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CO_2 EOR Modeling and performance prediction in conventional oilfield

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Abstract

Despite the ongoing investment in renewable energy sources, hydrocarbons are still the major source of energy. Even if in the future the energy produced from renewable sources will experience a major increase from current trends, due to energy-intensive nature of the globalized world, those sources, most probably, will not be able to keep up with the increased demand. This leads to the conclusion that the world is going to partly rely on hydrocarbons as a source of energy, at least in the near future.

Up to 20% of oil can be extracted from a field under primary production. Another 20-30% of oil can be produced by application of secondary recovery techniques. This means that there is still at least 50% of the oil left in underground reservoirs. The oil volume that is left underground after primary and secondary recovery techniques is usually produced with the aid of EOR techniques. There are a range of EOR techniques developed and applied to oilfields around the globe with a variable success.

In this work, a comparative study will be presented, where potential performance benefits of CO_2 EOR injection will be evaluated. Being a miscible EOR technique, CO_2 injection is one of the most commercially successful tertiary recovery methods along with thermal methods. The study is based on a field-scale inverted 5-spot patterned model. Using a field-scale model, the CO_2 injection will be simulated for the last 20 years of oil field and performance gains will be compared to the conventional waterflooding process.

Introduction

Global energy demand and energy-related carbon emissions will continue to rise through 2050, with oil remaining the largest energy source just ahead of surging renewables (International Energy outlook, 2018). EIA expects global energy demand to increase 47% in the next 30 years, driven by population and economic growth, particularly in developing Asian countries. This will require an increased oil and natural gas production, significant technological breakthroughs, or policy changes. Average recovery factor from oil reservoirs is about a third (Ali, S et al., 1996). This means that considerable fraction of hydrocarbons is left underground. After application of secondary recovery techniques such as gas or water injection, still more than half of oil volume is present in the reservoirs. To address the global demand, inevitably, new ways of increasing recovery from oil fields need to be developed.

One set of such advanced techniques that has been developed since 1970s and have been applied with variable success to a range of oil fields across the globe are EOR techniques (Nwidee et al., 2016). The two most popular EOR methods are thermal (steam) and miscible gas injection, which are mature technologies (Muggeridge et al., 2014). CO_2 injection as a miscible gas injection technique is especially popular, since on top of aiding the increased recovery, CO_2 injection is also an effective way of reducing the greenhouse gas emissions (Jia et al., 2019). There are over 100 commercial CO_2-EOR projects, the bulk of them is concentrated in the west Texas carbonates of the Permian Basin in the US (Roussanaly et al., 2014). Their success has partially been due to the availability of low-cost natural CO_2 from nearby fields and reservoirs.

In this comparative study, the production gain from CO_2 EOR injection process will be compared to performance of a field that is produced under waterflood only. Modeling, predictions, and interpretations of results will be based on field-scale inverted 5-spot patterned model.

Reservoir modeling

The study is performed on a field-scale 5-spot patterned model that is built using CMG. The field map containing the contours of the top of the reservoir is used to define the grid (Fig. 1).

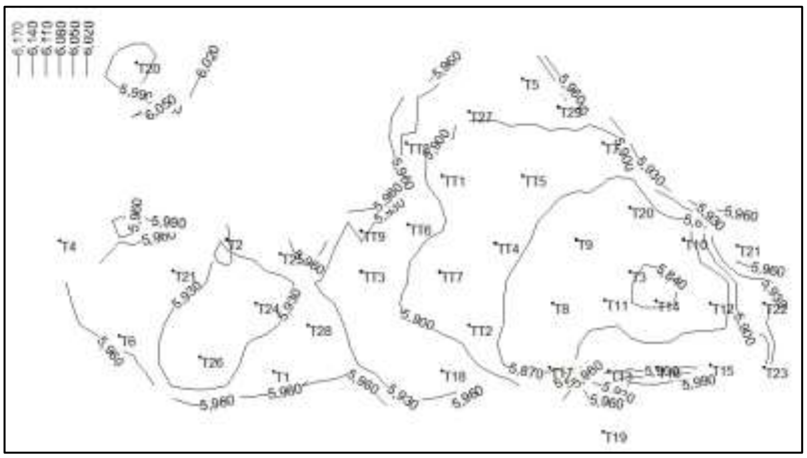

Figure 1. Field map

The reservoir model has been built on a sector of this field that includes wells TT1, TT4, TT6 and TT7 (Fig. 2).

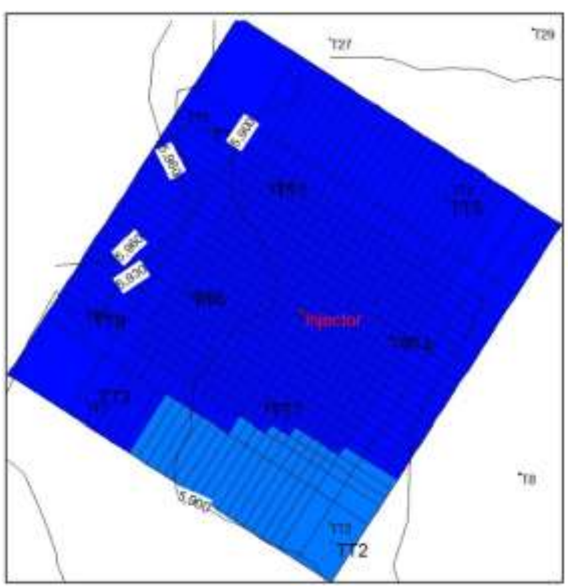

Figure 2. Sector model juxtaposed on a field map

The sector is discretized into 26x26x9 gridcells. The reservoir is defined by 4 distinct layers and each layer is modeled by 2 grid cells in z-direction. Once layer thicknesses, porosity and permeability values are defined based on well data, poroperm distribution is modeled using geostatistical algorithm.

The following rock-fluid properties are used in the model (Table 1 and Figure 3):

	Swcon	Swcrit	Krwiro	Soirw	Sorw	Krocw
Avg	0.06	0.185	0.23	0.28	0.3	0.35
2	0.05	0.2	0.24	0.29	0.33	0.35
3	0.05	0.2	0.23	0.28	0.32	0.35
4	0.06	0.185	0.23	0.29	0.29	0.4
5	0.03	0.155	0.24	0.3	0.36	0.35
	0.05	0.185	0.234	0.288	0.32	0.36

Table 1. Relative permeability model parameters

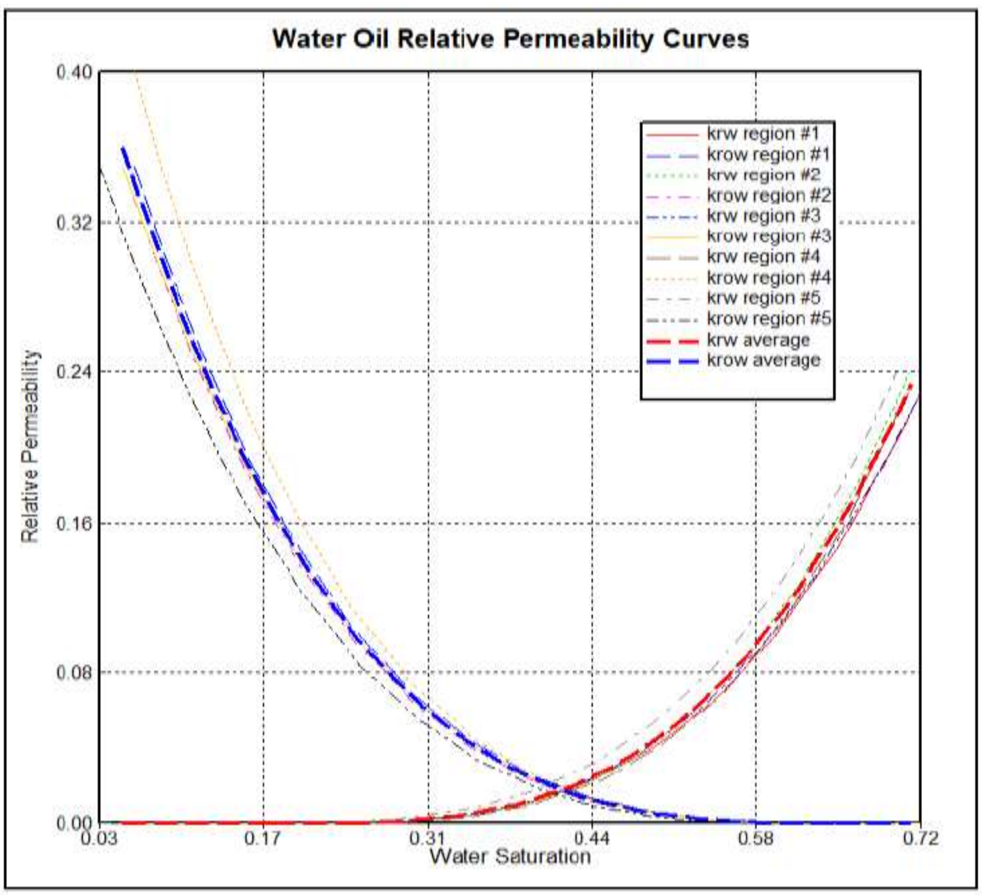

Figure 3. Water oil relative permeability curves

Initial conditions are the following:

- Reference pressure: 3500 psi
- Reference depth: 6000 ft
- Water-oil contact: 6000 ft

The model has 4 production and 1 injector wells. Producer wells are controlled using bottomhole pressure, whereas the injector is operated under rate constraint.

Historical data is from 1960 till 2000, simulation time is from 2000 to 2030. Waterflooding and CO_2 injection start date is 2000.

Results and Discussion

Case 1: Waterflood only

In this case, the field is produced based on primary production until 2000, after which waterflooding is initiated. The field production performance charts are summarized in the Figure 4.

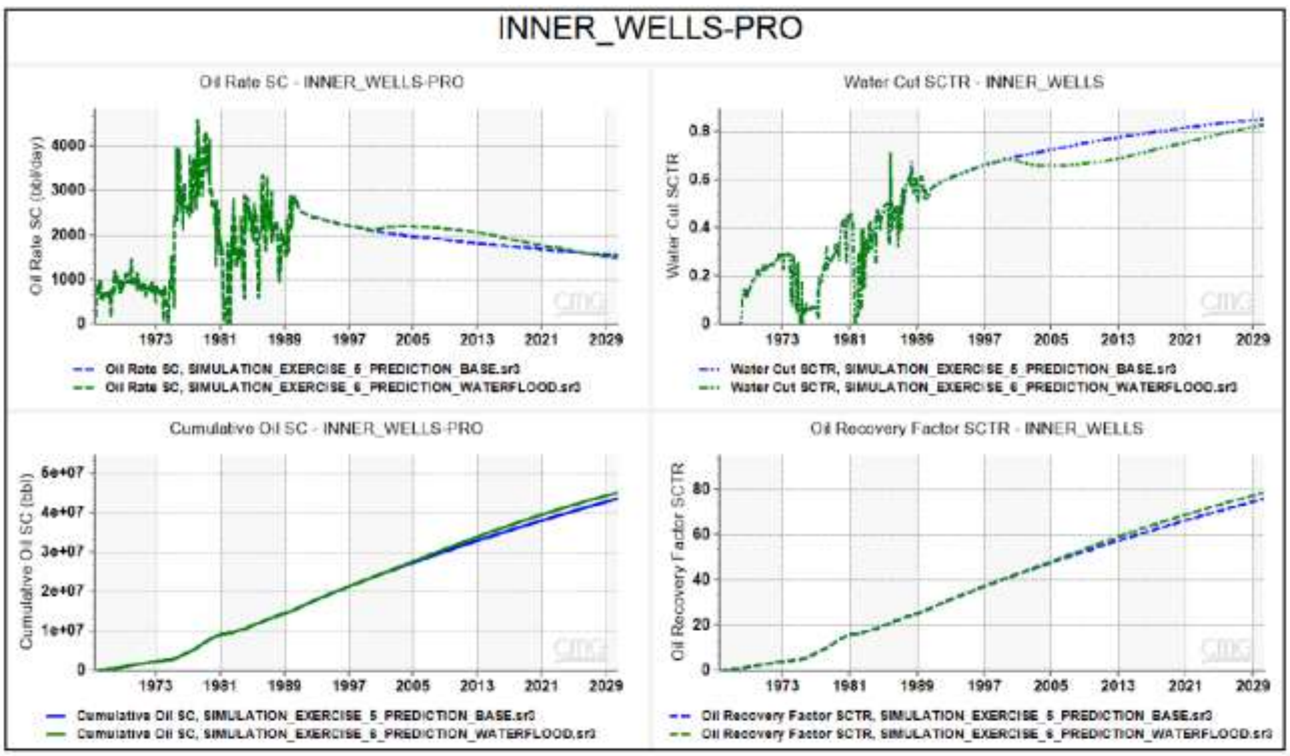

Figure 4. Oil rate, water cut, cumulative oil rate and oil recovery for case 1.

As it can be seen from plots, the application of waterflood (plots in green) results in higher oil rates and higher recovery, as expected. Also, it is interesting to note that although water is being injected, the water cut decreases. This is due to the additional pressure of the system not causing the production wells to cone the water up from the underlying aquifer at such a high rate.

Case 2. Waterflood and CO_2 injection.

In this case, the field is produced based on primary production until 2000, after which waterflooding and CO_2 injection have been applied simultaneously.

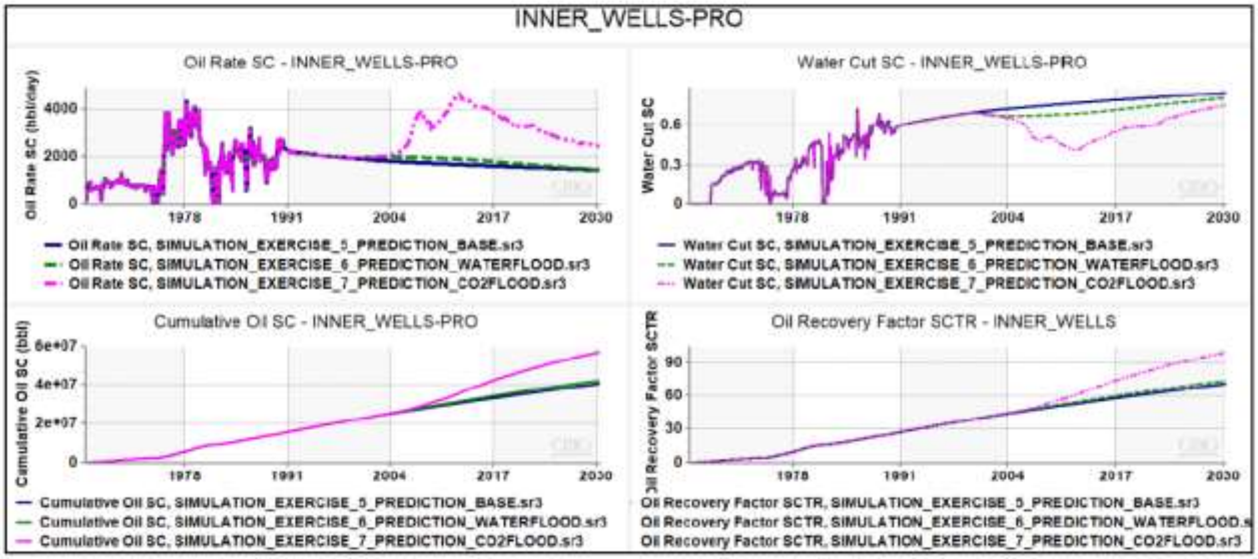

Figure 5. Oil rate, water cut, cumulative oil rate and oil recovery for case 2.

From Figure 5, it can be observed that the application of CO_2 injection (plots in pink) results in much higher oil rates and higher recovery, and lower water cut. CO_2 is miscible at reservoir conditions, and it is observed that oil recovery is significantly increased. Water injection still does not recover all the oil for two reasons. First, the reservoir rock is heterogeneous. The water may find a high permeability pathway from an injection well to a production well, leaving other regions that are not swept by the water. Second, in the small interstices between the rock grains, ganglia of oil surrounded by water are held in place by the water/oil surface tension and do not flow. The developed miscibility results in a miscible fluid that is capable of displacing all the oil which it contacts in the reservoir, and thus, results in low residual oil saturation and higher oil recovery.

Conclusion

In this study, a structured workflow for reservoir modeling, waterflooding and CO_2-EOR injection is presented. Performance differences between cases without any improved oil recovery methods, waterflooding only and waterflooding & CO_2-EOR injection processes have been demonstrated. Results show that both waterflooding and CO_2 injection can lead to an increased oil rate and cumulative recovery, while having lower water cut levels. Additionally, the potential gain from CO_2 injection is much higher compared to water flooding. To make this study even more comprehensive and insightful, economic analysis can further be conducted.

References

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