



# The effect of chemically enhanced oil recovery on thin oil rim reservoirs

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## Abstract

Oil rim reservoirs are characterised with a small thickness relative to their overlying gas caps and underlying aquifers and the development these reservoirs are planned very carefully in order to avoid gas and water coning and maximise oil production. Studies have shown low oil recoveries from water and gas injection, and while foam and water alternating gas injections resulted in positive recoveries, it is viewed that an option of an application of chemical enhanced oil recovery option would be preferable. This paper focuses on the application of chemical enhanced oil recovery to improve production from an oil rim reservoir in Niger Delta. Using Eclipse black oil simulator, the effects of surfactant concentration and injection time and surfactant alternating gas are studied on overall oil recovery. Surfactant injections at start and middle of production resulted in a 3.7 MMstb and 3.6 MMstb at surfactant concentration of 1% vol, respectively. This amounted to a 6.6% and 6.5% increment over the base case of no injection. A case study of surfactant alternating gas at the middle of production gave an oil recovery estimate of 10.7%.

**Keywords** Oil rims · Chemical enhanced oil recovery · Surfactants · And concurrent production

## Abbreviations

|      |                                |
|------|--------------------------------|
| FWCT | Field water cut                |
| FOE  | Field oil efficiency           |
| FOPT | Field oil production total     |
| EOR  | Enhanced oil recovery          |
| CEOR | Chemical enhanced oil recovery |
| FOPR | Field oil production rate      |

## Introduction

Oil rim reservoirs are reservoirs with a generally low thickness compared to thickness of the gas column above it and aquifer below it. Robert and Jacques (1953) described an oil

rim reservoir as one whose major drive mechanism is gas cap drive and has solution drive as a minor drive mechanism. An aquifer may be present, but its effect is usually not as pronounced as that of gas cap and solution drive mechanism. Oil rims have been classified into different categories including the ultrathin oil rim with oil reservoir thickness below 30 ft as described by Nagib et al. (2011), Vo et al. (2001), a pancake oil rim with reservoir thickness of 20–50ft Sulaiman and Bretherton (1989) and thin oil rims of 50–100 ft Sam-sunder et al. (2005). These reservoirs are located around the world and require careful planning and execution in order to optimise hydrocarbon production from them due to their low thickness. Various studies have been carried out on optimization of production parameters for oil rim reservoirs. Olabode et al. (2018a) observed that it is best to maintain and optimize reservoir and production parameters before carrying out recovery options on oil rim reservoirs. Their study suggests that a horizontal well at a rate of between 1000 and 1500 stb/day is optimum for oil recovery. These optimizations will help in proper production forecast for oil rim reservoirs (Olabode et al. 2018b). Olabode et al. (2020a) also emphasized the need for proper well placement with respect to fluid contacts as an essential factor for optimum oil and gas productivity. Olabode (2020b) concluded that for optimum oil recovery during secondary injection schemes, it is best to place the water injector

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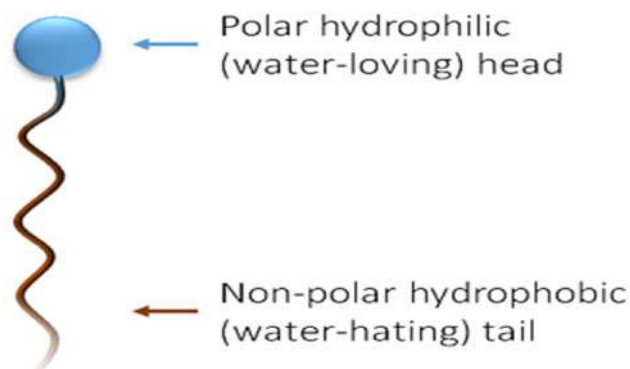
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at an up dip location of the reservoir. The use of enhanced oil recovery (EOR) techniques has also been investigated for oil rim reservoir development. Olabode et al. (2018c) studied the effect of foam and WAG (water alternating gas) injection on performance of thin oil reservoirs, showing that foam up dip and foam down dip gave increased oil recoveries of 8.57% and 8.56%, higher than 8.35% and 7.94% from WAG up dip and WAG down dip injections, respectively. Maroua and Mohsen (2019) did a simulation study on the impact of water flooding, immiscible gas injection and surfactant flooding on oil rim reservoir development; results from this study showed that surfactant flooding gave a higher displacement efficiency in comparison with water flooding and its application in reducing residual oil saturation could give a higher ultimate oil recovery. In this paper, the impact of water injection will be compared with surfactant injection at different concentrations on oil recovery from an oil rim reservoir in the Niger Delta basin.

Surfactants are added in small amounts of injection water to reduce the interfacial tension between oil and brine, helping to mobilise residual oil left behind during secondary recovery. Surfactants are also capable of altering the wettability of rocks by increasing the imbibition of water to the rocks, (Dieshad et al. 2009). However, the alteration of wettability by surfactants is more pronounced in carbonate formations as carbonate rocks are usually oil wet, (Sheng 2013). They can function as wetting agents, detergents, emulsifiers, dispersants and foaming agents. A surfactant molecule consists of a non-polar hydrophobic (lipophilic) tail and a polar hydrophilic (lipophobic) head.

The hydrophobic tail has a higher affinity for oil, while the hydrophilic head has a greater affinity for water (Fig. 1). This structure makes surfactants soluble in both the water and oil phases. When the surfactants are injected into the oil phase, it causes a disruption in the original oil structure because of the hydrophilic group and increases the free energy in the system, the system tries to adjust for the presence of this surfactant by reducing contact with the



**Fig. 1** General structure of a surfactant molecule. *Source* University of Bistol

hydrophiles. Likewise, when the surfactant is injected into the water phase, it causes a disruption in the original water structure due to the hydrophobic portion of the molecule and the system will also try to adjust for the presence of the hydrophobes by reducing contact with the hydrophobes. These adjustments cause the surfactant molecules to be absorbed at the interface of the two fluids causing a reduction in the interfacial tension, (Rosen and Kunjappu 2012). The surfactants accumulate at the interface in the form of micelles, Keshtkar et al. (2015)

Pope (2007) outlines the following four classes of surfactants:

- Anionic surfactants
- Cationic surfactants
- Non-ionic surfactants
- Zwitter-ionic surfactants

According to Sheng (2015), anionic surfactants are preferred for the following reasons:

- Low adsorption tendency on sandstones and carbonates
- Can be modified to fit different scenarios
- Inexpensive in special cases
- Sulphates can be applied to low temperature reservoirs

However, cationic surfactants can be applied as co-surfactants. Generally, non-ionic surfactants have not provided satisfactory results for EOR.

The success of a surfactant flooding process is a function of the type of reservoir rock, i.e. sandstone or carbonate. Most surfactant flooding treatments have been carried out on sandstone reservoirs because of its favourable characteristics. In this project, the effect of the concentration and injection rate of surfactant employed in surfactant flooding will be analysed in a numerical simulation study.

## Surfactant flooding

Surfactant flooding is one of the chemical EOR schemes. Surfactant flooding is carried out to recover oil that is trapped by capillary forces after secondary recovery has taken place. The mechanism behind this is to reduce the interfacial tension (IFT) between the oil and water in the pore spaces. When designed properly, a surfactant flooding scheme can reduce IFT by about  $10^{-3}$  dynes/cm. It aids to recover an additional 60% of original oil in place left behind in the reservoir after waterflooding.

## Mechanisms of surfactant flooding

Surfactants mobilise trapped oil through two major trapping mechanisms which include reduction of interfacial tension

and wettability alteration. There is also a third and less common mechanism that is known as swelling.

### Reduction of interfacial tension (IFT)

In order to describe this mechanism, the concept of capillary number and its relationship with residual oil saturation must be introduced first. The capillary number is the ratio of viscous forces to capillary forces. In its simplest form, it is given by the following equation:

$$N_c = \frac{U\mu}{\sigma(\cos \theta)} \quad (1)$$

where.

$N_c$  is the capillary number.

$U$  is the displacing Darcy velocity.

$\mu$  is the viscosity of the displacing fluid.

$\theta$  is the contact angle.

$\sigma$  is the interfacial tension between the displacing fluid and the displaced fluid.

### Oil swelling

This mechanism involves the formation of micro-emulsions after the injection of the surfactant, (Perm Inc). Relevant micro-emulsions under this mechanism include the type II micro-emulsion in which water is solubilised in the residual oil forming an upper emulsion phase, and the type III micro-emulsion in which both water and oil solubilise in each other and form middle emulsion phase. The solubilisation of water in oil causes the oil to swell; hence, its volume increases, thereby increasing its relative permeability and easing its production.

### Volumetric sweep efficiency

Volumetric sweep efficiency quantifies the three-dimensional effects of reservoir heterogeneities, Chauhan (2014). It is given as the product of the areal sweep efficiency and vertical sweep efficiency.

$$E_V = E_A * E_I = \left( \frac{A_d}{A_R} \right) * h * \Phi * S \dots \quad (2)$$

where

$E_A$  is the areal sweep efficiency.

$A_d$  is the area of displacement.

$A_R$  is the area of the reservoir.

$\Phi$  is the porosity.

$S$  is hydrocarbon saturation.

In surfactant flooding schemes, in order to maintain a good volumetric sweep efficiency, the mobility ratio must be kept lower than one to preventing viscous fingering from occurring. The surfactant slug that is injected should have a low mobility in order for it to move through low permeability zones and other parts of the reservoir that are not in close proximity to the injection well, thus improving volumetric efficiency.

### Screening criteria

Surfactant screening is carried out in order to evaluate the performance a single surfactant or a combination of different surfactants under different reservoir conditions in order to ascertain suitability for a particular flooding scheme, Hirasaki et al. (2008). The following parameters were outlined by Sheng (2015) as the important factors that affect the choice of surfactants:

- The type of formation, salinity of formation water and presence of divalent ions
- The depth and temperature of the reservoir
- Permeability of the formation
- Crude oil composition, API gravity and viscosity
- Residual oil saturation
- Storage capacity

According to NPC (1976), commercial availability, type of surfactants and economic conditions must all be put into consideration during screening activities.

In his paper, Sheng (2015) provided a summary of technical screening criteria proposed by various scholars in Table 1:

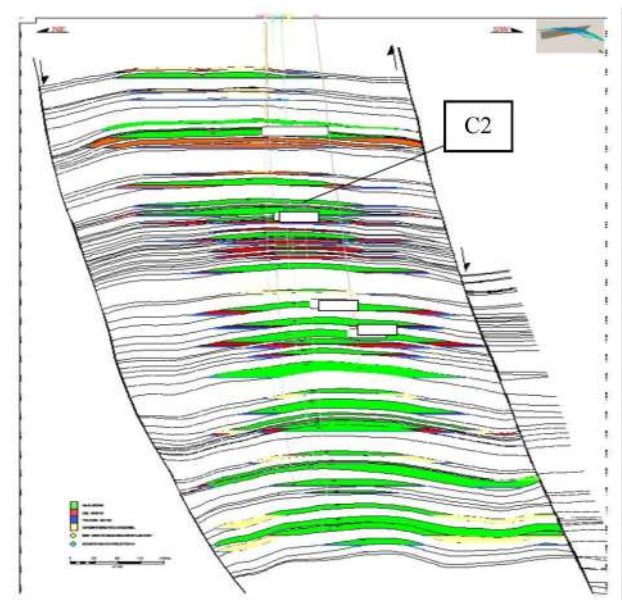
### Niger delta case study

The Niger Delta region of Nigeria holds a vast amount of hydrocarbon resources. The reservoirs found in this region are located in anticlinal and synclinal structures. The reservoirs are Early Miocene in age and record successive periods of outbuilding and early destruction of Niger Delta Fig. 2 is a particular field in the Niger Delta region which hold massive reserves of oil in its oil rim reservoirs. Gas, oil and water positions and volumes are each represented by green, red and blue colours, respectively.

Figure 2 shows the case study reservoir C2 field description with stacked oil rim reservoir layers.

Table 1 Surfactant screening criteria Sheng (2015)

| Proposed by                  | K (mD)    | $T_r$ (°C)   | Formation water salinity (TDS, ppm)   | Divalence (ppm) | Lithology               | Clay content | $\mu_o$ (cP) | $S_o$ (frac.) | Aquifer        | Gas cap        | API gravity | Depth (ft) |
|------------------------------|-----------|--------------|---|-----------------|-------------------------|--------------|--------------|---------------|----------------|----------------|-------------|------------|
| NPC (1976)                   | $\geq 20$ | $\leq 121.1$ | $\leq 200,000$  | –               |                         |              | $\leq 30$    | $\geq 0.2$    |                |                | $\geq 25$   |            |
| Brashear and Kuuskraa (1978) | $> 20$    | $< 93.3$     | 50,000  | 1000            | Sandstone               | Low          | $< 20$       | $> 0.25$      | None to weak   | None to weak   | $> 25$      | NC         |
| Carcoana (1982)              | $> 50$    | $< 80$       | Low   | Low             | Sandstone               |              | $< 40$       | $> 0.3$       | Weak           | Weak           |             | $< 6561$   |
| NPC (1984)                   | $> 40$    | $< 93.3$     | $< 100,000$   |                 | Sandstone and carbonate |              |              |               |                |                |             |            |
| Goodlet et al. (1986)        | $> 20$    | $< 93.3$     | 100,000   |                 | Sandstone pref-fered    |              | 100          | 0.3           |                |                | $> 25$      | $< 9000$   |
| Al-Bahar et al. (2004)       | $> 10$    | $< 93.3$     |   |                 | Sandstone pref-fered    |              | $< 35$       | $> 0.35$      |                |                | $> 20$      | $< 9000$   |
| Taber et al. (1997)          | $> 50$    | $< 70$       | 50,000  | 1000            | Sandstone               | Low          | $< 150$      | 0.35          | None           | None           |             |            |
| Dickson et al. (2010)        | $> 100$   | $< 93.3$     | $< 200,000$ if $T_r < 60^\circ\text{C}$<br>$< 50,000$ if $T_r > 60^\circ\text{C}$ |                 |                         |              | $< 35$       | $> 0.45$      |                |                | $> 20$      | 500–9000   |
| Surfactant projects          | 152       | 25.3         | 39,078  |                 | Majority sandstone      | Low          | 5.8          | 0.4           | Generally none | Generally none | 36.5        | 1808       |
| Sheng J. J. (2011)           | $> 10$    | $< 93.3$     | 50,000  | $< 100$         | Sandstone               | Low          | $< 35$       | $> 0.3$       | Weak           | Weak           | NC          | NC         |



**Fig. 2** Field description of C2 reservoir. *Source* The Shell Petroleum Development Company, Port Harcourt

**Methodology**

**C2 model grid description**

The oil rim reservoir C2 is used to verify the effect chemically enhanced oil recovery options on oil recovery. The Petrel software is used to discretize the subsurface map in Fig. 3 for easy upload into the grid section of Eclipse

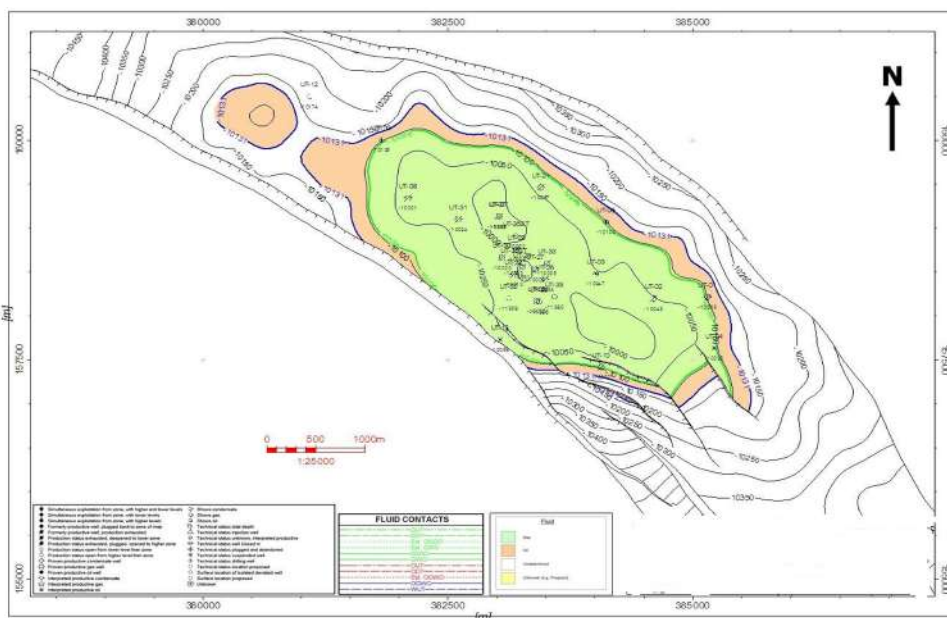
software (Fig. 4). The GridSim Module was used to build the reservoir grid model. The reservoir lies between 10,000 and 10,450 feet. The Cartesian grid is set into 75×50×20 grid cells with 74,000 cells set active by boundary definition and shaped according to the cross sections drawn across the reservoir sand map in both X and Y directions. There are 32,420 active cells and 41,580 inactive cells. The grid section is used to assign petro-physical properties and their values as described in Table 2. To initialise the active grid cells, the solution and PVT properties are incorporated and constructed by making use of black oil properties in the manual. The surfactant model in the Eclipse software is activated with all the necessary keywords and parameters as contained in the manual.

The reservoir has been history matched via 5 initial wells that were in production since 1968 and have reached peak water cuts and gas oil ratios after over 30 years of production (Fig. 4). This prompted the initialisation of 8 more wells (serving as base case at 2010) in locations of high oil saturation in the reservoir (Fig. 5). The simulation period for this prediction is between 2010 and 2046. To determine the performance of the reservoir drives, M-Bal is used to generate energy plots from reservoir properties in Table 2. Thus, Figs. 5 and 6 show the relative contribution different reservoir drives and that the reservoir is actively under aquifer drive with the gas cap the minor drive.

**Simulation cases**

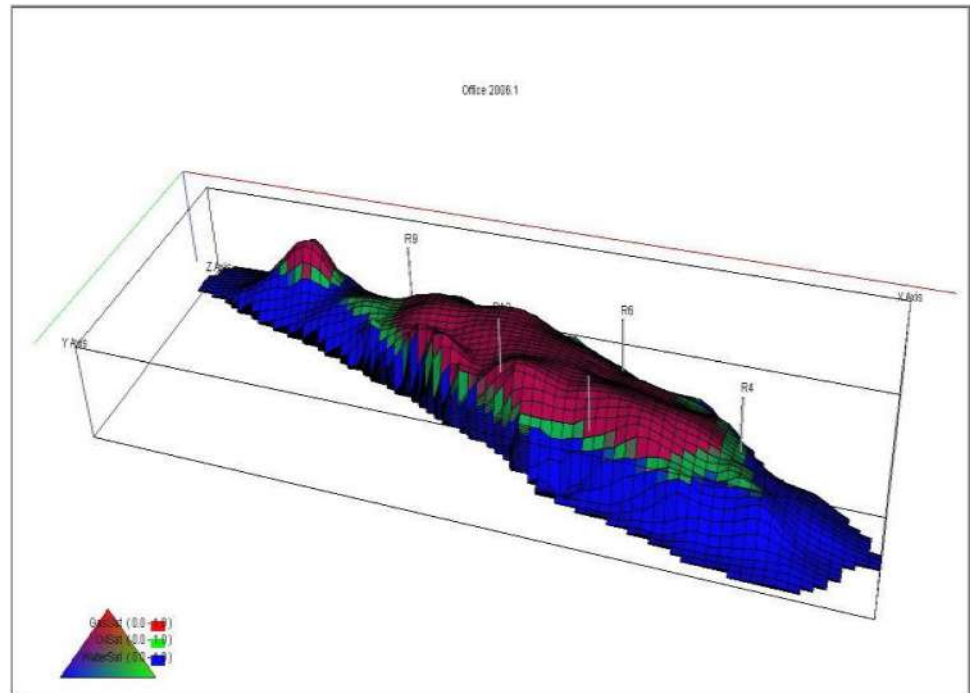
To verify the oil recovery from different scenarios of chemically enhanced oil recovery, a base case has to be recognised.

**Fig. 3** Sub surface geological map of C2



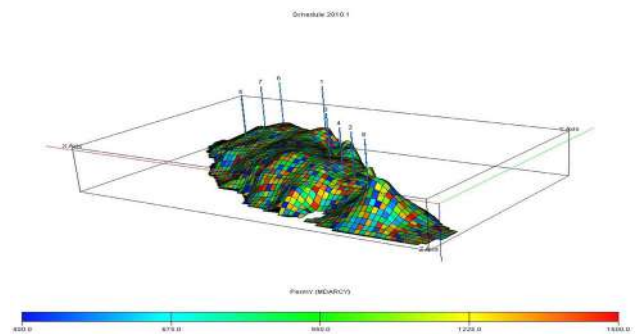


**Fig. 4** Floviz model of C2 reservoir before the start of simulation



**Table 2** Properties of C2 reservoir

| Properties          | Value    | Properties              | Value    |
|---------------------|----------|-------------------------|----------|
| Oil sand porosity   | 0.26     | Oil rim thickness (ft)  | 38       |
| Gas sand porosity   | 0.24     | Swc                     | 0.14     |
| Sh oil              | 0.9      | Oil viscosity (cP)      | 0.43     |
| Sh gas              | 0.77     | Oil gravity (API)       | 32       |
| NTG                 | 0.8      | Boi (bbl/STB)           | 1.48     |
| Permeability (mD)   | 400–1500 | Rsi (SCF/STB)           | 1035     |
| Sand thickness (ft) | 71       | Ti (f)                  | 179      |
| Pi (psi)            | 4394     | Np (MMstb)              | 10.73    |
| Pb (psi)            | 4394     | Free gas in place (bcf) | 128.5    |
| STOIP (MMbbls)      | 35.9     | $\Delta P/P_i @ N_p/N$  | 7% @ 26% |



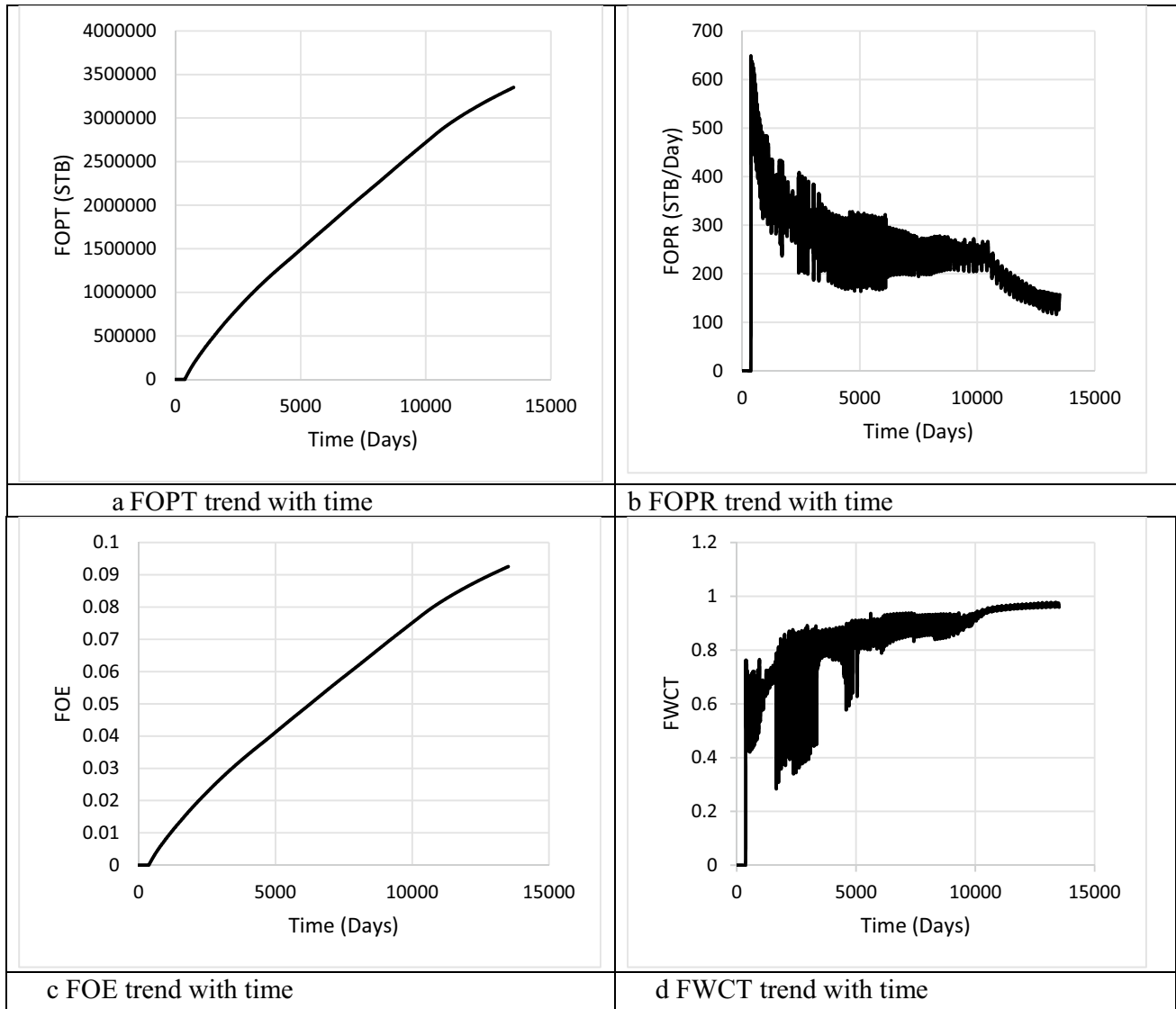
**Fig. 5** Floviz model of C2 reservoir showing 8 initialised wells

Since the scope of this work is outside secondary injection, the base case will be a case scenario of no injection (initial 8 horizontal wells producing at an optimised rate of 100 stb/day). Then, a case study of effect of varying surfactant concentration (via water injector well at an injection rate of

2500 stb/day) with respect to time and surfactant alternating gas is considered. Thus, the following case studies:

- No injection at all (at 2010)
- Injection at the start of production in December 2010
- Injection at the middle of production in November 2023
- Surfactant alternating gas.





**Fig. 7** **a** FOPT trend with time; **b** FOPR trend with time; **c** FOE trend with time; **d** FWCT trend with time

concentration. The plots show maximum and minimum oil recoveries at 1% and 30% surfactant concentration.

### Comparisons between scenarios 2 and 3

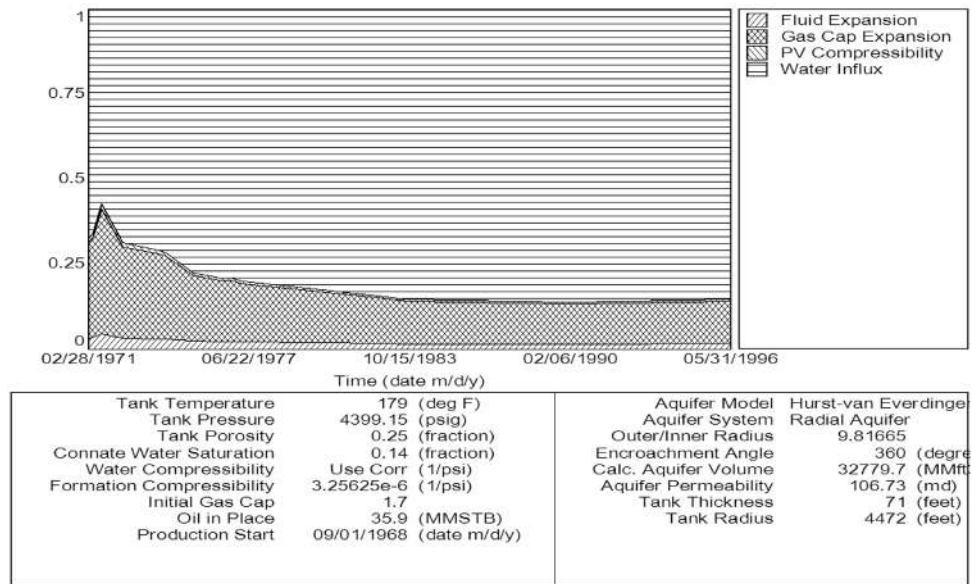
The charts in Fig. 11a, b, c and d show that injecting at a surfactant concentration of 1% vol is profitable for maximum oil recovery and this should be initiated at the onset of production.

### Scenario 4

Scenario 4 involves the application of surfactant alternating gas (SAG) injection for the development of the oil rim reservoir. For this scenario, simulation was also carried out for two cases: injection at the start of production and injection at the middle of production. A surfactant concentration of 1 volume % was selected since it gave the highest recovery amongst the previous scenarios and from Fig. 12c, surfactant



**Fig. 8** AR2 energy plot AR2 reservoir



**Table 4** Results summary for scenario 2

| Results at December 2010 |             |              |                  |            |
|--------------------------|-------------|--------------|------------------|------------|
| Surfactant Conc (vol%)   | (FOE)       | (FOPT) (STB) | (FOPR) (STB/day) | (FWCT)     |
| 0 (water injection)      | 0.096617751 | 3,499,010.5  | 157.76485        | 0.96075308 |
| 1                        | 0.098634697 | 3,571,968.5  | 211.14687        | 0.95357502 |
| 5                        | 0.097971737 | 3,548,131.8  | 178.27037        | 0.95054859 |
| 10                       | 0.098197669 | 3,556,198    | 150.6162         | 0.95584935 |
| 15                       | 0.097971737 | 3,548,131.8  | 178.27037        | 0.95054859 |
| 30                       | 0.090643935 | 3,282,718    | 220.88638        | 0.93922669 |

injection at the middle of production and at 1% weight volume gave the recovery. An optimal rate of 250 Mscf/day was used for gas injection. From the results, injection at the middle of production gave a higher recovery of 3,915,821 STB (Fig. 12a), about 2.5% higher than the recovery of 3,175,512 STB from injection at the beginning of production (Table 6). This can be attributed to late gas breakthrough in the case

of injection at the middle of production. The table shows the results of this scenario at the end of the simulation in November 2046:

The results from this scenario show that surfactant injection at middle of production will yield a higher recovery compared to the previous scenarios which suggests better recovery when surfactant is injected at onset.

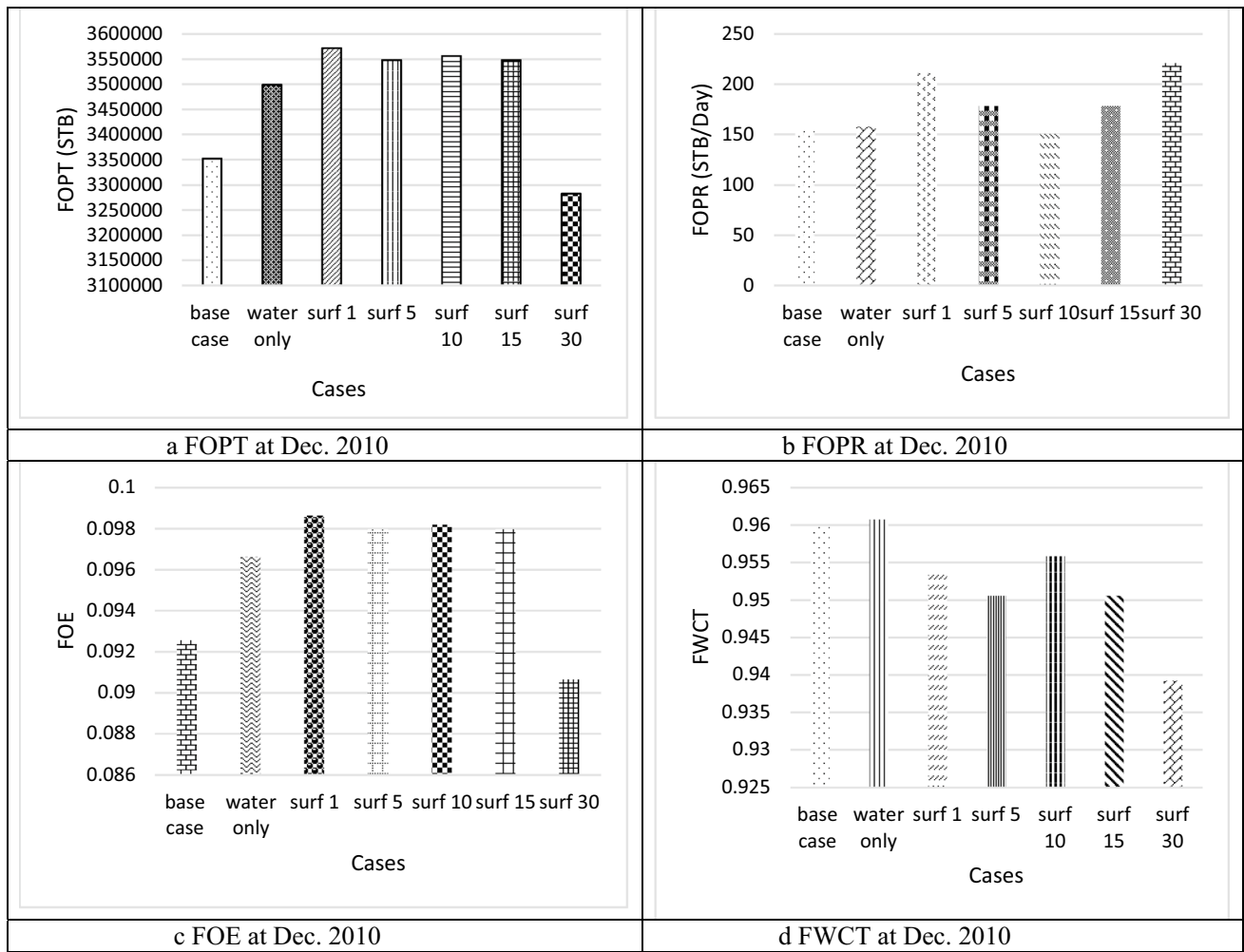
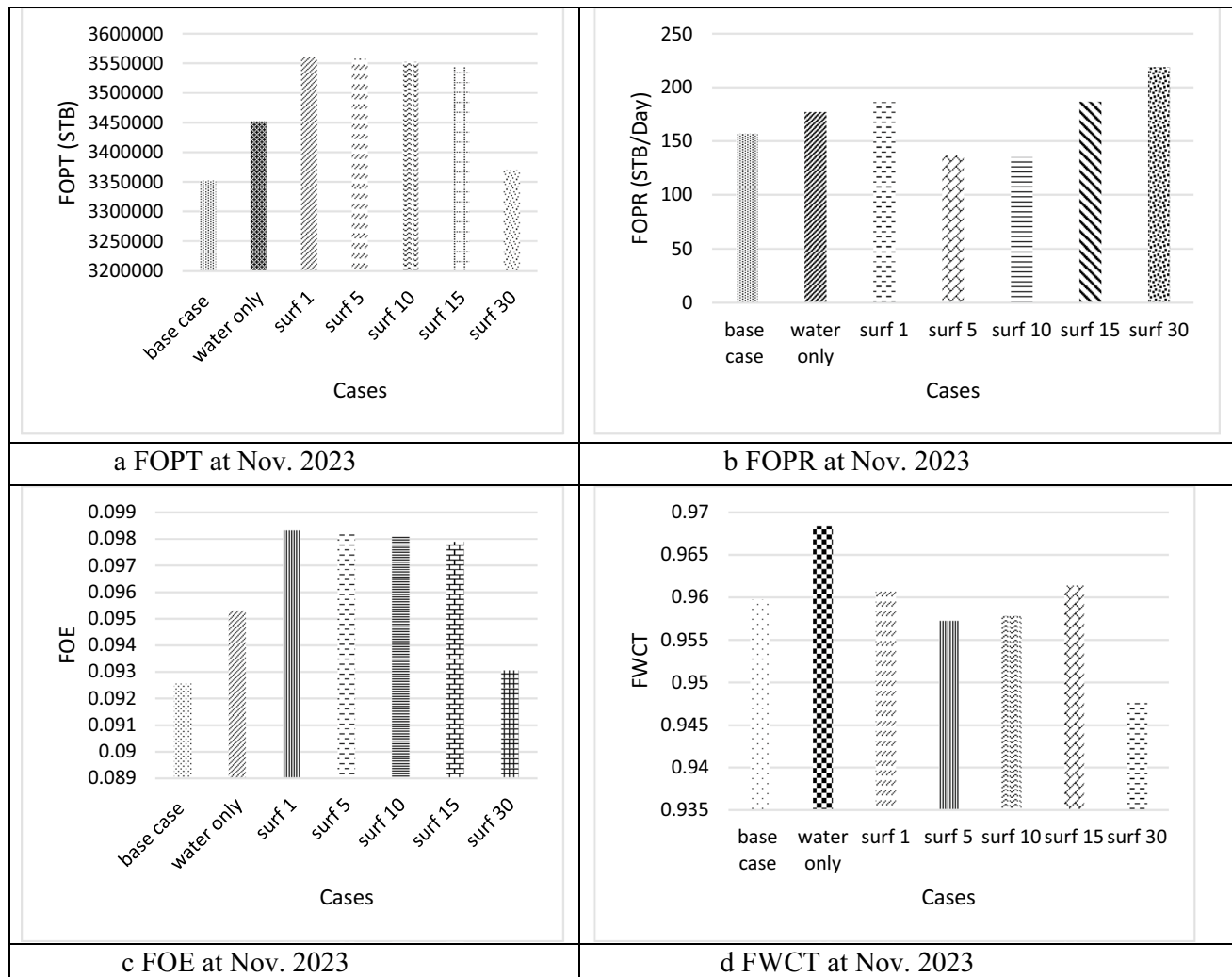


Fig. 9 a FOPT at December 2010; b FOPR at December 2010; c FOE at December 2010; d FWCT at December 2010

Table 5 Results summary for scenario 3

| Surfactant Conc                 | (FOE)       | (FOPT) (STB) | (FOPR) (STB/day) | (FWCT)     |
|---------------------------------|-------------|--------------|------------------|------------|
| <i>Results at November 2023</i> |             |              |                  |            |
| 0 (water only)                  | 0.095301099 | 3,451,587.8  | 177.06764        | 0.96842259 |
| 1                               | 0.09831766  | 3,560,780.3  | 188.8085         | 0.96123546 |
| 5                               | 0.098226346 | 3,557,526    | 136.8401         | 0.95724368 |
| 10                              | 0.098079242 | 3,552,244.8  | 134.84355        | 0.9578014  |
| 15                              | 0.097887054 | 3,545,377.3  | 186.62827        | 0.96139079 |
| 30                              | 0.093056202 | 3,369,926    | 218.87389        | 0.94760925 |



**Fig. 10** **a** FOPT at November 2023; **b** FOPR at November 2023; **c** FOE at November 2023; **d** FWCT at November 2023

## Conclusion and recommendation

Results show that surfactant injection either at onset or middle of production positively impacts oil recovery above water injection. For a reliable recovery, it is best to consider surfactant alternating injection at a concentration of 1% vol at the middle of production. Modifications can be made to the values of parameters used in the surfactant model based on laboratory data on different types of surfactant. If this is achieved, simulations can be carried out to determine the

best surfactants for different reservoir conditions and give more accurate recovery predictions from these reservoirs. To further study the applications of chemicals in EOR projects oil rim reservoirs, the use of polymers (bio and non-bio) as investigated by Olabode et al. (2020c) and Olabode et al. (2020d) can be applied to investigate its suitability in improving oil recovery in oil rims with medium or heavy crude.

There are no ethical issues or conflict of interests surrounding the development of this study. The data for this study will be made available on request.

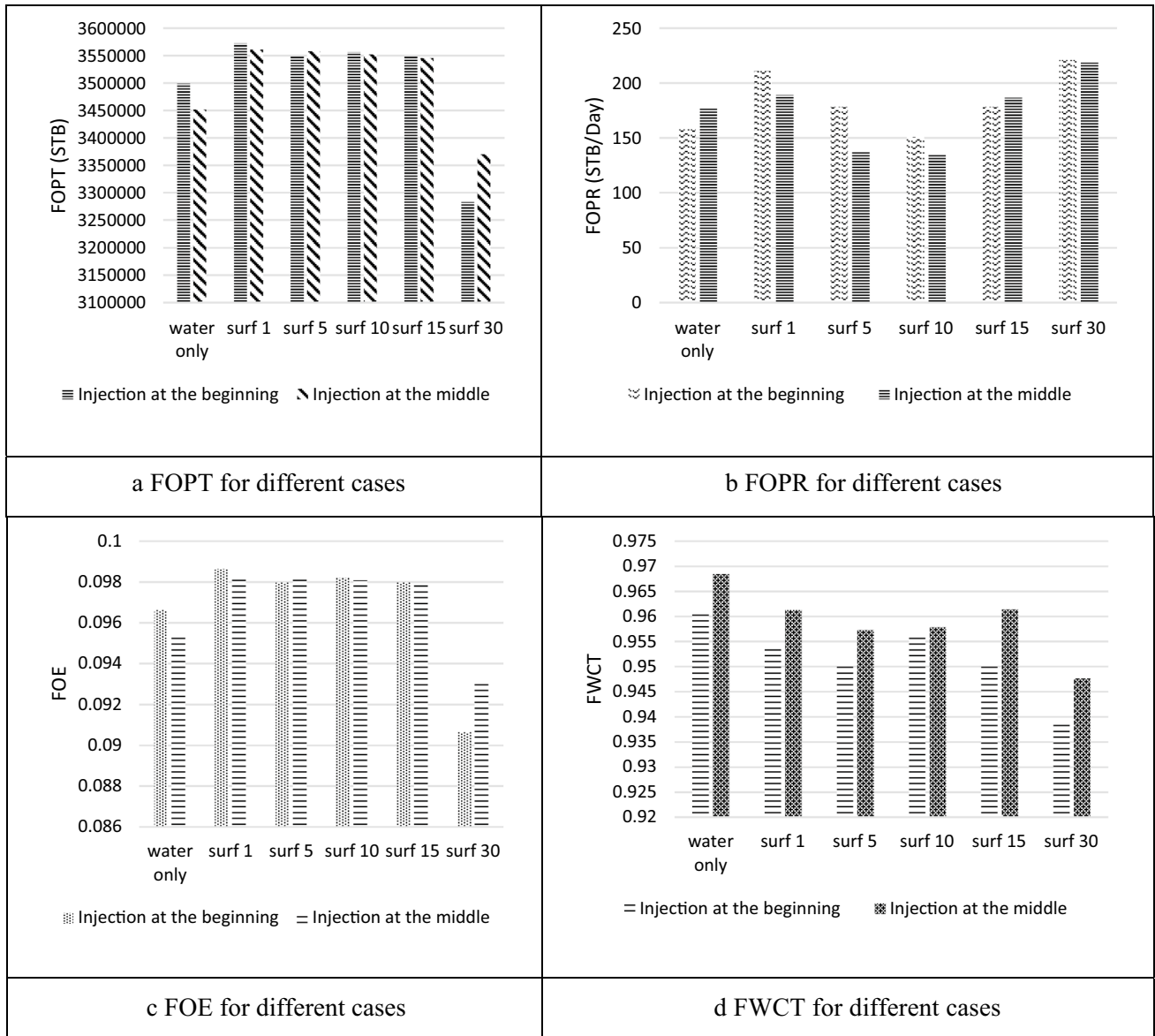


Fig. 11 a FOPT for different cases; b FOPR for different cases; c FOE for different cases; d FWCT for different cases

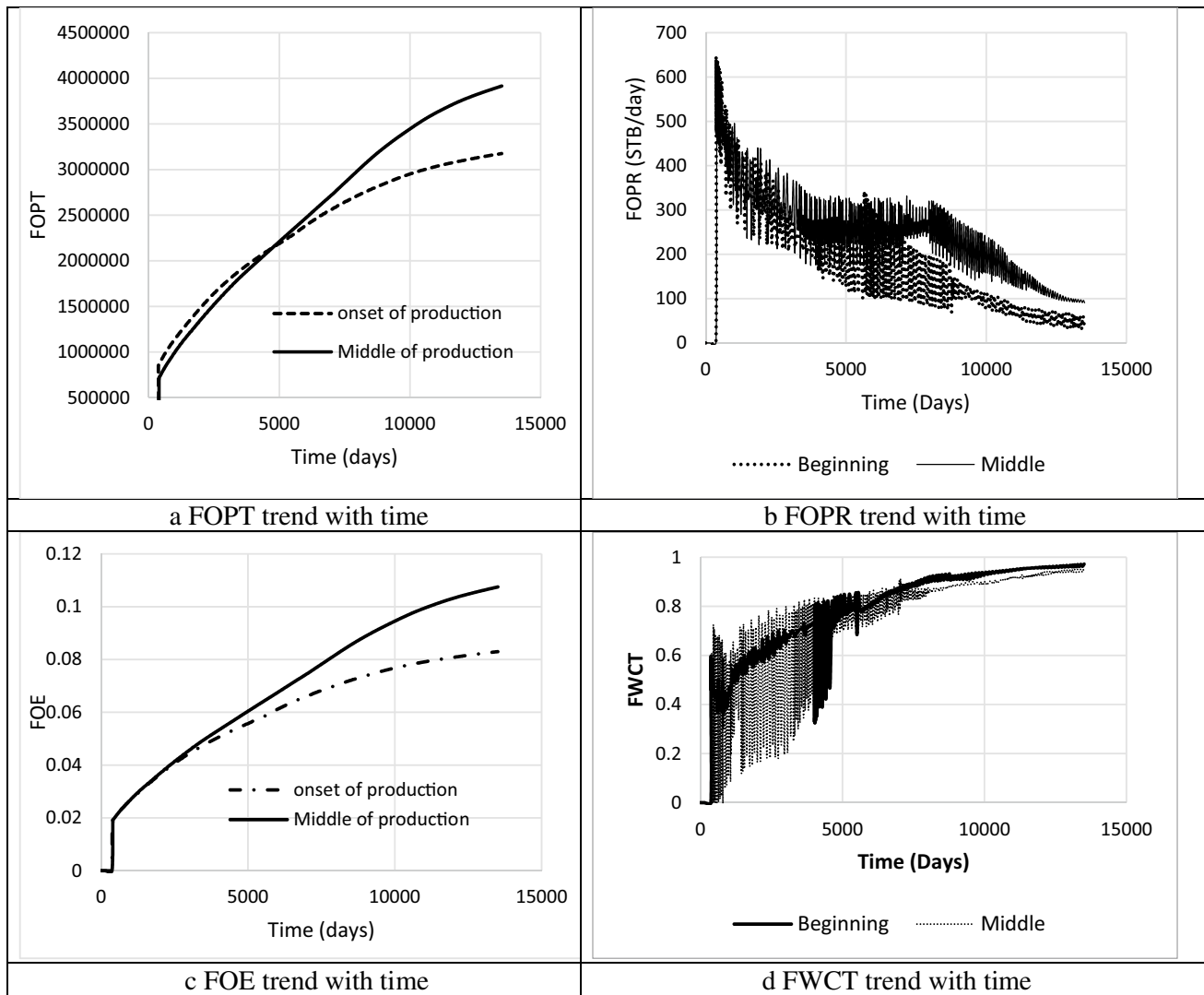


Fig. 12 a FOPT trend with time; b FOPR trend with time; c FOE trend with time; d FWCT trend with time

Table 6 Results summary for scenario 4

Results of SAG at November 2046

|                | Beginning of production (@ 2010) | Middle of production (@2023) |
|----------------|----------------------------------|------------------------------|
| FOPT (STB)     | 3,175,512                        | 3,915,821                    |
| FOPR (STB/day) | 26.80                            | 90.77                        |
| FOE            | 0.08296                          | 0.10749                      |
| FWCT           | 0.97                             | 0.94                         |

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