option, regardless of whether the oil price rises or falls, as it will always result in additional profits. The additional gain may be as much as 160.82×10^6 USD.

2.3.2. Sensitivity analysis on oil production

The NPV must now be calculated in accordance with the variability of oil production. The NPV must be calculated when oil production is increased by 30% and when it is decreased by the same percentage, as illustrated in Table 7.

The feasibility of each case can be determined in a manner analogous to that employed for oil price sensitivity. Moreover, the case exhibiting high probability, low expectation, and profitability demonstrates negative profitability, indicating that the injection of WJSTP is not a profitable venture. In contrast, the remaining two cases allow for the possibility of chemical injection of WJSTP, with potential gains reaching 112.53×10^6 USD.

2.3.3 Investment Sensitivity Analysis

The financial aspects of WJSTP and its application are likewise susceptible to modification in accordance with market developments. Consequently, an analysis of the variation in the total cost of acquiring and applying WJSTP, which has been assumed to be 7.7×10^6 USD, has been conducted. A sensitivity analysis was conducted, applying a plus or minus 40% variation to the investment, as illustrated in Table 8.

Accordingly, the net present value (NPV) is calculated at 10.78×10^6 USD and 4.62×10^6 USD, as presented in Table 8. In this instance, the elevation in investment will result in an uneconomical scenario for the high probability, low expectation, and profitable case. With regard to the remaining cases, they are all economically viable, and the additional profit when incorporating WJSTP is considerable, reaching 120.01×10^6 USD. This analysis revealed that the oil price is the most sensitive parameter. The results of this project demonstrate that the implementation of WJSTP as a permeability reducer in the high-permeability zones of the Gullfaks field reservoir is an effective method for enhancing oil production and reducing water cut.

Table 6. NPV results showing the feasibility of all cases in the oil price sensitivity analysis

	5% annual increase in oil prices			**3% annual decrease in oil prices**		
Number of Cases	**NPV from 2025**	**Profitability**	**Feasibility**	**NPV from 2025**	**Profitability**	**Feasibility**
	(MUSD)	(MUSD)	-	(MUSD)	(MUSD)	-
Basic case	442.78	-	-	315,79	-	-
Case 16-P90	442.67	-0.11	Not feasible	313.21	-2.58	Not feasible
Case 16-P50	486.09	43.31	Feasible	340.28	24.49	Feasible
Case 12-P10	603.65	160.87	Feasible	412.79	97	Feasible

Table 7. NPV results showing the feasibility of all cases in the oil production sensitivity analysis

	30% annual increase in oil production			**30% annual reduction in oil production**		
Number of Cases	**NPV from 2025**	**Profitability**	**Feasibility**	**NPV from 2025**	**Profitability**	**Feasibility**
	(MUSD)	(MUSD)	-	(MUSD)	(MUSD)	-
Basic case	463,17	-	-	249,39	-	-
Case 16-P90	463,15	-0,0165	Not feasible	245,84	-3,56	Not feasible
Case 16-P50	504,97	41,8	Feasible	268,36	18,95	Feasible
Case 12-P10	617,55	154,38	Feasible	328,97	79,57	Feasible

Table 8. NPV results showing the feasibility of all cases in the investment sensitivity analysis

	40% annual increase in investment			**40% annual reduction in investment**		
Number of Cases	**NPV from 2025**	**Profitability**	**Feasibility**	**NPV from 2025**	**Profitability**	**Feasibility**
	(MUSD)	(MUSD)	-	(MUSD)	(MUSD)	-
Basic case	356.28	-	-	356,28	-	-
Case 16-P90	351.42	-4,87	Not feasible	357,57	1.29	Feasible
Case 16-P50	383.58	27.29	Feasible	389.74	33.46	Feasible
Case 12-P10	470.18	113.89	Feasible	476.34	120.06	Feasible

3- Conclusion

In this paper, the depth profile reduction technique was employed to diminish the permeability of high-permeability zones within the reservoir through the introduction of chemical compounds, specifically WJSTP. The implementation of this method was based on data from the Gullfaks field provided by NGB Geosciences Consulting LTD, including well, surface, fault, isochore, velocity, and production data. This enabled the design of a static model of the Gullfaks field reservoir and, consequently, the quantitative estimation of hydrocarbons in place with the Petrel software. Subsequently, a dynamic model was constructed using the aforementioned static model and water injection parameters, and simulated with the Eclipse software. The results of the simulation demonstrated a significant increase in hydrocarbon quantities as a consequence of the reduction in permeability of the high-permeability zones within the Gullfaks field reservoir. The oil recovery factor exhibited an increase from 25.01% to 70%, representing a 44.99% rise, while the gas recovery factor demonstrated a similar trend, rising from 36.1% to 74% (a 37.9% increase). The sensitivity analysis, conducted on the variables of oil price, oil production, and investment, demonstrated that the viability of the project is highly contingent upon the oil price. The findings of this study indicate that the chemical injection of WJSTP represents a technically viable and economically profitable method for enhancing oil production in the Gullfaks field.

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تطبيق حقن كيميائي باستخدام WJSTP في حقل جولفاكس، يُعزى إلى نفاذية الخزان

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الخلاصة

يُعد حقل جولفاكس حقلًا معقدًا، وينقسم إلى عدة تكوينات، تحتوي على خزانات في طبقات طبقية متعددة وأجزاء من صدوع متعددة. مع التطورات التكنولوجية الحديثة المستخدمة في حقل جولفاكس، يُعدّ نظام WJSTP أحد منصات اختبار الحلول التي تُركز على معالجة المياه المُنتجة لإعادة حقنها في المكمن لزيادة إنتاج النفط. يهدف هذا البحث إلى تطبيق الحقن الكيميائي باستخدام نظام WJSTP في حقل جولفاكس، والذي يُعزى إلى نفاذية المكمن لزيادة إنتاج النفط. وللتحقق من ذلك، تم بناء نموذج ثابت ثلاثي الأبعاد للمكمن باستخدام بيانات مقدمة من شركة NGB Geosciences Consulting LTD. بفضل أداة محاكاة برنامج بيتريل، تمت مراجعة تقدير حجم الإنتاج في الموقع البالغ ٢,٧٤٨,٧٢٧,٦٧٢,٩٥ برميلًا من النفط و٩٧٠,٢٦٤,١٥٠,٩٤٣,٣٩ قدم مكعب قياسي من الغاز. بعد ذلك، تم بناء نموذج ديناميكي يعتمد على النموذج الثابت ومعايير حقن المياه المحددة، وتمت محاكاته باستخدام برنامج إكليبس. أدى انخفاض نفاذية المناطق عالية النفاذية في المكمن من خلال الحقن الكيميائي لـ WJSTP إلى استخلاص النفط بنسبة ٧٠%، أي بزيادة قدرها ٤٤,٩٩%، واستخلاص الغاز بنسبة ٧٤%، أي بزيادة قدرها ٣٧,٩%. يُظهر تحليل الحساسية الذي أُجري على أسعار النفط وإنتاجه والاستثمار أن جدوى المشروع تعتمد بشكل كبير على سعر النفط. تشير نتائج هذه الدراسة إلى أن الحقن الكيميائي لـ WJSTP يمثل طريقة مجدية تقنيًا ومربحة اقتصاديًا لتعزيز إنتاج النفط في حقل جولفاكس.

الكلمات الدالة: حقل جولفاكس، النموذج الثابت والديناميكي، النفاذية، WJSTP، بيتريل، إكليبس، الربحية.