Iranian Journal of Oil & Gas Science and Technology, Vol. 9 (2020), No. 4, pp. 68–84
http://ijogst.put.ac.ir

Screening of Enhanced Oil Recovery Methods in One of Iran's Offshore Oil Fields

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Highlights

- One of Iran's offshore oil fields was screened for enhanced oil recovery methods.
- The reservoir was sectioned into two parts with different fluid properties.
- Polymer flooding was ranked first with maximum matching with the screening criteria in the upper zone of the reservoir, and immiscible gas injection was selected for the other section of the reservoir.

Received: June 30, 2020; *revised:* August 21, 2020; *accepted:* August 23, 2020

Abstract

Enhanced oil recovery (EOR) is a vital part of the process of oil production from sandstone and carbonate reservoirs. Maintaining and increasing oil production from many fields require proper selection, design, and implementation of EOR methods. The selection of EOR methods for specific reservoir conditions is one of the most difficult tasks for oil and gas companies. Screening of different EOR techniques considering previous experiences from the methods applied in other fields is a first step in the recommendation of any costly EOR operations. In this paper, EORgui software was utilized to screen eight enhanced oil recovery methods in one of Iran's offshore sandstone oil fields. The reservoir is composed of two sections with different fluid properties, namely API, viscosity, and oil composition, but relatively homogeneous rock properties and high permeability (1500 mD). The results show that polymer flooding is technically the most suitable enhanced oil recovery method in the upper zone of the reservoir with a high percentage matching score of 90%, and immiscible gas injection with a matching score of 83% is ranked second. For the lower part of the reservoir containing a fluid with much higher viscosity, immiscible gas injection (83% matching) can be recommended. Furthermore, polymer flooding predictive module (PFPM) was utilized to investigate the impact of polymer concentration on oil recovery performance of the upper part with an ultimate recovery of about 40% at the optimum concentration.

Keywords: Enhanced Oil Recovery, EORgui Software, Polyacrylamide, Polymer Flooding, Screening Recovery Factor, Polyacrylamide

How to cite this article
Bahari Moghadam M, Fathalizade M, Screening of Enhanced Oil Recovery Methods in One of Iran's Offshore Oil Fields. Iran J. Oil Gas Sci. Technol., Vol. 9, No. 4, p. 68–84 2020.
DOI:

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1. Introduction

Enhanced oil recovery (EOR) is a vital part of oilfields life. EOR methods such as gas injection, chemical methods, and thermal techniques have been applied in many fields around the world for increasing oil recovery. The performance of any EOR project is highly dependent on reservoir characteristics and fluid properties (Kamari et al., 2014). Hence, it is not feasible to apply one particular method to all oil reservoirs. In addition, operation conditions and economic analysis must be considered for any successful EOR project. EOR operations are highly costly, and considering reservoir complexity and uncertainty along with the unstable oil market price, a careful screening must be carried out before any decision-making process. The advantage of performing screening is to find the best EOR technique without using reservoir simulation and history matching tools. Thus, the evaluation of primary screening of EOR projects is an effective approach. Technical screening is the first step for the selection of any EOR methods. Hence, many methods have been developed based on data gathering and lessons learned from the application of EOR to many onshore and offshore fields (Gharbi, 2005; Al-Adasani and Bai, 2011; Bang, 2013; Moreno et al., 2014; Suleimanov et al., 2016; Zhang et al., 2019).

Field data on numerous EOR projects around the world have been collected, and the optimum reservoir/oil characteristics of the successful projects have been specified in the literature. These screening criteria can be employed to evaluate the applicability of different EOR methods before any detailed studies. Therefore, the evaluation of an EOR project via primary screening appears to be a very effective tool (Alvarado et al., 2002; Fereidooni et al., 2012). In the past few decades, screening of EOR techniques has been performed at different levels, and many approaches, including statistical methods, machine learning, artificial intelligence, simulation, clustering, and other composite techniques have been employed for screening of EOR methods in reservoirs (Khojastehmehr et al., 2019). For the first time, Taber introduced a comprehensive table which was used for the development of many screening criteria. The criteria for fluid properties are API gravity, viscosity, and composition, while the formation type, the net thickness, the permeability, the depth, and the temperature of the reservoir are its characteristics. This table was based on three categories of miscible gas injection, modified water flooding methods, and thermal methods (Taber et al., 1996).

EOR screening can be classified in three broad types of conventional, geological, and advanced methods (Alvarado et al. 2010). Conventional screening has been widely used to find the best EOR technique without requiring reservoir simulation and history matching tools. Trujillo et al. (2010) described that conventional screening included four main stages: binary technical screening, analogies, benchmarking, and analytical prediction. Jensen et al. (2000) applied conventional EOR screening in Ekofisk field, and their results showed that the most proper EOR method was water-alternating-gas injection (WAG) and air injection. Conventional criteria may be sufficient at the early stages of screening, but there are some controls of EOR methods that require more detailed information on the geology of the reservoir being evaluated. The main geologic characteristics include trap type, depositional environment, lithology, type of structure, and diagenesis characteristics. Geologic screening is a way of looking at the reservoir type in the foregoing geologic terms that have been found to be important in managing risk or that correlate with process performance (Alvarado et al., 2010). Advanced screening techniques based on artificial intelligence, data mining, processing and analysis, and space reduction methods have been proposed in the literature. In the past few decades, different artificial intelligence methods, including artificial neural networks, fuzzy logic, machine learning, and expert systems have been used to develop screening. The development of this technique has been well documented in the literature (Gharbi, 2000; Shokir et al., 2002; Herna´ndez et al., 2002). Along with these steps, the laboratory tests can be used to facilitate EOR methods. The analytical or simplified numerical simulation can be combined with the screening phase to evaluate the field-scale performance of a reservoir with reservoir-data-driven segmentation procedures. Pilot testing plays a key role in evaluating the successful application of an EOR method in reservoirs; to this end, before field testing, the objectives of the pilot test should be clearly defined. Additionally, economic evaluations are used to rank EOR methods as part of the screening and decision-making process. If the selected EOR method is not beneficial or has inherent limitations in field application, the other recovery methods can be checked during the next decision-making period (Manrique et al., 2008). The workflow of the decision-making process of EOR methods is depicted in Figure 1.

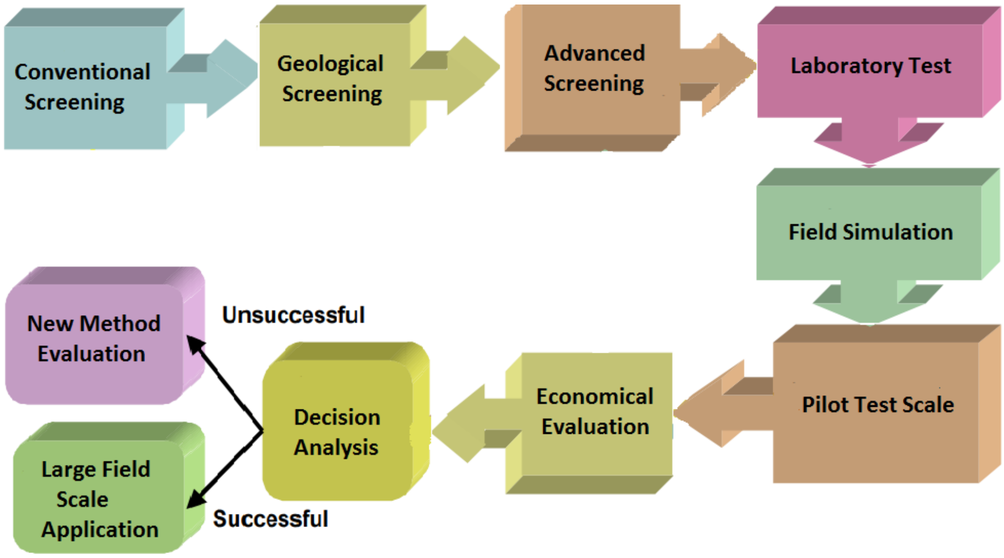

Figure 1

The workflow of EOR method decision-making.

The application of enhanced oil recovery in offshore oil fields has received significant attention due to the potentially enormous amount of recoverable oil (Bondor et al., 2005; Pan-Sang et al., 2016). However, EOR application in offshore fields is in its very early stage due to the more complex conditions of offshore fields compared to onshore oil fields, owing to the unique parameters present in the offshore fields (Pan-Sang et al., 2016). A number of successful EOR projects in the North Sea, the Gulf of Mexico, Brazil, and the Boahi Sea have been reported from 1975 to 2009 (Brodie et al., 2012; Kuuskraa, 2016; Pan-Sang et al., 2016, Vieira et al., 2020).

This study presents the technical screening process of different EOR methods for one of Iran's offshore sandstone fields which consists of two layers with different fluid properties. Due to the high cost of developing offshore fields and the significant difference in the reservoir fluid of this field, detailed EOR screening is required before making decision on production enhancement. On the other hand, a separate simulation study is necessary for such a unique reservoir and fluid properties along with the associated problems of selecting an EOR method for an offshore field. For this purpose, EORgui software, which covers a wide range of methods, including N_2 miscible injection; hydrocarbon gas miscible injection; CO_2 miscible injection; immiscible gas injection; alkaline surfactant polymer (ASP), micellar/polymer, and alkaline injection; polymer injection; in-situ combustion; and steam injection, was utilized. The final results are confirmed by using another software (EORt). In addition, the polymer flooding predictive module (PFPM) of the software was utilized to investigate the effect of polymer concentration on the recovery performance.

2. Material and methods

2.1. Conventional EOR screening method

In this study, conventional screening was applied to one of Iran’s offshore oil fields to rank and propose the more appropriate EOR methods. A list of EOR screening software packages and their criteria are presented in Table 1 (Ivanov et al., 2012). Generally, these tools include two main stages: binary technical screening and analytical prediction. The first stage is based on the comparison of the reservoir characteristics and its fluid properties with the screening criteria. The purpose of this stage is to determine the EOR method(s) that will be efficient and can be implemented in the given field. In the next stage, analytical models are utilized exclusively for some EOR methods to estimate and predict the production rate, cumulative oil production, and recovery factor of any EOR methods.

Table 1

List of EOR screening software packages (Ivanov et al., 2012).

Software name	Reference	Company	Ability to evaluate the applicability of EOR method (number of methods)	Ability to forecast oil production (number of methods)	Used criteria
SWORD	Surguchev et al.	PETEC Software	11	11	Data base
EORgui	Trujillo et al.	Petroleum Solutions	9	6	Taber, Martin, Seright
SelectEOR (PRIze)	Alvarado et al.	Alberta Research Centre	17	14	author’s Data base
Screening 2.0	Trujillo et al.	I.C.P. ECOPETROL	19	2	Lewin, Farouq, Taber, Seright
Expert System	Shindy et al.	Ciaro University	> 10	-	Data base
Expert Analytical system	Ibatullin et al.	TatNIPIneft	> 60	-	Data base
Expert System	Shokir et al.	King Saud University	+	-	Data base

2.2. Software description

In this study, EORgui version 1.1 was utilized to quickly screen the possible methods for EOR in field “A”. The software is based on the screening criteria of Taber, Martin, and Seright. EORgui software has the ability to apply the screening criteria of nine EOR methods and determine the most appropriate method. Additionally, the software includes six different predictive models which can be used to forecast the incremental oil production of different EOR techniques and perform sensitivity analysis so as to investigate the effect of controlling parameters on their performance (EORgui 1.1 Software

Technical Manual, 2016). EORgui was selected since it is a more comprehensive tool compared to other available software packages. It not only has general methods such as chemical or gas injection methods but also possess subdivisions such as polymer, alkaline–surfactant–polymer (ASP), miscible (CO_2, N_2, and HC), immiscible, etc.

3. Field description

One of Iran's offshore oil fields in the northwest of the Persian Gulf (Field A) was considered as a case study. The main reservoir characteristics and its fluid properties are listed in Table 2. Field A was discovered in 1962 by National Iranian Oil Company (NIOC), and 14 wells had been drilled in this field by 2001. The production from this field started in 1967 and continued until 1979; the development phase of the field was completed in 1999. The field is a domal structure related to Khafji-Nowrooz arch and is created with the assistance of salt flowage. As shown in Figure 2, many oil fields have been explored offshore in Iranian and Arabian areas along this arch. The north–northeast trending Khafji-Nowrooz arch is an important offshore structure. The arch plunges slowly toward the north–northeast, and it is asymmetric with a steeper western flank (Internal Documentation of Field A, 2016).

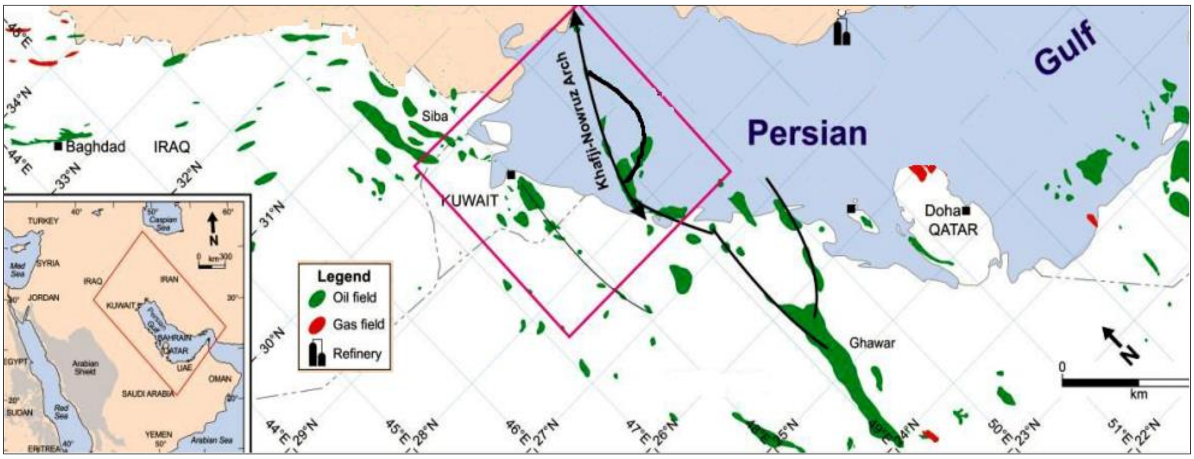

Figure 2

The map of the location of field A in the northwest of the Persian Gulf (Internal Documentation of Field A, 2016).

Figure 3 shows the litho-stratigraphy structure of oil filed A versus depth. Similar to most of the oilfields in this region, oil is produced from layers Burgan and Ghar. The Burgan reservoir is subdivided into three sublayers of A, B, and C. Burgan sublayers A and C contain a large amount of shale, while Burgan sublayer B is a relatively clean sandstone. Burgan sublayer B consists of three portions based on the size and shape of grain particles as follows (Internal Documentation of Field A, 2016):

- **Sand portion** consists of medium-to-large, coarse quartz grains, and—in some parts—fine, well-rounded, well-sorted, spherical, unconsolidated, and colorless/amber quartz grains.
- **Substrate portion** consists of sand and shales containing medium, fine sand grains, and—in some parts—coarse, well sorted, and colorless quartz grains.
- **Shale part,** which is dark gray to brown in color, contains impure hydrated silicates of iron and potassium with medium hardness, as well as iron sulfide, lime, and plant remains.

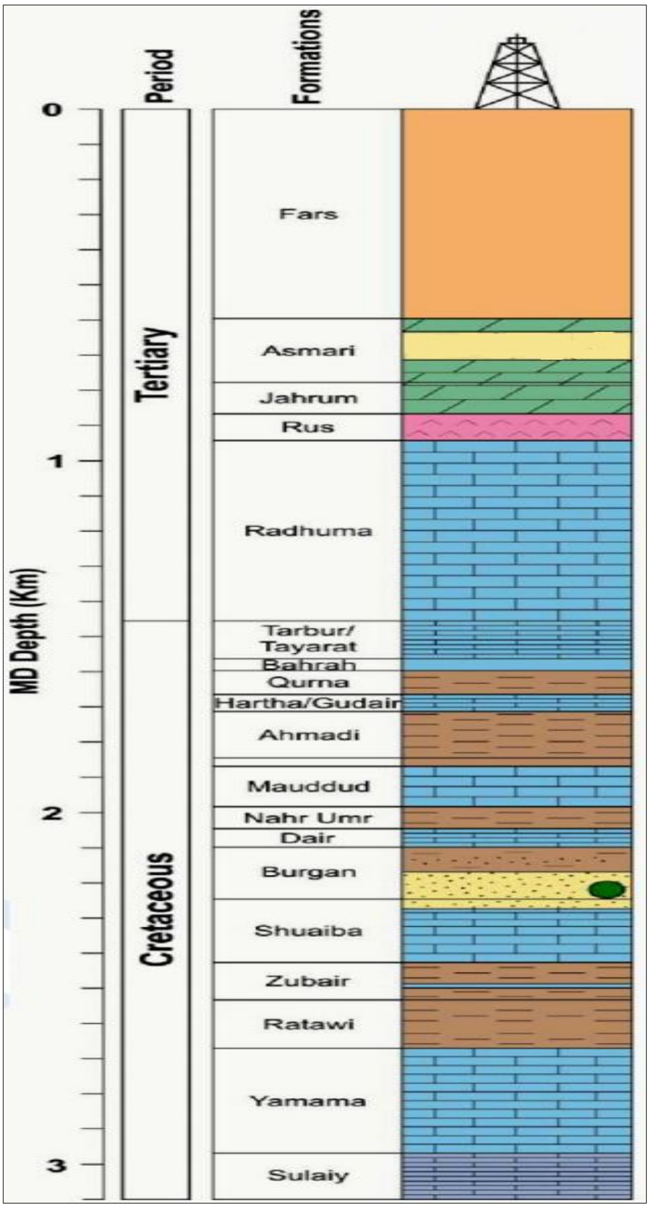

Figure 3

Stratigraphical subdivision of field A (Internal Documentation of Field A, 2016).

Table 2 presents reservoir rock characteristics and fluid properties of field A. Average rock porosity and permeability are similar almost for the whole reservoir. A little change in porosity from 27% to 31% is seen, which does not result in a big difference for quick screening purposes, and it is not a critical parameter for the evaluation of the screening. However, the fluid properties of the upper and lower parts of the reservoir are quite different. As can be seen in Table 2, oil viscosity and density (API) vary in a wide range. The upper part and the lower part both have similar oil components, but with different compositions; for instance, the oil in the lower part of the reservoir has higher viscosity, lower gas-to-oil ratio (GOR), and lower API gravity. Thus, for quick screening purposes, the reservoir was divided into two sections, namely the upper part and the lower part, mainly based on the fluid heterogeneity of the reservoir; this allows us to recommend more appropriate EOR methods.

Table 2

Rock characteristics and fluid properties of field A (Internal Documentation of Field A, 2016).

Properties	Value	Data source
Permeability (mD)	1500	Core data, drill stem test (DST), and modular formation dynamics tester (MDT)
Porosity (%)	27–31	Petrophysical log interpretation and core analysis reports
Depth (ft)	7099	Geological reports
Initial water saturation (%)	6	Petrophysical reports
Oil saturation (%)	0.94	Petrophysical, simulation, material balance, and 4D seismic reports
Reservoir pressure (psi)	2000	Testing reports
Reservoir temperature (°F)	182	Testing reports
Oil viscosity (cP)	15–500	Pressure–volume–temperature (PVT) and oil analysis reports
Formation type	Sandstone	Geological reports
Gross pay thickness (ft)	492	Petrophysical log interpretation reports and isopach maps
Net pay thickness (ft)	300	Petrophysical log interpretation reports and isopach maps
API gravity (°)	14–22	Laboratory test and PVT reports
Original oil in place (bbl)	9898×10^6	Full field study (simulation) material balance reports

4. Results and discussion

4.1. Quick screening

The reservoir data and the fluid parameters tabulated in Table 3 were used for the EOR screening of the upper part of field A. The oil API gravity ranged from 18 to 22 API°, so the average value of 20 API° was used in the software; also, an average oil viscosity of 15 cP, and a reservoir depth of 6950 ft were taken into account. Another important parameter was the permeability of the reservoir, and in this case study, an approximate permeability of 1500 mD was used. The other parameters used in this work include formation type, reservoir temperature, and reservoir pressure. Figure 4 graphically presents and ranks the recommenced methods. The screening finds polymer flooding to be the most suitable EOR method for the upper part of field A with a high percentage matching score of 90%. The in-situ combustion and immiscible gas methods are ranked next with a matching score of 83%. Nitrogen and hydrocarbon flooding are not strongly recommended for this case since they are ranked last.

Table 4 presents the results of the quick screening performed by EORgui software in a color coded mode. For each EOR process, the cells of the table indicate the best and the average value of each property as its criteria. A dark green cell represents the wells fulfilling the range of the criteria of a particular screening method, while a red-colored cell indicates that the reservoir parameters or fluid properties of the well do not satisfy the range of the criteria of a particular screening method. Light green implies that the well slightly meets the criteria of a particular screening method. Polymer flooding has six dark green cells such as API degree, viscosity, etc., which demonstrates that the characteristics of the upper zone of field A match well with its screening criteria.

Table 3

Reservoir characteristics and fluid properties of the upper part (Internal Documentation of Field A, 2016).

Reservoir and fluid properties	Value
API gravity	20
Oil viscosity (cP)	15
GOR (SCF/STB)	120
Permeability (mD)	1500
Initial water saturation (%)	6
Initial oil saturation (%)	94
Oil composition	C5–C12
Reservoir thickness (ft)	> 20
Reservoir depth (ft)	6950

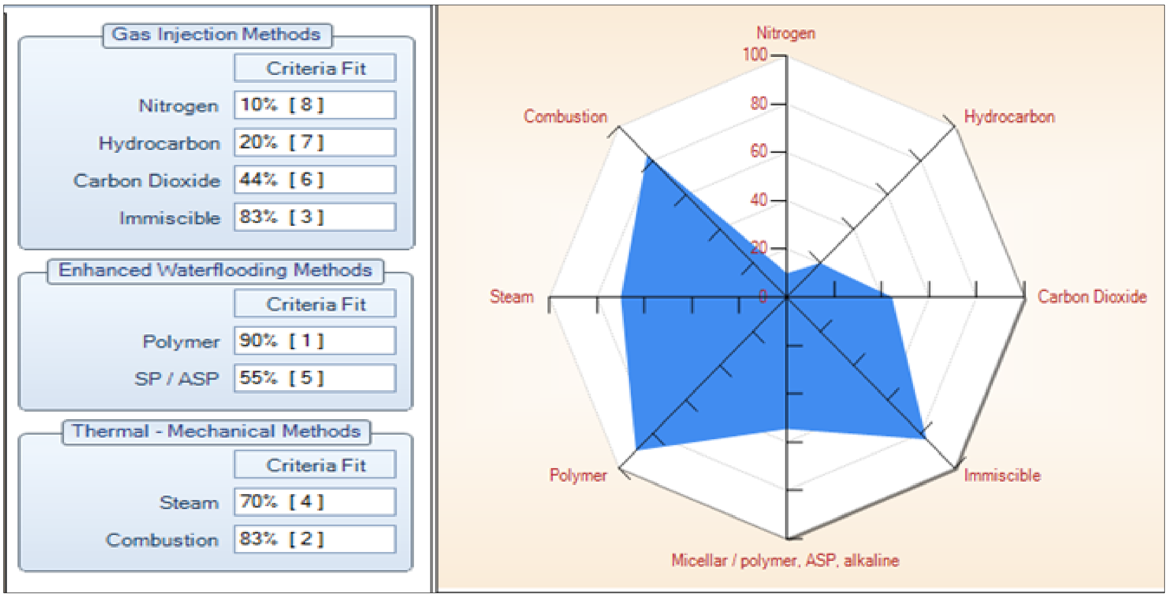

Figure 4

Graphical results of the screened EOR methods for the upper part of field A.

Similarly, the reservoir parameters and fluid properties summarized in Table 5 were used for conducting the EOR screening of the lower part of field A. The PVT reports clarify that the API gravity and viscosity of the oil of the lower part of field A, which are 14 API° and 400 cP respectively, are quite different from those of the oil in other parts of the reservoir. An average depth of 7050 ft was used for this section of the reservoir. The recommended EOR methods along with their ranks are depicted in Figure 5. It reveals that immiscible gas injection is the most favorable EOR method among potentially applicable EOR techniques for the lower part of field A with a matching score of 83%. In-situ combustion is ranked second among the potential methods with a matching score of 75%, while polymer flooding can be considered to be the third priority. The other methods like nitrogen and hydrocarbon injection are ranked last and are not recommended. The color-coded results of the quick screening performed by EORgui software are presented in Table 6. The characteristics of the lower part of field A better match the range of the screening criteria of immiscible gas injection with four dark green cells.

Table 4

Color-coded results of the screened EOR methods for the upper part of field A.

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

Table 5

Reservoir data and fluid properties of the lower part of field A (Internal Documentation of Field A, 2016).

Reservoir and fluid properties	Value
API gravity	14
Oil viscosity (cP)	400
GOR (SCF/STB)	60
Permeability (mD)	1500
Initial water saturation (%)	6
Initial oil saturation (%)	94
Oil composition	C5–C12
Reservoir thickness (ft)	> 20
Reservoir depth (ft)	7050

Table 6

Color-coded results of the screened EOR methods for the lower part of field A.

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

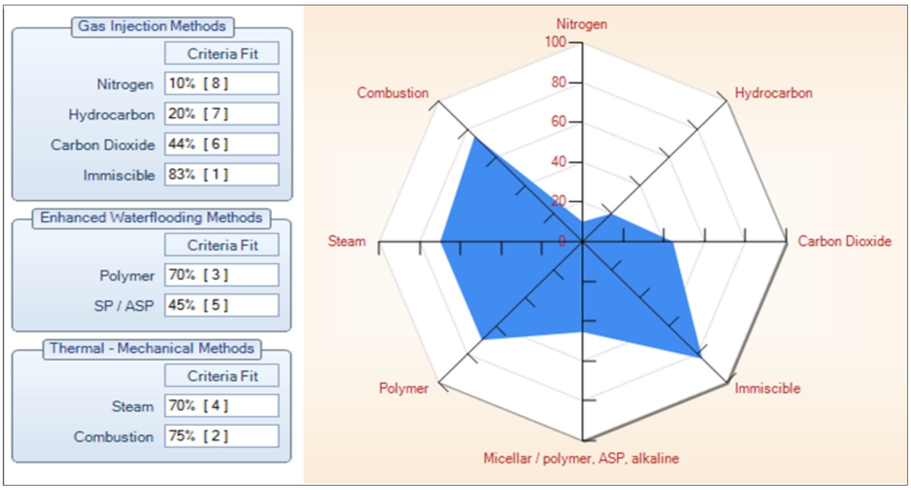

Figure 5

Graphical results of the screened EOR methods for the lower part of field A.

It is worth mentioning that this is just a technical screening, and other limitations such as operational conditions and economic criteria must be taken into account. In addition, a full-scale reservoir simulation of the methods selected in this study, namely polymer flooding and immiscible gas, is required for making the final decision. For example, for the upper part of field A, an uncertainty in oil API gravity from 20, to 15, or to 40 does not change the polymer rank. Also, a minimum viscosity of 15 cP was considered since a viscosity between 10 to 150 cP is favorable for the polymer flooding; for the normal changes in the fluid viscosity, polymer flooding method is selected. Moreover, high rock permeability (1500 mD) is a good option for polymer flooding. Any considerable change in average permeability from –20% to +20% does not remove polymer flooding method from the list; to this end, a k value of larger than 10 mD is required. Depth, temperature, and thickness are the almost fixed parameters. However, reservoir parameters are also favorable for immiscible gas injection, which may be considered as the first option based on the economic and operational conditions. To confirm the results of EORgui software, another screening software package, namely EORt, was also used; the same methods of polymer flooding for the upper part of field A and immiscible gas for the lower part of field A were selected again.

4.2. Analytical prediction of polymer flooding

Polymer flooding is one of the chemical EOR methods which has led to positive results in increasing oil recovery compared to conventional water flooding. The addition of water-soluble polymer to the waterflooding causes water to move further through the reservoir rock, which improves sweep efficiency and hence increases oil recovery (Lake, 1989). The polymer flooding predictive module of the software was utilized to study the polymer flooding scenario. In polymer flooding, oil forms its own liquid phase, and water and polymer coexist in the aqueous phase, which thus results in a two-phase immiscible displacement system. In the PFPM, the power law Corey's model (1954) is used to estimate the relative permeability of the two-phase flow in the porous medium. At the polymer flooding endpoint, the relative permeability to oil K_{ro} (S_{wc}) ranged from 0.6 to 1.0, the S_{wc} ranged from 0.38 to 0.10, and the endpoint relative permeability to water K_{rw} (S_{orw}) ranged from 0.19 to 0.49, which corresponded to S_{orw} values of 0.18 to 0.32 (Skauge et al., 2015). In this study, endpoint relative permeabilities K_{rw} (S_{orw}) and K_{ro} (S_{wc}) were considered to be 0.38 and 0.74 respectively. Also, the values of Corey's exponent to water (C_w) and to oil (C_o) were selected to be 2.3 and 2.7 respectively as shown in Figure 6.

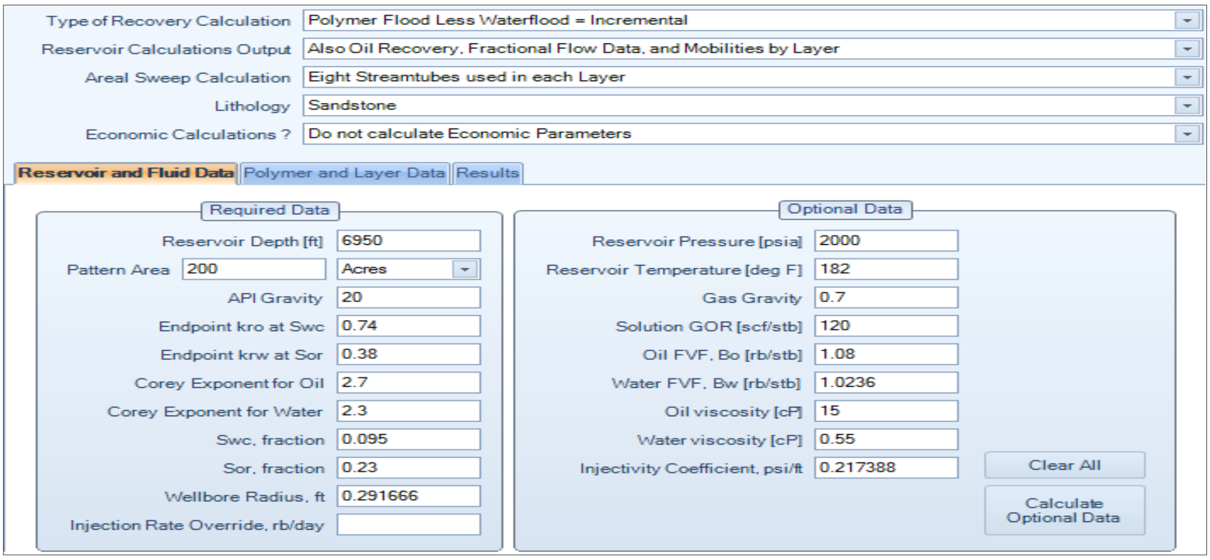

Figure 6.

Input data required to run the PFPM module of EORgui software.

Hydrolyzed polyacrylamide (HPAM) (Flopaam 3630S) with a molecular weight of 20×10^6 is the most commonly used polymer in EOR applications. It leads to a significantly greater recovery of oil since it possesses greater viscoelasticity than xanthan solutions (Yongpeng et al., 2015). Thus, the HPAM solution was selected herein as the polymer solution. The chemical structure of HPAM is demonstrated in Figure 7.

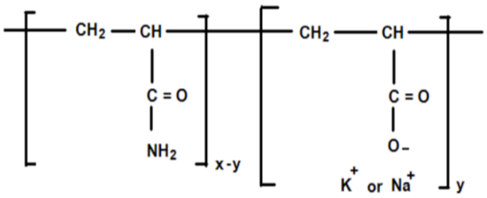

Figure 7

Chemical structure of HPAM (Aluhwal, et al., 2008).

The use of optimum polymer concentration is very crucial in the design of an effective polymer flooding project. The selected polymer concentration profoundly affects the cost, the economy, and the performance of a polymer flooding process. Usually polymer solutions are formed by dissolving polymer at a concentration ranging from 250 to 2500 ppm (0.25 to 2.5 kg/m) in water to attain the desired injection viscosities (Ayirala et al., 2014). In this study, concentrations of 500, 1000, and 1500 ppm were selected in order to find the effect of polymer concentration on the effectiveness of polymer flooding in the upper part of field A.

The other input parameters of the software are adsorption coefficient, resistance factor, and residual resistance factor of polymer solution, which are functions of the solution concentration. When polymer particles travel in the porous media, some of them are adsorbed onto solid surfaces or trapped within small pores. The degree of adsorption depends on the properties of the polymer and the rock surface. The polymer adsorption in porous media, i.e. Γ (mg/g), was calculated by a mass balance relation (Knobloch et al., 2018):

$$\Gamma = (C_0 - C_e)\frac{V}{m} \tag{1}$$

where C_0 and C_e (mg/g) stand for the initial and equilibrium concentration of polymer solutions respectively, V (L) represents the volume of the polymer solution, and m (g) is the weight of the sand particles (adsorbent) used. It is evident that a higher concentration of polymer leads to more adsorbed polymer. The resistance factor (FR), also known as the mobility reduction, is a measurement of the decrease in the mobility of a polymer solution in comparison with injection water and can be calculated by:

$$F_R = \frac{\lambda_w}{\lambda_p} = \frac{K_{rw}/\mu_w}{K_{rp}/\mu_p} \tag{2}$$

Where λ_w and λ_p are the mobility to water and the mobility to polymer respectively; K_{rw} and K_{rp} stand for the relative permeability of water and polymer respectively; μ_w (cP) is water viscosity, and μ_p (cP) represents polymer viscosity. The residual resistance factor (FRR), also known as the permeability reduction, is the reduction of permeability due to a number of mechanisms such as polymer adsorption onto the rock surface, the mechanical retention of polymer in pores that are of smaller than the polymer macromolecules, and any other conditions that retain the polymer in the porous media. The residual resistance factor is defined as (Mishra et al., 2014):

$$F_{RR} = \frac{\lambda_w}{\lambda_{wp}} = \frac{K_w}{K_{wp}} \tag{3}$$

where λ_w is the initial water mobility, and λ_{wp} represents the water mobility after polymer injection.

A detailed calculation of these parameters is beyond the scope of this paper. A proper overview is given in the literature (Ramazani et al., 2010; Veedu, 2010). The physical properties of the polymer solution as the input parameters of the model were determined as summarized in Table 7 for three different polymer concentrations. Heterogeneity is accounted for by either entering the detailed layer data or using the permeability Dykstra-Parsons coefficient of a reservoir with a log-normal permeability distribution. The Dykstra–Parsons (DP) of reservoirs ranges from 0.2 to 0.9, where smaller values may be observed for relatively uniform reservoirs, and higher values may be calculated for highly nonuniform reservoirs (Green et al., 2006). The KDP coefficient and the number of layers were considered to be 0.2 and 5 respectively. For simplicity, the input parameters of the PFPM module is depicted in Figure 8 for a polymer solution at a concentration of 1000 ppm.

Table 7

Physical properties of HPAM polymer solution at different concentrations (Ramazani et al., 2010; Veedu, 2010).

Parameter	Value		
Polymer concentration (ppm)	500	1000	1500
Polymer viscosity (cP)	6.3	16.71	32.15
Polymer adsorption (lb/ac-ft)	40.38	44.32	45.80
Resistance factor	13.86	45.87	109.31
Residual resistance factor	1.21	1.51	1.87
Power law coefficient (mPa·sn)	4.8	5.27	5.43
Power law exponent	0.94	0.79	0.7

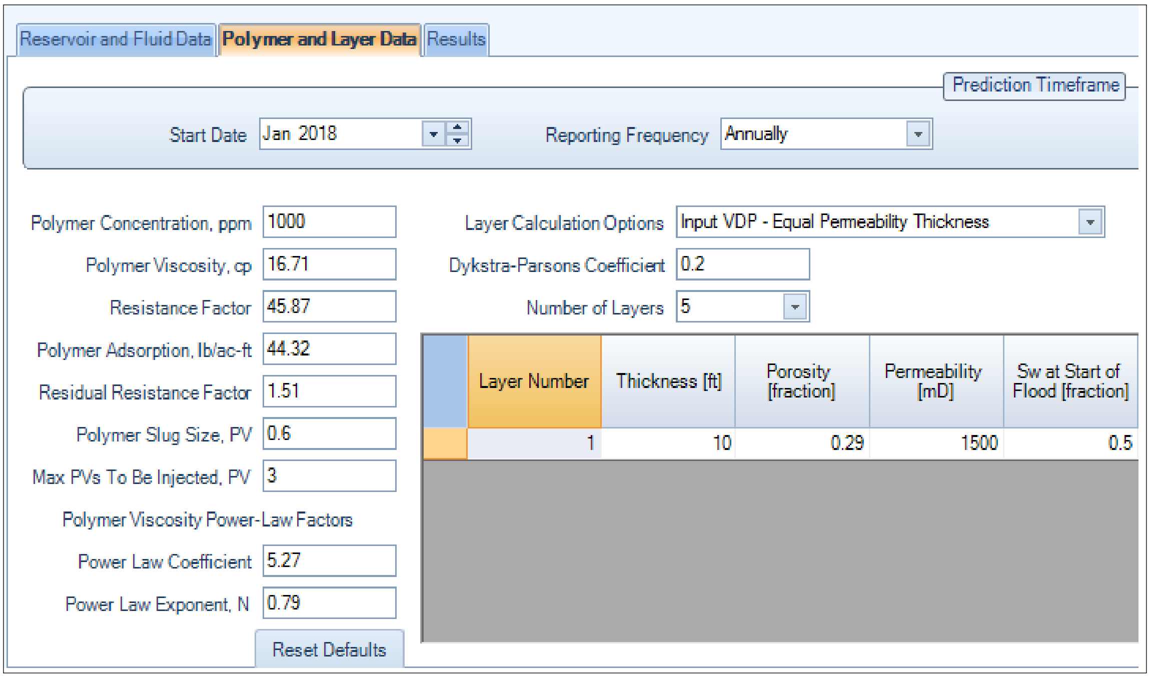

Figure 8

Polymer solution properties at a concentration of 1000 ppm and the data on the reservoir layer.

The polymer flooding predictive model was run for a polymer slug size of 0.6 pore volumes (PV) and the maximum injection volume of 3.0 PV. Figure 9 illustrates the trend in the rate of polymer injection and the cumulative injection volume during the flooding process for a polymer solution at a concentration of 1000 ppm. It is observed that the injection rate decreases and stops when reaching the setting value of the injection volume, and the cumulative volume of the polymer injection increases gradually and remains constant after the polymer injection stops.

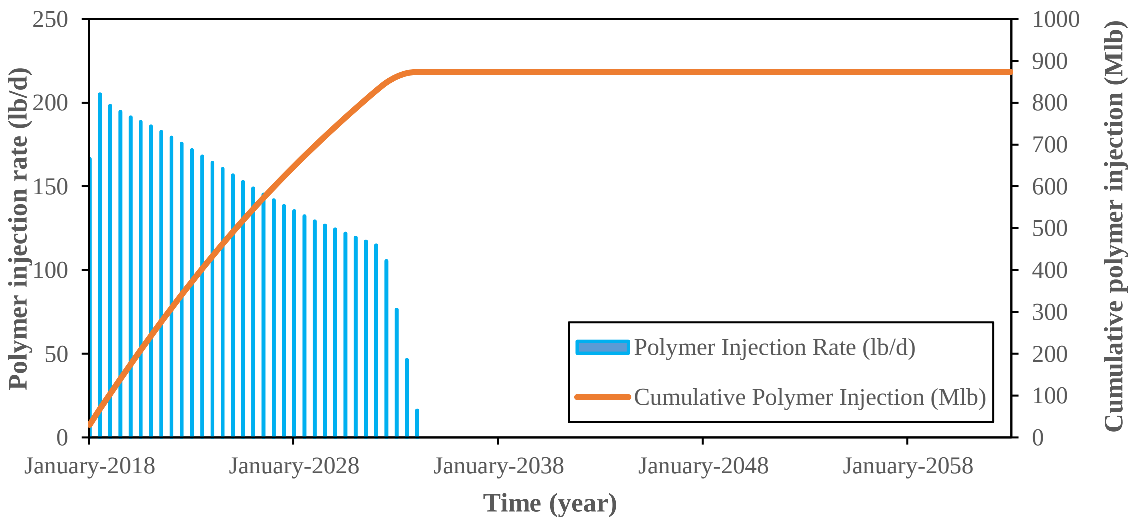

Figure 9

The cumulative injection and the injection rate of polymer solution versus time at a polymer solution concentration of 1000 ppm.

Figure 10 shows the oil recovery factor of the upper part of field A following the injection of polymer at different concentrations. The injection of polymer resulted in an improved oil recovery factor because of a more favorable mobility ratio between the injected and the displaced fluids. This effect appears to rise with an increase in the polymer concentration, which is in agreement with previous experimental results (Salehi et al., 2016). The simulation results imply that although the ultimate oil recovery enhances with increasing polymer concentration, but it takes a longer time to sweep the oil. This is due to the fact that as the polymer concentration rises, the viscosity of the polymer solution increases. Thus, as the viscosity of the polymer solution increases, its mobility declines, and it needs more time to displace oil bank. It is noticeable that there is a limit on the optimum polymer concentration to achieve a higher recovery factor at the early stages of the polymer injection process.

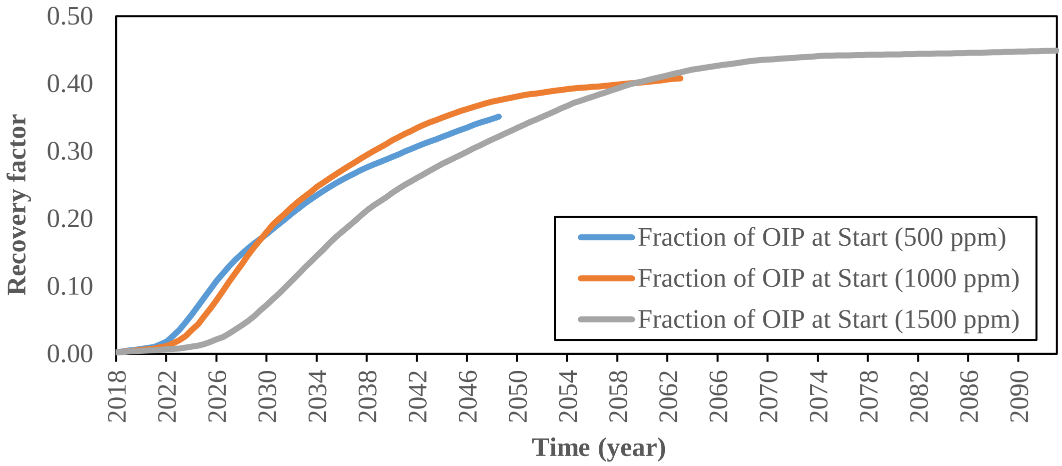

Figure 10

Oil recovery factor at different polymer concentrations.

5. Conclusions

In this study, a quick EOR screening of field A was performed using EORgui software. The reservoir was divided into two sections, namely the upper part and the lower part, based on the significant difference in fluid properties of the reservoir sections. EORt software was also utilized to confirm the results obtained from EORgui software. In addition, an analytical model was developed to evaluate the performance of the polymer flooding in the upper part of field A. The following conclusions can be drawn from the results of this case study:

- EOR screening using EORgui software shows that the upper part of field A is a good candidate for polymer flooding with a matching score of 90%. Immiscible gas injection is ranked second with a matching score of 83%.
- Immiscible gas injection is more appropriate for the lower part of the field.
- Economic evaluation of the methods proposed in this study along with the operational conditions must be considered for making the final decision.
- A comprehensive reservoir zonation, based on the accurate distribution of rock characteristics and fluid properties and the associated uncertainties, is required for detailed screening of EOR techniques in this field.
- The case simulation results demonstrate that the polymer concentration is a crucial parameter which controls the recovery factor of polymer flooding. The ultimate oil recovery improves with increasing polymer concentration; however, there is a limit for the optimum polymer concentration to obtain a higher recovery at the early stages of polymer injection.

Acknowledgements

The authors wish to express their appreciation to Department of Reservoir Engineering, Iranian Offshore Oil Company (IOOC) for supporting this work.

Nomenclature

API	American petroleum institute
ASP	Alkaline surfactant polymer
EOR	Enhanced oil recovery
EORgui	Enhanced oil recovery graphical user interface
GOR	Gas-to-oil ratio
HPAAM20	Hydrolyzed partially polyacrylamide with a molecular weight of 20×10^6
PV	Pore volume
RF	Recovery factor
WAG	Water-alternating-gas injection
WOR	Water-to-oil ratio

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