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Original scientific paper

EVALUATION OF IMMISCIBLE CO2 INJECTION IN HIGH WATER PRODUCTION RESERVOIR IN THE PANNONIAN BASIN

Ivan Al-Jeboore[1], **Danica Milićević**[1], **Bojan Martinović**[1], **Milica Ješić**[1]

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Abstract: Carbon dioxide (CO_2) flooding is one of the most important and most used enhanced oil recovery (EOR) method because it does not only increase oil recovery efficiency but also is used as an underground CO_2 storage. It is considered a very complex method as it involves knowing the fluid phase behavior with different CO_2 concentrations. It should be noted that oil swelling (volume increase) with the dissolution of carbon dioxide has a significant effect on increase of oil recovery. When this occurs, a significant decrease in the viscosity of the oil is observed. In this study, a reservoir 3D simulation modeling approach was applied to evaluate immiscible and miscible CO_2 flooding in a high WC reservoir. To reduce simulation time, the PVT composition was grouped into 5 fluid components. The 3-parameter, Peng–Robinson Equation of State (EOS) was used to match PVT experimental data by using the Schlumberger's ECLIPSE PVTi software. One-dimensional slim-tube model was defined using ECLIPSE 300 software to determine the minimum miscibility pressure (MMP) for injection of CO_2. Beside this approach, an analytical MMP estimation was carried out using several correlations. Schlumberger Petrel software was used to set up a 3D simulation model of a static and dynamic model. Various scenarios of immiscible and CO_2 injection have been simulated using ECLIPSE 300 software and these results have been compared.

Keywords: CO_2, Enhance Oil Recovery, Miscible fluids

1 INTRODUCTION

The use of carbon dioxide flooding to increase oil recovery started in 1950 and has been very successful. This success is firmly based on many laboratory studies, field trials and application experiences. Carbon dioxide is highly soluble in oil and soluble, to a lesser extent, in water. At the same time uses the following properties are known which enable carbon dioxide use in enhanced oil recovery when carbon dioxide mixes with the reservoir liquids:

- decrease in viscosity of crude oil and increase in viscosity of water.

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[1] NTC NIS Naftagas doo, Narodnog fronta 12, 21000 Novi Sad
E-mails: ivan.al-jeboore@nis.rs; danica.milicevic@nis.rs; bojan.martinovic@nis.rs; milica.jesic@nis.rs

- oil swelling and oil density reduction.
- multiple contact miscibility with hydrocarbons.
- acidic type interaction with the formation carbonates and clays.

As CO_2 is much more soluble in water than hydrocarbon gases, it increases the water viscosity which leads to better sweep efficiency. Also, when carbon dioxide is dissolved in water some carbonic acid is formed. The acid etches carbonates and clays. This etching opens and widens throats between formation grains and the permeability of carbonate rocks increases by 675%, and sandstone rocks by 515%. The acidic environment also reduces swelling of clays. These have a significant effect on increasing reservoir permeability.

Carbon dioxide could displace oil by either miscible or immiscible displacement. For pressures below MMP, immiscible displacement of oil takes place, in which oil viscosity reduction, swelling of reservoir oil, reduction of interfacial tension, and solution gas drive are major driving mechanisms. This combination of mechanism enables a portion of the reservoir's remaining oil to be mobilized and produced. At pressures above MMP, the most dominant mechanism is miscibility between CO_2 and the reservoir oil. Miscible displacement by CO_2 is a much-preferred process to immiscible displacement. The miscible process is best applicable to light and medium gravity crude oils, and the immiscible process may apply to heavy oils (ECLIPSE, 2014). In this study our main aim is to try to achieve a first contact miscibility to approach a zero interfacial tension and eventually increase a capillary number to infinity (Eq 1) as it is presented in Figure 1.

$$N_c = \frac{v_{CO2} \cdot \mu_{CO2}}{\phi \cdot \sigma_{CO2-Oil} \cdot cos\theta} \qquad \text{(Eq. 1)}$$

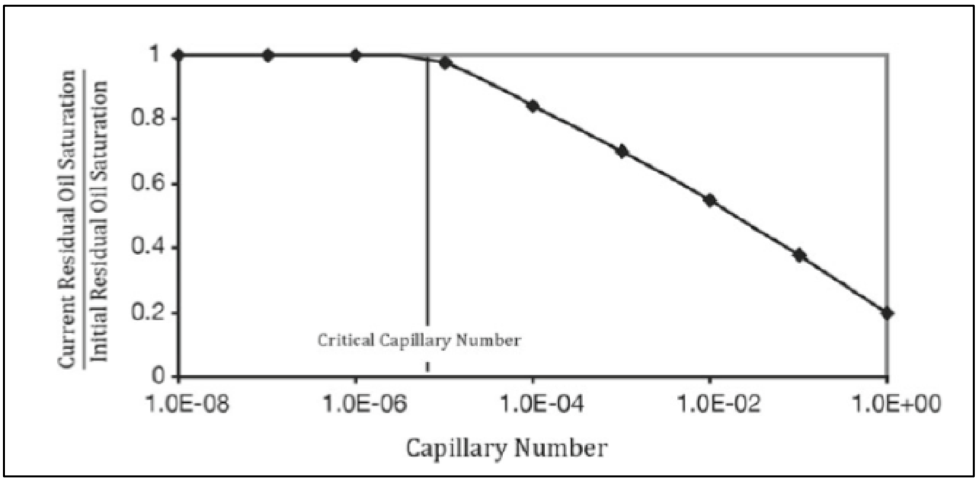


Figure 1 *Capillary number behavior (Lake L., 1989)*

On the other hand, CO_2 injection can have some disadvantages compared to other injection processes. One of the main problems in achieving profitable CO_2 flooding has been the high mobility of the CO_2. The relatively low density and viscosity of CO_2 compared to reservoir oil are responsible for gravity tonguing and viscous fingering. This behavior was observed on several sandstone oilfields where CO_2 projects have been ongoing for almost 4 years. The main conclusion from these projects is that CO_2 fingering in Pannonian sandstone reservoirs is very hard to control due to different relative permeabilities which leads to poor sweep efficiency. This problem can be solved by introducing a WAG injection where water is responsible for controlling the CO_2 saturation front.

2 PRODUCTION HISTORY

XX reservoir started production in 1968. The first stage of production was relatively fast, where 8 wells were drilled in the first year of production which led to a stable oil production rate with a very uniform WC increase in wells. In 2005, a significant production intensification was made which led to noticeable increases in water production. Introducing new production wells, this trend has continued and rapidly increase from 1500 m^3/month to 2000 m^3/month of oil (Figure 2).

Even though several actions were taken to reduce the amount of water production to some previous levels (after intensification), it was not achieved. Pressure data suggests that the reservoir is under a heavy waterdrive mechanism, which is later confirmed by a material balance calculation. This means that to achieve a first contact miscibility, we need to inject less amount of CO_2 in comparison with no aquifer mechanism. As this reservoir is among the best reservoirs with the highest values of permeabilities (core data in some wells have permeability more than 1000mD), the voidage replacement ration is almost 1. Considering all previously mentioned facts, this reservoir was considered among the first priorities for EOR study.

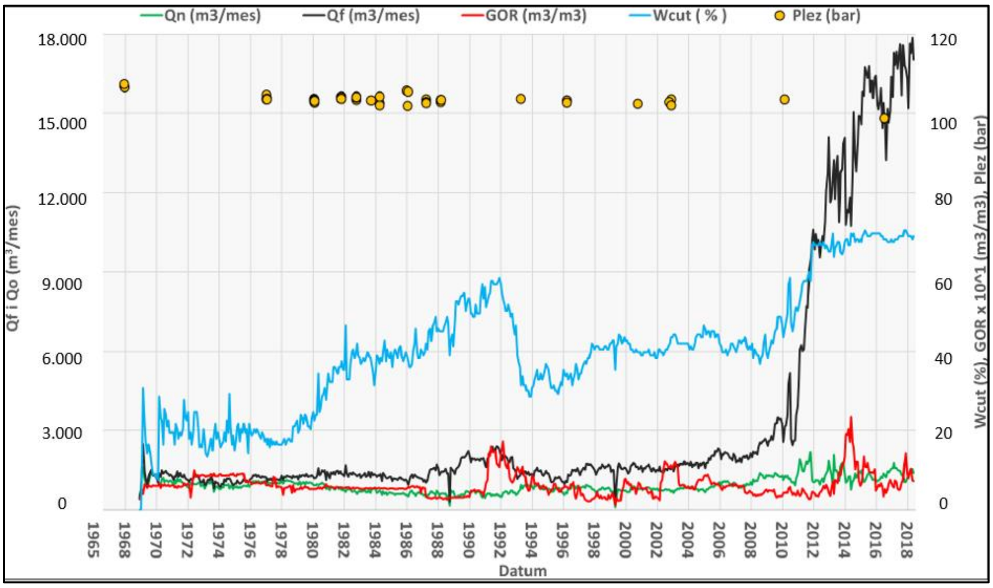


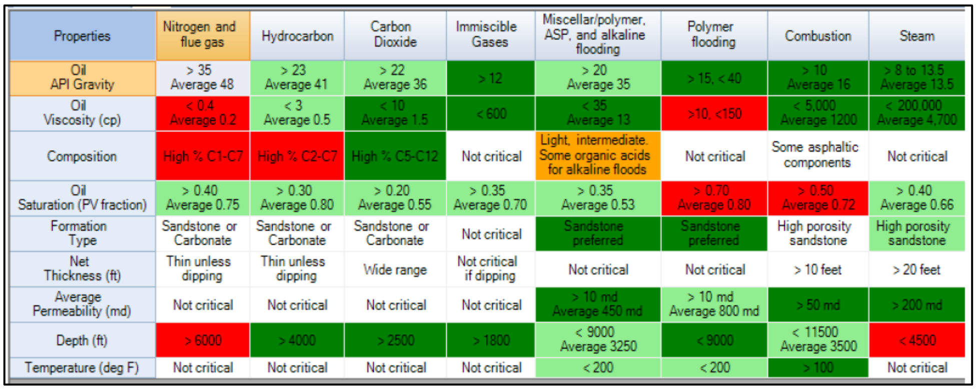
Figure 2 Reservoir and production history

3 SCREENING CRITERIA

The initial step before any Enhanced Oil Recovery method to a field (or more commonly to the specific reservoir or even oil containing strata) is to decide which oil production enhancement method or methods are most appropriate. This is done based on reservoir and oil properties analysis so named screening step. Screening studies are designed to assess the feasibility of using the enhanced oil recovery method based on a limited number of reservoir and fluid properties. Those properties are mostly regarded as critical. Screening is a comparison of the averaged characteristics of the reservoir with tabulated criteria of various methods applicability. The set of tabulated criteria is made based on the joint international oil industry experience. Taking into account reservoir and fluid description presented in Figure 3, a screening criteria was done as illustrated in Figure 3 and Figure 4. The screening criteria mentioned here are meant to be used as a first order of screening, and more detailed studies must be undertaken before a decision to implement new CO_2 flood projects. Reservoir screening criteria inputs are presented in Table 1.

Table 1 Reservoir properties for EOR screening

Initial reservoir pressure (bar)	148.3
Reservoir temperature (ºC)	81
Oil viscosity (cP)	1.39
Formation type	Sandstone
Average permeability (mD)	1000
Oil density at standard conditions (kg/m^3)	855



Properties	Nitrogen and flue gas	Hydrocarbon	Carbon Dioxide	Immiscible Gases	Miscellar/polymer, ASP, and alkaline flooding	Polymer flooding	Combustion	Steam
Oil API Gravity	> 35 Average 48	> 23 Average 41	> 22 Average 36	> 12	> 20 Average 35	> 15, < 40	> 10 Average 16	> 8 to 13.5 Average 13.5
Oil Viscosity (cp)	< 0.4 Average 0.2	< 3 Average 0.5	< 10 Average 1.5	< 600	< 35 Average 13	>10, <150	< 5,000 Average 1200	< 200,000 Average 4,700
Composition	High % C1-C7	High % C2-C7	High % C5-C12	Not critical	Light, intermediate. Some organic acids for alkaline floods	Not critical	Some asphaltic components	Not critical
Oil Saturation (PV fraction)	> 0.40 Average 0.75	> 0.30 Average 0.80	> 0.20 Average 0.55	> 0.35 Average 0.70	> 0.35 Average 0.53	> 0.70 Average 0.80	> 0.50 Average 0.72	> 0.40 Average 0.66
Formation Type	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate	Not critical	Sandstone preferred	Sandstone preferred	High porosity sandstone	High porosity sandstone
Net Thickness (ft)	Thin unless dipping	Thin unless dipping	Wide range	Not critical if dipping	Not critical	Not critical	> 10 feet	> 20 feet
Average Permeability (md)	Not critical	Not critical	Not critical	Not critical	> 10 md Average 450 md	> 10 md Average 800 md	> 50 md	> 200 md
Depth (ft)	> 6000	> 4000	> 2500	> 1800	< 9000 Average 3250	< 9000	< 11500 Average 3500	< 4500
Temperature (deg F)	Not critical	Not critical	Not critical	Not critical	< 200	< 200	> 100	Not critical

Figure 3 Results of screening criteria for XX reservoir

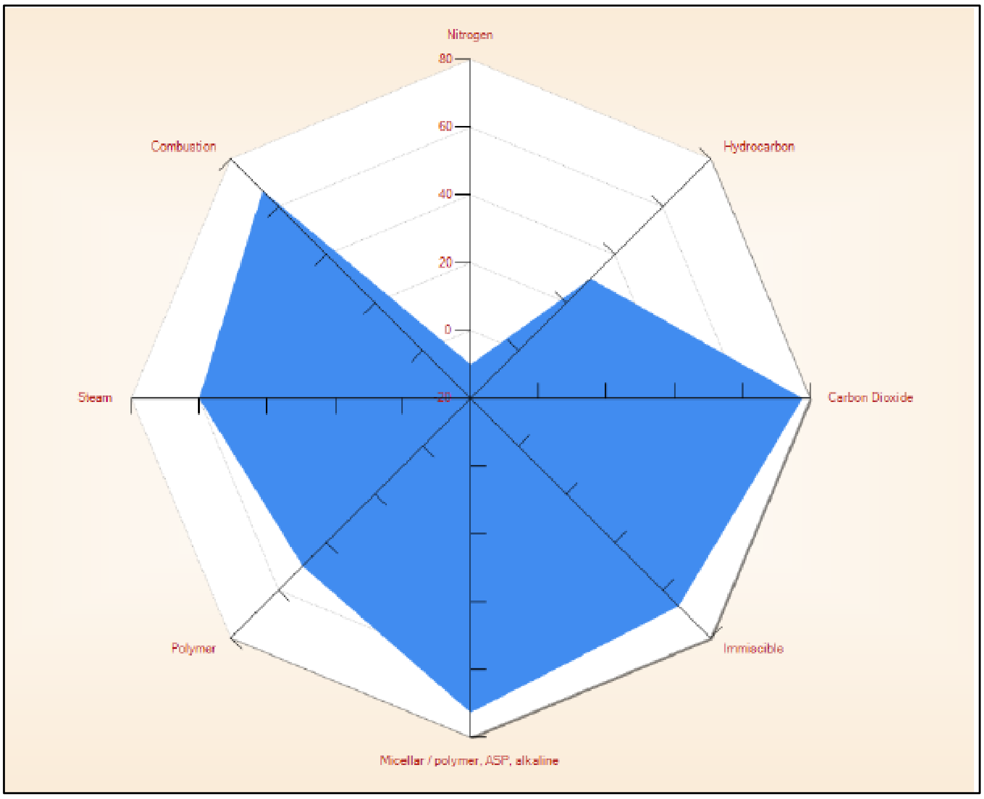


Figure 4 Spider plot of screening result for XX reservoir

Reservoirs suitable for EOR by implementing CO_2 floods have various degrees of suitability depending on the intrinsic reservoir and oil properties. The range of reservoir characteristics and fluid properties suitable for CO_2 miscible injection is quite broad, and ideal reservoirs should have:

- Oil density <900 kg/m3
- Oil saturation > 25%
- Reservoir pressure > 0.9 MMP
- Porosity >15%
- Permeability > 1mD
- Moderate Heterogeneity

All these parameters were analyzed in detail and presented in the next sections.

4 PVT DATA AND FLUID CHARACTERIZATION USING EQUATION OF STATE

Reservoir fluid and injection gas behavior under different pressures and injection concentrations are essential for accurate project performance prediction. Complex reservoir fluids behavior is understood based on laboratory experimental data and thermodynamic modeling. All this undertaking allows to predict fluid behavior in the feasible range of Pressure, Volume and Temperature and to see at which PVT conditions the fluid will be a single phase or will separate into multiple components. This is especially important as simulation flowing equation, or Darcy's flow rate equation, are only applicable to the single-phase flow. Multiphase flow is described by much more complex equations than Darcy's one.

Several PVT analyses were conducted in XX reservoir during the early period of production. The analysis covered the main PVT experiments.

- Constant composition expansion
- Differential liberation
- Viscosity test

Based on available information regarding PVT data and sampling pressures, two samples were neglected as they were not representative. It was decided to proceed with PVT laboratory data from well XX-9 as they are the most accurate. Laboratory PVT data are presented in Table 2, Table 3 and Table 4.

Table 2 CCE experiment - sample from well XX-9

Step	Pressure (at)	Pressure (bar)	ΔV (cm^3)	ΔV *100/Vo (%)	Relative volume
1	300	305.0	0	0	0.9851
2	275	279.7	0.15	0.2034	0.9871
3	250	254.3	0.31	0.4203	0.9892
4	225	229.0	0.485	0.6576	0.9916
5	200	203.7	0.666	0.903	0.994
6	175	178.3	0.865	1.1729	0.9966
7	150	153.0	1.066	1.4454	0.9993
8	145	147.9	1.116	1.5132	1.0000
9	143	145.9	1.396	1.8929	1.0037
10	142	144.9	1.915	2.5966	1.0107
11	137	139.8	2.392	3.2434	1.017

Table 3 Differential liberation experiment - sample from well XX-9

Step	Pressure (at)	Pressure (bar)	Rs (m^3/m^3)	Bo (rm^3/sm^3)	Oil density (kg/m^3)	Oil viscosity (cP)
15	300	303.98	52.92	1.1518	780.0	1.65
14	275	278.64	52.92	1.1543	778.3	1.60
13	250	253.31	52.92	1.1571	776.5	1.55
12	225	227.98	52.92	1.1599	774.5	1.50
11	200	202.65	52.92	1.1631	772.5	1.45
10	175	177.32	52.92	1.1664	770.2	1.40
9	150	151.99	52.92	1.1697	768.0	1.34
8	145	146.92	52.99	1.1704	767.6	1.39
7	125	126.66	45.54	1.1535	774.0	1.45
6	100	101.33	37.11	1.1356	780.6	1.69
5	75	75.99	27.69	1.1149	788.6	1.80
4	50	50.66	18.38	1.0949	796.7	2.05
3	25	25.33	9.39	1.0761	804.2	2.33
2	0	0.00	0.00	1.0531	814.2	2.62

Since this reservoir started to produce in 1969, no equipment was available at the time for determining the fluid composition. As liquid phase (oil) composition was not determined by chromatography, a simplified approach was applied to obtain a representative monophasic sample for EOS tuning. Using the only available gas composition it was assumed that the liquid composition is strictly 100% C7 fraction. The calculation of the reservoir fluid sample was done by recombination method using available GOR at separator conditions and reservoir oil density according to the equations 2 and 3.

$$z_i = \frac{2130 \cdot \rho_o \cdot x_i + M_o \cdot GOR \cdot y_i}{2130 \cdot \rho_o + M_o \cdot GOR} \qquad \text{(Eq. 2)}$$

Where:

- M_o – molecular weight of the separator liquid sample
- ρ_o – density of separator liquid sample at separator pressure and
- temperature, lb/ft^3
- GOR – recombined gas-oil ratio, scf/bbl
- x_i – mole fraction of component i in the separator liquid phase sample
- y_i – mole fraction of component i in the separator gas phase sample

Reservoir oil molar weight was calculated using oil density at separator conditions according to the following expression:

$$M_o = 0.048923 \cdot e^{(9.88378 \cdot \gamma)} - 33.085468 \cdot \gamma + \frac{39.598437}{\gamma} \qquad \text{(Eq. 3)}$$

The calculated reservoir composition is presented in Table 4.

Table 4 Recombined fluid composition.

Component	Gas composition (%)	Oil composition (%)	Reservoir fluid (%)
N2	2.69	0	1.0358
CO2	1.05	0	0.4043
C1	88.15	0	33.942
C2	2.16	0	0.83171
C3	1.53	0	0.58913
IC4	0.87	0	0.33499
NC4	1.12	0	0.43126
IC5	0.66	0	0.25413
NC5	0.7	0	0.26954
C6+	1.07	100	61.907

In this study, Schlumberger software PVTi was used for characterization of the reservoir oil sample. Insufficient description of heavier hydrocarbons reduces the accuracy of PVT predictions. Therefore, it is necessary to split the plus components into two or three pseudo components, specifically when there are many of them compared to the other components. As shown in Table 4, 61.907% of fluid is C6+.The C6+ component was split into three pseudo components by Whitson's method as shown in Table 5. Critical properties Tc and Pc as well as acentric factor ω for the new pseudo components, were defined by Lee–Kesler correlation.

Table 5 Fluid composition after splitting and grouping

Reservoir Fluid	Gas	Oil	Reservoir Fluid	Splitting	Group	P.Comp
CO2	2.69	0	0.40	CO_2	1	CO_2
N2	1.05	0	1.04	N2	2	C1-N2
C1	88.15	0	33.94	C1	2	
C2	2.16	0	0.83	C2	3	C2-C3
C3	1.53	0	0.59	C3	3	
IC4	0.87	0	0.33	IC4	4	C4-C5
NC4	1.12	0	0.43	NC4	4	
IC5	0.66	0	0.25	IC5	4	
NC5	0.7	0	0.27	NC5	4	
C6+	1.07	100	61.91	FR1	5	C6+
				FR2	5	
				FR3	5	

The main reason for grouping components is to speed-up the compositional simulation. In a compositional simulation the number of grouped components depends on the process that is modeled. For miscibility, more than 10 components may sometimes be needed. In general, 4–10 components should be enough to describe the phase behavior (ECLIPSE, 2014). The main issue for grouping is to collect components with similar molecular weights. For example, group C7 with C8 rather than with C2. As one would expect, the properties of C7 and C8 are similar, while the properties of C7 and C2 are very) different. Obvious candidates are to group iC4 with nC4 and to group iC5 with nC5. An exception to this rule is that N2 is added to C1, and CO_2 is usually added to C2. As the purpose of this study is to evaluate CO_2 injection potential, CO_2 must be single component in order to be pre-defined in ECLIPSE 300 using the keyword *STREAM*. The last stage was to fit an EOS to have an agreement between the observed data and the results calculated with the EOS. The 3-parameter, Peng–Robinson Equation of State (EOS) was used in this paper. Peng–Robinson, a cubic EOS that was developed by Peng and Robinson in 1976 (Ding-Yu et al., 1976), has been shown to accurately model hydrocarbons and is the most widely used EOS in compositional reservoir simulators (Søreide & Whitson, 1992). Tuning results are presented in Figure 5.

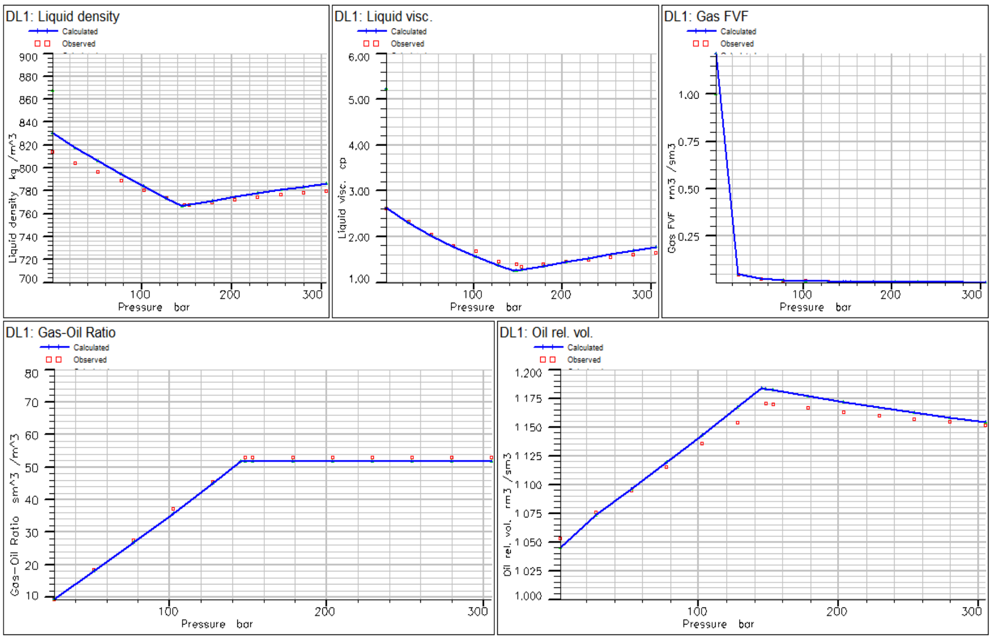


Figure 5 PVT experiment matching results

5 DETERMINING THE MINIMUM MISCIBILITY PRESSURE (MMP)

The minimum miscibility pressure (MMP) is the pressure corresponding to the transition point to the maximum achievable recovery (Figure 6).

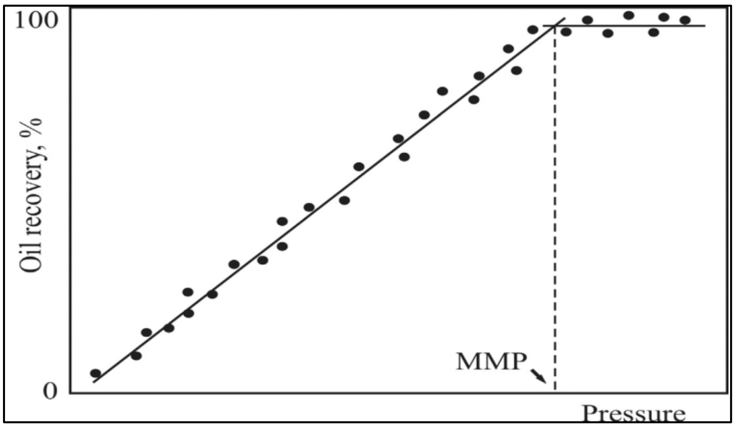


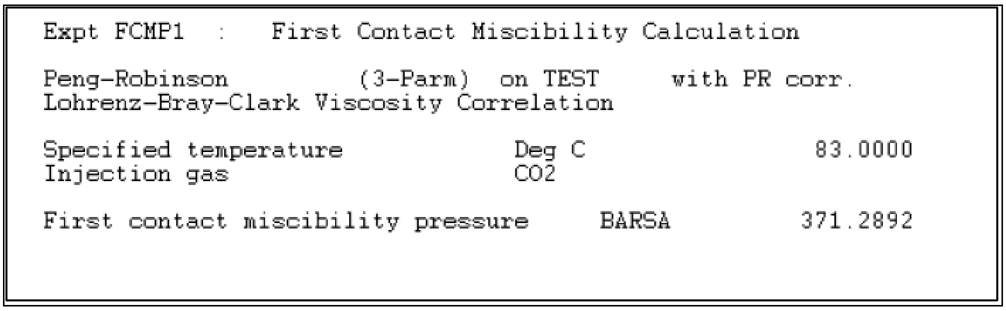
Figure 6 Minimal miscible pressure determination

The pressure of complete miscibility of carbon dioxide and the oil is determined experimentally. There are few methods to do it, but the most common are: gravitational-stable and slim tube tests. As there was not any slim tube experiment, MMP was calculated empirically using available correlation, one dimensional model to simulate a slim tube experiment, and already matched PVT model using 3 parameter PR EOS. Empirical correlations showed that based on our C5+ concentration the MMP is in range of 153 – 260 bar (Table 5). In Table 6 MMP calculations using empirical correlation is presented.

Table 6 MMP calculation using empirical correlation

Author	Calculated MMP (bar)
Cronquist (Cronquist C., 1978)	215.68
Lee (Lee I., 1979)	181.62
Yelling-Metcalfe (Yelling W. et al., 1980)	153.02
Orr-Jensen (Orr F. et al., 1987)	145.49
Glaso (Glaso O., 1985)	170.64
Alston (Alston R.et al., 1985)	260.91
Emera-Sarma (Emera M. et al., 2006)	240.9
Shokir (Shokir E., 2007)	207.84
Chen (Chen B. et al., 2013)	241.09

The matched PVT model gave much higher values comparing to empirical correlation presented above (Figure 7).



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Expt FCMP1  :   First Contact Miscibility Calculation

Peng-Robinson         (3-Parm)  on TEST     with PR corr.
Lohrenz-Bray-Clark Viscosity Correlation

Specified temperature            Deg C               83.0000
Injection gas                    CO2

First contact miscibility pressure     BARSA         371.2892
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Figure 7 MMP estimation based of PR EOS

One-dimensional compositional simulation of the slim-tube model was performed to determine the minimum miscibility pressure (MMP) of CO_2 with the reservoir fluid. The ECLIPSE 300 was used. As it can be seen from the Figure 8, the MMP is estimated to be 100bar which is significantly lower than MMP obtained by EOS and empirical correlations. Due to huge differences in MMP values, this study was done using the already matched PVT model as it is most reliable, where MMP is estimated to be 371.29 bar. Even though the reservoir pressure drop from initial values was very small, it is still much below the MMP value that was calculated. On the other hand, the fracture pressure was estimated using hydraulic fracture pressure data from already fractured wells in the nearby fields and that value is estimated to be 210 bar. That suggests that it is not possible to achieve first contact miscibility (FCM) in the reservoir as the bottom hole pressure must be set below that value.

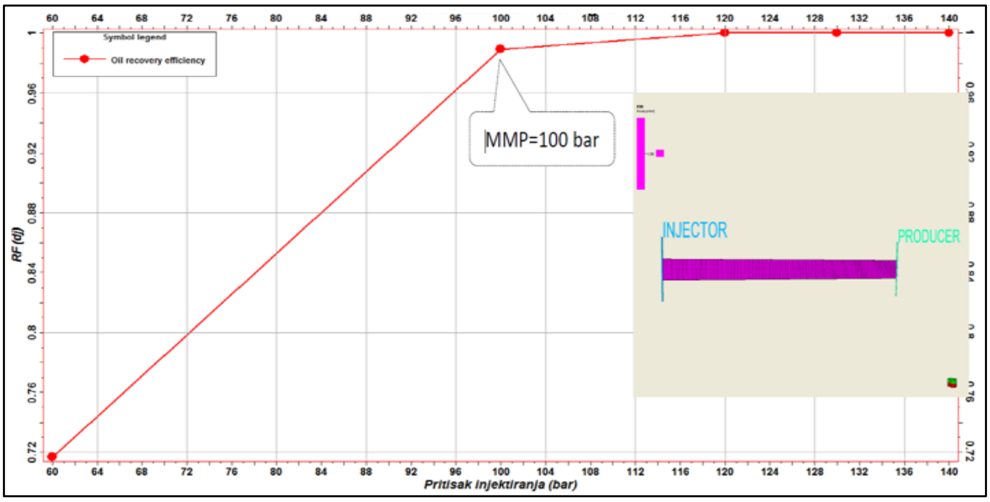

Figure 8 MMP estimation based on one dimensional model

6 MODEL ADAPTATION AND PREDICTION ANALYSIS

Before starting any prediction analysis, it is required to history match the reservoir production and pressure to obtain current fluid saturations and pressure. This process was done using all available information gathered from the beginning of production. The history matching process was carried out using ECLPISE 300 compositional simulator with adapted PVT data. A relatively good match was achieved by using assisted history matching tool with changing fluid relative permeabilities end points. Matching results are presented in Figure 9.

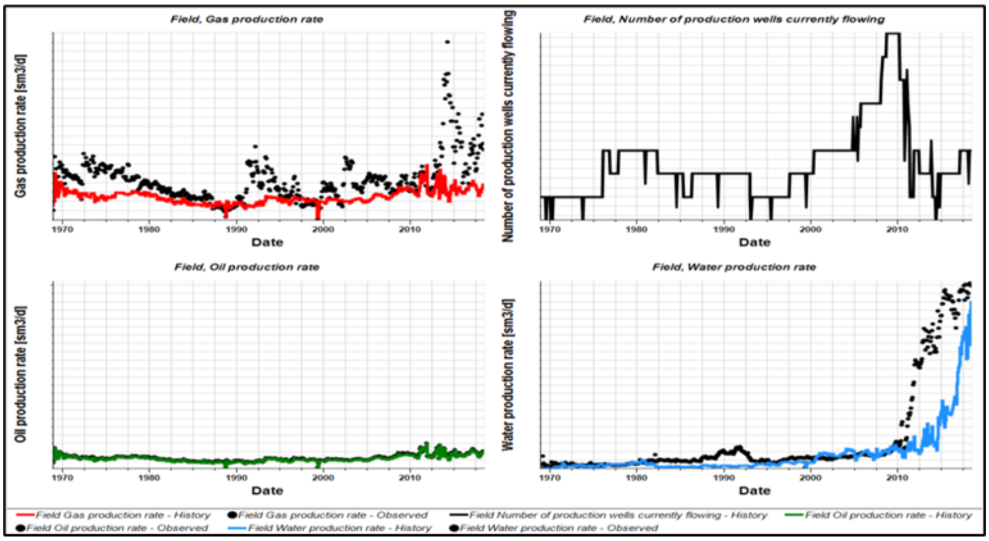

Figure 9 History match results for reservoir XX

It must be noted that the water production mismatch in the late period of production is directly related to the inaccurate fluid measurement during commingled production which was carried out on several wells on that field. The oil production rate and oil production cumulative were matched with error of ±5%. The remaining oil saturation based on history matching results is concentrated in the central part of the reservoir as it can be seen from Figure 10.

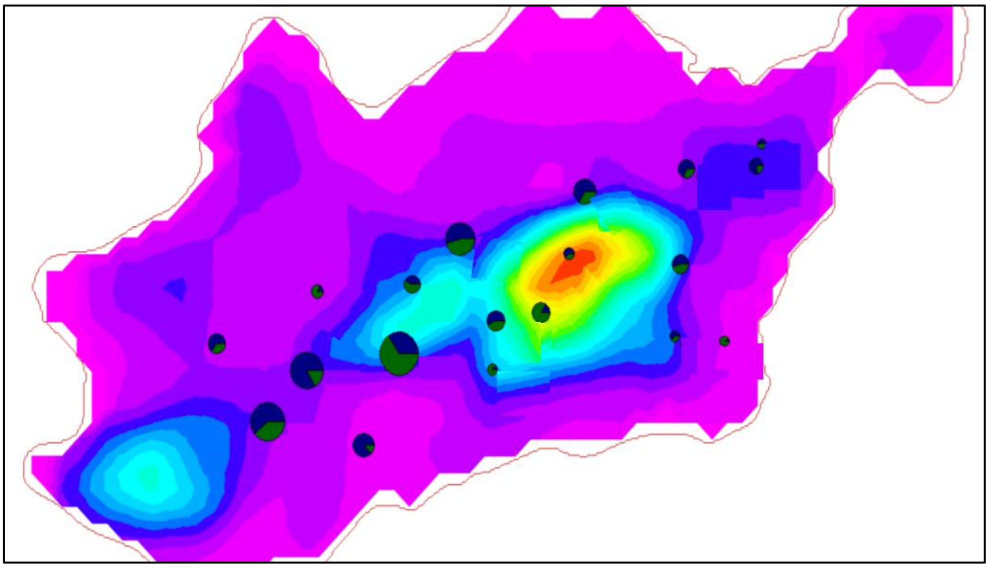

Figure 10 Remaining oil saturation at the end of HM

After the history matching process, the model is set for prediction of different scenarios. Several injection scenarios were analyzed which take into consideration the amount of injected CO_2 gas.

As hydrocarbon components exist in the oil and gas phases they are not allowed to dissolve in the aqueous phase. Usually, this assumption is adequate since the hydrocarbon solubility in water is low over the range of temperature and pressure for gas injection. CO_2, however, is an exception to this assumption. The solubility of CO_2 in water is much higher than that of hydrocarbon components and is a factor that cannot be neglected in the simulation process. To model a process where CO_2 is soluble in aqueous phase, in Schlumberger ECLIPSE E300 *CO2SOL* must be applies. The amount of CO_2 dissolved in water, and other aqueous phase properties, are computed using solubility data that is entered with either the *SOLUBILI*, *SOLUBILS* or *SOLUBILT* keywords. Due to lack of laboratory data of CO_2 solubility at different injection pressures, an analytical model was developed using reservoir water salinity at different reservoir pressure steps. Based on Chang method (Chang et al., 1996), properties of water are calculated for different pressures at reservoir temperature and given in Table 7. As can be seen from the table, water viscosity is considered not to be affected by CO_2 injection above 50°C temperature and therefore it remains constant.

Table 7 Water properties with dissolved CO_2

P (bar)	R_{sw} (sm^3/sm^3)	B_w (rm^3/sm^3)	μ_W (cP)	C_w (bar^{-1})
100	3,7	1,0277	0,3440	5,34E-05
120	4,0	1,0267	0,3440	5,39E-05
140	4,3	1,0258	0,3440	5,43E-05
160	4,7	1,0248	0,3440	5,47E-05
180	5,0	1,0239	0,3440	5,51E-05
200	5,3	1,0229	0,3440	5,54E-05
220	5,6	1,0219	0,3440	5,56E-05
240	6,0	1,0210	0,3440	5,58E-05
260	6,3	1,0200	0,3440	5,60E-05

Different scenarios were run with daily injection rates from 100.000 m^3/d to 500.000 m^3/d. The CO_2 injection rate was assigned to 3 wells located in the central part of the reservoir. Simulation results are presented in Table 8 and in Figure 11.

Table 8 Injection conditions

Scenario	Well shut in conditions	Injection wells		RF (%)
		Injection parameters	Number of wells	
Scenario I	$Qo_{min}=0.5 m^3/d$ WC=99%	Qinj=100.000 m^3/d BHIP (max)=200 bar	3	70.68
Scenario II		Qinj=200.000 m^3/d BHIP (max)=200 bar		71.5
Scenario III		Qinj=300.000 m^3/d BHIP (max)=200 bar		72.33
Scenario IV		Qinj=400.000 m^3/d BHIP (max)=200 bar		72.86
Scenario IV		Qinj=500.000 m^3/d BHIP (max)=200 bar		73.09

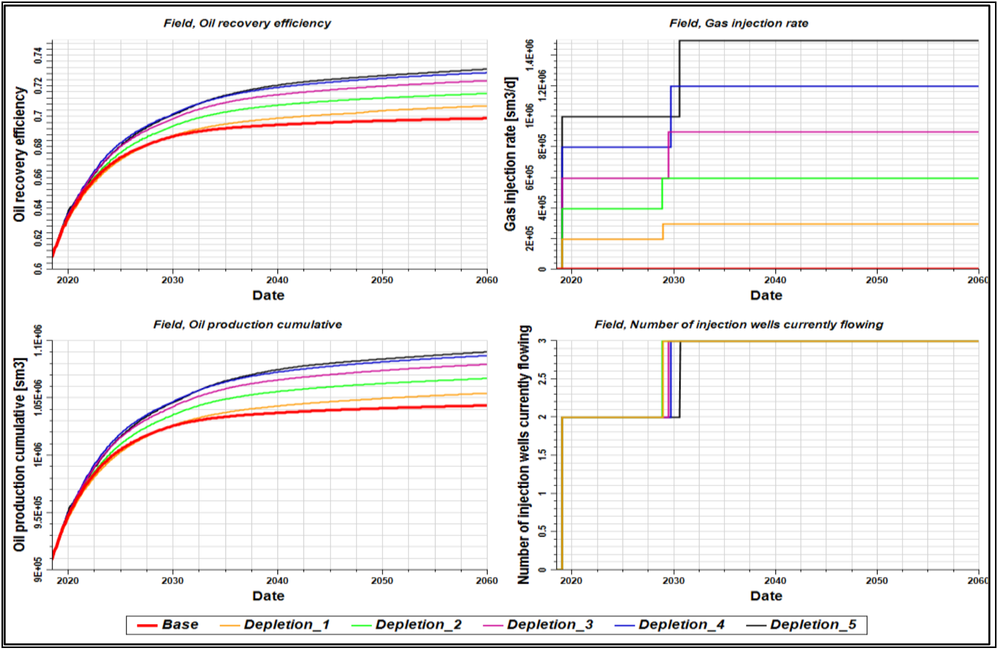

Figure 11 Simulation results for different injection scenarios

7 CONCLUSION

Estimating MMP using slim tube test is essential for CO_2 injection study as different approaches give a very wide range value of MMP.

Reservoir fluid characterization is considered as the most important parameter when planning CO_2 EOR study. A precise determination of C7+ critical values (Tc, Pc) and acentric factor ω has a significant impact on the minimum miscibility pressure.

The injection rate is the most important parameter that can affect the oil recovery factor, specifically in highly permeable reservoirs.

In the immiscible CO_2 injection, increasing the gas injection rate leads to faster movement of CO_2 front toward production wells which resulted in increase in CO_2 content and well GOR, thus it causes the shutdown of some of the production wells and the oil recovery factor will be less.

The amount of CO_2 solubility in aqueous phase has a large impact of the final recovery factor especially in highly water cut reservoir. A significant amount of CO_2 is soluble in aqueous phase, and this is causing a high CO_2 concentration on nearby production wells.

An interesting finding from the literature study is that an oilfield that has behaved well under waterdrive mechanism seems to behave well under CO_2 flooding. Another finding is that increased oil production, up to a certain point, is almost linear to the amount of CO_2 injected.

As this study did not cover reservoir fracture pressures, it is highly recommended to estimate this parameter and use it as a constrain, (otherwise simulator will increase bottom hole injection pressure to abnormal values to achieve given injection rates and oil RF can be unreal).

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