Sensitivity Analysis of Oil Production Models to Reservoir Rock and Fluid Properties

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Abstract

Improving the efficiency and optimization of oil recovery with a special focus on digitalization is on the spotlight. Achieving an optimized and successful automatic production highly depends on the ability to monitor and control the well performances. This requires a suitable dynamic model of the oil field and production equipment over the production lifetime. One of the main barriers to developing such dynamic models is that generally, it is very difficult to observe and understand the dynamic of fluid in a porous medium, describe the physical processes, and measure all the parameters that influence the multiphase flow behavior inside a reservoir. Consequently, predicting the reservoir production over time and respond to different drive and displacement mechanisms has a large degree of uncertainty attached. To develop long-term oil production models under uncertainty, it is crucial to have a clear understanding of the sensitivity of such models to the input parameters. This helps to identify the most impactful parameters on the accuracy of the models and allows to limit the time of focusing on less important data. The main goal of this paper is to do sensitivity analysis for investigation of the effect of uncertainty in each reservoir parameter on the outputs of oil production models. Two simulation models for oil production have been developed by using the OLGA-ROCX simulator. By perturbation of reservoir parameters, the sensitivity of these model outputs has been measured and analyzed. According to the simulation results after 200 days, it can be argued that the most affecting parameter for accumulated oil production was the oil density with sensitivity coefficients of -1.667 and 1.610 and relative permeability (-0.844 and 0.969). Therefore, decreasing the degree of uncertainty in those input parameters can highly increase the accuracy of the outputs of oil production models.

Keywords: sensitivity analysis, OLGA, ROCX, Norne field, oil production

1 Introduction

Oil is a crucial element of our modern society and plays an important role in improving the welfare of human beings. There is no immediate alternative for oil and as a result, oil production cannot be stopped over a night. In order to achieve maximized oil recovery with minimized carbon footprint, accurate and efficient modelling and simulation of oil production are of key importance. The performance of oil simulation models for the evaluation and prediction of oil production highly depends on the reservoir parameters. Uncertainty in any of these parameters can considerably impact the accuracy of such models. Therefore, it is very important to identify which reservoir parameters are the most impactful parameters on the accuracy of the models. The sensitivity analysis assesses the contribution of the uncertainty of each model input to the uncertainty of the model outcomes and identifies the most important parameters of the system. This allows to limit the time for focusing on less important data and improve the accuracy and efficiency of the models.

Oil reservoirs have different properties, and each reservoir performs differently during various methods of oil recovery. This paper provides insight into the most important reservoir rock and fluid properties needed for accurate modeling of horizontal wells with Inflow Control Device (ICD) completion during primary oil recovery. This is achieved by doing sensitivity analysis for two near-well simulation models for two reservoirs with different properties. One of these models is based on the realistic characteristics of the Norne field located in the Norwegian Sea and the other one is developed for a synthetic reservoir. Moreover, the OLGA simulator which is a dynamic multiphase-flow simulator in combination with the ROCX module which is a near-wellbore reservoir simulator is used in this study.

2 Sensitivity Analysis

It has been in the trend since old days that before putting some engineering equipment to work, it must be designed and tested first. Several methods and approaches can be used to achieve that. One of the methods is to develop a model using several logical steps to determine the parameters which influence the results the most. This method is known as 'Sensitivity Analysis' and it is not only important for validation of a model but also guides to future research (Hamby, 1994).

Depending upon the complexity of the model and the type of parameters being used there are many sensitivity analysis methods. The different methods are differential analysis, one-at-a-time sensitivity measures, factorial design, sensitivity index, importance factors, subjective sensitive analysis. All the methods are unique and can be used for the models that are suitable according to the type of results needed. In this paper, differential analysis method is applied which is the simplest and the generalized method of the analysis. Because of its simplicity and generalization, this method is also considered as the backbone of all other analysis techniques (Hamby, 1994).

Differential analysis also known as the direct method, is a technique structured based on the model with a set of specific input parameter values. Assuming this case as a base case scenario, where all other input parameters are held constant, they are set to their mean value. A sensitivity coefficient (ϕ_i) is termed to the value that describes the change of the output parameter. Basically, sensitivity coefficient is the ratio of change in output to change in input by keeping all other parameters constant(Hamby, 1994).

$$\phi_i = \frac{\%\Delta Y}{\%\Delta X_i} \quad (1)$$

where $\frac{\%\Delta Y}{\%\Delta X_i}$ is the partial derivative of Y with respect to X_i and ϕ_i is a dimensionless quantity.

3 Characteristics of the Reservoir for the Simulation Models

The simulations that increase the knowledge about sensitivity analysis of various reservoir parameters requires a model. This model could be either realistic or synthetic. Evaluating the sensitivity analysis in only one model could be specific to that case only which may or may not be the generalized case for all the models. Therefore, two models, one from the Norne field and one synthetic case are simulated and evaluated. Hence, the characteristics of each of these models need to be studied.

3.1 The Norne Model

Since Norne had potential for yielding high amount of oil and gas, there were several wells developed for maximum and optimized extraction of oil. Well 6608/10-D-2H is one of the wells, and the data needed as input for OLGA/ROCX were taken and calculation of the well was performed.

The well test data gave the temperature values for the reservoir near Well 6608/10-D-2H which is 115℃ (388 K). Based on pressure formation data, the pressure was approximated to be 277 bar.

The OLGA/ROCX requires the value of viscosity in the form of dynamic viscosity but the values from Equinor’s crude summary report provided the values in the form of kinematic viscosity at different temperatures (Equinor, 2021). MATLAB was used to extrapolate the value of the viscosity from the available data. Equation 2 is the empirical equation and by using the linear regression technique the value of viscosity was extrapolated for the given temperature and pressure value.

$$\mu = Ae^{B/T} \quad (2)$$

where μ is viscosity [cP], T is temperature[K] and A and B are unknown constant parameters which should be defined empirically. To calculate the value of viscosity at reservoir condition (388K) curve fitting is used. The values obtained from linear regression and the MATLAB code is then used to extrapolate the value as shown in Figure 1. At temperature 388K the oil viscosity was found to be 0.471cP.

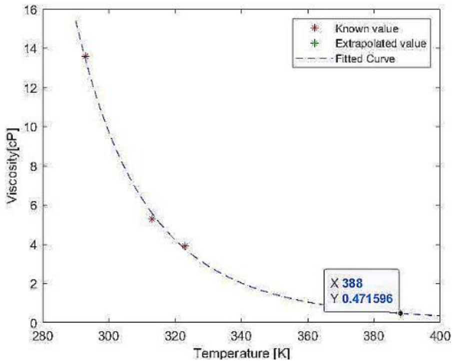

Figure 1. Extrapolated value of viscosity at reservoir conditions by curve-fitting

Permeability anisotropy (a) is the ratio of vertical permeability (k_v) to horizontal permeability (k_H). Well 6608/10-D-2H of the Norne field is divided into several layers and each layer or formations have different values for net pay thicknesses , effective porosity (ϕ_e) and shale volume (V_{sh}). These layers are called zones and the values for each zone are shown in Table 1.

Table 1. Zone thickness and the values of the rock parameters

Zones	Net Pay Thickness	Effective porosity (ϕ_e)	Shale volume (V_{sh})
Zone 1	35 m	0.2	0.31
Zone 2	46 m	0.24	0.15
Zone 3	55 m	0.27	0.14

Based on the analysis of well logs from NPD factpage, the value of average effective porosity (ϕ_e) for well 6608/10-D-2H is 0.23 and the median permeability (k) near this well is 0.3D.

By using the given data in Table 1, and Equations 3, 4 and 5 which are empirical correlations for the sandstone reservoir, the anisotropy permeability, $a = k_v / k_H$, near Well 6608/10-D-2H can be calculated (Igbokoyi et al., 2012).

$$k_H = \sqrt{k_x k_y} \quad (3)$$

$$k = \sqrt[3]{k_x k_y k_z} \quad (4)$$

$$k_v = k_z = 0.0718 \times \sqrt{\left[\frac{k_H(1-V_{sh})}{\phi_e}\right]^{2.0901}} \quad (5)$$

The results obtained from Table 1 and Equations 3, 4 and 5 for permeability anisotropy is shown in Table 2.

Table 2. Permeability anisotropy near Well 6608/10-D-2H

Parameters	k_x	k_y	k_z	a
Values	0.469D	0.469D	0.121D	0.257

The value of rock compressibility usually ranges from 1.5 × 10^{-6} to 20 × 10^{-6} 1/psi and the value used in OLGA/ROCX was 0.0001 1/bar that is approximately 1.4 × 10^{-5} 1/psi (Satter et al., 2016).

The data for relative permeability and capillary pressure for different saturations is not available in the NPD fact page so, the relative permeability and capillary pressure data are obtained from the OPM database (Open datasets, OPM, 2021). The calculated relative permeability curves for water and oil shown in Figure 2 can be used for the Norne field.

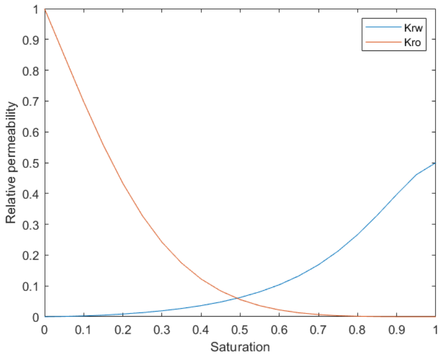

Figure 2. Relative permeability curve for Norne field

The values for oil density and Gas Oil Ratio (GOR) were 860 kg/m^3 and 82 Sm^3/ Sm^3, respectively (Norwegian Petroleum Dirctorate, 2021).

3.2 Synthetic Model

In the synthetic model, reasonable values for all the parameters required in OLGA/ROCX were concidered based experience and the ranges of values used in literature. Table 3 shows the values chosen for the synthetic model.

Table 3. Reservoir fluid and rock properties of synthetic model

Parameters	Values
Oil density	880 kg/m^3
Porosity	0.27
Viscosity	5 cP
Gas Oil Ratio (GOR)	40 Sm^3/ Sm^3
Rock Compressibility	0.0001 1/bar
Permeability anisotropy	0.3
Reservoir temperature	80 ℃
Reservoir pressure	200 bar

4 Development of the OLGA/ROCX Model

In this section, a simulation model was developed using OLGA/ROCX. The methodology adopted to build the dynamic reservoir wellbore model is described along with the selection of different input parameters for the model.

4.1 Development of the Reservoir Model for the Norne Model in ROCX

Based on data from various sources for Well 6608/10-D-2H at the Norne field, a model was developed in ROCX. Developing the model includes many step-by-step processes which is explained in detail.

4.1.1 Determining the Dimensions of the Reservoir Drainage Area and the Grid Setting

To prepare a reservoir model, drainage area of the near-well reservoir must be made. In actual practice the area of the drainage is ellipsoidal. However, when modelling in ROCX, it is not possible to feed the data for an ellipsoidal area, and therefore a rectangular reservoir is used.

The dimensions of the rectangular well need to be defined for the Well 6608/10-D-2H. For the calculation of the horizontal length of well, Total Vertical Depth (TVD) and Measured Depth (MD) of the well is needed which are 2647m and 4174m respectively (Norwegian Petroleum Directorate, 2021). Kickoff point is the point from which the deviation starts for drilling the hole in horizontal direction, and the length ($L_{kick\text{-}off}$) is also needed to determine the measured depth:

$$L_{MD} = L_{TVD} + L_{horizontal} + L_{kickoff} \qquad (6)$$

Based on the types of horizontal well, it is assumed that Well 6608/10-D-2H is a long horizontal well so the value for $R_{kickoff}$ is 457.2 m and from all these values the length of the horizontal section of the well is calculated to be 945m. When dividing the wellbore in zones, approximating the length of the well as 992 m was easier for modelling and did not affect the output of the well.
The thickness of net pay reservoir near Well 6608/10-D-2H can be calculated from Table 1 which is 136m (35+46+55=136m). The width, however, was determined by simulation of test model for oil production of five test cases done in OLGA. This is done by keeping the height and length of the drainage area constant and varying the width between 230m and 310m. The result is shown in Figure 3 where it is clearly seen that changing the width of the drainage area seems to have very less effect on the output of oil production. The drainage width was assumed to be approximately 270m (twice the thickness) but the results from the five simulations indicates that considering the width to be 230m seems to have almost same results as with width 270m.

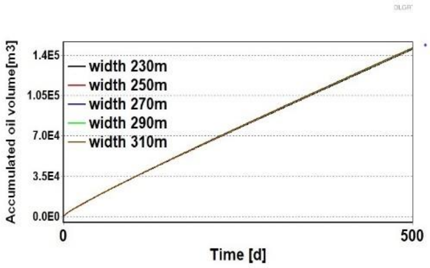

Figure 3. Different widths simulation for 500 days

Now based on the dimensions approximated for Well 6608/10-2H, the geometry of the drainage area and the position of the well are schematically shown in Figure 4. In the figure, the position of well is kept near the surface away from the aquifer to prevent early water breakthrough.

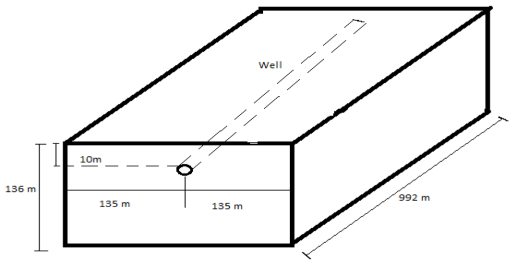

Figure 4. Geometry of the drainage area and position of well

The computational simulation should be accurate and time efficient. Finer grids and small-time steps give more accurate results but require a significant amount of time as well as computational resources. Finer mesh towards the well in y-direction was chosen with 19 cells in the Y direction and 24 cells in the Z-direction. The simulation was done using 8 equivalent ICDs, hence the length of the well was divided into 8 zones of equal size. The developed grid dimensions are shown in Figure 5. Finer mesh size in the places with high variation of fluid properties and coarser mesh size in the other places were adopted for the reservoir. This is done in order to maintain the accuracy of the results.

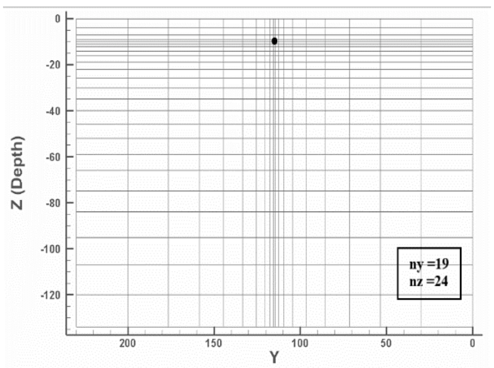

Figure 5. Grid setting for model base case of Norne well

4.1.2 Fluid Properties

It is essential to know the Pressure Volume Temperature (PVT) relation of the fluids that is used in simulations. The crude oils have a wide range of physical and chemical properties. One of the models used to estimate the PVT relations is the black oil fluid model. The black oil fluid model is a model that assumes that the oil components will always be in the liquid phase and does not evaporate at any conditions. So, the black oil model was selected over the PVT table model in ROCX. The basic properties of light oil used in the simulations are presented in Table 4.

Table 4. Oil properties used for ROCX

Parameters	Values
Oil Viscosity(cP)	0.471
Oil specific gravity	0.86
Gas specific gravity	0.64
GOR (Sm^3/ Sm^3)	82

The values of these parameters were considered at measured reservoir temperature of 115℃ and pressure of 277 bar.

4.1.3 Reservoir Properties

In the reservoir properties, the rock properties of the Norne oil field are specified. There are some assumptions made while feeding the inputs to the parameters where porosity of the Norne oil field is constant everywhere and the rock thermal properties has no effect on the production. The permeabilities in x, y and z directions are included for a rectangular drainage area. Table 5 represents the values that are used in ROCX for reservoir properties of Well 6608/10-D-2H.

Table 5. Reservoir properties for the Norne field

Parameters	Values
Porosity	0.23
Rock compressibility	0.0001 1/bar
Permeability(x-direction)	469 mD
Permeability(y-direction)	469 mD
Permeability(z-direction)	121 mD

4.1.4 Initial Condition

The initial values of temperature and pressure (115℃ and 277 bar) are the same as provided in the fluid property setting. The values of saturations of water (s_w), oil (s_o) and gas (s_g), are 0.3, 0.7 and 0 respectively.

4.2 Development of the Reservoir Model for the Synthetic Model in ROCX

The ROCX model for the synthetic case are based on the same procedures as for Well 6608/10-D-2H, with some changes in the drainage area of the reservoir. The values of the rock and fluid parameters of the well were also changed.

4.2.1 Dimensions of the Reservoir Drainage Area and the Grid Setting

The dimensions of drainage area for the synthetic model are shown in Table 6. The length of the reservoir is divided in 8 zones of equal length with one ICD in each zone. Just as for the Norne well, ICDs were installed along the length of the well.

Table 6. Dimension of reservoir of synthetic model

Parameters	Span (m)
Length	2000
Width	70
Thickness	30

The location of the horizontal well is in X-direction and the well location in the drainage area is show in Figure 6.

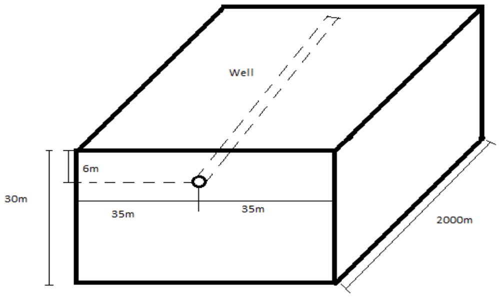

Figure 6. Location of well in drainage area of reservoir

After the location was defined for the synthetic case, the drainage area was needed to be discretized. Figure 7 shows the discretization of grid in *Y-Z* plane where the value of number of grids in Y and Z directions are 13 and 8 respectively. The length of the well along x axis is divided into 8 zones of 250 m each.

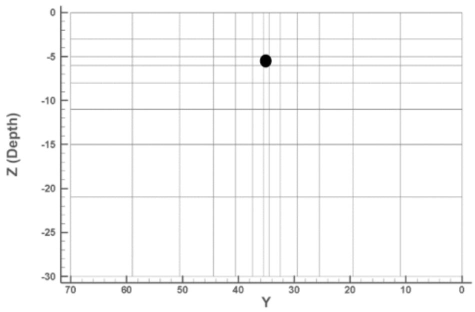

Figure 7. Grid setting for base case of synthetic well

The fluid properties for the synthetic model is presented in Table 7. The PVT selection is the same as for the Norne field. The reservoir properties needed for ROCX are shown in Table 8. The assumptions made for the Norne field for porosity and the rock thermal properties are also used in the synthetic model. The initial conditions for reservoir temperature and pressure were 80℃ and 200 bar respectively. The saturation values of fluids of water, oil and gas are s_w = 0.15, s_o = 0.85 and s_g = 0 respectively.

Table 7. Fluid property setting for synthetic model

Parameters	Values
Oil Viscosity(cP)	5
Oil specific gravity	0.88
Gas specific gravity	0.65
GOR (Sm^3/ Sm^3)	40

Table 8. Reservoir properties of synthetic model

Parameters	Values
Porosity	0.27
Rock compressibility	0.0001 1/bar
Permeability(x-direction)	2000 mD
Permeability(y-direction)	2000 mD
Permeability(z-direction)	600 mD

4.3 Development of the Well Model for the Norne Model in OLGA

There are two pipes, one for wellbore (annulus) where various flow components are installed, and the other is the production tubing. The information about each of these pipelines is required in OLGA model. The diameter of production tubing is 0.1397 m (5.5 inches), and the length is 992 m long. The diameter of the wellbore is 0.2286 m (9 inches) and has same length as the production pipe. The value of surface roughness (ε) is 0.00015 m. Each zone is further divided in two hypothetical sections and the details of these zones are presented in Figure 8.

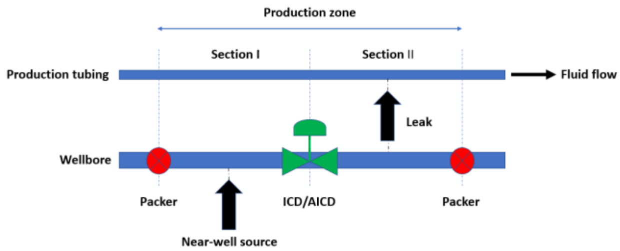

Figure 8. Simplified representation of a single production zone (Moradi et al, 2020).

Each of the zones contains two sections in the wellbore and has four components. The first component is a packer, which is used to separate zones by preventing the fluid to flow from one zone to another. The near-well source in first section of each zone is connected with ROCX and presents the fluid flow from the reservoir to the annulus. The ICD valves are installed on the wall of the pipeline, and the flow through the ICD, enters the pipeline from the annulus. The leak gives the connection from the ICD to the production pipeline. The coefficient of discharge (CD) for each valve is different as required in the wellbore. Production occures from all zones in the well, and the fluid moves towards the heel.

Considering the frictional pressure drop in the well and pressure difference across the ICDs, the pressure drawdown for this well is assumed to be 12 bar. Moreover, the hole diameter of the equivalent valve is calculated as d = 0.09m. The simulation of this model is run for 200 days and the cumulative oil production and volumetric flow rate of oil and water are recorded.

4.4 Development of the Well Model for the Synthetic Model in OLGA

Similarly for the model development of the synthetic case in OLGA, few changes were made in the value of some parameters and apart from that, the flow component setup was exactly same as shown in Figure 8.

The length of the wellbore and production tubing were 2000m and were divided into 8 equal zones (250m each). The diameter of production tubing is 0.2159m and that of wellbore is 0.1397m. The material of pipe used is same in both cases so, the surface roughness is 0.000015m for both pipes. The pressure drawdown in the synthetic case is 10 bar and the orifice diameter is 0.015m. The simulations were run for 200 days.

4.5 Simulated Cases

Once all the parameters were set and the model was completed in OLGA/ROCX, a base case model was developed and a sensitivity analysis was performed for different rock and fluid properties of Well 6608/10-D-2H and for the synthetic model.

For the Norne oil field, the sensitivity analysis was done by increasing and decreasing the value of parameters by 20% from their mean value given in Table 10.

Table 10. Simulated cases of Norne field

Parameters	**Base case**	**Case 1 (20% increase)**	**Case 2 (20% decrease)**
Viscosity	0.471cP	0.565	0.376
Porosity	0.23	0.276	0.184
GOR	82 Sm^3/Sm^3	98.4	65.6
Initial water saturation	0.3	0.36	0.24
Oil density[1]	860 kg/m^3	951.5	778.5
Absolute Permeability	0.3 D	0.36	0.24
Permeability anisotropy	0.257	0.309	0.206
Rock compressibility	0.0001 1/bar	0.00012	0.00009

The relative permeability curves and capillary pressure table in ROCX were also changed from their mean values and simulated in OLGA.

[1] Oil density was changed by ± 10% only because increasing by 20% gave a value greater than 1000 which is practically not possible.

The simulated cases for the synthetic model are presented in Table 11. In these cases, the values of the parameters were increased and decreased by 10% from their mean values.

Table 11. Simulated cases of synthetic case

Parameters	**Base Value**	**Case 1 (10% increase)**	**Case 2 (10% decrease)**
Viscosity	5 cP	5.5	4.5
Porosity	0.27	0.297	0.243
GOR	40 Sm^3/Sm^3	44	36
Initial water saturation	0.15	0.165	0.135
Oil density	880 kg/m^3	968	792
Absolute Permeability	1.3 D	1.43	1.17
Permeability anisotropy	0.3	0.33	0.27
Rock compressibility	0.0001 1/bar	0.00012	0.00009

5 Results and Discussion

In this section, the base case model of Well 6608/10-D-2H of Norne field and of synthetic well are graphically explained. The method used for the simulations is described. A sensitivity analysis for oil and water production is carried out for Norne and the synthetic well.

5.1 Cumulative Oil and Water Production

For the sensitivity analysis of the two reservoirs, a model for a base case is developed. The graphs obtained from these cases are for accumulated volume of oil and water for the Norne well and for the synthetic case. These graphs give the idea of the quantity of oil and water in the reservoir after a certain period. The water breakthrough time can be determined based on these graphs. From Figure 9, the oil production at the end of 200 days for Norne is approximately 140000 m^3 and that for synthetic case is around 220000 m^3. Similarly, the water production for the Norne case and the synthetic case are somewhere near 11000 m^3 and 35000 m^3.

5.2 Oil and Water Flow Rate

The volumetric flow rate is another important factor which must be taken into consideration for the sensitivity analysis. The peak value of flow rate of oil for Norne in Figure 10 is around 1100 m^3/d. This value is very close to the original value which is 1250 m^3/d which indicates that the model is accurate. Also, the ratio of the peak values of water flow rate to oil flow rate from Figure 10 is around 0.2 (200/1100). Comparing this value with the relative permeability curve for Norne in Figure 2 by dividing the rises of water and oil saturations of relative permeability, the values are approximately the same($0.2/0.68 \approx 0.3$). This is another verification of accuracy of the model.

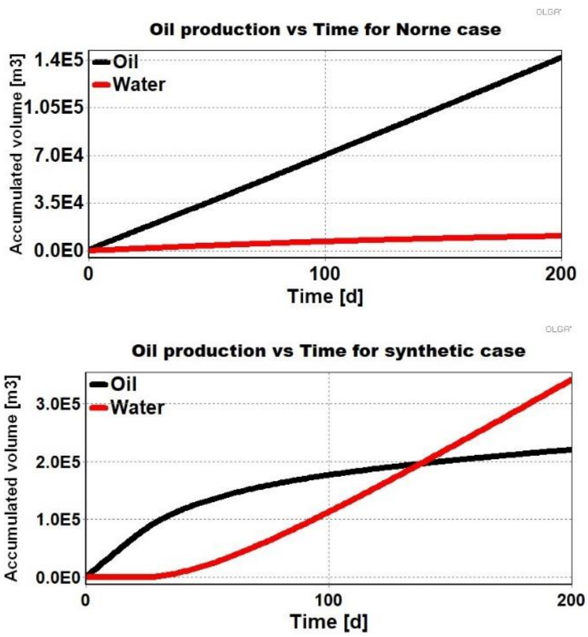

Figure 9. Accumulated oil and water production from Norne well and synthetic well

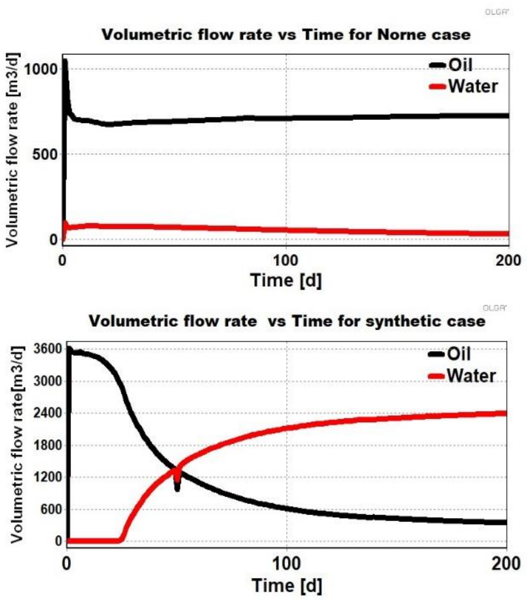

Figure 10. Volumetric flow rates of oil and water for Norne well and synthetic well

5.3 Sensitivity Coefficient for Oil Production

The parameters in the base case that are analyzed are changed in OLGA/ROCX by keeping all other parameters constant. In case of the Norne oil field, the parameter values have been changed by $\pm$ 20% and for the synthetic case, the parameter values were changed by $\pm$ 10%.

The model with the new parameter values was simulated for 200 days and the accumulated oil and water volume flows were registered. Based on the production data from the new case and the base case, the sensitivity coefficients for the different parameters were calculated. Figure 11 shows the comparison of the most affecting and the least affecting parameters for Norne and for the synthetic reservoir.

For the Norne oil field, the most affecting parameter is oil density with sensitivity coefficients -1.667 and 1.610. Oil density is then followed by initial water saturation, relative permeability, oil viscosity, and absolute permeability. The least affecting parameter is the porosity.

For the synthetic case, the most affecting parameter is the relative permeability with sensitivity coefficients of -0.844 and 0.969 for increase and decrease of the parameter values, respectively. Relative permeability is followed by porosity, oil density, initial water saturation down to capillary pressure which is the least affected parameter.

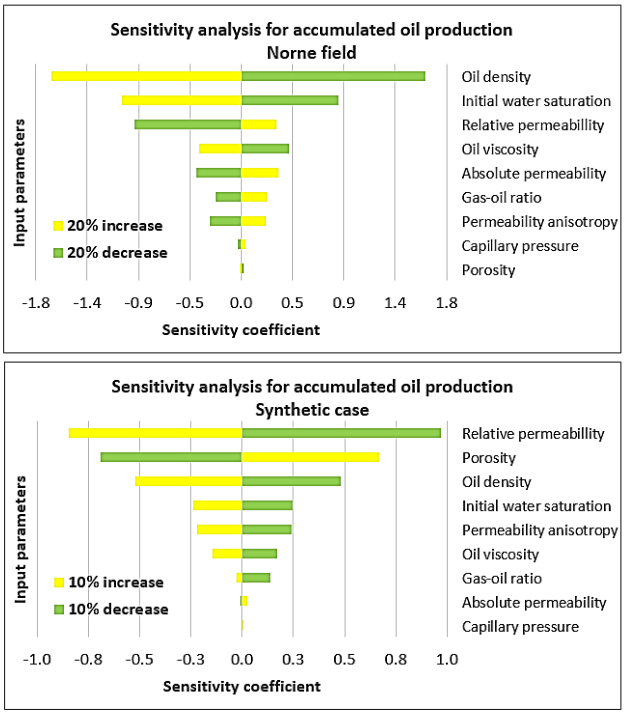

Figure 11. Sensitivity analysis of oil production of rock and fluid parameters of two cases

5.4 Sensitivity Coefficient for Water Production

The results presented in Figure 12 are obtained from the sensitivity analysis in OLGA/ROCX regarding water production.

The most affecting parameter in case of sensitivity analysis of water production for the Norne field is the initial water saturation with sensitivity coefficients of 4.516 and -3.592 for increase and decrease in the parameter values, respectively. The initial water saturation is followed by relative permeability, oil viscosity, oil density and absolute permeability. For the synthetic case, the most affecting parameter is relative permeability with sensitivity coefficients of -0.467 and 0.323 for increase and decrease of the parameter values, respectively.

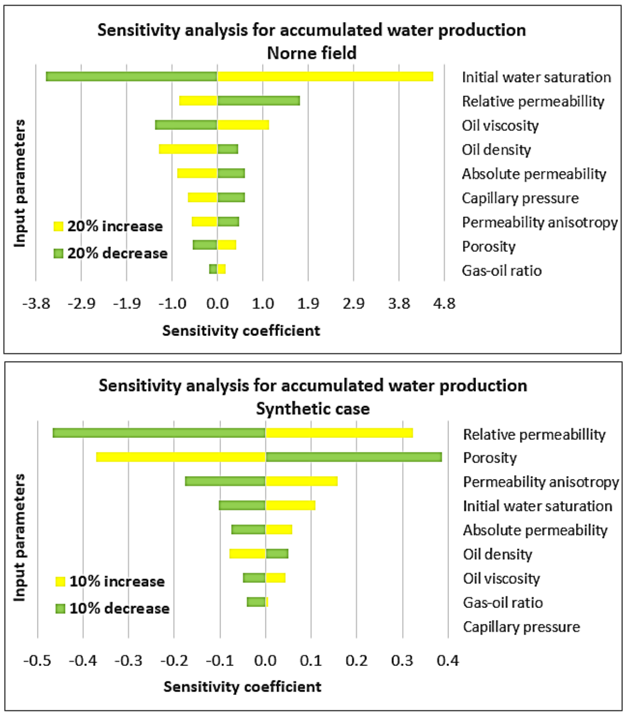

Figure 12. Sensitivity analysis of water production of rock and fluid parameters of two cases

6 Conclusion

The results obtained from the sensitivity analysis of rock and fluid parameters based on 200 days of production simulated in OLGA/ROCX shows the following key points. In the case of the Norne oil field, the most affecting parameter for accumulated oil volume was oil density with sensitivity coefficients -1.667 and 1.610 for increase and decrease of values respectively, followed by initial water saturation, relative permeability, oil viscosity, and absolute permeability. The least affecting parameter was porosity. The change in rock compressibility seemed to have no effect on the production output.

For the water production at Norne, the most affecting parameter was the initial water saturation with sensitivity coefficients of 4.516 and -3.592 for increase and decrease in the parameter values. The initial water saturation is followed by relative permeability, oil viscosity, oil density and absolute permeability.

In the synthetic case, the most impactful parameter for accumulated oil production was found to be the relative permeability (-0.844 and 0.969) followed by porosity, oil density, and initial water saturation.

For the accumulated water production, the most impactful parameter was relative permeability (-0.467 and 0.323) followed by porosity, permeability anisotropy and initial water saturation. In the synthetic case, the rock compressibility and capillary pressure seemed to have no effect on the production output.

Therefore, it can be concluded that the most affecting parameters in oil field varies based on the type of oil fields. Two different reservoirs have different parameters for the most and least affecting properties.

Acknowledgments

We gratefully acknowledge the economic support from the Research Council of Norway and Equinor through Research Council Project No. 308817, “Digital Wells for Optimal Production and Drainage” (DigiWell).

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